Supplemental Environmental Impact Statement

DOE/EIS-0158

Petroleum Production at Maximum Efficient Rate
Naval Petroleum Reserve No. 1 (Elk Hills)
Kern County, California

July 1993

FINAL
SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT

Project Sponsor:	The Department of Energy Naval Petroleum Reserves in California 28590 Highway 119 Tupman, California 93276
Proposed Action:	Petroleum Production at Maximum Efficient Rate Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California, DOE/EIS - 0158
Project Location:	The proposed site is located in a predominately rural area in Kern County, California, about 25 miles southwest of the City of Bakersfield, and approximately 100 miles north of Los Angeles.
Project Contact:	James C. Killen, Technical Assurance Manager, U.S. Department of Energy Naval Petroleum Reserves in California P.O. Box 11, Tupman, CA 93276 Telephone: (805) 763-6038
Project Abstract:	The proposed action involves the continued operation of the Naval Petroleum Reserve No. 1 (NPR-1) at the Maximum Efficient Rate (MER) through the year approximately 2025 in accordance with the requirements of the Naval Petroleum Reserves Production Act of 1976 (P.L. 94-258). NPR-1 is a large oil and gas field comprising 74 square miles. MER production primarily includes continued operation and maintenance of existing facilities; a well drilling and abandonment program; construction and operation of future gas cogeneration, and butane isomerization facilities; enhanced recovery projects; and continued implementation of a comprehensive environmental protection program.
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FOREWORD

This document, which is a Supplement to the Naval Petroleum Reserve No. 1 (NPR-1) 1979 final Environmental Impact Statement *(SEIS), has been prepared by the Department of Energy (DOE). Preparation of the SEIS has been a lengthy undertaking that represents the most comprehensive effort to date to assess and report the environmental consequences of NPR-1 activities.*

NPR-1 is a large (74 square miles) and profitable oil and gas field in south central California jointly owned and operated by the federal government and Chevron USA Inc. (CUSA). The government's interest is approximately 78% and CUSA's interest is approximately 22%. The federal government's interest is under the jurisdiction of DOE. The DOE/CUSA relationship is set forth in a Unit Plan Contract (UPC) that originally became effective in 1944. The UPC provides for producing federal and CUSA properties on NPR-1 in a cooperative manner (as a "unit") that maximizes the value of NPR-1 hydrocarbon resources.

NPR-1 was established by Presidential Executive Order in 1912 for national defense purposes. For the most part, the facility was maintained in a reserve shut-in status until 1976. Since then, production has been at the maximum efficient rate (MER), pursuant to the Naval Petroleum Reserves Production Act of 1976 (Public Law 94-258) which was passed as the result of oil shortages in the 1970's. MER is the maximum rate that optimizes ultimate hydrocarbon recovery and economic return.

NPR-1 production peaked at approximately 180,000 barrels of oil/day in 1981. Since then, production has declined steadily in a manner typical of oil field operations; current oil production is approximately 70,000 barrels/day. In addition to oil, NPR-1 produces large quantities of natural gas and natural gas liquids (NGL's) consisting of propane, butane, and natural gasoline. Current natural gas and NGL production is approximately 305-327 million cubic feet/day and 420,000-440,000 gallons/day, respectively. Estimated remaining oil reserves in 1988 were 524.4-831.5 million barrels. Estimated remaining gas reserves in 1988 were 1,790-2,497 billion cubic feet. NPR-1 hydrocarbon product is delivered on-site to CUSA and government purchasers. Government receipts are deposited in the United States Treasury. It is anticipated that NPR-1 would continue to be profitable until 2010-2025, and perhaps much longer.

The basis for the SEIS proposed action is the April 1989 NPR-1 Long Range Plan which describes a myriad of planned operational, maintenance, and development activities over the next 25-30 years. These activities include the continued operation of existing facilities; additional well drilling; expanded steamflood operations; expanded waterflood programs; expanded gas compression, gas lift, gas processing and gas injection; construction of a new cogeneration facility; construction of a new isobutane facility; and a comprehensive environmental program designed to minimize environmental impacts. Based on the results of planning activities it is possible that future development could result in exceeding some of the environmental impacts that *were projected in the 1979 EIS. Accordingly, the decision was made to prepare an SEIS, and a Notice of Intent was published in the Federal Register on April 4, 1988 (53 FR 10922).*

The SEIS addresses all major environmental impact areas for the proposed action and alternatives to the proposed action. Major areas of investigation include geology and soils, wastes, water, air, the terrestrial biota (including threatened and endangered species), cultural resources, land use, socioeconomics, and other risks. The primary areas of concern are potential adverse impacts to the endangered San Joaquin kit fox and to useful groundwater aquifers on the periphery of and adjacent to the site. As the analysis indicates, NPR-1 management recognizes the risks, and comprehensive programs are well established to mitigate impacts (and risk of impacts), monitor mitigation success, and design and implement additional mitigations, as appropriate. In addition to adverse impacts, the proposed action includes numerous activities that would impact favorably, including well and facility abandonments, habitat reclamation, additional secondary containment facilities, formal closure of waste sites, repair/replacement/relocation of aged facilities in sensitive areas, and reductions in hydrocarbon and nitrogen oxide emissions.

A Notice of Availability of the Draft SEIS was published in the Federal Register on June 5, 1992, (57 FR 24038), establishing a public comment period ending July 31, 1992. Comments were received from various public agencies and interested individuals. All comments were considered, and the Draft SEIS was revised appropriately.

Questions regarding the SEIS may be directed to Mr. James C. Killen, DOE, NPRC Technical Assurance Manager and the SEIS Project Manager. Mr. Killen can be contacted either by writing the Department of Energy, Naval Petroleum Reserves in California, P.O. Box 11, Tupman, California, 93276, Attn: James C. Killen, or by calling (805) 763-6038.

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ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
bbl	barrel(s)
BLS	Bureau of Labor Statistics
bp	before present
BPOI	Bechtel Petroleum Operations, Inc.
BTU	British Thermal Unit(s)
CAAQS	California Ambient Air Quality Standards
CARB	California Air Resources Board
CCR	California Code of Regulations
CDFA	California Department of Food and Agriculture
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CEQ	President's Council on Environmental Quality
CFR	Code of Federal Regulations
C_6H_6	benzene
CL	ceiling limit
CLGL	Closed-loop Gas-lift
cm	centimeter(s)
CNEL	Community Noise Equivalent Level
CO	Carbon monoxide
Cr^{+3}	Trivalent chromium
Cr^{+6}	Hexavalent chromium
CUSA	Chevron U.S.A. Inc.
CVRWQCB	Central Valley Regional Water Quality Control Board (Calif.)
d	day(s)
dBA	decibel(s), A-weighted
DGZ	Dry Gas Zone
DOE	U.S. Department of Energy
DOG	California Division of Oil and Gas
DSEIS	Draft Supplemental Environmental Impact Statement
EA	environmental assessment
EC	electrical conductivity
EDD	Employment and Development Department of the State of California
EG&G/EM	EG&G Energy Measurements, Inc.
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency

°F	degree(s) Fahrenheit
FCAA	Federal Clean Air Act
FERC	U.S. Federal Energy Regulatory Commission
ft	foot (feet)
ft^2	square foot (feet)
ft^3	cubic foot (feet)
FWS	U.S. Fish and Wildlife Service
FY	fiscal year
gal	gallon(s)
h	hour(s)
HC	hydrocarbons
hp	horsepower
HPI	high-pressure injection facility in Section 35R
H_2S	hydrogen sulfide
I/M	inspection/maintenance
in.	inch(es)
I-0	input-output analysis
ISC	industrial source complex
KCAPCD	Kern County Air Pollution Control District[1]
KCWA	Kern County Water Agency
Ker-xxx	Refers to Kern County Archeological site number xxx as recorded in the State of California files.
Kg	kilogram
km	kilometer(s)
Kw	kilowatt(s)
Kv	kilovolt(s)
l	liter
LACT	lease automatic custody transfer
lb	pound(s)
LD_{50}	median lethal dose
Ldn	day-night average sound level
LOAP	lean oil absorption plant in Section 35R
LOSF	light-oil steamflood
LPG	liquid petroleum gas
LRP	NPRC Long Range Plan, FY 1989-1995
LTS	low-temperature separation
LTS-1	low-temperature separation plant number one in Section 35R
LTS-2	low-temperature separation plant number two in Section 35R

m	meter(s)
M	thousand
m^3	cubic meter(s)
MBB	Main Body B Reservoir (Stevens Zone)
MCL	maximum contaminant level
MER	maximum efficient rate
MEQ	milliequivalent
mg	milligram(s)
mi	mile(s)
mi^2	square mile(s)
mi^3	cubic miles
MM	million
mmho	millimho(s)
MPTER	multiple point Gaussian dispersion algorithms with terrain adjustments
MSDS	material safety data sheets
MSL	mean sea level
MW	megawatt(s)
MWe	megawatt(s)-electric
NAAQS	national ambient air quality standards
NEPA	National Environmental Policy Act
NESHAP	national emission standards for hazardous air pollutants
NGF	natural gas-fired
NGL	natural gas liquid
NRHP	National Register of Historic Places
NO	nitrogen oxide
NORM	naturally occurring radioactive materials
NO_2	nitrogen dioxide
NO_3	nitrate
NO_X	nitrogen oxides
NPR-1	Naval Petroleum Reserve Number 1
NPR-2	Naval Petroleum Reserve Number 2
NPR-3	Naval Petroleum Reserve Number 3
NPRC	Naval Petroleum Reserves in California
NWS	Northwest Stevens
O_3	ozone
O&M	operations and maintenance
OPEC	Organization of Petroleum Exporting Countries
OSHA	U.S. Occupational Safety and Health Administration
Pb	lead
PCB	polychlorinated biphenyl
PCC	precombustion chamber

PDSEIS	Preliminary Draft Supplemental Environmental Impact Statement
PEL	permissible exposure level
PG&E	Pacific Gas and Electric Company
PM_{10}	particulate matter with aerodynamic diameters $\leq 10\ \mu m$
ppm	part(s) per million
PSC	prestratified charge
PSD	prevention of significant deterioration
psig	pounds per square inch gauge
PWI	produced water injection
RCRA	Resource Conservation and Recovery Act
RIMS	Regional Input-Output Modeling System (U.S. Department of Commerce)
RMCI	Research Management Consultants, Inc.
ROG	reactive organic gases; includes C_6H_6
s	second(s)
SARA	Superfund Amendments and Reauthorization Act
SCS	U.S. Soil Conservation Service
SDWA	Safe Drinking Water Act
SEIS	Supplemental Environmental Impact Statement
SHPO	State Historic Preservation Office (California)
SIC	standard industrial category
SIP	state implementation plan
SJVAB	San Joaquin Valley Air Basin
SJVUAPCD	San Joaquin Valley United Air Pollution Control District[1]
SMS	Systematic Management Services, Inc.
SO_2	sulfur dioxide
SO_4	sulfate
SoCal	Southern California Gas Company
SOZ	Shallow Oil Zone
SPCC	spill prevention control and countermeasure
STEL	short-term exposure limit
STLC	California soluble threshold limit concentration
TD	total depth
TDS	total dissolved solid(s)
TLBP	Tulare Lake Basin Plan
TLV	threshold limit value
TSCA	Toxic Substance Control Act
TSP	total suspended particulates
TTLC	California total threshold limit concentrations
TWA	time-weighted average

UIC	underground injection control
UNAMAP	User's Network for Applied Modeling of Air Pollution
UPC	Unit Plan Contract
USDA	U.S. Department of Agriculture
USDW	underground source of drinking water
USLE	Universal Soil Loss Equation
USGS	U.S. Geological Service
WBAN	Weather Bureau-Air Force-Navy
WDR	Waste Discharge Requirements
WET	waste extraction test
WKWD	West Kern Water District
yd^3	cubic yard(s)
yr	year
v	volt(s)
%	percent
μg	microgram(s)
μm	micrometer(s)
μmho	micromho(s)

1.Subsequent to the release of the DSEIS, administration of the Clean Air Acts was transferred from the KCAPCD to the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). References to KCAPCD should be read as being equivalent to the SJVUAPCD and its counterpart regulations.

SUMMARY

Introduction

Background and Purpose

This document provides an analysis of the potential environmental impacts associated with the proposed action, which is continued operation of Naval Petroleum Reserve No. 1 (NPR-1) at the Maximum Efficient Rate (MER) as authorized by Public Law 94-258, the Naval Petroleum Reserves Production Act of 1976 (Act). The document also provides a similar analysis of alternatives to the proposed action, which also involve continued operations, but under lower development scenarios and lower rates of production. NPR-1 is a large oil and gas field jointly owned and operated by the federal government and Chevron U.S.A. Inc. (CUSA) pursuant to a Unit Plan Contract (UPC) that became effective in 1944; the government's interest is approximately 78% and CUSA's interest is approximately 22%. The government's interest is under the jurisdiction of the United States Department of Energy (DOE). The facility is approximately 47,409 acres (74 square miles), and it is located in Kern County, California, about 25 miles southwest of Bakersfield and 100 miles north of Los Angeles in the south central portion of the state. The environmental analysis presented herein is a supplement to the NPR-1 Final Environmental Impact Statement of that was issued by DOE in 1979 (1979 EIS). As such, this document is a Supplemental Environmental Impact Statement (SEIS).

NPR-1 was created in 1912 by Presidential Executive Order for national defense purposes. Except for significant amounts of production during wartimes, the facility was maintained in what was essentially a shut-in reserve status until the mid-1970's; wells were drilled and facilities constructed, but for the most part production was limited to only that needed for readiness testing. Prompted by oil shortages, in 1976 Congress passed and the President signed the Naval Petroleum Reserves Production Act (the Act) providing for the production of NPR-1 at the MER, consistent with the UPC and all other laws and regulations, including federal, state, and local laws pertaining to the environment. MER is the maximum rate that optimizes both economic return and ultimate hydrocarbon recovery. In accordance with the Act and the UPC, CUSA's equity share of hydrocarbon product is delivered to them, and the government's share is sold by competitive bid in the open marketplace and/or retained by the government. Hydrocarbon product includes crude oil, natural gas, and natural gas liquids (NGL) consisting of propane, butane and natural gasoline. Government receipts are deposited in the United States Treasury, Miscellaneous Receipts Account. Production costs are shared between the government and CUSA on the basis of equity ownership of hydrocarbon products produced.

Following passage of the Act, DOE issued the 1979 EIS covering MER production in accordance with the requirements of the National Environmental Policy Act (NEPA). The scope of the 1979 EIS included all of the drilling, construction, operations and maintenance activities normally associated with developing a large and complex oil field utilizing generally accepted primary and secondary hydrocarbon recovery techniques (e.g., naturally flowing wells, artificial-lift, gas-injection, waterflooding, etc.). Among other impacts, the 1979 EIS addressed significant land disturbances, waste generation and disposal (including disposal of substantial quantities of saline water produced with oil and gas), and increases in air emissions. In addition to the 1979 EIS, an Environmental Assessment (EA) and Finding of No Significant Impact (FONSI) were issued by DOE in 1985 to support construction and operation of a tertiary recovery steamflood project that had not been included in the scope of the 1979 EIS.

As the result of field maturation and accumulated experience, current plans provide for the eventual implementation of recovery strategies and efficiency projects that are more aggressive than were originally believed necessary to comply with MER requirements. Most notably, current plans include an expanded drilling program (including horizontal drilling), a potential that expanded steamflooding may be needed, expanded waterflooding, expanded gas-injection operations, expanded gas-lift operations (enhanced artificial-lift), additional gas-processing and compression capacity, cogeneration, and butane isomerization. Based on current plans, it is projected that some environmental impacts could exceed those that were identified in the 1979 EIS and 1985 EA. Accordingly, the decision was made to prepare another NEPA document to update the environmental analysis of continued MER production. Pursuant to this decision, a Notice of Intent to prepare a Supplemental EIS was issued on April 4, 1988 (53 FR 10922). A Notice of Availability of the DSEIS was published in the Federal Register on June 5, 1992 (57 FR 24038), establishing a comment period ending July 31, 1992. All comments received during the review period were considered and revisions to the DSEIS in response to the comments were made as appropriate (see Appendix H).

Hydrocarbon Production, Reserves and Economics

Original recoverable oil-in-place has been estimated to be 1,384-1,691 million barrels. As of 1988, 860 million barrels had been recovered, 630 million as the result of MER production. Therefore, remaining recoverable oil reserves in 1988 were about 424-831 million barrels. Oil production peaked in July of 1981 at approximately 180,000 barrels/day. Since then, production has declined steadily in a manner typical of oil-field operations. During the fiscal year ending September 30, 1990 (FY 1990), oil production averaged approximately 82,000 barrels/day. FY 1992 oil production normally averaged 70,000 barrels/day.

Original recoverable gas-in-place has been estimated to be 2,404-3,111 billion cubic feet. As of 1988, 1,246 billion cubic feet of gas had been produced, leaving 1,158-1,865 billion cubic feet of original recoverable reserves still in place. Essentially all produced gas was processed to extract NGL products. As of 1988, over 2.1 billion gallons of NGL's had been extracted. Approximately 632 billion cubic feet of processed gas was reinjected into producing reservoirs to enhance oil recovery (oil being the more valuable commodity). Injected gas quantities are available for future recovery (in addition to original recoverable reserves still in place). In FY 1990, gas production averaged approximately 344 million cubic feet/day, gas injection averaged 200 million cubic feet/day, and NGL production averaged 541,000 gallons/day. In FY 1992, gas production, gas injection, and NGL production averaged approximately 313 million cubic feet/day, 207 million cubic feet/day, and 440,000 gallons/day, respectively.

All quantities of oil and NGL production are divided as equity product between the government and CUSA. Approximately 60% of total gas production is consumed in operations (injection, fuel, etc.). The balance is divided as equity product.

Cumulative government revenues during the period 1976-1990 were approximately $13.7 billion. Government costs during the same period were approximately $2.1 billion. Government revenues and costs in FY 1990 were approximately $547.4 million and $162.6 million, respectively. Based on best available information, it is anticipated that NPR-1 would continue to be profitable through the year approximately 2010-2025. For the period 1990-2010, a cursory estimate indicates that cumulative government revenues and costs could be approximately $14.5 billion and $4.5 billion, respectively. The foregoing figures are exclusive of the economic benefits and costs associated with CUSA's 22% interest.

Facilities

Of the 47,409 acres comprising the site, approximately 10,360 are owned in fee by CUSA. Almost all of the remaining 37,049 acres are owned in fee by the federal government. The major facilities at the site include:

- Approximately 2,315 active, idle, and abandoned wells as of 1988. Active wells include hydrocarbon producers, waterflood injectors, gas injectors, steam injectors, waterflood source water producers, and wastewater disposal injectors. By 1988, approximately 776 hydrocarbon producers had been equipped with pumping units driven either by electric motors or internal combustion engines.

- About 121 tank settings used to separate produced gas from produced oil/water.

- Five dehydration/lease automatic custody transfer (LACT) facilities for separating oil from water, disposing of the water, and transferring custody of oil product to CUSA and DOE product purchasers.

- Approximately 112,000 horsepower of gas compression used to transport and inject gas; compressors are driven either by electric motors or internal combustion engines.

- Three on-site gas-processing plants used to extract NGL's from produced gas with a total nominal capacity of about 300 million cubic feet/day. A gas-processing agreement with CUSA for use of another 60 million cubic feet/day of capacity off-site at their nearby 17Z gas plant.

- Four facilities for transferring custody of equity gas to CUSA and DOE purchasers, one of which is located off-site at CUSA's 17Z gas plant.

- Three facilities for storing, truck loading and transferring custody of equity NGL's to CUSA and DOE purchasers, one of which is located off-site at CUSA's 17Z gas plant.

- Three waterflood pump stations driven by electric motors capable of injecting approximately 200,000 barrels/day of water into producing formations.

- One steam-injection plant capable of injecting approximately 5,200 barrels/day of water as steam into producing formations.

- Fresh water system with a capacity of about 42,000 barrels/day.

- Electrical distribution system with a capacity of about 80 megawatts.

- Several emergency wastewater sumps (lined and unlined); two landfill/waste handling facilities, one of which contains an inactive hazardous waste unit that is in the process of being formally closed; a scrap/recycling yard; and numerous old abandoned waste sites (approximately 106) that are in various stages of review, investigation and remediation.

- Thirty-two permits allowing outside parties (third parties) to conduct a variety of surveys, construction, operations and maintenance activities on NPR-1 lands.

- Numerous building complexes, pipelines, communications systems, air monitoring equipment, vehicle fleets, fuel depots, fire water systems, roads, and other infrastructure.

Operations

The UPC provides that establishing the time and rate of production are the exclusive right of the government. The government also has the exclusive right to carry out the actual operation of the site. Production decisions, however (e.g., number, design, and location of wells, facilities, etc.), are made by an Operating Committee consisting of one government member and one CUSA member, each member having an equal vote.

NPR-1 operations consist of the following four major areas of activity: operations and maintenance; exploratory drilling; development drilling; and the planning, design, construction, and start-up of development facilities. Site activities are carried out by a permanent staff of approximately 800 DOE, CUSA and DOE contractor employees. In addition, approximately 400-500 subcontractor employees could be on-site at any given time. With the exception of the endangered species program, almost all operations are carried out by a DOE management and operating contractor. The current management and operating contractor is Bechtel Petroleum Operations, Inc. (BPOI). Management and operating contractors prior to BPOI included Williams Brothers Engineering Company and Standard

Oil Company of California (now CUSA). Endangered species and cultural resource activities are carried out by EG&G Energy Measurements, Inc. (EG&G/EM) under contract to DOE. Management guidance for the endangered species program is provided by an Endangered Species Advisory Committee consisting of representatives from the various NPRC organizations, the U.S. Fish and Wildlife Service, California Fish and Game, Bureau of Land Management and the California Energy Commission. DOE also has contracts with Jerry R. Bergeson and Assoc., Inc., for reservoir engineering support, and Research Management Consultants, Inc., for administrative and technical support. The total NPR-1 budget, including CUSA's share, was projected in FY 1989 to increase from approximately $172 million in FY 1989 to $225 million in FY 1995.

Proposed Action

The proposed action is to continue producing NPR-1 at MER in accordance with the requirements of the Naval Petroleum Reserves Production Act. This would involve the continued operation of existing facilities plus additional development. For the purpose of this SEIS, it has been assumed that operations and development activities would be carried out as described in the FY 1989-1995 Long Range Plan for as long as the field continues to be economic (approximately 2010-2025). The activities included under the proposed action to be initiated or continued in accordance with the Long Range Plan (LRP), and projected over the foreseeable future years, are summarized as follows:

- Approximate maximum production quantities would be 80,000-99,000 barrels/day of oil; 181,000 barrels/day of produced water requiring disposal; 415 million cubic feet/day of natural gas; 768,000 gallons/day of NGL's; 272 million cubic feet/day of gas injection; 254,000 barrels/day of waterflood injection; 37,000 barrels/day of fresh water injection as steam; and the acquisition of up to 75,000 barrels/day of fresh water for steam injection and other operational purposes. To the extent technically and economically feasible, plans are to recycle produced water for use as source water for waterflood operations. The balance of waterflood source water requirements would be withdrawn from NPR-1 groundwater aquifers in the Tulare Formation. Current groundwater withdrawals for this purpose are about 148,000 barrels/day. It is anticipated that as proposed recycling projects become operational, groundwater withdrawals could decline substantially. Produced water that is not recycled would be disposed of into the Tulare Formation (UIC exempt aquifer). Currently, approximately 80,000-100,000 barrels/day of produced water are disposed of in this way. As recycling projects become operational, disposal into the Tulare should decline.

- Continued operation and maintenance of all existing facilities.

- A program to drill, redrill, or deepen approximately 382 wells, 148 of which would be for the proposed steamflood project described below.

- A program to perform approximately 2,663 well remedial jobs (such as stimulations, recompletions, artificial-lift installations, and conversions) as needed to ensure efficient operation and maintenance of approximately 2,697 wells.

- A program to abandon approximately 1,080 wells.

- Construction and operation of approximately 46,250 horsepower (37,500 horsepower gas; 8,750 horsepower electric) of additional gas compression for gas-lift projects, gas-injection projects, and the continued transportation of field gas as reservoir pressures decline.

- Construction and operation of compression and processing facilities to compress, transport and process up to an additional 100-150 million cubic feet/day of gas on-site (fourth NPR-1 gas plant).

- A phased multi-year initiative to construct and operate a 148-well, 500-acre, 625 million BTU/hour steamflood project which, if fully implemented, would increase steam injection by approximately 33,000-34,000 barrels/day of fresh water. Implementation of individual phases would be dependent on the technical and economic success of preceding phases. The need to expand the capability of the fresh water system to accommodate the project would be addressed within the scope of each phase.

- Construction of new facilities and increased use of existing facilities as needed to expand waterflooding by approximately 106,000 barrels/day.

- Construction and operation of a 42 megawatt cogeneration facility.

- Construction and operation of a 170,000-220,000 gallon/day butane isomerization facility.

- Activities to permit third parties to construct, operate and maintain pipeline projects, geophysical surveys, and other projects/activities on NPR-1 lands. Permits would address NPR-1 legal, technical, environmental, safety, security and other requirements for the on-site and off-site components of each activity. Approximately 3-4 third-party projects are anticipated each year.

- Projects to investigate, remediate, or otherwise manage numerous old and inactive waste sites.

- A program to reclaim/revegetate by about the year 1998 approximately 1,045 acres of disturbed lands not needed for operations. Additional areas also would be reclaimed/revegetated as they are identified as no longer needed for operations.

- A comprehensive environmental program designed to address all aspects of environmental protection.

Alternatives to the Proposed Action

The primary alternatives to the proposed action are (1) no future development (no action) (Alternative 1); (2) future development as specified in the proposed action, but without the steam expansion, the fourth gas plant, or the cogeneration project (Alternative 2); and (3) future development as specified in the proposed action, plus the implementation of nonsteamflood tertiary-recovery techniques (Alternative 3). Another alternative is to sell the government's interest in NPR-1 (divestiture), a possibility requiring Congressional authorization that was identified in the Notice of Intent to prepare this SEIS. Proposed divestiture legislation was prepared for Congressional consideration, but to date Congress has not acted. For this reason, divestiture is no longer considered to be a viable alternative, and therefore it was not analyzed in this document. The U.S. Environmental Protection Agency proposed an additional alternative in their review and comment on the DSEIS. This alternative, which combines provisions of the no action alternative for the short term with provisions of the proposed action for the future, would not satisfy the purpose and need of the proposed action, which is to produce NPR-1 at the maximum efficient rate in accordance with the Naval Petroleum Reserves Production Act. Therefore, this alternative also was not analyzed in detail in this document.

Alternative 1 is considered to be a continuation of existing operations and maintenance only, without additional production-related developments. A detailed analysis of this alternative is presented herein. Under this scenario, hydrocarbon recovery would be greatly reduced over the long term (by up to approximately 58% of remaining oil reserves and 20% of remaining gas reserves), which does not conform to current legislated MER production and economic requirements. Alternative 3 was considered and dismissed because it does not appear that for the foreseeable future nonsteamflood tertiary-recovery techniques would satisfy project goals (based on available technical information and existing economic conditions). A viable alternative to the proposed action is Alternative 2, and a detailed analysis of this alternative was conducted.

Alternative 1 and Alternative 2 include all of the development projects needed to maintain safety and environmental quality that are included in the proposed action.

Existing Environment

The most significant aspects of the existing environment are summarized as follows:

- Approximate baseline production quantities used in this assessment were:

  Oil -- 99,000 barrels/day
  Gas -- 365 million cubic feet/day
  NGL's -- 654,000 gallons/day
  Produced Water -- 100,000-110,000 barrels/day
  Tulare Groundwater Production -- 148,000 barrels/day

Waterflood Injection -- 148,000 barrels/day
Produced Water Deep Zone Disposal -- 10,000- 20,000 barrels/day
Tulare Zone Produced Water Disposal -- 80,000- 100,000 barrels/day
Gas Processing -- 330 million cubic feet/day
Gas Injection -- 188 million cubic feet/day
Equity Gas Distributed -- 118 million cubic feet/day
Steam Injection -- 5,200 barrels/day water
Fresh Water Purchases -- 29,000 barrels/day

- Almost all of NPR-1 is located in the Elk Hills which are on the western side of the San Joaquin Valley. Elk Hills consists of a line of hills that are approximately 16 miles long and 6 miles wide with as much as 1,200 feet of relief. Some of NPR-1, consisting of most of the periphery, is located on or immediately adjacent to the valley floor. Almost all development has taken place in the upland areas of the site. The lower, flatland areas on the periphery of the site are comparatively undeveloped.

- Subsurface geology at NPR-1 is very complex. Hydrocarbons are extracted from four different geologic zones (Stevens Zone, Shallow Oil Zone, Dry Gas Zone, and the Carneros Zone) that are made up of 14 separate major reservoirs, or pools, ranging in depth from approximately 1,500 to 10,000 feet. Noncommercial hydrocarbons also are present in the Tulare Formation where groundwater is present.

- The southern San Joaquin Valley is an arid region with an average precipitation of approximately 5-6 inches/year. The excess of evaporation over precipitation is approximately 45 inches/year.

- Numerous older inactive waste sites (approximately 106) are present at NPR-1 as the result of past disposal practices that, although allowable under the regulations previously in force, are no longer acceptable. All of these sites have been addressed through remediation or Preliminary Assessments/Site Investigations.

- The San Joaquin Valley Air Basin portion of Kern County is a nonattainment area for federal and state limits on ozone, and is a serious nonattainment area for particulate matter of 10 microns or less (PM_{10}). Nitrogen oxides (NO_x) and hydrocarbons, both of which are emitted at NPR-1, are precursors to the formation of ozone. NPR-1 programs are well established to control NO_x, hydrocarbons, and other emissions in accordance with regulations. Formal rule-making activities by the Kern County Air Pollution Control District and the California Air Resources Board to control PM_{10} emissions are in progress. NPR-1 is participating in this activity, and programs to address eventual requirements have been incorporated into the planning process.

- There are no significant surface water resources on or near NPR-1, and low levels of precipitation preclude significant run-off. No wetland resources have been designated to date. However, some small widely scattered areas have been identified as potential wetland sites. These sites are not in or near any of the areas to be disturbed as the result of the proposed action. Plans are to evaluate these sites further for designation as wetlands, and to avoid them unless they are determined to not meet wetland criteria.

• The great majority of NPR-1 groundwater is in the Tulare Formation at depths that range from approximately 400 to in excess of 1,000 feet. This water is poor quality with no known beneficial uses except as waterflood source water. In approximately 1983, the NPR-1 Tulare Formation was exempted under the Underground Injection Control (UIC) Program as an underground source of drinking water when the Environmental Protection Agency approved the California Division of Oil and Gas application for primacy pursuant to Section 1425 of the Federal Safe Drinking Water Act (40 CFR Part 147, Subpart F). In addition, the NPR-1 Tulare Formation has been permitted since the 1950's by the Central Valley Regional Water Quality Control Board for surface disposal of produced wastewater. Groundwater beneath the valley floor on the periphery of and adjacent to the site is in the Alluvium and Tulare Formation. This groundwater is closer to the surface and it has beneficial uses requiring protection. The quality of groundwater on the western margin of the San Joaquin Valley in the vicinity of oil and agricultural development is generally lower than in other areas of the Valley. This has led some investigators to suspect that oil and agricultural activities may have contributed to some groundwater degradation. These investigators have theorized that at NPR-1, for example, it is possible that flow paths exist in the subsurface above the water table between useful groundwaters and unlined sumps that have been used intermittently over the years to dispose of produced wastewater (primarily during off-normal situations of short duration). This has been an area of intense investigation without resolution because in addition to a very complex hydrogeologic setting that is not well understood, there are other investigators who have theorized that lower groundwater quality in the western Valley is primarily the result of natural hydrogeologic factors. This is an area of continuing assessment by NPR-1 and local water authorities. NPR-1 wastewater sumps posing the greatest risks to groundwater quality are now lined.

• Construction of a project to recycle approximately 50,000 barrels/day of produced wastewater for use as waterflood source water was recently completed. Currently, the project is in the start-up phase; however, it does not appear that the facilities installed are capable of meeting waterflood water quality specifications. An initiative is in progress to identify and implement the actions necessary to make use of this major capital investment as intended. Additional recycling projects have been incorporated into the planning process.

• The northeast corner of NPR-1 is adjacent to the western boundary of a planned 20,000 acre water banking project: the Kern Fan Element of the Kern Water Bank Project. This project is part of the California State Water Project for recharging, extracting and storing State Water Project water. Current plans are to develop the water bank in a manner that maintains a safe distance between water that is eventually banked and the poorer quality groundwaters that currently are present on the western margins of the San Joaquin Valley.

• Projects are in various phases of planning, design and construction to repair, replace, modify, and relocate facilities on the northeast flank of NPR-1 that pose the greatest risk to the water bank and useful groundwaters in that area.

• Cumulative habitat disturbance due to development at NPR-1 amounts to approximately 6,546 acres (approximately 14% of the site), the great majority of which are in the upland areas of the site. Of this, approximately 3,306 acres were the result of MER production. To mitigate the impacts of disturbances, a comprehensive habitat reclamation/revegetation program was implemented and is well established. Reclamation/revegetation activities have taken place on approximately 1,689 acres of previously disturbed area identified as not needed for future operations (approximately 4% of the site). This results in a net disturbed and developed area of approximately 4,857 acres (10% of the site).

• NPR-1 supports a diverse variety of flora and fauna, including four federally endangered animals (the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, and Tipton kangaroo rat); one state threatened animal (San Joaquin antelope squirrel); and one federally threatened plant (Hoover's woolly-star). Another 27 plant and animal species that have been categorized at various levels of concern less than that of threatened are known to be present, or suitable habitat for them exists. Comprehensive endangered species and wildlife management programs to minimize biological impacts are well established.

• The minimum population of the San Joaquin kit fox in a study area comprising about half of the NPR-1 site declined from 153 animals in 1981, when population monitoring began, to approximately 28 animals in 1990. The great majority of the decline occurred during the period from 1981-1985. Although the kit fox population was relatively stable between 1986 and 1990, ranging from 33-50 animals from 1990-1991, the evidence suggests the population may have declined again. Data in 1992 suggests a significant increase. An analysis conducted in 1986 indicated that the decline in developed areas was about the same as the decline in undeveloped areas. Based on recent observations, very few kit foxes are now present in the developed upland areas of the site. The extent to which the foregoing is the result of development and/or natural factors is not known. Principal development impacts known or suspected to have occurred include vehicle mortality, harassment, and potential adverse effects of oil-field chemicals. Principal natural factors include the following: a significant decline in food supplies as the possible result of a long period of diminished precipitation; an increase in coyote abundance and predation; disease; and the possibility that the upland habitat comprising the great majority of the site is not as suitable for kit foxes as the lower flatland areas that comprise the site periphery and surrounding valley floor. Kit fox mortalities known to have occurred as the result of development averaged approximately three foxes/year during the 11-year period 1980-1990, almost all of which were due to collisions with vehicles. This decreased to an average of approximately one mortality/year during the most current 5-year period. Wildlife conservation and the relationship between oil-field development and kit fox population dynamics have been and continue to be the major focus of the NPR-1 wildlife and endangered species programs.

• A comprehensive sample survey of NPR-1 lands to identify cultural resources was recently completed in consultation with the State Historic Preservation Office. There are 40 recorded archaeological sites and 101 recorded historic sites on NPR-1. No NPR-1 sites are presently listed in the National Register. However, 12 prehistoric sites are potentially eligible for listing and evaluation of their listing eligibility is planned. Several archaeological and historic sites are also known to be present in areas adjacent to NPR-1.

• NPR-1 land use is consistent with that of the general area. The areas adjacent to NPR-1 consist almost entirely of oil and agricultural development. Some small communities are present nearby.

• Kern County has a broad industrial base with oil and agriculture being predominant. Kern County is the leading petroleum producing county in California and the leading oil producing county in the United States. During 1987, oil production averaged approximately 675,000 barrels/day, or about two-thirds of the total oil production in the state. In 1985 the total value of mineral production in Kern was about $6.5 billion. Kern County is also one of the top three agricultural producers in the United States. In 1985 the total value of all farm production exceeded $1.2 billion. The Kern County budget in 1987-1988 was approximately $443 million. The population of Kern County in 1987 was approximately 500,000, over half of which live in unincorporated areas. The city of Bakersfield is the most populous incorporated area with a population of about 190,000 in 1988. In 1987, median household income in Kern was approximately $20,700. The total Kern County labor force in 1986 was approximately 224,000, 11.8% of which were unemployed.

• NPR-1 operations are subject to the normal kinds of occupational and industrial risks associated with oil-field operations. The most significant of these include occupational injuries, gas fires/explosions and well blowouts. Occupational injury rates have typically been significantly less than the industry average. Since MER production began in the mid-1970's there have been six well blowouts which is consistent with industry experience based on level of activity. There also have been four gas explosions. Assessment and corrective action programs are well established to address actual incidents, near misses, and unusual occurrences. There have been no well blowouts or gas explosions since 1985.

Impacts of the Proposed Action

A summary of the impacts of the proposed action (favorable and unfavorable), together with planned mitigation, are provided by Table S-1 for each major impact area. Potential impacts to the San Joaquin kit fox and useful groundwater aquifers on the periphery of and adjacent to the site are the primary areas of concern. As explained in the Table, aggressive mitigation programs are in place to minimize environmental impacts and risks.

Impacts of the Alternatives to the Proposed Action

The near-term environmental impacts associated with Alternative 1 (no action) would be essentially the same as the impacts associated with continuing current operations as described in the existing environment. However, these impacts would decline rapidly and significantly in a manner that parallels the rapid and significant decline in production associated with this Alternative. Implementation of Alternative 1 (no action) would disturb approximately 741 acres of habitat on and off NPR-1 over the next 30 years. In comparison to no action, the proposed action would increase habitat disturbance by 828 acres, Alternative 2 would increase habitat disturbance by 378 acres, and both the proposed action and Alternative 2 would increase other areas of significant impact accordingly. Other areas of significant impact reduction, by similar comparison, would be air emissions, waste generation, fresh water requirements, and site operations safety.

A viable alternative to the proposed action is Alternative 2 which is the same as the proposed action except that it excludes the steamflood project, the fourth gas plant, and the cogeneration facility. It has been estimated that the excluded projects could have a combined net present value as high as $2 billion: i.e. the net present value of future project cash flows at 10% discount factors equals approximately $2 billion. The environmental impacts of Alternative 2 would be of the same type as those described for the proposed action but smaller in magnitude by an amount that equals the magnitudes of the impacts of the excluded projects. The most significant differences between Alternative 2 and the proposed action are that under Alternative 2 the drilling program and habitat disturbances would be significantly reduced. Of the 382 well drilling program associated with the proposed action, 148 wells are for the steamflood. If the steamflood project is not implemented, this would reduce the drilling program to 234 wells which would have a corresponding decrease on spent drilling fluids requiring disposal, risk of well leaks into groundwater, and other risks associated with drilling and well operations. Alternative 2 would result in habitat disturbance to 1,119 acres on and off of NPR-1 over the next 30 years which compares to 1,569 acres for the proposed action, or a reduction of 450 acres. All of this reduction would occur on NPR-1. Accordingly, the 979 acres of habitat disturbances on NPR-1 associated with the proposed action would be reduced to 529 acres. Other impact reductions would be an 8,500 to 34,500 barrel/day reduction in each of water injection as steam, produced wastewater requiring disposal, and fresh water requirements.

The proposed action represents the Department of Energy's preferred alternative.

TABLE S-1 Summary of Impacts and Mitigation for Each Major Impact Area of the Proposed Action

Impact Area	Adverse Impacts	Favorable Impacts/Mitigation Programs	Other Considerations
1. a. Geology	Increased withdrawals of oil/produced wastewater/gas from deep producing formations and continued withdrawals of source water from groundwater aquifers (for waterflooding deep producing formations) could increase the possibility of surface subsidence or induced seismic activity in the underlying geologic structures.	1. Injection of gas and water into deep producing formations to enhance oil and gas recovery would reduce the possibility of surface subsidence and induced seismicity. Planned projects to recycle wastewater for waterflood uses could reduce groundwater withdrawals significantly. 2. NPRC facilities would continue to be constructed to seismic safety building codes applicable to California. 3. Older facilities constructed to potentially outdated earthquake codes would be evaluated for seismic safety and upgraded as appropriate.	1. Deep formations are resistant to subsidence due to tight anticlinal structures. 2. Producing zones are well consolidated with a low potential for subsidence. 3. NPRC facilities have been constructed to applicable California earthquake codes.
1. b. Soils	Development related disturbances to approximately 1,569 acres on and off of NPR-1 over 30 years could increase water borne soil erosion in these areas. The NPR-1 portion of these disturbances would be 979 acres.	1. Amimoto and Soil Conservation Service erosion control measures would be followed in planning/design, and operational activities. 2. Implementation of the PM_{10} control program would decrease potential construction and operations related fugitive dust emissions/wind borne soil erosion rates over the short term. 3. Revegetation/reclamation of approximately 1,045 acres through 1998 would decrease potential soil erosion over the long-term on these areas. 4. Additional areas of existing development would be reclaimed following operational abandonment.	The amount, duration and frequency of precipitation and surface run-off are small, short, infrequent events.
2. Waste	1. The 382-well drilling program would generate significant quantities of nonhazardous spent drilling fluids. 2. Significant quantities of nonhazardous produced wastewater with high total dissolved solids (TDS) would be generated. 3. Oils, chemicals, and produced wastewater could be inadvertently spilled, creating wastes requiring disposal. 4. The current very low level of hazardous waste generation could increase slightly.	1. Toxicity of drilling fluids has been reduced due to elimination of hazardous additives. Waste minimization program initiatives would continue in this regard. 2. Planned projects to recycle wastewater for waterflood uses should reduce the volume of wastewater requiring disposal. 3. Inactive waste sites that accumulated over decades of operation, but are no longer needed, would be addressed/cleaned/closed in accordance with regulations. This includes the only hazardous waste facility on-site (currently inactive). 4. Projects would be implemented to enhance secondary containment around tanks. 5. All wastes would be disposed of in accordance with laws, regulations and DOE requirements. 6. Spill prevention, control and countermeasure (SPCC) plan.	1. The proposed drilling program would be significantly smaller than the past program which would reduce impacts correspondingly. Drilling fluid waste volumes have already decreased by almost one-half since 1987. 2. Precipitation and surface run-off at NPR-1 are comparatively small.

TABLE S-1 (cont'd)

Impact Area	Adverse Impacts	Favorable Impacts/Mitigation Programs	Other Considerations
2. Waste (cont'd)		7. Waste minimization plan. 8. Pollution prevention awareness program.	
3. Air	Net CO, total suspended particulates and PM_{10} emissions would be increased.	1. Net ROG, NO_x, and SO_2 emissions would be reduced. HC (a component of ROG) and NO_x are O_3 precursors. 2. Implementation of Kern County Air Pollution Control District Rule 427 NO_x reduction program projects would continue to reduce existing NO_x emissions. 3. NO_x monitoring program would continue. 4. Fugitive ROG/HC emissions monitoring program would continue. 5. PM_{10} control program would be implemented. 6. Compliance with applicable laws, regulations, and permits issued by government regulatory entities.	1. Kern County is in nonattainment for PM_{10}. 2. Kern County is in nonattainment for Ozone (O_3). 3. Proposed action would not qualify as a major modification subject to new source review or PSD review.
4. a. Surface Water	No significant adverse impacts.	1. Projects to reclaim drainages and restore local hydrologic regimes would be implemented. 2. SPCC Plan would be implemented to reduce spill effects. 3. See 1.b. above.	1. Surface run-off is minimal due to arid conditions. 2. Limited nearby surface-water resources.
4. b. Ground Water	1. Significant quantities of high TDS nonhazardous produced wastewater would be disposed of on-site into the Tulare Formation. Significant quantities of groundwater from the Tulare Formation would be withdrawn for waterflood source water purposes. 2. During off-normal situations, small quantities of produced wastewater would be released to lined and unlined sumps and secondary containment structures around tankage. 3. Oil, chemicals, and produced wastewater spills would occasionally occur. 4. The proposed 382-well drilling program would increase the risks of wells leaking oil and/or poor quality water into overlying NPR-1 groundwaters. 5. If flow paths exist between NPR-1 sediments and usable groundwater aquifers located adjacent to the site, these aquifers could be degraded by NPR-1 wastewater disposed of into the Tulare.	1. Projects to recycle wastewater for waterflood uses could reduce disposal into groundwater aquifers underlying NPR-1. Tulare groundwater withdrawal also could be reduced significantly. 2. Unlined wastewater sumps that are unnecessary would be eliminated and cleaned, closed, or managed as appropriate. 3. Projects would be completed to enhance secondary containment facilities. 4. Approximately 1,080 wells no longer needed would be abandoned, thus reducing the risk of well leaks into groundwater. 5. SPCC plan. 6. Wastewater sumps on the periphery of the site nearest usable groundwater would continue to be lined.	The NPR-1 Tulare Formation is exempted under the UIC Program as an underground source of drinking water. The groundwater in this aquifer is of poor quality with no known beneficial uses other than as a potential source water for waterflooding operations. 13.O-3

TABLE S-1 (cont'd)

Impact Area	Adverse Impacts	Favorable Impacts/Mitigation Programs	Other Considerations
4. b. Ground Water (cont'd)	6. Implementation of the proposed steamflood project could place additional demands on sources of fresh water.	7. Releases of wastewater to all sumps would continue to be limited to off-normal situations. 8. An analysis that is in progress to assess risks associated with hydrologic flow uncertainties would be completed. Based on preliminary results it appears that groundwater monitoring wells could be needed on the northeast portion of the site. Additional mitigation measures would be implemented if appropriate.	
5. Terrestrial Biota	Some destruction of plants, and death or injury to animals would occur. Of particular concern are threatened and endangered species, especially the federally endangered San Joaquin kit fox. From 1981 to 1985, the minimum kit fox population in the NPR-1 study area declined significantly and very few foxes are currently present in developed areas; it is not clear to what extent this was due to petroleum production activities and/or natural factors. Future impacts on listed species would probably be comparable to past impacts. Kit fox impacts known to have occurred during the 11 year period 1980-1990 include: (1) an average of about three kit foxes have been killed each year as the direct result of operations; during the most recent 5 years, this average declined to one/year; (2) another three/year were killed by vehicles on public roads adjacent to, but outside of, NPR-1's jurisdiction, and some of these vehicles could have been associated with NPR-1; and (3) 47 kit fox dens or potential dens were inadvertently destroyed or intentionally excavated. During the same period, two blunt-nosed leopard lizards were killed and four were harassed; and 72 giant kangaroo rats were assumed to have been killed when their burrow systems were destroyed, and another 4 were harassed. Specific adverse impacts of the proposed action would include potential for vehicle mortality; potential for inadvertent harassment; potential for contact with hydrocarbons and/or oil-field chemicals; and loss of approximately 1,569 acres of habitat over 30 years due to development activities (or .3% of the remaining undeveloped habitat in the southern San Joaquin Valley in 1979), 979 acres of which would be on NPR-1 (or 2.0% of the site). Threatened, endangered, candidate, or species of special concern could be impacted as the result of activities carried out under the Endangered Species Program.	1. Approximately 1,045 acres of disturbances not needed for operations would be reclaimed/revegetated through the year 1998, 685 acres of which would be on-site (or 1.4% of the site). As additional areas not needed for operations are identified, they also would be reclaimed. 2. A comprehensive endangered species program would continue. The effects of operations and mitigations, including habitat reclamation, would be monitored and appropriate programs to conserve threatened and endangered species would be implemented. Preactivity surveys would be used to site projects to minimize impacts. Studies and research to determine the relationship between operations and endangered species would continue. 3. Third-party projects (including both on-site and off-site components) would be required to comply with NPR-1 environmental, safety, legal, technical, security, and other requirements. 4. The endangered species program would continue to be managed in close association with applicable regulatory agencies and other industry organizations or representatives with endangered species expertise through the Endangered Species Advisory Committee, or by other appropriate means.	1. Kit fox population monitoring commenced in 1981. Immediately prior to 1981, precipitation was above average, sometimes significantly. Following 1981, precipitation declined significantly. It is suspected that this has resulted in a significant decline in food supplies that could have contributed significantly to the decline in kit fox numbers. 2. Coyote abundance increased significantly during the 1980's when kit fox population declines were most significant. Coyote predation has accounted for approximately 80% of kit fox mortalities for which a cause of death could be determined. 3. Most development on NPR-1 is in upland areas. There is evidence that upland areas may not be as suitable for kit foxes as the lowland areas on the periphery of and adjacent to NPR-1 where most kit foxes now live. 4. Of the 47 kit fox dens and potential dens previously destroyed, 22 were the result of a Southern California Gas Company third-party project (not an NPR-1

TABLE S-1 (cont'd)

Impact Area	Adverse Impacts	Favorable Impacts/Mitigation Programs	Other Considerations
5. Terrestrial Biota (cont'd)		5. Other features of the comprehensive Wildlife Management Plan would continue to be implemented in order to minimize impacts on all species and their habitat. 6. All Endangered Species Program activities would be conducted in strict accordance with requirements of permits and guidelines issued by state and federal agencies (such as trapping permits, etc.).	4. (cont'd) project) on NPR-1 and Bureau of Land Management lands to replace sections of major public utility gas transmission pipelines installed in the 1930's.Thiswas an atypical project that could not be sited to avoid impacts as usual because it involved the removal of "existing" pipelines. The SoCal pipelines would have required replacement irrespective of NPR-1 operations. 5. The maintenance of a fire break around NPR-1, which is part of the program to protect habitat from fire, was the cause of 66 of the past 76 cases of mortality and harassment of giant kangaroo rats. The other 10 cases were the result of the SoCal project.
6. Cultural Resources	Approximately 1,569 acres would be disturbed over a 30 year period, 979 of which would be on NPR-1. These disturbances could adversely affect cultural resources.	A comprehensive survey of NPR-1 cultural resources, designed in consultation with the State of California Historic Preservation Office (SHPO), recently has been completed. Based on the survey, a comprehensive cultural resource management plan would be developed and implemented in consultation with the SHPO. In addition, 12 prehistoric sites identified on NPR-1 during the survey would be tested to determine eligibility for listing on the National Historic Preservation Register.	Investigations conducted to date indicate that almost all non-oilfield-related cultural resources on NPR-1 are located on the periphery of the site away from the majority of planned ground disturbance.
7. Land Use	An additional 1,569 acres on and off NPR-1 would be committed to petroleum related activities over the next 30 years; of this, about 979 acres would be on NPR-1 (2.0% of the site).	1. Approximately 1,045 acres would be reclaimed/revegetated on and off of NPR-1 through the year 1998. Of this, 685 acres would be on NPR-1 (1.4% of the site). Additional lands would be reclaimed/revegetated as facilities no longer needed for operations are abandoned. 2. Activities explained in 1.b. and 6 above to mitigate impacts to the terrestrial biota and soils would also minimize adverse land use impacts.	Planned development on NPR-1 would be consistent with oil-field development already surrounding much of NPR-1.
8. Socio-economics	No significant adverse impacts.	An otherwise steep production decline would be reduced significantly, and petroleum resources ultimately recovered would be increased significantly. This would stabilize the NPR-1 employment base which in turn would help stabilize the local tax base, housing market, and trade sectors. Additional revenues would be available to offset the federal budget deficit.	

TABLE S-1 (cont'd)

Impact Area	Adverse Impacts	Favorable Impacts/Mitigation Programs	Other Considerations
9. Risk Assessment	In addition to the adverse impacts presented above, NPR-1 operations could result in well blowouts and fires/explosions, especially in connection with gas compressor operations. Occupational accidents would also occur.	1. A multitude of safety and environmental projects would be completed/ continued. These are currently in various stages of planning, design, construction, and operation and are the direct result of a myriad of NPR-1 and DOE internal investigations/appraisals including those associated with past fires/explosions, blowouts, and occupational accidents. 2. The risk of well blowouts and occupational accidents would be slightly higher than for the no action alternative, but significantly less than past operations. 3. NPR-1/DOE policies and procedures would be continued that stress intensive internal investigations/appraisals and comprehensive systems that emphasize corrective action identification, implementation, and monitoring.	1. Reservoir pressures have and would continue to fall which diminishes the possibility of blowouts, fires/explosions, etc. 2. Occupational accident rates at NPR-1 have been comparatively low.

1.0 INTRODUCTION AND DESCRIPTION OF THE PROPOSED ACTION

1.1 INTRODUCTION

1.1.1 Background

The following discussion summarizes the history of Naval Petroleum Reserve No. 1 (NPR-1) as it was described in detail in the NPR-1 1979 Final Environmental Impact Statement (EIS) (DOE 1979) prepared in accordance with the National Environmental Policy Act (NEPA).

Located in Kern County, California, about 25 miles southwest of Bakersfield (Figure 1.1-1), NPR-1 was created by an Executive Order issued by President William H. Taft on September 2, 1912. Except for a period between 1921 and 1927, when the Reserve was assigned to the Department of the Interior, management of NPR-1 was vested in the Secretary of the Navy until 1977. Since October 1977, management has been under the authority of the Secretary of Energy pursuant to the Department of Energy (DOE) Organization Act (Public Law 95-91).

The NPR-1 site comprises approximately 47,409 acres (74 square miles) of the Elk Hills, a long, narrow ridge about 16 miles long by 6 miles wide, oriented generally east-west in the southern San Joaquin Valley (see Figures 1.1-1 and 3.1-2). NPR-1 includes portions of seven townships, identified in Figure 1.1-1 by the letters Z, R, S, T, B, G, and M. Each township comprises 36 one-mile-square sections numbered 1 through 36. Each section is uniquely identified by section number and township: e.g., Section 35 in Township R is identified as 35R. NPR-1 contains production development at various levels in 90% of the 78 sections that lie partially or entirely within its civil boundaries. Within the boundaries of NPR-1, Chevron U.S.A. (CUSA) owns 10,360 acres (about 22%), and the remaining 37,049 acres are owned by the government (about 78%). NPR-1 is surrounded on three sides by extensively developed oil and gas fields that have been in production since the early 1900's. Extensively developed agricultural lands lie to the north and northeast of NPR-1. Naval Petroleum Reserve No. 2 (NPR-2) is south of NPR-1 and shares a common border with NPR-1 in Township B. NPR-2 consists of approximately 30,000 acres, 10,000 acres of which are owned by the government and have been developed under lease to private oil companies since the 1920's. The other 20,000 acres are owned by private oil companies. Like NPR-1, NPR-2 government lands are under the jurisdiction of DOE. Together, NPR-1 and NPR-2 constitute what is known as Naval Petroleum Reserves in California (NPRC).

Commercial oil production at NPR-1 began in 1919 with a well drilled in the Shallow Oil Zone (SOZ) by Standard Oil Co. of California (now CUSA) (DOE 1979). Development of NPR-1 by private industry yielded about 150 million barrels of oil by 1942. During World War II (1942-1945), production was approximately 27 million barrels of oil. Following the war, production was maintained at a low level until 1976 (essentially shut-in status).

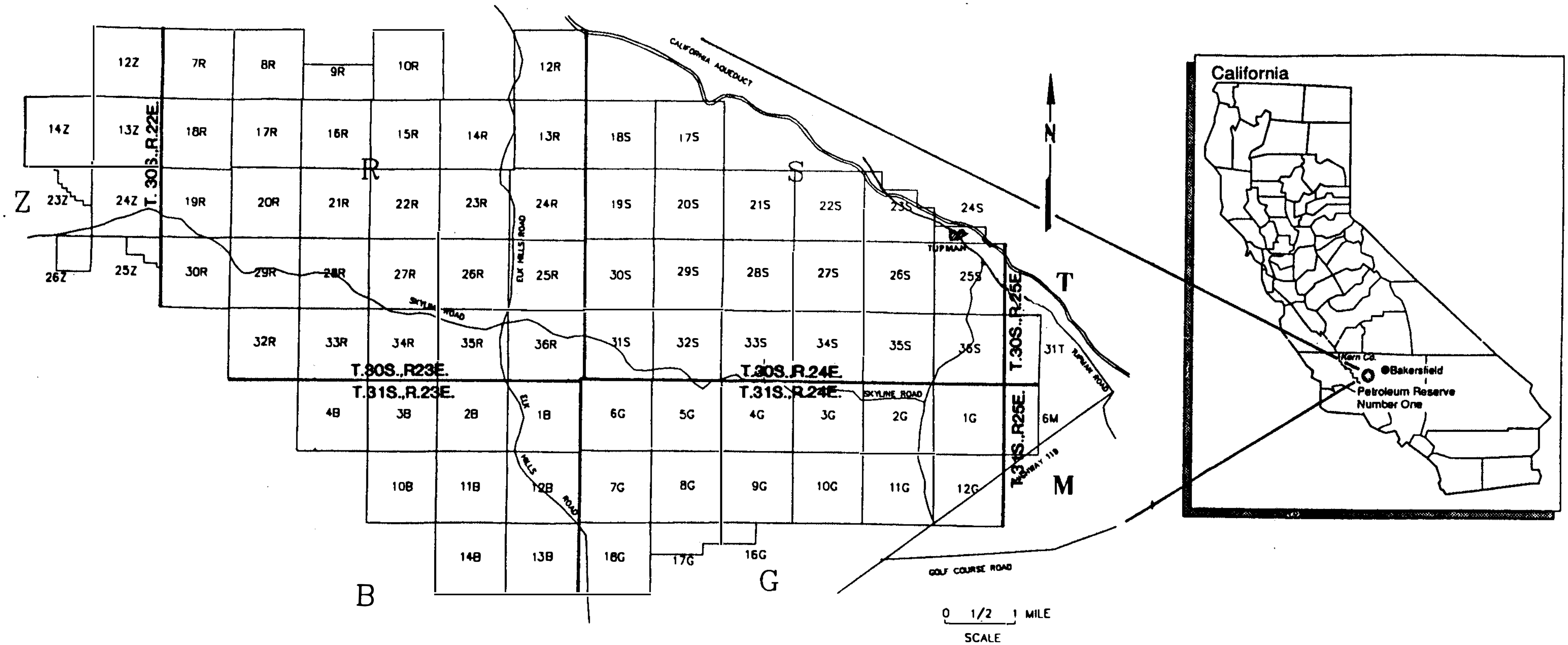


FIGURE 1.1-1 MAP OF NPR-1 SITE

Prompted by oil shortages in the mid-1970's, Congress, on April 5, 1976, passed the Naval Petroleum Reserves Production Act (Public Law 94-258), which directed that NPR-1 and Naval Petroleum Reserve No. 3 (NPR-3) in Wyoming be produced for an initial period of 6 years at the maximum efficient rate (MER), consistent with environmental and other laws and regulations. The Act also provided that following this period the President could extend MER production in 3-year increments, if in the national interest and if not disapproved by Congress. A fourth 3-year extension beginning April 6, 1991, was authorized based on military preparedness, national economic impacts, national energy strategy, and local and regional concerns (DOE 1990a). Changing developments in world-wide politics and military strategies will be considered by the Congress and the President in 1994 when the subject of reauthorization is by law addressed again.

The Act defines MER production as the maximum rate of production that optimizes economic return and ultimate recovery (see Section 1.1.3). Following the opening of NPR-1 in July 1976, oil production increased to a peak of about 180,000 barrels/day in 1981. Oil production declined to an average of about 82,000 barrels/day during fiscal year (FY) 1990 and about 74,000 barrels/day in FY 1991. During FY 1992, oil production averaged about 70,000 barrels/day.

On November 20, 1942, a Unit Plan Contract (UPC) was negotiated between the government and Standard Oil Company of California (now CUSA) to cooperatively explore, develop and produce all NPR-1 reservoirs underlying lands owned by both the government and CUSA; these lands comprise what is referred to as the Unit. The purpose of the UPC is to enhance recovery and efficiency by eliminating the possibility of applying competitive production strategies on a single reservoir underlying separately owned lands. The UPC was authorized by Congress on June 17, 1944, and approved by the President on June 28, 1944.

The UPC provides that establishing the time and rate of production are the exclusive right of the government. In addition, the government has the exclusive right to carry out the actual operation of the Unit. However, Unit production decisions (e.g., number and location of wells, facilities, etc.) are made by an Operating Committee consisting of one member representing the government and one member representing CUSA, each member having an equal vote. Some lands and production within the boundaries of NPR-1 owned 100% by the government were excluded from the UPC. These primarily include Asphalto Zone production in Sections 14Z and the NE 1/4 of 26Z, which are under the exclusive control of the government.

With the exception of endangered species activities, the day-to-day operation of NPR-1 is conducted by a management and operating contractor under contract to DOE. The present management and operating contractor is Bechtel Petroleum Operations, Inc (BPOI). Prior to BPOI, the management and operating contractors were William Brothers Engineering Company, and Standard Oil Company. Endangered species and cultural resource activities are conducted by EG&G Energy Measurements, Inc. (EG&G/EM) under contract to DOE. Management guidance for the endangered species program is provided by an Endangered Species Advisory Committee consisting of representatives from the various NPR-1 organizations, U.S. Fish and

Wildlife Service, California Department of Fish and Game, and the California Energy Commission. DOE also has contracts with Jerry R. Bergeson & Associates, Inc., for reservoir engineering support and with Research Management Consultants, Inc. (RMCI) for a variety of technical and administrative support services (prior to January 2, 1992, the support services contractor was Systematic Management Services, Inc.).

1.1.2 Purpose and Need of Proposed Action and Purpose of the Supplemental EIS

The purpose and need of the proposed action is to operate and produce Naval Petroleum Reserve No. 1 at the maximum efficient rate in accordance with the requirements of the Naval Petroleum Reserves Production Act (Public Law 94-258). Congress has directed that maximum efficient rate production be continued at NPR-1 with the latest 3-year statutory extension of the Naval Petroleum Reserves Production Act. This obligates the Department of Energy to produce the NPR-1 hydrocarbon reservoirs in the most efficient manner possible so as to provide maximum returns to the U.S. Treasury and maximize ultimate recovery of hydrocarbons. In order to meet the intent of this Congressional mandate, continued and enhanced NPR-1 operations are necessary. Additional developmental and infill drilling projects and facility development projects that satisfy maximum efficient rate criteria are needed to enhance NPR-1's operating efficiency and to offset natural declines in NPR-1's hydrocarbon production.

An EIS was released by DOE in 1979 based on development activities that were anticipated at that time. In addition, an environmental assessment (EA) was completed to initiate a steamflood of the SOZ (DOE 1985a), a project that had not been included in the 1979 document. As a result of monitoring activities and consultations with regulatory agencies, it has been determined that the scope of some impacts, most notably land and wildlife habitat disturbances, are expected to exceed the levels projected in the previous assessments. In addition, as the result of improved reservoir information, technological advancements, and changes in economic conditions, it is anticipated that future development activities may need to be adjusted/expanded significantly in order to ensure continued production in conformance with MER requirements; accordingly, a determination was made to prepare a Supplemental EIS (SEIS) to supplement the 1979 EIS document. In FY 1988, DOE contracted with Argonne National Laboratory (ANL) to provide assistance in the preparation of the SEIS document.

The remaining portions of this Section describe the SEIS proposed action in greater detail (production, facilities, operations, projects, etc.). Section 2 summarizes three alternative actions, including the no action alternative, provides a comparative table summarizing the impacts of the alternatives, and identifies the preferred alternative. Section 3 describes the existing environment on and near NPR-1. This was accomplished by updating the existing environment descriptions that were contained in the 1979 EIS through an evaluation of the impacts of activities that have taken place since then from continued petroleum operations at NPR-1. The updated description provides the baseline against which the incremental effects of the proposed action and Alternative 2 are assessed. Probable impacts of the proposed action and the alternatives to the proposed action are discussed in Section 4. Section 5 addresses unavoidable adverse impacts; Section 6 discusses short-term use and long-term productivity;

Section 7 addresses commitment of resources; and Section 8 provides a list of the preparers of this document.

1.1.3 Definition of Maximum Efficient Rate (MER)

The Maximum Efficient Rate (MER) is defined in the Naval Petroleum Reserves Production Act of 1976 as "The maximum sustainable daily oil and gas rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to the ultimate recovery." DOE has interpreted this to mean that MER reservoir determinations are to be made and updated on a regular basis taking into account the "unique characteristics of each reservoir," and "sound engineering practices designed to maximize both economic return and ultimate recovery" (DOE 1985b). Stated in other words, MER is dependent on an evolving understanding of reservoir characteristics; sound engineering practices as these change with technological advancements; the economic return of competing development strategies as economic conditions fluctuate over time; and the impact of competing strategies on ultimate recovery. These characterizations result in MER determinations that are in a constant state of change, and this has broad implications in planning future activities and establishing the proposed action which is the subject of this document. These implications are discussed further in Section 1.2.1 -- Summary of Proposed Action.

1.1.4 Production Summary

Since its establishment in 1912, more than 860 million barrels of oil were produced from NPR-1 through 1988, including about 630 million barrels since 1976. Remaining oil reserves are estimated to be between 524.4 million barrels (DOE 1990b) and 831.5 million barrels (Jerry R. Bergeson & Assoc. 1988). Oil production peaked at about 180,000 barrels/day in July 1981. Since then, oil production declined to an average of about 82,000 barrels/day during FY 1990 and about 74,000 barrels/day during FY 1991. In FY 1992, oil production normally averaged 70,000 barrels/day.

Substantial gas production is associated with oil production (i.e., gas produced along with the oil from the same well bore). This gas contains natural gas liquids (NGL) which are separated from the gas into NGL products. Gas and NGL production averaged approximately 344 million cubic feet/day and 541,000 gallons/day, respectively, during FY 1990. In FY 1992, gas production and NGL production normally averaged 313 million cubic feet/day and 440,000 gallons/day, respectively. In 1988, remaining gas reserves were estimated to be between 1,158 billion cubic feet (DOE 1990c) and 1,865 billion cubic feet (Jerry R. Bergeson & Assoc. 1988).

Production statistics for NPR-1 from FY 1976 through FY 1990 are presented in Table 1.1-1. Production at NPR-1 is from four geologic zones located at various depths beneath the surface (see Figure 1.1-2). Approximately 82% of all production is from the Stevens Zone, 17% from the SOZ, and 1% from the Carneros Zone and the Dry Gas Zone (DGZ).

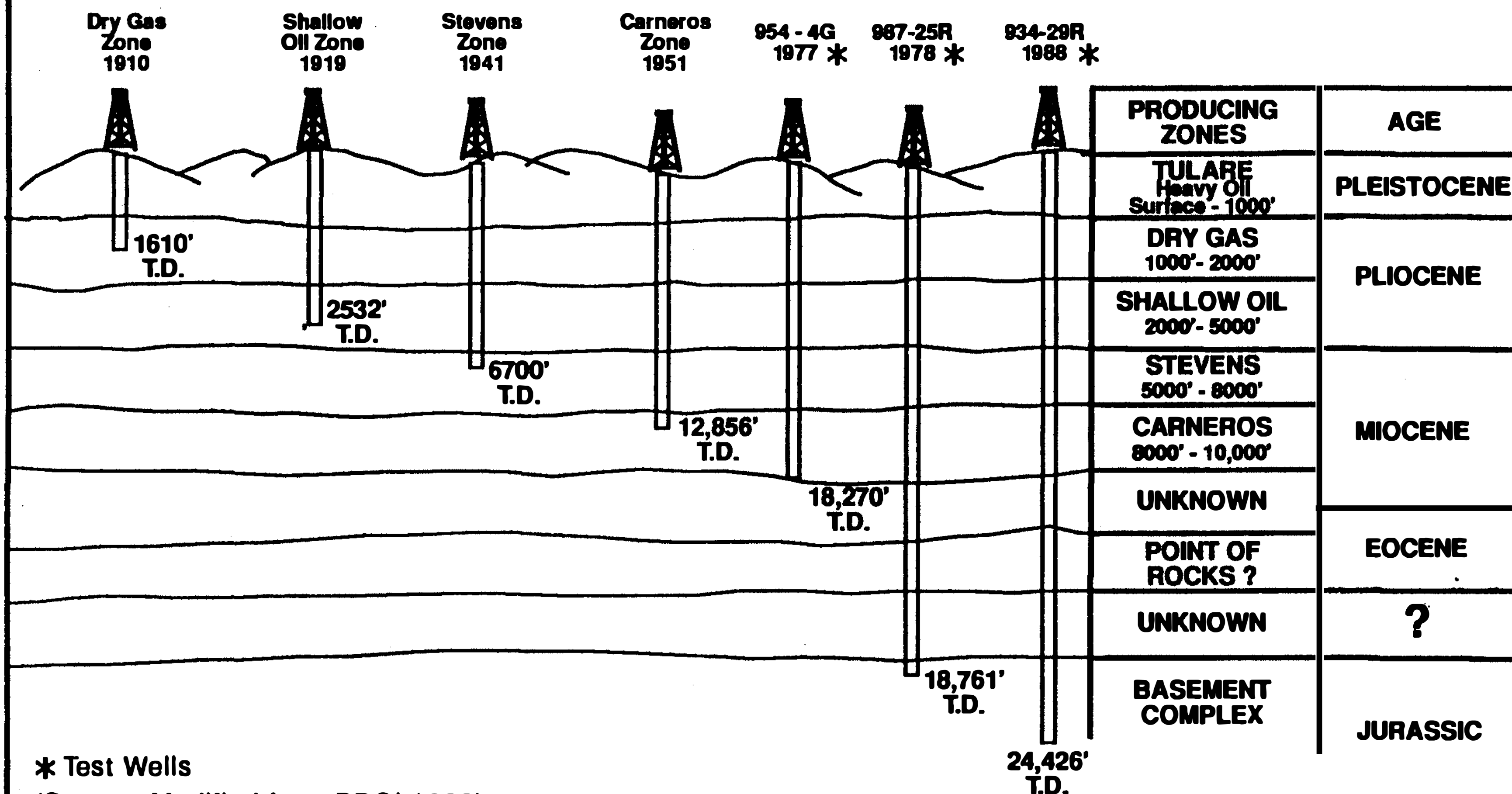
TABLE 1.1-1 NPR-1 Production Statistics, FY 1976-1990

Fiscal Year	Crude Oil (10^6 bbl)	Natural Gas (10^9 ft^3)	Natural Gas Liquids		
			Gasoline (10^9 gal)	Butane (10^9 gal)	Propane (10^9 gal)
1976	3.8	0.8	0.5	0.4	0.7
1977	36.9	19.5	8.7	12.5	13.1
1978	43.5	34.3	19.4	16.4	20.5
1979	52.6	53.3	35.1	21.1	40.1
1980	58.3	60.6	40.4	38.1	54.2
1981	62.6	101.0	48.9	60.7	75.9
1982	60.7	119.5	63.3	73.0	100.1
1983	57.4	121.3	61.5	79.5	96.3
1984	50.5	129.0	64.1	74.6	89.3
1985	47.7	134.7	80.7	72.0	96.7
1986	42.2	127.4	69.0	69.0	93.1
1987	39.8	125.2	71.0	69.8	89.5
1988	39.2	130.9	76.2	71.6	90.0
1989	35.5	134.6	75.7	68.8	86.7
1990	29.5[a]	125.6[b]	65.0[c]	58.7[c]	74.1[c]
TOTAL	660.5	1,418.5	779.2	785.9	1001.9

[a]82,000 barrels/day average in FY 1990.
[b]344 million cubic feet/day in FY 1990.
[c]541,000 gallons/day gasoline, butane and propane in FY 1990.

Source: DOE 1988, 1990d; BPOI 1988, 1989.

FIGURE 1.1-2
NAVAL PETROLEUM RESERVE NO.1 (ELK HILLS)
GENERALIZED GEOLOGIC CROSS SECTION
SHOWING PRODUCING ZONES AND TEST WELLS



* Test Wells
(Source: Modified from BPOI 1988)

1.1.5 Facilities Summary

The major facilities at NPR-1 are shown in Figure 1.1-3. These facilities include:

- Approximately 1,253 active wells for hydrocarbon production (flowing, pumping, and gas lift), waterflood source water production, gas injection, waterflood injection, wastewater disposal injection, and steam injection.

- Approximately 1,055 existing wells that are shut-in (idle) or abandoned (792 shut-in and 263 abandoned).

- One hundred and twenty-one tank settings used to separate produced gas from produced oil and water, and to meter individual well oil, water and gas production.

- Five dehydration/lease automatic custody transfer (LACT) facilities used to separate oil and water, inject wastewater into disposal wells, and measure and transfer oil to CUSA and DOE purchaser pipelines and trucks.

- One crude oil tank farm.

- Numerous gas-gathering compressor plants (one of which has been abandoned) used to deliver gas separated at the tank settings to the gas plants for further processing.

- Two gas-lift compressor facilities used to reinject produced gas back into some oil wells to stimulate their production of oil.

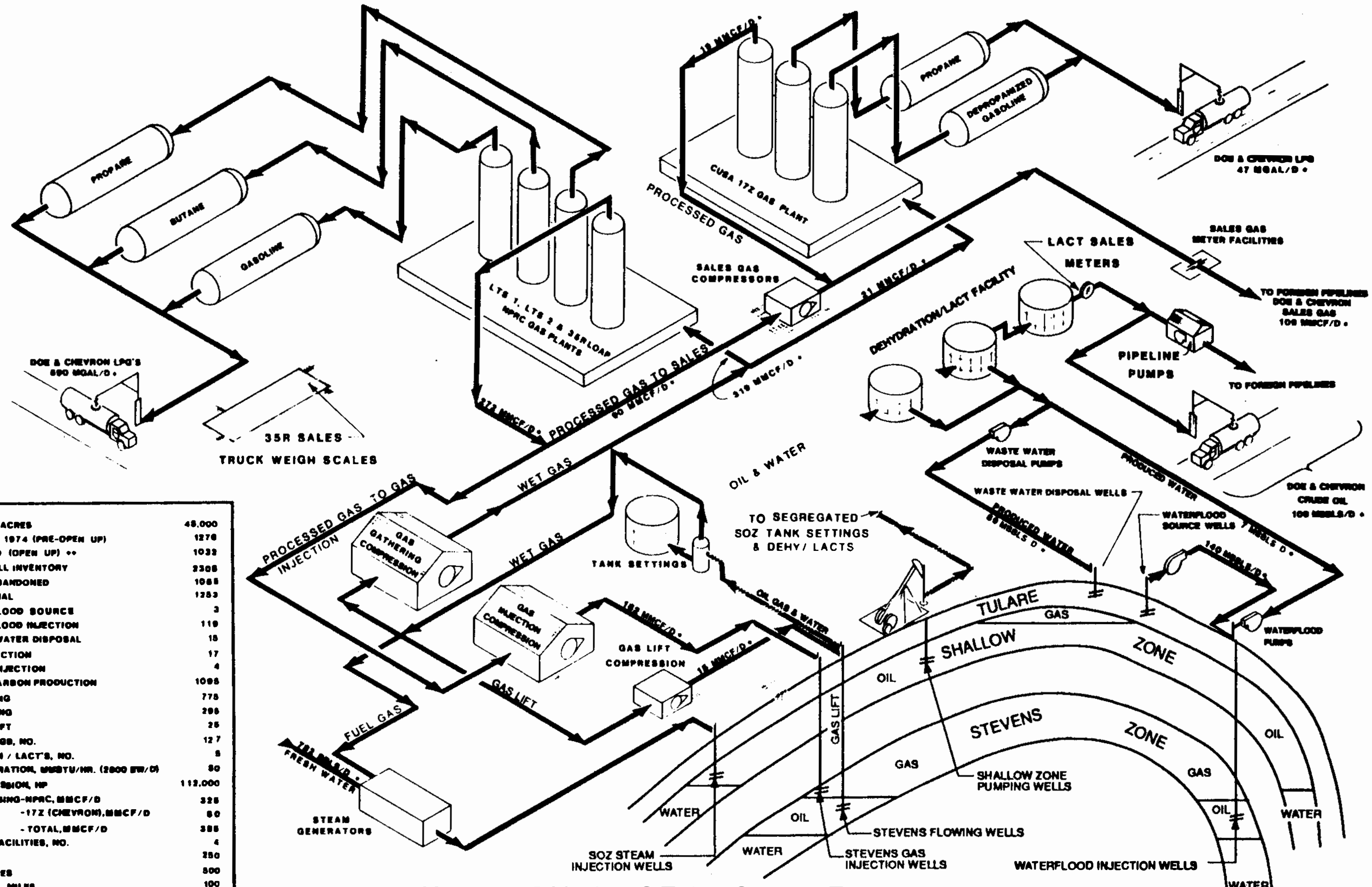
- Four gas-processing plants used to separate NGL products from gas, three of which are owned and operated by NPR-1 and located on NPR-1; the other is a CUSA gas plant which is located off-site in Section 17Z, a portion of which can be utilized by NPR-1 under a gas processing agreement.

- Four gas-injection compressor plants used to inject portions of the processed gas back into producing reservoirs as needed to maintain reservoir pressures for the purpose of enhancing oil recovery.

- One sales gas compressor facility used to transport gas not needed for pressure maintenance to gas sales facilities.

- Four sales gas facilities used to measure and transfer gas to CUSA and DOE purchaser pipelines; three of these are located on NPR-1 and the other is located at CUSA's 17Z plant approximately 3 miles west of the NPR-1 western boundary.

- Three NGL storage and loading facilities for measuring and transferring NGL product to CUSA and DOE purchaser trucks, one of which is located at CUSA's 17Z plant.



NPR-1 AREA, ACRES	48,000
WELLS AS OF 1974 (PRE-OPEN UP)	1270
WELLS ADDED (OPEN UP) **	1032
CURRENT WELL INVENTORY	2308
SHUT-IN/ABANDONED	1065
OPERATIONAL	1253
WATERFLOOD SOURCE	3
WATERFLOOD INJECTION	119
WASTE WATER DISPOSAL	15
GAS INJECTION	17
STEAM INJECTION	4
HYDROCARBON PRODUCTION	1095
PUMPING	775
FLOWING	295
GAS LIFT	25
TANK SETTINGS, NO.	127
DEHYDRATION / LACT'S, NO.	5
STEAM GENERATION, MMBTU/HR. (2800 BW/D)	80
GAS COMPRESSION, HP	112,000
GAS PROCESSING-NPRC, MMCF/D	325
-17Z (CHEVRON), MMCF/D	60
- TOTAL, MMCF/D	385
GAS SALES FACILITIES, NO.	4
ROAD, MILES	250
PIPELINE, MILES	500
POWER LINES, MILES	100
LPG STORAGE, MGAL	2300

** EXCLUDE 29 DEEPENING/ REDRILL

NPR-1 SURFACE FACILITIES
FLOW DIAGRAM

• ESTIMATED ACTUALS THRU JUNE FY 89

FIGURE 1.1-3

- One booster pump plant used to deliver water from three to six waterflood source water wells to two waterflood plants which inject water into the Stevens Zone to enhance oil recovery.

- One steam generator facility used to inject steam into the SOZ for enhanced oil recovery.

- Several emergency wastewater sumps (lined and unlined); two landfill/waste handling facilities, one of which contains a permitted hazardous waste unit that is in the process of being formally closed; a scrap/recycling yard; and numerous old abandoned waste sites that are in various stages of review, investigation and remediation.

- Oil, gas, water, NGL, and condensate pipelines, some of which are pipelines that have been installed, and are operated and maintained by outside third parties at their expense for the purpose of connecting to NPR-1 facilities (such as oil and gas sales facilities), or to traverse NPR-1 lands for other purposes that are not related to NPR-1 operations.

- Three building complexes for offices, maintenance, storage, and warehousing.

- Communications systems; air monitoring equipment; vehicle fleets including fuel depots; electrical distribution systems; fire water systems; fresh water systems; road systems; and a wide variety of supporting infrastructure.

For additional information pertaining to facilities refer to Appendix A.

1.1.6 Operations Summary

Operations at NPR-1 consist of all activities needed to ensure MER production. Generally, this involves (1) locating reserves and drilling wells, (2) withdrawal of oil, gas and water from wells, and (3) processing and distributing same for sale, injection, and other disposition. Also included in operations are processing requests by outside third parties for facility installations on NPR-1 lands, and issuing permits for same.

Operations are carried out by a staff of approximately 800 full time government, CUSA, BPOI, RMCI, and EG&G/EM personnel, plus up to 400-500 additional subcontractor and vendor personnel involved in a variety of construction and support activities. Current revenues are anticipated to be approximately $700 million annually, and the total operating budget is about $175 million annually.

Operations are generally broken down into four major areas: (1) operations and maintenance (O&M), (2) exploratory drilling, (3) development drilling, and (4) development facilities. These areas are described in more detail as follows:

O&M

This area includes:

- All administrative activities such as general management, planning, legal, financial management, procurement, contracts, personnel management, inventory control, and audits.

- All geology and engineering activities, such as reservoir engineering and geology, production engineering, facility engineering, corrosion engineering, and process engineering.

- All technical assurance activities such as environmental support (including endangered species and cultural resources), health and safety, quality assurance, emergency preparedness, and security.

- All operations and maintenance activities and projects, such as operating, maintaining, repairing, and replacing surface facilities; well maintenance/stimulations, such as remedial projects and workovers; and environmental remediation and restoration.

- Processing third-party requests for permits to install, operate and maintain facilities on NPR-1 lands, and monitoring same for compliance with permit requirements.

Exploratory Drilling

This area consists of the drilling, redrilling, deepening, completion, recompletion, and testing of wells to discover new reserves, and to obtain new geologic information which could ultimately be used to design new programs for the same purpose.

Development Drilling

This area consists of the drilling, redrilling, deepening, completion, recompletion, and testing of wells that are needed to enhance the drainage of known hydrocarbon producing reservoirs (such as hydrocarbon production offset and infill wells, gas injection wells, waterflood injection wells, and steam injection wells); water wells that are needed to provide a source of water for waterflood operations; and water injection wells that are needed for disposal of produced wastewater.

Development Facilities

This area consists of the design, construction, installation, and start-up of new surface facilities, or modifications to existing facilities, needed as the result of changing conditions e.g., changes in environmental, safety, and health laws and regulations; changes in economic conditions; technological advances; changes in reservoir conditions and enhancements in reservoir information. Examples of facilities that are affected include gas plants, compressors, tank settings, and artificial-lift equipment.

For additional information pertaining to operations, refer to Appendix A.

1.2 PROPOSED ACTION AND ASSOCIATED FACILITIES

1.2.1 Summary of Proposed Action

The proposed action is to continue producing NPR-1 at MER in compliance with the requirements of the Naval Petroleum Reserves Production Act. As previously explained (see Section 1.1.3), this requires activities that are based on the unique characteristics of the reservoirs (as this understanding matures with time), technological advancements, and economic conditions. Given that these variables are difficult to predict, it is correspondingly difficult to determine future activities with precision. However, a range of possibilities has been described in general terms in the NPRC FY 1989-1995 Long Range Plan (LRP), a copy of which is provided in Appendix G for reference. The LRP describes two scenarios: a "maintenance" case and a "full development" case. The "maintenance" case assumes that production continues, but without the benefit of further development -- i.e., no further drilling, stimulations, efficiency projects, etc. As such, this case represents a minimum scenario, both from the standpoint of production and environmental impacts. The "full development" case assumes the implementation of all ordinary oil-field hydrocarbon recovery techniques (including steamflooding) as needed to enhance recovery and operational efficiency in accordance with MER requirements. This scenario is much more optimistic from the standpoint of future production levels and profitability, and it would also result in greater environmental impact.

In terms of MER requirements, the "full development" case is considered to be the most realistic. Accordingly, this scenario is probably the most representative of the types and magnitudes of impacts that are likely to result from producing at MER. On this basis, the proposed action has been assumed to be "full development", as this scenario is described in the LRP (Appendix G) and amplified/supplemented herein, or variations of "full development" that have comparable impacts. Alternative 1, the no action alternative, is based on the "maintenance case". See Section 2.1 for a description of this alternative.

The principal elements of "full development" include: (1) the continuation of current oil and natural gas production at NPR-1 (LRP maintenance case), with implementation of additional activities to enhance recovery and efficiency, such as infill drilling, well remediation, artificial lift, gas-lift, gas injection and water injection; (2) the expansion of SOZ steamflooding activities; (3) construction and operation of a cogeneration power-production facility; (4) construction of a fourth NPR-1 gas plant; (5) construction of butane isomerization facilities; and (6) various other development projects required to maintain MER.

The LRP (Appendix G) presents a discussion of tertiary recovery opportunities that might be possible in the future, such as in-situ combustion, chemical flooding, etc. The proposed action does not include any of these techniques because they are not considered viable alternatives for the foreseeable future based on available data and the existing economic environment. If these techniques become necessary to achieve MER compliance in the future, an appropriate assessment and NEPA documentation will be prepared at that time.

The proposed action includes the implementation of all activities that make up O&M, development drilling, exploratory drilling, and development facilities as needed to ensure MER production. These activities are intended to achieve MER production goals for each individual production zone. The various elements of the proposed action are summarized as follows:

- Production at MER, estimated in the LRP (Appendix G) to be approximately 99,000 barrels/day of oil in FY 1990, declining to approximately 72,000 barrels/day in FY 1995; 365 million cubic feet/day of gas in FY 1990, increasing to 417 million cubic feet/day in FY 1995; and 654,000 gallons/day of NGL products in FY 1990, increasing to 768,000 gallons/day in FY 1995;

- Remediations, workovers, abandonments, and other operational and maintenance activities needed to ensure that approximately 2,697 existing and future wells produce at rates consistent with MER and other requirements;

- Operation and maintenance of existing collection, injection, and distribution systems and shipping facilities for oil, gas, NGL's and water (potable, fire, waste, and waterflood source waters);

- Operation and maintenance of the existing gas-processing facilities (nominal current capacity of 360 million cubic feet/day);

- Operation and maintenance of existing storage tanks, process equipment, LACTs and loading facilities for crude oil and NGL's;

- Operation and maintenance of existing gas-injection compression plants (estimated current capacity of 299 million cubic feet/day);

- Operation and maintenance of existing gas-lift compressor plants (estimated current capacity of 37-38 million cubic feet/day);

- Operation and maintenance of electric power distribution system;

- Operation and maintenance of existing waterflood source water facilities and injection plants (estimated current capacity of 200,000 barrels/day);

- Operation and maintenance of existing SOZ steam injection facilities which are currently injecting approximately 3,100 barrels/day of water as steam;

- Operation and maintenance of existing facilities for collecting, storing, treating, injecting, and disposing of produced wastewater, which is currently approximately 100,000-110,000 barrels/day;

- Operation and maintenance of a myriad of existing support facilities and infrastructure such as cathodic protection facilities, communication systems, vehicle fleets, roads, fresh water systems, chemical treatment facilities, and buildings;

- Development and exploratory drilling, redrilling, deepening and completion/ recompletion of approximately 382 wells required to maintain MER production, 148 of which are for the SOZ Steam Project;

- Purchase, construction, operation and maintenance of new facilities such as a 148-well, 500-acre, 625 million BTU/hour steam injection project to increase SOZ steam injection by 32,805-34,478 barrels/day of water; a new 100-150 million cubic feet/day gas plant; a new 42 megawatt cogeneration facility; facilities to increase gas injection, gas-gathering and gas-lift by 46,250 horsepower (37,500 horsepower gas; 8,750 horsepower electric); facilities to add 48,000 barrels/day of waterflood injection capacity and increase waterflood injection by 106,500 barrels/day; additional wastewater handling, treatment and disposal capacity; a 170,000-220,000 gallon/day butane isomerization project; and a wide variety of other modifications and additions to process facilities, support facilities, and infrastructure, as needed to accommodate MER productions and all laws and regulations (including safety and environmental laws and regulations) under changing field and economic conditions.

- Environmental investigation and remediation initiatives such as clean-up and closure of abandoned waste sites; groundwater characterization/monitoring initiatives; sump reduction/ elimination projects; drainage restoration projects; soil erosion repair and prevention activities; air quality enhancement projects; secondary containment projects; etc.

- Endangered species activities, including monitoring, preactivity surveys, habitat restoration/reclamation, and biological/reclamation research and studies.

- Personnel requirements estimated to be 800 full time government, CUSA and contractor personnel, and subcontract personnel varying from a few to 400-500 each day.

The NPR-1 budget for all activities was estimated to increase from $172,293,000 in FY 1989 to $224,622,000 in FY 1995. Government revenues were estimated to increase from $707,336,000 in FY 1989 to $901,659,000 in FY 1995.

1.2.2 Description of the Proposed Action

The proposed action would involve four basic activities: (1) drilling of new wells; (2) withdrawal of oil, gas, and water from new and existing production wells; (3) injection of gas, water, and steam into new, converted, or existing injection wells as needed to maintain MER production (gas and water are injected into selected wells to dispose of wastewater, to reduce the possibility of subsidence, to restore reservoir pressure losses from production withdrawals, and as part of recovery operations to ensure that the desired MER is achieved); and (4) selling, delivering, and otherwise distributing oil, NGL's, and gas not needed for injection (DOE 1979). This section provides additional descriptions for 22 of the more important elements of the above activities.

1.2.2.1 Reservoir Development Plans

Stevens Zone

Main Body B (MBB)/Western 31S (W31S) -- The management strategy for this reservoir includes the maintenance case plus development drilling with infill wells in the northern and western portions of the structure. In addition, waterflood expansions are planned in Sections 34S, 33S, and 32S. See pages 2-18 to 2-35 in the LRP (Appendix G) for more information.

24Z Sands -- The management strategy for this reservoir includes the maintenance case plus development drilling. The maintenance case includes peripheral water injection, gas injection, and remedial actions (such as artificial-lift installations, stimulations, recompletions, and conversions). Development activities include waterflood surveillance and optimization, plus drilling of one new well. See pages 2-35 to 2-46 in the LRP for additional information.

2B Sands -- The management strategy for this reservoir is the maintenance case only, which includes well stimulations and recompletions and installations of artificial-lift equipment. See pages 2-46 to 2-52 in the LRP for additional information.

29R/24Z Shales -- This reservoir management strategy includes the maintenance case plus a development drilling project. The maintenance case consists of stimulations, recompletions, and artificial-lift installations, plus gas and water injection projects to replace voidage and maintain reservoir pressure. Development drilling would include two wells. See pages 2-52 to 2-63 in the LRP for additional information.

26R Sands -- The strategy for this reservoir includes the maintenance case and a horizontal drilling project. The maintenance case emphasizes remedial activities, such as stimulations and recompletions. Production would continue under gas injection assisted by gravity drainage. Development drilling would involve horizontal drilling that would improve recovery efficiency and that might be capable of sustaining production for an extended period. See pages 2-63 to 2-73 in the LRP for additional information.

31S C/D Shales -- The management strategy includes the maintenance case, plus drilling new wells, deepening existing wells currently completed in overlying structures, and a pilot waterflood project. The maintenance case includes remedial activities (such as stimulations, recompletions, and installation of artificial-lift systems). It is anticipated that approximately five new wells will be required, and five existing wells will require deepening. See pages 2-74 to 2-85 in the LRP for more information.

31S N/A Shales -- The management strategy for this reservoir consists of the maintenance case, which includes routine remedial activities such as stimulations, recompletions, and artificial-lift installations. These activities are directed toward maintaining production levels and conserving reservoir energy by shutting-in wells with high gas-to-oil ratios. See pages 2-85 to 2-92 in the LRP for additional information.

Northwest Stevens (NWS) A1-A3 Sands -- The total development strategy for this reservoir includes the maintenance case plus a horizontal drilling project. The maintenance case consists of maintaining reservoir production and pressure by gas injection to balance voidage and by conducting isolation remedial projects. In addition, two horizontal wells are planned. See pages 2-92 to 2-103 in the LRP for additional information.

NWS A4-A6 Sands -- The strategy for development of this reservoir consists of the maintenance case and a development drilling project. The maintenance case includes remedial actions (recompletions and stimulations) and continued peripheral water injections to support reservoir pressure and improve production recovery. Development drilling would include two wells. See pages 2-103 to 2-114 in the LRP for additional information.

NWS T Sands and N Shales -- The reservoir development strategy is a combination of the maintenance case and a hydraulic fracture project (applying high pressure water and sand down hole to fracture the producing structure to increase permeability and production). The maintenance case consists primarily of remedial activities (recompletions and stimulations) and one hydraulic fracture test. The hydrofracture project involves continued hydraulic fracturing in at least one well/year through FY 1996. Also included are studies for waterflooding that (depending on results) could lead to initiation of a waterflood pilot. See pages 2-114 to 2-125 in the LRP for additional information.

Asphalto -- The management strategy for this reservoir consists of the maintenance case only. This case is directed toward continued primary production of both the Asphalto-Stevens and nonunit Antelope shale reservoirs by performing routine remedial activities (primarily pump replacements). See pages 2-146 to 2-151 in the LRP for additional information.

Shallow Oil Zone

The total development management strategy for the SOZ is a combination of the maintenance case plus five production enhancement projects. The maintenance case includes well remedial actions to facilitate production, which consists of gravity drainage in the eastern SOZ and gravity drainage with gas expansion in the western SOZ. Production enhancement projects include drilling of six new wells/year through FY 1995 (42 new wells); hydraulic fracturing (four wells) steamflood pilot phase II (includes four patterns); steamflood expansion project (major new field expansions through FY 1994); and a potential waterflood project for the SS-2/Mulinia sands.

Alternative strategies that will be incorporated as appropriate based on simulation and pilot testing include waterflooding portions of the SS-1, in lieu of steamflooding, and gas injection (Querin 1989). See pages 2-125 to 2-146 in the LRP (Appendix G) for additional information.

Carneros Zone

The total development strategy consists solely of the maintenance case. Activities planned include one well deepening, nine remedial stimulations, and installation of artificial-lift equipment. See pages 2-151 to 2-158 in the LRP (Appendix G) for additional information.

Dry Gas Zone

Included in the total development strategy for this reservoir are the maintenance case, a remedial project, and a compressor project. The maintenance case represents base production with remedial actions such as recompletions and artificial-lift installations. See pages 2-158 to 2-169 in the LRP (Appendix G) for additional information.

1.2.2.2 Production Quantities

It has been estimated that continued MER production would result in the production quantities shown by Table 1.2-1. This table illustrates that as the field matures oil production and gas sales would decline; however, gas production, produced water, gas injection and water injection would increase. This has major implications, especially from the standpoint of facility requirements. These implications are the subject of much of the following description of the proposed action. Table 1.2-2 provides quantities of some of the various product streams by producing zone during FY 1988; these quantities are comparatively typical. Figure 1.2-1 is a graphical representation of how crude oil production would probably decline.

1.2.2.3 Operation, Maintenance, and Personnel Requirements

The proposed action includes all operation and maintenance activities and procedures needed to ensure MER production for all existing and planned facilities, programs and activities, as described in Appendix A (A.9) and the LRP (Appendix G). All currently operating systems would be available (with some modification, additions, or replacements) throughout the useful life of NPR-1.

Abnormal conditions (e.g., oil spills, fires) could occur periodically. Site operations and maintenance staff are trained to expect and prevent or mitigate the full range of potential abnormal conditions. Specific abnormal conditions are discussed in Section 3.9, Risk Assessment.

Staff requirements for maintaining MER production rates would not change significantly from the current levels. This is approximately 800 full time personnel employed by the government, CUSA, and contractors. In addition, up to approximately 400-500 subcontractor and vendor

TABLE 1.2-1 Summary of NPR-1 Proposed Production Program

Program Element	FY 1990	FY 1991	FY 1992	FY 1993	FY 1994	FY 1995
Oil production (bbl/day)	98,957	95,574	91,895	83,629	76,286	71,515
Produced Water (wastewater) (bbl/day)	129,271	151,107	171,368	175,291	181,067	172,076
Gas production (10^3 ft^3/day)	65,028	356,643	355,958	352,459	351,262	417,414
Gas injection (10^3 ft^3/day)	188,182	195,101	200,813	203,994	208,821	271,542
Water injection (bbl/day)	200,085	229,862	247,543	252,220	254,521	235,396
Steam injection (bbl/day)	5,200	13,705	21,410	27,508	32,805	31,305
Fuel gas consumption (10^3 ft^3/day)	20,090	22,465	25,137	27,247	29,167	32,000
Gas sales (10^6 ft^3/day)	118,500	102,250	93,410	84,950	77,410	69,060
NGL extraction (10^3 gal/day)	654,270	636,340	632,680	623,970	620,600	767,800
Pool operating costs ($\$10^3$)	67,450	76,926	85,476	86,865	88,914	91,246
Unit expenditures ($\$10^3$)	174,883	170,155	165,103	170,722	164,748	176,153
DOE-NPR allotment ($\$10^3$)	9,098	9,057	9,521	9,479	9,910	10,382
Unit revenue ($\$10^6$)	929,300	928,910	944,880	921,360	891,580	901,659

Source: BPOI 1989

TABLE 1.2-2 Production and Disposition of Primary Oil, Gas, and Water Streams at MER in 1988 (Oil, 10^3 barrels/day; gas, 10^6 feet/day; water, 10^3 barrel/day)

Production and Disposition	Zone of Origin					
	Stevens	Shallow Oil	Asphalto	Carneros	Dry Gas	Total
Oil stream[a]	92.6	16.4	0.2	0	0	109.5
Gas Streams						
Used as fuel[b]	17.4	1.0	0.1	0.5	0.4	19.4
NPR-1 gas plants[c]	320.0	0	0	0	0	320.0
CUSA gas plant[c]	30.0	0	0	0	0	30.0
Injection[d]	205.0	0	0	0	0	205.0
Water streams						
Stevens/Tulare Waterflood[e]	148.0	0	0	0	0	148.0
Associated water[f]	76.5	18.6	3.8	0.2	0.1	99.2

[a]Oil production by zone.
[b]Gas production by zone.
[c]Plant feed.
[d]Gas injection by zone.
[e]Water produced from Tulare for waterflooding Stevens.
[f]Water associated with oil and gas production by zone of origin. (Disposed of into Tulare SOZ, Stevens, and Olig.)

Source: BPOI 1988.

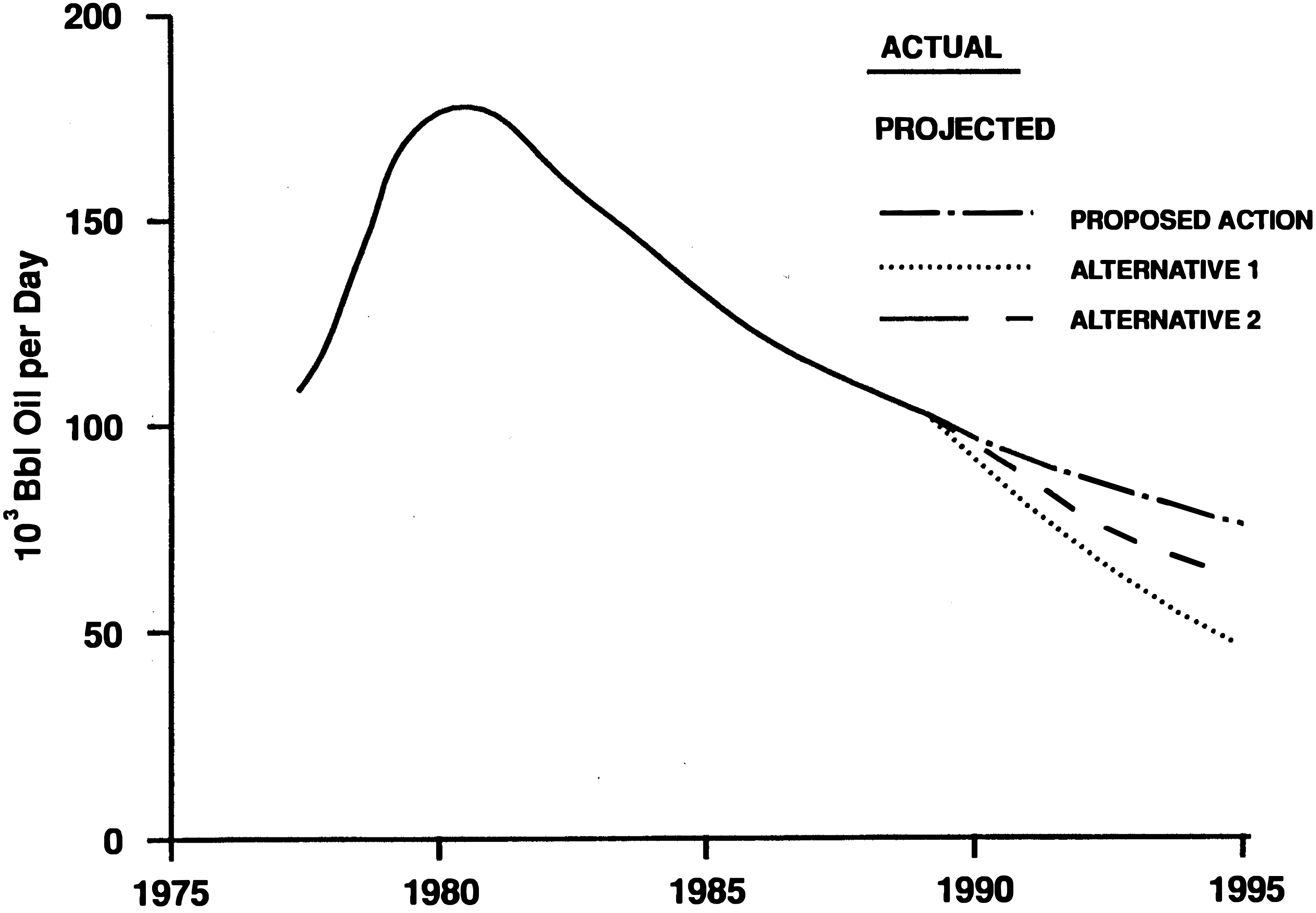


FIGURE 1.2-1 ACTUAL AND PROJECTED MER OIL PRODUCTION AT NPR-1
(SOURCE: MODIFIED FROM BPOI 1989)

personnel are on-site each day conducting maintenance, construction, and a wide variety of other services.

1.2.2.4 Drilling Activity

Based primarily on Reservoir Development Plans (see Section 1.2.2.1) and Well Remedial Actions (see Section 1.2.2.5), additional wells would be required to continue producing at MER. Before FY 1974, about 1,279 wells had been drilled at the NPR-1. Between FY 1974 and FY 1988, an additional 1,036 wells were drilled, bringing the total to 2,315. Development and exploratory drilling and testing through FY 1995 includes an additional 259 new wells, redrills and deepenings. Wells are redrilled when mechanical problems or reservoir conditions necessitate abandonment of the original well bore. Typically, the redrilled well is completed in the same geologic formation as was targeted for the original well. The deepening of a well is normally intended to achieve production from a deeper reservoir. Projections for the period FY 1996 through FY 2025 include another 123 new wells, redrills and deepenings. This results in a total of 382 new wells, redrills, and deepenings and would bring the total well count to approximately 2,697. Table 1.2-3 shows an estimate of the distribution of the projected new well activity for the periods of interest. Significant activities within each major production pool are described below.

In the Stevens Zone, the MBB/W31S pool is the largest drilling and development project planned. Of the 123 new wells planned, 41 are for infill drilling to reduce well spacing from 20 to 10 acres. Proposed activity in the 26R sand pool of the Stevens Zone includes drilling seven horizontal holes. Seven standard vertical wells are also planned. Other well drilling activity that may be included for the Stevens Zone includes two new wells in the 24Z sand, two new wells in the A1-A3 sands in the Northwest Stevens pool, and two new wells plus deepening of an existing well in the A4-A6 sands of that pool.

Activities planned in the SOZ (SS-1 and SS-2 Mulinia) include evaluating the steamflood project started in FY 1987. If initial phases of the steamflood prove successful, the SS-1 sand steamflooding would be incrementally increased in successive years. Alternately, portions of the SS-1 might be waterflooded depending on the results of steam evaluation and additional simulations and pilot testing of waterflood strategies. A waterflood in the SS-2 Mulinia is also being considered, as well as a gas injection strategy (Querin 1989).

In the Carneros Zone, one well is being considered for deepening. Additional development and exploratory drilling, completion and seismic work are described in the LRP (Appendix G) in Chapters 1 and 2.

It has been estimated that the total land disturbance for the projected 382 new wells to be drilled would be 579 acres of land. This is based on the assumptions that approximately 71% of the wells would be sited in previously undisturbed areas and that 2.2 acres would be required for each new well pad and ccess road, etc.

TABLE 1.2-3 Summary of Well Drilling in 1989 and Projected through 2025 for NPR-1[a]

Reservoir	1989	1990	1991	1992	1993	1994	1995	1996-2025	Total
Stevens[b]									
MBB/W31S	10	7	15	14	15	15	15	32	123
24Z	1	0	1	0	0	0	0	0	2
2B	0	0	0	0	0	0	0	0	0
29R/24Z	1	1	0	0	0	0	0	0	2
26R	1	2	2	2	0	0	0	0	7
31S C/D	0	2	11	9	8	8	8	0	46
31S N/A	0	0	0	0	0	0	0	0	0
NWS A1-A3	0	1	1	0	0	0	0	0	2
NWS A4-A6	0	1	1	1	0	0	0	0	3
NWS T/N	0	0	0	0	0	0	0	0	0
Subtotal	13	14	31	26	23	23	23	32	185
Other Zones									
SOZ[c]	7	6	6	6	6	6	6	0	43
SOZ[d]	0	8	0	27	0	22	0	91	148
Asphalto	0	0	0	0	0	0	0	0	0
Carneros[e]	1	0	0	0	0	0	0	0	1
Dry Gas Zone	0	0	0	0	0	0	0	0	0
Tulare[f]	0	0	0	0	0	0	0	0	0
Exploration	0	1	1	0	1	1	1	0	5
Subtotal	8	15	7	33	7	29	7	91	197
Total	21	29	38	59	30	52	30	123	382

[a]Includes new wells, redrills, deepenings, and associated tests.
[b]Stevens Zone section locations are 22R, 23R, 24R, 25R, 26R, 29R, 30S, 36S, 36R, 31S, 32S, 33S, 35S, 2G, 3G, 4G, 5G, 6G, 1B, 2B, 14B, 35R, 24Z, 34R, 16R, 17R, 7R, 8R, 9R, 14R-20R, 27R, 30R, 33R, 14Z, 23Z, and 25Z.
[c]Does not include SOZ steamflood.
[d]SOZ steamflood.
[e]Carneros Zone section location is 29R, 19R, 30R, 24Z, 26Z.
[f]The Tulare Zone is a secondary production zone that is uneconomic to produce at this time.
Source: Compiled from BPOI 1988, 1989.

1.2.2.5 Well Remedial Actions

To maintain MER, a number of remedial activities would be necessary at wells where production has fallen off (including shut-in wells) or other circumstances require a change in operation. Major remedial activities include: (1) Well stimulations -- physical or chemical treatment of a well at production zones to revitalize decreasing production; (2) recompletions -- physical reconstruction of well bores to increase lower-than-expected production rates; and (3) conversion -- e.g., physically retrofitting a production well to convert it to an injection well when production has become uneconomic to maintain or remediate.

Other remedial activities involve maintaining oil production via well-bore delivery systems. When free flow decreases or ceases, flow enhancement/recovery techniques must be applied. These techniques consist of using various forms of artificial-lift, including rod pumping, electrical submersible pumps, and gas lift. Repressuring the reservoir by gas, water, and steam injection (flooding) would also cause wells to flow again. Table 1.2-4 lists the number of remedial activities planned for each zone or pool. Total projects planned through the year 2025 would be approximately 2,663, 1,288, and 1,375 for the periods FY 1989-1995 and FY 1996-2025, respectively. Table 1.2-5 summarizes estimated equipment use (including duration and numbers of units required) for new well drilling, well completion, and remedial work.

1.2.2.6 Light Oil Steamflood Activities

The SOZ Light Oil Steamflood (LOSF) project was initially planned to be carried out in two pilot phases (DOE 1985) which, if successful, would be expanded by implementing up to approximately five additional phases. The phase I pilot project, which was placed into production in FY 1987, called for producing a 59-acre area of the SOZ by continuous steam injection. The project is located in an area that was previously produced on a 10-acre well spacing by conventional production methods. Updated plans include a total of 20 project wells -- 5 existing wells, 13 new wells, and 2 redrills. These wells include 12 producers, 5 injection wells, and 3 observation wells. Facilities for the LOSF were completed at a cost of approximately $4 million. Newly constructed equipment and piping included the following:

- Piping and connections from the fresh water system to the steam generator.
- Piping and connections for a fuel line to supply field gas to the steam generator.
- Water-filtration system to remove iron and iron oxide corrosion products from the fresh water system.
- A water-softening system to remove naturally occurring calcium and magnesium ions in the fresh water system.
- A 3,000-barrel fresh water tank.

TABLE 1.2-4 Remedial Activities Planned at Existing NPR-1 Production Wells

Activities	1989-1995	1996-2025	Total	Section Locations
Stimulations				
MBB/W31S Sands	59	202	261	22R, 23R, 24R, 26$, 30S, 36R, 31S, 32S, 33S, 34S, 35S, 2G, 3G, 4G, 5G, 6G
24Z Sand	15	15	30	13Z, 24Z
2B Sand	4	25	29	2B, 35R
29R/24Z Shales	8	4	12	34R
26R Sand	53	25	78	26R, 25R, 36R, 31S
31S C&D Shales	28	57	85	31S, 32S, 36R
31S N&Z Shales	14	26	40	Same as MBB/21S Sands
NWS A1-A2 Sands	9	27	36	7R, 8R, 17R, 18R
NWS A3-A6 Sands	15	26	41	8R, 17R, 16R, 9R
NWS T&S Sands	12	26	38	16R, 17R
SOZ	70	120	190	Many sections
Carneros	3	0	3	29R, 30R
Dry Gas Zone	31	0	31	Many Sections
Subtotal	321	553	874	
				Same as identified above
Recompletions				
MBB/31S	162	118	280	
24Z Sand	11	15	26	
2B Sand	6	0	6	
29R/24Z Shales	14	10	24	
31S C&D Shales	38	58	96	
31S N&A Shales	9	26	35	
NWS A1-A3 Sands	6	0	6	
NWS A4-A6 Sands	28	52	80	
NWS T Sand & N Shales	7	13	20	
SOZ	67	91	158	
Dry Gas Zone	22	0	22	
Subtotal	370	383	753	

TABLE 1.2-4 (Cont'd)

Activities	1989-1995	1996-2025	Total	Section Locations
Artificial Lift Installations				
MBB/31S	154	34	188	Same as identified above
24Z Sand	16	4	20	
2B Sand	5	0	5	
29R/24Z Shales	81	30	111	
26R Sand	0	0	0	
31S C&D Shales	45	45	90	
31S N&A Shales	14	16	30	
NWS A1-A3 Sands	0	0	0	
NWS A4-A6 Sands	1	0	1	
NWS T Sand & N Shales	4	0	4	
Carneros	6	0	6	
Dry Gas Zone	9	1	10	
Subtotal	335	130	465	
Conversions				
MBB/W31S	10	0	10	Same as identified above
24Z Sand	2	0	2	
26R Sand	58	14	72	
31S C&D Shales	20	0	20	
NWS A1-A3 Sands	13	54	67	
NWS A4-A6 Sands	11	18	29	
NWS T Sand & N Shales	17	13	30	
Carneros	1	0	1	
Tulare	17	52	69	
SOZ	113	158	271	
Subtotal	262	309	571	
Total	1,288	1,375	2,663	

Source: Compiled from BPOI 1989.

TABLE 1.2-5 Summary of Estimated Equipment Use During New Well Drilling, Remedial Work, and New Well Completion Activities at NPR-1

Type of Activity	Zone	Depth (ft)	Drilling[a]			Moving		
			Machine	No.	Days	Machine	No.	Hours
New Well drilling/ deepening[b]	Deep Stevens/Carneros	8,500	Engine, diesel (912 hp)	1	30	Crane, diesel (65-85 tons)	2	10-12 (70%)
			Engine, diesel (610 hp)	1	30	Truck, diesel (400 hp)	6-8	10-12 (100%)
	Shallow Stevens	7,000	Engine, diesel (380 hp)	7[c]	20	Same as above	Same as above	Same as above
	Shallow Oil	3,500-4,000	Engine, diesel (380 hp)	3	10	Crane, diesel (65 tons)	1	6-8
			Engine, diesel (285 hp)	1	10	Engine, diesel (380 hp)	1	2
						Engine, diesel (285 hp)	1	2-4
Remedial work/new well completion	Various	Various	Engine, diesel (380 hp)	2	1-25	Engine, diesel (380 hp)	1	1.5-2
			Engine, diesel (175 hp)	1	1-25	Truck, heavy-duty (highway-type)	1	2-2.5

[a]Typically at any one time throughout the NPR-1, there are 3 drilling rigs in operation at the deep Stevens/Carneros or shallow Stevens Zones (24 hr/day, 100% utilization), 1 drilling rig at the SOZ (24 hr/day, 100% utilization), and 5 remedial work rigs (24 hr/day, 90% utilization).
[b]Well deepening requires the same equipment as new drilling, but takes less time by about 8-10 days.
[c]5 of 7 engines are in operation at any one time.

- Pumps and piping to circulate water in the fresh water tank to a heat exchanger at the production tank setting.

- A natural-gas-fired steam generator rated at 62.5 million BTU/hour and capable of delivering approximately 3,100 barrels/day of 80% quality steam (quality is the weight fraction of dry saturated steam contained in wet steam).

- Insulated piping to four injection wells.

- A production tank setting to separate and meter liquid and gas production. A 3-phase test separator separates and meters oil, water, and gas production for individual wells. A pool separator is used to separate liquid and gas production for the remaining wells entering the manifold. The liquids are stored in a production tank and eventually pumped through a pipeline to the 10G dehydration/LACT facilities. The gas is collected into a vacuum system with SOZ compressors located in Section 3G. Water from the fresh water tank is pumped to a heat exchanger at the tank setting, where heat is transferred from the produced fluids to the fresh water. The preheated water is then pumped to the steam generator.

- Modified piping from the wellhead to the production tank setting for 12 production wells.

The phase II pilot project consists of 12 wells (10 of which will be new); 6 wells will be producers, 4 will be injectors, and 2 will be observation wells. The phase II pilot project would require one additional steam generator, additional piping, and modification of one existing tank setting.

Assuming the phase II pilot project proves successful, proposed future expansions of the SOZ steamflooding into other areas could ultimately encompass more than 500 acres (but only about 35-46% of this area would be disturbed). Expansion would consist of development of five additional areas in five phases of about 100 acres each (Figure 1.2-2). The most economically promising areas would be developed first, with development of subsequent phases depending on the success of the preceding phase. Phase I includes further expansion of the previous projects in Sections 3G, 4G, 9G, and 10G, with primary expansion planned for Section 3G (Figure 1.2-2). All other phases would introduce steamflooding to new areas. Phase II would be in Sections 35S and 36S. Phase III would be in two separate areas -- one including portions of Sections 9G and 10G (essentially expanding on the phase I area), and one in Section 1G, including a small portion in Section 36S. Phase IV would be in Section 36S, where it would bridge the gap between areas in Section 36S developed in phases II and III. Phase V would introduce steamflooding into Section 34S and extend the development of new areas in Section 35S initiated during phase II.

The five-phase LOSF expansion project requires phased construction of steam-generating facilities to meet production expansion plans. New facilities would consist of a maximum of 10 additional 62.5 million BTU/hour steam-generating units to support expanding steamflood activity. The steam generation units would be installed and/or operating on a schedule

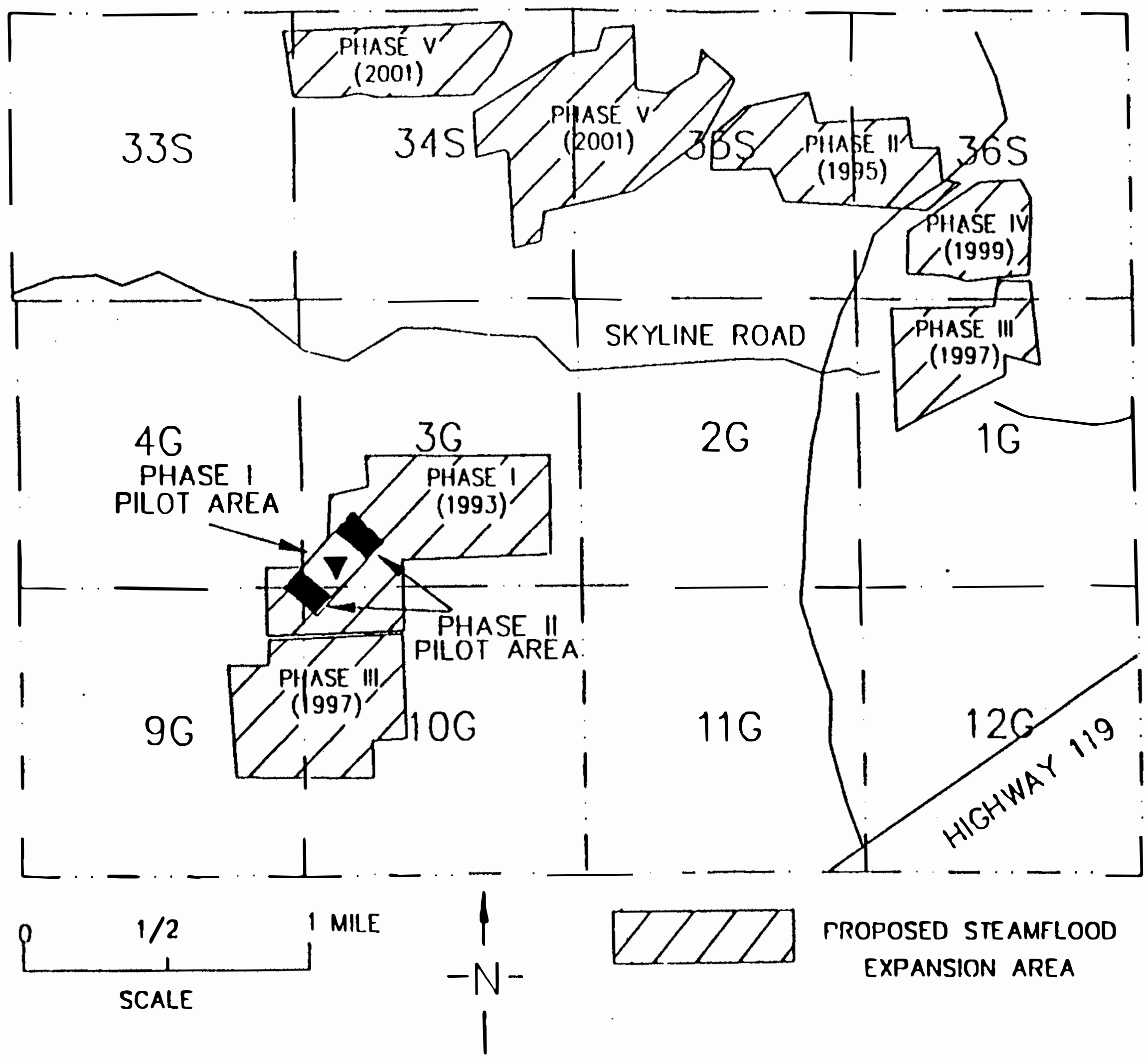


FIGURE 1.2-2 LOCATIONS OF PROPOSED STEAMFLOOD PROJECT DEVELOPMENT PHASES

developed to coincide with implementation of the five phases of steamflood expansion. Table 1.2-6 lists the number of steam generators expected to be operational and the steam requirements by year and phase. Table 1.2-3 summarizes the number of new wells planned in support of the five phases of the project.

Gas-fired equipment, including each steam generator unit, would operate on produced gas that has been processed at the gas plants. Each unit would occupy about 0.5 acre of land (similar to land requirements for tank setting and gas/liquid separation units), for a total of about 5 acres. In addition, installation of each unit would result in an additional disturbance of about 1 acre, for a total of an additional 10 acres. This would result in 15 acres of disturbance. Also, because some of these units would be moved from one location to another as the phased expansion is implemented, cumulative area of disturbance could double to as much as 30 acres. Abandoned steam generator sites would be revegetated as the phased expansion proceeds.

1.2.2.7 Waterflood Activities

The proposed action includes the operation, maintenance, and construction of all existing and planned waterflood facilities. Currently, there are three areas being waterflooded. The MBB/W31S area is being flooded using the 33S waterflood plant. This facility has a capacity of approximately 140,000 barrels/day, and injection is currently about 94,000 barrels/day. The other two areas being flooded are in the 24Z area and the 17R area. These areas are being flooded using a waterflood plant in 17R. This facility is currently operating at a rate of approximately 54,000 barrels/day, and it has a capacity of approximately 60,000 barrels/day. The source water for the 33S and 17R plants comes from approximately five active Tulare Formation source water wells. These waters are pumped from the source wells to a booster pump plant in section 18G and then pumped to the 33S and 17R plants. Total source water is currently 148,000 barrels/day.

A 20,000 barrel/day increase in the 24Z waterflood is planned. This expansion would include (1) construction of a pipeline and distribution system to extend from the 17R injection plant to injection wells in Sections 18R, 19R, 13Z, and 24Z, (2) construction of additional pump capacity at the 17R injection plant, and (3) a pipeline connecting the 17R plant to a source water well in 8R.

A new waterflood of the SOZ SS-2 Mulinia is also planned. Initially, preliminary plans are to flood a portion of the south flank at a rate of approximately 24,000 barrels/day using 12 existing idle wells that have been converted from production to injection. This would also require the expansion/modification of existing waterflood pumps, piping and related systems. Additional SOZ areas would be flooded in stages that would proceed on the basis of the technical and economic success of each preceding stage. As in the case of the initial stage, preliminary plans are to use existing facilities to the maximum extent possible; accordingly, new land disturbances should be minimal.

TABLE 1.2-6 SOZ Steamflood Expansion Steam Requirements

Year	Steam Requirements (bbl/d as water)						
	Phase I	Phase II	Phase III	Phase IV	Phase V	Total	Number of Steam Generators
1991	8,505	0	0	0	0	8,505	6[a]
1992	17,010	0	0	0	0	17,010	6
1993	17,010	7,148	0	0	0	24,158	10[b]
1994	17,010	14,295	0	0	0	31,305	10
1995	8,505	14,295	10,091	0	0	32,891	10
1996	0	14,295	20,183	0	0	34,478	10
1997	0	7,148	20,183	5,801	0	33,131	10
1998	0	0	20,183	11,603	0	31,785	10
1999	0	0	10,091	11,603	10,065	31,759	10
2000	0	0	0	11,603	20,130	31,733	10
2001	0	0	0	5,801	20,130	25,931	8
2002	0	0	0	0	20,130	20,130	6
2003	0	0	0	0	10,065	10,065	6[a]

[a]Six generators operating at half power.
[b]Five generators operating at half power.

Source: Wei 1988.

An initiative is in the planning phase to study the economics of waterflooding the SOZ in selected portions of the SS-1 Mulinia, as an alternative to the planned steamflood. Initial efforts would focus on simulation studies. If areas in the SS-1 are identified as potentially being more responsive to waterflooding than steamflooding, field pilot tests would be implemented. To the extent pilot tests were successful, SS-1 waterflooding would be expanded appropriately. The areas of the SS-1 that could be affected are shown by Figure 3.4-5.

As the result of increasing waterflood requirements, it would be necessary to increase the supply of waterflood source water. Future requirements would increase from the current rate of approximately 148,000 barrels/day to 254,521 barrels/day by approximately FY 1994 (see Table 1.2-1) or a total increase of about 106,521 barrels/day. Plans are to provide waterflood source water by using produced wastewater, thus accomplishing another objective of reducing wastewater requiring disposal.

Produced wastewater availability is projected to be approximately 100,000-110,000 barrels/ day initially, increasing to approximately 181,067 barrels/day by approximately FY 1994 (see Table 1.2-1). Produced wastewaters are currently being disposed of by injecting them into the Tulare Formation utilizing a separate wastewater disposal system. Rather than continuing this practice, plans are to treat, clean, and filter produced wastewaters, and recycle them into the waterflood source water system to supplement the water from the Tulare source water wells, as needed to satisfy overall waterflood requirements. Operation of the facility generates small to moderate amounts of non-hazardous filter waste residues, which are currently being disposed of into the wastewater disposal system. This project is planned in stages that will proceed on the basis of the technical and economic success of each preceding stage.

For additional information refer to Appendices A.6. and A.7, and the project descriptions in the LRP (Appendix G).

1.2.2.8 Gas Injection Activities

Plans are to construct two surface gas injection facilities for injecting gas into the Stevens 26R sand reservoir wells 334A-36R and 312-36R by FY 1995. This would require approximately 4 acres of land. An initiative is also planned to study the possibility of enhancing SOZ production through a gas injection project (Querin 1989) (see Figure 3.4-6) Initial efforts would concentrate on simulation studies. These would be expanded to field tests and more comprehensive programs, if appropriate. It is anticipated that the program can be implemented with existing facilities.

1.2.2.9 Gas Compression Facilities

This involves the installation of ten 1,000 horsepower natural gas-fired (NGF) compressor drivers and three 1,500 horsepower NGF compressor drivers each equipped with pre-combustion chamber technology for gas-gathering (see Table 1.2-7 and P49312 described in Table 1.2-10). Approximately 10 acres of land would be required.

TABLE 1.2-7 Number of Planned Gas Gathering Compressor Installations (FY 1989 through FY 1995[a])

Section	Total
19R	3
30R and 29R	2
33S	2
35R	3
36R	3
Total	13

[a]Each compressor would be 1,000 hp, except at 19R, where they would be 1,500 hp each.

Source: BPOI 1989

1.2.2.10 Closed-Loop Gas-Lift Facilities

These facilities would provide additional field gas handling and compression capacity to furnish compressed gas for current and future gas-lift wells. One new facility is proposed; also one existing facility would be expanded. A new 24Z/29R gas-lift facility would be installed; preliminary plans are to locate it immediately north of the 3-19R Stevens tank setting. About 2 acres of land would be disturbed for pad preparation and construction. The facility would include the following components: four 1,750 horsepower electric motor-driven compressors, an electric power substation, a glycol dehydration system, and associated equipment. Currently, 23 gas-lift wells are in operation in the 24Z/29R area, and 9 more are planned. Additionally, a new 4-inch pipeline would be installed to supply high-pressure gas to injection well 36S-24Z. The pipeline would follow existing right-of-ways with minimal disturbances.

The existing 4G Main Body B Reservoir (MBB) gas-lift facility would be expanded from 20 million cubic feet/day to 32 million cubic feet/day by adding a fourth compressor (1,750 horsepower electric). There would be no additional land disturbances.

1.2.2.11 Gas Operations Expansion

The objective of the proposed gas operations expansion is to sustain continued MER production by constructing and operating an additional gas-processing plant as needed to handle projected increases in gas production and to reduce reliance on CUSA's 17Z gas plant. This expansion would increase gas-processing capacity by 100-150 million cubic feet/day. This project would also provide additional gas-gathering and injection compression (22,000 horsepower) and it would expand other existing related components. Preliminary plans are to site the new plant at the Section 35R gas plant complex just northwest of the LTS-2 plant. The project would disturb about 15 acres of land, including the plant site, substation, and construction staging area. Construction is expected to last 16 months.

1.2.2.12 Butane Isomerization

The butanes produced at NPR-1 consist of commingled normal butane and isobutane. Recent trends in the California butane market place suggest that it might be economical to separate the two butanes and convert normal butane into isobutane. Unlike normal butane, isobutane is a good source for producing lead-free high-octane gasoline, and therefore it is the more valuable of the two butane components.

This project includes the design, acquisition, and installation of a butane isomerization facility. The facility, which is proposed for construction over a two-year period, would consist of the following components:

- Butane isomerization unit and fraction facilities for separation of isobutane and normal butane,

- Mixed butane feed storage, and
- Electrical distribution, relief and blowdown facilities, fuel and air supply, process water supply, and other utilities.

About 5 acres of land would be disturbed during site clearing. The facility would be located in the existing 35R gas plant complex area. Operational requirements include 973 kilowatt electricity, steam at two different volumes and pressures; and a small amount of makeup water. The single fractionation column also would be used to recover isobutane contained in the mixed butane feed, as well as in the reaction section. The proposed feed rate, based on current butane sales, is expected to be approximately 170,000-220,000 gallons/day.

1.2.2.13 Cogeneration Plant

This facility would include two gas-turbines with an estimated output of 21 megawatts each while producing a total of approximately 126,000 pounds/hour of approximately 566 pounds/square inch gauge (psig) steam for process heat. Plans are to locate the plant adjacent to the LTS gas processing plants at the 35R complex. The skid-mounted turbines would be packaged for outdoor installation. The facility would require about 3 acres of land. The associated electrical equipment would be housed in a building of about 4,000 square feet with a heating, ventilation, and air conditioning system to provide climate and dust control to protect electronic equipment. Ancillary equipment/facilities would include a forced draft decarbonator tower and catch tank, two approximately 1,900 gallon capacity bulk storage tanks for acids and caustics storage, two automatic, co-current regenerated strong base anion exchanger vessel units for the demineralizer system, one approximately 26,000 gallon capacity waste neutralization tank, demineralized water and feedwater storage tankage, an ammonia storage tank, a hook-up to existing or installation of a new septic system, along with associated pumps, blowers, piping, and control systems. Facility inputs would include natural gas fuel produced at NPR-1 (approximately 924,000 cubic feet/day), fresh water from the West Kern Water District (WKWD) (approximately 6,500 barrels/day), and selective catalytic reduction with ammonia injection (approximately 29 pounds/hour of ammonia), to reduce nitrogen dioxide (NO_x) emissions. Outputs would include boiler blowdown, system losses, water treatment backwash, domestic wastewater, and exhaust emissions. The plant would generate electricity and process steam for NPR-1 use.

1.2.2.14 Abandoned Waste Site Closure and Facility Decommissioning

A program is in place to identify, review, investigate, characterize, evaluate, remediate and formally close all abandoned unneeded waste disposal sites in accordance with applicable regulations and DOE Orders, including wastewater sumps, chromium spill sites, two arsenic contaminated sites, landfills, etc.

Project facilities and equipment that become inoperable or unnecessary at the end of their useful life or upon depletion of the oil reservoirs would be decommissioned and removed. Table 1.2-8

TABLE 1.2-8 Proposed Well Abandonments in FY 1989-1995 and Projected for FY 1996-2025[a]

Fiscal Year	Stevens	SOZ	Total
1989	-	10	10
1990	2	23	25
1991	2	23	25
1992	2	28	30
1993	2	28	30
1994	2	28	30
1995	2	28	30
Subtotal	12	168	180
1996-2025	60	840	900
Total	72	1,008	1,080

[a]Assumes same rate for FY 1996 through FY 2025 as in FY 1995.

Source: BPOI 1989.

shows that approximately 180 wells would be abandoned during the period FY 1989 through FY 1995, or about 26 wells/year for the foreseeable future. For the period FY 1996-2025, it is anticipated that another 900 wells would be abandoned. Wells would be abandoned in accordance with applicable regulations.

A program is in place to remove all asbestos field-wide, almost all of which is installed on pipes and process vessels at the 35R gas plant constructed in the 1950's. This program would continue.

The 3G gas plant is abandoned. Under the proposed action, it would be demolished and the components would be sold, recycled or disposed of by the demolition subcontractor. Alternatives are being evaluated to achieve the objective of relocating, repairing, or replacing parts of the 25S dehydration/LACT and tank setting facilities as needed to increase groundwater protection in the 25S area.

Other miscellaneous construction reclamation activities associated with expansion or replacement of gathering and processing systems are planned. For additional information refer to Appendix A.10 and LRP project listings.

1.2.2.15 Power Supply

The proposed action includes the construction, operation and maintenance of all planned and existing power systems. Electric power at 115 kilovolts is currently purchased from Pacific Gas and Electric Company (PG&E), primarily at the 35R substation. Total connected capability is approximately 80 megawatts. Current running load is approximately 24 megawatts, which is distributed through major substations at 35R, 18G, 33S, 3G, 4G, and 17R by 115-kilovolt, 12-kilovolt and 4160-volt transmission systems to gas compressor stations, waterflood pump stations, well pumps, cathodic protection facilities, gas plants, and buildings. Planned projects to expand waterflood injection, gas-lift compression, well electrifications and other projects would increase running load to approximately 50 megawatts. Land disturbances for these projects would be minimal since the necessary system capability is already in place.

A future source for meeting on-site electrical power needs is the cogeneration plant described in Section 1.2.2.13. This plant would use a gas-fired generator to produce up to 42 megawatts of electricity. The waste heat from the generator would be provided to the gas plants as process heat, replacing process heat that is currently being provided by gas-fired boilers and heaters. This facility could provide most, if not all, NPR-1 electrical requirements, thus reducing the amount of power purchased.

Another significant source of power at NPR-1 is produced natural gas which is commonly used as a source of fuel for well pumps, compressors, and process equipment such as heaters and boilers. Quantities of natural gas consumed as fuel would increase from approximately 20 million cubic feet/day in FY 1990 to 32 million cubic feet/day in FY 1995 (see Table 1.2-1).

For additional information on NPR-1 power systems refer to Appendix A.8.3.

1.2.2.16 Water Supply and Sewer System

The proposed action includes all activities associated with the water supply and sewer systems.

NPR-1 purchased approximately 29,000 barrels/day of water from WKWD in FY 1988 for a variety of purposes: drinking water, construction, process water, drilling operations, fire protection, SOZ steamflood, etc. NPR-1 recently provided WKWD with projected requirements through April 1995 (BPOI 1988). These requirements are expected to increase to 74,800 barrels/day (3.1 million gallons) by April 1995. This increase is primarily due to an anticipated stepwise increase in the SOZ steamflood along with smaller contributions from other facility projects, such as the butane isomerization project and cogeneration project. West Kern Water District has recently determined that due to a reduction in water deliveries to other westside oil companies, they would have sufficient water supplies to meet the NPR-1 request (BPOI 1991).

Sewage treatment facilities at NPR-1 are composed of septic tanks with leach fields. Twelve septic systems currently are in use. Additional septic systems could be constructed, if necessary. The septic systems are emptied regularly by a subcontractor, and the wastes are hauled off the site for disposal. Timing varies from twice/month at 11G to one to two times/year at all other sites.

1.2.2.17 Fire Protection

The proposed action includes the conduct of all fire protection activities, as follows: coordination with the Kern County Fire Department, which has primary fire fighting responsibility; the operation, maintenance and construction of all existing and planned fire water systems and fire prevention/protection/fighting equipment; personnel training; and fire drills. One noteworthy activity is the maintenance of a 12 to 20-foot wide fire break around the periphery of the site. The fire break is disced 12 inches deep to remove revegetation annually, or as needed to prevent the spread of fires. Discing did not take place in 1989 or 1990 because there was insufficient vegetation to pose a threat as the result of a continuing drought. To the extent possible, existing roads are used to minimize discing requirements; typically, this reduces discing by about 20%. Other planned projects are identified in Table 1.2-10 and in the LRP (Appendix G); additional initiatives will be implemented based on a complete review of fire protection systems including the fire water systems. For more information refer to Appendix A.8.6.

1.2.2.18 Roads

The proposed action includes the construction and maintenance of all roads required for MER production. Currently, there are over 1,100 miles of primary, secondary and tertiary (unpaved access) roads. No new primary or secondary roads are planned; however, unpaved access roads would be needed for new wells and new facilities located in areas not currently served by roads. These requirements are presented separately in the discussion of wells (see Section 1.2.2.4), in other project descriptions contained herein, and in the LRP (Appendix G). Abandoned roadways would be reseeded and reclaimed as part of the ongoing restoration program. Unpaved roads would be watered to minimize fugitive dust in accordance with applicable requirements, as appropriate. For additional information refer to Appendix A.8.1.

1.2.2.19 Erosion Control and Contemporaneous Revegetation

Where land disturbance is unavoidable, the extent of disturbances would be minimized as a matter of policy. This includes implementation of sound erosion and sediment control practices and reclamation during and after the various construction activities. New construction project design and specifications would include erosion control and reclamation measures. Culverts would be installed and appropriate stabilization methods would be implemented at construction crossings of drainageways. Areas of disturbance not needed permanently would be contemporaneously revegetated. Topsoil would be conserved and stockpiled for use in future reclamation efforts. Disturbed areas would be stabilized and reclaimed consistent with the surrounding terrain. Natural drainageways would be reestablished. Annual reclamation plans would be prepared for abandonment of access roads, well pads, and other facilities. Site development and reclamation plans would include (1) salvaging and protecting topsoil for use in site reclamation, (2) revegetating disturbed areas with native and naturalized perennial and annual grasses, forbs, and shrubs, (3) applying erosion controls, (4) minimizing damage to on-site and off-site hydrologic regimes, and (5) minimizing the extent of disturbance to natural habitat.

1.2.2.20 Endangered Species Program

There are four major components of the endangered species program. Under one component preactivity surveys are conducted for all potential and planned construction, maintenance and operations sites. A qualified biologist surveys the sites to ensure that endangered species and endangered species habitat are avoided to the maximum extent possible. Since preactivity surveys began in 1980, the loss of habitat has been minimized and the loss of kit fox dens has almost been eliminated.

The second component is revegetation of disturbed sites that have been abandoned. After the sites are revegetated they are monitored annually to document that vegetation has reestablished successfully. It is estimated that 625 acres will be revegetated during the period 1990-1998.

The third component encompasses investigations, studies, and research. Currently, the effects of large predators on kit fox carrying capacity are being evaluated, as are the influence of food supplies on kit fox survival, factors influencing kit fox abundance and distribution, and the effect of oil-field chemicals on kit foxes. Techniques to increase prey abundance on burned areas and to relocate kit foxes on NPR-1 are also being studied. This research will be used to mitigate impacts to threatened and endangered species.

Monitoring and documenting conservation of endangered species and habitat is the fourth component. Using a mark-and-capture method, kit fox abundance on NPR-1 is assessed annually. Kit fox reproduction, mortality and dispersal are also monitored using radio telemetry. Blood samples are occasionally collected to monitor diseases in kit foxes. Scent stations surveys are used to monitor the abundance of kit fox predators and prey. Other species are also monitored to assess the status of their populations on NPRC. (See LRP -Appendix G for more detail of the Endangered Species Program.)

1.2.2.21 Future Non-Federal Actions

NPR-1 routinely receives requests for easements, right-of-ways and cooperation/assistance for third-party pipelines and other facilities and actions on NPR-1 lands. Third-party projects are activities conducted on NPR-1 lands by others: i.e., not by DOE and CUSA, otherwise known as the Unit (first party), or by the management and operating contractor, currently BPOI (second party). Generally, these are projects to conduct geophysical surveys, or to construct, operate, and maintain pipelines and ancillary equipment (such as LACT units, pumps, compressors, etc.). In some cases, however, they involve other miscellaneous types of facilities and actions. Examples of the current inventory of third-party actions include geophysical surveys, pipelines and ancillary equipment, sewer facilities, and microwave towers. The projects are always carried out by the third-party at its own expense in accordance with the terms of legal agreements between appropriate NPR-1 entities (DOE/CUSA management and operating contractor) and the third party. Usually these agreements are DOE revocable permits which specify security requirements, technical requirements (design, engineering, construction, operations, maintenance, etc.), environmental requirements, safety requirements, and other legal terms. Currently, there are approximately 30 permits in place. Many of these have been amended, sometimes on several occasions, to accommodate changing third-party requirements.

An important non-federal action at NPR-1 involves the aerial application of the insecticide malathion by the California Department of Food and Agriculture (CDFA), as part of their state-wide curly top virus control program. An environmental assessment of the program was prepared by the CDFA in March 1991 and adopted by DOE on April 8, 1992 (DOE 1992a). This pest control program is conducted annually by the CDFA throughout the south and central portions of California. Except for 1990, the CDFA has conducted annual aerial applications of the insecticide malathion on portions of NPR-1 and NPR-2 since 1987 under the terms of a Cooperative Agreement between DOE and CDFA. The term of the Cooperative Agreement was extended in 1992 for the period 1992 through 1996 (DOE 1992b).

The CDFA's malathion spraying program controls populations of the beet leafhopper, an insect that threatens many commercial agriculture crops by transmitting the curly top virus. This insect overwinters on the west side of the San Joaquin Valley and migrates back to cultivated croplands in the late spring. The amount of acreage on NPR-1 and NPR-2 that will be included in the program will vary from year to year, but is expected to be approximately 10,000 acres. However, the malathion spraying activities will not disturb additional acreage on NPR-1 as all ground support activities are restricted to existing developed areas and roads. All program activities are monitored and reported by CDFA in accordance with the terms of the Cooperative Agreement. For a complete evaluation of the program's impacts and required mitigation, please refer to the Environmental Assessment of Curly Top Virus Control in California (DOE 1992a).

Pipelines that are constructed sometimes pass through NPR-1 without actually connecting to NPR-1 facilities. Except for permit requirements, these projects have no effect on, nor are they affected by, NPR-1 operations. In other situations, the pipelines tie-in to NPR-1 facilities. Generally, the purpose of these pipelines is to deliver DOE products to market. Generally, they are only one of several pipelines capable of delivering the same product and therefore are not necessary for MER production. In all cases, they are installed at the request of the third party for the economic benefit of the third party and its customers. However, this also has the potential of benefitting the government and the government's purchasers. This is because connected third-party pipelines provide more options for distributing product which could result in greater demand and more attractive prices for the government's product. Typically, significant portions of third-party projects are located off NPR-1, as needed for the third parties to tie-in to their existing pipeline facilities located in surrounding areas. Usually, the total length of a third-party pipeline is less than 3 miles; very rarely it is over 10 miles. The pipeline diameters are typically 4- to 8-inch. Construction occurs both above ground and below ground on both new right-of-ways and on existing previously disturbed right-of-ways. Pipeline right-of-ways can vary from 10 feet to 60 feet in width.

Geophysical surveys use sound waves directed into the substructures to analyze for hydrocarbon-bearing potential. Typically, these surveys are made by emitting and recording the reflections of sound waves that have been directed into the subsurface using vibrating or small detonating devices. These devices and the necessary recording equipment are usually truck-mounted for transport along a right-of-way area of investigation. Sometimes, small, widely spaced drilling pads are constructed along the survey route for placement of dynamite charges at depths which are typically 100-300 feet deep. The surveys conducted on NPR-1 by third parties are generally part of a larger analysis of regional substructures. Accordingly, large portions of the surveys normally take place off NPR-1. Geophysical survey right-of-ways are typically 20 feet wide.

Pipeline and other "construction" right-of-ways are generally wider than "surveying" right-of-ways, such as geophysical surveys, due to the additional area required for construction equipment as opposed to survey equipment.

Third-party projects on NPR-1 would undergo environmental, safety, and engineering reviews prior to receiving NPR-1 permit approval. Third-party activities would be spot monitored to determine if they are in compliance with applicable laws and regulations and permit requirements. If third parties are determined not to be in compliance, appropriate enforcement actions would be taken pursuant to the terms of the permits, including DOE's right of revocation, if necessary.

On the basis of ongoing inquiries and permit applications by third parties, and an analysis of historical third-party projects, an estimate of future third-party projects has been made for planning purposes (Killen 1990). On the basis of this estimate, the proposed action includes three to four third-party projects and geophysical surveys each year. Projects would disturb approximately 23 acres per year (total of both on and off NPR-1). Geophysical surveys would affect approximately 226 acres per year (total of both on and off NPR-1). All disturbed areas not needed for future operations and maintenance activities would be contemporaneously revegetated by the third party. This is estimated to be approximately 14 acres per year for both pipelines and geophysical surveys. Additional details of future plans are shown by Table 1.2-9.

1.2.2.22 Miscellaneous

In addition to the foregoing, the proposed action includes numerous other activities, such as replacements necessary as the result of corrosion, and additions, expansions and modifications necessary as the result of changing legal/regulatory, technical, and economic conditions. Projects are also planned to enhance secondary containment facilities.

Miscellaneous activities would primarily involve pipeline components, gas processing and sales/delivery facilities, oil processing and sales/delivery facilities, NGL storage and sales/delivery systems, waste and waterflood source water systems, tank settings, and compressor and pump components. For a more complete listing of activities included in this Section, refer to the LRP (Appendix G). For convenience, the more important of these activities, some of which have been described in preceding Sections, are shown by Table 1.2-10. For the most part, the referenced activities are expected to take place on areas that have already been disturbed. In the cases of pipelines, however, new disturbances would be approximately 50 acres through FY 1995.

1.3 LAND REQUIREMENTS

Typical unit values of disturbance and volume of earthwork are listed in Table 1.3-1. Preparation of new sites generally follows a sequence of stripping and stockpiling of topsoil, cutting and filling, and watering and compacting to stabilize the site. Table 1.3-2 summarizes the major facilities proposed for NPR-1 and lists the estimated land requirements for each type. Site preparation activities required for new facilities previously described would involve varying amounts of land disturbance and volumes of surface earthwork.

Site preparation activities for well pads, access roads, and similar facilities generally require about 7 days/site. Site modifications (e.g., for tank setting modifications) at existing facilities require an order of magnitude less earthwork than for a new facility.

TABLE 1.2-9 Annual Average Habitat Disturbance[a] Associated with Projected Third-Party Pipeline and Geophysical Projects at NPR-1[e]

Type of Third-party Project	Number	Acres Affected[b]					Acres Cont. Reveg.[c]		
		Total	On NPR-1		Off NPR-1				
			Dev.	Undev.	Dev.	Undev.	Total	On NPR-1	Off NPR-1
Pipelines/Other									
Underground	1.2	19	2.0	0.75	8.0	8.25	12	1.7	10.3
Aboveground	0.2	4	0.6	0.00	1.7	1.70	2	0.3	1.7
Subtotal	1.4	23	2.6	0.75	9.7	9.95	14	2.0	12.0
Geophysical surveys	2.0	226	17.0	96.00	56.00	57.00	[d]	[d]	[d]

[a]Disturbance numbers are based on informal third-party inquiries, projections based on historical experience, and judgement based on general knowledge pertaining to factors associated with site operations. All numbers assume implementation of the standard mitigation activities.
[b]Dev. = developed, Undev. = undeveloped
[c]Cont. Reveg. = contemporaneous revegetation.
[d]Included in pipelines/other.
[e]For the purpose of the SEIS it was assumed that none of the acres affected would be on previously disturbed lands.

Source: Killen 1990

TABLE 1.2-10 Summary of NPR-1 Proposed Projects

Title	Project Number	Description
Stevens tank setting modification.[a]	P49313	Modifications are necessary to provide capacity to meet production requirements (e.g., larger flow lines, add shipping pumps).
Repair or replace pipelines, oil and water pipelines.	P40301A	Includes replacement or repair (oil and water) necessary to ensure continued safe operation.
Tank setting liquid containment.	P49202	Provide secondary containment as necessary on a priority basis at selected storage tanks that present danger to off-site property, potable groundwater, and surface water.
Surge tank repair/replacement/relocation at 25S dehydration/LACT and Stevens tank setting.	P40302	Relocate facilities to the extent possible. Clean and inspect remaining facilities, tanks, make necessary repairs or replace.
Artificial-lift projects.	P49309	Various artificial-lift installations are planned in production zones experiencing declining pressure [e.g., MBB/31S, 24Z, NWS (A4-A6), 2B sands, 31S N/A shales and 29R shales].
Replace 16-in. NF S0Z gravity line.	55008B	Replace 7,400 ft. of 16-in. NF gravity line with approximately 6,000 ft. of 10-in. and 1,400 ft. of 12-in. fiberglass piping.
LTS vent modifications	P47615	Minimization of air pollution related to gas venting/stacking and other emission sources.
LTS gas/gas exchanger	P48792	Minimization of air pollution related to gas venting/stacking and other emission sources.
TS flare bypass	P49208	Minimization of air pollution related to gas venting/stacking and other emission sources.
1-7R TS vapor recovery installation	P48796	Same as above.

TABLE 1.2-10 (Cont'd)

Title	Project Number	Description
Pipeline repair/replacement	P40301B	Includes replacement or repair of gas pipelines as necessary to ensure continued safe operation.
New NWS HP pipeline	P48767A	Replacement of 32,000 ft of 14-in. diameter HP pipeline from 1-7R tank setting to 35R gas processing facilities.
Compressor optimization implementation[a]	P49312	Implement recommendations of compressor optimization study to ensure MER production rates.
Environmental trigger	P40201	Reduction of NO_x emissions from stationary internal combustion engines at NPR-1.
Minimize gas stacking	P48850	Same as above.
Carneros compressors[a]	P48304	Includes, design, construction, and installation of low-pressure gas compression at 30R to maintain Carneros gas production at MER.
Install/replace HP gas dehydrators, and provide glycol dehydrators throughout.	P48814A P48814B P40310	Gas dehydrators are necessary for reducing internal pipe corrosion. One new system is currently planned at 33S to control and process discharge gas.
Gas-lift compressors MBB.[a] Gas-lift compressors NWS.[a] Gas-lift compressors 4G.[a]	P47751C P47751D P49343	Provide additional compression at Sections 7R and 4G.
Recylindering of K57 and KS8 compressor units.[a]	P49349	Recylindering compressor units at 1-7R tank setting to increase gas-handling capacity.
Condensate collection system.	P49304	Project is intended to improve condensate collection, reduce hydrocarbon emissions, and enhance production.
30R LP gas separation.[a]	P55127	Includes installation of equipment to improve LP gas separation and operation of the 30R compressor station.

TABLE 1.2-10 (Cont'd)

Title	Project Number	Description
DGZ program and $H_2$0 collection.	P49324 P46121	Upgrading of DGZ processing facilities to maintain production of sales-quality gas and installation of a booster compressor are planned. H_2O collection project includes putting in service shutdown separators.
35R gas plant upgrade, lighting modification, asbestos removal and asbestos abatement.	P48815 P49107 P47536A P49003	Projects relate to needed improvements to satisfy requirements of the 35R Gas plant Safety Analysis Report (SAR).
Abandonment/demolition of 3G gas plant.	P49102	Project involves removal of plant cooling tower and abandoning the remainder of the plant in place. The plant is not required and is too expensive to rebuild for operation.
24Z gas sales point.[a]	P48878A	Project involves increasing the capacity of 24Z sales point from 60 x 10^6 ft^3/day to 150 x 10^6 ft^3/day.
H_2S program project.	P49210A	Includes monitoring and if necessary, installation of equipment to reduce H_2S concentrations in sales gas.
Cathodic protection replacements, anode bed replacements and pipeline corrosion inspection.	P49314 P48724 P49703	Projects include replacement of: 105 weak ground beds; restore cathodic protection to 429 wells. Corrosion inspection of critical gas systems pipelines to identify problems needing correction.
Gas operations expansion.[a]	P49346	Project described in Section 1.2.2.11.
24Z/29R closed-loop gas-lift compressors.[a]	P49335	Project described in Section 1.2.2.10.
Butane isomerization.[a]	P41104	Project described in Section 1.2.2.12
Produced water injection and wastewater disposal system.	P40309A P40307	These projects all relate to design and installation of wastewater injection alternative for Tulare disposal. Includes conversion of 24Z and NWR Stevens

TABLE 1.2-10 (Cont'd)

Title	Project Number	Description
18G wastewater tanks improvements.	P55182	waterflood to produced water, water knockouts at 10 tank settings per year,cleaning of SOZ water to injection quality, improvements in 18G wastewater tanks, conversion of a portion of 33S plant to produced water and repairing/replacing 18G/24Z wastewater pipeline.
Waterflood expansions: SOZ (SS-2 and SS-1),Stevens, 24Z (Phase 2),NWR spare pump, and 18G booster pump spare.[a]	P46263 P49308 P49305 P49325 P49322	Projects include installation of injection facilities to inject SOZ-produced water into production zones. The Stevens waterflood expansion will aid in eliminating wastewater injection into Tulare. The 24Z expansion will increase injection capacity at the 17R injection plant (e.g., new pump train).
35R sump replacement and 27R oil recovery/ truck washout facilities replacement.	P49201 P48201	Includes replacing the 35R sump with tankage, a new pipeline that will bring Carneros water to be processed at 18G, and elimination of 27R oil-recovery sumps to be replaced by aboveground facilities.
Industrial hygiene special projects.	P49104	Projects necessary to ensure compliance with OSHA and DOE requirements related to: Potable water system, bulk storage and piping system, bulk storage and piping systems for hazardous chemicals, upgrading emergency showers/eyewashes, and H_2S safety systems.
New fire protection systems.	P49105	Projects include modifications to fire protection systems after review of existing systems in order to upgrade protection.
SOZ steamflood expansion.[a]	P40306	This project is intended to provide design, purchase and installation of surface facilities for continued expansion of the SOZ steamflood. See Section 1.2.2.6 for more information.

TABLE 1.2-10 (Cont'd)

Title	Project Number	Description
Cogeneration.[a]	P47697	This project is described in Section 1.2.2.13.
Chromium cleanup. CERCLA cleanup of hazardous waste sites. Sump cleanup/closure.	P78102 P78103 P78104	Projects are intended to result in remedial actions to cleanup CERCLA hazardous waste sites, including abandoned sites; also includes sump cleanup and closures.
Calderon solid waste facility characterization/ cleanup/ closure.	P78106	Includes site characterizations to determine health threats of both active and inactive sites. Includes repairing existing areas where erosion damage is a problem, and where drainages require restoration of habitat for wildlife.
Groundwater monitoring.	P79107	Project includes groundwater/vadose zone monitoring to determine if groundwater contamination has or has not occurred at various sites on the NPR-1 (e.g., at the 25S LACT area to determine potential for contamination of the Kern Water Bank project).
Endangered species program.	Numerous projects	Projects include monitoring of endangered species populations; habitat restoration; preactivity surveys; development of techniques to enhance developed habitats; influence of supplemented food supplies on kit foxes; investigate the relationship between kit foxes and coyotes; reclamation of habitat for giant kangaroo rats; development of a computerized geographic information system (GIS); investigation of the relationship between oil field practices and wildlife.

[a]All listed projects (those with and without footnote [a]) are included in the proposed action. Projects with footnote [a] are production related projects which are not included in the "no action" alternative (Alternative 1). Projects without footnote [a] are included in the "no action" alternative because either they are operations and maintenance projects, or they are development projects needed to maintain environmental and safety quality. Projects without footnote [a] do not require new land disturbances.

TABLE 1.3-1 Typical Unit Values for Land Disturbance and Earthwork Volumes Associated with Site-Preparation Activities

Site Preparation	Volume of Earthwork (yd^3)	Area of Disturbance (acres)
Well pad	3,000[a]	2.0
Well pad access	1,000	0.2
Steam generation units	400	0.5
Tank settings (modifications)	400	0.2

[a]For new pads; at existing pads volumes would be much less.

Source: Jackson 1988.

TABLE 1.3-2 Primary Land Requirements for Proposed Action

Facility	Number of Units	Acres Required		
		On NPR-1	Off NPR-1	Total
Federal Facilities				
Wells	382[a]	579[b]	0	579
Cogeneration facility	1	3	0	3
Gas Operations Expansion	1	15	0	15
Butane isomerization	1	5	0	5
Gas compression facilities	10	10	0	10
24Z/29R CLGL compressor	4	2	0	2
SOZ Steamflood	10	210[c]	0	210
Pipeline replacement/maintenance	NA[d]	50	0	50
Gas injection facilities	2	4	0	4
Subtotal Federal Actions Developed		878	0	878
Non-Federal Third-party Actions				
Pipeline-Developed 30 years[j]	NA	101	590	691
Seismic-Affected 30 years[e]	NA	3,390	3,390	6,780
Subtotal Non-Federal Actions		3,491	3,980	7,471
Total Developed Acreage[f]		979[h]	590	1,569
Total Developed and Affected Acreage[g]		4,369	3,980	8,349
Revegetation				
Abandoned Sites[i]		625	0	625
Third-Party Pipeline Construction Contemporaneous[j]		60	360	420
Total Revegetation		685	360	1,045
Net Increase in Developed area		294	230	524

TABLE 1.3-2 (Cont'd)

[a]Number of planned new wells in the full development case includes redrills and deepenings. Table 1.2-3 summarizes well drilling planned through 1995 and projected from 1996-2025.
[b]Assuming 31% of planned new wells are developed on existing well pads, approximately 263 wells would result in disturbance of 2 acres for a drill pad and 0.2 acre for an access road for each well, or a total of 579 acres.
[c]This estimate is based on land disturbance expected from moving and installing steam generators in the phased steamflood expansion areas.
[d]NA = not applicable.
[e]Total projected temporary disturbance that would result from third-party seismic surveys over a 30-year project life.
[f]Denotes total acreage that would be developed for the life of the project (30 years).
[g]Denotes total acreage that would be both developed and temporarily disturbed during the life of the project.
[h]750 acres of this is anticipated to occur by 1998.
[i]See Table 3.5-1 for additional information
[j]Of the 101 acres to be disturbed pursuant to third-party pipelines on NPR-1, 60 acres would be contemporaneously revegetated. Of the 590 acres of third-party pipeline off-site disturbances, 360 acres would be contemporaneously revegetated.

For typical site preparation projects lasting 7 days (8 hours/day), the following items of equipment would be used for the periods indicated: two bulldozers (300 horsepower each) or a front loader (days 1-6); one compactor (75 horsepower)(days 1-6); one 4,000 gallon heavy duty diesel water truck (15 trips, average one way distance of 3 miles) (days 2-7); and one motor grader (75 horsepower) (day 7). An average of three site preparation projects are in progress at any one time at the NPR-1 site.

1.4 ONGOING NON-FEDERAL-CONNECTED ACTIONS

The permitting process to construct, operate and maintain two third-party pipelines connecting to NPR-1 facilities were ongoing prior to and during the preparation of this SEIS document (Figure 1.4-1). Construction is essentially complete. These projects were assessed separately (DOE 1989 and BLM/DOE 1990) and are not evaluated within this document as part of the proposed action because third-party projects are routine activities which are considered to be part of continuing development; the projects were not needed for MER production; and construction was anticipated to be completed before this SEIS is released. For information purposes, the impacts of these projects are included in Section 3 as part of the description of the existing environment and in the cumulative impact discussions in Section 4.

1.4.1 SoCal Gas Pipeline

Southern California Gas Company (SoCal) installed a new aboveground, 30-inch pipeline which replaced 10.4 miles of an existing 26-inch pipeline, and 14.5 miles of an existing 20-inch pipeline. The 26-inch pipeline extends from southern California to northern California and almost all of the 10.4 mile section was on NPR-1; a small portion was on Bureau of Land Management (BLM) land. The 20-inch line was entirely off of NPR-1. The new 30-inch line was installed in the 26-inch pipeline right-of-way. The existing 26-inch pipeline was connected to an existing 8-inch NPR-1 sales gas pipeline. By use of this connection SoCal was able to distribute NPR-1's sales gas. The NPR-1 8-inch pipeline was tied in to the new 30-inch pipeline. Otherwise, the 8-inch pipeline was not affected. NPR-1's sales gas is distributed by several pipelines in addition to the SoCal pipeline.

Project construction was completed on December 10, 1990 and disturbed a total of approximately 180 acres on and off of NPR-1. The NPR-1 portion of the disturbance was estimated to be 75 acres in sections 14Z, 24Z, 25Z, 30R, 32R, 4B, 1OB, 11B, 14B, and 13B along a 60-foot right-of-way. Revegetation of the disturbed areas was completed by December 31, 1990.

1.4.2 Santa Fe Energy Co. Oil Pipeline

In 1990, Santa Fe Energy Co. completed construction of an aboveground, 8-inch pipeline for the purpose of purchasing and transporting DOE oil from NPR-1. The pipeline extends for 9 miles between the shipping station at the Section 18G LACT facility on NPR-1 and the Midway shipping terminal off of NPR-1 in Section 31B. The pipeline was constructed above

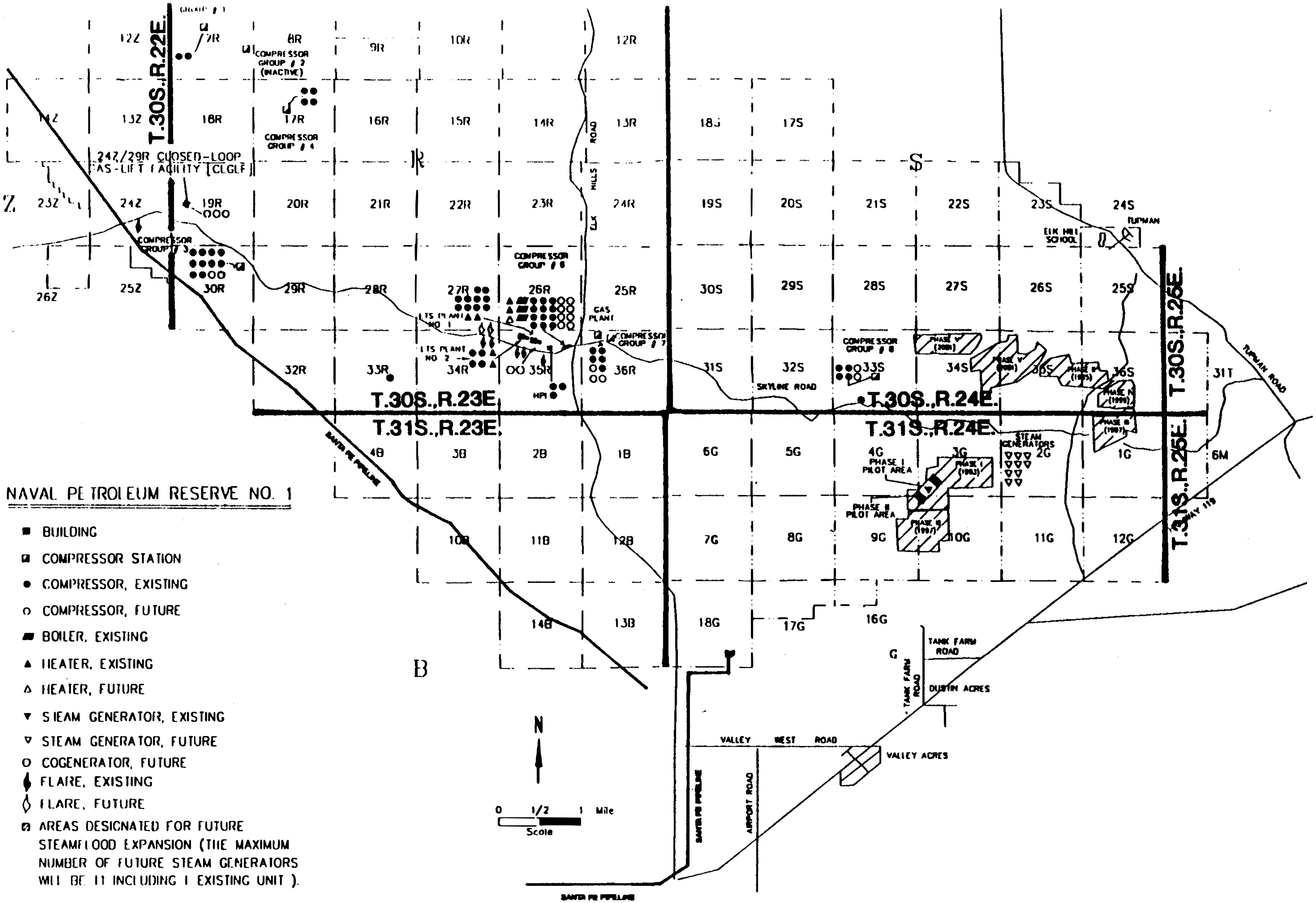


FIGURE 1.4-1 ROUTES OF THIRD-PARTY PIPELINES AT AND IN THE VICINITY OF NPR-1

the ground within a 10- to 20-foot right-of-way. Project construction was completed in February 1990. The disturbance associated with pipeline installation was about 20 feet wide for approximately 0.7 miles of previously undisturbed areas, narrowing to 10 feet for approximately 8.3 miles where roads or existing right-of-ways were followed. Although the pipeline is about 9 miles long, only about 1 mile is on NPR-1 land. Total disturbance on and off of NPR-1 was estimated to be 12 acres, of which 4 acres are within portions of Sections 18G, 30G and 31G on NPR-1. All disturbances are to be revegetated.

1.5 REFERENCES*

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Bechtel Petroleum Operations, Inc., 1991, Memorandum from R. L. Donahoe to J. C. Killen, Responses to DOE/HQ Comments on the SEIS, November 8.

BLM - See U.S. Bureau of Land Management.

BPOI - See Bechtel Petroleum Operations, Inc.

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*Copies of correspondence and unpublished documents included in this list may be obtained upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves In California, Tupman, California 93276.

2.0 ALTERNATIVES

The three primary alternatives to the proposed action are: continued operation, maintenance and production of existing facilities, but no future development (no action) (Alternative 1); future development as specified in the proposed action, but without the SOZ steam expansion, the gas processing expansion (fourth gas plant), or the cogeneration project (Alternative 2); and future development as specified in the proposed action, plus the implementation of other tertiary recovery techniques (Alternative 3). Alternative 3 was not evaluated for lack of information, as explained in more detail in Section 2.3.

A fourth alternative would be to sell the government's interest in NPR-1 (divestiture). This possibility was announced initially in the Notice of Intent to prepare a Supplemental EIS (53 FR 10922, April 4, 1988) as an alternative in the context of continued operation and development. Analysis of this alternative would have expanded on the 1987 Environmental Assessment of Divestiture (DOE 1987). This alternative is now considered highly speculative in the absence of congressional action to implement divestiture and, therefore, it is not reasonable to include it in this SEIS document.

As a result of public comment on the DSEIS, a fifth alternative was suggested. The U.S. Environmental Protection Agency (EPA) recommended analysis of an alternative that would involve implementing the no action alternative for the near term and then proceeding with the proposed action at a later date. Though this suggested alternative is technically feasible, it is not practical. An analysis performed to estimate oil and gas reserves that would be lost by deferring development activities at NPR-1 for a period of 10 years concluded that ultimate hydrocarbon recovery from NPR-1 reservoirs would decrease by approximately 66 million barrels of oil and 132 billion cubic feet of natural gas (BPOI 1992). This is due to unfavorable changes in reservoir characteristics that would occur which would increase recovery costs. This together with the costs of shutdown and restart would render some hydrocarbons uneconomic to recover. Because this alternative would not allow DOE to meet the purpose and need for the proposed action, which is to produce NPR-1 at MER, it was dismissed from further consideration in the SEIS.

Table 2.0-1 provides a comparative summary of the major elements of the proposed action, Alternative 1 (no action), and Alternative 2. A comparative summary of major impacts is provided by Table 2.0-2.

2.1 ALTERNATIVE 1: NO FUTURE DEVELOPMENT (NO ACTION)

This alternative is based on the "maintenance case" as described in the LRP and provides for the continued production of NPR-1 by operating and maintaining existing wells and facilities, but without the benefit of further development to enhance efficiency or offset natural production declines (no new drilling, enhanced recovery, cogeneration, etc.). It does, however, include operations and maintenance projects, and development projects needed to maintain safety and environmental quality (see footnote at the end of Table 1.2-10).

TABLE 2.0-1 Comparative Summary of Major Elements of Proposed Action, Alternative 1 (No Action) and Alternative 2

Element	Proposed Action	Alternative 1 (No Action)	Alternative 2
1. Reservoir Development Plans	Reservoirs would be developed in accordance with LRP "Full Development Case" (see Appendix G, Chapter 2).	Reservoirs would be developed in accordance with "Maintenance Case" (see Appendix G, Chapter 2).	Same as proposed action but excluding development of certain SOZ reservoirs by steamflood. Development of certain Stevens reservoirs would be limited by the elimination of the fourth gas plant.
2. Production Quantities	Per Table 1.2-1, production would decline to an uneconomic level by approximately the year 2010-2025.	Current production would decline to an uneconomic level by approximately the year 2000-2010 (see Figures 2.2 through 2-5, pages 2-2, 2-3, and 2-4 LRP).	Production level would be the same as the proposed action, less: approximately 8,000-12,000 barrels/day of oil; approximately 50 million cubic feet/day of produced gas; approximately 100,000 gallons/day of NGL's; and approximately 8,505-34,478 barrels/day of produced water.
3. Operation, Maintenance, and Personnel Requirements	Operation and maintenance of all existing and new facilities under the proposed action until approximately 2010-2025.	Operation and maintenance of all existing and proposed facilities under Alternative 1 (no action) until approximately 2000-2010.	Approximately the same as proposed action.
4. Drilling Activity	382 new development wells.	No new development wells.	234 new development wells.
5. Well Remedial Actions	Approximately 2,663 remedial projects.	Approximately 1,500-2,000 remedial projects.	Approximately 2,400 remedial projects.

TABLE 2.0-1 (cont'd)

Element	Proposed Action	Alternative 1 (No Action)	Alternative 2
6. Light Oil Steam-flood Activities	Steam injection would increase from the current level of approximately 3,100-5,200 barrels/day of water as steam to approximately 35,905-39,678 barrels/day.	Steam injection would continue at the current level. (The steam project would not be expanded.)	Same as Alternative 1.
7. Waterflood Activities	Expand current waterflood capacity of approximately 200,000 barrels/day by 48,000 barrels/day. Peak waterflood source water would increase by approximately 106,521 barrels/day (from the current level of 148,000 barrels/day to 254,521 barrels/day).	Waterflood capacity and water-flood source water both would be about 200,000 barrels/day. (Waterflood capacity would not be expanded.)	Same as proposed action.
8. Gas Injection, 9. Gas-Gathering, & 10. Gas-Lift	Add approximately 46,250 hp (37,500 gas; 8,750 electric).	No additional hp.	Add approximately 16,250 hp (15,500 gas; 8,750 hp electric).
11. Gas Operations Expansion	Expand NPR-1 gas processing capacity by 100-150 million cubic feet/day. Reduce off-site gas processing from approximately 60 million to approximately 15 million cubic feet/day.	No gas processing expansion. Off-site gas processing would be approximately 60 million cubic feet/ day.	Same as Alternative 1.

TABLE 2.0-1 (cont'd)

Element	Proposed Action	Alternative 1 (No Action)	Alternative 2
12. Butane Isomerization	Install new 170,000-200,000 gallons/day butane isomerization facility.	No new butane isomerization facility.	Same as proposed action.
13. Cogeneration Plant	Install 42 megawatt plant.	No new plant.	No new plant.
14. Abandoned Waste Site Closure and Facility Decommissioning	Close approximately 106 abandoned waste sites; abandon approximately 1,080 wells; demolish 3G gas plant.	Same as proposed action.	Same as proposed action.
15. Power Supply	Increase running load from approximately 24 megawatts to approximately 50 megawatts.	No additional running load.	Running load would be increased to somewhat less than the 50 megawatts needed for the proposed action due to the elimination of SOZ steam, cogeneration, and the fourth gas plant.
16. Water Supply	Increase water supply from approximately 29,000 barrels/day to approximately 74,800 barrels/day.	No increase in water supply.	No increase in water supply.
17. Fire Protection	Fire breaks, and facility projects (see Table 1.2-10 and LRP).	Same as proposed action.	Same as proposed action.
18. Roads	Maintain existing roads.	Same as proposed action.	Same as proposed action.

TABLE 2.0-1 (cont'd)

Element	Proposed Action	Alternative 1 (No Action)	Alternative 2
19. Contemporaneous Revegetation and Habitat Reclamation	Mitigation program for all surface disturbance activities. Revegetate/reclaim 1,045 acres.	Same as proposed action.	Same as proposed action.
20. Endangered Species Program	Continue comprehensive program. 13.B-4	Approximately the same as the proposed action. The only significant differences are that pre-activity surveys would be significantly less because there would be signifcantly fewer development projects to survey.	Approximately the same as proposed action.
21. Future Non-Federal Actions	Approximately 3-4 third-party projects/year until 2010-2025.	Approximately 3-4 third-party projects/year until 2000-2010.	Approximately the same as proposed action.
22. Miscellaneous	Variety of miscellaneous operations, maintenance, safety, environmental, and production-related development projects (see Table 1.2-10 and LRP).	Includes only those projects comprising operations, maintenance, safety and environment, and not those that are production-related (see footnote [a] on the last page of Table 1.2-10).	Approximately the same as proposed action.

TABLE 2.0-2 Summary Comparison of Impacts for Proposed Action, Alternative 1 (No Action), and Alternative 2*

Impact Area	Proposed Action	Alternative 1 (No Action)	Alternative 2
1. Geology & Soils			
a. Construction Impacts (soil erosion)	Construction disturbances to 979 acres on NPR-1. Construction disturbances to 1,569 acres on and off NPR-1.	Construction disturbances to 50 acres on NPR-1. Construction disturbances to 741 acres on and off NPR-1.	Construction disturbances to 529 acres on NPR-1. Construction disturbances to 1,119 acres on and off NPR-1.
b. Operational Impacts (subsidence/seismicity)	Slight possibility of subsidence and induced seismicity due to increased withdrawal of source water from the Tulare Formation and oil and gas withdrawal from deep producing formations.	The potential for subsidence and induced seismicity would be less than the proposed action and Alternative 2.	The potential for subsidence would be less than for the proposed action because gas withdrawals could be reduced by as much as approximately 50 million cubic feet/day of gas. The potential for induced seismicity would be less than the proposed action.
2. Waste			
a. Drilling, Remedials, and Abandonments	Production of drilling wastes associated with a 382-well drilling program, 2,663 remedials, and 1,080 abandonments.	Production of drilling wastes associated only with approximately 1,500-2,000 remedials and 1,080 abandonments (no new development drilling).	Production of drilling wastes associated with a 234-well drilling program, approximately 2,400 remedials, and 1,080 abandonments.
b. Produced Wastewater	100,000-181,000 barrels/day of produced wastewater would require recycling or disposal.	100,000-130,000 barrels/day of produced wastewater would require recycling or disposal.	In comparison to the proposed action 8,505-34,478 barrels/day reduction in produced wastewater would require recycling or disposal.
c. Solid Waste	Solid waste quantities from construction and operation would increase above current volume of 24,000 cubic yards/year by as much as approximately 100 cubic yards/year. In addition, approximately 140 cubic yards would be generated from one time construction projects.	Solid waste quantities from construction and operations would be no more than current levels.	Solid waste quantities from construction and operations would increase slightly over current volume, but less than the proposed action.
d. Hazardous Waste	Hazardous waste from construction and operations would increase slightly above the current level of approximately 19,800 pounds/year. 13.H-2	Hazardous waste quantities from construction and operations would be no more than current levels.	Hazardous waste quantities from construction and operations would increase slightly above current levels, but less than the proposed action.

TABLE 2.0-2 (cont'd)

Impact Area	Proposed Action	Alternative 1 (No Action)	Alternative 2
3. Air Quality			
a. Construction Emissions	Construction and seismic disturbances to approximately 8,349 acres.	Construction and seismic survey disturbances to approximately 7,521 acres.	Construction and seismic survey disturbances to approximately 7,899 acres.
b. Operational Emissions	Increases in current emission levels by a maximum of approximately 133.6, 124.2, 367.0, 0.7, 5.8, and 85.8 pounds/hour of ROG, NO_x, CO, SO_2, TSP and PM_{10}, emissions, respectively, as the result of proposed new sources.	Current ROG, NO_x, CO, SO_2, TSP, and PM_{10} emissions would decline over time corresponding to declines in oil and gas production.	Increases in current emission levels by a maximum of approximately 90.4, 63.3, 242.6, 0.2, 1.3, and 1.3 pounds/hour of ROG, NO_x, CO, SO_2, TSP, and PM_{10}, emissions, respectively.
4. Water Resources			
a. Surface Water	No significant adverse impacts.	No significant adverse impacts.	No significant adverse impacts.
b. Groundwater	1. A 382-well drilling program, including as many as 105 injection wells. Steam injection would increase from 3,100-5,200 barrels/day of water as steam to 35,905-39,678 barrels/day.	1. No new development drilling or steam injection.	1. A 234-well drilling program, including as many as 60 injection wells. In comparison to the proposed action, steam injection would be reduced by 8,505-34,478 barrels/day of water as steam.
	2. Approximately 100,000-181,000 barrels/day of produced wastewater would require recycling or disposal by injection/sumping.	2. Approximately 100,000-130,000 barrels/day of produced wastewater would require recycling or disposal by injection/sumping.	2. Produced wastewater requiring recycling or disposal would be reduced by 8,505-34,478 barrels/day in comparison to the proposed action due to the absence of the steam project.

TABLE 2.0-2 (cont'd)

Impact Area	Proposed Action	Alternative 1 (No Action)	Alternative 2
4. Water Resources (cont'd) b. Groundwater (cont'd)	3. Oils, chemicals, and produced wastewater could be inadvertently spilled and degrade groundwater. 4. Fresh water requirements would increase from the current level of 29,000 barrels/day to a peak of 74,800 barrels/day.	3. Risk of spills would be less than proposed action and Alternative 2. 4. Slight increase in fresh water requirements, but much less than the proposed action or Alternative 2.	3. Risk of spills would be more than Alternative 1, but less than the proposed action. 4. In comparison to the proposed action, a 15,005-40,978 barrels/day reduction in fresh water requirements. 13.H-2
5. Terrestrial Biota	1. Development of 1,569 acres of habitat on and off NPR-1, 979 acres of which would be on NPR-1. 2. Revegetation of approximately 1,045 acres: 685 acres on NPR-1 and 360 acres off NPR-1. 3. Net decrease of 524 acres in undeveloped area: a 294-acre decrease on NPR-1 and a 230-acre decrease off NPR-1. 4. Potential for adverse impacts from inadvertent harassment, vehicle mortality and contact with hydrocarbons and/or oil-field chemicals would be greatest. 5. Endangered Species Program activities could impact listed/candidate/sensitive species.	1. Development of 741 acres of habitat on and off NPR-1, 50 acres of which would be on NPR-1. 2. Same as proposed action. 3. Net increase of 304 acres in undeveloped area: a 635-acre increase on NPR-1 and a 331-acre decrease off NPR-1. 4. Potential for adverse impacts from inadvertent harassment, vehicle mortality and contact with hydrocarbons and/or oil-field chemicals would be lowest. 5. Same as proposed action.	1. Development of 1,119 acres of habitat on and off NPR-1, 529 acres of which would be on NPR-1. 2. Same as proposed action. 3. Net decrease of 74 acres in undeveloped area: a 156-acre increase on NPR-1 and a 230-acre decrease off NPR-1. 4. Potential for adverse impacts from inadvertent harassment, vehicle mortality and contact with hydrocarbons and/or oil-field chemicals would be slightly less than the proposed action alternative. 5. Same as proposed action.
6. Cultural Resources	Total disturbance on and off NPR-1 of 1,569 acres in connection with construction could adversely affect cultural resources.	Total disturbance on and off NPR-1 of 741 acres in connection with construction could adversely affect cultural resources.	Total disturbance on and off NPR-1 of 1,119 acres in connection with construction could adversely affect cultural resources.

TABLE 2.0-2 (cont'd)

Impact Area	Proposed Action	Alternative 1 (No Action)	Alternative 2
7. Land Use	The proposed action would result in a net increase in developed area committed to petroleum related activities (new disturbance less reclaimed acreage) of 524 acres: a 294-acre increase on NPR-1 and a 230-acre increase off NPR-1.	The no action alternative would result in a net decrease in developed area committed to petroleum related activities of 304 acres: a 635-acre decrease on NPR-1 and a 331-acre increase off NPR-1. This would amount to an 828-acre reduction in land requirements in comparison to the proposed action.	This alternative would result in a net increase in developed area committed to petroleum related activities of 74 acres: a 156-acre decrease on NPR-1 and a 230-acre increase off NPR-1. This would amount to a 450-acre reduction in land requirements in comparison to the proposed action.
8. Socioeconomics	The total budget for drilling, construction, and operations and maintenance for the proposed action is anticipated to increase from approximately $172 million in FY 1989 to approximately $225 million in FY 1995. These expenditures would increase incremental output, earnings and employment in Kern County. Additional federal revenues would be available to offset the federal budget deficit.	Incremental output, earnings and employment would be significantly less than either the proposed action or Alternative 2, as would revenues available to offset the federal budget.	The budgets for the SOZ steam project, the fourth gas plant and the cogeneration facility would be approximately $700-$750 million through approximately 2025. In comparison to the proposed action, incremental output, earnings, employment would be decreased correspondingly. Revenues available to offset the federal budget deficit also would be less.
9. Risk Assessment	1. Based on experience, 1-2 blowouts could occur during the period 1990-2025. 2. There would be six closed compressor facilities - the facilities most susceptible to gas explosions. 3. Oil production posing a risk of oil spills would gradually decline to about 71,500 barrels/day by FY 1995.	1. Based on experience, the risk of a blowout would be negligible. 2. There would be five closed compressor facilities. 3. In comparison to the proposed action, oil production would be reduced by about 31,500 barrels/day by FY 1995.	1. Based on experience, one blowout could occur during the period 1990-2025. 2. There would be five closed compressor facilities. 3. In comparison to the proposed action, oil production would be reduced by about 8,000-12,000 barrels/day.

[a]The quantitative and qualitative information provided for the proposed action and the alternatives to the proposed action generally represent maximum impacts that over the economic life of the oil-field would decline to negligible levels. In the case of the proposed action and Alternative 2, the oil field would probably be economic until 2010-2025. In the case of Alternative 1 (no action) the oil field would decline very rapidly and probably would not be economic beyond 2000-2010.

Under this alternative, the economic life of the field would expire by approximately 2000-2010. The impacts of this Alternative are based on the impacts described in Section 3.0: Description of Existing Environment (see Section 3.0 and 4.2.1).

If this alternative were implemented, production would decline rapidly to a level significantly below MER (see Figures 2.2 through 2.5 on page 2-2, 2-3, and 2-4 in the LRP). In addition, the ultimate recovery of oil and gas reserves would be reduced substantially. It has been estimated that nearly 500 million barrels of oil and more than 250 billion cubic feet of natural gas reserves would not be recovered, which represents a reduction of 58% of the remaining oil reserves and 20% of the remaining gas reserves (Jerry R. Bergeson & Assoc. 1988). Under this alternative, the economic return on the NPR-1 investment to the public would be greatly diminished in comparison to that of the proposed action.

The Naval Petroleum Reserves Production Act of 1976 mandated the production of NPR-1 at MER for as long as it is determined to be in the national interest. Continued MER production has been determined to be in the national interest. This determination was made for a number of reasons, but primarily because the MER strategy maximizes economic benefits to the public (the primary equity owner of NPR-1) by optimizing hydrocarbon recovery, revenue, economy of scale and return on investment. MER strategy is also consistent with that which is generally pursued within the private sector of the oil-field industry. A fourth 3-year extension beginning April 6, 1991 was recently authorized by Congress based on economic and military preparedness criteria.

2.2 ALTERNATIVE 2: PROPOSED ACTION EXCLUDING SOZ STEAM EXPANSION, GAS PROCESSING EXPANSION, AND COGENERATION PROJECT

This alternative provides for the same activities included in the proposed action, except that the 148-well, 500-acre SOZ steam project would not be implemented (see Section 1.2.2.6); the expansion of gas processing capacity by 100-150 million cubic feet/day would not be undertaken (see Section 1.2.2.11); and the 42-megawatt cogeneration plant would not be constructed. Table 2.2-1 summarizes the major facilities and associated land requirements for this alternative. The impacts of this Alternative are based on the impacts described in Section 3.0 (Description of Existing Environment), plus the impacts of new development (see Section 3.0 and 4.2.2). As indicated, an additional 1,119 acres would be developed: 529 acres on NPR-1 and 590 acres off of NPR-1. In addition, 1,045 acres would be revegetated: 685 acres on NPR-1 and 360 acres off of NPR-1. The net increase in developed areas on and off of NPR-1 would be 74 acres.

The strategy set forth in the LRP (Appendix G), which is the basis for the proposed action, assumes that the expanded SOZ steam project, the fourth gas plant, and the cogeneration project, would all be needed to comply with legislated MER requirements; however, this may not be the case. These initiatives are under study, and based on analyses completed to date, additional analysis is needed to determine if they meet MER criteria. (As discussed in Sections 1.1.3 and 1.2, MER strategies are in a constant state of change due to changing reservoir, technical and

TABLE 2.2-1 Facilities and Primary Land Requirements for Alternative 2

Facility	Acres Required		
	On NPR-1	Off NPR-1	Total
Federal Facilities			
Wells	357[a]	0	357
Butane isomerization	5	0	5
Gas compression facilities	10	0	10
24Z/29R CLGL compressor	2	0	2
Pipeline replacement/maintenance	50	0	50
Gas injection facilities	4	0	4
Subtotal-Federal Facilities Developed	428	0	428
Non-Federal Third-Party Actions			
Pipeline-Developed 30 years	101	590	691
Seismic -Affected 30 years[b]	3,390	3,390	6,780
Subtotal-Non-Federal Actions	3,491	3,980	7,471
Total Developed Acreage[c]	529	590	1,119
Total Developed and Affected Acreage[d]	3,919	3,980	7,899
Revegetation			
Abandoned Sites	625	0	625
Third-party Pipeline Construction Contemporaneous	60	360	420
Total Revegetation	685	360	1,045
Net Increase (Decrease) in Developed Area	(156)	230	74

TABLE 2.2-1 (Cont'd)

[a]For the alternative, it is assumed that the 148 wells projected for the SOZ would not be completed. Thus, only 234 wells of the 382 wells that comprise the proposed action (see Table 1.2-3) are included in this estimate. Assuming 31% of planned new wells are developed on existing well pads, approximately 161 wells would result in disturbance of 2 acres for a drill pad and 0.2 acre for an access road for each well, or a total of 357 acres.

[b]Total projected temporary disturbance that would result from seismic surveys over a 30-year project life.

[c]Denotes total acreage that would be developed during the life of the project (30 years).

[d]Denotes total acreage that would be both developed and affected (temporarily disturbed) during the life of the project.

economic considerations.) Given the uncertainty, this alternative is a viable MER scenario requiring analysis.

If implemented, reserves recovered under this alternative would be less than the proposed action by 15-50 million barrels of oil and 800-2,400 million cubic feet of natural gas; oil production rates would be less by as much as 8,000-12,000 barrels/day initially (based on information in and data taken from Jerry R. Bergeson & Assoc. 1988; BPOI 1989a; BPOI 1989b; and BPOI 1989c). In addition, the recovery of up to approximately 50 million cubic feet/day of natural gas which is scheduled in the proposed action to occur over the next 15 years would not commence under the alternative for perhaps another 5 years and would not be completed for perhaps another 25 years after that (based on information in and data taken from Jerry R. Bergeson & Assoc. 1988; BPOI 1989a; and BPOI 1989b). In addition, there could be a much greater reliance on processing gas at CUSA's 17Z gas plant (gas processing at 17Z could increase). Subject to verification of assumptions, preliminary analyses of the SOZ steam expansion, the fourth gas plant, and the cogeneration facility indicate that at a 10% rate of return the projects could have a combined net present value as high as $2 billion.

2.3 ALTERNATIVE 3: NONSTEAMFLOOD TERTIARY OIL-RECOVERY STRATEGIES

This alternative provides for the same activity included in the proposed action, plus implementation of some of the nonsteamflood tertiary recovery techniques that have been carried out on a limited basis at other oil fields. Examples of these techniques include alkali surfactant polymer injection, micellar polymer injection, carbon dioxide injection, and in-situ combustion. Based on a recent study, it has been suggested that these techniques could have future applicability at NPR-1 (given the right technical and economic circumstances), and therefore they should be studied (Jerry R. Bergeson & Assoc. 1988).

Although the techniques described have potential in the long term, it does not appear that their implementation can be considered by decision-makers in the reasonably foreseeable future (based on limited technical data, and current and expected economic conditions). For this reason, studies have not been completed to scope programs to the level of detail needed to address potential environmental impacts. Accordingly, it is not possible at this time to include the implementation of the described recovery techniques in this document; therefore, they were dismissed from consideration without further analysis at this time.

A discussion of the studies in progress has been included in the proposed action. It is not anticipated that the studies would be completed in the near future. When and if the studies are completed, proposed implementation projects would be given the appropriate level of environmental review, if nonsteamflood tertiary oil-recovery strategies are determined to be appropriate at NPR-1.

2.4 PREFERRED ALTERNATIVE

The proposed action represents the Department of Energy's preferred alternative. This alternative would involve the continued operation of NPR-1 at the MER, the continued operation of existing facilities plus additional development as provided in the Long Range Plan.

2.5 REFERENCES*

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*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California, 93276.

3.0 DESCRIPTION OF EXISTING ENVIRONMENT

The existing environment was established by updating the existing environment descriptions in the 1979 EIS: i.e., by adding the impacts of post-1979 operations to the 1979 EIS descriptions and by incorporating such changes as may have occurred naturally during the intervening years. This methodology necessitated an analysis of actual impacts from 1979 to the present, and as such this section contains many of the impact discussions that are usually reserved for the impact sections of a NEPA document. Given that the no action alternative (Alternative 1) is defined as continuing existing operations without further development (see Sections 2.1 and 4.2.1) it should be noted that the impacts described in this section for the period following 1979 are essentially the same as would occur if Alternative 1 was implemented. As such, the impacts described in this section are the baseline against which the incremental effects of the proposed action and Alternative 2 are assessed in subsequent sections. It should also be noted that the impacts described in this section also constitute a portion of the impacts associated with the proposed action and Alternative 2. The impacts of the proposed action and Alternative 2 being the sum of the impacts associated with continuing existing operations plus the impacts of new development of the alternative (see Sections 2.2, 4.1, and 4.2.2).

3.1 GEOLOGY AND SOILS

3.1.1 Regional Geologic Setting

NPR-1 is located about 25 miles southwest of Bakersfield near the southwestern edge of the San Joaquin Valley in Kern County, California (Figure 3.1-1). The site encompasses almost the entire Elk Hills and some surrounding areas (Figure 3.1-2).

3.1.1.1 Physiography

The San Joaquin Valley is the southern half of a large structural depression called the Central Valley of California, which extends for nearly 500 miles parallel to the coast (Figure 3.1-1). The Sacramento Valley forms the northern half of the Central Valley.

The San Joaquin Valley is surrounded by the Coast Ranges on the west, the San Emidio and Tehachapi Mountains on the south, and the Sierra Nevada Mountains on the east. The Elk Hills protrude above the flat, uniform valley with as much as 1,200 feet of relief in the southwestern corner of the valley. The Elk Hills consist of a line of hills about 16 miles long and 6 miles wide. The line is a surface expression of a large anticlinal extension of the Temblor Mountain Range, which forms the easternmost part of the Coast Ranges. The juncture of the Elk Hills with the main foothills of the Temblor Range is marked by a prominent stream gap called Railroad Gap. The hills terminate eastward in low, stream-cut bluffs along the Kern River where the river enters Buena Vista Lake. This lakebed is one of several lacustrine and marsh deposits that crop out in the San Joaquin Valley. The expansion of these ancient lakes resulted in the deposition of extensive clays in the San Joaquin Valley. It is believed that the most

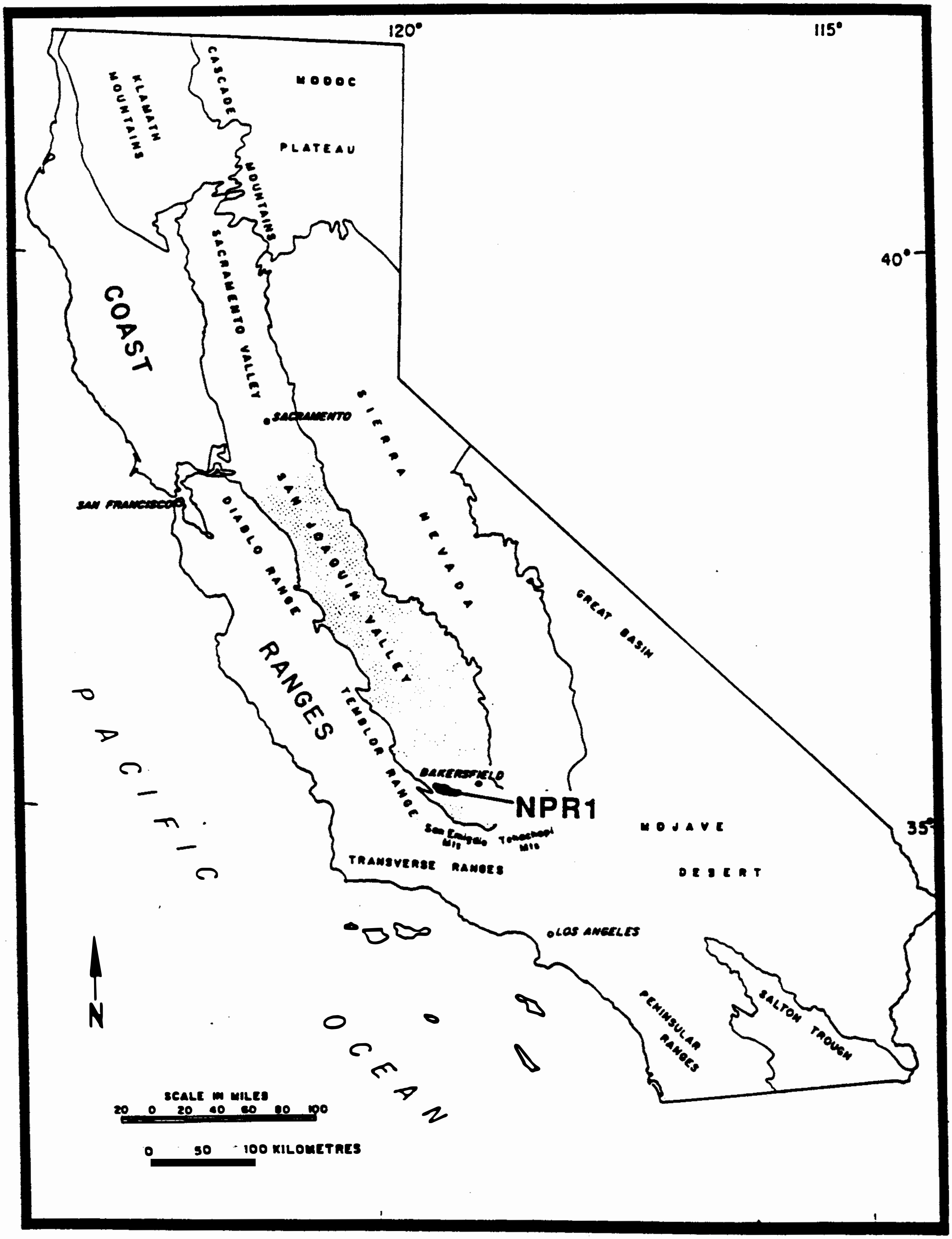

FIGURE 3.1-1 LOCATION OF NPR-1 RELATIVE TO MAJOR LAND FEATURES OF CALIFORNIA (SOURCE: MODIFIED FROM MAHER ET AL 1975)

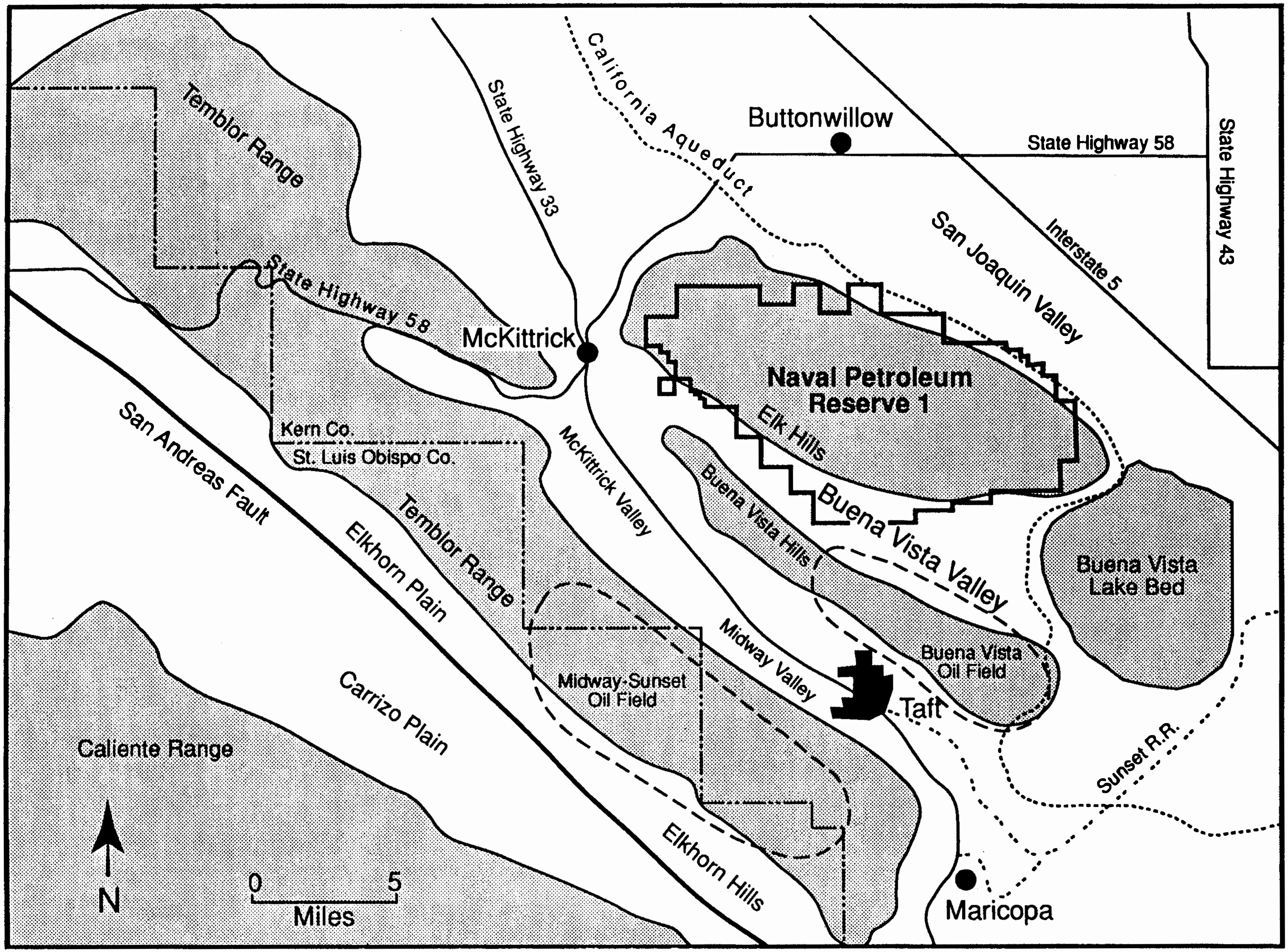

FIGURE 3.1-2 PHYSIOGRAPHIC FEATURES IN THE VICINITY OF NPR-1
(Source: Modified from Maher et al 1975)

extensive of these clays is the modified E-Clay, which lies beneath the Buena Vista Lakebed (Page 1986). Currently, the lakebed is dry except for two small lakes maintained as part of the Buena Vista Recreation Area. During unusually wet years, other portions of the original lakebed may become flooded.

The Central Valley is an elongated trough formed along the depressed western part of the Sierra Nevada fault block (Maher et al 1975). The valley is filled with several thousand feet of unconsolidated and partially consolidated sediment eroded from surrounding mountains (DOE 1979). The sedimentary strata in the eastern part of the San Joaquin Valley dip gently westward toward the axis of the Central Valley and reflect the subsurface extension of the westward-tilting Sierra Nevada fault block. In contrast, the sedimentary strata beneath the western side of the valley dip steeply eastward and are sharply folded, with many faults. The structure of the strata was largely determined by the development of the Coast Ranges, specifically the Temblor Range. The Temblor Range is composed of a series of tight *en echelon* folds that diverge from the generally southerly trend of the other mountains of the Coast Ranges and plunge southeastward into the San Joaquin Valley. The Elk Hills represent one anticline associated with the Temblor Range (DOE 1979).

A recent seismic correlation study of the modified E-Clay in the southern San Joaquin Valley revealed the complexity of the shallow subsurface geology in the region. This study suggested the presence of subsurface structures that may divide the valley into as many as eight structural subbasins (Kern County Water Agency (KCWA) 1990).

3.1.1.2 Stratigraphy

The Tertiary and Quaternary deposits underlying Elk Hills and nearby areas are up to 24,000 feet thick. Cretaceous sedimentary rocks below formations of Miocene, Eocene, and Oligocene ages are the oldest rocks penetrated by oil and gas wells at NPR-1 (Fishburn and McJannet 1989). Table 3.1-1 shows the geologic age, relative position, and approximate thickness of the formations penetrated at NPR-1 and adjacent areas. Figure 3.1-3 shows a generalized geologic cross section of the San Joaquin Valley and Elk Hills area. A detailed description of regional stratigraphy is presented by Maher et al (1975). Petroleum reservoirs at NPR-1 are further discussed in Section 3.1.2.3, and petroleum production at the site is summarized in Section 1.1.4.

3.1.2 Local Geologic Setting

3.1.2.1 Geomorphology and Surficial Geology

The elevations of the Elk Hills within NPR-1 range from 290 feet above mean sea level (MSL) on the valley floor at the northeastern boundary of NPR-1 (near Tupman) to 1,551 feet MSL at Hillcrest Point along the main ridge in the western part of NPR-1 The southeastern end of the Elk Hills beyond the NPR-1 boundary is marked by 15 feet high bluffs that have been cut by

TABLE 3.1-1 Stratigraphic Units and Their Approximate Thickness in the Elk Hills and Vicinity

Stratigraphic Unit	Thickness (ft.)
Pliocene and Pleistocene Age	
Tulare Formation	600-2,200
Pliocene Age	
San Joaquin Formation	1,200-2,100
Etchegoin Formation	1,700-3,500
Carman Sandstone Member	900-2,000
Tupman Shale Member	750-2,000
Middle and Late Miocene Age	
Reef Ridge Shale	200-1,150
Monterey Shale (Antelope Shale)	2,100-4,100
Elk Hills Shale Member	1,800-3,300
McDonald Shale	80-600
Gould and Devilwater Shale Member	100-655
Early Miocene and Oligocene	
Temblor Formation	2,900-4,100
Media Shale Member	150-560
Carneros Sandstone Member	0-950
Santos Shale Member	1,340-3,090
Wygal Sandstone Member	450
Cymric Shale Member	300
Oligocene Age	
Wagon Wheel Formation	250-700
Late Eocene Age	
Kreyenhagen Formation	2,300-2,900+
Welcome Shale Member	900-1,950+
Point of Rocks Sandstone Member	400-2,000+
Gredal Shale Member	?

Source: Modified from Maher et al. 1975.

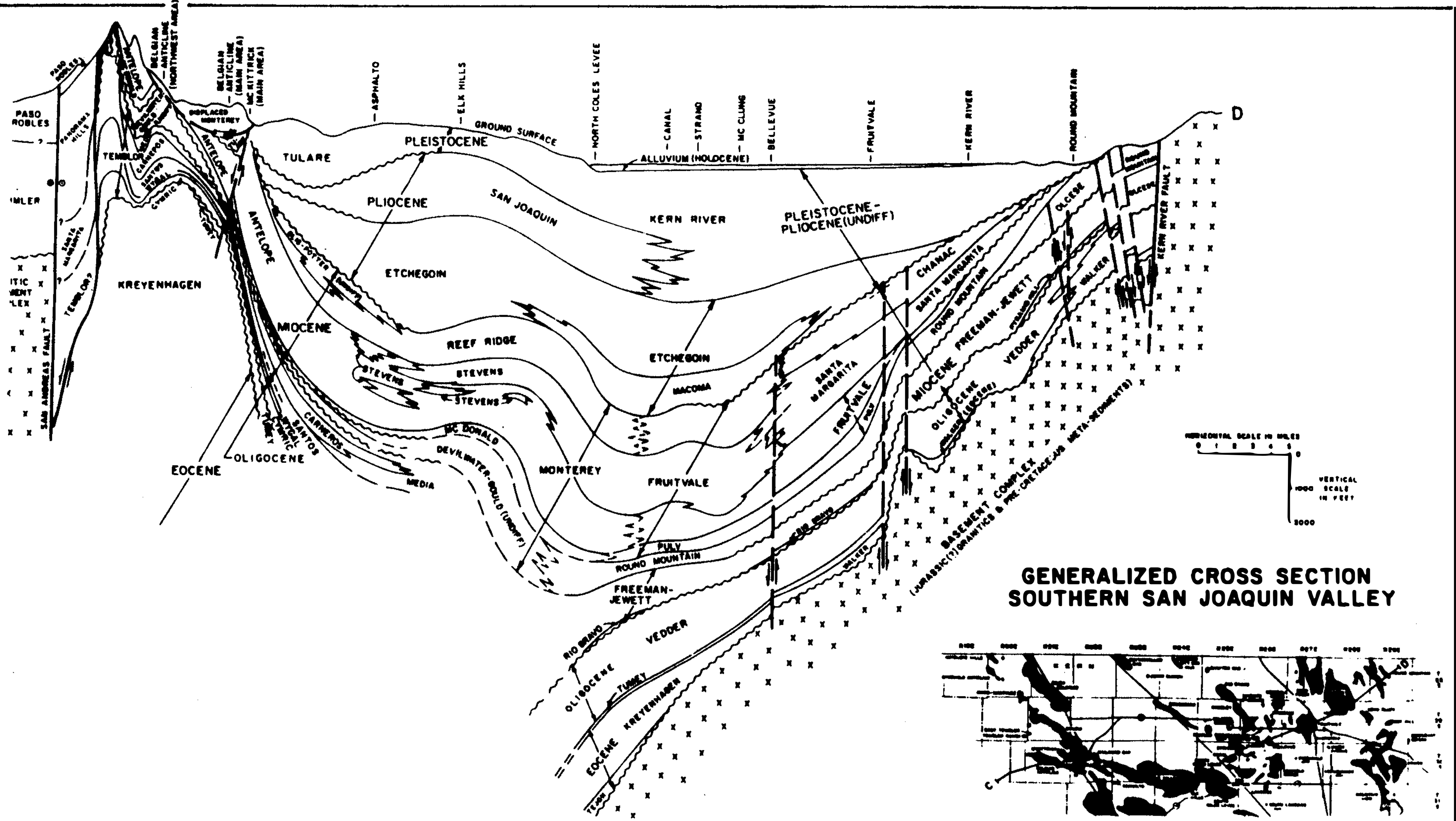

FIGURE 3.1-3 GEOLOGIC CROSS SECTION OF THE SOUTHERN SAN JOAQUIN VALLEY AND THE ELK HILLS AREA (SOURCE: CALIFORNIA DEPARTMENT OF CONSERVATION 1986)

the Kern River and the Buena Vista Slough near the mouth of Buena Vista Lakebed (DOE 1979). The California Aqueduct extends along the northeastern and eastern boundaries of Elk Hills.

The shape and relief of the hills reflect the anticlinal structure of the underlying rocks. Rocks and soils in the Elk Hills are sparsely vegetated and easily erodible. A large number of ephemeral streams draining the hills have carved an intricate dendritic pattern of channels and gullies. The stream divides are numerous and narrow and have rounded crests; the valley walls are generally smooth. Sediments eroded from uplands have been deposited along the base of the hills. This action has created a smooth topographic transition into the adjacent flat valley except at the southern end of the hills. Slopes are steepest at the eastern and western ends of the hills because of erosion by the Kern River at an earlier time and by the ephemeral stream running through Railroad Gap (Maher et al 1975).

The exposed strata in the anticlinal Elk Hills consist of poorly consolidated sandstone, claystone, and conglomerate beds of the Tulare Formation of late Pliocene to early Pleistocene age (Maher et al 1975). A fringe of Quaternary-age Alluvium occurs around the perimeter of the hills. Figure 3.1-4 is a generalized geologic map of the Elk Hills area.

The surface geology of Elk Hills was initially mapped and described by Woodring in 1932 (Woodring et al. 1932). On the basis of this work, Woodring divided the Tulare into Upper and Lower members based on color differences in the interbedded mudstones: light buff for the Upper member and olive gray for the Lower member. Woodring's map also included Limestone A, which he described as lying near the contact point of the Upper and Lower members.

The subsurface geology of Elk Hills was described by Maher in 1975 (Maher et al, 1975). Maher's work was based on his interpretation of well log data and Woodring's surface maps. Maher described an upper sandstone and conglomerate, a middle clay, and a lower sandstone and conglomerate. The upper sandstone and conglomerate are unconsolidated, medium-to-very-coarse grained sand with thin interbeds of siltstone and claystone. The lower sandstone and conglomerate are a poorly consolidated light olive-gray, pyritic, very-fine to very-coarse grained sandstone. The sandstone beds are up to 50 feet thick and are separated by much thinner beds of siltstone and claystone. The middle clay, which separates the upper and lower sandstones and conglomerates, is light olive-bluish color and is slightly dolomitic. Beck (1969) reported small gastropods, questionably identified as *Amnicola*, in the middle clay subsequently described by Maher (1975); consequently, Maher's middle clay is often referred to as the Amnicola clay.

The middle clay is a part of the anticlinal structure of Elk Hills and is present beneath much of NPR-1 (present beneath cross sections A-B, B-C, C-D, G-H, and K-L in Figure 3.1-5). The clay does not appear in boreholes located east of Section 32S along cross section A-F, nor in boreholes located north of Section 19R along cross section I-J. Where it does exist, the clay member ranges from 20 to 100 feet thick (Maher et al 1975). Along the crest of the Elk Hills, the clay is at elevations of 600-1,100 feet MSL. Toward the western end of NPR-1, the elevation of the clay decreases to 120 feet MSL at borehole G and 80 feet below MSL just east

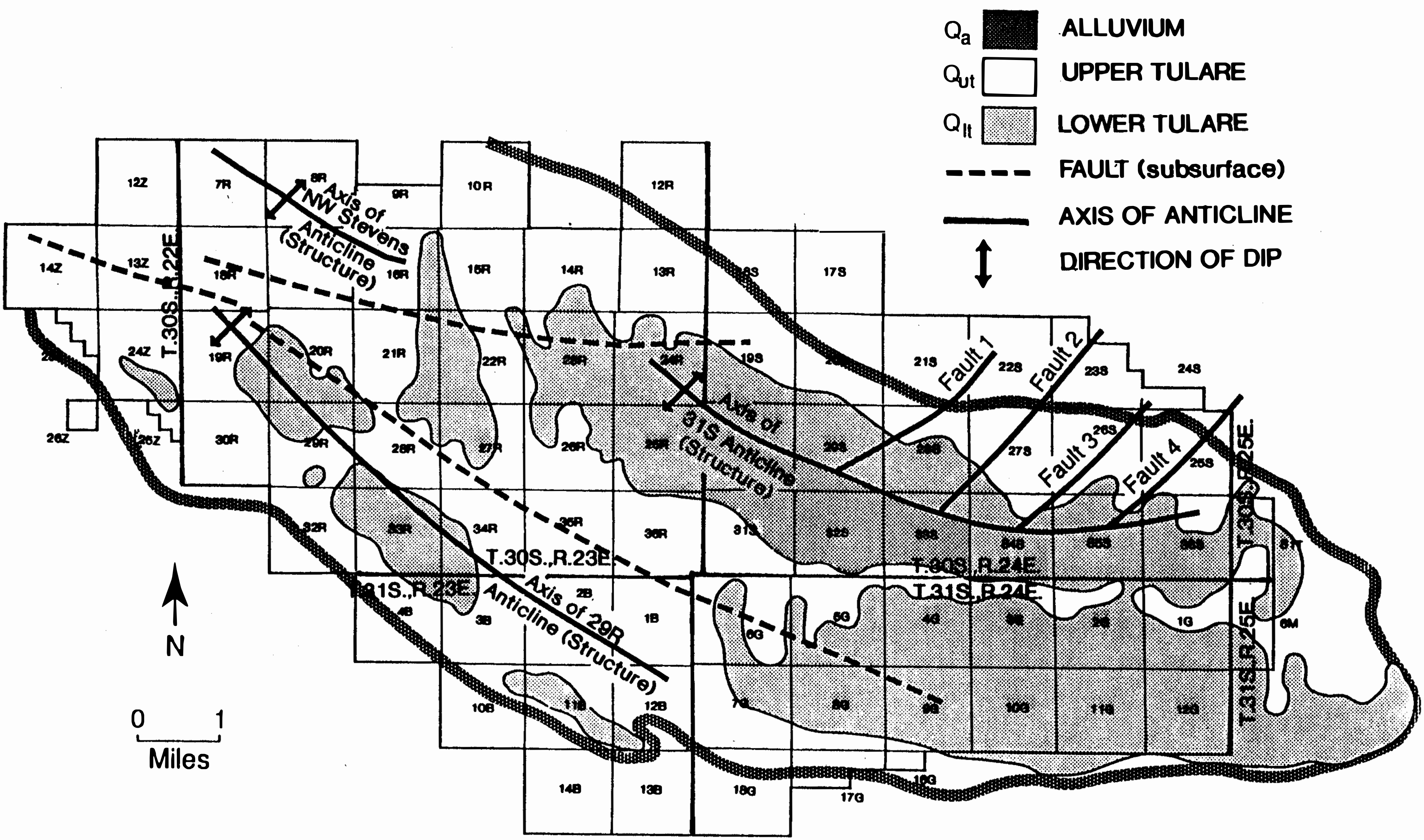

FIGURE 3.1-4 GENERALIZED GEOLOGIC MAP OF THE NPR-1 AREA
(Source: MODIFIED FROM Maher et al 1975)

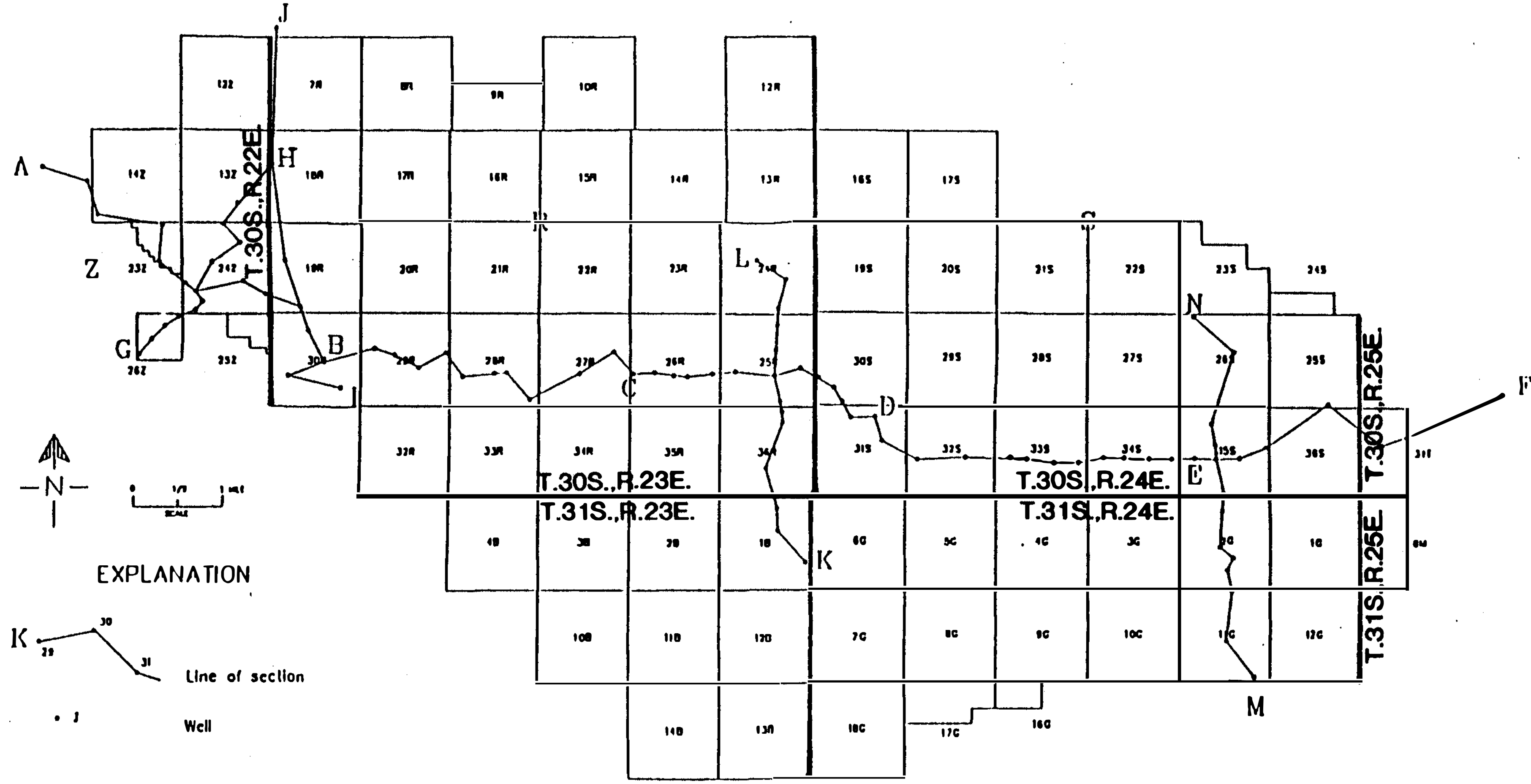

FIGURE 3.1-5 LINE OF STRUCTURE SECTIONS ACROSS THE ELK HILLS
(SOURCE: MODIFIED FROM MAHER ET AL 1975)

of borehole A (Figure 3.1-5). Along the southern edge of NPR-1, near Section 18G, the elevation of the clay decreases from about 40 feet MSL to 1,100 feet below MSL over a horizontal distance of less than 1 mile (BPOI 1987; Maher et al 1975). In reviewing the geological discussions that follow, it is important to note that Maher (1975) and Woodring (1932) descriptions of the Tulare correlate closely and that Maher's lower Tulare, middle clay, and upper Tulare all fall within Woodring's Lower member (Remsen, 1990). This is illustrated by Figure 3.1-6.

3.1.2.2 Stratigraphy and Structure

The geologic strata beneath the Elk Hills are similar to those discussed under regional setting (Section 3.1.1). Except for the Alluvium, the strata beneath the Elk Hills have been folded into an anticlinal structure. Although not readily discernible at the surface, this structure consists of two large, *en echelon* anticlines, commonly referred to as the 29R structure and the 31S structure, and one relatively small anticline known as the Northwest Stevens structure. The axis of the 29R structure is oriented in a southeasterly direction, while the 31S structure curves eastward. The 29R structure is tightly folded, asymmetrical, and faulted. The 31S structure is cut by numerous normal faults, four of which reach the surface. Both structures have broad tops and steep flanks. From its structurally highest point, the 29R structure plunges to the west-northwest and terminates in a very sharp nose. The axis of the 31S structure trends southeastward at its western end, but curves eastward and plunges into the San Joaquin Valley, where it terminates in a broad, blunt nose (Maher et al 1975). The Northwest Stevens structure is located in the northwestern area of NPR-1. It is a small asymmetrical anticline that plunges to the west-northwest. The anticline is about 4 miles long and 1 mile wide. The geologic cross section in Figure 3.1-3 depicts the subsurface folding and faulting. The folding becomes sharper and more distinctly separable with depth. The folding and faulting, along with lithologic changes within the geologic formations, are important factors in the entrapment and concentration of formation oil, water and natural gas.

3.1.2.3 Geologic Resources

The Elk Hills oil field, which constitutes NPR-1, is one of the largest in the United States. As shown in Figure 3.1-7, four major oil- and gas-producing zones of NPR-1 are, from youngest to oldest, the Dry Gas Zone (DGZ), the Shallow Oil Zone (SOZ), the Stevens Zone, and the Carneros Zone.

The DGZ includes all dry gas-bearing rocks above the top of the oil sands of the San Joaquin Formation of Pliocene age. The reservoir in the DGZ consists of thin, lenticular, loosely cemented sandstone with relatively high permeability. At present, gas production is mostly from the Mya sand zone, an alternating succession of shale and lenticular sandstone beds. Dry gas produced from these sands is mostly methane (Maher et al 1975).

The SOZ includes all oil- and gas-bearing rocks of Pliocene age above the ReefRidge Shale and below the Subscalez sand zones. The SOZ includes reservoirs in the Etchegoin Formation and

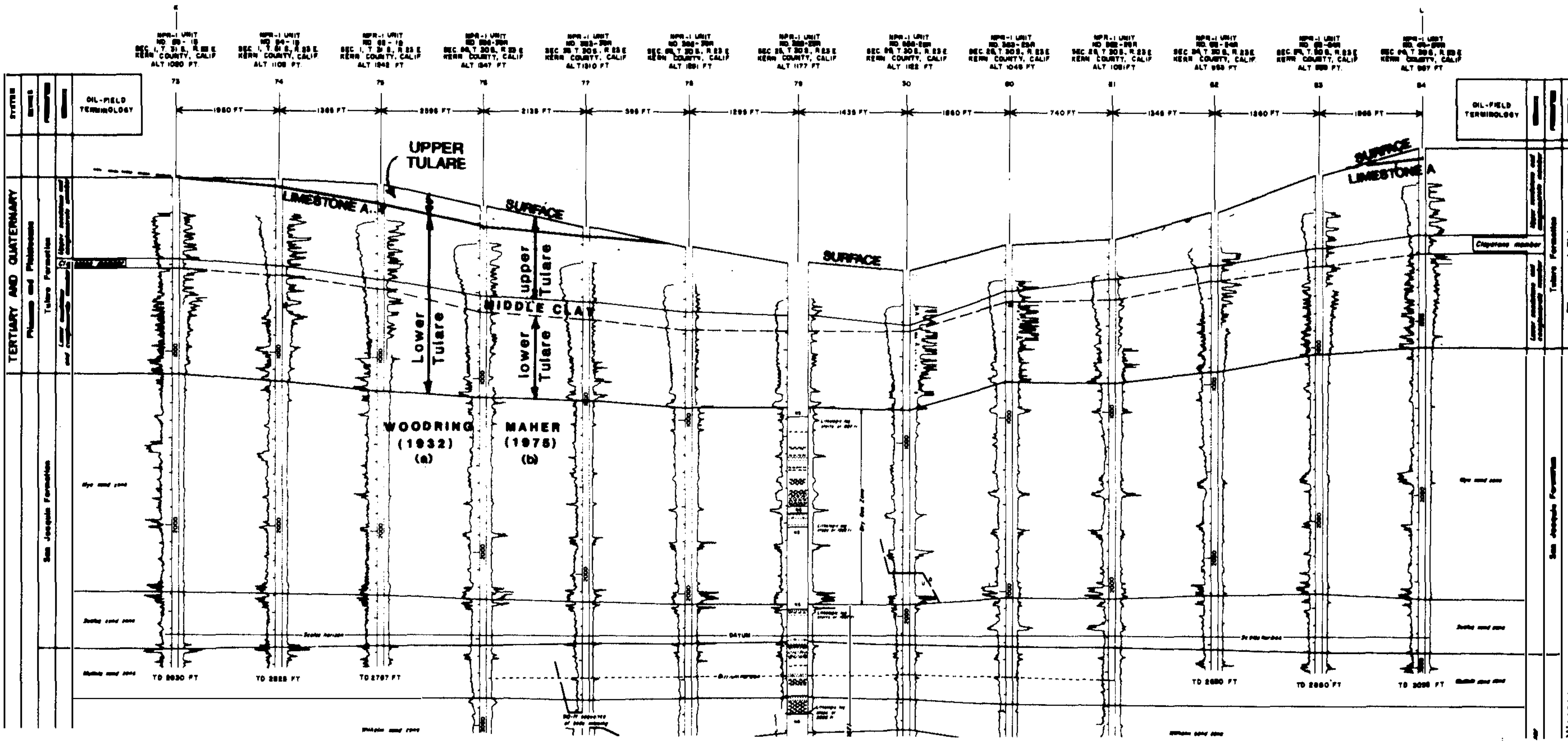

FIGURE 3.1-6 STRATIGRAPHIC SECTION OF THE TULARE FORMATION AT ELK HILLS (NORTH/SOUTH) KERN COUNTY, CALIFORNIA
(SOURCE: MAHER ET.AL. 1975 WITH WOODRING ET. AL. 1932 IMPOSED)
(a) STRATIGRAPHIC NOMENCLATURE WOODRING 1932
(b) UNIT DESIGNATION MAHER 1975

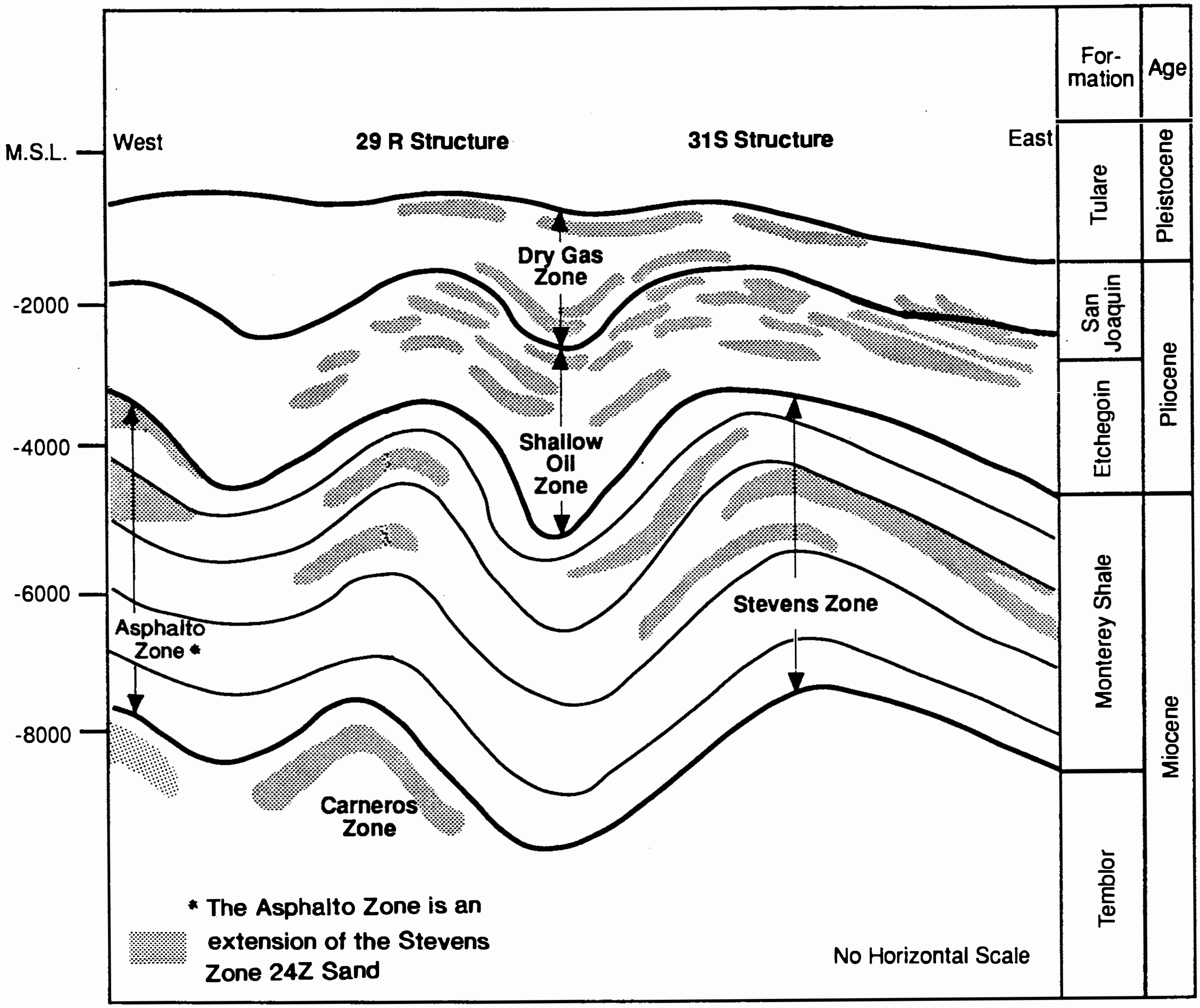

FIGURE 3.1-7 SCHEMATIC GEOLOGIC CROSS SECTION OF ELK HILLS OIL FIELD SHOWING MAJOR PRODUCING ZONES (SOURCE: MODIFIED FROM DOE 1979)

in the lowest sandstones of the San Joaquin Formation. The numerous reservoirs of this zone include thin, lenticular, highly permeable sandstone, as well as less permeable siltstone and shale. Average porosities and permeabilities of the sandstone reservoirs increase upward; the highest are found in the Scalez sand zone. The SOZ has estimated recoverable oil reserves of 165 million barrels (DOE 1990) to as high as 358 million barrels (Jerry R. Bergeson & Assoc. 1988). The estimate of recoverable gas reserves for the SOZ is 97 billion cubic feet (Jerry R. Bergeson & Assoc. 1988), less reserves withdrawn since this estimate was made.

The Stevens Oil Zone contains all oil- and gas-bearing formations in the upper part of the Elk Hills Shale member of the Monterey Shale of late Miocene age. The reservoirs in the Stevens Oil Zone are thick, lenticular to tabular, sheet sandstones and thick intervals of fractured siliceous shale. Both types of reservoirs have relatively low permeabilities. The estimates of remaining recoverable oil reserves in the Elk Hills fields range from 356 million barrels (DOE 1990) to as high as 500 million barrels (Jerry R. Bergeson & Assoc. 1988). The Stevens reservoirs at Elk Hills have estimated recoverable gas reserves of 1,583 billion cubic feet (Jerry R. Bergeson & Assoc. 1988), less reserves withdrawn since this estimate was made.

The Carneros Oil Zone consists of one to three thick sandstones of Miocene age in the uppermost part of the Temblor Formation. The deepest economic oil production in NPR-1 has been from the Carneros. Three relatively thick sandstones of low porosity and permeability produce minor amounts of oil and a considerable amount of gas and condensate. The estimate of remaining reserves of the Carneros Oil Zone in the Asphalto and Elk Hills fields is 5.3 million barrels of oil and 36 billion cubic feet of gas (BPOI 1989).

The source rocks for oil at Elk Hills are thought to be shales rich in organic material that were deposited by marine waters from middle Eocene to middle Pliocene time. It seems likely that much petroleum came from the Tejon basin and the trough of the southern San Joaquin Valley basin and was trapped in the Elk Hills structure and other nearby traps in its general migration updip toward the western edge of the basin (Maher et al 1975).

<ins>Section 1.2.2.1</ins> and <ins>Appendix A</ins> discuss the important oil and gas reservoirs in the producing zones and the history of production at NPR-1. No mineral resources other than oil and gas have been commercially developed within NPR-1. However, the coarser deposits of alluvium and the Tulare Formation could be used as a local source of sand and gravel (DOE 1985).

3.1.2.4 Surface Subsidence

Land surface subsidence has not been reported at NPR-1 (DOE 1985). The two major geologic characteristics that control oil-field subsidence are geologic structure and physical properties of producing zones (DOE 1979). Geologic structures under NPR-1 could be rated as good to fair for self-support, depending on the production zone considered. The Stevens and Carneros zones are located within a rather tight anticline at depths of 7,000 to 9,300 feet, respectively. These conditions are favorable for resisting subsidence. The SOZ and DGZ, however, are located near the top of the Elk Hills structure, where the anticline is much broader and thus offers less self-support.

Major physical properties of producing zones affecting subsidence potential include lithology and degree of consolidation. The reservoir rocks at NPR-1 are fairly well consolidated, particularly in the deeper Stevens and Carneros zones, and have only a low to moderate potential for compaction.

3.1.2.5 Seismicity

NPR-1 is situated in a region of intense seismic activity. Since 1852, 19 major earthquakes, with Richter scale magnitudes ranging from 5.9 to 8 (estimated), have been reported in southern California. The largest recorded earthquake in this region measured 7.7 and occurred in 1952. The epicenter was about 24 miles southeast of the NPR-1 along the White Wolf fault at the southern end of the San Joaquin Valley. In addition to the major earthquakes, numerous smaller seismic events are recorded each year. For example, since 1973, 353 earthquakes with magnitudes of 3.5 or greater have been recorded in the immediate vicinity of NPR-1.

Although NPR-1 is in a seismically active region, no historically active faults within NPR-1 boundaries have been identified by either the State Geologist or the California Division of Mines and Geology (California Division of Mines and Geology 1975). Some minor inactive faults and other indications of possible faulting are present, however. In addition, some earthquake epicenters of Richter magnitude 3.5-4.0 have been recorded near the site, and some larger earthquakes have occurred within 10 miles of NPR-1. The two major active faults in the immediate vicinity of NPR-1 are the San Andreas and White Wolf faults. These faults are located about 14 miles southwest and 25 miles southeast of NPR-1, respectively.

3.1.3 Geologic Description of Waste-Disposal Areas

3.1.3.1 27R Waste-Management Area

An active waste-disposal facility is operated at the 27R site on NPR-1, near the crest of the Elk Hills, in the southeastern quarter of Section 27, T30S/R23E (Township R). This site includes an oil-recovery facility with two open unlined oil-recovery sumps, approximately 75 feet by 150 feet each, a truck-washout station with two open unlined sumps, approximately 125 feet by 150 feet each, an inactive hazardous waste disposal-trench area of 4.5 acres, and a 27.7-acre landfarming field. The topographic relief is low across the waste disposal area, with no steep slopes or areas susceptible to erosion and landsliding. No known natural water bodies, springs, or seeps exist within 1 mile of the sumps (Kaman Tempo 1987). The 27R site is not within a 100-year floodplain, and no perennial or ephemeral streams exist near the site (Mark Group 1987).

The site is underlain by about 1,000 feet of unconsolidated silty sands and silt and clay interbeds of the Tulare Formation. Nineteen boreholes drilled at the site have shown several silt/clay interbeds beneath the facility. A deep borehole (BEH-14) encountered a layer of dense greenish-gray clayey silts at a depth of 385 feet. This correlates to Maher's middle clay, and it was observed to be 75 feet thick based on another deep borehole well that was completed in May 1990 (BPOI 1990).

The May 1990 deep borehole well was drilled to 1,000 feet without encountering groundwater. Available oil well and geologic data indicate that the groundwater table at the 27R site is approximately 1,100 feet deep. No perched water table or water-bearing strata exist at the 27R site that could be affected by the wastes (Kaman Sciences Corp. 1987). Because of the depth of the water table and the existence of the clay layer as a barrier, potential downward migration of the leachate from the oil recovery sumps to the groundwater is minimal. No faults have been found near the 27R site that could act as migration paths through the clayey silt. Further, downward migration would also be inhibited by the high evaporation rate and low rainfall (Kern County Water Agency 1987).

3.1.3.2 10G Waste-Disposal Area

The 10G waste-disposal area, located in Section 10, T31S/R24E (Township G), consists of a permitted 10-acre landfarming unit used only to dispose of drilling fluids and operational oil-field waste fluids. The fluid mixtures consist of water, bentonite clay, barium, sulfate, and other additives including corrosion inhibitors, oxygen scavengers, thermal stabilizers and weighing agents (DOE 1985). All additives utilized at NPR-1 are included on the list of approved nonhazardous drilling fluid additives issued by the California Department of Health Services in 1982. The 10G site is underlain by Tulare sediments that are stratigraphically above the middle clay and below Limestone A. The closest available geologic cross section to the 10G disposal area is section M-N (Figure 3.1-5), located about 1 mile to the east (Maher et al 1975). The Tulare Formation is 1,100-1,500 feet thick. The middle clay member of the Tulare Formation is absent in this cross section. The depth to groundwater is approximately 400-500 feet below ground surface (Golder 1990).

A normal fault trending from northeast to southwest occurs at the northwestern corner of Section 10G (DOE 1985). The ephemeral streams in the vicinity of the disposal area flow generally south toward Buena Vista Creek. Flows would percolate rapidly into the ground.

3.1.3.3 18G Disposal-Wells Area

The 18G area includes eight Tulare Zone produced wastewater disposal wells in Sections 7G, 8G, and 18G (see Figure 3.4-7). The middle clay is present at a depth of 800-1,700 feet under the 18G disposal area, and it is about 55 feet thick. A groundwater table exists above the middle clay and below Limestone A at depths of 300-400 feet below ground surface (Golder 1990).

The disposal wells in this area are perforated starting at between 347 and 428 feet below ground surface. The perforation intervals in the wells range from 215 feet to 511 feet.

Although the risk of communication with off-site groundwaters from use of these disposal wells is unknown, available data suggests that injected water is moving updip and laterally rather than downdip towards Buena Vista Valley (Deutsch 1991). See Section D.4.2.2.

3.1.3.4 24Z Disposal-Wells Area

The 24Z area includes three Tulare Zone produced wastewater disposal wells in Section 24 of T30S/R22E (Township Z) and is underlain by Tulare sediments that are stratigraphically between Limestone A and the middle clay (Figure 3.4-7). Cross-section data presented by Maher et al (1975) indicate that the Tulare is 1,000-1,400 feet thick under this area. The middle clay is 60-100 feet thick and occurs at depths of 500-700 feet. The depth to groundwater is greater than 700 feet below ground surface (Golder 1990).

The 24Z wells are perforated starting at between 362 to 424 feet, with perforation intervals ranging from 473 to 541 feet. The risk of communication with off-site groundwaters from use of these disposal wells is also unknown.

3.1.3.5 26Z Disposal-Wells Area

The 26Z area included a Tulare disposal well and an Olig disposal well (see Figure 3.4-7). The Tulare well was recompleted into the Olig in FY 1992, leaving disposal into only the Olig Sand.

3.1.4 Soils

3.1.4.1 General Description

The soils of the Elk Hills are fairly typical of those developed from relatively fine-grained, alluvial material under semiarid to arid conditions. A characteristic soil tends to be loose, light-colored, well-drained, and loamy in texture, with abundant rock fragments. As with other soils occurring in analogous climatic conditions, the Elk Hills soils generally contain an abundance of gypsum and alkaline salts and may be calcareous. These soils also tend to have abundant plant nutrients (DOE 1979, p. II-9).

Some of the local soils that developed from fine-grained materials contain elevated levels of salts. Because of the lower permeability associated with these finer grained materials and because of insufficient water, these salts have not been leached from the soil. Where such soil conditions exist, plant growth is naturally reduced. This also affects vegetative cover in that north-facing slopes generally have more vegetation than do the southern slopes. This condition occurs in part because evaporative moisture losses tend to be less on the northern slopes. Furthermore, southern slopes in general tend to have higher levels of salts than do northern slopes, which also can be related to increased rates of water evaporation (Soil Conservation Service (SCS) undated).

The SCS described, classified, and mapped the soils of the Elk Hills (SCS undated). Although 26 distinct soil map units were identified, most of these units could be divided among six basic soil types: (1) Cajon sandy loam, (2) Elk Hills sandy loam, (3) Elk Hills sandy loam, saline-sodic, (4) Garces fine sandy loam, (5) Kimberlina sandy loam, and (6) Torriorthents soils.

Appendix C describes these soil types (Section C.1) and summarizes information on general physical and geotechnical characteristics of the Elk Hills soils (Section C.2). Data presented in Appendix C describe the clay content, permeability, available water capacity, hydrologic soil group, flooding frequency, salinity, shrink-swell potential, and soil erodibility by water and wind erodibility group. Although considerable variation exists among the various soil types, most soils at the site have about 5-20% clay, a permeability of about 2.0-6.0 inches/ hour in the surface horizon, an available water capacity of approximately 0.10-0.15 inches/ inch, and salinity values of less than 4 millimhos/centimeter. Most of the soils have moderate infiltration and water transmission rates when thoroughly wet, have low to moderate shrink-swell potential, are moderately susceptible to sheet and rill erosion, and have wind erosion potentials ranging from light to very slight.

Section C.3 of Appendix C summarizes information available on chemical analyses of major Elk Hills soils at disturbed and undisturbed locations. Data presented include pH values and mean concentrations of arsenic, barium, boron, cadmium, calcium, chromium, copper, iron, lead, magnesium, manganese, molybdenum, nickel, potassium, selenium, sodium, and zinc.

Two reports recently published by the SCS (undated and 1988) present more detailed descriptions of the soils and contain maps (based on aerial photographs) showing the occurrence of specific soil map units on NPR-1.

3.1.4.2 Soil Erosion

Although the processes and effects of soil erosion by wind and water have been studied intensely in the United States since the 1930's, the complex processes of soil entrainment, transportation, and subsequent deposition are not completely understood. Currently, it is possible to provide only general estimates of erosion rates and quantities for specific site conditions. These estimates tend to be more reliable under some specific climatic, pedologic, and land use conditions than under others. Erosion under arid to semiarid conditions, with significant surface disturbance and modifications, such as those caused by activities at NPR-1, provide the more difficult circumstances to quantify. Furthermore, estimates of soil loss obtained for these circumstances would involve much greater uncertainty than would estimates for farmland in the humid, temperate climate of the eastern United States, for example. Techniques that can be used to estimate soil erosion quantities are discussed in Section C.4 of Appendix C.

Due to the age of NPR-1, the sequence, spatial distribution, types of activities that have occurred since oil-field development began, and details of past erosion-control and mitigative measures implemented are not well known. Consequently, it would be difficult to segregate current and past erosion rates and consequences among those that would occur naturally and those resulting from petroleum-development activities. This difficulty is compounded by the potential uncertainties associated with procedures available to estimate erosion and the lack of soil loss or erosion data for any portion of the study site. This would make soil study results questionable, and therefore no soil studies have been attempted. Logically, most of the activities associated with petroleum-field development and production would tend to increase erosion at the site. Numerous studies have shown that construction and earth-moving activities analogous to those at NPR-1, including road construction, can cause a profound increase in soil loss unless adequate erosion control measures are taken. At NPR-1, an erosion control program was initiated in the early 1980's and was fully operational by about 1988. This is discussed in more detail in Sections 4.1.1.1 and 1.2.2.19. It also is logical that naturally occurring erosion in areas such as the Elk Hills is significant. This is supported by studies conducted by the SCS.

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3.2 WASTE GENERATION AND MANAGEMENT

3.2.1 Introduction

Activities at NPR-1 generate many types of wastes, almost all of which are nonhazardous wastes associated with drilling and oil and gas production. Almost all nonhazardous wastes have been disposed of on-site. Prior to 1985, hazardous wastes were also disposed of at an on-site permitted hazardous waste site. Since then, all hazardous wastes have been disposed of at permitted hazardous waste facilities located off-site in accordance with applicable regulations.

The three largest waste streams are nonhazardous; these are produced water, spent drilling fluids, and solid wastes. Oil and gas production generates approximately 37 million barrels/year of produced water, almost all of which is reinjected into the Tulare, SOZ, and Stevens zones; some is placed in lined and unlined evaporation/percolation sumps. Up until 1987, well drilling generated a total of about 700,000 barrels/year of spent drilling fluids that were disposed of at two on-site landfarms in Sections 27R and 10G. As of 1989, this volume had decreased to 417,000 barrels/year (BPOI 1990b) and by 1990 it decreased to 315,000 barrels/year (BPOI 1991a). The reduced level of drilling activity brought about this reduction and has, midway through 1990, eliminated the need to dispose of spent drilling fluids at the 10G landfarm (BPOI 1990b, 1991a). A total of about 24,000 cubic yards/year of nonhazardous solid wastes, such as construction debris and domestic-type wastes and trash, are removed from NPR-1 for disposal in the Kern County solid-waste landfill. NPR-1 activities also involve the use of a variety of chemicals and other materials (both nonhazardous and hazardous) that can be released with wastes generated by normal operation and occasionally by spills. Table 3.2-1 lists annual chemical usage exceeding 1,000 gallons at NPR-1.

Programs have been initiated to remediate the impacts of past practices that, although allowable under the regulations then in force, are no longer acceptable. For example, in some cases, hazardous wastes such as chromium and arsenic were introduced into the environment. Use of these chemicals was discontinued by 1983, and cleanup programs have been initiated to mitigate impacts. There also is a continuing program to identify other sites contaminated by past operations.

NPR-1 operations are conducted in accordance with the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), as amended by the federal Superfund Amendments and Reauthorization Act (SARA), but are specifically exempted from certain federal hazardous waste regulations under the Resource Conservation and Recovery Act (RCRA). This is because RCRA (Section 3001(b)(2)(A)) exempts specific wastes associated with the exploration, development, or production of crude oil and natural gas. The reauthorization for RCRA, currently being debated in Congress, may mandate a regulatory structure to govern oil-field wastes in the future. The current RCRA exemption does not apply to California law. Under California law and the California Code of Regulations (CCR), oil-field

TABLE 3.2-1 Annual Chemical Usage at NPR-1 (1988)

Material	Main Components	Annual Use (gal)
Methanol	Methanol 100	121,970
Magnicide 434	1-(alkyl amino)-3-amino-propane (48%) Isopropanol (25%)	76,011
Magnicide 407	Isopropanol (10%)	43,045
Coreexit 7754	2-Butoxyethanol Acid/amino salts Aromatic naphtha	39,329
Cronox E-200	Methanol (20%)	36,178
Glycol	Triethylene glycol	33,544
Kontol KW 132	Oxydiethylene Bis (6%) Methanol ammonium bisulfite	33,009
Magnicide 495	Glutaraldehyde (50%)	28,262
XC 107	Isopropyl alcohol	22,203
RP 4014	Light aromatic naphtha, Oxylated alkyl phenol, Formaldehyde, Polyglycols	12,898
Calnox 216R	Polyacrylate	11,975
SPO 237	Methanol	11,477
Ethylene glycol	Ethylene glycol	11,320
Betz 736	Sodium nitrate, Sodium molybdate	10,595
YP 168	Heavy aromatic naphtha	10,460

TABLE 3.2-1 (cont'd)

Material	Main Components	Annual Use (gal)
Oil-Flo safety degreaser	Aromatic Hydrocarbons	7,920
P 6865	Ammonium chloride, Potash, Sodium bicarbonate	6,000
Barquat	N-Alkyl dimethy benzyl ammonium	5,765
Sodium bisulfite	Sodium bisulfite	5,400
Sulfuric acid	Sulfuric acid	3,460
Aquasurf 10-TA	Isopropanol (10%)	2,947
Betz 30K	Sodium hydroxide	2,320
Liquimine II	Methoxypropylamine 3	2,320
Neutrafilm 436	Octadecyclamine acetate	2,320
Ethyl mercaptan	Ethyl mercaptan	2,000
Betz 25K	Potassium hydroxide	1,420
Betz Inhibitor 562	Sodium hydroxide 1-H Benzotriazole	1,320
Slimicide 508	2,2 Dibromo-3-nitril-propionamide	1,260
PD 11	Heavy aromatic naphtha Isopropyl alcohol	1,200

Source: Wilkins 1989.

wastes may be considered hazardous if contaminant levels exceed California hazardous waste criteria (22 CCR 66680, 66699).

DOE requires that each DOE facility establish and implement a waste-minimization program to reduce the volume and toxicity of all wastes for which the facility is responsible (DOE Order 5400.1). Several waste-minimization programs have been implemented at NPR-1. Utilizing waste hydrofluoric/hydrochloric acid mixtures to stimulate the performance of SOZ wastewater disposal wells through acidization has eliminated the need to otherwise dispose of these materials. Use of bulk containers for storage of chemicals needed at well-development sites has reduced the amount of leftover waste chemicals. Recycling of hazardous materials such as degreasing solvents, spent lead-acid batteries, petroleum-based drilling fluids (1,500 barrels in 1988), and oils (engine, lubricant, crankcase) has been employed to reduce the amount of wastes. Currently, NPR-1 generates approximately 19,800 pounds/year (9,000 kilograms/year) of hazardous wastes that are disposed of at off-site permitted facilities.

The following subsections identify requirements (DOE, state and federal) pertaining to hazardous and nonhazardous wastes; and the historical and current generation and management of wastes at NPR-1, including waste streams, volumes and facilities.

3.2.2 Applicable Regulations and DOE Orders

As a DOE facility, NPR-1 follows the provisions of DOE Order 5400.1, which is the principal document defining environmental-protection program requirements. Requirements, authorities, and responsibilities are established in this Order to ensure compliance with applicable federal, state, and local environmental protection laws and regulations; the document also establishes guidelines for implementing good management practices to comply with legal and regulatory requirements. One of the more important requirements of DOE Order 5400.1 is to establish waste-minimization programs to reduce the volume and toxicity of all wastes.

NPR-1 also must comply with CERCLA and its amendments under SARA to develop and implement a program to control or remove environmentally hazardous substances from inactive sites. A program to characterize and remediate these sites is well established. NPR-1 is subject to the PCB regulations authorized under the federal Toxic Substance Control Act (TSCA).

The California State Safe Drinking Water and Toxic Enforcement Act (Proposition 65), requires the state to publish a list of chemicals known to cause cancer or reproductive harm. Businesses must warn the public of any risk of exposure to any of the chemicals listed. Some of the constituents of crude oil, and some chemicals imported by NPR-1 for use in operations, are on the state's list. Accordingly, NPR-1 has posted warning signs of the possibility of exposure to these substances.

The California Health and Safety Code, Section 41805.5, requires the California State Water Resource Control Board to rank active and inactive solid-waste-disposal sites throughout the state with respect to their potential to adversely affect groundwater or surface water. A solid-waste assessment test report must also be submitted by site operators to the appropriate Regional Water Quality Control Board. Provisions of this code directly affect solid-waste-disposal facilities at NPR-1 (see Sections 3.2.3.2 and 3.2.5.2).

The characterization and closure programs for parts of the waste-management facilities at NPR-1 (see Section 4.1.2.3) are subject to many regulations, including (but not limited to) the following:

- California Health and Safety Code, Section 41805.5,

- The Toxic Pits Cleanup Act (AB 3566, CA), which limits use of surface impoundments for hazardous waste management,

- Title 23 of the California Code of Regulations (CCR), Subchapter 15, which addresses discharges of waste to land,

- California Department of Health Services hazardous waste site investigation criteria (Interim Status Document, CA 4170024414), and

- Title 22 of the CCR, which categorizes the types and minimum contaminant levels of hazardous substances.

Asbestos was installed at some NPR-1 locations, mostly as insulation on pipes and other equipment in the 35R Gas Plant that was constructed in the early 1950's. Currently, there is a program to remove this asbestos according to applicable regulations which include: U.S. Occupational Safety and Health Administration Regulations OSHA 1910.1001; National Emission Standards for Hazardous Air Pollutants (NESHAP); and Title 8 of the CCR, Section 5208.

Additional regulations and statutes that address the environmental aspects of control and disposal of waste and may apply to specific situations on NPR-1 include the Endangered Species Act; the Clean Water Act; the California Water Code, Section 1; and Title 14 of the CCR, Parts 720, 1773, 1775, and 1776.

3.2.3 Historical Waste Generation and Management

3.2.3.1 Historical Waste Streams

Nonhazardous Waste Streams

Almost all of the wastes generated at NPR-1 are characterized as nonhazardous. These are discussed as follows:

Wastewater: Produced water is the largest volume nonhazardous waste stream on the site. Almost all of this waste is disposed of by reinjection into the Tulare, SOZ, and Stevens Zones; some is placed in evaporation/percolation sumps (see Section 3.4 and Appendix D for details). Other wastewater streams generated at NPR-1 include gas plant cooling tower and process effluent, 27R truck wash effluent, pipeline hydrotest effluent, and 36R and 36S car wash and each field effluents.

Drilling Fluids: Another large-volume nonhazardous waste is spent drilling fluid. Drilling fluids are complex mixtures that serve many functions in the drilling of wells. Although drilling fluids are nonhazardous, they do contain hazardous substances (22 CCR 66699) which are needed for effective drilling. Spent drilling muds and liquids are routinely tested and have been shown to be non-hazardous (BPOI 1991b). Hazardous drilling fluid additives are discussed later in more detail.

Spent drilling fluid disposal methods have varied. Before 1974, they were either left in the drilling sumps or reclaimed. Since 1974, most of the spent drilling fluids were deposited in the landfarm areas of Sections 10G and 27R pursuant to Central Valley Regional Water Quality Control Board (CVRWQCB) Waste Discharge Requirements 73-141 and 73-42 issued in 1976; some, however, continued to be left in drilling sumps, and some were spread on roads, embankments, and drill pads to aid in soil stabilization prior to 1979. Since mid-1990, all drilling fluids have been disposed only in the 27R landfarm (BPOI 1990b).

Solid Wastes: Nonhazardous solid wastes have historically been generated in large volumes. These wastes consist mainly of paper, wood, metal parts, tires, cardboard, garbage, and construction debris. Prior to 1986-1987 most of these materials were deposited in landfills and surface dumps throughout NPR-1. Since then, all of these wastes have been deposited off-site at the Kern County landfill.

Hazardous Waste Streams

Drilling Fluid Additives: Drilling fluids are explicitly excluded from designation as a hazardous waste under the Code of Federal Regulations, Title 40, Part 261.4 (40 CFR 261.4). In addition to federal regulations, state regulations are also applicable. Inclusion of any materials listed as hazardous by the state of California (22 CCR 66300, 66680) will cause the state to consider the drilling fluid to be hazardous, if state-defined hazardous substances exceed state-defined limits (22 CCR 66699). Drilling fluid additives utilized at NPR-1 such as chromium lignosulfonate, chromates, and dichromates, were designated hazardous by the State of California in 1979, but their concentrations in drilling fluids did not exceed the chromium limits established by the state in 1985; thus, drilling fluids with chromium additives are not hazardous materials. Some individual constituents of drilling fluids are discussed below.

Chromium Lignosulfonate -- Chromium lignosulfonate was used at NPR-1 in drilling fluids at over 500 deep wells from the mid-1950's to 1983. This material, produced from the dichromate oxidation of lignosulfonate liquor, forms a strongly bound trivalent (Cr^{+3}) chromium organo-complex with lignosulfonate. Cr^{+3} is a federal (40 CFR 261) and state listed (22 CCR 66680) hazardous substance. Chromium lignosulfonate complexes may also contain some hexavalent chromium (Cr^{+6}), which is an extremely hazardous substance.

Although there is some uncertainty about the amount of Cr^{+6} originally available in chromium lignosulfonate, acidic conditions and reactions with native clays and various lignin compounds within the borehole would be expected to reduce virtually all Cr^{+6} to Cr^{+3} which is the less hazardous state (BPOI 1991b). Thus, Cr^{+6} should not be a problem as a result of past disposal of spent drilling fluids that contained chromium lignosulfonate.

Concentrations of chromium lignosulfonate in a typical drilling fluid vary from 0% to 4%. Toxicity to various marine animals was observed in tests on chromium lignosulfonate (Neff 1982; Duke et al 1984). Inorganic trivalent chromium has been found to exhibit relatively low levels of toxicity in animals (Languard and Norseth 1986). Warren et al (1981) indicated that some Cr^{+3} organo-complexes were as toxic as Cr^{+6}. The toxicities of other trivalent organo-complexes were closer to that of inorganic Cr^{+3}. Data are not available on the toxicity of the organo-complexes that were contained in the chromium lignosulfonate spent drilling fluids used at NPR-1 prior to 1983.

Hexavalent Chromium -- Sodium dichromate ($Na_2Cr_20_7 \bullet 2H_20$), sodium chromate ($Na_2Cr0_4$), and potassium dichromate ($K_2Cr_20_7 \bullet 2H_20$) were used as drilling fluid additives from about 1954 until 1983. The chromium in these compounds is in the highly toxic hexavalent form (Cr^{+6}). These compounds are both hygroscopic and quite water soluble. They are listed as hazardous materials both by the Environmental Protection Agency (EPA) (40 CFR 261) and the State of California (22 CCR 66680).

When used as an additive to drilling fluid, Cr^{+6} soon reacts in the borehole with native clays, and various lignin compounds, and is reduced to the less hazardous trivalent form (Cr^{+3}). The trivalent form then binds in general to various non-reactive clays. Tests of the spent drilling fluid show that virtually no hexavalent chromium remains (BPOI 1991b).

Hexavalent chromium compounds were typically stored in bags at the well pads and were added to the drilling fluid when needed. Occasionally, the contents of these bags were spilled and these spills and/or the bags themselves became inadvertently buried. Chromates and dichromates are soluble in water and can be transported by capillary action to the surface, where they appear as a powdery yellow to yellow-green deposit that can best be seen after a rain.

NPR-1 drilling logs indicate that as many as 554 wells may have been drilled during the period of suspected hexavalent chromium use (1954-1983). To date, 65 Cr^{+6} spill sites have been identified (see Figure 3.2-1). The State of California requires remedial action to remove hexavalent chromium from the soil whenever the concentration exceeds the State of California soluble threshold limit concentration (STLC) of 5 milligrams/liter (BPOI 1987). Contaminated soils at the 65 hexavalent chromium sites on NPR-1 have been properly managed as hazardous wastes. Because of their potential for contaminating surface water run-off, a chromium cleanup level of 1 part/million was negotiated with the California Department of Health Services, Toxic Substances Control Division (CAL-EPA), in 1988. All 65 sites have now been remediated. Contaminated soils from all 65 sites have been excavated and hauled to Class I hazardous waste facilities for disposal. Verification testing to ensure complete remediation of these sites has been completed.

Chromium tests in the hazardous waste trench area of the 27R waste management facility indicate that total chromium (chromium and/or Cr^{+3} compounds) levels in this area range from 19 to 210 milligrams/kilogram which is below the CCR, Title 22 TTLC of 2,500 milligrams/kilogram. Hexavalent chromium analyses of the two samples with the highest total chromium concentrations (210 milligrams/kilogram and 200 milligrams/kilogram) revealed Cr^{+6} concentrations of 3.60 milligrams/kilogram and 2.60 milligrams/kilogram, respectively. These Cr^{+6} concentrations are well below the TTLC for Cr^{+6} compounds of 500 milligrams/kilogram. Due to minimal rainfall, depth to groundwater, and covering of wastes with clean fill, there is little potential impact anticipated from contaminants in the 27R hazardous waste trench (BPOI 1991b). Because of the low levels of chromium encountered at 27R, it was decided to defer further review of roads, embankments and drill pads where waste drilling fluids are suspected of being spread. This matter will be reviewed further as part of the site-wide cleanup/closure program.

Corrosion Inhibitor W-41 (Arsenic): During past drilling of wells in the SOZ, an appreciable time often elapsed between completion of drilling and production startup. During that interval, acidic conditions in the borehole could have caused corrosion of the metal casing and the suckerrod assembly, which is a downhole rod that assists in pulling oil out of the ground. To minimize this, an arsenic-containing anticorrosion compound, W-41, was added to the borehole. Arsenic is considered a hazardous material both by the EPA (40 CFR 261) and by the State of California (22 CCR 66680). The W-41 compound (composed of caustic lye and sodium meta-arsinite) was used for nearly 50 years, from the early 1920's until 1970 (Suter 1988). During this period, no state or federal regulations existed prohibiting the use described.

The W-41 compound was known to be highly toxic, and workers took special precautions when using the material. These precautions included use of rubber gloves, avoidance of spills, and careful disposal of contaminated equipment. At the SOZ wells where W-41 was used, bottom hole testing was carried out before production commenced. Testing equipment, gloves, buckets, and other contaminated items were disposed of in an open trench in Section 4G. Spent W-41

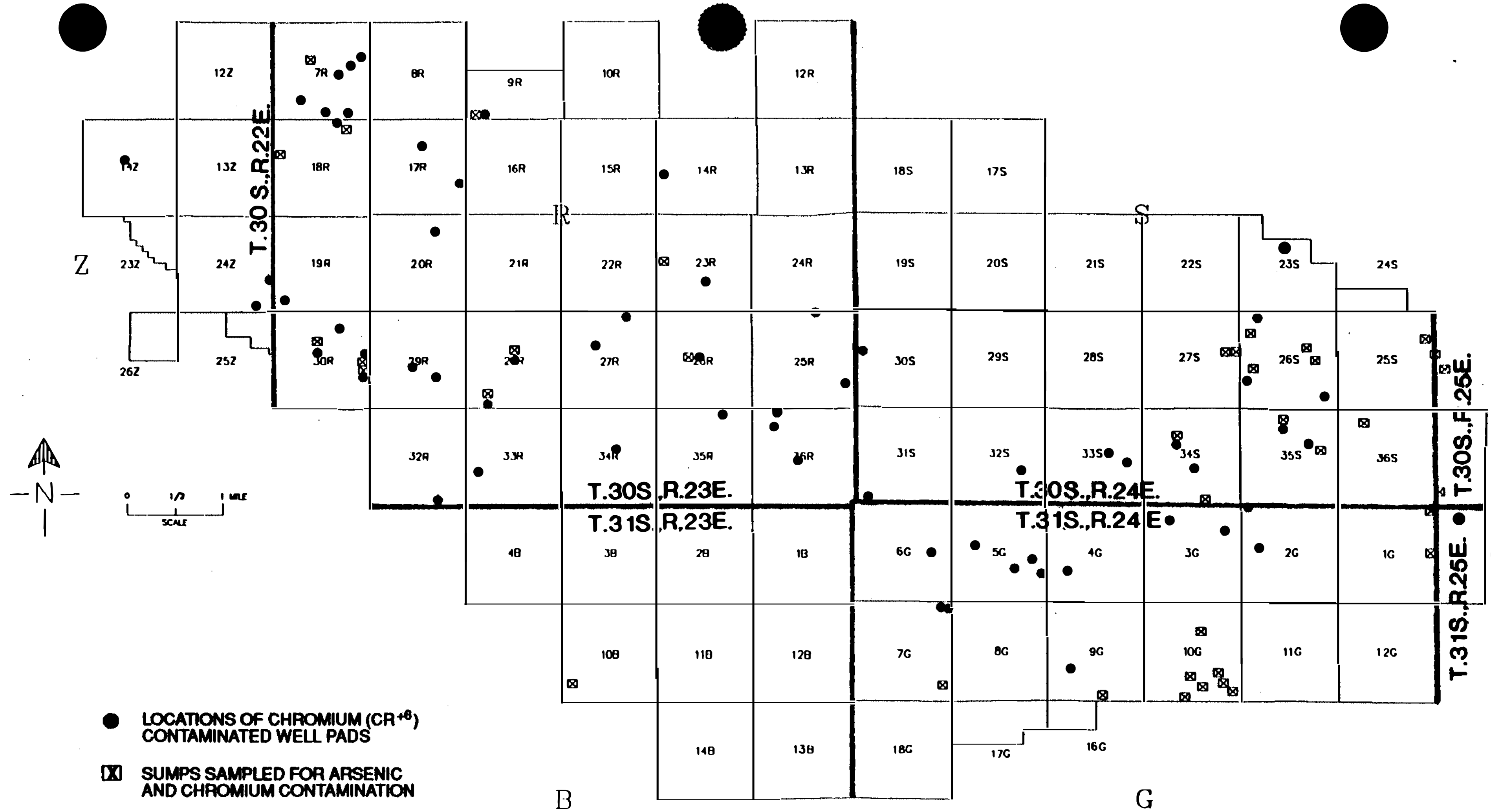

FIGURE 3.2-1 SECTION MAP OF NPR-1 SHOWING LOCATIONS OF CHROMIUM AND ARSENIC CONTAMINATION

was removed from the well bores by releasing initial production (oil and water) into six sumps at two sites. This practice resulted in what is believed to be localized arsenic contamination of soils within and possibly adjacent to and down gradient of the sumps. Five of the six sumps are in various stages of investigation and remediation as part of the on-going program to formally close inactive/abandoned waste sites (see Sections 3.2.4.2, 3.2.4.3, and 3.2.4.4).

Arsenic contamination in sumps and other surface areas cannot be located visually because the arsenic does not cause soil discoloration. Test results to-date have shown that arsenic concentrations in sump sediments can vary by a factor of 100 (Kaman Tempo Division 1987). For example, surface concentrations of arsenic in the vicinity of the saltwater brine sump 3 in Section 23S are shown in Figure 3.2-2. The highest concentrations were approximately 1,400 milligrams/kilogram at the sump intake, and these declined rapidly across the sump to approximately 17-66 milligrams/kilogram within 150-200 feet. Further characterization and remediation planning is in progress.

Produced Oil and Process Chemicals: Occasional spills and leaks of oil and process chemicals at NPR-1 also produce hazardous wastes. Detailed records of the number and volume of oil spills have been kept since 1979 (Table 3.9-1). Most oil is recovered with vacuum trucks and is recycled back through the production lines. The volumes of oil not recovered have remained more or less constant at a relatively low level. In addition to oil spills, small amounts of various process chemicals (such as 1,1,1-trichlorethane, waste lubricant oils, fluoride salts, carbon disulfide, and xylene) have been inadvertently released.

A study has been completed to evaluate the adequacy of secondary containment facilities at NPR-1 (BPOI 1990a). This study indicated a need to enhance these facilities especially around older tanks and bulk chemical-storage containers. Projects to accomplish this are in various stages of planning, design, procurement and construction. All new tanks, tank settings, and bulk chemical-storage tanks are installed or constructed with adequate secondary containment as required by the California Division of Oil and Gas regulations in Title 14 CCR, Part 1773.

Acids and Neutralized Acids: Well stimulation activities at NPR-1 generate approximately 9,500 barrels/year of spent waste acids (Owens 1992). Both hydrochloric and hydrofluoric acids are used in stimulation of work-over wells. Upon retrieval from the wells, these acids either are neutralized with lime or soda ash. Prior to November 1985, sodium fluoride salts of neutralization were disposed of in the hazardous-waste trenches at the 27R waste-management facility. Since 1985, these materials have been disposed of as hazardous wastes at an off-site permitted hazardous waste facility. A program recently has been initiated to reuse the acids in the SOZ Tulare and disposal-well-acidizing program. When recycled, the material is no longer considered a waste (Greenberg 1989).

Used Lead-Acid Batteries: Lead-acid batteries are used for the vehicle fleet and the field pumping-unit service trucks. NPR-1 has generated about 20 used batteries per month. Historically, undamaged batteries were recycled. Damaged batteries were shipped to the 2B storage yard, where they were packaged and sold as scrap or shipped off-site to permitted

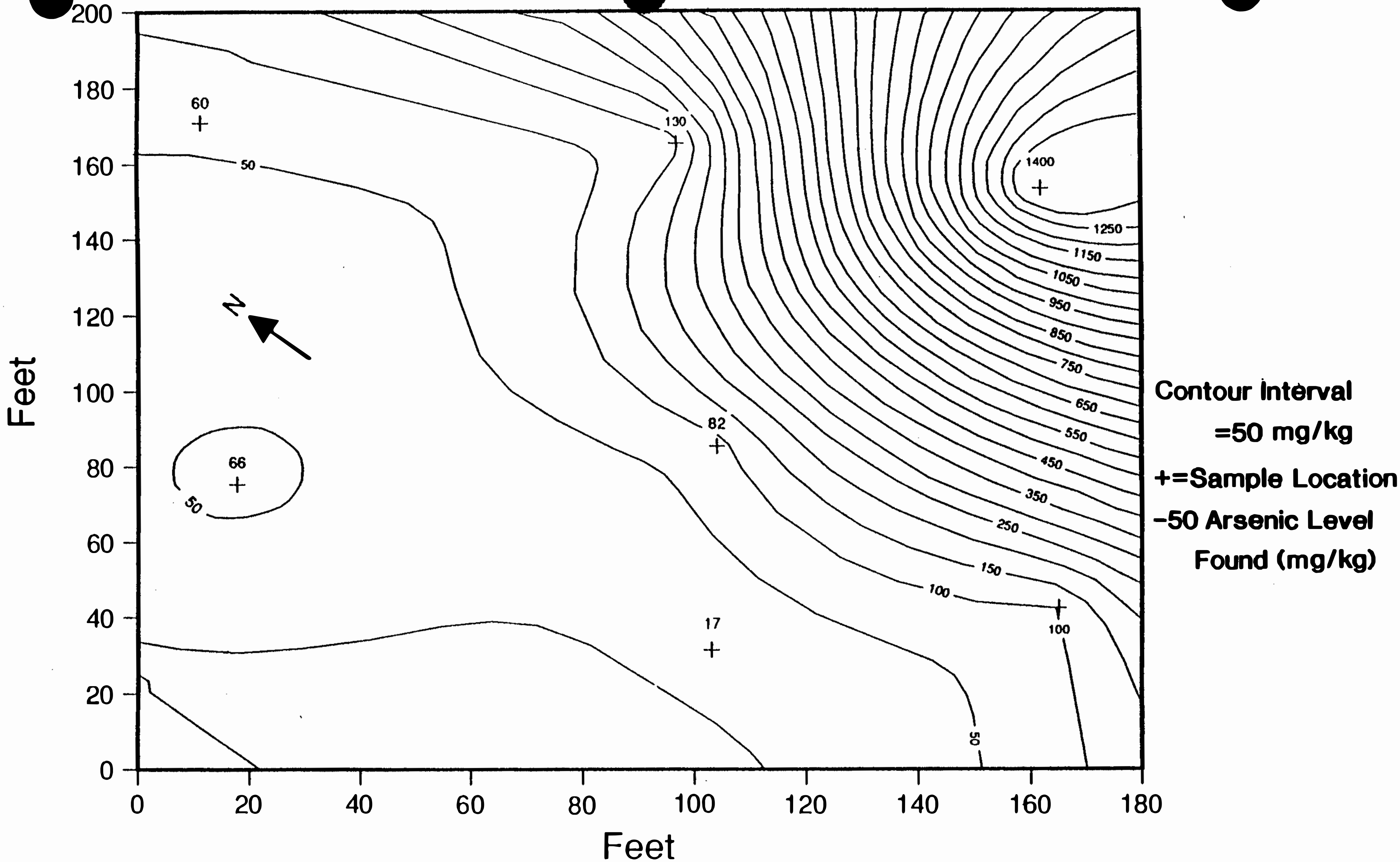

FIGURE 3.2-2 ISOPLETHS OF ARSENIC CONCENTRATIONS (mg/kg) IN VICINITY OF THE SALTWATER BRINE SUMP 3 IN SECTION 23S AT NPR-1 (+ MARKS THE LOCATIONS OF ACTUAL SOIL SURFACE SAMPLES) (SOURCE: MODIFIED FROM KAMAN TEMPO DIVISION 1987)

disposal sites. After 1985, damaged batteries were disposed of off-site at permitted hazardous waste facilities. More recently, spent batteries have been recycled pursuant to 22 CCR 66822.

3.2.3.2 Historical Waste-Management Facilities

Nonhazardous-Waste-Management Facilities

Landfills: Three landfills (located at 26S-East, 26S-West, and 35R) were placed in service between 1978 and 1982. These facilities were used only for disposal of nonhazardous wastes, such as construction wastes, wood, paper, asphalt, concrete, metal strapping, tires, and up to 50% garbage. The three landfills were taken out of service in 1986-1987 due to new, additional operating requirements in the Calderon Act (AB 3525, CA) and have been regraded (DOE 1989). Plans are to formally close these facilities; these initiatives are in various stages of investigation, internal review, regulatory agency review, and remediation. It is anticipated that formal closure with regulatory approval will be accomplished by the end of FY 1993.

Surface Dumps: Small amounts of trash, paper, glass, wood, pipes, and similar materials have been dumped (but not buried) at many small surface dumps on NPR-1. Pursuant to the initiative to identify and formally close all inactive historical waste sites, 24 such surface dumps have been identified (Williams Brothers Engineering 1985). These 24 sites are currently in various stages of investigation, review, and remediation.

Sumps: Open, unlined sumps have been used for the disposal of various types of waste- water by percolation/evaporation. The two major sources of this wastewater have been (1) drainage water from gas plants and (2) produced wastewater. These waters are a highly mineralized nonhazardous waste. Currently, sumping occurs only on an emergency basis, averaging about 1,000-2,000 barrels/day field-wide at about five different locations. For the period 1979 to 1989, the average sumping was about 10,000 barrels/day (McLemore 1989). Sumps are also used to collect spent drilling fluids and cuttings during drilling operations. Prior to 1974, these sumps were also used to dispose of spent drilling fluids. Four sumps at the 27R waste-management facility have been used to recover waste oil and to dispose of water used to wash equipment.

27R and 1OG Waste-Management Facilities: The 27R waste-management facility contains a landfarm area, an oil-recovery facility, and a truck-washout facility, all of which are/were used to handle nonhazardous materials.

The landfarming area is a 27-acre field where nonhazardous spent drilling fluids are spread to dry and be reworked into the soil. This area was put into service in 1974. Other federally-exempt wastes, such as well cellar wastes, cement, water, and oily polymers are also disposed of at the 27R landfarm. The total combined volume of waste disposed of at the landfarm in 1987 was nearly 500,000 barrels (BPOI 1988a).

The 27R facility includes two oil-recovery sumps that receive crude oil and water mixtures from oil spills, well cellar cleanout, and storage tank cleanout. These sumps, which have been in operation since 1979, are fenced impoundments in the landfarm area. The sumps are netted to keep out wildlife. Plans are to replace these sumps with tanks and formally close them. Closure is tentatively scheduled to take place in FY 1993 (BPOI 1991b).

From 1983 to 1990, two sumps disposed of water used to wash down trucks after they had unloaded waste cargo or recoverable products. These sumps have now been replaced with tankage, and the wastewater is disposed of from the tankage into the produced wastewater system. An annual volume of about 80,000 barrels was disposed of by these sumps (Mark Group 1987). One sump is to be formally closed. The other will remain in service as a backup in the event truck wash-out and oil-recovery tanks inadvertently overflow.

The 1OG waste-management facility contains a permitted 10-acre landfarm area that has received spent drilling fluids. Disposal procedures were similar to those used at the 27R landfarm area. Due to the reduced level of drilling activity, the site has not received wastes since midway through 1990. In 1989, the facility received 46,000 barrels of waste (BPOI 1990b).

Hazardous-Waste-Management Facilities

Sumps: At various times during past operations, wastewater placed in six sumps at two sites contained arsenic from W-41, as previously explained. In addition, soluble barium, apparently from drilling fluids, has been observed in some wastewater sumps. These sumps are discussed in more detail in Section 3.2.4.

Drum Storage and Chemical Containers: Six drum-storage locations have been identified at NPR-1 (Williams Brothers Engineering Co. 1985). These areas were used for interim storage of drums of hazardous and nonhazardous wastes, prior to off-site disposal. In 1985, the 2B storage yard was used to collect 2,600 drums, eight pieces of polychlorinated biphenyl (PCB) equipment, and more than 11,000 gallons of solid and liquid waste (including 700 gallons of PCB-contaminated oil). The drums contained petroleum products, acids, bases, corrosion inhibitors, neutralized hydrofluoric acid, herbicides, chromium, and arsenic waste. All drums from these sites have either been disposed of as hazardous waste at permitted off-site facilities or returned to vendors for reuse or recycling (BPOI 1991b).

Waste-Disposal Trenches: In 1980, a 4.5-acre disposal trench area at the 27R waste-management facility was set aside for the disposal of hazardous waste, pursuant to an Interim Status Document (CA 4170024414) from the California Department of Health Services. Waste sediments from tank bottoms, hydrofluoric salts of neutralization, and sludges from oil reclamation and truck-washout sumps were placed in the trenches and mixed with soil. This area has not been used since 1985, and it is currently in the process of being formally closed. Closure activities required to obtain a post-closure permit have been completed during FY 1992.

3.2.4 Sites Identified for Characterization

Several historic waste-management and spill sites that have been identified as requiring characterization and possible further remedial action are discussed below.

3.2.4.1 Hexavalent Chromium Spill Sites

Field inspections of 554 locations where chromium spills are suspected have been completed, 65 chromium spill sites were identified (Figure 3.2-1), and a program to remediate them is underway. Of the 65 sites, 52 have been remediated and verification testing performed. The contaminated soils removed from the sites have been disposed of at an off-site permitted hazardous waste disposal facility. Subsequently, they have been backfilled. The remaining 13 sites have been remediated and verified. An annual visual inspection of all potential 554 chromium sites was initiated in 1986. A visual program to inspect other potential sites is continuing.

3.2.4.2 23S Saltwater Brine Sumps

The 23S saltwater disposal sumps were used to hold produced water from the SOZ wells; W-41 (containing arsenic) was used in these wells. Significant arsenic contamination has been found in sumps 1, 2, and 3 of the 23S system. One sample from sump 3 during initial screening evaluations contained 2,630 milligrams/kilogram (BPOI 1987), well above the State of California total threshold limit concentration (TTLC) value of 500 milligrams/ kilogram for arsenic. Kaman Tempo Division (1987) subsequently characterized this sump as having a maximum arsenic level of 1,400 milligrams/kilogram (see Figure 3.2-2). Analysis of samples from sumps 1 and 2 showed extractable arsenic contamination levels above the STLC value of CCR Title 22 (BPOI 1987). These sumps will be further characterized as part of sump closure plans described in Section 4.1.2.3 and Table 1.2-10.

3.2.4.3 Site 1A-6M Well Pad and Sumps

Site 1A-6M is an abandoned well pad with a primary sump and an overflow sump. In 1960, the water in the overflow sump was determined to be contaminated with W-41; the arsenic concentration in the water was about 4,500 parts/million. After 1960, both sumps were partially filled inadvertently with soil when a new well pad and drilling sump were constructed nearby. Three composite soil samples recently were taken in the area between the primary sump and the well pad and from the well pad itself. The highest arsenic concentration, 190 milligrams/kilogram, was in the sample taken on the well pad. Extractable arsenic concentrations in the samples ranged from 5.0 to 8.4 milligrams/liter, compared with the California STLC limit for arsenic of 5.0 milligrams/liter. Accordingly, these soils are hazardous, and remedial action alternatives are being considered (Kaman Tempo Division 1987). A feasibility study evaluating the alternatives in detail is planned. Based upon the results of the feasibility study, a remedial action will be selected.

3.2.4.4 4G-W41 Disposal Site

The 4G disposal area as discussed in Section 3.2.3.1, consisted of a trench that was used for disposal of various materials contaminated with W-41 (arsenic). Investigations at this site unearthed piping, tubing, and valves contaminated with arsenic. These materials were removed and disposed of at an off-site permitted disposal facility. Additional sampling has been completed to determine the need for additional remediation.

Sample analyses indicated the absence of further arsenic contamination (Akers 1991). No further characterization or remediation of this site is planned under CERCLA.

3.2.4.5 3G Gas Plant Cooling Tower

In 1987, the 3G gas plant was removed from service. Plans are to demolish the facility and permit the demolition subcontractor to sell, recycle, or dispose of the components at his/her discretion. Among other tests, the internal parts throughout the cooling tower were sampled and tested to determine concentrations of various metals. The results showed an extractable copper concentration of 30-40 milligrams/liter (using the WET process) for several samples. These values exceed the STLC standard of 25 milligrams/liter for copper (22 CCR 66699). Thus, demolition plans will generate hazardous waste requiring disposal at a permitted hazardous waste facility (CCR, Title 22).

3.2.4.6 Drainageways From 3G Gas Plant

Drainageways from the 3G gas plant have received effluent from the facility. The drainageway from the western end of the plant supports a more dense vegetation than surrounding areas. Analyses of five soil borings and four surface samples taken along the drainageway indicated no elevated metals concentrations, but volatiles were present in surface soil and at depths up to 7 feet. Contaminant concentrations of 18 milligrams/kilogram tetrachloroethylene; 18 milligrams/kilogram 1,1,1-trichlorethane; 140 milligrams/kilogram methyl ethyl ketone; and 70 milligrams/kilogram methyl isobutyl ketones were found in the samples. These findings and a no-action recommendation were forwarded to the CVRWQCB for their review, and approval is expected.

3.2.4.7 Underground Petroleum Tank Soil Contamination

During removal operations, it was found that 10 underground storage tanks at three locations (36S gas station, 36R gas station, and 36S garage) had leaked. In particular, soil beneath several of the tanks was found to be contaminated with volatiles and petroleum hydrocarbons. Ten borings up to a depth of 70 feet were drilled at these sites. Two of the borings showed minor levels of hydrocarbon contamination (Campbell 1989a). Based on these results, a no-action alternative was recommended and approved by the Kern County Environmental Health Services Department (1989).

3.2.4.8 18R Drilling Fluid Tanks

From approximately 1974-1978, an attempt was made to recycle used drilling fluids. Eight above ground tanks in Section 18R were used to store reclaimed drilling fluids. One of the tanks was observed to be seeping oily liquids through pinholes in the tank sides (BPOI 1986). Preliminary screening tests indicated that the materials in this tank may have been hazardous. Additional samples were obtained and more testing has been completed. The results of the tests determined the materials to be non-hazardous (Akers 1991). Currently, three of the four remaining tanks still contain solid non-hazardous waste materials, which are to be removed in FY 1993.

3.2.4.9 2B Drum Storage Area

Approximately 2,600 drums of waste material were kept at the 2B drum storage area until they were shipped off-site for disposal late in 1985. Many of the drums were old and were not labeled and contained unknown types of waste (Williams Brothers Engineering 1985). Subsequently, a complete drum-removal program meeting federal and state regulatory guidelines was implemented. Soil staining was noted around groups of drums stored directly on the ground and at the transformer-oil-collection tank (Williams Brothers Engineering 1985). These areas have been sampled, tested and determined to be nonhazardous (Golder 1989). No further action is needed or planned.

3.2.4.10 36R Abandoned Gas Plant

A gas plant was operated in Section 36R between 1915 and 1940 and then dismantled; it could have generated hydrocarbon waste streams, the disposition of which is unknown. A layer of black ash of unknown origin is deposited around a foundation that remains. Samples of the black ash were tested and determined to be nonhazardous (Golder 1989). Additional consideration is to be given to this site as part of the NPR-1 cleanup/closure program.

3.2.4.11 Additional Sump Investigations

An additional 30 sumps (drilling-fluid sumps, produced-water sumps, and miscellaneous sumps) were screened by testing one sample taken from the surface at each sump for possible contamination with arsenic or chromium, primarily at the inlets where contaminant levels are usually the highest (Figure 3.2-1). Except for arsenic levels in one sample from sump 3 at 23S, CCR Title 22 TTLC and STLC levels were not exceeded. A further review of these sites is in progress as part of the site-wide program to cleanup/close abandoned waste sites.

The total volume of arsenic-contaminated soils from sumps at 23S and 1A-6M is estimated to be 48,000 cubic yards. Because of low rainfall, depth to groundwater and the remote locations of these sumps, no adverse impacts are anticipated to result from the contamination (BPOI 1991b).

3.2.5 Current Waste Generation and Management

3.2.5.1 Current Waste Streams

Nonhazardous

Drilling Fluids: Drilling fluids and oily water from drilling sumps constitute a large-volume waste stream on NPR-1. NPR-1 drilling fluids have been determined to be nonhazardous as defined by 22 CCR 66680 and 66699. These materials have been disposed of at the 10G and 27R landfarm areas. In 1987, well drilling generated 700,000 barrels of these wastes (BPOI 1988a). By 1990, reduced drilling activity accounted for only 315,000 barrels of these wastes and use of the 10G landfarm for disposal was discontinued (BPOI 1991a).

Soluble Barium: Oil-field sumps could contain all of the necessary species to form soluble barium, primarily as the result of the use of barite (barium sulfate) as a weighting additive in drilling fluids. Barium, excluding barium sulfate utilized in drilling fluids, is regulated under 22 CCR 66699. Deeley and Canter (1986) found high concentrations of soluble barium (up to 6 milligrams/liter) in water from drilling pits at various oil fields around the country. Tests for soluble barium were performed at various NPR-1 surface water sources to assess the potential for impact to NPR-1 wildlife and resulted in typical concentrations ranging from 0.027 milligrams/liter to 11 milligrams/liter (Suter, 1988). The highest concentration of soluble barium measured at NPR-1 was 51 milligrams/liter which was obtained from a wastewater sump at site 26Z-3 (Kaman Tempo Division 1988). The 26Z sumps have been taken out of service and formally closed.

Animals exhibit a great range of sensitivity to the effects of soluble barium. The median lethal dose (LD_{50}) for ingested soluble barium chloride ranges from 7 to 29 milligrams/ kilogram for mice, 90 milligrams/kilogram for dogs, and 800 to 1,200 milligrams/kilogram for horses (Reeves 1986). The sensitivity of animals at NPR-1 to the effects of soluble barium is not known. Closure of sumps (see Section 1.2.2.14, Table 1.2-10, and Section 4.1.2.3 for details) should effectively eliminate any potential problems from soluble barium.

Produced Water: Approximately 99% of water produced in association with oil production is currently disposed of by reinjection into the Tulare Formation, SOZ wells, and Stevens wells; the remainder is placed in evaporation/percolation sumps. Current NPR-1 operations generate about 37 million barrels of produced water/year (DOE 1989) (see Section 3.2.3 for more details). This wastewater stream may also include blowdown water, runoff, and water treatment additives such as corrosion inhibitors, biocides, slimicides, and scale inhibitors. Typical materials used in inhibitor additives include heavy aromatic naphtha, methanol, thioalkyl-substituted nitrogen heterocycle, tridecanol, alkylpyridines salts, fatty quaternary ammonium chloride, ammonium bisulfite, salts of fatty acid/polyamine reaction products, thiophosphates, isopropanol, ethylene glycol, and acid phosphate esters.

Solid Waste: Solid waste generated at NPR-1 consists mainly of paper, wood, metal equipment parts, cardboard, garbage, and construction debris. These wastes are placed in receptacles outside site buildings, and are gathered from field locations and placed in the solid-waste transfer stations at Sections 35R and 36S. Once collected, the solid waste is taken to the Kern County landfill located near Taft. These solid wastes are not inventoried, but it is estimated that 24,000 cubic yards of solid waste are generated annually (DOE 1989). No landfill sites for solid waste are active on NPR-1.

Sewage: Sewage facilities at NPR-1 consist of 12 septic tanks with leach fields. Wastes from the septic tank systems are pumped out as necessary by a subcontractor and hauled off-site for disposal. Additionally, portable sewage-holding tanks are provided by subcontractors at the drilling rigs. Local Kern County ordinances govern the construction and use of septic fields. No permits are required (BPOI 1991b).

Third-Party Actions on NPR-1: Third-party permits are reviewed by NPR-1 environmental, engineering, safety, and legal staff to ensure compliance with all environmental regulations and DOE Orders. The following third-party actions are evaluated in this subsection: (1) SoCal 30-inch pipeline and (2) Santa Fe Energy Co. 8-inch pipeline. Construction debris (such as wood, scrap metal, and scrap insulation) generated by these projects are be disposed of at the Kern County landfill near Taft, or at other permitted landfills, as nonhazardous solid waste. Hydrocarbon spills from pumping stations and leaking valves must be managed and cleaned up in accordance with the appropriate spill prevention, control and countermeasure (SPCC) plan. Water used to hydrostatically test equipment must also be disposed of. Third-party activities are discussed further in Section 3.4.3.

Hazardous

Used Oil and Lubricants: Used motor oils are recycled. Lubricant streams are generated as the result of changing hydraulic fluids, spills of same, oil spills, oily wastewater spills, and sludge and other waste-oil solids obtained from facility and well cleaning/maintenance. These waste streams are tested, and if they are nonhazardous (CCR, Title 22), they are recycled into production facilities. If they are hazardous, they are disposed of off-site at permitted hazardous waste disposal facilities.

Herbicides and Pesticides: Approximately 100 pounds of herbicides and pesticides are used by BPOI subcontractors annually at NPR-1, usually in conjunction with office building and landscape maintenance, and for control of weeds and plants in the vicinity of gas plants and well pads as part of the site fire prevention program (Bennett 1992). Such materials are used in accordance with accepted practices. Storage containers and applicators used by the subcontractors in this regard are considered hazardous waste and are disposed of off-site by the subcontractors. Herbicides and pesticides are not stored or disposed of on-site.

Tank Bottoms: Aboveground tanks are used at NPR-1 to store crude oil, produced water, NGL's, gasoline, and waste oil. Many of these tanks are used as settling tanks where oil, water, and sediments are separated. Tank-bottom sediments accumulate in these tanks, and periodically they must be removed. These sediments are tested, and if determined to be hazardous, they are removed from the site for disposal at a permitted hazardous waste disposal facility. If the materials are nonhazardous, that are disposed of at the 27R landfarm. Tank bottoms rarely test hazardous; during 1990 and 1991, a total of 75 cubic yards of tank bottoms have been removed from NPR-1 for off-site disposal as hazardous waste (Valentino 1992).

Chemical Containers: Hazardous chemicals are used at NPR-1 for the maintenance and operation of process equipment and facilities. The chemicals are stored on-site in tanks and drums. In many cases, these are owned by BPOI subcontractors who have the primary responsibility for their operation, maintenance, and disposal. Storage and handling of these hazardous chemicals is required to be carried out in accordance with a hazard communication plan that consists of maintaining material safety data sheets (MSDS) on each chemical and employee training on chemical handling and management. As the storage tanks and drums are emptied, they are reused or disposed of off-site at permitted hazardous waste facilities.

Spills of Produced Oil and Process Chemicals: Spills of produced oil and process chemicals occur intermittently. All spills are cleaned up immediately upon identification in accordance with the facility SPCC plan (BPOI 1992), and BPOI policy and procedures manuals (BPOI 1988c, 1988d). These provide instructions for maintaining an emergency response team, cleanup procedures, and documentation. Where subcontractors share these responsibilities, they are required to follow the same procedures that have been adopted by BPOI. Detailed reports on both major and minor oil spills are maintained. Oil spills are characterized as major if (1) 100 barrels or more are released or (2) 1 barrel or more enters navigable water.

Polychlorinated Biphenyls (PCB): PCB's may be present at NPR-1, primarily in electric transformer dielectric oils. Of the approximately 400 existing oil-filled transformers in service at NPR-1 (Williams Brothers Engineering 1985), none are known to contain PCB's. Of the 400, about 300 are older units that might contain PCB's (BPOI 1988b). The remaining 100 transformers are relatively new, and they are known to have been purchased PCB-free. The transformers that might contain PCB's have been labeled, and they are inspected quarterly for leaks. Transformers are not tested for PCB's while they are in service. When they are removed from service (e.g., for repairs), they are stored in the PCB-storage area in the 2B storage yard, and they are tested at that time. Transformer oils that test above 5 parts/million PCB, and the transformers themselves, are disposed of off-site at a permitted hazardous waste disposal facility. Transformers and their oils that do not test above 5 parts/million PCB are either salvaged or returned to service depending on their condition. Since 1986, approximately 130 transformers have been tested. Three of these were hazardous and were disposed appropriately. A recent routine EPA investigation of NPR-1 PCB practices indicates compliance with federal requirements (EPA 1990).

Asbestos: Asbestos is present at NPR-1. NPR-1's goal is to ultimately remove all asbestos. This goal, however, is balanced with the strategy of not disturbing asbestos unless necessary by maintaining asbestos in a manner that prevents it from coming into contact with personnel and by removing it only when disturbance is necessary.

Almost all NPR-1 asbestos is on piping and other process equipment in the 35R Gas Plant constructed in the early 1950's. It is estimated that there are 3,800 linear feet of pipeline containing asbestos (DOE 1989). These areas have been marked, and projects to remove and dispose of portions of this asbestos are in various stages of planning, review, approval, design, and construction. Other facilities and areas known or suspected of containing asbestos are being addressed similarly. Until asbestos can be removed and disposed of, current policy and practice requires encapsulation of all friable and exposed asbestos. Asbestos areas are monitored to determine airborne particulate levels. Removed asbestos is disposed of off-site at a permitted hazardous waste facility. Asbestos-removal subcontractors are licensed by the state and are required to pass state examinations and follow a thorough training program.

Solvent Wastes: Approximately 900 gallons of hazardous solvent wastes are generated annually at the 35R and 36S laboratory facilities (Gough 1992). Operations there include distillations, product testing, water analysis, and degreasing. Some of the hazardous solvents used in these operations include 1,1,1-trichlorethane, 1,1,2-trichlorethane, carbon disulfide, chloroform, toluene, and xylene. Wastes containing these substances are collected in drums and disposed of off-site at permitted hazardous waste facilities. Prior to 1988, all liquid waste at 35R was disposed of into laboratory drains, which discharged to the 35R sump. This sump is no longer in service, and is to be formally closed as part of the site-wide cleanup and closure program.

Used Lead-Acid Batteries: Spent batteries are provided to recyclers pursuant to 22 CCR 66822.

3.2.5.2 Current Waste-Management Facilities

Nonhazardous

27R Facility: The 27R waste-management facility is a 32.5-acre site. It consists of a 27-acre landfarming area, which includes an oil-recovery area and a truck-washout area that operates under CVRWQCB Waste Discharge Requirement 73-141, and an inactive 4.5 acre hazardous-waste-disposal trench which was taken out of service in 1985. The trench is in the process of being formally closed. No hazardous wastes are currently disposed of at this facility. The landfarm area is used primarily for the disposal of nonhazardous materials such as spent drilling fluids and tank bottoms. The oil-recovery facility includes two sumps that are in use to dispose of wastes (primarily water) that are associated with oil being recovered. Plans are to replace these sumps with tanks and formally close them. The truck-washout facility includes two additional sumps that until 1990 were used to dispose of waste washwater. These sumps have now been replaced with tanks, and they are no longer in service. One sump is to be formally closed. The other sump is to be used as a backup for the truck-washout and oil-recovery tanks during off-normal situations (such as tank over-flows) that might occasionally occur.

10G Landfarm Area: The 10G landfarm area is a permitted 10-acre disposal site that receives nonhazardous spent drilling fluids. This site operates under CVRWQCB Waste Discharge Requirement 73-42. Disposal procedures are similar to those in use at the 27R landfarm area. As discussed in <u>Sections 3.2.1 and 3.2.3.2</u>, this site has not received any drilling fluid wastes since mid-1990. This facility may be utilized in the future and is still maintained as an operational facility.

Produced-Water-Injection Wells: Produced water is disposed of principally by reinjection. Approximately 100,000-110,000 barrels/day of wastewater currently are disposed by this method (DOE 1989). Stevens Zone wastewater, totaling approximately 72,000 barrels/day, is injected into the Tulare Zone through 11 disposal wells in Sections 18G, 7G, 8G, and 24Z. An additional 5,500 barrels/day of Stevens wastewater is reinjected into four wells in Section 24Z. Approximately 18,000 barrels/day of SOZ wastewater is injected into the SOZ through two disposal wells in 15G and 16G. In addition, approximately 4,000 barrels/day of Asphalto Zone wastewater is injected into two Olig wells in Section 26Z. For additional information see <u>Section 3.4.2.4</u> and <u>Figure 3.4-7</u>.

Solid-Waste-Transfer Station: Nonhazardous wastes such as wood, metal equipment parts, damaged tools, construction debris, and other refuse from field operations are collected at two solid-waste-transfer stations - one each in Sections 36S and 35R. Both stations consist of a 40-cubic yard dumpster where the wastes are collected for transfer to the Kern County-Taft landfill adjacent to the NPR-1 site.

Hazardous

Section 35R 90-Day Storage Area: Under current practice, hazardous wastes are stored for no more than 90 days at a waste-storage area in Section 35R; then they are transported off-site for disposal at a permitted hazardous waste disposal facility.

PCB Storage Area: A small covered and contained pad at the 2B storage yard is used to receive electrical transformers and other electrical equipment suspected of being contaminated with PCB's. If equipment is found to be contaminated with PCBs above the California hazardous waste limit, it is shipped off-site within 30 days directly from this pad to a permitted hazardous waste disposal facility.

3.2.6 References*

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*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California 93276.

3.3 AIR RESOURCES

3.3.1 Climatology and Meteorology

The 1979 EIS for NPR-1 (DOE 1979) describes in detail the climate and dispersion characteristics that affect air quality in the area surrounding the site. Meteorological and climatological data representative of the site area that have become available since the preparation of the 1979 EIS and additional information developed using that recent data are presented in Section B.1 of Appendix B. Included are wind direction and speed, atmospheric stability, and mixing-height data needed to perform an air quality impact analysis for the proposed action.

3.3.2 Ambient Air Quality and Current NPR-1 Emissions

3.3.2.1 Ambient Air Quality

The 1979 EIS describes in detail the regional and local ambient air quality during the late 1970s in the areas surrounding NPR-1. The data base used was primarily from the ambient air quality monitoring network operated by state and local agencies and reported by the California Air Resources Board (CARB). Of the six air pollutants for which the National Ambient Air Quality Standards (NAAQS) are established (EPA 1971), the levels of ozone (O_3), total suspended particulates (TSP), carbon monoxide (CO), and sulfur dioxide (SO_2) exceeded applicable standards in 1977 in all or parts of Kern County. The level of O_3, which is a regional air quality problem, exceeded the standard throughout the San Joaquin Valley Air Basin (SJVAB), including Kern County. Ambient standards for TSP were frequently exceeded at many locations in Kern County, and the 8-hour CO ambient standard was exceeded predominantly in the Bakersfield metropolitan area. Violations of annual SO_2 and NO_2 standards were also recorded at isolated monitoring stations within or near Bakersfield. As of 1979, the SJVAB portion of Kern County was designated as a nonattainment area (an area not attaining NAAQS) for O_3, TSP, CO, and SO_2.

Table B.6 (Section B.2 in Appendix B) lists the current NAAQS and the California State Ambient Air Quality Standards (CAAQS), which are in general more stringent than the NAAQS and cover several more pollutants. Section B.2 presents details of ambient air quality standards and other air pollution regulations relevant to the NPR-1 project.

The Kern County Air Pollution Control District (KCAPCD)[1] in 1979 adopted a state implementation plan (SIP) outlining measures necessary to attain the NAAQS. In 1982 and in

[1]Subsequent to the release of the DSEIS, administration of the Clean Air Acts was transferred from the KCAPCD to the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD). References to KCAPCD should be read as being equivalent to the SJVUAPCD and its counterpart regulations.

1986, more stringent, revised plans were adopted. Implementation of these plans has resulted in steady improvements in several air quality parameters. However, ambient air quality standards for O_3 and suspended particulate matter have not been attained.

During the 1987-1988 period, the levels of O_3 and suspended particulate matter with a diameter less than 10 microns (PM_{10}) exceeded the NAAQS and CAAQS at one or more monitoring stations in western and central Kern County. (See Figure B.6 and accompanying text in Section B.2 of Appendix B for a discussion of the basis for dividing the SJVAB portion of Kern County into western and central Kern County for air quality planning purposes. The NPR-1 site is located in western Kern County.) Tables 3.3-1 and 3.3-2 show the current status of ambient air quality for O_3 and PM_{10} in western and central Kern County. With respect to NAAQS, the SJVAB portion of Kern County had been designated (as of the end of 1987) as a nonattainment area for O_3 and TSP, an attainment area for SO_2, and an unclassified area for NO_2. The nonattainment area for CO in Kern County is now limited to the Bakersfield metropolitan area. With respect to CAAQS, the SJVAB portion of Kern County is designated as a nonattainment area for O_3 a serious nonattainment area for PM_{10}, an attainment area for CO, NO_2, SO_2, and Pb, and an unclassified area for SO_4 and H_2S. Further details of current ambient air quality in the areas surrounding the NPR-1 site are described in Section B.2 of Appendix B.

3.3.2.2 Current Emissions at NPR-1

The various sources of air pollutants currently released to the atmosphere at NPR-1 can be grouped into four broad categories: (1) stationary combustion sources, (2) drilling and construction-related sources, (3) noncombustion oil and gas production sources, and (4) vehicular sources. The locations of major existing and proposed stationary combustion sources are shown in Figure 3.3-1. Table B.21 in Appendix B gives the locations of other sources by the section designation, except for the source types with numerous small sources, such as well pump engines that are scattered over the entire NPR-1 site area. The air pollutants emitted by these sources include (1) reactive organic gases (ROG), (2) oxides of nitrogen (NO_x = nitric oxide [NO] plus nitrogen dioxide [NO_2], expressed as NO_2), (3) carbon monoxide (CO), (4) sulfur dioxide (SO_2), (5) sulfate (SO_4), (6) total suspended particulate matter (TSP), (7) particulate matter equal to or smaller than 10 microns in aerodynamic diameter (PM_{10}), (8) hydrogen sulfide (H_2S), (9) lead (Pb), and (10) benzene (C_6H_6), Table 3.3-3 summarizes the current atmospheric emissions of each pollutant by major source category at NPR-1. Further details of these emissions are provided in Section B.4 of Appendix B.

Each major source category listed in Table 3.3-3 represents the dominant emission sources for some pollutant. For ROG, the noncombustion production sources are responsible for about 74% of the total emissions at NPR-1, with stationary combustion sources supplying about 25%. The stationary combustion sources are responsible for about 87% of the NO_x and 93% of the CO emissions. Compressor engines and gas-fueled pump engines are the most important of the stationary combustion sources of these emissions. Drilling and construction activities are responsible for about 80% of the total SO_2 emissions. Vehicular traffic is responsible for 97% and 94% of the TSP and PM_{10} emissions, respectively. These emissions consist primarily of

TABLE 3.3-1 Status of Ambient Air Quality for Ozone in Western and Central Kern County Relative to Ambient Air Quality Standards During the 1987-1988 Period[a]

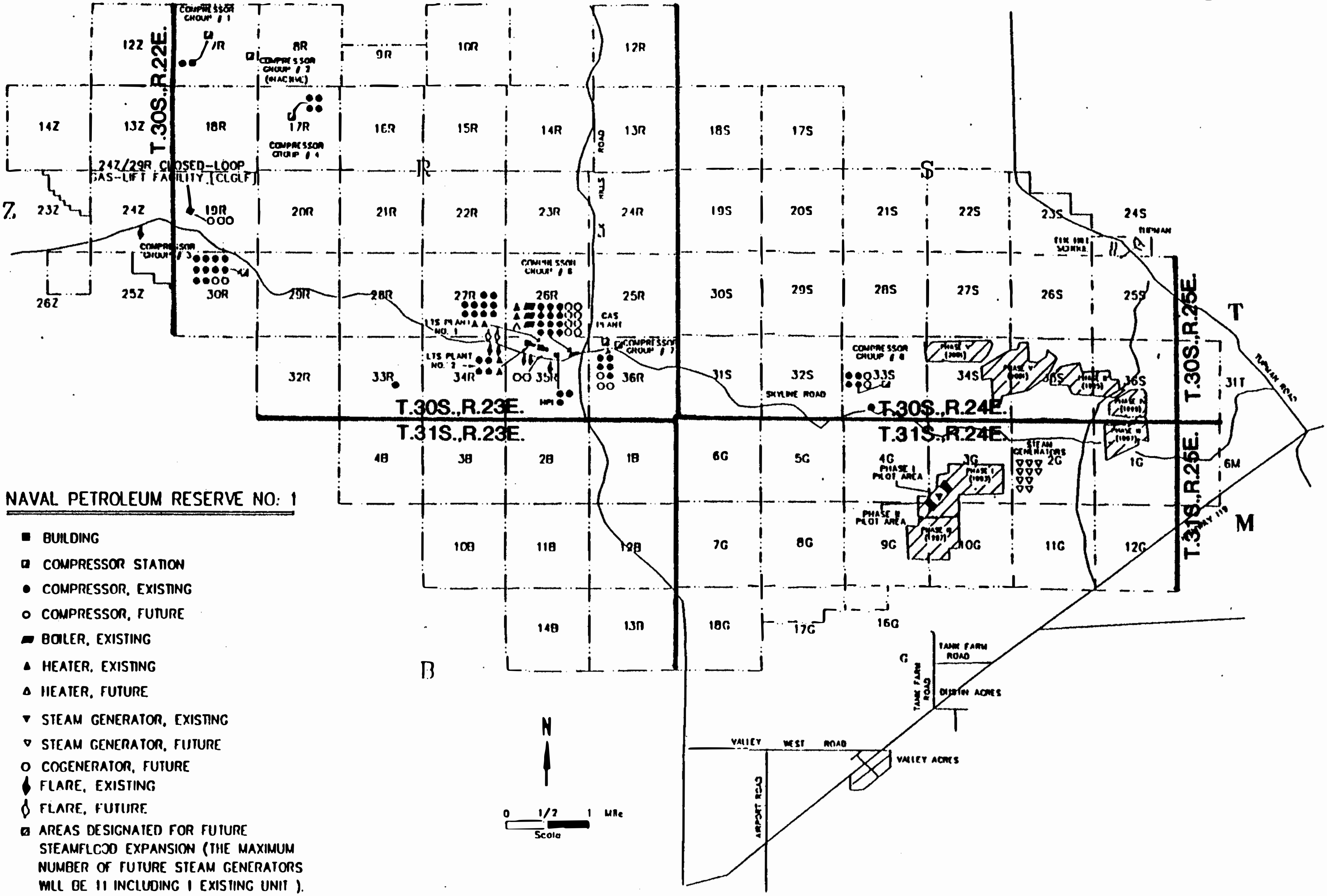
Monitoring Station[b]	Number of Hours (days) Exceeding			
	California 1-hour Standard (0.09 ppm)[c]		National 1-hour Standard (0.12 ppm)[d]	
	1987	1988	1987	1988
Western Kern County				
Kern Wildlife Refuge[e]	-[f]	3 (3)[g]	-	0 (0)[g]
Kernridge[e]	37 (10)	5 (3)[g]	0 (0)	0 (0)[g]
McKittrick	224 (43)	9 (2)[g]	14 (14)	0 (0)[g]
Taft[e]	0 (0)	0 (0)[g]	0 (0)	0 (0)[g]
Maricopa[e]	114 (30)	359 (76)	0 (0)	30 (8)
Maricopa	363 (59)	321 (69)	20 (9)	13 (6)
Central Kern County				
Oildale	158 (43)	300 (73)	1 (1)	5 (5)
Bakersfield	256 (68)	289 (76)	12 (10)	8 (5)
Edison	444 (110)	562 (125)	88 (43)	100 (54)

[a]Concentrations of air pollutants other than ozone and PM_{10}, i.e., CO, NO_2 SO_2, Pb, and total particulate SO_4, were all below applicable ambient air quality standards during 1987 and 1988.
[b]Monitoring stations operated by the state unless otherwise noted. Locations are shown in Figures B.1 and B.9 of Appendix B.
[c]Not to be exceeded.
[d]The 1-hour O_3 standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard (averaged over the past 3 calendar years) is equal to or less than 1.
[e]Monitoring stations operated by the Westside Operators.
[f]Data not available.
[g]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness due to termination or relocation during the year.

TABLE 3.3-2 Status of Ambient Air Quality for PM_{10} in Western and Central Kern County Relative to Ambient Air Quality Standards During the 1987-1988 Period[a]

Monitoring Station[b]	Number of 24-hour Samples Exceeding				Annual Mean Concentration ($\mu g/m^3$)			
	California Standard (50 $\mu g/m^3$)[c]		National Standard (150 $\mu g/m^3$)[d]		Geometric		Arithmetic[f]	
	1987	1988	1987	1988	1987	1988	1987	1988
West Kern County								
Kern Wildlife Refuge[g]	-[h]	18[i]	-	0[i]	--	60.1[i]	--	67.9[i]
Kernridge[g]	36	22[i]	8	6[i]	59.5	85.4[i]	77.2	109.7[i]
McKittrick[g]	29	13[i]	1	1[i]	45.5	45.9[i]	51.6	53.6[i]
Taft	24	30	0	2	42.5	50.5	47.7	54.6
Central Kern County								
Oildale	30	37	0	5	56.5	65.4	62.8	77.8
Bakersfield	37	41	1	4	57.4	64.6	64.4	73.3

[a]Concentrations of air pollutants other than ozone and PM_{10}, i.e., CO, NO_2, SO_2, lead, and total particulate sulfate, were all below applicable ambient air quality standards during 1987.
[b]Monitoring stations operated by the state and local agencies unless otherwise noted. Locations are shown in Figures B.1 and B.9 of Appendix B.
[c]Not to be exceeded.
[d]The 24-hour PM_{10} standard is attained when the expected number of days with a 24-hour average concentration above the standard (averaged over the past 3 calendar years) is equal to or less than 1.
[e]All values exceed California annual standard of 30 μ/m^3, which is not to be exceeded.
[f]All values exceed national annual standard of 50 $\mu g/m^3$. (The PM_{10} standard is attained when the expected annual arithmetic mean concentration [averaged over the past 3 calendar years] is less than or equal to the standard.)
[g]Monitoring stations operated by the Westside Operators.
[h]Data not available.
[i]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness due to termination or relocation during the year.



LOCATIONS OF MAJOR EXISTING AND PROPOSED NEW STATIONARY COMBUSTION SOURCES AT NPR-1

FIGURE 3.3-1

TABLE 3.3-3 Summary of Existing Source Emissions at NPR-1

Source Category	Total Capacity	Emission Rate (1b/h)[a]						
		ROG	NO_x	CO	SO_2[b]	TSP	PM_{10}	H_2S
Stationary Combustion								
Compressor engines	100,090 hp	321	956	1,172	0.4	2.0	2.0	0
Boilers and Heaters	452.1×10^6 Btu/h	1	34	8	0.2	0.9	0.9	0
Flares	296×10^6 ft^3/d	1	13	3	0.1	0.7	0.7	0
Pump engines	18,000 hp	26	255	33	0.0	0.3	0.3	0
Miscellaneous field engines	3,077 hp	0	0	1	0.0	0.0	0.0	0
Fugitive emissions	-	26	0	0	0.0	0.0	0.0	0.001
Subtotal[c]		375	1,258	1,216	0.7	3.9	3.9	0.001
Drilling, Construction, and Maintenance	-	14	177	38	11.9	16.1	13.0	0
Noncombustion Oil and Gas Production	-	1,128[d]	0	0	0	0	0	0.031
Vehicular Traffic								
On-site	-	3	4	27	0.4	622.2	251.5	0
Off-site[e]	-	4	12	31	1.8	100.8	35.9	0
Total[c]	-	1,524	1,451	1,313	14.8	743.0	304.2	0.032

[a]Annual average values; multiply by 4.38 to convert to units of tons/year.
[b]5% of SO_2 is estimated to be emitted as SO_4.
[c]Individual values may not add up to totals because of rounding.
[d]0.30 1b/hr of C_6H_6 is included in ROG emission rate.
[e]Refers to vehicle emissions resulting from NPRC employees driving to and from work.

road dusts. Emissions of H_2S are minor in comparison with applicable standards. The emission sources of H_2S are noncombustion oil and gas production and fugitive emissions associated with stationary combustion sources. The main source of benzene (C_6H_6) is evaporation from oil spills and unburned gas releases.

The emission values shown in Table 3.3-3 reflect the results of several ongoing and recently completed emission-control programs. A vapor-recovery system at NPR-1 is connected to all of the major storage tanks at the tank settings and LACT units, as well as to the various liquid product loading facilities. The system consists of a vacuum line maintained by suitable compressors and connected directly between these sources and the gas plant or the gas-gathering system of individual tank settings. Emissions of ROG are significantly reduced by the vapor-recovery system.

A recently completed emission-control program at NPR-1 is the NO_x reduction project. This project, initiated in 1987 and completed in February 1989, involved the retrofitting of 34 gas-fired internal combustion compressor engines at the 35R gas plant, at the two low-temperature separation plants (LTS 1 and 2), and at several on-site compressor stations. The retrofit consisted of replacement or modification of the engines with precombustion chamber (PCC) or prestratified charge (PSC) technologies. New compressor engines recently installed are already equipped with PCC technology and do not require retrofitting.

A third major emission-control program at NPR-1 is the inspection/maintenance (I/M) program. Values listed for fugitive emissions in Table 3.3-3 are derived from estimates of leakage from pipeline connections, valves, seals, and other components. Fugitive ROG emissions represent a significant source for these substances in any oil and gas production or processing facility that necessarily involves the use of a large number of such components. It is estimated that a carefully implemented I/M program can reduce fugitive emissions up to 42% and 29% from the valves serving liquid and gas lines, respectively, and up to 45% and 47% from the connections serving liquid and gas lines, respectively (California Air Resources Board 1981). Another fugitive-emission-reduction program at NPR-1 involves inspecting tank settings equipped with vapor-recovery systems to minimize hydrocarbon leaks. Other types of hydrocarbon emission sources often classified as fugitive sources and not subject to the I/M program are listed individually in Table B.21.

Other common emission-control practices utilized at NPR-1 include the flaring of gas from LTS 1, LTS 2, and 35R/HPI during upset conditions, rather than direct venting of the gas to the atmosphere, and the use of watering to control fugitive dust emissions during site clearing, preparation for construction, drilling, and remedial work activities. The extensive use of electrically driven oil-well pumping units also significantly reduces combustion-related emissions.

3.3.3 Acoustic Conditions

The major audible-noise sources within NPR-1 include compressors, steam generators, drilling rigs, heavy-duty vehicles, and miscellaneous engines. In areas of the NPR-1 remote from these noise sources, the acoustic environment is that of a rural location with typical residual sound levels of 30-35 decibels (A-weighted) (Miller 1968; Fidell et al 1981; BB&N 1984). (A residual level represents a low-limit value to which the ambient environmental noise drops frequently, but below which it seldom goes.) However, close to the noise-generating facilities, the residual environmental noise levels rise to those typical of industrial and construction sites, i.e., on the order of 60-80 decibels (DOE 1978).

The nearest residential areas to the existing major noise sources within NPR-1 are in the towns situated along bordering roads, such as Tupman, Dustin Acres, and Valley Acres. If the NPR-1 were not present, these residences would have residual night time sound levels typical of rural communities near a lightly traveled highway (30-40 decibels) (Miller 1968; Fidell et al 1981; BB&N 1984). However, acoustic emissions from the multitude of sources such as compressors, drilling rigs, and well pumps at NPR-1 raise the residual background environmental noise levels in these residential areas to the range of 40-45 decibels (DOE 1978). These levels are still low enough to not be generally noticeable to the community; no complaints have been recorded.

The ambient environmental noise level in these residential areas is substantially increased when traffic is passing on nearby roadways. An automobile can produce a momentary level of up to 77 decibels when passing along a roadway at a distance of 50 feet from a residence. A large, heavily loaded tractor-trailer truck can create maximum levels as high as 87 decibels when passing at a distance of 50 feet (Harris 1979; Fuller and Brown 1981). At such times, vehicular noise completely masks (makes inaudible) all other environmental background noise, including the levels attributable to the noise sources within NPR-1.

3.3.4 References*

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EPA -- See U.S. Environmental Protection Agency

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U.S. Environmental Protection Agency, 1971, National Primary and Secondary Ambient Air Quality Standards, 40 CFR, Part 52, Federal Register, 36(228):22384, Washington, DC, November 25.

*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California 93268.

3.4 WATER RESOURCES

3.4.1 Surface Water

3.4.1.1 Surface Drainage Features

The combined effects of topography and meteorology cause aridity to increase in the San Joaquin Valley from east to west and from north to south. Thus, almost all of the streamflow that reaches the valley originates in the Sierra Nevada, and much of this is snowmelt (Figure 3.1-1). Nady and Larragueta (1983) estimated that about 95% of the 317 million acre-feet of streamflow that enters the Central Valley each year is from streams (mostly perennial) draining the eastern side of the valley. In contrast, the streams draining the western side of the southern San Joaquin Valley are ephemeral and carry water only after sustained periods of significant rainfall. The Elk Hills are located near the southwestern edge in the most arid portion of the San Joaquin Valley.

A drainage divide follows the crest of the Elk Hills, causing runoff to flow generally to the north and south. Drainage from the northern flank of the hills flows into elongated, nearly parallel channels that open onto a gently sloping apron of alluvial material deposited at the base of the upland area. This alluvial apron, formed from coalescing alluvial fans, begins at about the 500-foot surface contour. The primary drainage channels occur at about 0.5 mile increments along the flanks of the hills and do not merge into an integrated network. Instead, they individually terminate on the valley floor. The natural course of some of these channels is interrupted by the California Aqueduct; in such cases, provisions have been made to redirect the surface flows. Many of the channels terminate naturally; some terminate in man-made obstructions, termed gully plugs, as a means of controlling the spread of potential spills. The drainage pattern to the south is generally similar. However, channels draining the central portion of the southern flank join Buena Vista Creek in Buena Vista Valley. The natural drainage in this trunk channel is southeastward toward Buena Vista Lakebed. Watersheds draining the western part of the Elk Hills convey runoff in the direction of McKittrick Valley, which slopes toward the northwest.

Table 3.4-1 presents selected characteristics of a sampling of drainage basins in the Elk Hills. The data were obtained from 7 1/2-minute topographic maps. The basins were selected to be representative of those in the immediate area, and only those specific channels and their associated basins were examined. No attempt was made to trace tributary channels based on crenulations in contour lines. The data indicate that the channels draining the northern flank tend to be larger and have greater relief, a slightly longer main stream channel, and a steeper slope than the basins draining the southern flank. For comparison with the basins included in the table, Buena Vista Creek has a slope of 71 feet/mile in a 10.6-mile reach adjacent to the southern margin of the hills.

Figure 3.4-1 shows the longitudinal profiles of selcted stream channels in this small sample. Each profile is relatively straight, as opposed to the smooth, concave profile characteristic of alluvial stream channels in more humid environments and under perennial flow regimes. This

TABLE 3.4-1 Selected Geomorphic Characteristics of a Sample of Drainage Channels in the Elk Hills

Channel[a]	Relief (ft.)	Area (acres)	Main Channel Length (mi)	Main Channel Average Slope (ft/mi)
N-4	760	950	3.43	222
N-6	420	347	1.80	232
N-8	700	1491	3.38	207
N-10	750	1556	4.12	182
N-12	920	1764	4.71	195
N-14	750	1208	3.71	202
N-16	840	1614	4.57	184
N-18	550	631	2.47	222
N-22	1100	4617	7.36	150
S-29	459	1146	2.76	166
S-31	616	734	3.31	186
S-37	470	1118	2.57	183
S-40	730	1074	3.76	194
S-42	560	1140	3.42	164

[a]Channels coded with the letter N drain the northern flank of the Elk Hills, and those coded with the letter S drain the southern flank.

Source: Derived from USGS 7 1/2 minute topographic maps.

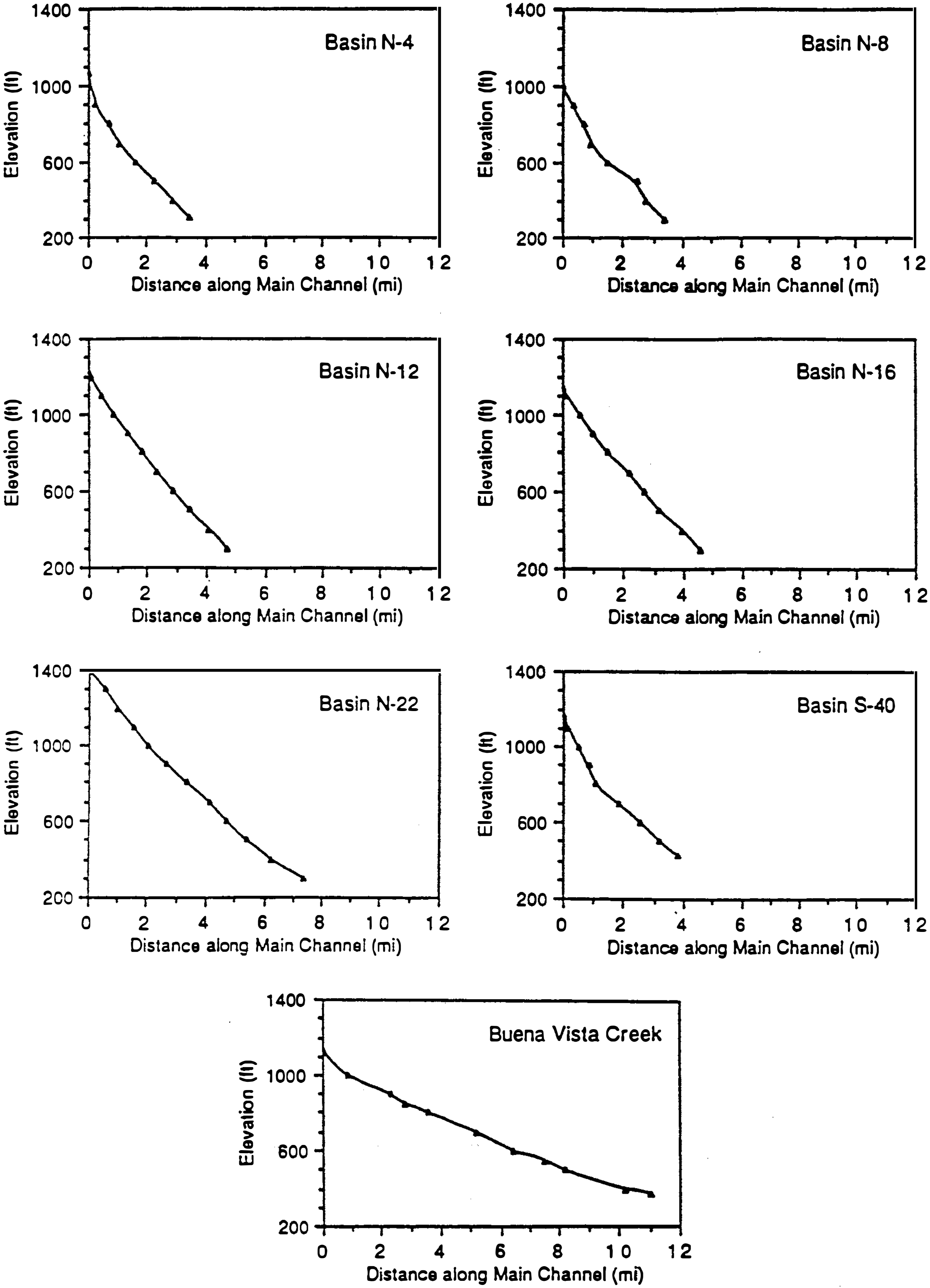


FIGURE 3.4-1 LONGITUDINAL PROFILES OF BUENA VISTA CREEK AND SELECTED STREAMS DRAINING THE ELK HILLS (SOURCE: DERIVED FROM USGS 7-1/2' TOPOGRAPHIC MAPS)

characteristically straight profile is caused by accumulation of sediment in the middle portions of the channels. This is related to the fact that streamflow decreases quickly downstream because of infiltration through the stream bed. These illustrations suggest that very little sediment and water are being conveyed through the channel from the watershed divide to the mouth of the basin. Thus, runoff only rarely reaches the floor of San Joaquin Valley. Conditions such as these are indicative of alluvial stream channels in arid environments.

To date, no wetland resources have been formally designated on NPR-1. Draft U.S. Fish and Wildlife Service National Wetlands Inventory maps were reviewed to determine the potential existence of such resources on NPR-1 (FWS 1986 a, b, c, d). This inventory identified 33 potential wetland locations of various classifications. These locations were identified on the basis of photogrammeteric interpretation; none of the locations were field checked by FWS.

A preliminary evaluation of the above wetland inventory maps was performed to determine the nature of these potential resources (Fries 1993, see Appendix J). As a result of this review, it was determined that 25 of these locations consist of oil field sumps and gully plugs, which are not likely candidates to qualify for wetland designation under wetland classification criteria. An additional location identified on the inventory consists of a diked impoundment that had been developed in the early 1960's with artificial watering to enhance wildlife habitat. The artificial watering at this location was discontinued subsequent to the FWS inventory for operations related reasons.

Of the remaining potential sites, 6 consist of portions of ephemeral stream channels, the most notable being the lower reaches of Buena Vista Creek located on the south flank of NPR-1. The last site identified on the FWS inventory consists of a lowland site northwest of Tupman in Section 23S. This site is associated with the historic channels of the Buena Vista Slough.

3.4.1.2 Hydrologic Data

Very little data are available to define the surface-water hydrologic conditions of the Elk Hills and surrounding areas, nor are regular data-collection programs in place. In part this is because streamflow varies greatly both with time and place, and the streams of the western valley area are dry for extended periods. Furthermore, much of this part of the San Joaquin Valley is sparsely populated, thus reducing the apparent need for hydrologic analyses and forecasting for most of the ephemeral streams.

Because no recording stations are located in the study area, no data on average or mean flows are directly available. However, the supply of water available in a stream at a given location can be estimated based on average or mean annual flow or runoff. Using the gauging station data that are available, Nady and Larragueta (1983) developed an equation for estimating average annual runoff into the Central Valley from ungauged drainage areas. From a drainage area of 58.9 square miles, they estimated the average annual Elk Hills runoff to be 390 acre-feet/year with a standard error estimate of 172%. The 390 acre-feet/year converts to an average runoff of approximately 0.12 inches/year.

The Kern County Water Agency has published a compilation of drainage areas and peak discharge data for selected streams in the county for the period 1958-1985 (Sorenson et al 1985). Table 3.4-2 lists the data and corresponding maximum runoff rates for five of the streams located near the NPR-1 site. The table shows that streamflow varies widely by time and place. Drainage areas of similar size can produce peak streamflows that vary by orders of magnitude.

Several investigations of flood conditions that have been conducted in the vicinity of the Elk Hills provide general information on high-flow conditions that might be encountered in the area. The Corps of Engineers (1965) evaluated flood conditions in several westside drainages intersected by the proposed California Aqueduct route. It was determined that two types of floods produce damaging flows in westside streams: rain floods resulting from general winter storms, and floods resulting from local thunderstorms that usually occur during summer or early fall. In the area of interest, both standard project general floods and standard project local floods were considered for each basin. The standard project rainstorm for a particular drainage area reflects the most severe flood-producing rainfall depth-area-duration relationship and isohyetal pattern of any storm that is considered reasonably characteristic of the hydrologic region. Standard project general floods and local floods were computed by taking into account appropriate flow losses (such as infiltration), evaluating historical flood records, and estimating some hydrographs.

Of particular interest are analytical results for several watersheds draining portions of the Elk Hills, Buena Vista Creek, and other streams in the vicinity of McKittrick and Taft. Table 3.4-3 summarizes basin, storm, and flood conditions computed by the Corps of Engineers (1965) for the westside streams and basins in the immediate vicinity of Elk Hills. Three of the basins (Southern Pacific, No Name, and Buena Vista Valley) drain a portion of the southern flank of the Elk Hills; the remaining basins listed are in the general vicinity of the Elk Hills, but have somewhat different characteristics than would probably be encountered within the NPR-1 area. Much of the information presented in the table and in the Corps of Engineers 1965 report is computed, not observed, and the original document should be consulted for full details of the procedures and assumptions leading to the results indicated.

Federal regulation of surface discharge is provided in 40 CFR 435, which states that "there shall be no discharge of wastewater pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling fluids, drill cuttings, and produced sand)." Some stream beds on the NPR-1 were observed to contain hydrocarbon stain, which is evidence of the presence of oil-field fluids within ephemeral channels. As previously discussed in this section, however, the arid climate and infrequent channel flows should provide for a low probability for off-site migration of surface-water contaminants. As hydrocarbon stains are identified, they are cleaned up in accordance with the NPR-1 SPCC (BPOI 1992a). Sources are controlled and eliminated by NPR-1 corrosion control, facility replacement, and secondary containment projects, and the SPCC.

TABLE 3.4-2 Drainage Area, Peak Discharge, and Maximum Runoff Rate for Selected Streams near NPR-1[a]

			Peak Discharge		
Stream	Period of Record[b]	Drainage Area (mi^2)	Date	Rate (ft^3/s)	Maximum Runoff Rate (ft^3 ● mi^2)
Sandy Creek (at Taft)	Oct. 1979-Aug 1984	12.5	March 1, 1983	220	17.6
Wagon Wheel Creek (near McKittrick)	Oct. 1958-Dec. 1984	1.38	June 6, 1972	338	244.9
Sand Creek (near McKittrick)	Oct. 1958-Sept. 1968 Feb. 1976-Dec. 1979	0.32	Feb. 10, 1978	124	387.5
Oil Creek (near Taft)	Oct. 1958-Oct 1969	35.0	May 28, 1963	11	0.7
Shale Creek	Oct. 1958-[c]	5.86	Feb. 9, 1978	143	24.4

[a]Data on period of record, drainage area, and peak discharge are from Sorenson et al. (1985); maximum runoff rates have been calculated from those data for purposes of this EIS.
[b]Many years within each gage record had no measurable flow.
[c]This gage was still in operation in 1985 when Sorenson et al. published these data.

Source: Adapted from Sorenson et al. 1985.

TABLE 3.4-3 Summary of Basin Design Precipitation and Flood Conditions for Selected Westside Basins

Location	Drainage Area (mi^2)	Precipitation (inches)								24-h Floods			
		10-yr Storm	Normal Annual	General Storm			Local Storm			General		Local	
				6-h	24-h	96-h	1-h	2-h	3-h	Peak (ft^3/s)	Vol. (acre-ft)	Peak (ft^3/s)	Vol. (acre-ft)
Seventh Standard	8.8	2.2	5.0	1.26	3.25	5.05	2.06	2.8	3.13	220	102	1,650	579
Temblor	82.8	3.0	8.0	1.69	4.20	6.53	1.10	2.0	2.38	3,400	2,410	9,000	4,330
Brown's Canyon	12.0	3.1	7.9	1.56	3.89	6.10	1.80	2.49	2.79	700	526	2,730	1,150
McKittrick	13.1	2.9	7.1	1.46	3.65	5.70	1.80	2.50	2.80	700	409	3,300	1,230
Southern Pacific	28.8	2.5	5.8	1.48	3.72	5.74	2.65	3.15	3.35	750	533	5,900	3,090
No Name	1.4	2.2	7.5	1.32	3.31	5.05	2.65	3.15	3.35	70	31	1,500	195
Buena Vista	93.0	2.6	6.6	1.46	3.62	5.68	1.07	1.85	2.32	2,860	2,410	10,700	7,230
Sandy Creek	38.4	2.6	6.2	1.54	3.82	5.97	1.40	2.30	2.70	1,150	735	7,800	3,500

Source: Corps of Engineers 1965

3.4.1.3 Surface-Water Quality

A single surface water sample analysis is available from an ephemeral stream flowing off the northeast flank of Elk Hills in Section 19S. As reported by Dale et. al (1966), the water was of the sodium sulfate type with total dissolved solids of 1,300 milligrams/liter. Dale goes on to state that probably this water is typical of water draining from the Elk Hills. These TDS levels make surface waters unsuitable for most uses.

3.4.2 Groundwater

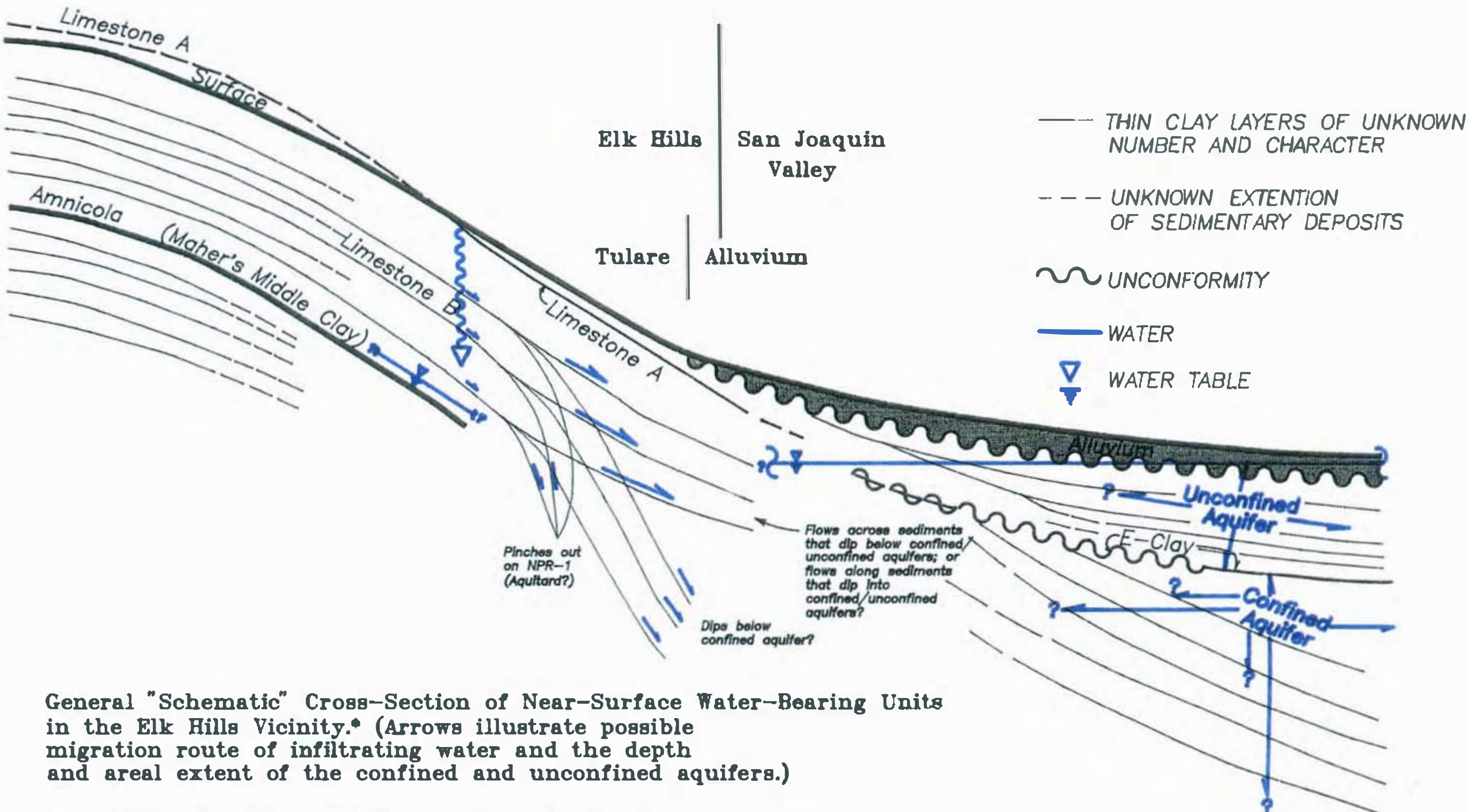
3.4.2.1 Regional Groundwater

Within Kern County, groundwater occurs in the surface Alluvium and underlying sediments. The sediments containing potable water can be hydrogeologically classified as unconfined and confined aquifers (KCWA 1987). The unconfined aquifer consists primarily of surface Alluvium and is separated from the confined aquifer by the Corcoran clay, or E-Clay (Croft 1972), and/or other clays that have the same confining effect (Figure 3.4-2) (hereinafter, these clays will be referred to as the E-Clay). The Alluvium is a poorly sorted sand, silt, and clay sequence that is difficult to differentiate from the underlying Tulare Formation. The Tulare Formation consists of a thick succession of nonmarine, poorly consolidated sands, conglomerates, and clays (Maher et al 1975). In the San Joaquin and Buena Vista valleys, the thickness of the Alluvium varies from a few feet to several hundred feet (Wilson and Zublin 1988). The Tulare Formation varies from 600 to over 2,100 feet thick in Kern County. The thickness of the confined aquifer is variable and has been defined as extending from the base of the E-Clay to the base of fresh water: i.e., TDS does not exceed 2,000 parts/million [California Department of Water Resources (CDWR) and KCWA 1977; Bean and Logan 1983]. In addition to the unconfined and confined aquifers, perched groundwater may exist at shallow depths, i.e., above the unconfined and confined aquifers.

The depth to groundwater in the San Joaquin and Buena Vista valleys ranges from approximately 50 feet beneath the Kern River channel to more than 650 feet in southern extremes of the valley near the White Wolf fault (KCWA 1987, Plate 4). The depth to perched groundwater is typically no more than 20 feet beneath the surface along western margins of the San Joaquin Valley (KCWA 1987).

The extensive agricltural economy in Kern County requires large quantities of water for irrigation. Much of this water is obtained from groundwater resources; the rest is supplied from northern California through the California Aqueduct or the Friant-Kern Canal. In 1986, 813,900 acres were irrigated in Kern County, requiring approximately 2,513,600 acre-feet of water (KCWA 1987). Municipal and industrial users, excluding NPR-1, required about 85,000 acre-feet.

Groundwater recharge in the valley aquifers is obtained from artificial and natural sources. Kern River water is recharged to groundwater through spreading in recharge areas and natural



General "Schematic" Cross-Section of Near-Surface Water-Bearing Units in the Elk Hills Vicinity.* (Arrows illustrate possible migration route of infiltrating water and the depth and areal extent of the confined and unconfined aquifers.)

* This is provided to illustrate schematically the possible hydrologic flow regimes described in Section 3.4.2.3.

Figure 3.4.-2

infiltration. State Water Project water is recharged by the KCWA and by several of the local water districts in the Kern River channel, unlined irrigation canals, and other recharge sites. The State of California has recently purchased a large tract of land in the San Joaquin Valley to be used for the Kern Water Bank Project. Water banking involves the management and storage of water supplies in underground reservoirs for subsequent extraction and use. This tract of land is near the northeastern boundary of the Elk Hills (Figure 3.4-3). Precipitation, which averages about 6 inches/year in the area, contributes little recharge to the groundwater system. In the San Joaquin Water District, the excess of evaporation over precipitation can be more than 45 inches/year (Erlewine 1988).

Figure 3.4-3 illustrates the groundwater surface of the unconfined aquifer in the San Joaquin and Buena Vista valleys. The general direction of flow is away from a northeast-southwest trending groundwater ridge beneath the Kern River. Maher et al (1975) reported that more than 100 groundwater wells have been drilled into the Tulare Formation around the southeastern, northeastern, and northern sides of NPR-1. The West Kern Water District (WKWD), which supplies freshwater to NPR-1, has groundwater production wells along the northeastern side of the NPR-1. The proximity of these wells to Elk Hills is shown by Figure 3.4-3.

Groundwater in the confined aquifer is generally of lower fluid potential (pressure exerted by fluid) than that in the unconfined aquifer. This is thought to be the result of greater groundwater withdrawals from the confined aquifer. Bean and Logan (1983) postulated that groundwater from the unconfined aquifer flows into the confined aquifer along the margins of the San Joaquin Valley. This is due to the thinning of the alluvial cover and consequent disappearance of the E-Clay in these areas (Bean and Logan 1983).

Very limited hydraulic conductivity data exist for the aquifer sediments. Hydraulic conductivity is the capacity of a rock to transmit water. A numerical model calibration study estimated that hydraulic conductivity of the unconfined and confined aquifers is 48 feet/day and 30 feet/day, respectively (CDWR and KCWA 1977). Rector (1983) compiled groundwater data from approximately 1,000 valley wells. Eight of these wells are located near the northeastern border of the NPR-1 and show an average specific capacity of 40 gallons/minute per foot of drawdown. Specific capacity is the yield of a well per unit of drawdown.

The groundwater basin in the Kern County portion of the San Joaquin Valley has no surface outflow except in extremely wet years. This condition causes salt magnification (accumulation) in the local unconfined groundwater. Surface water imported into the valley during the 1988 water year introduced approximately 484,000 tons of new salt into the groundwater basin (KCWA 1990).

The water quality of the confined aquifer is normally better than that of the unconfined. This condition may be due to the E-Clay providing a protective seal for the confined aquifer (KCWA 1987). The unconfined aquifer has received salt loading both from natural and artificial recharge. Perched groundwater in the San Joaquin Valley generally has a much higher salt content than groundwater located at depth. The confined aquifer has a TDS level of 50-500 ppm

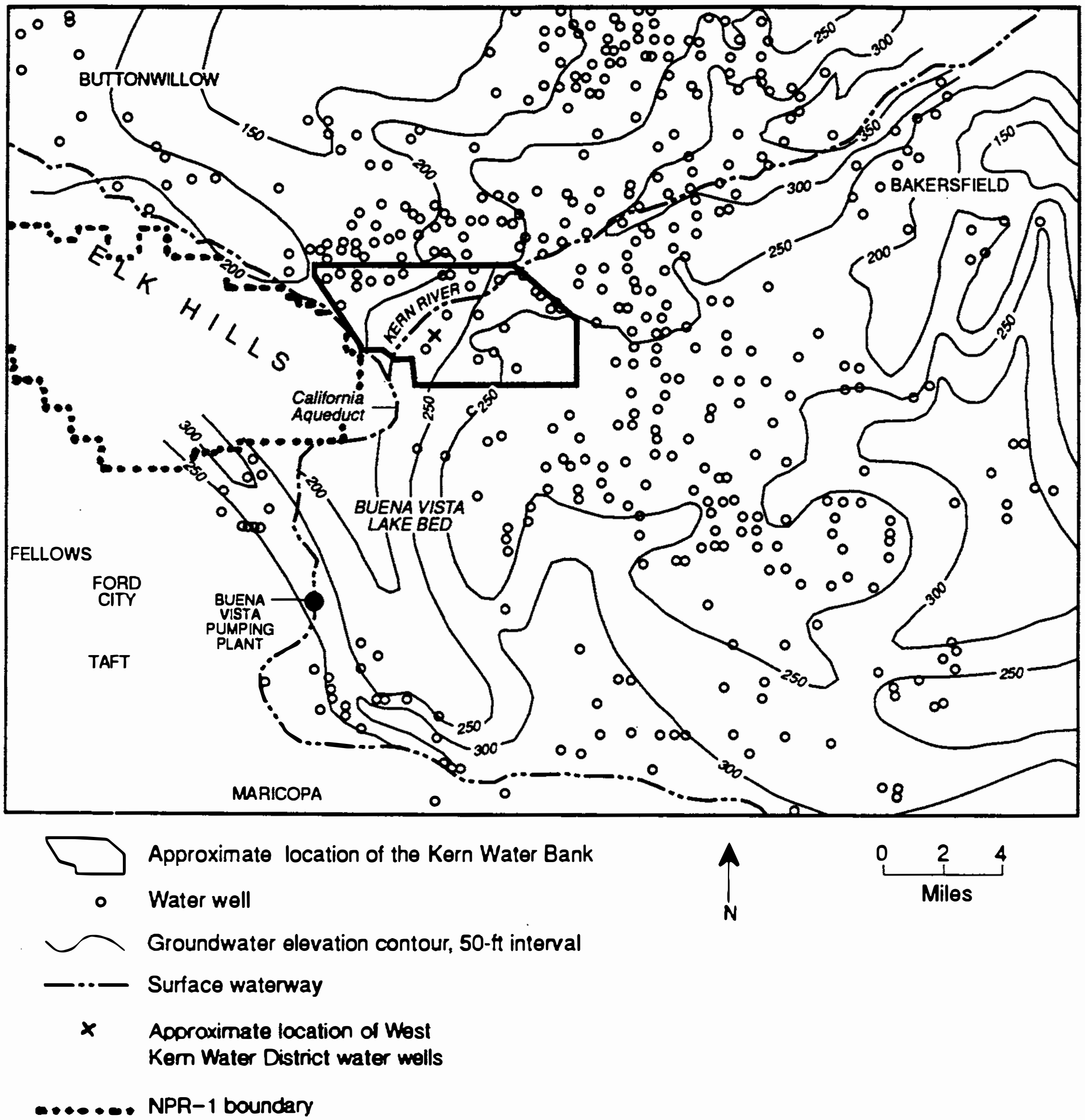


FIGURE 3.4-3 GROUNDWATER SURFACE ELEVATION MAP FOR ELK HILLS VICINITY (SOURCE: MODIFIED FROM KCWA 1987)

throughout most of the San Joaquin Valley (KCWA 1987). The unconfined aquifer, however, has TDS values in excess of 1,000 ppm in areas along the San Joaquin Valley margins and in several isolated locations. The literature suggests several explanations for this. Freeze and Cherry (1979) suggest that the age and distance along the groundwater flow path and local surface and subsurface activities could be responsible. Bean and Logan (1983) postulated that artificial recharge from oil-field wastewater disposal and agricultural irrigation might be contributory. Maher et al (1975) and Waldron (1989) suggest the higher TDS groundwater of the western areas may also be due to eastward migration of more saline groundwater derived from marine sediments in the Temblors.

3.4.2.2 Regional Produced-Water Disposal

Wilson and Zublin (1988) compiled data on the method, locations, and volumes of production water disposal in the Buena Vista and Midway Valley portions of Kern County. They estimate that historically, 3,178 million barrels of wastewater have been produced from oil operations since the 1900's. Of this amount, 91 million barrels have been reinjected into the subsurface in enhanced recovery operations. Another 253 million barrels have been injected into the subsurface for disposal; an estimated 2,328 million barrels have been disposed of through percolation in sumps, stream channels, and ditches; and 506 million barrels have evaporated. Rector (1983) and Bean and Logan (1983) identified the locations of percolation/evaporation sumps known to be in existence for at least 20 years (see Figure 3.4-8). Appendix D presents a more detailed discussion of the regional groundwater.

3.4.2.3 Elk Hills Groundwater

The Elk Hills area is located at the southwestern margin of the San Joaquin Valley and is separated from the Buena Vista Hills to the south by the Buena Vista Valley. It is a topographic highland with as much as 1,000 feet of relief with the adjacent valleys. The Tulare Formation is exposed throughout the interior of Elk Hills, while the periphery is a thin cover of Alluvium (Maher et al 1975). The sediments that form the confined and unconfined valley aquifers are also present at Elk Hills.

Figure 3.4-2 shows the relationship between Elk Hills sediments, infiltration water, and groundwater and San Joaquin Valley sediments. This figure shows that the confined aquifer is present near the San Joaquin Valley/Elk Hills interface, but the character and depth of its base are not known. It also shows that infiltration water on Elk Hills will move along clay and shale units that are dipping down as much as 20 degrees to 30 degrees on Elk Hills in the direction of valley aquifers (Fishburn 1990). Hydrologic flow regimes and the precise geology in the vicinity of the interface are not known. If flows are along the clay and shale units, and if they continue to dip sufficiently, infiltration water could ultimately be separated at lower depths from the confined aquifer. If flow is across the clay and shale units, or if dips are more shallow, infiltration water could eventually communicate with the confined and unconfined aquifers. It is possible that the dip, geometry and character of clay beds on NPR-1 between Limestone A and the middle clay could act as an aquitard (barrier) that prevents migration off of NPR-1

(Fishburn 1990). Hydrologic regimes are further complicated by uncertainties over the existence (and location) of the E-Clay in NPR-1 sediments (see Appendix D.1).

A map approximating groundwater surface elevations at Elk Hills has been recently completed (Figure 3.4-4). The depth to groundwater in the Elk Hills ranges from 50 to 100 feet below the ground surface on the periphery to in excess of 1,000 feet below the surface in higher elevations. The depth to perched groundwater south of NPR-1 near Buena Vista Lake is 20 feet below ground surface (KCWA 1987). Water has been observed intermittently at the surface on NPR-1 in Sections 3G, 4G, and 35S. The source of this water was investigated. Potential sources investigated include faulting, leaking wells, natural seepage (springs), sump leakage and leaking underground fresh water pipelines (Nicholson 1989). Based on preliminary findings, the most likely source appeared to be leaking underground fresh water pipelines. Water-saturated sediment was reported 60 feet beneath a truck washout sump at the 27R waste management facility (Kaman Tempo Division 1987; Mark Group 1987). In a subsequent investigation for the purpose of characterizing this water, investigators were unable to locate any saturated sediment (Kaman Tempo Division 1989).

Groundwater within the Elk Hills has both natural and artificial sources. Maher et al (1975) and Waldron (1989) suggest that the natural source is recharge from the Temblor Range to the west. The artificial source is produced wastewater that has been disposed of by injection into the Tulare Formation and by percolation through unlined sumps.

Groundwater withdrawals within NPR-1 total approximately 148,000 barrels/day. This groundwater is withdrawn from the Tulare Formation for use in the Stevens waterflood program.

Rector (1983) has interpreted the direction of groundwater flow to be from the Elk Hills into the adjacent valleys. KCWA (1990) has suggested that the flow of groundwater in the northern portions of NPR-1 is into the "Buttonwillow structural subbasin", and that flow in the southern portions is into the "Buena Vista structural subbasin." Wilson and Zublin (1988) constructed a groundwater surface map for the southern flank that suggests groundwater movement into the Buena Vista Valley.

NPR-1 groundwater quality is variable, and generally poor. Groundwater withdrawn in association with oil production is highly mineralized and can have TDS values as high as 35,000 ppm (Stuart 1987). Water obtained from southern flank wells from the Tulare Formation has shown TDS values between 4,000 and 6,000 parts/million; this is the highest quality groundwater observed at NPR-1.

A more detailed treatment of groundwater on the Elk Hills is given in Appendix D.

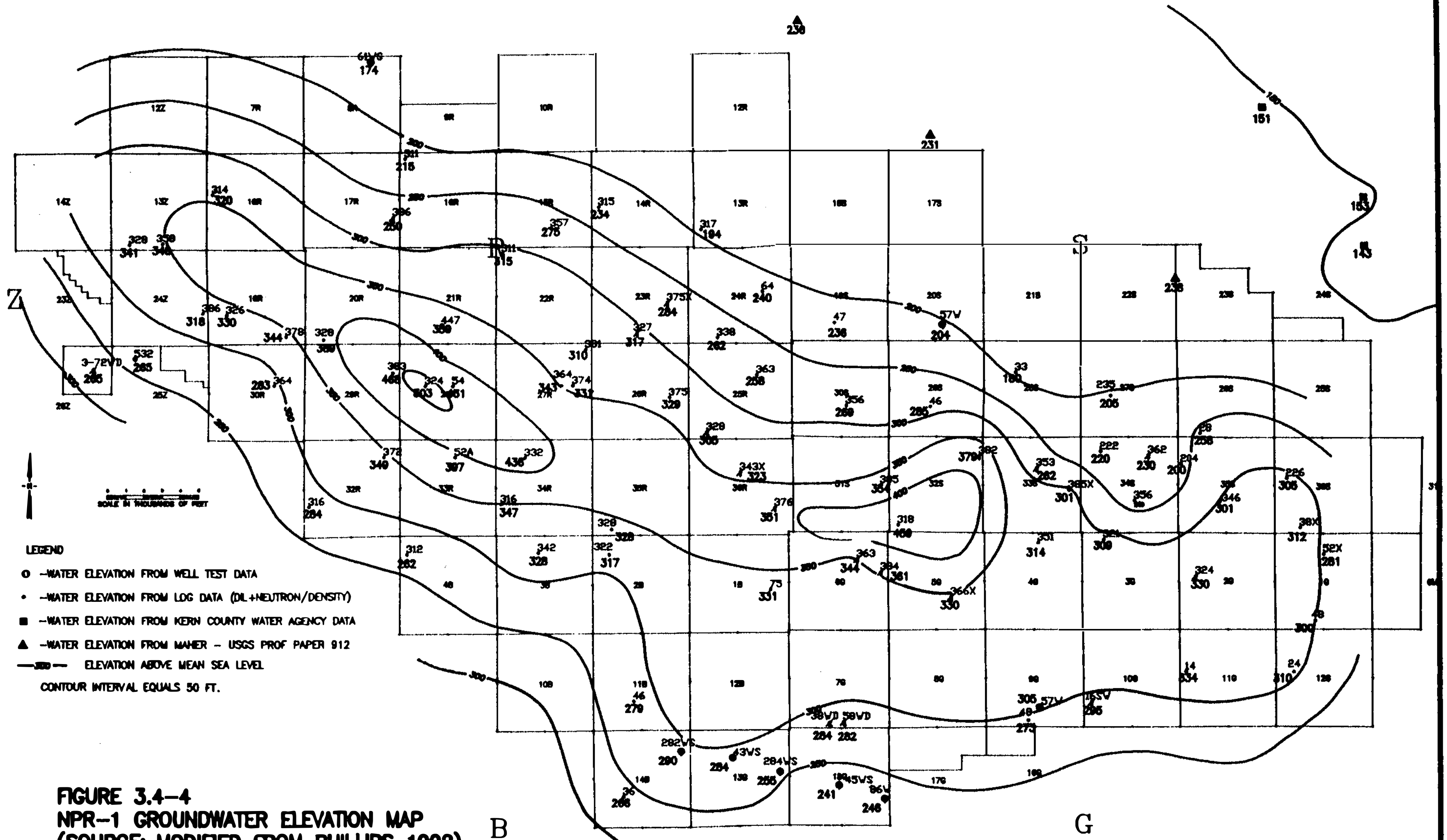


FIGURE 3.4-4
NPR-1 GROUNDWATER ELEVATION MAP
(SOURCE: MODIFIED FROM PHILLIPS 1992)

3.4.2.4 NPR-1 Operations Related to Potential Groundwater Impact

Regulations applicable to groundwater protection are presented and discussed in Appendix D. The facilities and activities at NPR-1 that have the greatest potential of impacting groundwater are: (1) hydrocarbon, equipment lubricant, and fuel spills; solid wastes; and surface soil contamination; (2) producing well cellars; (3) abandoned and idle wells; (4) disposal of fluids associated with drilling, degreasing and equipment washing; (5) dehydration/LACT stations and associated storage facilities; (6) injection of fluids associated with hydrocarbon recovery enhancement; (7) disposal of oil production wastewater; (8) source water withdrawal activities; and (9) fresh water activities. These items are discussed in the following subsections.

Hydrocarbon, Equipment Lubricant, and Fuel Spills and Solid Wastes and Other Surface Soil Contamination

Several NPR-1 sites have been exposed to hydrocarbon, equipment lubricant, and fuel spills; solid waste disposal; and surface soil contamination (see Section 3.2.3.3 and Table 3.9-1). If these sites receive fluid streams, or are exposed to precipitation, the potential exists for contaminants to be transported to groundwater. Operations that pose this risk are subject to the NPR-1 SPCC plan; programs to identify, clean up and formally close inactive historical waste sites; and waste disposal permits incorporating practices that minimize risks.

Well Cellars

There are two producing wells located on or near alluvial sediments in the 25S area adjacent to the Kern Water Bank Project. Sometimes well operations result in the accumulation of oil in well cellars which, if not removed, could eventually degrade groundwater. These cellars are inspected daily, and accumulations are removed promptly if observed. Each producing well is permitted separately by the California Division of Oil and Gas (DOG) and regulated in accordance with the provisions set forth in 14 CCR Division 2, Chapter 4.

Wells

Production zone brines under high formation pressures may migrate (leak) up an idle or active well casing, if the integrity of the casing is compromised. This could also occur if the integrity of the cement plugs used to abandon wells is compromised. If leaks such as these were to occur, and if they are in sediments that communicate with valley aquifers, degradation of useful groundwaters could occur. NPR-1 has approximately 2,415 existing active, idle and abandoned wells, and many of them are in sediments that could communicate with valley aquifers. Injection wells have an added risk of leaking; this is covered below under the topic of injection. In recognition of the risks associated with well operations, stringent laws and regulations are in place to govern these activities. Each NPR-1 well abandonment is permitted separately by DOG and regulated in accordance with the provisions set forth in 14 CCR Division 2, Chapter 4.

Disposal of Fluids Associated with Drilling, Degreasing, and Equipment Washing

Section 3.2 discusses the current waste management facilities on NPR-1. The 27R waste management facility is located in an area that is stratigraphically above Limestone A. Depth to groundwater at this location is in excess of 1,000 feet, and studies indicate that groundwater communication is highly unlikely (Mark Group 1987 and Kaman Tempo Division 1989). The 10G waste management facility is located on sediments that are stratigraphically above the middle clay and below Limestone A. These sediments could communicate with useful groundwaters, but it is less likely than in areas that are stratigraphically above Limestone A.

Dehydration/LACT Station and Associated Storage Facilities

LACT stations and associated storage facilities are located in the northwestern (Sections 24Z and 26Z), northeastern (Section 25S), and southern (Sections 18G and 10G) portions of NPR-1. These facilities have the potential to leak, and the leaking fluids could migrate through NPR-1 sediments into useful groundwater aquifers adjacent to the site. The risks associated with this are highest at 25S, 18G and 26Z which are located on or near the Tulare/Alluvium contact; in addition, the 25S facility is near the boundary of the Kern Water Bank Project. The 24Z facility is located on the Tulare Formation in an area that is stratigraphically above Limestone A; this area could communicate with useful groundwaters, but the risks are not as great as the 25S, 18G and 26Z areas. The 10G facility, which is located on sediments that are below Limestone A and above the middle clay, is the least likely to pose a risk to useful groundwaters.

Facility leaks have occurred; for example, a project was recently completed to repair a leaking aboveground tank at 25S. Plans are to close this facility and divert production to tankage at 23S and then to the 10G LACT station (DOE 1991). Groundwater monitoring wells are presently being considered for this location (Golder 1990).

Injection of Fluids Associated with Hydrocarbon Recovery Enhancement

Gas, water and steam injected into zones to enhance hydrocarbon recovery could leak into useful groundwaters by the mechanisms described above for wells. In comparison to producing wells, this risk is greater for injection wells because operating pressures are greater. Injection operations have an added risk in that injection pressures could exceed formation fracture pressures, and fractures in formations could provide another flow path to shallow groundwater aquifers. The laws and regulations governing injection operations recognize these risks and have been structured to address them. In addition, NPR-1 groundwaters at risk are poor quality. Currently, NPR-1 has 151 injection wells (132 Stevens waterflood, 14 Stevens gas, 2 SOZ waterflood and 3 SOZ gas) (BPOI 1991), and they are located in the areas shown in Figures 3.4-5, and 3.4-6, respectively. Each injection well is permitted separately by the DOG and regulated in accordance with the provisions set forth in 14 CCR Division 2, Chapter 4.

FIGURE 3.4-5

NAVAL PETROLEUM RESERVE NO. 1
EXISTING AND PROPOSED WATERFLOOD PROJECTS

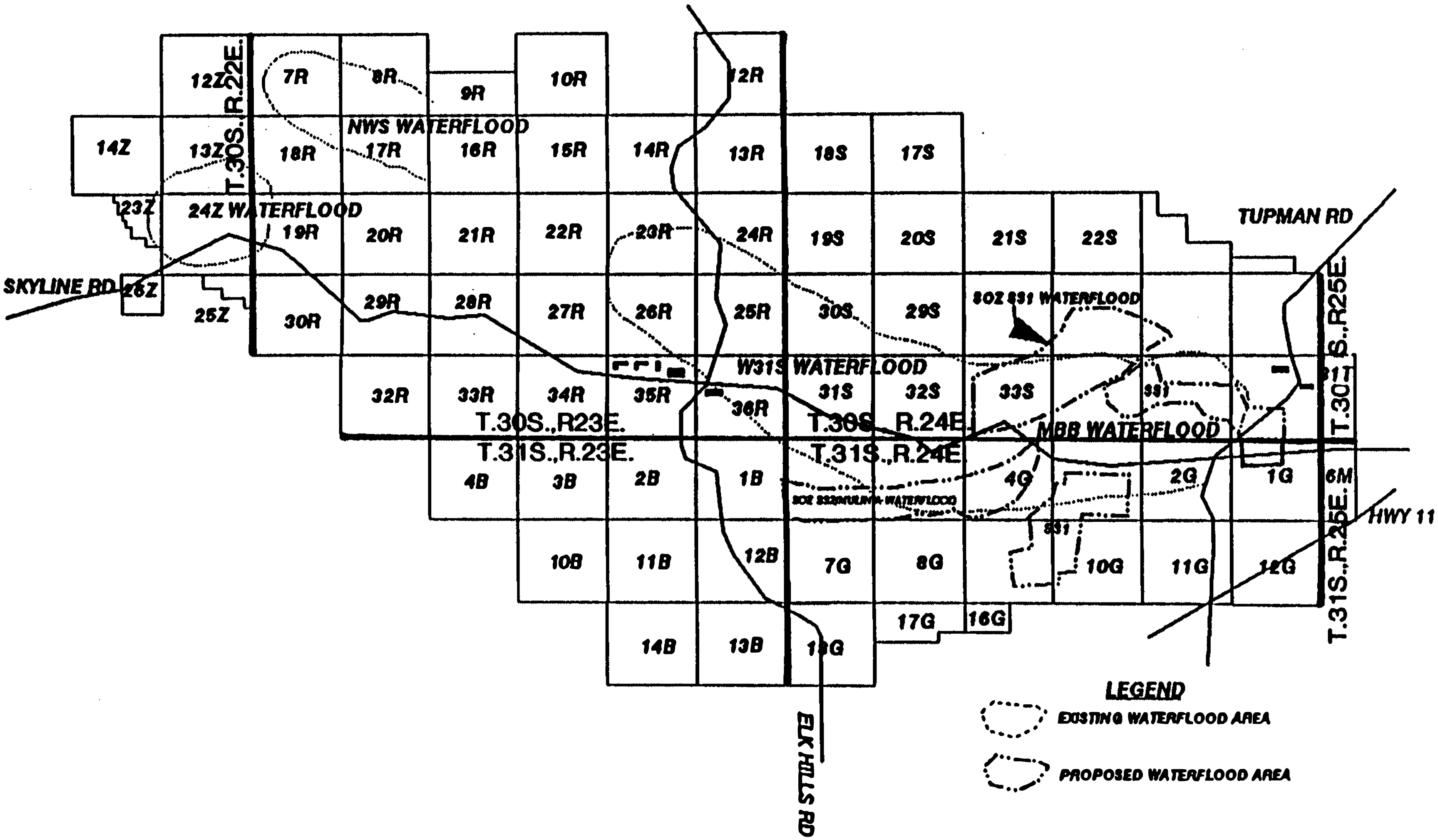
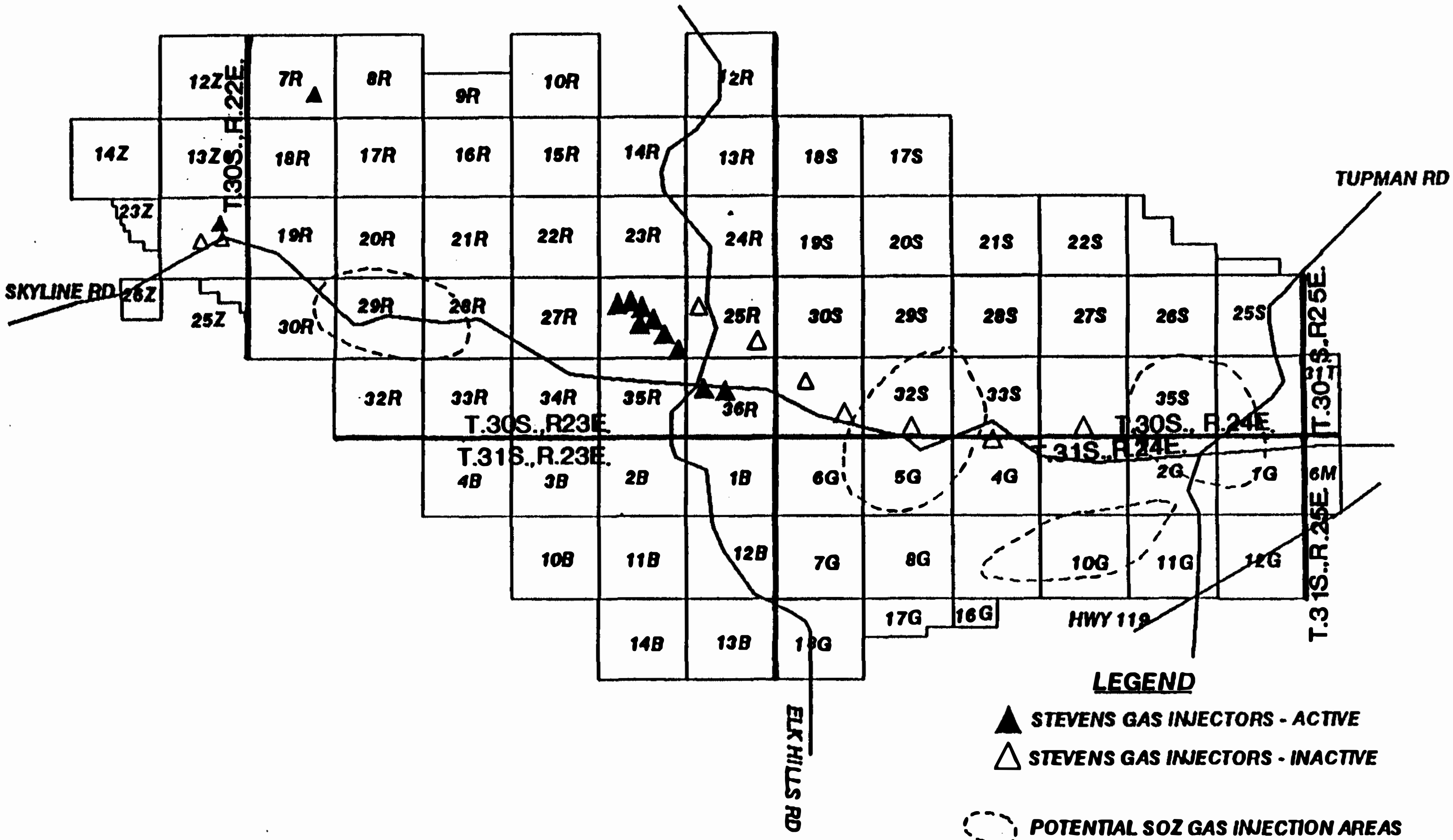


FIGURE 3.4-6
NAVAL PETROLEUM RESERVE NO. 1
GAS INJECTORS



Produced Water Disposal

Approximately 100,000 to 110,000 barrels/day of produced water are currently disposed of (injected) into 19 wells. These wells are shown by Figure 3.4-7. Eleven wells are completed within the Tulare Formation and are located in Sections 7G, 8G, 18G, and 24Z (BPOI 1987a-d). Two wells completed in the SOZ are located in Sections 15G and 16G. The 15G well is outside of the boundaries of NPR-1 on CUSA property; by agreement with CUSA, however, the wells were constructed and are owned and operated by NPR-1. Two wells are completed in the Olig in 26Z. Four wells are completed in the Stevens Zone in 24Z. Each produced wastewater disposal well is permitted separately by the DOG and is regulated in accordance with the provisions set forth in 14 CCR Division 2, Chapter 4.

On an annual basis, a range of approximately 2,000 to 21,000 barrels/day of produced water was placed in unlined evaporation/percolation sumps or secondary containment "field-wide" from 1979 through 1989 (McLemore 1990). This was an average of about 10,000 barrels/ day over the 11-year period. Currently, sumping is ordinarily 1,000-2,000 barrels/day "field-wide". The TDS value of wastewater is typically 20,000 - 40,000 parts/million.

Eight produced wastewater sumps currently are active, and they are shown by Figure 3.4-8. Records are not readily available on the quantities of wastewater released at individual sumps. However, it is known that the overwhelming majority of sumping was concentrated at the 10G and 24Z sumps (Appendix D).

Historically, approximately 14 sumps were located near the contact of the Tulare/Alluvium, primarily for use during off-normal situations (e.g., to catch tank overruns that would have otherwise been uncontained), and as such, some wastewater may have been released into alluvial soils. In recognition of this possibility, these sumps have been taken out of service, or they were lined. The last phase of this project (18G) was completed in August 1990.

The risk of communication with groundwater at 24Z, 26Z 10G, 18G and 25S is the same as presented under the dehydration/LACT station discussion above. The 35S sump is located on sediments that are stratigraphically below Limestone A and above the middle clay. Therefore, 35S poses a risk that is similar to 10G. Sumping operations are carried out under the authority of CVRWQCB Waste Discharge Permit Nos. 58-491 and 68-262.

Sumps in operation prior to 1979 were identified by Rector (1983) and Bean and Logan (1983); these are shown by Figure 3.4-9.

Source Water Withdrawal

Based on studies and observations, there has been no significant "mining" of groundwater as the result of withdrawals from the Tulare groundwater aquifer underlying NPR-1. NPR-1 currently withdraws approximately 148,000 barrels/day of Tulare Formation groundwater from six south flank source wells for use in Stevens Zone waterflood operations. The water quality from these

NAVAL PETROLEUM RESERVE NO. 1

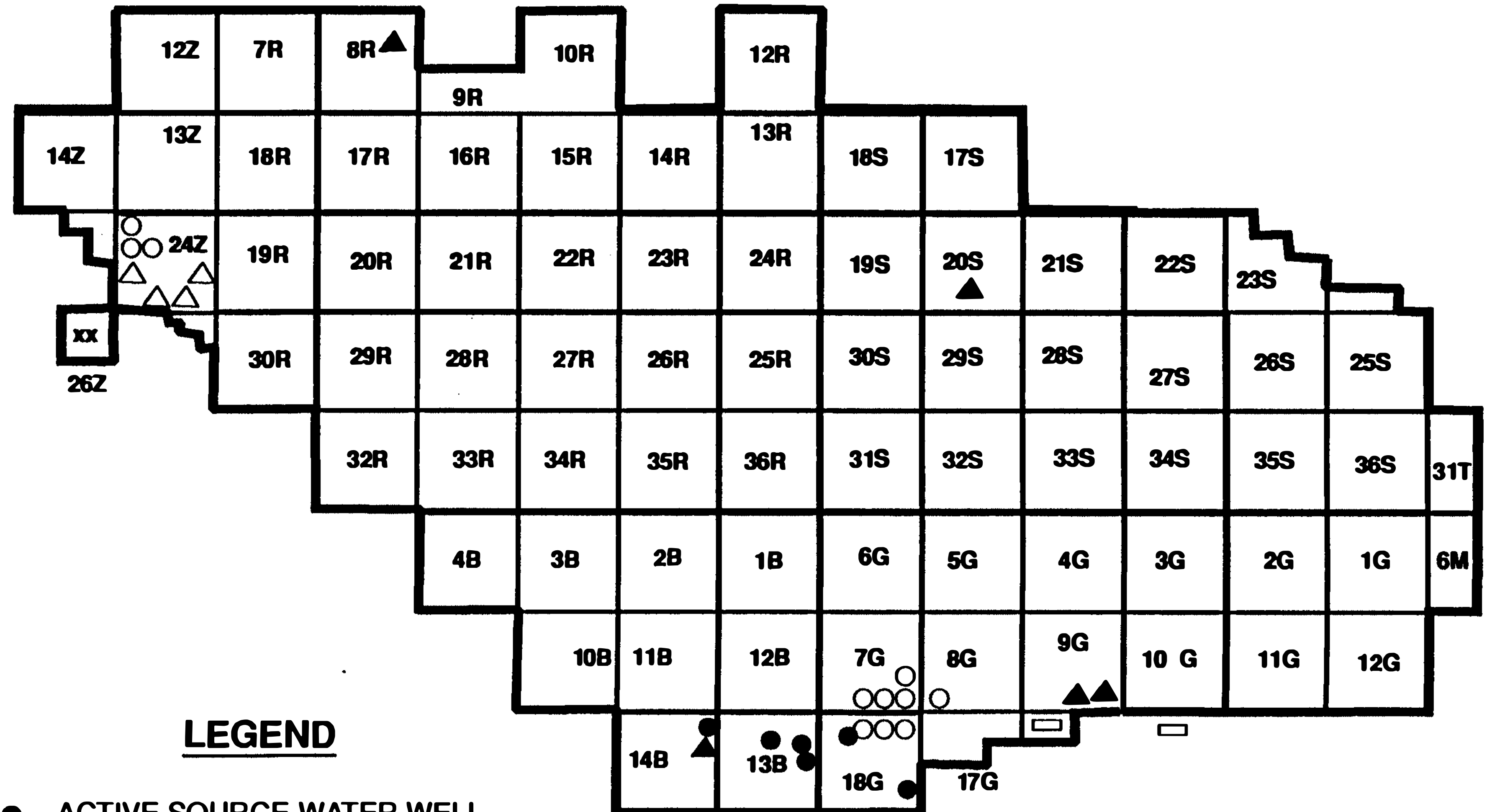
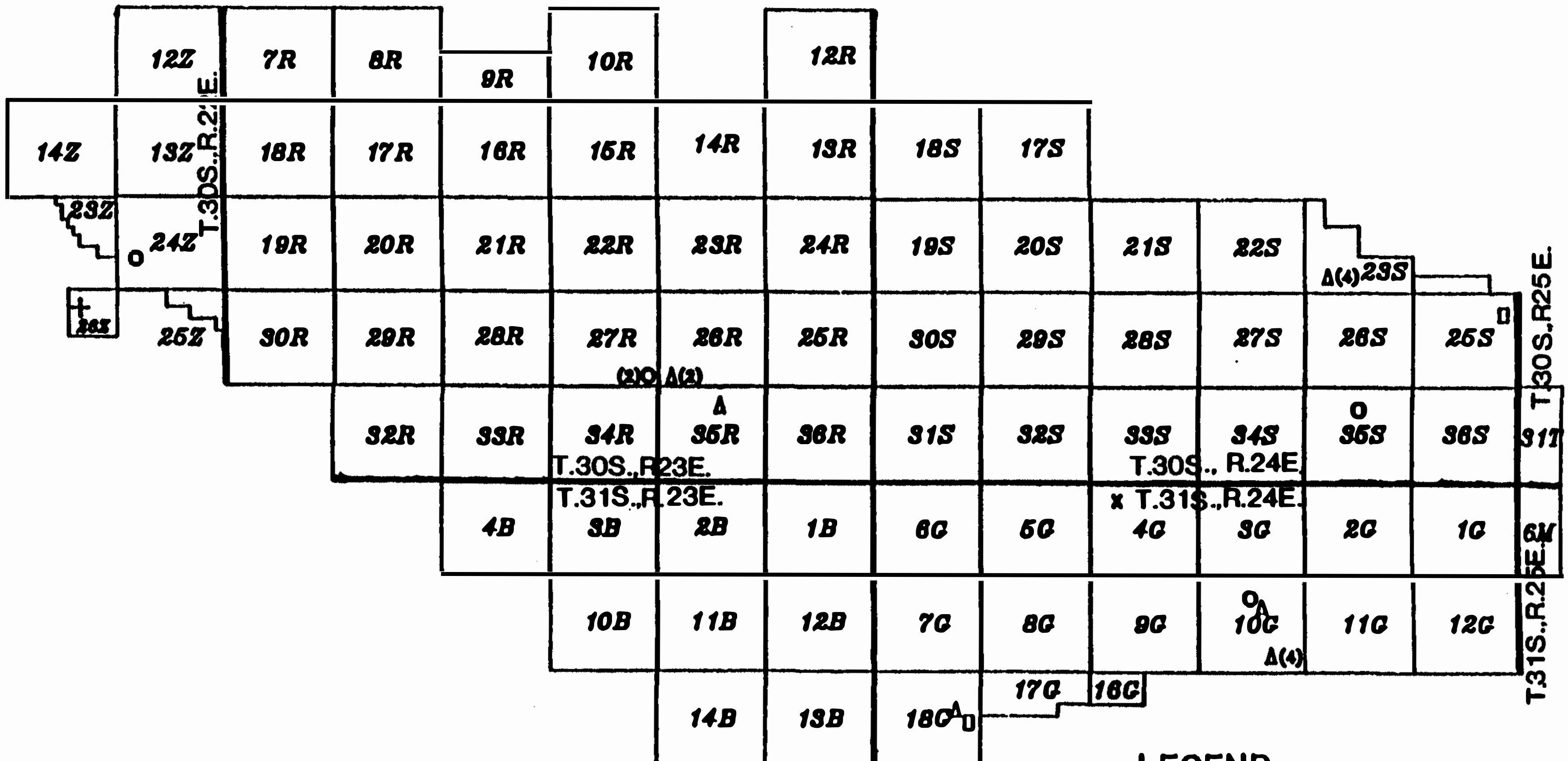


FIGURE 3.4-7

NPR-1 SOURCE WATER WELLS AND PRODUCED WASTEWATER DISPOSAL WELLS

NAVAL PETROLEUM RESERVE NO. 1



LEGEND

- O ACTIVE UNLINED PRODUCED WASTEWATER SUMP
- ▯ ACTIVE LINED PRODUCED WASTEWATER SUMP
- + EMERGENCY UNLINED SECONDARY CONTAINMENT BASIN
- Δ INACTIVE UNLINED SUMP
- x ACTIVE UNLINED PIGGING SUMP

FIGURE 3.4-8
AND INACTIVE SUMPS
NPR-1 CURRENT ACTIVE

NAVAL PETROLEUM RESERVE NO. 1

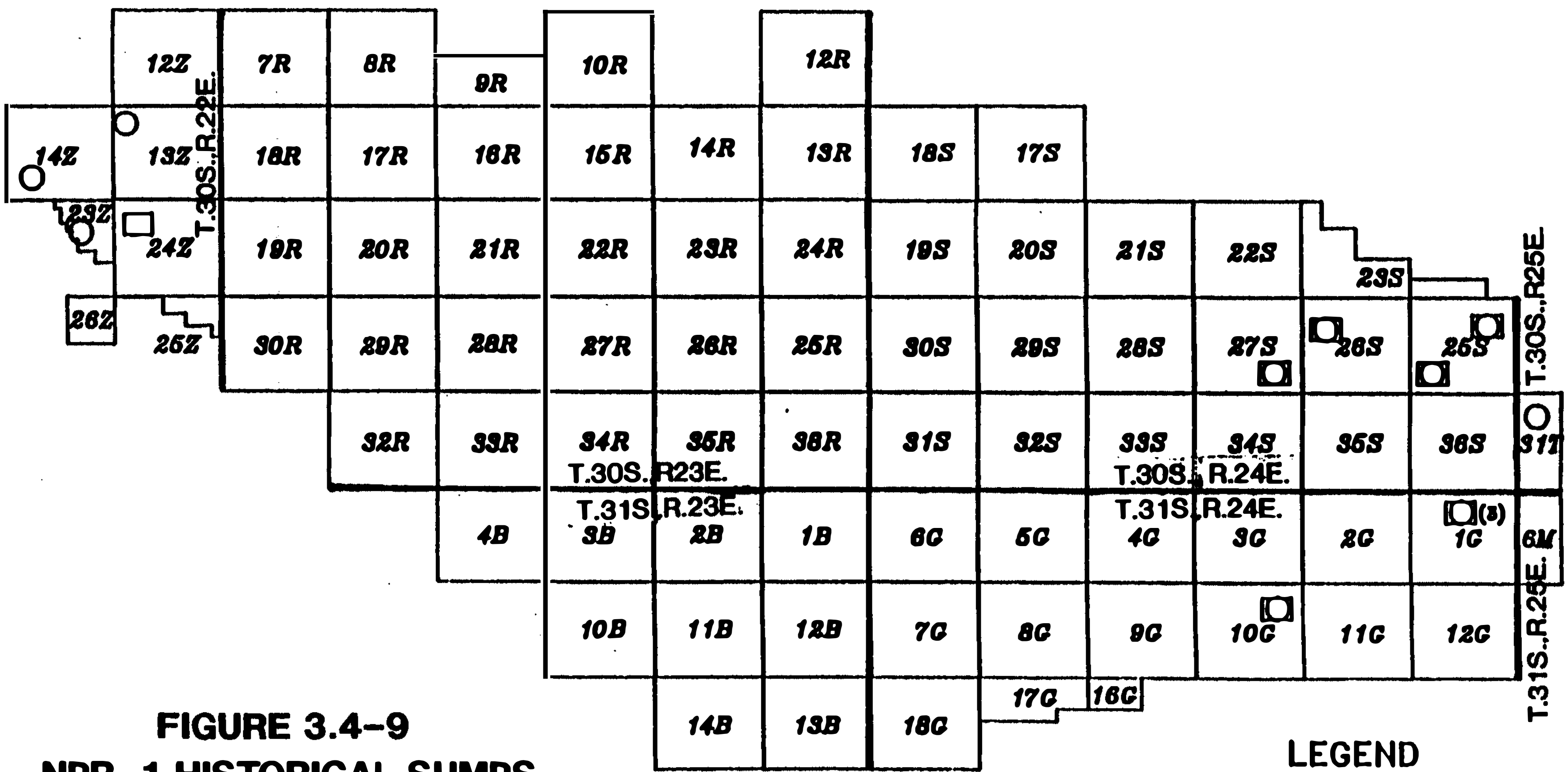


FIGURE 3.4-9
NPR-1 HISTORICAL SUMPS
BEAN & LOGAN/RECTOR

LEGEND

○ EVAPORATION AND PERCOLATION SUMP BEAN AND LOGAN (1983)

□ SUMP LOCATION 1955-1960 RECTOR (1983)

source wells ranges from approximately 4,000-6,000 parts/million TDS. Source well locations are given in Figure 3.4-7.

Source water withdrawal from the NPR-1 Tulare aquifer is off-set by the injection of approximately 100,000-110,000 barrels/day of produced wastewater with a TDS value of approximately 30,000 ppm TDS into eight Tulare south flank injection wells located updip from the source wells (see Figure 3.4-7). Wastewater injection is a California Division of Oil and Gas permitted activity. This results in a net drawdown of the aquifer of approximately 38,000-48,000 barrels/day.

Source water withdrawals at NPR-1 over the past 13 years have not produced significant declines in Tulare groundwater elevations (Phillips 1992). Due to the existence of subsurface clays which prevent migration, groundwater mounding has been observed in the vicinity of some of the south flank injection wells (Milliken 1992). No adverse impact on Tulare source well water quality has been observed to date (BPOI 1992b, Phillips 1992). The source wells are monitored monthly for water quality (BPOI 1992c).

Fresh Water Activities

NPR-1 purchases fresh water from the West Kern Water District (WKWD). NPR-1 is required to purchase a minimum of 23,500 barrels/day of water but WKWD is not obligated to provide more than 48,000 barrels/day. This water is obtained from the WKWD A-line in Section 5 of T31S/R25E. In 1988, an average of 29,000 barrels/day of fresh water was delivered to NPR-1 (Filley 1989), and this has not changed significantly.

It is estimated that up to 15,000 barrels/day of fresh water are used in construction, remediation work, and gas plant operations at NPR-1; 2,200 barrels/day in steamflood operations; 5,000 barrels/day for domestic needs; and an additional 6,800 barrels/day for miscellaneous uses (Filley 1989). NPR-1 uses bottled water for drinking because of periodic problems with chlorination of the fresh water system.

3.4.2.5 Fate and Transport of Disposed Wastewater on NPR-1

Subsurface Disposal

The eight southern Tulare disposal wells have the greatest potential for impacting useful groundwater; this is because of their proximity to the useful groundwater in the eastern area of the Buena Vista Valley aquifer (KCWA 1987). This aquifer is reported to lie within the Buena Vista Valley structural subbasin (KWCA 1990). The southern flank disposal wells are located along the central portion of the northern limit of the Buena Vista Valley. They are completed below Limestone A and above the middle clay. Therefore, the wastewater disposed of into these wells could communicate with the Buena Vista Valley subbasin aquifers (see Wilson and Zublin 1988, plate 32A) in a manner similar to that previously presented for the San Joaquin Valley (Bean and Logan, 1983) (see Figure 3.4-2). In recognition of this risk, a project was initiated in 1986 with the objective of reducing or eliminating wastewater injection into the Tulare on the southern flank of NPR-1. Recently, construction on a major facilities project to reduce this injection by approximately 50% was completed. It has not been possible to put this project in operation due to technical difficulties in achieving water quality requirements for waterflood purposes. Additional projects to address this difficulty are being evaluated.

Surface Disposal

Bean and Logan (1983) speculated that sumps utilized on the northeastern flank of NPR-1 may be responsible for groundwater anomalies in the adjacent San Joaquin Valley. This speculation was based in part on water quality samples obtained from two wells near the northeastern boundary of NPR-1, one in 1964 and one in 1969. Studies undertaken following the Bean and Logan work show that a groundwater anomaly exists in the area of the two wells tested by Bean and Logan, in a northwest-southeast trending structural trough along the western margin of the San Joaquin Valley (Rector 1983, CDWR 1990). A more recent study indicates that these sumps and wells are located in the Buttonwillow subbasin (KCWA 1990), which suggests that communication between them is possible. Waldron (1989) suggests, however, that Bean and Logan (1983) may have misinterpreted some data in their analysis. He and Maher et al (1975) suggest/imply that the source of poor quality groundwater found on the westside of the San Joaquin Valley is the result of natural flow from the Temblor Range.

In recognition of the risks, the NPR-1 sumps in question are either no longer in service, or have been lined. A more detailed treatment of the fate and transport of disposed water on the Elk Hills is given in Appendix D.

3.4.3 Ongoing Non-Federal-Connected Actions

The potential impacts from construction and operation of the SoCal third-party pipeline included those associated with meeting fresh water requirements, disposal of hydrostatic testing water, equipment lubricant and fuel spills, and solid wastes and surface soil contamination. These conditions are similar to that described in Section 3.4.2.4.

It was estimated that the SoCal project would require approximately 23,800 barrels of fresh water to hydrostatically test the pipeline. Before beginning the test, the pipeline was swabbed clean. After being used, the water was disposed of in the 14Z area by releasing it onto a metal plate over an 8-10 hour period in a V-shaped grass-covered draw. Operation of this pipeline should not require any additional volumes of water.

The potential existed for fuel or equipment lubricant spills to occur during construction. In addition, operation of the proposed pipeline and connections may cause unexpected hydrocarbon releases due to system breakdowns. These will be managed in accordance with the SPCC plan.

The impacts, or potential impacts, of the construction and operations of the Santa Fe third-party pipeline, and associated mitigative measures, were/are qualitatively the same as described for the SoCal project. The only significant difference is that hydrostatic test water was not released directly to the soil. This water was obtained from the Santa Fe system, then returned following use.

3.4.4 References*

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3.5 TERRESTRIAL BIOTA

This section discusses existing ecological conditions at NPR-1, including plant and animal communities and threatened and endangered species. Some of the discussion includes impacts resulting from past development activities, and associated mitigative measures, as needed to fully describe development risks. Much of the discussion is based on information collected in connection with the NPR-1 and NPR-2 endangered species program. This program involves ongoing surveys, field studies and research projects which have been designed to better characterize endangered species impacts. Given the long term nature of the studies and research projects, most are still in progress; in some respects, therefore, this document serves as a status report on the progress of the study and research effort. This is important for several reasons, but principally because the NPR-1 population of one endangered species, the San Joaquin kit fox, has declined significantly, and it is not clear to what extent contributing factors were related to development and/or natural occurrences. The principal development impacts include vehicle mortality, harassment, and adverse effects of oil-field chemicals. The principal natural factors include the following: an apparent significant decline in food supplies as the possible result of a long period of below average precipitation; an increase in coyote abundance and predation; disease; and the possibility that the upland habitat comprising most of NPR-1 is not as suitable for kit foxes as the lower flatland habitat on the margins of and adjacent to the NPR-1 site.

The San Joaquin Valley has experienced considerable development over the past century, predominantly in the form of agriculture; in addition, development from oil and gas production and grazing have also been significant (Twisselman 1967; Heady 1977; Sims 1988). NPR-1 is surrounded by areas of oil production (including NPR-2 to the south and several privately operated oil fields), agriculture, and some relatively undisturbed areas (see Section 3.7). Most development on NPR-1 has occurred within the interior of the site, where topographic relief is greatest; relatively little has taken place in the flats along the perimeter. Approximately 42,552 acres (90%) of the site are relatively undeveloped.

3.5.1 Plant Communities

NPR-1 vegetation is part of a major floristic zone within California known as the Valley Grassland (Heady 1977). Valley Grassland is dominated by annual grasses such as red brome (*Bromus rubens*), slender oats (*Avena barbata*), foxtail fescue (*Festuca megalura*) and foxtail (*Hordeum glaucum*); and a variety of forbs, especially red-stemmed filaree (*Erodium cicutarium*) (Twisselmann 1967; Heady 1977; O'Farrell and Mitchell 1985; Sims 1988). Shrubs such as desert saltbush (*Atriplex polycarpa*), bladderpod (*Isomeris arborea*), and cheesebush (*Hymenoclea salsola*) are also common (O'Farrell and Mitchell 1985).

Prior to settlement, well-drained upland sites apparently were dominated by perennial grasses (e.g., *Stipa pulchra, S. cernua*, and *Poa scabrella*), but numerous annual species were also present (Heady 1977; Sims 1988). The annual grassland now present is apparently a result of past grazing activities and the introduction of numerous adventive species from Europe and other continents (Heady 1977; O'Farrell and Mitchell 1985; Sims 1988). The new dominants in this grassland are extremely persistent and effectively resist reestablishment by much of the native vegetation even after grazing is stopped.

Succession in the San Joaquin Valley tends to proceed from forbs in early successional stages to annual grasses at climax, although many species found in climax communities also are early invaders following disturbance (Heady 1977). Species found at climax include red brome, red-stemmed filaree, and slender oats. Species common shortly after slight disturbance (e.g., discing, off-road operational activities) include red-stemmed filaree, fiddleneck (*Amsinckia tessellata*), and desert saltbush (O'Farrell and Mitchell 1985). Construction activities, especially those that result in the exposure of saline substrates, generally favor the establishment of desert saltbush. Herbaceous species often reinvade slowly after such severe disturbances and usually appear under shrubs and in depressions where organic matter and moisture levels are higher.

Fires have little long-term effect in this community, because few seeds are destroyed by grassland fires (Heady 1977). Redevelopment of herbaceous cover usually occurs within 3 years, but since most shrubs are killed by fire, they must become reestablished from seed. Some shrubs, such as bladderpod and cheesebush, can resprout from undamaged crowns (O'Farrell and Mitchell 1985). In the short term, fire seems to favor forbs, such as red-stemmed filaree and *Medicago hispida* (Heady 1977; O'Farrell and Mitchell 1985; Sims 1988).

Common species on NPR-1 are those typical for the San Joaquin Valley and include red brome, red-stemmed filaree, and desert saltbush (O'Farrell and Mitchell 1985). The distribution of vegetation on the site is strongly affected by microclimate. Cooler, moister, north-facing slopes tend to support a more diverse, productive plant community. South-facing slopes support fewer species and are frequently bare.

Disturbances that have affected plant communities on NPR-1 include grazing, fires, and activities associated with operation of the site. Cattle and sheep grazed on NPR-1 until the late 1960's (O'Farrell and Mitchell 1985); current policy prohibits grazing within site boundaries. Fires, both natural and man-made, burned approximately 5,455 acres from 1976 to 1988 (Kato 1990a).

Disturbances at NPR-1 since development began in the early part of the century amounts to approximately 6,546 acres, including buildings, well pads, gas plants, LACT's, pipelines, third-party projects, and other facilities (Table 3.5-1). Of this, approximately 3,306 acres occurred after the mid-1970's as the result of MER production. In addition, an unquantified amount of area has been disturbed by accidental spills of oil, oily water, and oil-field chemicals. Since 1979, approximately 16,439 barrels of oil spilled on NPR-1 have not been recovered (see Section 3.9). Almost all of this oil has been contained within the site. Areas where oil has absorbed into the ground are typically disced with clean soil to accelerate natural biodegredation processes. Other oil-field chemicals (e.g. barium, chromium, arsenic) associated with past production activities have been introduced into the environment as the result of spills, handling and disposal practices (see Section 3.2).

TABLE 3.5-1 Areas Disturbed and Available for Reclamation on NPR-1 (Acres)

Type of Development	Development from Inception	MER Development	Proposed Action Reclamation (1990-1998)
Facilities	666		0
Well pads and sumps	1,930		132
Roads	1,928		189
Pipelines	585		17
Landfill	11		0
Wastewater sumps	132		53
Borrow or scraped areas	810		124
Firebreaks	230		30
Other	175		80
Subtotal	6,467[a]	3,227[a]	625[a]
Ongoing Third-Party Projects[b]	79[b]	79[b]	
Total Development	6,546	3,306	
Developed Areas Revegetated[c]	1,689[c]	1,689[c]	
Net Areas in Development	4,857	1,617	

TABLE 3.5-1 (Cont'd)

[a]Source: Modified from Kato (1990a). As of June 1988, total area developed since inception in the 1920's was approximately 6,467 acres. Of this, 3,227 acres, were associated with MER production pursuant to the Naval Petroleum Production Act of 1976. Approximatley 625 acres of this development has been or will be abandoned and is to be reclaimed (revegetated, etc.) between 1990 and 1998 as part of the proposed action. These 625 acres are in addition to the 1,689 acres identified in Footnote c.
[b]Total disturbed area for SoCal and Santa Fe is 192 acres, of which 79 acres are on NPR-1. (All disturbed areas have been revegetated, or are in the process of being revegetated - see Footnote c).
[c]As of FY 1988, a total of 1,689 acres had been revegetated, or revegetation was in progress. Of this, 920 acres were revegetated naturally, 690 acres were associated with abandonments, and 79 acres were associated with the NPR-1 portion of ongoing third-party projects.

A reclamation program has been in operation on NPR-1 since 1985 (see Section 4.1.5.4; O'Farrell and Mitchell 1985). As of FY 1988, a total of 1,689 acres have been either revegetated, or revegetation was in progress: 920 acres naturally, 690 acres associated with abandonments, and 79 acres associated with the NPR-1 portion of ongoing third-party projects (Table 3.5-1). Another 625 acres associated with abandonments have been identified for reclamation through the year 1998. Additional areas of development will be reclaimed as they are abandoned.

3.5.2 Animal Communities

Despite the relatively harsh environmental conditions, the San Joaquin Valley supports a diverse vertebrate fauna. Species inhabiting NPR-1 are those adapted to the arid grassland environment of the site or those tolerant of a wide range of environmental conditions. Surveys have determined the presence of 2 amphibians, 8 reptiles, 92 birds, and 25 mammals (O'Farrell and Scrivner 1987). No native fish are present; however, mosquitofish (*Gambusia affinis*) are periodically stocked in sumps to aid in mosquito control. Little is known about the invertebrates inhabiting NPR-1.

Both the western toad (*Bufo boreas*) and Pacific treefrog (*Hyla regilla*) occur on NPR-1 (O'Farrell and Scrivner 1987) and are associated with springs and ephemeral water bodies. Several species of lizards and snakes make up the reptilian fauna of the site; included are the side-blotched lizard (*Uta stansburiana*), western whiptail (*Cnemidophorus tigris*), coachwhip (*Masticophis flagellum*), and western rattlesnake (*Crotalus viridis*).

Approximately half of the bird species found on NPR-1 are either permanent or seasonal residents; other species are migratory transients (O'Farrell and Scrivner 1987). Frequently observed birds include the California quail (*Callipepla californica*), mourning dove (*Zenaida macroura*), common raven (*Corvus corax*), Le Conte's thrasher (*Toxostoma lecontei*), western meadowlark (*Sturnella neglecta*), and lesser goldfinch (*Carduelis psaltria*). The northern harrier (*Circus cyaneus*), red-tailed hawk (*Buteo jamaicensis*), American kestrel (*Falco sparverius*), great-horned owl (*Bubo virginianus*), and burrowing owl (*Athene cunicularia*) are commonly seen raptors.

Most of the mammal species on NPR-1 are rodents (e.g., San Joaquin pocket mouse, *Perognathus inornatus*; western harvest mouse, *Reithrodontomys megalotis*; and deer mouse, *Peromyscus maniculatus*) (O'Farrell and Scrivner 1987). Other common species are the desert cottontail (*Sylvilagus audubonii*) and black-tailed jackrabbit (*Lepus californicus*). The number of coyotes (*Canis latrans*) on NPR-1 increased noticeably from 1979 to 1984, especially in developed upland areas (Scrivner and Harris 1986). Concern over this increase and an increase in coyote predation on kit foxes prompted the establishment of a coyote-control program (Scrivner and Harris 1986; Scrivner 1987; EG&G/EM 1988a) which was in operation intermittently at different levels of intensity from 1985 to May 1990, when it was suspended pending evaluation of its effectiveness. Coyote scent-station surveys initiated in 1984 indicate that coyote numbers have declined since then (Scrivner 1987) (Figure 3.5-1).

FIGURE 3.5-1
COYOTE SCENT STATION VISITATION INDEX FOR NPR-1
EG&G/EM 1990b & UNPUBLISHED DATA

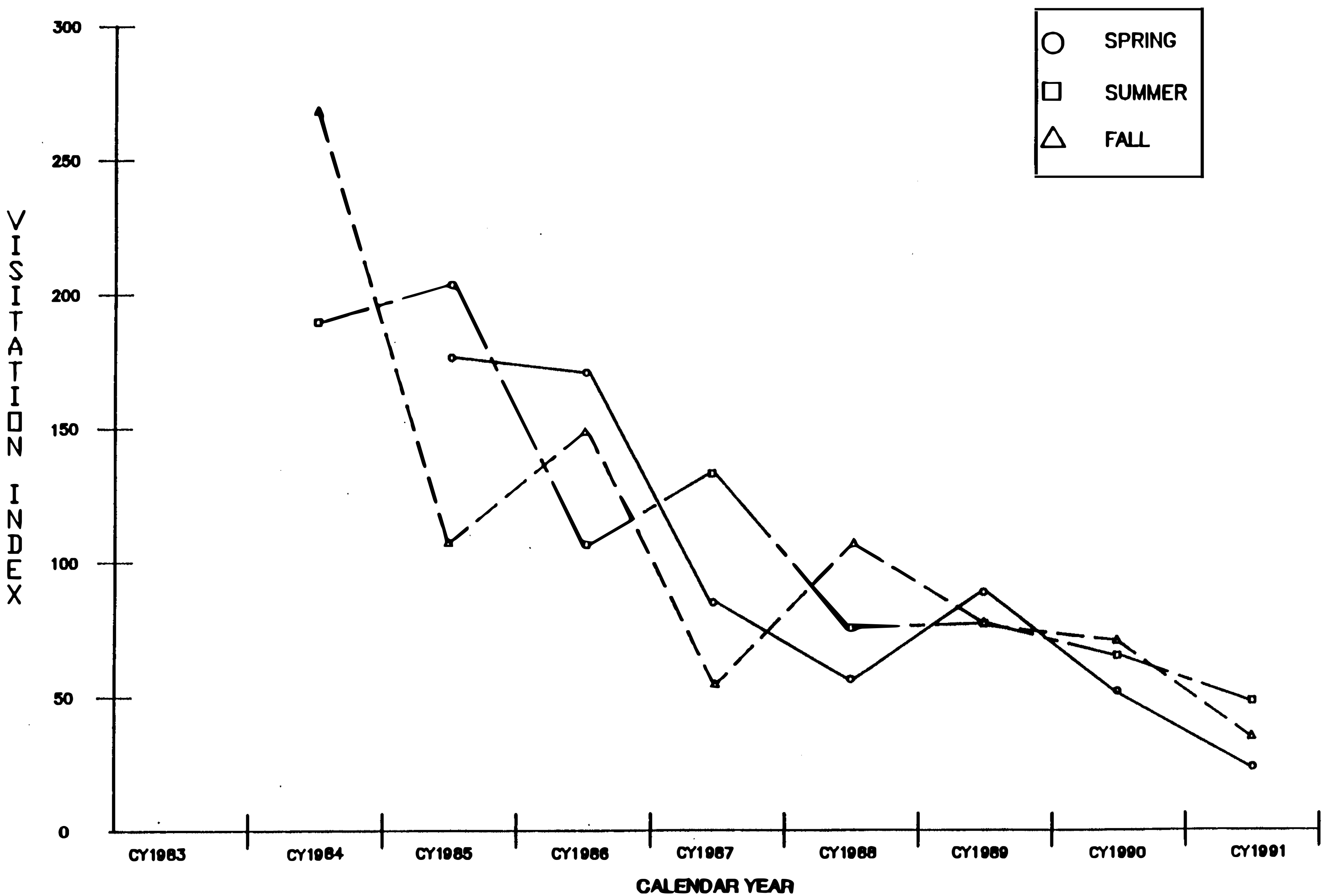


Table 3.5-2 shows the results of comprehensive wildlife and habitat transect observations completed in 1979, 1984, and 1989. The number of observations of wildlife, dens and burrow systems have varied between 1979 and 1989. Additional population/abundance data are presented later on. Programs are in place to mitigate development impacts, and studies are in progress to develop additional mitigation strategies--strategies that could have applicability both on and off of NPR-1. These studies are also designed to contribute to the objective of characterizing the relative magnitude/importance of impacts that may have been caused by natural factors and those that may have been caused as the result of development.

3.5.3 Threatened and Endangered Species

The intense agricultural development that has occurred in the San Joaquin Valley has increased the significance of relatively undisturbed natural habitat to rare native species. Undeveloped habitat on NPR-1 supports several such species. This section discusses species that have been listed as threatened or endangered by either the federal government or the state of California, and species that are candidates for such listing, or are considered species of special concern to the state. Applicable status categories are defined as follows:

- Endangered (federal and state): Any species (plant or animal) that is in danger of extinction throughout all or a significant portion of its range.

- Threatened (federal and state): Any species (plant or animal) that is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.

- Proposed (federal): Any species (plant or animal) for which proposed rules have been published in the Federal Register by the U.S. Fish and Wildlife Service (FWS) for protecting the species as endangered or threatened under the Endangered Species Act.

- Category 2 (federal): Any species (plant or animal) for which FWS has information that suggests that proposing to list it as threatened or endangered is possibly appropriate, but for which substantial data on biological vulnerability and threat(s) are not currently known to support the immediate preparation of rules (Federal Register 1985a).

- Category 3C (federal): Any species (plant or animal) that has proven to be more abundant or widespread than was previously believed, and/or those that are not subject to any identifiable threat (Federal Register 1985a). Species placed in this category are subsequently dropped from consideration for listing.

- Rare (state): Any plant species that is thought to exist in sufficiently small numbers throughout its range that it could become threatened or endangered if its environment worsens.

- Species of Special Concern (state): Species inventoried by the Natural Diversity Data Base of the California Department of Fish and Game Natural Heritage Program. Generally, these are

TABLE 3.5-2 Number of Observations of Wildlife, Dens and Burrow Systems During the 1979, 1984, and 1989 Surveys on NPR-1.

	1979	1984	1989[a]
Kit Fox Dens	667	664	515
Jackrabbits	1314	4286	1961
Cottontails	672	2140	649
Blunt-Nosed Leopard Lizards	18	1	7
Antelope Ground Squirrels	196	271	72
Coyotes	8	108	40
Quail	3489	6425	4310
Ravens	13	141	64
Red-tailed Hawks	24	11	26
Rattlesnakes	3	8	2
Giant Kangaroo Rat Burrow Systems	-	149	58

[a]Data for 1989 are preliminary

Source: EG&G/EM 1990f

species that are federally or state listed as endangered, threatened, or rare, or proposed for such, or restricted in distribution, or associated with habitat that is declining at an alarming rate.

Species that are federally listed as threatened or endangered, or proposed for such, receive legal protection under the Endangered Species Act of 1973. Given that the status of the species in the other categories is such that they could be listed in the future, impacts on these species are avoided to the maximum extent practical.

3.5.3.1 Plants

Hoover's woolly-star (*Eriastrum hooveri*) (federal threatened) is the only listed plant species known to exist on NPR-1. Suitable habitat also exists for the listed Kern mallow (*Eremalche kernensis*) (federal endangered), but it has not been observed on the site to date. No state-listed species are known to occur on the site, but four species of special concern to the state are present. Table 3.5-3 provides additional information pertaining to these and other plants of concern at NPR-1. A discussion of these species follows.

Surveys for Hoover's woolly-star, Kern mallow, California jewelflower (*Caulanthus californicus*), and San Joaquin woolly-threads (*Lembertia congdonii*) were conducted in 1988 (EG&G/EM 1988b). Proposed rules for protecting these species as threatened/endangered under the Endangered Species Act were published by FWS in 1989 (Federal Register 1989). The survey was conducted in potentially suitable habitat on the site, which was essentially the lower flanks of the Elk Hills along the perimeter of the site.

During field surveys, 28 populations of Hoover's woolly-star, with an estimated total of more than 40,000 individuals, were observed on NPR-1 (EG&G/EM 1988b). These populations were located on alluvial fans and plains in Townships B (Sections 4, 10), G (Section 12), R (Sections 7, 8, 10, 12, 13, 32), and S (Sections 17, 18, 20, 21, 22, 23, 26) (see Figure 1.1-1 for section locations). Hoover's woolly-star populations occurred in areas where other vegetation was sparse, such as washes and formerly disturbed but currently unused sites (e.g., abandoned or little-used roadways).

In July 1990, Hoover's woolly-star was federally listed as threatened (Federal Register 1990). In 1991, a survey of selected portions of NPR-1 identified 24 populations of Hoover's woolly-star which included many of those populations identified in 1988 (EG&G/EM Unpublished Data). Four populations in Township B (Sections 3, 4) and S (Sections 30, 31) were recorded at elevations at or above 1,000 feet. Populations were found on the rounded crests of ridges, upper slopes, alluvial fans, and alluvial plains. In addition to the locations identified in the 1988 survey, Hoover's woolly-star was identified in Townships B (Sections 3, 12, 13), G (Sections 1, 10), S (Sections 25, 27, 30, 31), and Z (Section 14).

Other locations of Hoover's woolly-star have been identified that were not included in the 1988 or 1991 survey. To-date, over 150 populations of Hoover's woolly-star have been observed on or adjacent to NPR-1. Numerous populations have been observed on formerly disturbed but

TABLE 3.5-3 Federally and State-Listed Plant Species Observed on NPR-1 or for Which Suitable Habitat Exists

Common Name[a]	Scientific Name	Federal Status	State Status
*Hoover's Woolly-star	*Eriastrum hooveri*	Threatened	Special
*Cottony Buckwheat	*Eriogonum gossypinum*	Category 3C	Special
*Temblor Buckwheat	*Eriogonum temblorense*	None	Special
*Kern Tarplant	*Hemizonia pallida*	None	Special
*Gypsum-loving Larkspur	*Delphinium gypsophilum gypsophilum*	None	Special
California Jewelflower	*Caulanthus californicus*	Endangered	Endangered
Kern Mallow	*Eremalche kernensis*	Endangered	Special
San Joaquin woolly-threads	*Lembertia congdonii*	Endangered	None
Lost Hills Saltbush[b]	*Atriplex vallicola*	Category 2	Special

[a]An asterisk in front of the name indicates that the species has been observed on NPR-1.
[b]An observation of this species was made during an endangered species survey in 1988. The location was unconfirmed; it was either in 12G (on NPR-1) or 13G (off of NPR-1).

Source: Based on data from EG&G/EM 1988b; California Department of Fish and Game 1988; and Federal Register 1990.

currently unused sites (e.g., abandoned or little-used roadways). Although this species colonizes disturbed areas and thus benefits from some previous disturbance, its tolerance to ongoing disturbance is unknown (EG&G/EM, 1988b).

Kern mallow, San Joaquin woolly-threads, and California jewelflower were not found during the 1988 field surveys (EG&G/EM 1988b). Apparently, suitable habitat for Kern mallow exists in the northwestern portion of NPR-1 (Sections 12Z, 13Z, and 14Z), and it is likely that the species either exists in low numbers or could establish itself on the site (EG&G/EM 1988b). Potential habitat for San Joaquin woolly-threads exists along the northern flanks of the Elk Hills, but these habitats may be suboptimal because of the dense cover of red brome present (EG&G/EM 1988b). Suitable habitat for California jewelflower probably does not exist on NPR-1 (EG&G/EM 1988b). The Kern mallow, San Joaquin woolly-threads, and California jewelflower were federally listed as endangered in July 1990 (Federal Register 1990).

In the course of the 1988 survey, four species of special concern to the State of California were observed to be present (rare to uncommon): Temblor buckwheat (*Eriogonum temblorense*), cottony buckwheat (*Eriogonum gossypinum*), Gypsum-loving larkspur (*Delphinium gypsophilum gypsophilum*), and Kern tarplant (*Hemizonia pallida*).

Lost Hills saltbush (*Atriplex vallicola*), a federal Category 2 species and a state species of special concern, may also be present on NPR-1. This species was observed during the 1988 survey (EG&G/EM 1988b) but the exact location was unconfirmed. It was either in 12G which is on NPR-1 or in 13G which is off of NPR-1.

3.5.3.2 Animals

Four animal species that are federally listed as endangered are known to be present on NPR-1. These are the San Joaquin kit fox (*Vulpes macrotis mutica*), blunt-nosed leopard lizard (*Gambelia silus*), giant kangaroo rat (*Dipodomys ingens*), and Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*). Three mammal, two bird, and four invertebrate species with Category 2 status either have been observed, or suitable habitat for them exists. One of the Category 2 species is the San Joaquin antelope squirrel (*Ammospermophilus nelsoni*), which has been listed by the state of California as threatened. An additional 11 species are listed by the state as species of special concern. See Table 3.5-4 for additional information.

In 1980 and 1987, FWS reviewed several proposed actions on NPR-1 and issued Biological Opinions on the impacts of these actions on federally threatened and endangered species (Martinson 1980; Kobetich 1987). Primarily as the result of the magnitude of the disturbances proposed, the 1980 Opinion concluded that impacts might jeopardize the continued existence of the San Joaquin kit fox and the blunt-nosed leopard lizard. The Opinion proposed six alternatives to avoid jeopardy to these species, while also allowing NPR-1 activities to continue.

These alternatives focused on a commitment to avoid impacts to the maximum extent practical, reclaim disturbed habitat, offset loss of habitats through compensation and mitigation, and study

TABLE 3.5-4 Federally and State-Listed Animal Species Observed on NPR-1 or for Which Suitable Habitat Exists

Common Name[a]	Scientific Name	Federal Status	State Status
Mammals			
*San Joaquin Kit Fox	*Vulpes macrotis mutica*	Endangered	Threatened
*Giant Kangaroo Rat	*Dipodomys ingens*	Endangered	Endangered
*Tipton Kangaroo Rat	*Dipodomys nitratoides nitratoides*	Endangered	Special
Greater Mastiff Bat	*Eumops perotis californicus*	Category 2	Special
*San Joaquin Antelope Squirrel	*Ammospermophilus nelsoni*	Category 2	Threatened
*Short-nosed Kangaroo Rat	*Dipodomys nitratoides brevinasus*	Category 2	Special
*Badger	*Taxidea taxus*	None	Special
Birds			
*Ferruginous Hawk	*Buteo regalis*	Category 2	None
Mountain Plover	*Charadrius montanus*	Category 2	None
*Cooper's Hawk	*Accipiter cooperii*	None	Special
*Northern Harrier	*Circus cyaneus*	None	Special
*Golden Eagle	*Aquila chrysaetos*	None	Special
*Sandhill Crane	*Grus canadensis*	None	Special
*Short-eared Owl	*Asio flammeus*	None	Special
*Burrowing Owl	*Athena cunicularia*	None	Special
*Willow Flycatcher	*Empidonax traillii*	None	Special
*Le Conte's Thrasher	*Toxostoma lecontei*	None	Special
*Yellow Warbler	*Dendroica petechia*	None	Special
*Yellow-breasted Chat	*Icteria virens*	None	Special
Reptiles			
*Blunt-nosed Leopard Lizard	*Gambelia silus*	Endangered	Endangered
Invertebrates			
Hopping's Blister Beetle	*Lytta hoppingi*	Category 2	None
Moestan Blister Beetle	*Lytta moesta*	Category 2	None
Molestan Blister Beetle	*Lytta molesta*	Category 2	None
Morrison's Blister Beetle	*Lytta morrisoni*	Category 2	None

[a]An asterisk in front of the name indicates that the species has been observed on NPR-1.

Source: Based on data from EG&G/EM 1988b; Federal Register 1985b; O'Farrell and Scrivner 1987; Remsen 1978; and Williams 1986.

the kit fox and blunt-nosed leopard lizard. The 1980 Opinion also specified the need for a subsequent consultation and Opinion to evaluate the results of the studies.

To comply with the 1980 Opinion, preconstruction surveys were initiated in 1980. These were surveys conducted by qualified biologists to determine if threatened and endangered species or their habitats were present in areas to be disturbed by construction projects (see Section 4.1.5.4; Kato et al 1985; O'Farrell and Scrivner 1987; Kato and O'Farrell 1987). If protected species or their habitats were observed, mitigation measures were implemented to avoid or minimize impacts. In addition to preconstruction surveys, a program was implemented to reclaim habitat (see Section 4.1.5.4; O'Farrell and Mitchell 1985), and a wide assortment of research/studies and surveys were initiated on both NPR-1 and NPR-2 to gain insight into the factors affecting endangered species population dynamics.

Prior to the 1987 Opinion, Biological Assessments were submitted to FWS for their use in preparing the Opinion, pursuant to the requirements of the Endangered Species Act. During the period 1980-1985, immediately preceding the 1986 Assessment, kit fox populations at NPR-1 had declined significantly. This decline paralleled a significant decline in precipitation and food availability, an apparent significant increase in coyote abundance from 1979-1984, and continued development. To address the effect of development, the Assessments included a large body of information generated in connection with the survey and research requirements contained in the 1980 Opinion--information that was not available when the 1980 Opinion was being formulated. Among other things, this information included an analysis of the kit fox population decline in developed and undeveloped areas of the site; at that time no differences were detected. FWS concluded in their 1987 Opinion (see Appendix I) that, although "there are no assurances" that development activities will not "eventually contribute to the extirpation" of the kit fox from the site, development activities are "not likely to jeopardize the continued existence" of the species. The Opinion also concluded that development was not likely to jeopardize the continued existence of the blunt-nosed leopard lizard or the giant kangaroo rat. The Opinion specified several reasonable and prudent measures to minimize impacts.

The most significant measure was an aggressive habitat reclamation program. This included a comprehensive up-to-date inventory of all disturbances before and after MER production; an estimate of future disturbances; an estimate of existing or future disturbances that can be reclaimed because they are not needed for operations (e.g., abandoned well pads and roads); and a program to provide an amount of habitat equal to past and future MER disturbances, through one or a combination of on-site reclamation, off-site compensation, or some other equivalent means. Since then, it has been established that through the year 1998, approximately 4,056 acres will have been disturbed as the result of MER--3,306 as of 1989 (see Table 3.5-1), plus another 750 acres by 1998 (see Table 1.3-2). It has also been estimated that a total of 1,689 acres have been revegetated, or revegetation is in progress: 920 acres naturally, 690 acres associated with abandonments identified to date, and 79 acres associated with the NPR-1 portion of ongoing third-party projects (see Table 3.5-1). It is anticipated that another 625 acres are (or will be) available for future on-site reclamation (see Table 3.5-1). This results in the need to address a remaining 1,742 acres (4,056 - 1,689 - 625 = 1,742). Plans in this regard are being developed.

The 1987 Opinion also suggested implementing additional conservation measures that were originally suggested by NPRC in the Biological Assessments preceding the Opinion. These included changing "preconstruction" surveys that only address construction projects to "preactivity" surveys that address all land disturbances (including those associated with operations and maintenance activities) and studies to investigate the effects of oil-field chemicals on kit foxes. The 1987 Opinion suggested the need to continue the endangered species program, and to reopen consultations in conjunction with the development and release of this SEIS. Accordingly, consultation with FWS was reiniated in October 1991. In December 1992, FWS completed a partial draft Biological Opinion and a final draft Biological Opinion in May 1993 (see Appendix I.1), which state that the proposed action activities are not likely to jeopardize the continued existence of listed species. This consultation is still in progress (for more details see Section 4.1.5-4).

San Joaquin Kit Fox

Prior to European settlement, the San Joaquin kit fox presumably occurred throughout the arid plains of the San Joaquin Valley (FWS 1983). Although the kit fox still is found over much of its original range, animal numbers have declined (20-43% since 1930), and most of the population is now concentrated in the southern half of the valley in western Kern and eastern San Luis Obispo counties (FWS 1983). Total population size of the San Joaquin kit fox in 1975 was estimated at 6,961 individuals (FWS 1983). The kit fox population apparently has declined as a result of the rapid conversion of native habitat to agriculture and other developed areas (Morrell 1975). Only 6.7% of the valley was estimated to be undisturbed in 1979 (FWS 1985). Because of the significance of habitat loss and population declines, the San Joaquin kit fox was listed by the federal government as an endangered species in 1967.

The San Joaquin kit fox has been studied extensively on NPR-l and NPR-2 since 1979 and 1983, respectively. This section focuses on the current status of the species on NPR-1, as indicated by study results. The life history of the kit fox is presented as follows:

Life History of the San Joaquin Kit Fox.

The kit fox (*Vulpes macrotis*), of which the San Joaquin kit fox is a subspecies, is the smallest fox in North America. Adults weigh between 3 and 7 pounds and are between 24 and 33 inches long, including the tail (Samuel and Nelson 1982; O'Farrell 1987). Males weigh approximately 8% more than females (Egoscue 1962; Morrell 1972; O'Farrell 1987).

Female San Joaquin kit foxes are capable of breeding at 10 months of age (O'Farrell 1987), but most animals do not breed until 22 months of age (Morrell 1972; O'Farrell 1984). Kit foxes breed during early winter (December to January) (Morrell 1972; Samuel and Nelson 1982; O'Farrell 1987) and produce 3 to 5 pups/litter (O'Farrell 1987). Pups do not emerge from their natal den until they are at least 1 month old (Morrell 1972). Both parents provide food for the pups until they are approximately 4 to 5 months old, at which time the pups begin to forage for themselves and disassociate from their parents (Morrell 1972; O'Farrell 1987). On NPR-1, Scrivner et al (1987a) observed that of 129 radiocollared juveniles studied, 37 dispersed from their natal den within their first year, and 11 did so as adults. The natal dens for the remainder of the juveniles were not known. Average dispersal distance was about 5 miles (Scrivner et al 1987a).

The San Joaquin kit fox prefers habitats with loose, relatively stone-free soils that are well above the water table (FWS 1983; O'Farrell 1987). Such soils allow kit foxes to construct underground dens, which they occupy during most of the daylight hours. Relatively flat valley floors appear to be the preferred habitat of the kit fox, but they also occur in foothills where slopes do not exceed 40 degrees (Egoscue 1962; Morrell 1975; FWS 1983). Sandy washes are preferred hunting areas; open areas with grass, or with grass and scattered shrubs, are preferred den sites (Morrell 1972).

Kit foxes occupy underground dens throughout the year (FWS 1983; O'Farrell 1987). The occupation of dens changes, however, as foxes abandon one den and move into another; many dens in an area are vacant at any one time (Egoscue 1962; Morrell 1972). Dens are only shared by mated pairs or family groups (Morrell 1972; O'Farrell 1987). A mated pair may have as many as 39 dens distributed over an area of 320-480 acres (FWS 1983). Dens vary in appearance and function. Small dens with usually one to three entrances are used for shelter during the nonbreeding season; larger dens with three or more entrances are usually used for the raising of pups (Egoscue 1962; Morrell 1972; FWS 1983; O'Farrell 1987). Kit fox dens are widely distributed on NPR-1. A study conducted on the site in 1984 found dens in all but two sections (16G and 16R), and approximately 95% of all dens showed some sign of occupancy (O'Farrell and Mathews 1987). The average density of dens was estimated to be 59.3 dens/square mile, which is comparable to the density calculated in 1979 (O'Farrell 1980; O'Farrell and Mathews 1987).

Estimates of kit fox home range size vary, with reported values ranging from 580 to 3,500 acres (Morrell 1972; Daneke and Sunquist 1984; Zoellick et al 1987). Home range size is estimated to be 1,143 acres on NPR-1 and NPR-2 (Zoellick et al 1987). The home ranges of adjacent unpaired adults overlap little, whereas those of mated pairs coincide (O'Farrell 1987; Zoellick et al 1987).

The San Joaquin kit fox is carnivorous and generally captures live nocturnal prey; however, carrion, including road-killed animals, also are consumed (Morrell 1972). Prey items include lagomorphs (rabbits and jackrabbits), small rodents, birds, reptiles, and insects (Egoscue 1962, 1975; Morrell 1972; FWS 1983; O'Farrell 1987). The importance of different species in the kit fox diet varies among locations and seasons and may depend upon the relative abundance of prey. San Joaquin kit foxes do not need a source of drinking water, but instead obtain sufficient water from their prey (Morrell 1972; FWS 1983; Golightly and Ohmart 1984).

On NPR-1, lagomorphs and kangaroo rats are the most important components of the kit fox diet; these two prey types constitute approximately 73% and 13%, respectively, of all food items (Scrivner et al 1987b). Most (97%) of the lagomorph prey on NPR-1 are desert cottontails (Kato 1989); the remaining 3% are black-tailed jackrabbits.

Population Dynamics of the San Joaquin Kit Fox on NPR-1.

The kit fox population on NPR-1 has been monitored semiannually since 1981 on a 28,480-acre study area that encompasses the southern half of the site and approximately 2,880 acres in the adjacent Buena Vista Valley (Harris et al 1987). This area was chosen because in terms of developed and undeveloped areas it is representative of the entire NPR-1 site. As previously stated, NPR-1 itself is approximately 47,409 acres. Figure 3.5-2 shows the relationship between NPR-1, NPR-2, and the NPR-1 study area.

Minimum known population size (the number of marked individuals known to be alive at some point in time) in the study area was determined for each trapping period based on capture-recapture data (Harris et al 1987). From 1981 to 1990, the minimum population size in the study area declined from 153 foxes in the summer of 1981, when trapping began, to 28 in the summer of 1990 (Figure 3.5-3). On the basis of winter data only, the decline was from 165 in the winter 1981-1982 to 19 in the winter of 1990-1991. This represents an 81.7%-88.5% decline over the 10-year period. The great majority of the decline appears to have occurred during the period from 1981 to 1985. Minimum population size estimates during both winter and summer were relatively stable between winter 1985-1986 and winter 1989-1990 and ranged between 33 and 50 animals. From 1990-1991 the evidence suggests the population may have again declined; in summer 1991, the minimum population size was 10 (Figure 3.5-3). Data in 1992 suggests a significant increase. In winter 1991, two foxes were trapped in the NPR-1 study area. This compares to 16 trapped in winter 1992 (EG&G/EM unpublished data). Although the overall population in the NPR-1 study area was relatively stable between 1985 and 1989, the distribution of the population has changed. Currently, very few of the foxes in the NPR-1 study area occupy the upland developed areas; most are now situated in the more flat lowland areas.

With the exception of the urban areas of Taft and Ford City that fall within NPR-2 (see Figure 3.7-3), all approximate 30,000 acres of NPR-2 have been studied (Figure 3.5-2). Within NPR-2's boundaries, where recent development has been significantly less intense than on NPR-1, the minimum kit fox population has declined from 177 in the summer of 1983 to 74 in the summer of 1990 (Figure 3.5-3). On the basis of winter data only, numbers have changed from 119 in the winter of 1983-1984 to 67 in the winter of 1990-1991. This represents a decline of 43.7%-58.2% over a 6-year period.

Kit foxes on NPR-1 and NPR-2 may represent one population rather than two separate populations. The two NPRs share a common border in approximately 3 of the 81 Sections that fall within NPR-1, and the other areas adjoining their borders are contiguous with similar habitats and without physical barriers to prevent free movement. It is possible, however, that

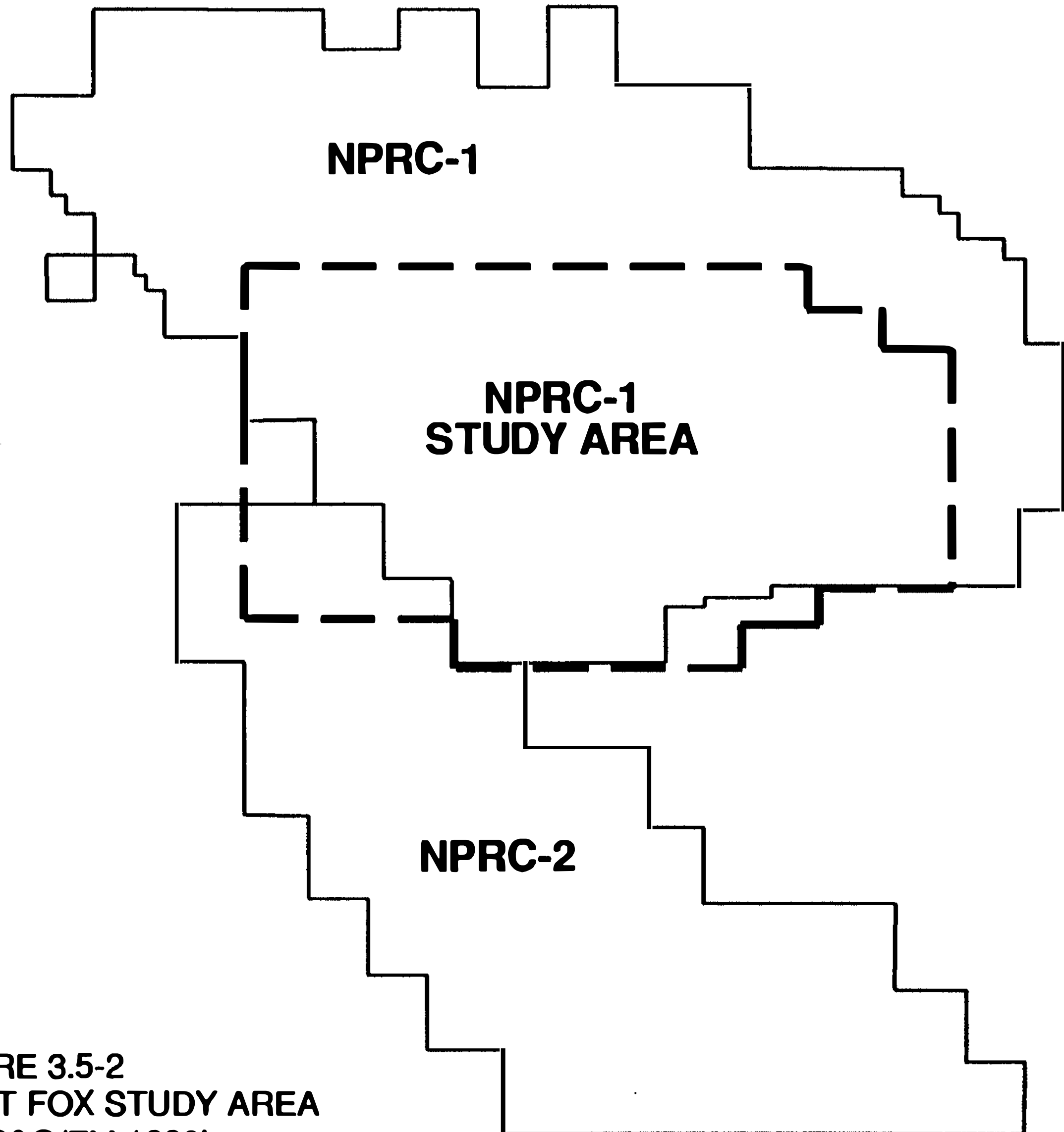


FIGURE 3.5-2
MAP OF NPR-1 KIT FOX STUDY AREA
SOURCE EG&G/EM 1990b.

NPRC1&2

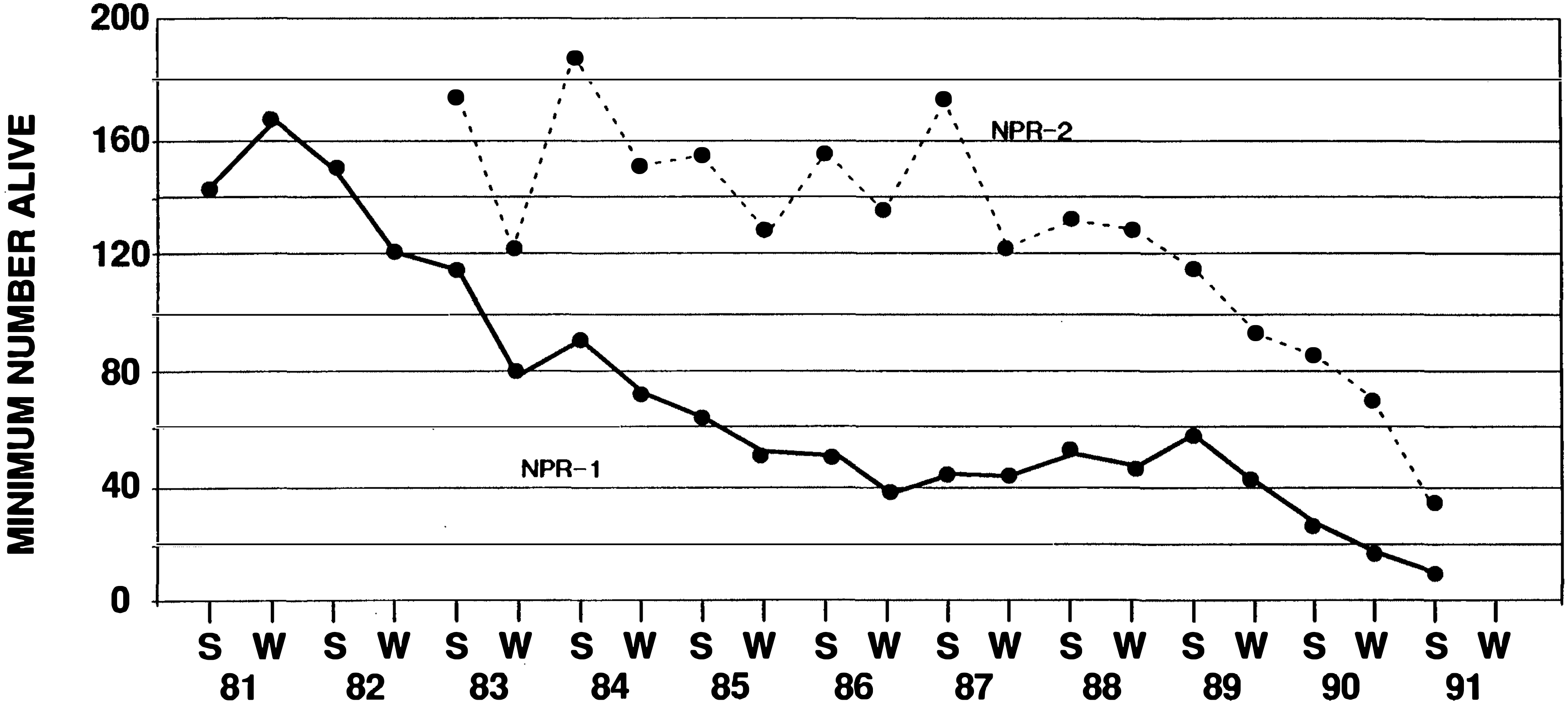


FIGURE 3.5-3 MINIMUM NUMBER OF KIT FOX ALIVE ON NPR-1 STUDY AREA (APPROXIMATELY 28,480 ACRES) FROM 1981 TO 1991 AND NPR-2 (APPROXIMATELY 30,000 ACRES) FROM 1983 TO 1991 DURING SUMMER(S) AND WINTER(W)(SOURCE;BASED ON UPDATED DATA FROM HARRIS ET AL 1987; O'FARRELL ET AL 1987a; EG&G/EM 1988a; KATO 1989; EG&G/EM 1990d.)

movement could be affected by factors other than physical barriers, such as habitat suitability (e.g., uplands versus lowlands), and/or development intensity.

Table 3.5-5 shows estimated density data for the NPR-1 study area, NPR-2, Buena Vista Valley, and the San Joaquin Valley. For the NPR-1 study area, the minimum population of 153 foxes in the summer of 1981 computes to a density of 5.37 animals/1,000 acres.

The decline to a minimum population of 10 by the summer of 1991 computes to a density of 0.35/1,000 acres. In the summer of 1983, the minimum population was 114; this computes to a density of 4.0/1,000 acres.

The density on NPR-2 in the summer of 1983 was approximately 5.90 foxes/1,000 acres, based on a minimum population of 177. By the summer of 1991, the density had declined to 1.23/1,000 acres, based on a minimum population of 37.

During a 14-month period in 1970-1971, Morrell (1972) observed that an estimated 1 square mile area on the Buena Vista Valley floor maintained a population of approximately six kit foxes. This conclusion was based on trapping, ear tagging, and radiocollaring in 3 month intervals. Six foxes in a 1 square mile area computes to a density of 9.35 foxes/1,000 acres.

FWS (1983) estimated that in 1975 the overall kit fox density in the San Joaquin Valley floor and foothills was equivalent to 2.19 foxes/1,000 acres: 3.14 for the valley floor and 1.88 for the foothills. The estimate was based on a 2-year aerial and ground investigation of a 70-110 square mile area comprising both valley floor and foothills. The kit fox density was determined by estimating the density of "active" dens, and assuming two kit foxes for each. Although not specifically stated, it is believed that the term "active den", as it was used in this investigation, closely corresponds to "pupping den", due to the time and methodology of the den survey.

Based on information provided by a trapper who had trapped extensively on the west side of the San Joaquin Valley, Grinnell et al (1937) reported a gross density estimate equivalent to 1.56 foxes/1,000 acres prior to 1925. Although this estimate does not appear to have any scientific basis, it is useful to consider in the absence of any other information about the period of time preceding intense development.

NPR-1 and NPR-2 densities are based on the "minimum" number of foxes known to be alive; actual populations are probably considerably higher. Commonly accepted computer models have been used to estimate "actual" population size. Generally, however, the NPR-1 study area sample size has not been sufficient to meet minimum model requirements. For example, 21 trapping sessions were conducted within the NPR-1 study area from the summer of 1981 to the summer of 1991; only two of these sessions produced sufficient sample sizes and total population estimates that were not obviously incorrect. To the extent these two data points are useful, they indicate that the actual population exceeds the minimum population by 54%-59% (EG&G/EM 1990e, Kato 1991). The implication of using "minimum" population data needs to be considered when making density comparisons; true densities are probably considerably higher than those

TABLE 3.5-5 Estimated Population Densities of San Joaquin Kit Foxes within the San Joaquin Valley

Location	Year	Estimated Density (No./1,000 acres)	Source[a]
NPR-1 Study Area	1981	5.37	1,2,3,7,8
	1983	4.0	7,8
	1991	0.35	2,7,8
NPR-2	1983	5.90	2,3,4,7
	1991	1.23	2,7,8
Buena Vista Valley	1970-1971[b]	9.35	5
San Joaquin Valley	1975[c]	2.19	6
	Pre-1925	1.56	6

[a]Sources:
1 = Harris et al. 1987;
2 = Kato 1989;
3 = EG&G/EM 1988a;
4 = O'Farrell et al. 1987a;
5 = Morrell 1972;
6 = Grinnell et al. 1937; and
7 = EG&G/EM 1990d.
8 = Kato 1991.

[b]Study based on trapping in a one square mile area of Buena Vista Valley.

[c]In areas of suitable habitat.

derived from minimum populations. Also, individual foxes differ in their tendency to enter traps, and the comparability of habitats and densities on trapped and untrapped areas has not been tested (O'Farrell et al 1986).

To gain insight into the cause of the population decline on NPR-1, a life table analysis was performed based on radiocollared kit fox data collected during the period 1981-1988 (see Appendix E). Additional analyses are in progress to investigate differences between the period 1981-1985, when the decline occurred, and the period of relative stability since 1985; the results of these analyses will be reported when completed. On the basis of the fecundity and mortality investigations that comprise life table analyses, mean fecundity for all age classes was 2.2 over the period 1981-1988. Mortality during this period ranged from a low of 0.432 for 2-year old foxes to a high of 0.829 (17.1% survivorship) for foxes less than 1 year old. As a consequence, the net reproductive rate was a low 0.56, generation time was 2.0 years, and the rate of population increase was approximately -0.30. During the period 1981-1985, population curves derived from this rate of increase matched fairly well with those derived from actual observations; however, the curves diverge beginning in 1985 when the population began to stabilize (see Figure E.1-1).

The conclusion that can be drawn from the foregoing is that if the kit fox population were to begin declining again in the near future before it has an opportunity to reestablish itself, kit foxes could possibly become extirpated from NPR-1 within a few years. As will be explained in more detail later, it is possible that in addition to the effects of development, a substantial decline in kit fox food supplies, possibly as the result of a decline in precipitation and vegetative production, could have contributed significantly to the population decline that has occurred. Therefore, it is possible that if precipitation, vegetative production and food supplies return to prior levels, the population could increase, precluding extirpation; or if extirpation does occur, it might only be temporary (the population could reestablish). Evidence supporting this was observed during recent assessments of kit fox reproduction and population size. Concurrent with the significant increase in precipitation during the 1991-1993 water years, the percentage of radiocollared female kit foxes that showed evidence of reproducing increased from 18% in spring 1991 to 100% in spring 1992 (EG&G/EM 1992). Similarly, the number of kit foxes trapped on the NPR-1 study area increased from two in winter 1991 to 16 in winter 1992 (EG&G unpublished data).

The proximate causes of death of radiocollared kit foxes on NPR-1 from 1980-1988 are shown by Table 3.5-6. These data are primarily based on mortality monitoring methods discussed by Zoellick (1986), and data reported by Berry et al (1987) which identified several contributory factors. From 1980-1988, 291 foxes were recovered dead. Approximately 54.6% of these were determined to have been killed by predators; 29.9% were classified as unequivocal predation, while an additional 24.7% were classified as probable predation (factors other than predation were unlikely, but they could not be completely ruled out). Almost all predation was by coyotes. The cause of death could not be determined for 32.3% of the foxes because carcasses were either decomposed or scavenged, or only the collar was found (Berry et al 1987). Vehicles caused 10.0% of the mortalities, and 3.1% died from other causes. Identified sources of mortality other than predation and vehicles included drowning and burying associated with development, disease, and shooting.

Disregarding foxes for which a cause of death could not be established, 80.7% of those for which a cause could be established were the result of predation, 14.7% were due to vehicles, and 4.6% were for other reasons. Cause of death did not appear to be related to the age, sex of fox, or year of study.

Effects of Natural Environmental Factors on Kit Fox Population Dynamics.

Several natural environmental factors could have played a role in the decline of kit fox numbers in the NPR-1 study area. These include precipitation, food availability, predation, disease, and habitat suitability. The following discussion addresses the role of each of these factors.

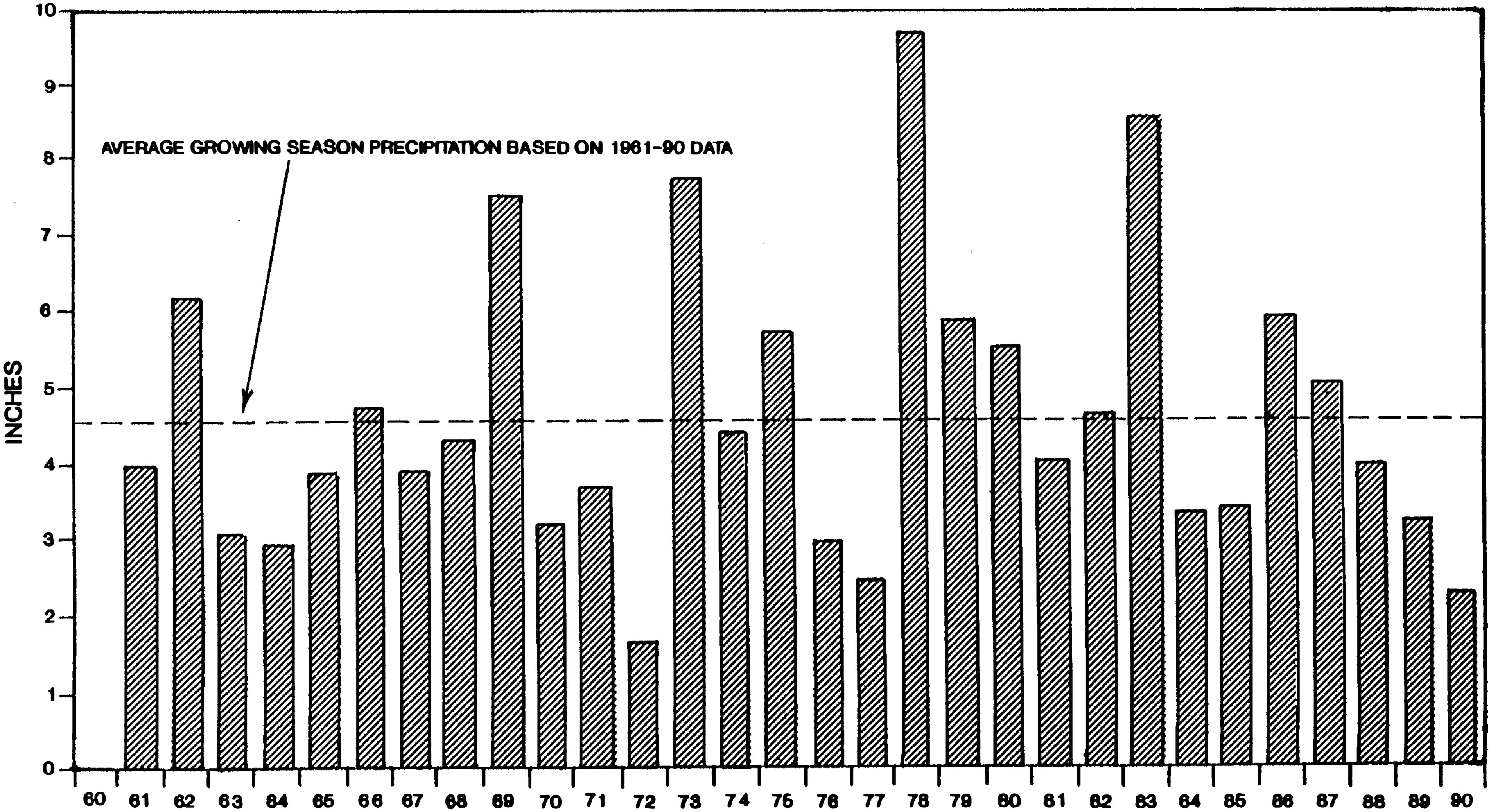
Figure 3.5-4 shows annual "growing season" precipitation for Bakersfield, California, which is approximately 25 miles northeast of NPR-1. Growing season is defined as January-March of the current year, plus October-December of the previous year. Growing season is reported because precipitation occurring outside of the growing season does not contribute significantly to the vegetative production that sustains lagormorphs and small mammals, the primary source of food for kit foxes. Growing season precipitation has been below average for 5 of the last 7 years, and 6 of the last 10 years since 1981 when kit fox population estimating began. In comparison, average growing season precipitation was above average (sometimes significantly) during the 3-5 year period immediately preceding 1981. A further discussion of precipitation data is presented in Appendix E.

Although it is apparent from visual inspection that vegetative production has declined significantly since 1981, a site-wide program to obtain the data needed to confirm this scientifically has not been in place; however, careful observations of annual production changes have been documented at a 320-acre site in Sections 21S/22S where a giant kangaroo rat habitat manipulation study has been in progress since 1988. At this site, which is situated on the north side of NPR-1, where precipitation is greatest, annual production fell from 1,596 pounds/acre in 1988 to 644 pounds/acre in 1989 to 85 pounds/acre in 1990.

It is also noteworthy that plant cover on revegetation program control sites averaged 77% in 1987. By 1990, cover on these sites had dropped to 16%.

Food availability could affect the kit fox population on NPR-1. Egoscue (1975), for example, determined that the size of the kit fox (*Vulpes macrotis nevadensis*) populations in Utah tracked the abundance of black-tailed jackrabbits. In years of low jackrabbit numbers, the density of foxes was lower, fewer litters were produced, and average litter size was reduced relative to periods when jackrabbits were abundant. Morrell (1972) speculated that the starvation of pups was an important factor in limiting the population of San Joaquin kit foxes he studied near NPR-1. In a study of red foxes in Sweden, Lindstrom (1989) determined that growth, ovulation rate, mean litter size, and survival were positively correlated to vole population levels.

AVERAGE GROWING SEASON PRECIPITATION FOR BAKERSFIELD, CALIFORNIA



GROWING SEASON DEFINED AS PRECIPITATION FOR JAN.-MAR. OF CURRENT YEAR PLUS OCT.-DEC. OF PREVIOUS YEAR

FIGURE 3.5-4
SOURCE: EG&G/EM 1990b

TABLE 3.5-6 Percentage of Radiocollared San Joaquin Kit Foxes Dying from Various Causes on NPR-1 from 1980 to 1988

		Cause of Death (as % of total deaths)			
Class	Number	Predation[a]	Vehicle	Other	Unknown
Sex					
Male	137	51.8	11.0	3.7	33.6
Female	154	57.1	9.1	2.6	31.2
Age					
Pup	126	52.4	9.5	3.2	34.9
Adult	137	61.3	11.0	2.9	24.8
Year					
1980-82	76	47.7	11.8	0.0	40.8
1983-85	158	57.0	8.9	5.7	28.5
1986-88	57	57.9	10.5	0.0	31.6
TOTAL	291	54.6	10.0	3.1	32.3

		Cause of Death (as % of deaths of identified cause)		
Class	Number	Predation	Vehicle	Other
Sex				
Male	91	78.0	16.5	5.5
Female	106	83.0	13.2	3.8
Age				
Pup	82	80.5	14.6	4.9
Adult	103	81.6	14.6	3.9
Year				
1980-82	45	80.0	20.0	0.0
1983-85	113	79.6	12.4	8.0
1986-88	39	84.6	15.4	0.0
TOTAL	197	80.7	14.7	4.6

[a]Includes mortalities classified as probable predation.

Source: Based on data provided by EG&G/EM.

To examine the importance of food availability in determining the size of the San Joaquin kit fox population on NPR-1, the relative abundance of lagomorphs (their preferred source of food) was studied concurrently with kit fox population studies (Harris 1986; O'Farrell and Mathews 1987; Scrivner et al 1987a; EG&G/EM 1988a, 1989b). From 1980 to 1991, lagomorph abundance exhibited a strong decline (Figure 3.5-5 and Figure 3.5-6). Lagomorph counts were made during road surveys between 1980 and 1984. Both cottontail and jackrabbit counts declined annually over this period, suggesting that a lagomorph population decline began as early as 1980 (EG&G/EM 1988a). From 1983 to 1991, lagomorph densities based on transect surveys conducted three times a year exhibited a strong decline, especially black-tailed jackrabbits. Populations of small mammals increased from 1980 to 1984 (Figure 3.5-6). On NPR-2, where the kit fox population decline has been less pronounced, lagomorph populations did not begin to decline until 1986 (Figure 3.5-7) (EG&G/EM 1989b and EG&G/EM 1990b). Estimated densities for NPR-2 in fall 1990 and spring and summer 1991 should be viewed with caution because of low sample size.

Lagomorphs are known to sustain themselves on grasses, forbs and shrubs (Hansen and Flinder 1969). In addition, it is possible that there is a positive relationship between lagomorph densities and shrub cover (Zollick et al 1987). Given the positive relationship between precipitation and annual vegetation production (previously presented), it is possible that the decline in lagomorph abundance was due, at least in part, to a decline in site vegetative production which occurred as the result of a decline in growing season precipitation.

Changes in prey populations were reflected in the diet of the kit fox. From 1980 to 1984, when kit fox diet was studied on NPR-1, the percentage of fox scats that contained cottontail remains decreased from about 83% to about 58%; over this same period the percentage of small mammals increased from about 10% to about 35% (Figure 3.5-6). Thus, kit foxes appear to be able to shift diet in response to changes in prey abundance.

It is possible that diminished food supplies could result in starvation, diminished reproductive capacity, an increase in vulnerability/exposure to predation (due to weakened animals being less able to avoid predation and the need to spend more time foraging over a larger area), and an increase in vulnerability to other mortality sources. Lindstrom (1989) found that supplemental feeding during periods of low vole abundance increased the number of litters produced by red foxes in Sweden.

In an attempt to characterize the relationship between food supplies and kit fox mortality on NPR-1, a supplemental feeding study was carried out in 1988 and again in 1989. Results of the 1988 study suggest a direct and strong relationship between food availability and mortality. Between May 1988 and May 1989, the percentage of fed pups surviving was approximately 50% compared with less than 10% for pups that were not fed (EG&G/EM 1990c). For adults, the 14-month survival rates for fed and unfed foxes were approximately 70% and 30%, respectively (EG&G/EM 1990c). Weight gain was also greater in fed male pups than in control males, but no difference was observed in female pups. No evidence of starvation was observed in control

Densities of Lagomorphs

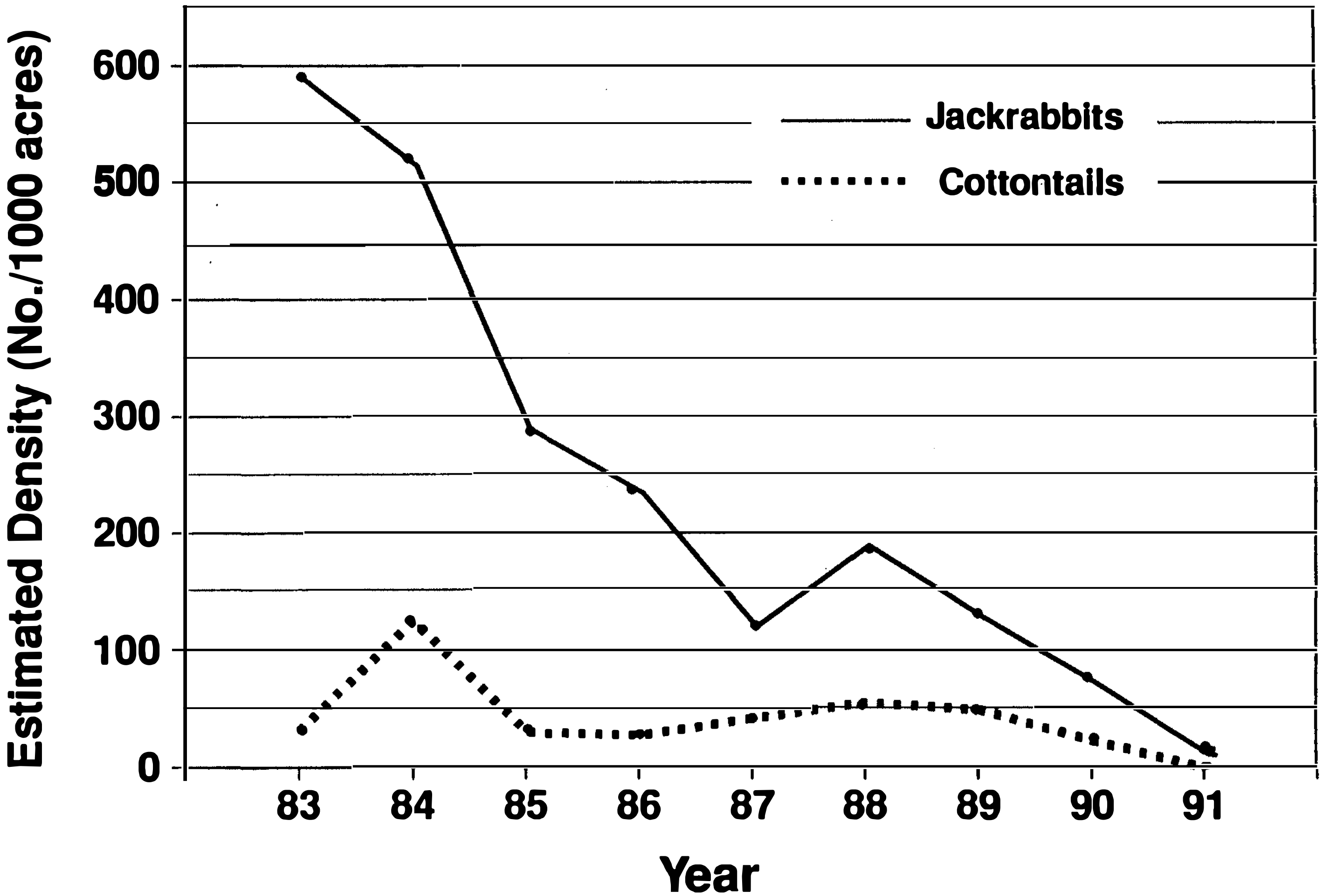


FIGURE 3.5-5 ESTIMATED DENSITY OF LAGOMORPHS ON NPR-1 FROM 1983 TO 1991 (SOURCE: BASED ON UPDATED DATA FROM HARRIS 1986; EG&G/EM 1988a, 1988b).

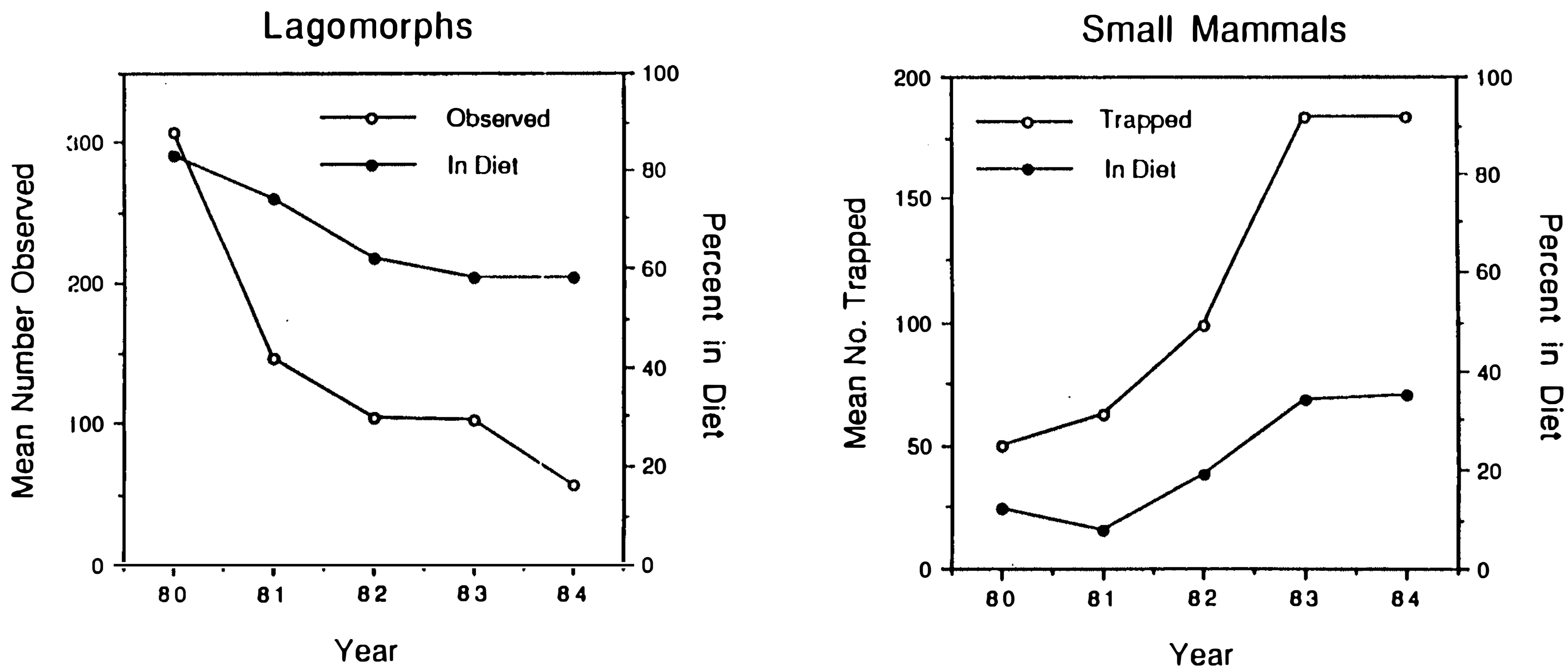
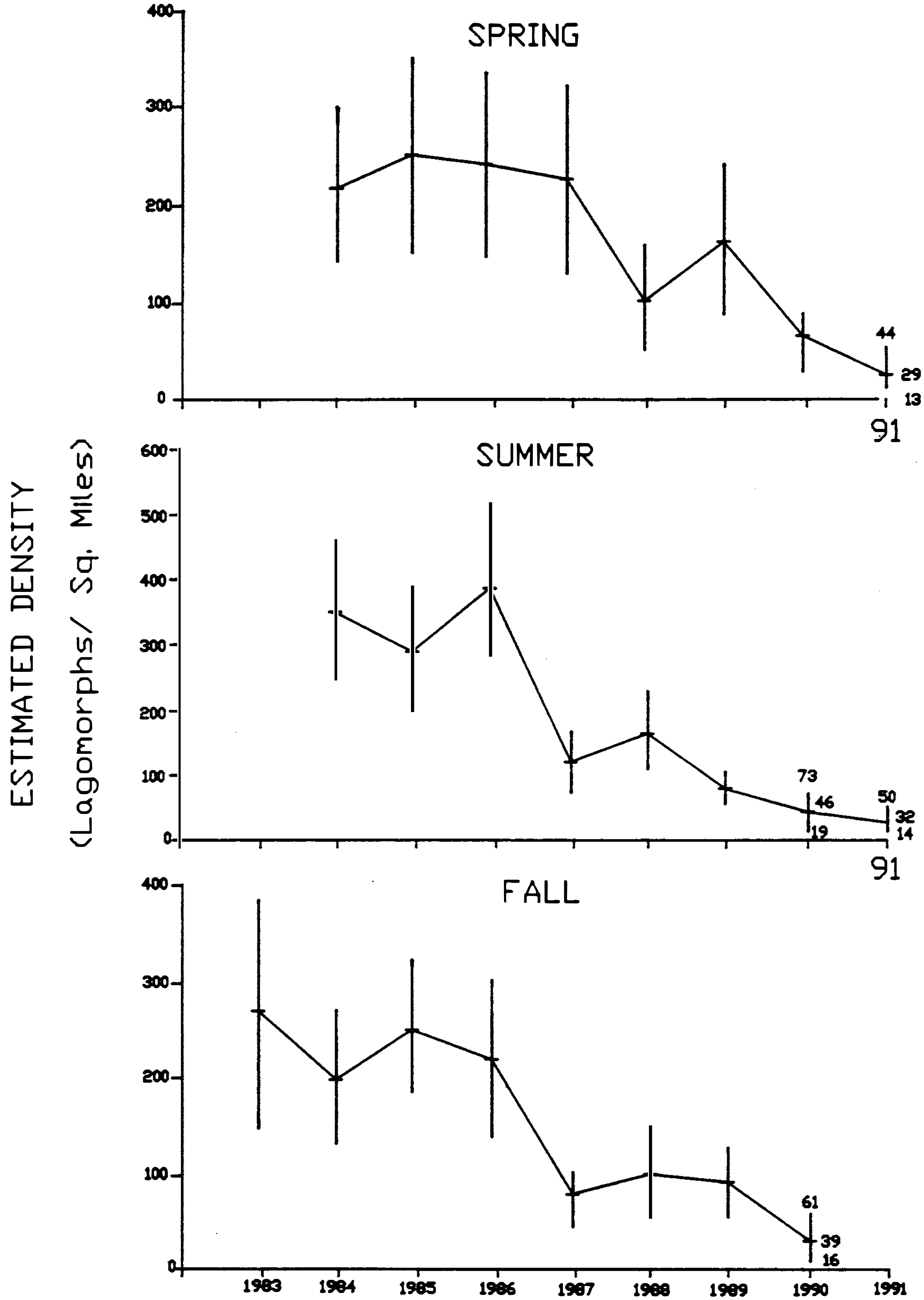


FIGURE 3.5-6 POPULATIONS OF SAN JOAQUIN KIT FOX PREY AND OCCURRENCE IN DIET ON NPR-1 FROM 1980 TO 1984 (SOURCE: BASED ON DATA FROM O'FARRELL ET AL 1986; EG&G/EM 1988a; KATO 1989)

FIGURE 3.5-7
LAGOMORPH DENSITY ESTIMATES
NPR-2
EG&G/EM 1990C, SCRIVNER 1991



foxes. Control foxes may have had higher rates of mortality because they had to spend more time foraging over a larger area, and thus were exposed to a greater predation risk.

Based on a preliminary analysis, the results of the 1989 study do not duplicate the results of the 1988 study. Although it appears that the mortality of control foxes was greater than that of treatment foxes, the difference was not statistically significant. The apparent difference between 1988 and 1989 is that survivorship of control pups was significantly higher in 1989 than in 1988. Explanations for this are being analyzed. One avenue of investigation is that control survivorship was influenced by the coyote control program. The intensity of the coyote control program in 1989 was significantly greater than in 1988 (see Figure 3.5-8). It is possible that this contributed to differences in control fox survivorship, thus skewing the comparability of the results of the two study years. It is also possible that the sample sizes used in the studies are insufficient to produce repeatable results. Plans are to complete the analysis of the 1988-1989 supplemental feeding studies, and implement a new study, if one can be designed to clarify/supplement prior findings. As study results are finalized, they will be reported.

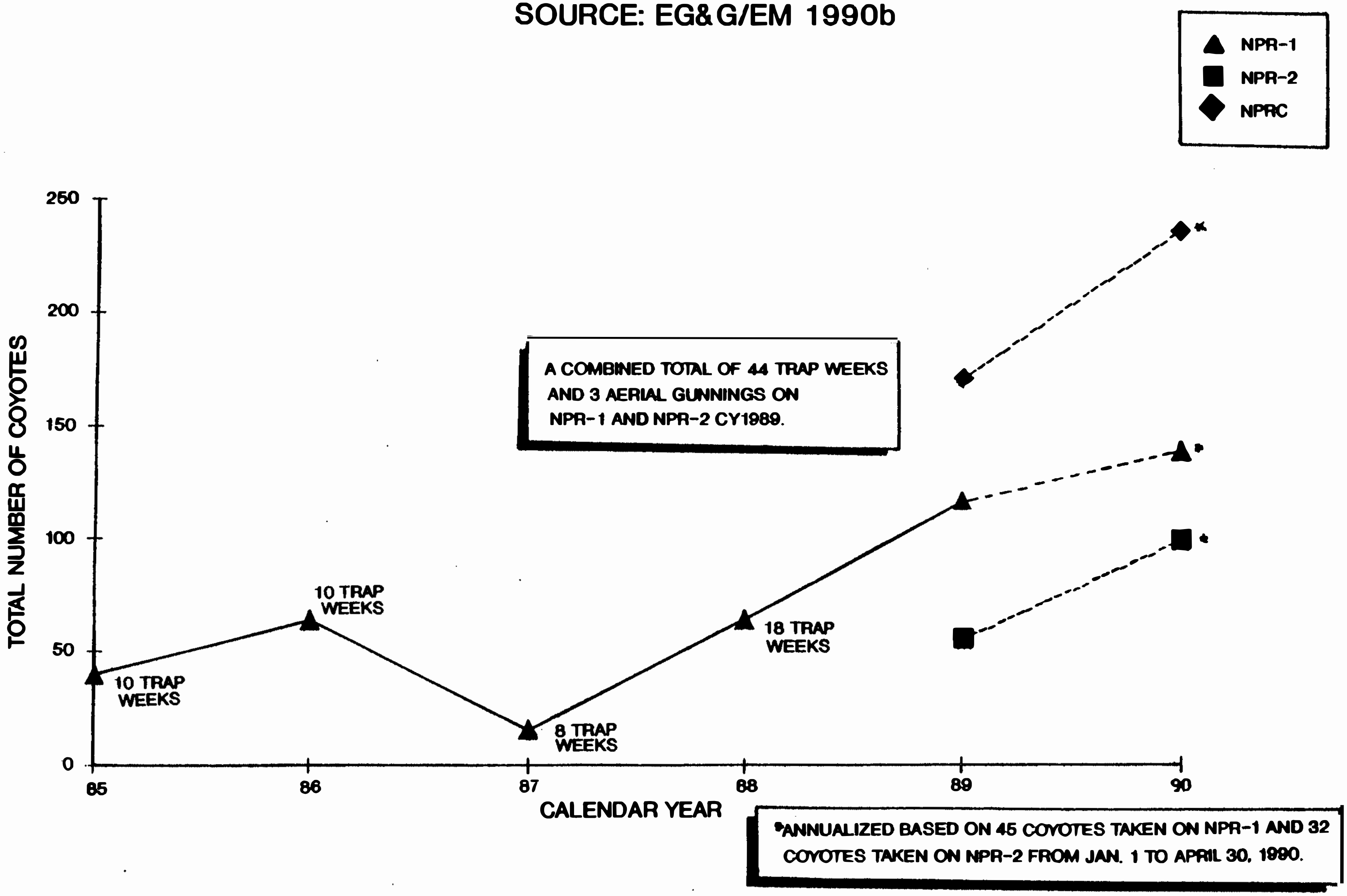
The mortality data previously discussed strongly suggests that coyote predation has contributed significantly to the decline of kit foxes on NPR-1 (see Table 3.5-6). Coyotes do not kill foxes for consumption (Berry et al 1987), but rather, predation apparently acts as a mechanism to relieve interspecific competition. Such aggressive displacement of sympatric canids has been observed for a number of species in North America (Bekoff 1982; Carbyn 1982; Harrison et al 1989). During much of the period of kit fox population decline, coyote numbers increased substantially from the very low numbers observed in 1979 when kit fox numbers were high.

Several studies have indicated that increased numbers of coyotes have induced population declines in both red foxes (*Vulpes vulpes*) (Major and Sherburne 1987; Sargeant et al 1987; Harrison et al 1989) and bobcats (*Felis rufus*) (Litvaitis and Harrison 1989). These studies have linked such declines to aggressive displacement of the smaller species by coyotes and a reduction in prey abundance because of overlap in diet.

Coyotes appeared to be more abundant in the developed upland areas of NPR-1 than in the undeveloped lowlands (based on data taken from Scrivner and Harris 1986, and Scrivner 1987). The underlying reasons for higher coyote abundance in developed areas are not known. During the period 1981-1985 when kit fox populations declined, the percentage of kit foxes that were killed by coyotes in developed areas was slightly higher than in undeveloped areas (56.1% versus 53.0%) (based on data in Berry et al 1987). This factor could be contributing somewhat to the comparatively lower kit fox population levels in developed areas. This notwithstanding, it is clear that coyote predation has been an important factor throughout the site (developed areas and undeveloped areas), and for this reason it is unlikely that predation alone can explain differences in population levels from one area to another.

In an attempt to reduce coyote predation, a coyote control program was implemented in 1985. As previously indicated, the program was in effect intermittently at various levels of intensity until May 1990 when it was suspended pending evaluation (Figure 3.5-8). Control measures

FIGURE 3.5-8
COYOTES TAKEN PER YEAR ON NPRC
SOURCE: EG&G/EM 1990b



included trapping, denning, shooting and aerial gunning. The evaluation of the program is in progress. Preliminary observations are presented in Appendix E.

Disease can be an important source of mortality in fox populations (Nicholson and Hill 1984; Berry et al 1987). The importance of disease in the NPR-1 kit fox population was examined from August 1981 to January 1982 and again in June and July 1984 (McCue and O'Farrell 1988). Serum from trapped adult foxes was tested for the presence of antibodies for 10 infectious pathogens; presence of these antibodies indicates past exposure to these diseases. The occurrence of antibodies was highest for canine parvovirus, tularemia, infectious canine hepatitis, and canine distemper. In 1981-1982, only canine parvovirus was observed frequently (100% of kit foxes tested). In 1984, canine parvovirus was found in 64%, tularemia in 31%, infectious canine hepatitis in 21%, and canine distemper in 14% of kit foxes tested. Despite the presence of these antibodies, no clinical indication of disease was observed. All foxes examined appeared to be in good health and none appeared malnourished. As a result of the investigation, it was hypothesized that the high kit fox density that existed on NPR-1 in 1981 may have resulted in the prevalence of disease in the population (McCue and O'Farrell 1988). Given that juveniles were not included in the investigation, less information was available about the prevalence and effects of disease in juveniles. It was suggested that canine parvovirus in particular could have caused high rates of juvenile mortality without being observed by the investigators (McCue and O'Farrell 1988).

Disease was addressed in an investigation (Berry et al 1987) of 225 radiocollared kit foxes recovered dead from 1980-1986, 95 of which were juveniles from approximately 1-12 months old. Seven of the 225 were suspected of having died as the result of disease. Two of these were apparently the result of pneumonia. The other five died in their dens, which suggests disease; however, they were in advanced states of decomposition which precluded a cause of death determination. The investigation concluded that disease was not an important mortality factor on NPR-1 in the group of dead foxes that were investigated; however, it was recognized that disease could make foxes more susceptible to other types of mortality, such as predation. It has also been recognized that the role of disease in pups less than 1 month old is not known. Since pups do not emerge from their dens until they are approximately 1 month, they were not trapped or radiocollared; therefore, they were not included in any of the groups of foxes that were investigated.

Two initiatives are in progress to expand the understanding of the role of disease. Selected foxes are screened routinely for the presence of antibodies associated with three diseases: canine parvovirus, canine distemper, and infectious canine hepatitis. These data are maintained and analyzed as a matter of standard practice to detect changes from baseline conditions; it will also serve as the basis for future investigations that might be appropriate. In addition to antibody screening, mortality differences in pups less than 1 month old are being evaluated as part of the ongoing analyses of the periods 1981-1985, when the kit fox population decline occurred, and the period of relative stability from 1985-present. This could clarify the relative importance of this age group in overall mortality, which could be useful information in addressing the role of disease.

Differences in habitat suitability could be an important factor in the distribution of kit foxes on the NPR-1 site. It has been observed that kit fox densities are generally greater in lower flatland areas than in upland foothill areas (Egoscue 1962; Morrell 1975; FWS 1983) that comprise the great majority of NPR-1. This suggests that the lower flatland habitat on the margins of and adjacent to the site may be more suitable for kit foxes, and could explain in part why very few of the remaining NPR-1 foxes are in the developed upland areas. A component of habitat suitability is the extent to which it affects predation. As previously indicated, there is evidence that during the period of the kit fox decline from 1981-1985 coyote abundance and predation were greater in the developed upland areas than in the undeveloped lower flatlands (based on data taken from Scrivner and Harris 1986; Scrivner 1987; Berry et al 1987). This could have contributed to comparatively lower kit fox populations in the developed uplands.

Effects of NPR-1 Operations on Kit Fox Population Dynamics.

The activities that have occurred on NPR-1 since 1976 could have affected kit fox numbers. As of June 1988, approximately 6,546 acres (14% of the site) were reported as disturbed as a result of development activities (EG&G/EM 1989a), of which 1,689 acres (4% of the site) have been reclaimed (Kato 1990a); of the 6,546 acres, approximately 3,306 acres (7% of the site) were disturbed since MER activities began in 1974-1976. These disturbances have probably reduced the carrying capacity of the site (O'Farrell et al 1986) and could have contributed to the reduction in kit fox numbers. Although foxes frequently use developed areas (O'Farrell 1984, 1987; O'Farrell et al 1986; O'Farrell and Mathews 1987), there is evidence to suggest that development may have had adverse effects. First, the density of kit fox dens was significantly lower in areas of greater oil development on both NPR-1 and NPR-2 (<u>Figure 3.5-9</u>). Second, from 1982 to 1985, several measures of reproductive success (pregnancy rate of yearlings, number of litters/square mile, number of females successfully raising pups) were lower in developed areas than in undeveloped areas (Zoellick et al 1987). Third, most kit foxes now occur along the undeveloped periphery of the site, rather than in developed upland areas. The causes of these relationships are not known, but could include direct mortality, loss of dens, human disturbance, exposure to oil-field chemicals, or induced changes in habitat quality. Evidence regarding the relative importance of each of these factors is discussed in the following paragraphs.

Since 1980 a total of 37 foxes were found dead on NPR-1 which were known to have been caused by NPR-1 activities: 34 as the result of vehicle collisions, 1 due to construction burial (O'Farrell et al 1987), 1 due to an oil spill, and 1 due to pipe entrapment. From 1980-1988, vehicles were the cause of 10% of radiocollared fox deaths annually (see <u>Table 3.5-6</u>). Although 10% vehicle mortality is significant (second only to coyote predation), it is comparable to that reported for the gray fox (*Urocyon cinereoargenteus*) in rural Alabama (Nicholson and Hill 1984). Covering open pipes, preactivity surveys, and the SPCC program precludes open pipes, construction burial and spills from becoming important sources of mortality. Several measures have also been implemented to control vehicle mortality (e.g. controlling speed and off-road driving).

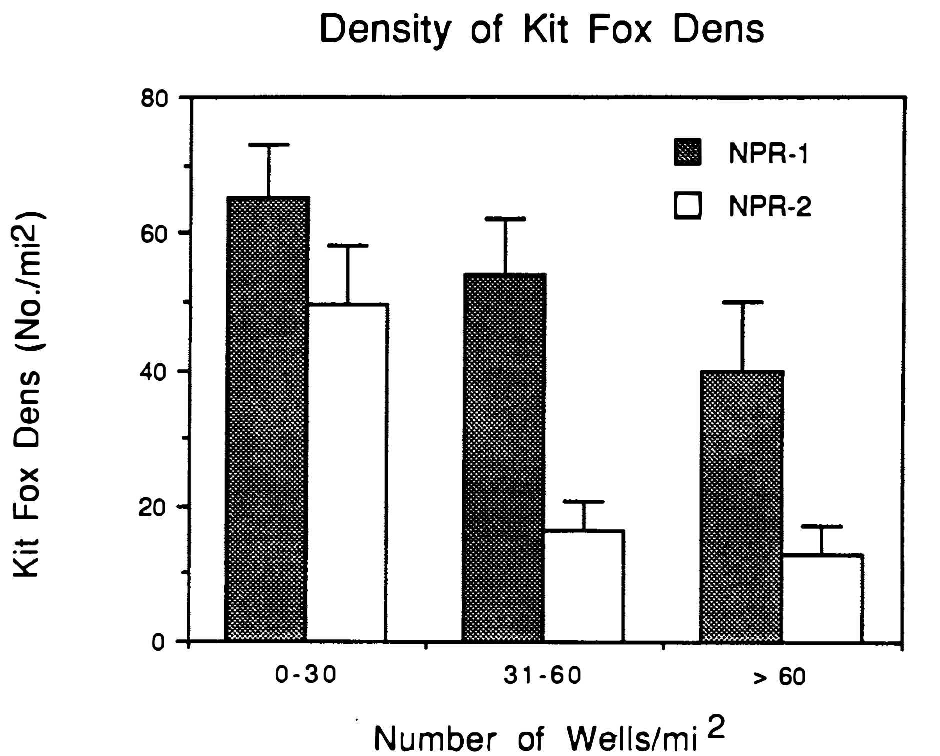


FIGURE 3.5-9 ESTIMATED DENSITY (± STANDARD ERROR) OF SAN JOAQUIN KIT FOX DENS ACCORDING TO INTENSITY OF DEVELOPMENT ON NPR-1 AND NPR-2 (SOURCE: BASED ON DATA FROM O'FARRELL AND MATTHEWS 1987; O'FARRELL AND SAULS 1987)

It is unlikely that the loss of dens has resulted in the observed decline in kit fox numbers over the past decade. A total of five dens were destroyed inadvertently during construction activities and another 20 were excavated intentionally to prevent the burial of foxes (O'Farrell et al 1986). Further inadvertent loss of dens was eliminated as a result of the implementation of preactivity/preconstruction surveys (Kato et al 1985; Kato and O'Farrell 1987; O'Farrell and Scrivner 1987).

Kit foxes do not appear to be particularly sensitive to human disturbance (Egoscue 1962; O'Farrell and Gilbertson 1986; O'Farrell et al 1986; O'Farrell 1987), as evidenced by observations of kit fox activity in the immediate vicinity of operating facilities on the site. On the basis of these observations, it appears unlikely that this factor could have a strong influence on the population dynamics of the kit fox population on NPR-1.

Oil and oil-field chemicals (e.g., chromium, arsenic, hydrocarbon gases, etc.) have been spilled or released on NPR-1 (see Section 3.2) and may have been inhaled or ingested by kit foxes through contaminated drinking water or prey (O'Farrell et al 1986). Oil-field wastewater often contains high concentrations of dissolved solids, salt, and various other minerals and can cause death, nervous disorders, tissue damage, and decreased reproduction in livestock and wildlife if ingested (Monlux et al 1971; Therklesen 1973).

Screening samples of tissues, hair, and feces were collected in 1983 from kit foxes occupying areas of NPR-1 at highest risk of chemical contamination; these samples were analyzed for cadmium, vanadium, and selenium (O'Farrell and Scrivner 1987). The analyses indicated that levels of cadmium were low, but levels of vanadium and selenium were relatively high. Additional analyses were conducted in 1986-1988, primarily to determine if any additional chemicals at NPR-1 might require investigation (Suter 1988). Based on the results of the 1983 and 1986-1988 studies was implemented in 1988 to determine in a more scientific way the extent to which oil-field chemicals may be entering the tissue of NPR-1 kit foxes and kit fox prey. The study strategy was to investigate kit fox fur, soil, water available for drinking, lagomorph, and small mammal samples in developed and undeveloped areas of NPR-1, developed areas of NPR-2, and other areas that are ecologically similar to NPR-1 but which have not been exposed to oil-field development.

As a result of the decline in lagomorph populations, it was not possible to collect sufficient lagomorph and small mammal samples as originally specified. An analysis of the soil, water, and fur portions of the study has been completed (Suter 1992). The analysis concluded it is unlikely that oil-field chemicals were responsible for the decline in the NPR-1 kit fox populations that occurred in the early 1980s. As a result of the definite nature of this conclusion, an analysis of lagomprphs and small mammals is not needed.

Effects of Natural Factors and/or NPR-1 Operations on Kit Fox Population Dynamics.

Differences in prey availability may have existed between developed and undeveloped areas of the site which may have contributed to the comparatively fewer number of kit foxes in the developed upland areas of NPR-1. In general, lagomorph densities have been higher in the developed upland areas (Harris 1986; O'Farrell et al 1986; O'Farrell and Mathews 1987; EG&G/EM 1988a, 1989b). Kangaroo rats are more common in the undeveloped lowlands than in the developed upland areas (Scrivner et al 1987b). The differences in the abundance of kangaroo rats in developed and undeveloped areas are probably a function of habitat type rather than an effect of development (Scrivner et al 1987b). These differences are not well understood, but may be related to shrub densities and cover (Zoellick et al 1987).

Differences in lagomorph densities were most pronounced in 1980 and 1981, when the number of lagomorphs observed during monthly road surveys was as much as 5 times higher in developed areas than in undeveloped areas (Harris 1986). From 1982 to 1985, the numbers of lagomorphs observed in developed areas were less than half of the level in 1981, but were still higher than in undeveloped areas. Line-transect data from 1986 to 1991 indicate that during this period the density of lagomorphs in developed areas was usually higher than in undeveloped areas (EG&G/EM 1988a, 1989b, Kato 1991). The significant decline in lagomorph numbers in developed areas could have been a result of natural phenomena, such as climatically induced fluctuations in food supply, or it could have been a result of habitat degradation caused by oil-production activities, or a combination of both (Zoellick et al 1987).

As discussed previously, lagomorphs, especially cottontails, are the preferred prey of kit foxes on NPR-1, but small mammals such as kangaroo rats also can be important, depending on their relative availability (see Figure 3.5.9). Following the decline in lagomorphs, insufficient numbers of alternative prey may have existed in developed upland areas to support a viable kit fox population (Zoellick et al 1987).

Effects of Trapping and Radiocollaring on Kit Fox Population Dynamics.

Intensive trapping and radiocollaring of kit foxes is part of the Endangered Species Program and has occurred on NPR-1 since 1980. These activities could have affected kit fox population dynamics, if trapping resulted in the death of trapped individuals or facilitated the spread of disease. Radiocollars themselves could have conceivably reduced survivorship.

Based on available evidence, trapping and handling apparently had no direct effect on kit fox survivorship. Very few individuals (four) died in traps, or died as a direct result of handling or collaring (Berry et al 1987). In addition, it appears unlikely that trapping and handling significantly affected the spread of disease, because antibodies for pathogens were more prevalent in the beginning of the trapping program (McCue and O'Farrell 1988) before such an effect would be expected.

Radiocollars can adversely affect the animals wearing them, especially during the initial period when the animal adjusts to the presence of the collar. Adverse effects, such as the fox's ability to capture prey or evade predators, could be subtle and difficult to detect (Kenward 1987). Foxes were fitted initially in 1980-1981 with radiocollars weighing 4 ounces; beginning in 1984, pups were fitted with radiocollars weighing 2 ounces (Berry et al 1987). Collars averaged

5.2% of fox body weight, ranging from 2.4% to 7.9%. For 86% of these foxes, the recommended maximum weight of 4% of body weight (Cochran 1980) was exceeded. To test the effect of radiocollars, the survivorship of 115 kit foxes marked with ear tags alone was compared to that of 198 that were also equipped with radiocollars. When the apparent effects of sex and age on survivorship were considered, no significant differences between the survival of ear-tagged and radiocollared individuals were detected (three-factor ANOVA, $\underline{P} > 0.18$ for main effect of tag type and statistical interactions). During the period 1986-1988, all adult foxes were converted from 4 ounce collars to 2 ounce collars.

Documented Cases of Kit Fox Mortality, Harassment, and Den Destruction

Exclusive of the SoCal third-party project discussed in Section 3.5.4, impacts to kit foxes known to have been caused by NPR-1 operations during the 11 year period 1980-1990 include 37 mortalities and 25 dens and potential dens destroyed. Of the 37 mortalities, 34 were the result of collisions with vehicles; 1 apparently drowned in an oil spill; 1 was inadvertently buried in a den during construction activities; and 1 apparently died when it became trapped in a pipe. Mortality by year was: 4 in 1980, 2-1981, 5-1982, 10-1983, 8-1984, 2-1985, 2-1986, 2-1987, 1-1988, 0-1989, and 1-1990. (The 1990 mortality was an offspring (bred in captivity) of a fox relocated to NPR-1 from another habitat that was to be developed--see the LRP (Appendix G) for a description of the kit fox relocation program. The NPR-1 program and the fox relocation program are permitted separately by FWS. Relocation foxes are not considered to be a part of the NPR-1 population.) Mortality known to have been caused as the result of NPR-1 operations during the 11-year period averaged about three foxes/year. During the 5-year period 1986-1990, the average was about one fox/year. Of the 25 dens and potential dens destroyed, 5 occurred inadvertently during construction activities. The other 20 were hand excavations during construction activities.

An additional 36 foxes were found dead (about 3/year) as the result of collisions with vehicles on state and county roads adjacent to NPR-1, but outside of NPR-1's jurisdiction. Some of these vehicles could have been associated with NPR-1 operations.

Except for the SoCal project (see Section 3.5.4.1), there have been no known impacts associated with NPR-1 third-party projects.

Blunt-Nosed Leopard Lizard

The blunt-nosed leopard lizard (*Gambelia silus*) was listed as endangered in 1967 because of continued habitat loss in the San Joaquin Valley and adjacent foothills (FWS 1985). The original range of the blunt-nosed leopard lizard incorporated the San Joaquin Valley south of Stanislaus County, the Kettleman and Carrizo Plains, and the Cuyama Valley (FWS 1985). The range of the blunt-nosed leopard lizard incorporated 7.5 million acres of the San Joaquin Valley in 1877. Agricultural development and urbanization have eliminated many populations as a result of habitat destruction; mining, oil and gas development, grazing, and off-road recreational vehicle use have degraded parts of the remaining habitat (FWS 1985). An estimated 50% of the original habitat was lost by 1960, and the completion of the California Aqueduct, with subsequent development of irrigated agriculture, further reduced the habitat to small isolated patches (FWS 1985). By 1979, priority habitat for the lizard had been reduced to 141,650 acres in the San Joaquin Valley (FWS 1985). Table 3.5-7 lists the remaining habitat found in 1980 and 1983 by wildland units. Wildland units comprise habitat essential for species conservation and do not include all remaining habitat. The total for 1983 represents a 19% reduction in wildland habitat from 1980 (from 128,530 acres to 104,480 acres). In addition, because these units are geographically isolated, populations of the blunt-nosed leopard lizard on each unit are reproductively isolated from other populations in the San Joaquin Valley (FWS 1985). While NPR-1 is not urbanized or developed for agriculture, suitable habitat for the blunt-nosed leopard lizard exists in only 28 of the 81 sections that fall within the boundaries of the site; these 28 sections contain alluvial soils or washes that penetrate the central hills (Kato et al 1987).

Life History of the Blunt-Nosed Leopard Lizard

The blunt-nosed leopard lizard feeds primarily on insects. In addition, smaller lizards comprise a minor (less than 10%) proportion of the diet of adults (Kato et al 1987b; Montanucci 1967). While the blunt-nosed leopard lizard is both an active and passive (sit and wait) forager that locates prey by sight, passive foraging dominates the time spent searching for prey (Pietruszka 1986). A passive feeding strategy is more efficient in habitat that consists of small open patches, while habitat with dense grass cover requires an active foraging pattern. This could explain, in part, the lizard's preference for more open habitats (Tollestrup 1979; Jones 1980; O'Farrell and Kato 1980). Chesemore (1980) suggested that 15-30% bare ground may have provided optimum habitat for the lizards.

Blunt-nosed leopard lizards will use rodent burrows to escape unfavorable environmental conditions (winter or excessive surface temperatures) or to escape predators (FWS 1985). Montanucci (1967) describes a related species , the short-nosed leopard lizard as laying eggs in a burrow within an enclosure. While Dorff (1981) noted that kangaroo rat and blunt-nosed leopard lizard abundance and frequency coincided, other studies found no correlation between rodent burrow density and lizard abundance (Chesemore 1980; O'Farrell and Kato 1980). Predators of the blunt-nosed leopard lizard include the loggerhead shrike (*Lanius ludovicianus*), American kestrel (*Falco sparverius*), burrowing owl (*Athene cunicularia*), roadrunner (*Geococcyx californianus*), San Joaquin whipsnake (*Pituophis melanoleucus*), coyote, and San Joaquin kit fox (Montanucci 1965).

Blunt-nosed leopard lizards hibernate from September through early April, and breeding occurs from May to mid-June (Montanucci 1967). The first eggs are deposited in early June to mid-July in underground chambers. Females typically lay one clutch per year, but two clutches per year have been observed (Montanucci 1967; Tollestrup 1982). The average clutch size is three, and the young emerge in August (Tollestrup 1979, 1982). Females become sexually mature in 9 months, while males do not usually breed until 21 months. Stressful environmental conditions, such as low winter rainfall or cool spring temperatures, could reduce reproductive activity and limit recruitment during those years (Mullen 1981).

TABLE 3.5-7 Amount of Undeveloped Wildland within Blunt-Nosed Leopard Lizard Priority Habitat Units - San Joaquin Valley Floor 1980 and 1983

Unit	Acres Remaining[a]	
	1980	1983
Lone Tree Road	5,200	3,360
Firebaugh	16,890	13,940
Whitesbridge	6,500	6,420
Horse Pasture	2,880	3,790
Pixley Refuge	4,740	4,680
Earlimart	1,300	2,080
Allensworth	14,060	9,200
Kern Refuge	50,020	34,750
Buttonwillow	10,200	9,720
Tupman	16,740	16,540
TOTALS	128,530	104,480

[a]Based on aerial surveys conducted in April of each year. Priority habitat units are those land parcels identified by the survey teams that appear to contain the best remaining habitat and should be considered first for protective actions.

Source: FWS 1985.

Males and females maintain separate home ranges, with males actively defending territories during the breeding season (Tollestrup 1979; Montanucci 1965). Overlap between male and female home ranges provides opportunities for successful mating (Kato et al 1987a). On NPR-1, Kato et al (1987a) calculated home-range size from radiocollared lizards using a minimum polygon method. They found that home ranges varied between 1.3 and 9.4 acres. The lizards were found to use primarily washes and alluvial areas on NPR-1. Radiocollared lizards, while not noticeably impaired in movement ability by the radiocollars, were found to have lost an average of 13% and 20% of initial body weight for males and females, respectively, during the breeding season. Breeding requires additional energy, and the weight of the radiocollars (7-9% of total body weight) could have resulted in the lizards expending more energy than they were consuming. Kato et al (1987a) state that these animals gained weight after the breeding season but no percentages are given.

The sizes of home ranges for the blunt-nosed leopard lizard are almost two orders of magnitude larger than home ranges for other insectivorous iguanid lizards and are closer in size to large carnivorous or herbivorous lizards (Kato et al 1987a). By comparison, the home range of the carnivorous, but nonterritorial, leopard lizard, *Gambelia wislizenii*, averages 0.3 acres (Tollestrup 1982). This could be explained in part by the observed weight loss which could have resulted in an expansion of home-range in order to increase available foraging area. However, optimal home-range size depends on a number of energetic, reproductive, and competitive factors (Jones and Krummel 1985). It is not clear, based on energetic factors alone, if this weight loss would affect home-range size. The combination of territorial behavior and large home-range size may contribute to low population density.

Calculated population densities of the blunt-nosed leopard lizard vary throughout the San Joaquin Valley as a function of habitat structure and food availability, as well as sampling intensity and method. For example, Mullen (1981) found that lizards were difficult to sight while walking transects, and Kato et al (1987a) stated that visual surveys could not often document the presence of radiocollared lizards aboveground. Thus, estimates of population numbers and density must include the sampling method to adequately evaluate the uncertainty of any estimate. Tollestrup (1979) estimated population densities of between 1.3 and 3/acre on the valley floor. Sheppard (1970) estimated population density at about 0.5/acre in optimal habitat and 0.2/acre in the remaining study area near Maricopa in southwestern Kern County. In suitable habitat on NPR-1, Kato et al (1987a), estimated (in a radiocollar study) minimum density at 0.24, 0.12, and 0.16/acre in three intensively sampled study areas. Based on a review of studies conducted in the San Joaquin Valley, FWS (1985) estimated that unmodified valley floor habitat supports blunt-nosed leopard lizard densities of approximately 1/acre, while adjacent unmodified foothills and washes support less than 0.5/acre.

Status of the Blunt-Nosed Leopard Lizard on NPR-1.

The number of sightings of blunt-nosed leopard lizards on NPR-1 during comprehensive site-wide biological surveys conducted in 1979, 1984 and 1989 were 18, 1, and 7, respectively (see Table 3.5-2). An additional 136 blunt-nosed leopard lizards were sighted in 28 of the 74 sections of NPR-1 from 1979 to 1987 (Kato et al 1987a). The lizards are found at densities of 0.16-0.24/acre in washes and areas of low relief located around the perimeter of NPR-1 and from six sections in the hilly portion of the site (Figure 3.5-10). Kato et al (1987a) found that 70% of the blunt-nosed leopard lizards sighted during 1979, 1980, and 1981 surveys occurred on flat portions of NPR-1. The variability in lizard density is a function of prey availability, sex ratio differences, habitat structure, and temperature regimes. Small mammal burrows are used to escape predators, lay eggs, and hibernate or escape the hottest and/or coldest parts of the day during April through September. The lizards establish territories that average 2.7 acres for females to 3.5-5.4 acres for males (Kato et al 1987a). The ratio of females to males is about 1:2.4; females may be a limiting resource to males, and this might explain the larger territory size of the male. Male territories are adjacent to those of females to facilitate mating, and the larger male territory allows access to more females (Kato et al 1987a). On NPR-1, the diet of the blunt-nosed leopard lizard is similar to that found at other sites, with insects comprising 95% of the biomass, and other lizards making up the remaining 5% (Kato et al 1987b).

Documented Cases of Blunt-Nosed Leopard Lizard Mortality and Harassment

Except for the SoCal project (see Section 3.5.4.1), only five known cases of mortality or harassment of blunt-nosed leopard lizards occurred during the period 1980-1990 as the result of NPR-1 activities: one died when its radiocollar snagged the branches of a shrub in 1982, two died in pools of oil in 1982, and two died in well cellars in 1987 (EG&G/EM unpublished data).

Giant Kangaroo Rat

Historically, the giant kangaroo rat (*Dipodomys ingens*) inhabited 1.3-2.5 million acres of south-central California (FWS 1987). Because of the widespread development of irrigated cropland, the range of the giant kangaroo rat was reduced to 77,000 acres by 1980. Range was further reduced to about 40,000 acres by 1985, and the giant kangaroo rat was listed as an endangered species in 1987 (FWS 1987).

Life History of the Giant Kangaroo Rat.

The preferred habitat of the giant kangaroo rat is flat terrain with annual grasslands and forbes occupying soils that are easily excavated for burrows (Grinnell 1932; Hawbecker 1951). Populations usually consist of colonies of individuals occupying acceptable habitat. Braun (1985) estimated 8 individuals/acre on a 10.2-acre study site in the Carrizo Plain, while Grinnell (1932) reported historical densities at about 20 individuals/acre. Individuals occupy discrete burrows and defend home ranges around these burrows. The home ranges vary in size from 0.005 to 0.12 acres (Braun 1985). Male and female home ranges overlap. Individuals harvest seeds, which are stored in burrows for fall and winter food supplies. Foraging activity occurs during 2-hour periods after dusk; this is the only time individuals spend aboveground.

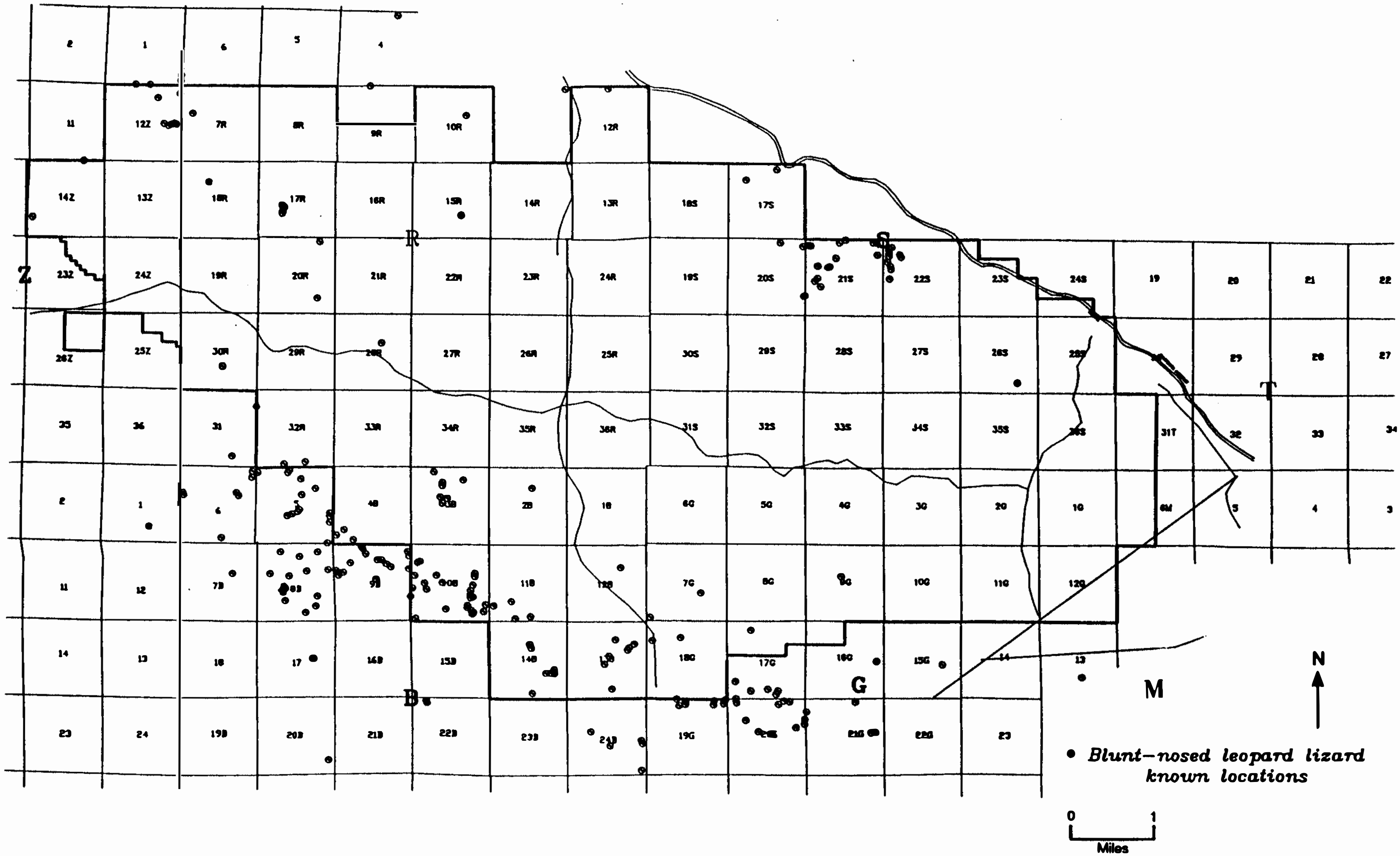


FIGURE 3.5-10 LOCATIONS ON NPR-1 WHERE BLUNT-NOSE LEOPARD LIZARDS WERE OBSERVED (SOURCE: BASED ON DATA FROM KATO ET AL 1987b)

Status of the Giant Kangaroo Rat on NPR-1.

During comprehensive site-wide surveys conducted on NPR-1 in 1984 and 1989, the number of burrow systems observed was 149 and 58, respectively. Giant kangaroo rat burrow systems have been found in 30 sections of NPR-1 (O'Farrell et al 1987b) (Figure 3.5-11). The majority of the burrows were found in Township B along the Buena Vista Valley, but burrows also were found in upland sections of NPR-1. Burrow systems were found at elevations ranging from 316 to 1,510 feet, with most occurring on slopes of less than 10% (O'Farrell et al 1987b). However, all burrow systems were surrounded by annual vegetation and located in well-drained, sandy loams that could be excavated easily. Section 8B in NPR-2, representative of relatively good habitat, contained numerous burrow systems at an average density of 28/acre in the sampled transects. Evidence of recent burrow activities (e.g., loose dirt, scats, footprints) was observed around 92% of all burrow systems. Dominant annual vegetation around the burrow systems included red brome, red-stemmed filaree, and Arabian grass; shrubs occurred within an average of 3.3 and 5.1 yards of burrows in valley and hilly locations, respectively (O'Farrell et al 1987b). As part of the Endangered Species Program, a study is currently underway to determine whether giant kangaroo rats discriminate against habitat characteristics that can be identified and used to characterize preferred habitat.

Human disturbances occurred within 50 yards of 61% of 71 intensively analyzed burrow systems, while 73% of the burrow systems had disturbances within 100 yards (O'Farrell et al 1987b). Disturbances included roads, pipelines, and well pads. Although burrows occur in areas of intensive oil development (see Figure 3.5-11), the highest density of burrows occurs in Township B, where there is little oil and gas development. This distribution pattern is related primarily to habitat quality; Township B is located in the Buena Vista Valley, which contains prime habitat for the giant kangaroo rat.

Documented Cases of Giant Kangaroo Rat Mortality, Harassment, and Burrow Destruction

Except for the SoCal third-party project discussed in Section 3.5.4.1, the only known cases of the types of impacts identified above during the period 1985-1990 are 66 burrow systems that were destroyed during fire break maintenance activities: 42 in 1987 and 24 in 1988. Immediately prior to the 1987 fire-break maintenance activity, four kangaroo rats were observed leaving their burrow systems, therefore, these four cases were documented as cases of harassment. The other 62 systems that were destroyed were assumed to have resulted in the death of one kangaroo rat for each system; this assumption was based on the results of trapping activities conducted the day before the burrow systems were destroyed. Fire break maintenance is not associated with third-party projects.

Research conducted on the giant kangaroo rat since 1980 under the Endangered Species Program often requires live trapping and releasing of animals to determine their distribution or abundance. Since 1980, when live trapping of giant kangaroo rats began, there has been 12 giant kangaroo rats deaths out of 1,489 captures (unpublished data EG&G/EM).

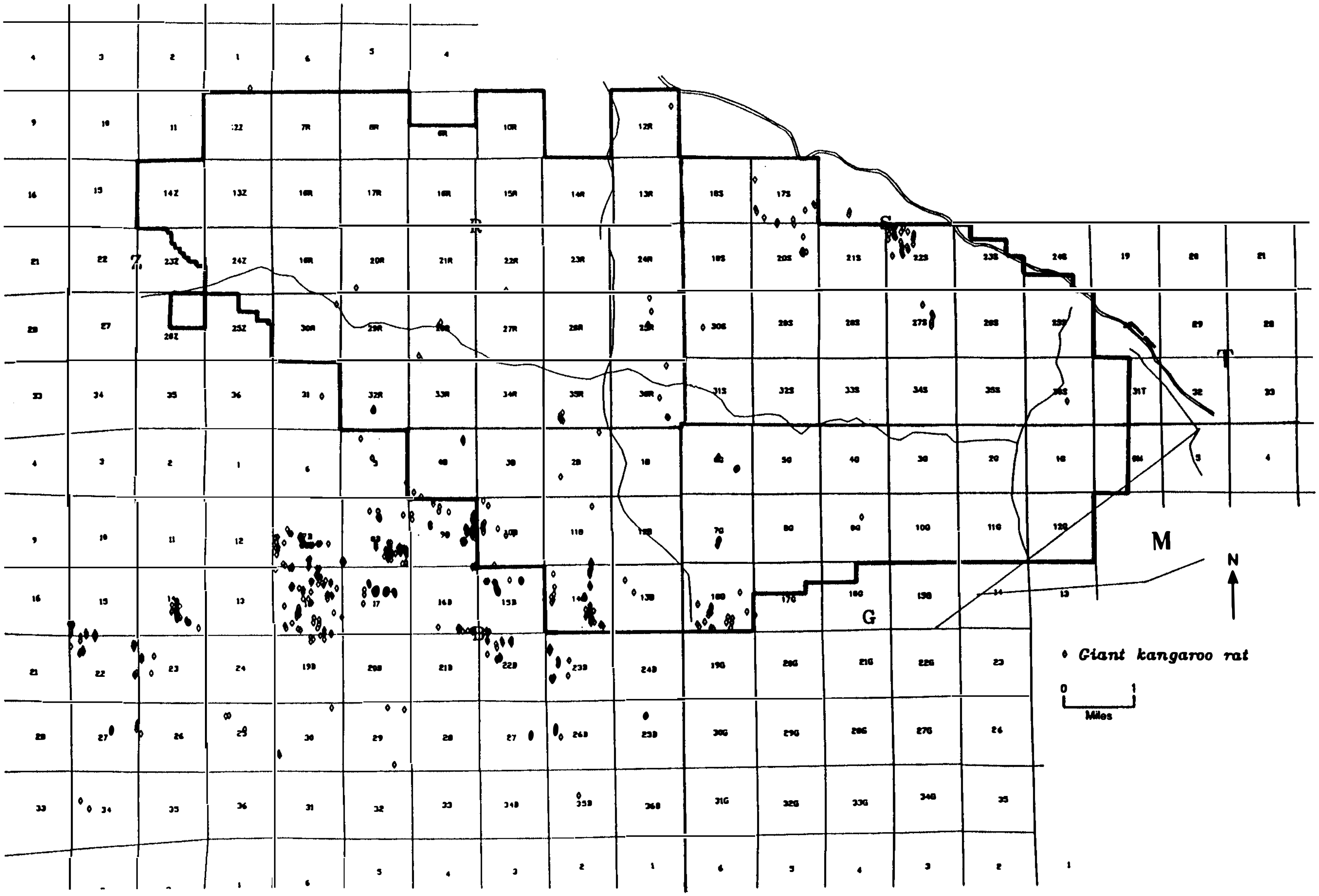


FIGURE 3.5-11 LOCATIONS OF GIANT KANGAROO RAT BURROW SYSTEMS
(SOURCE: BASED ON DATA FROM O'FARRELL ET AL 1987b)

Tipton Kangaroo Rat

The historical range of the Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*) has been estimated at 1,716,480 acres in south-central California (Williams 1985). By 1985, range had been reduced to 63,367 acres, of which only 6,137 acres existed on federal property that could be restricted from agricultural development or urbanization. Because of continued habitat destruction by agricultural development and urbanization, the Tipton kangaroo rat was listed as an endangered species on August 8, 1988 (FWS 1988).

Life History of the Tipton Kangaroo Rat.

Tipton kangaroo rats occupy alluvial fan and floodplain areas composed of fine-textured alkaline soils that can be easily excavated. The vegetation of these sites consists primarily of grasses, with only limited intrusion by shrubs. Burrow systems are constructed in elevated areas within these soils to avoid flooding that can occur during winter and spring. The density of burrow systems has been found to range from less than 1/acre to about 20/acre in favorable habitats not subjected to flooding (Williams 1985). Limited evidence suggests that Tipton kangaroo rats forage year-round for seeds and will consume green forage and insects when available. Because this subspecies sometimes occupies areas subjected to periodic flooding, seed storage may be limited (Williams 1985). Extrapolating from data available for the Fresno kangaroo rat, female Tipton kangaroo rats probably produce an average of two young/litter (Williams 1985).

Status of the Tipton Kangaroo Rat on NPR-1.

Tipton kangaroo rats have been found on approximately 63 acres of NPR-1 (Section 23S) that border the California Aqueduct. By definition of the range of this subspecies, this is the only location that Tipton kangaroo rats can occupy on NPR-1. On three consecutive nights in 1988, 25 Sherman live traps were placed in this location and 6 to 12 individuals were captured/night (EG&G/EM 1988b). No oil and gas development occurs on these 63 acres.

There have been no known impacts to Tipton Kangaroo rats as the result of NPR-1 operations, including third-party projects.

San Joaquin Antelope Squirrel

The San Joaquin antelope squirrel (*Ammospermophilus nelsoni*) originally inhabited approximately 3.4 million acres of grasslands in California (Steinhart, 1990); less than one hundred thousand acres of this currently remains, primarily in the southern San Joaquin Valley, Carrizo Plain, Elkhorn Plain, Cuyama and Panoche Valleys. The species has been listed by the State of California as threatened. In addition, it is currently a federal Category 2 species.

During a comprehensive biological survey of NPR-1 in 1984, 271 antelope squirrels were sighted in 70 of 82 sections (O'Farrell and Mathews 1987) (see Table 3.5-2). The greatest number of these (15) occurred in Section 19R. In a similar survey in 1989, 72 individuals were sighted.

Candidate Species and Species of Special Concern

Small-mammal surveys were conducted on NPR-1 from 1980 to 1984 (EG&G/EM 1988b). One federal Category 2 species, the short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*) was observed. The relative abundance of short-nosed kangaroo rats was determined by live-trapping along four established transects in various portions of the site. During 20,076 trap-nights, 518 individuals were captured, representing approximately 31% of all rodents captured during the survey. Most captures were along the transect located on the flat valley floor (EG&G/EM 1988b).

Surveys for four Category 2 blister beetles (Table 3.5-4) were conducted on NPR-1 from April to May of 1988 (EG&G/EM 1988b). Sixty sections were covered in an initial survey; 12 sites (located in Sections 7R, 10R, 18R, 28R, 18S, 19S, 20S, 25S, and 31T) were deemed to have the most suitable habitat for these species and were studied more intensively. Although no individuals of these species were found during the survey, it is possible that this may have been due to drought conditions.

The ferruginous hawk has been observed on NPR-1 in the past (O'Farrell and Scrivner 1987), but distribution and abundance have not been documented. This species only occurs in the San Joaquin Valley during the winter. Neither the greater mastiff bat nor the mountain plover have been documented on NPR-1, but based on habitat present and the range of these species, they could occur.

3.5.4 Ongoing Non-Federal-Connected Actions

As explained in Section 1.4, prior to and during the preparation of this SEIS, Santa Fe Energy Company and SoCal initiated projects that involve the construction, operation and maintenance of pipeline facilities on and off of NPR-1; these pipelines connect with NPR-1 sales facilities and distribute NPR-1 hydrocarbon product. Since the projects were part of continuing development and were expected to be constructed before this document is released, they were assessed separately outside of the scope of the proposed action; as such, the impacts of these projects are considered to be part of the existing environment. Construction of both pipelines is now complete.

As part of the assessments, separate informal and formal consultations with FWS were conducted for both projects which resulted in separate nonjeopardy Biological Opinions (Harlow 1988; White 1990). The Opinions contained requirements to mitigate impacts, and these requirements appear as conditions in the NPR-1 permits approving the requests to install the facilities. These conditions apply to both the on-site and off-site components of the projects. Compliance with permit conditions was assured through routine monitoring by qualified NPR-1 biologists. As a matter of standard practice, all construction disturbances were revegetated with native seed mixtures following project completion. Revegetation efforts will be monitored to assess effectiveness. Additional mitigation measures and project impacts are presented below.

3.5.4.1 Southern California Gas Company

Threatened and Endangered Plants

Populations of Hoover's woolly-star were known to exist within the rights-of-way of SoCal pipelines No. 73.90 and No. 85, both of which were to be replaced. Project preactivity surveys of pipeline No. 73.90 indicated that this species occurred in five locations occupying 8.1 acres of right-of-way (Sections 1OB and 11B) (EG&G/EM 1990a; Kato 1990b).

Preactivity surveys conducted along the right-of-way for pipeline No. 85 identified two populations of Hoover's woolly-star occupying approximately 9.9 acres (Sections 4B, 5B, 9B, 10B) (EG&G/EM 1988b and 1990a; Kato 1990b). Destruction of plants within these right-of-ways were unavoidable because this project required excavation of existing pipelines: i.e., unlike new pipelines, there was no flexibility where the disturbance was to take place. Based on consultations with FWS regarding the effects of this project (White 1990), it was determined that the following mitigative measures required implementation: (1) removal and stockpiling of topsoil along lines No. 85 and No. 73.90 in areas where Hoover's woolly-star was found to preserve dormant seeds of this species within the soil; (2) replacement of stockpiled topsoil following completion of construction to encourage recolonization of the rights-of-way by this species; (3) adjustment of the seed mix used for revegetation of the rights-of-way to exclude aggressive non-native grasses; and (4) scheduling of construction to avoid the flowering period of this species.

San Joaquin Kit Fox

The construction area of the SoCal project was approximately 180 acres, 97 of which were in the Buena Vista Valley. Surveys indicated the presence of 7 known kit fox dens and 20 potential dens (including 4 pipes that could be used as shelter) within the proposed construction corridor (EG&G/EM 1990a), all with the potential of being destroyed as the result of construction. Three of these dens were known to have been used in the past by radiocollared foxes, and three others showed signs of recent use (scat or prey remains); none were pupping dens. The number of foxes using these dens was not known, but it was speculated that it could have been from one to six. As a matter of standard practice, when den destruction was unavoidable, they were inspected for the presence of kit foxes immediately prior to destruction. If foxes were determined to be present, they were removed before destruction was allowed to proceed. In addition to affecting foxes that might be using the dens in the construction corridor, additional foxes inhabiting adjacent areas could have been affected by construction activities. The Biological Opinion specified an incidental take of no more than 2 kit foxes as the result of death or injury and no more than 10 cases of harassment (e.g., forcing or otherwise removing a kit fox from a den prior to excavation).

Potential impacts as the result of the SoCal project were determined to be: (1) a temporary reduction in carrying capacity, (2) direct mortality, (3) human disturbance, and (4) destruction of dens. Impacts due to reduced carrying capacity were expected to be temporary because reclamation of disturbances shortly after project completion was specified. Direct mortality was possible as a result of burying or collisions with vehicles. Vehicle-induced mortality was not expected to be significant because it was specified that construction activities be limited to daylight hours when kit foxes are not active (EG&G/EM 1990a). Trapping kit foxes in open trenches or burying them in dens was possible, but mitigation measures included in the specifications of the project were determined to preclude this from being significant. Construction was carried out intermittently over approximately a 1-year period of time. Construction activities have the greatest potential for adverse impacts from December to May when kit foxes breed and care for their young (Martinson 1980).

Den destruction was expected to be the most significant consequence of the project. Because this project involved removal of existing pipelines, no opportunity existed to alter the location of the project to avoid existing dens. Therefore, dens being used by foxes were destroyed and it cannot be assumed that any foxes forced to leave dens could find equally suitable dens elsewhere. Nevertheless, the dens that could have been destroyed represented a small percentage of the total number of dens present on NPR-1 (EG&G/EM 1990) which suggested that the likelihood of finding replacement dens was good and that impacts would be minimal.

During construction, there were no actual cases of known kit fox mortality or injury, 8 kit fox dens were excavated, and 14 potential kit fox dens were excavated.

Blunt-Nosed Leopard Lizard

As stated above, the SoCal project was expected to disturb approximately 97 acres in the Buena Vista Valley. The Buena Vista Valley portion of NPR-1 and adjacent lands contained 81% of the blunt-nosed leopard lizard sightings reported by Kato et al (1987a). Preactivity surveys conducted for the SoCal project found 17 washes and sighted 1 blunt-nosed leopard lizard within the construction zone and 2 blunt-nosed leopard lizards within an area immediately adjacent to the construction zone (EG&G/EM 1990a). Assuming 0.16-0.24 lizards/acre in modified valley floor habitat (Kato et al 1987), approximately 16-23 individuals could have been directly or indirectly affected. In issuing a nonjeopardy Biological Opinion, FWS (White 1990a) estimated that 27 lizards could inhabit the pipeline corridor, and specified that no more than 5 lizards could be killed or harmed, and that there could be no more than 10 instances of harassment.

It was determined that the SoCal project could impact the blunt-nosed leopard lizard as follows: (1) direct vehicle mortality, (2) loss of habitat during construction and the recovery period following reclamation, (3) inadvertent entrapment in collapsed burrows and dens, (4) inadvertent wildfires started as a result of welding operations, (5) harassment from the increased levels of human activity during construction, and (6) drowning as a result of the release of hydrostatic test water. Mitigation measures put in place to minimize impacts included: (1) reclamation of the construction corridor to preproject conditions and revegetation to stabilize soils and provide cover and forage, (2) covering open trenches greater than 2 feet deep at the end of each work day or providing escape ramps and checking all trenches for trapped lizards before work begins, (3) confining all construction activities to the 75-foot construction corridor, (4) cleaning all spills as they occur, (5) restricting vehicle speeds to 20 miles per hour, (6) conducting routine biological inspections during construction, and (7) surveying any spillway for animals before the release of the water used for hydrostatic testing.

During construction, there were no actual cases of known mortality or injury. Four blunt-nosed leopard lizards were entrapped in and had to be removed from the construction trench; these were recorded as harassment.

Giant Kangaroo Rat

The Buena Vista Valley, where the SoCal Project is situated, is optimal giant kangaroo rat habitat. A survey conducted in Section 8B of the Buena Vista Valley found an average of 28 burrow systems/acre (O'Farrell et al 1987b). The project preactivity survey identified 20 burrow systems within the 75-foot construction corridor and another 9 systems immediately adjacent. In issuing a nonjeopardy Biological Opinion, the FWS specified that no more than 20 burrow systems could be destroyed during construction and that there could be no more than 15 instances of giant kangaroo rat harassment (White 1990).

Potential impacts to the giant kangaroo rat as the result of the SoCal project, and mitigation measures to minimize impacts, were the same as those described above for the blunt-nosed leopard lizard.

During construction, there were no actual cases of known direct mortality, but 10 burrow systems were destroyed which were assumed to result in 10 cases of mortality (based on prior trapping results and field observations during construction activities). There were no cases of harassment.

Tipton Kangaroo Rat

Tipton's kangaroo rat is only found in Section 23S on NPR-1. Since construction did not occur in this Section, there were no impacts.

3.5.4.2 Santa Fe Energy Company

During construction, there were no known instances of destruction, of endangered or threatened plants, or death or injury to endangered or threatened animals.

Threatened and Endangered Plants

The Santa Fe pipeline (see Section 1.3) does not cross areas where threatened or endangered plant species or their habitat have been found; therefore, endangered plants were not affected.

San Joaquin Kit Fox

The Santa Fe project had little potential for direct effects on the current NPR-1 kit fox population because the right of way for this aboveground pipeline was not located within areas occupied by many foxes. Preactivity surveys identified four kit fox dens within the construction area (Harlow 1988), and the project was designed to avoid contact with these dens. Habitat disturbance associated with the project was estimated to be 12 acres, about 4 of which were located on NPR-1. Except for a narrow strip along the right of way occupied by the pipeline itself, all disturbances were revegetated following the completion of the project. FWS (Harlow 1988) anticipated that two kit foxes could be subject to incidental take (killed or injured) as the result of the project.

Blunt-Nosed Leopard Lizard

The pipeline right of way crosses four washes that contain potential habitat for the blunt-nosed leopard lizard. Although no lizards were observed during the preactivity survey conducted on September 23, 1988, this may have been because lizards were hibernating at that time (EG&G/EM 1988c). FWS (Harlow 1988) anticipated that one lizard would be subject to incidental take as a result of construction activities.

Giant Kangaroo Rat

The project preactivity survey identified 23 giant kangaroo burrows within the 75-foot construction zone (EG&G/EM 1988c). The project was designed to avoid direct impact to these burrows. The FWS (Harlow 1988) estimated that one incidental take of a giant kangaroo rat could occur during construction.

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3.6 CULTURAL RESOURCES

3.6.1 Regional Setting

3.6.1.1 History of Archaeological Research

The southern San Joaquin Valley, which constitutes an appropriate regional context for cultural resources in the Elk Hills area, has a long history of archaeological investigation (Chavez and URS Co. 1978; Moratto 1984). Studies began with P. M. Jones' examination of aboriginal mound sites in Kern County during 1899. This was followed by the discovery of Kern County site number 185 (Ker-185), a rockshelter burial site near Bakersfield in 1903 (Heizer 1951), and reports of the first finds (two burials) along Buena Vista Lake by N. C. Nelson in 1909 (Gifford and Schenck 1926).

The first large-scale project in the region (1923-1925) produced many new site discoveries and excavations; however, the focus of the resulting synthesis (Gifford and Schenck 1926) was confined to the late prehistoric period. Evidence of earlier settlement did not emerge until excavation of a group of shell midden and burial sites along Buena Vista Lake by the Civil Works Administration in 1933-1934 (Wedel 1941). Older prehistoric components were encountered at several of these sites (Ker-39 and Ker-60), along with hundreds of late prehistoric burials (Ker-40 and Ker-41). Another large late prehistoric/historic cemetery (Ker-64) on Buena Vista Lake was excavated in 1935 (Walker 1947), and much of the field research in subsequent decades has continued to reflect an emphasis on late prehistoric/ historic cemeteries [e.g., Tulare County site number 90 (Warren and McKusic 1959)] (Moratto 1984). However, renewed investigations of the Buena Vista Lake sites in 1963-1965 produced evidence of very early prehistoric occupation (Fredrickson and Grossman 1977).

3.6.1.2 Prehistory

The current synthesis of southern San Joaquin Valley prehistory draws heavily on the data recovered from the important stratified sites along the margins of former Buena Vista Lake. The oldest radiocarbon-dated occupation horizon [8,200-7,600 Before Present (B.P.)] occurs among this site group at Ker-116 (Fredrickson and Grossman 1977). The assemblage from this horizon (containing fragments of points, knives, and crescents) apparently reflects a widespread pattern of adaptation to large pluvial lakes in the far west during the terminal Pleistocene/early Holocene (Moratto 1984). The discovery of fluted points (dated elsewhere to >11,000 B.P.) along the shores of former Lake Tulare suggests even older sites further north, but these finds remain undated (Riddell and Olsen 1969).

Although more arid climates prevailed after 8,000 B. P., and many of the pluvial lakes dried up, poor drainage conditions helped create extensive marsh and wetland areas in the southern San Joaquin Valley. This habitat provided a rich subsistence base for local human populations during the Holocene. Occupation layers that are tentatively dated to the middle

Holocene (ca. 4,500 B.P.?) have been excavated at Ker-39 and Ker-60 along Buena Vista Lake (Wedel 1941). They contain impoverished assemblages of stemmed and leaf-shaped points, and milling stones associated with burials (extended position) and former hearths.

After 3,000 B.P., the prehistoric archaeological record reflects increasingly strong ties to the historic native American inhabitants of the region (Gifford and Schenck 1926). Assemblages from the upper levels of Ker-39 and Ker-60 contain Brown Ware pottery, coiled basketry, lanceolate points, charmstones, shell ornaments, and other diagnostic items (Gifford and Schenck 1926; Wedel 1941). Hundreds of flexed burials (with grave goods) have been excavated from the associated cemetery sites at Ker-40 and Ker-41. The final phase at Buena Vista Lake extends into historic times [e.g., Ker-64 (Walker 1947)].

3.6.1.3 Ethnography

The first Euro-Americans entering the southern San Joaquin Valley found the region occupied by the Penutian-speaking Yokuts tribes (Kroeber 1925; Latta 1977; Wallace 1978). The Yokuts people appear to have been present in the area for at least several millennia. Although sustained by a nonagricultural economy, they lived in permanent villages and at remarkably high levels of population density. Each village community is estimated to have contained 300-400 individuals (Kroeber 1925). Kroeber (1925) identified three major Yokuts groups in the Elk Hills area: Tulamni (southern Elk Hills and Buena Vista Lake area), Hometwoli (Kern Lake), and Tuhohi (northern Elk Hills). As in late prehistoric times, their economy was based on hunting, fishing, and collecting (Wallace 1978).

The U. S. Census of 1910 recorded 533 Yokuts, and Kroeber found only a handful of survivors during his study; the Tuhohi were completely extinct (Kroeber 1925). Diseases introduced by early Euro-American arrivals initially decimated the tribes. An epidemic in 1833 is believed to have killed at least 75% of the tribal populations (Wallace 1978). The influx of gold miners to the region after 1849 caused further disruption and decline. Nevertheless, 325 Yokuts were living on the Tule River Reservation in 1970 (Wallace 1978).

3.6.1.4 History

Spanish explorers and missionaries were the first recorded Europeans to enter the San Joaquin Valley (Gifford and Schenck 1926). As early as 1772, Pedro Fages, accompanied by a band of soldiers, visited a village along Buena Vista Lake. Several expeditions were sent north from Mexico into the valley in 1806, and attempts at missionizing (largely unsuccessful) followed in subsequent years. Most of the Euro-American intrusions during the early 19th Century were confined to punitive expeditions for the purpose of recovering livestock and capturing slaves. The first Anglo-American explorer to reach the valley was Jedediah Smith (1827), followed by several others in the final years before California became a part of the United States (Bailey 1957; Boyd 1972).

California was annexed as a territory in 1848, and became a state within two years. In 1854, several years after the arrival of the gold miners, Fort Tejon was established in the Tehachapi Mountains. Establishment of the fort encouraged further settlement of the region by merchants and cattlemen. The stagecoach began operating in the area in 1858 and the telegraph in 1860. Development of a petroleum industry began in 1864 at the McKittrick oil seeps. In 1912, NPR-1 was established in the Elk Hills (DOE 1986).

3.6.2 Elk Hills Resources

3.6.2.1 Cultural Resources Surveys

Various cultural resource surveys and evaluations have been conducted on NPR-1 since 1973 (Schiffman 1975; Chavez and URS Co. 1978; King and Craig 1978; DOE 1986; BPOI 1986; Hartzell 1988; Schiffman 1989, 1990; Jackson 1990; Sutton 1990; Yohe 1991; Peak 1991). The most comprehensive effort undertaken was the recently completed survey by Peak (1991) which encompassed 18,650 acres on NPR-1. In compliance with requirements of the National Historic Preservation Act, this survey was conducted in consultation with the State Historic Preservation Office (SHPO) to provide a representative sample of NPR-1's cultural resources.

In addition to the cultural resource surveys, an inventory and evaluation of paleontological resources (surface reconnaissance) was undertaken at NPR-1 (Repenning unpublished data).

3.6.2.2 Archaeological Sites

Peak's comprehensive 1991 survey determined that 40 prehistoric archaeological sites have been recorded on NPR-1. None of these sites are currently listed in the National Register of Historic Places (NRHP). However, Peak recommended the testing of 12 archaeological sites to determine their eligibility to the NRHP. The potential nomination of NPR-1 sites to the NRHP will be addressed in the course of developing a comprehensive cultural resource management plan in consultation with the SHPO. This is further discussed in Section 4.1.6.

3.6.2.3 Historic Sites

No historic sites are currently listed in the NRHP for NPR-1, although several sites (associated with the development of the local petroleum industry) located near NPR-1 are listed in the state files (BPOI 1986). Peak determined that 101 historic sites have been recorded on NPR-1. The management and evaluation of these 101 historic sites will be addressed in the course of developing the cultural resource management plan discussed in Section 4.1.6.

3.6.2.4 Paleontological Sites

Although important paleontological localities are situated near NPR-1 (most notably the McKittrick oil seeps), a broad surface reconnaissance conducted during 1980 found few fossil exposures on the site (Repenning unpublished data).

3.6.3 Ongoing Non-Federal-Connected Actions

The SoCal and Santa Fe projects were two third-party projects mentioned in Section 3.6.2.1 that were determined in consultation with the SHPO to have no effect on cultural resources.

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3.7 LAND USE

3.7.1 Kern County

Major land uses within Kern County include agriculture, petroleum production and related development, recreation/open space, and several areas of urban development. The land use pattern across the county is influenced by the variety of the terrain, which ranges from flat to hilly to mountainous, as well as by proximity and access to water. About 60% of Kern County's total land area is devoted to agriculture (DOE 1985), including sheep and cattle grazing and crop production (e.g., potatoes, alfalfa, grapes and cotton). Most of the residential, commercial, and industrial development is located within Bakersfield and its surrounding unincorporated metropolitan area, which had an estimated 1986 population of more than 270,000 people (see Section 3.8). Other, smaller communities are located throughout the county.

Major federal land holdings within the area include the Sequoia and Los Padres National Forests, Kern National Wildlife Refuge, Edwards Air Force Base, China Lake Naval Weapons Center, NPR-1 and NPR-2 (Figure 3.7-1). In addition, the Bureau of Land Management manages extensive federal land holdings, especially in the eastern portion of the county. The mountain, desert, and valley environments provide a variety of recreational opportunities. Recreational use is often associated with dispersed, open space activities such as camping, hiking, hunting, and biking. Visual resources in the region are varied and include such features as Red Rock Canyon, fields of colorful wildflowers, and pastoral foothills with little or no noticeable human development (Kern County Planning Commission 1974).

Major transportation corridors include Interstate 5, State Route 99, and a network of other state, county, and local roads. The California Aqueduct extends north and south through the western portion of Kern County.

3.7.2 Naval Petroleum Reserve No. 1

NPR-1 consists of 47,409 acres and has been used for petroleum extraction and processing since the early 1900's. Oil production, gathering, and processing (and related support activities) currently are the predominant land uses within the boundaries of the site. While sheep and cattle grazing were widespread on NPR-1 in the past, the practice was discontinued on Government lands in 1960 when 500 sheep died after drinking arsenic-contaminated water from a sump in section 6M (DOE 1989). It is anticipated that NPR-1 lands will continue to be used for petroleum extraction and processing for several decades.

Various state, county, and private roads are located on the site. State Route 119 extends through the southeastern section of NPR-1, and Elk Hills Road (county) and Skyline Road (private) extend through the center of the site in a north/south and east/west direction, respectively. In addition, many paved and unpaved access roads are located throughout the

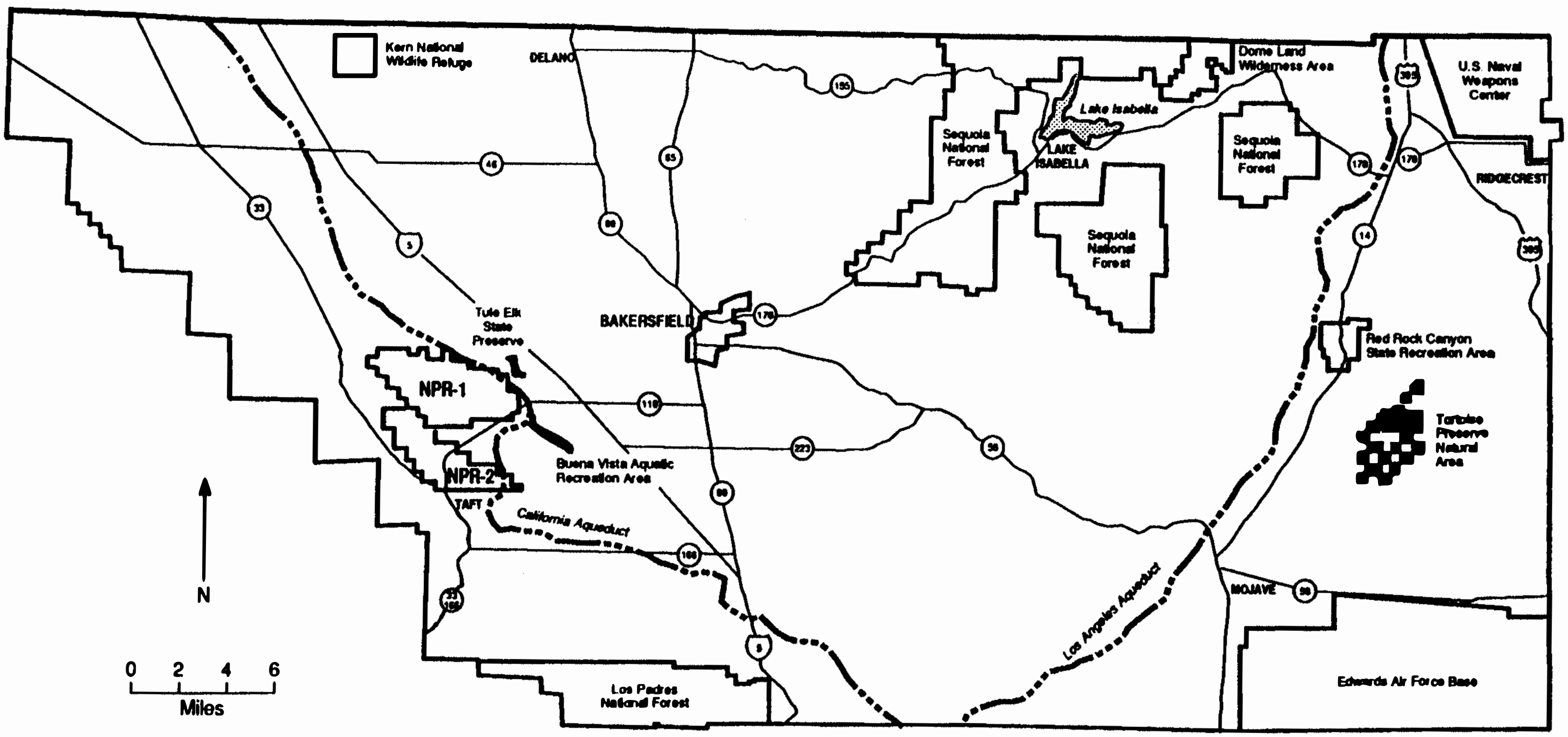

FIGURE 3.7-1 MAJOR LAND HOLDINGS, TRANSPORTATION ROUTES, AND COMMUNITIES WITHIN KERN COUNTY

site. Portions of the perimeter of NPR-1 are fenced and/or patrolled to restrict public access.

The great majority of NPR-1 consists of the Elk Hills. The Elk Hills consist of a long narrow ridge about 16 miles long and 6 miles wide, with up to 1,200 feet of topographic relief. The Elk Hills are sparsely covered with a saltbush/red brome steppe vegetation and are fragmented by numerous small canyons and gullies (DOE 1985). The Elk Hills are bordered by the flat valley floor, which is part of the southwestern edge of the San Joaquin Valley. Much of the periphery of NPR-1 lies within the flat valley floor. Drilling rigs, pumps, pipelines, storage tanks, processing facilities, utility lines, and communication towers, are prevalent throughout almost all of the Elk Hills portions of NPR-1.

No public recreation occurs within the boundaries of the NPR-1. The site and portions of the surrounding area are considered important habitat for wildlife, including several threatened and endangered species (see Section 3.5). A policy of habitat reclamation has been pursued on NPR-1 (and NPR-2) lands, including regrading and planting of native vegetation on disturbed areas.

The federal government owns about 78% (37,049 acres) of NPR-1, and with a few exceptions, the remainder (10,360 acres) is owned by Chevron U.S.A. (CUSA) (Figure 3.7.2). Exceptions include the surface rights to 120 acres of the site that have been granted to the community of Tupman. In addition, the surface rights to 75% of Section 22S are under multiple private ownership. Mineral rights in Section 31T are shared between Atlantic Richfield Company, the federal government, and CUSA. The State of California is currently contesting the ownership of two sections of land (Sections 16R and 36R) with the federal government by claiming entitlement under a 19th century school land grant (DOE 1987). Site activities are managed by DOE. Almost all production activities are carried out according to a Unit Plan Contract between the federal government and CUSA, under which the participants develop the oil field on a reservoir basis rather than a parcel basis. Disturbances on NPR-1 as the result of petroleum development activities, including third-party projects have been approximately 6,546 acres; 3,306 acres were the result of MER production that began in the mid-1970's. A total of 1,689 acres of these disturbances have been reclaimed (see Table 3.5-1).

3.7.3 Adjacent Land Uses

Land uses in the area surrounding NPR-1 follow the general patterns found throughout Kern County, which are dominated by agriculture and oil and gas extraction and production (Figure 3.7-3). Surface and mineral rights on lands surrounding the site are owned primarily by major oil companies. The Kern County Year 2000 Plan (Kern County Planning Commission 1988) acknowledges the economic importance of petroleum and agricultural resources and states that one of its goals is "... to contain new development within an area large enough to meet generous projections of foreseeable need, but in locations which will not impair the economic strength derived from the petroleum, agriculture, rangeland, or

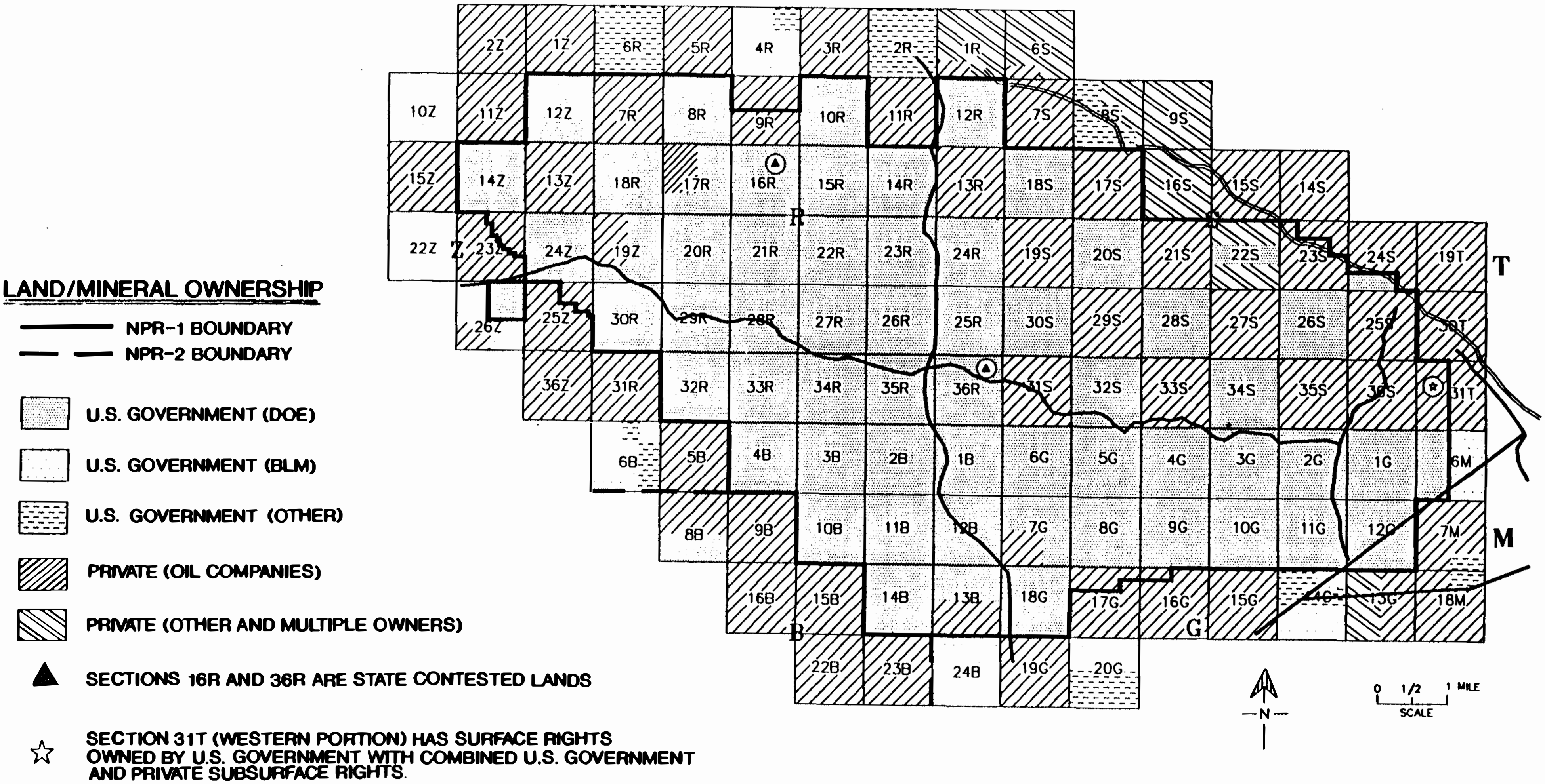

FIGURE 3.7-2 NPR-1 LAND AND MINERAL OWNERSHIP PATTERN (SOURCES: ADAPTED FROM WILLIAMS BROTHERS ENGINEERING 1985; BUREAU OF LAND MANAGEMENT 1978; AND DOE UNDATED)

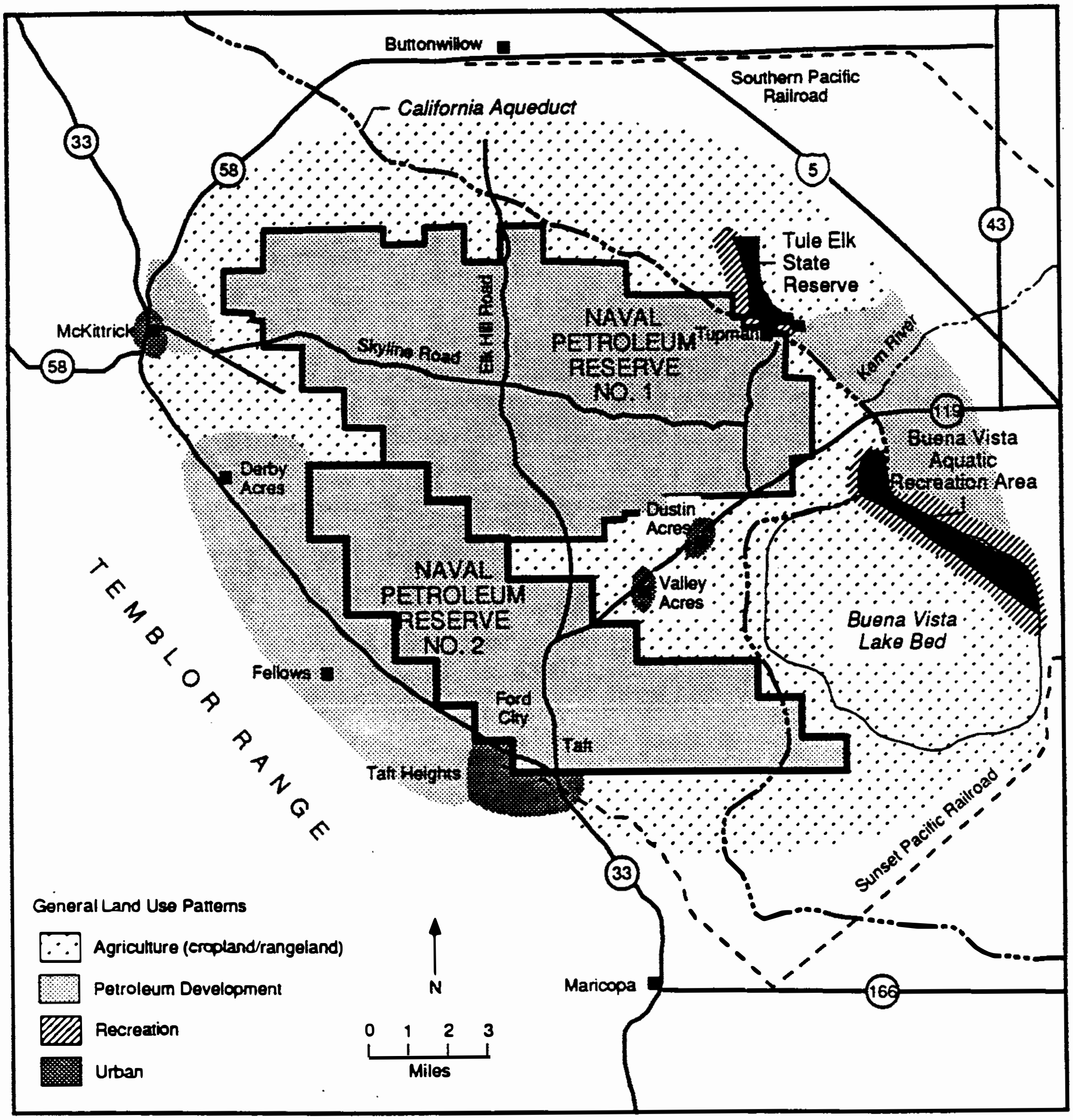

FIGURE 3.7-3 GENERAL LAND USE PATTERN SURROUNDING THE NPR-1 RESERVE (SOURCES: ADAPTED FROM DOE 1979; BUREAU OF LAND MANAGEMENT 1978)

mineral resources, or diminish the other amenities which exist in the County." This goal is to be implemented by enforcement of the 1986 Kern County Zoning Ordinance (Kern County Board of Supervisors 1986). Information about the major types of land uses surrounding the site is presented below.

3.7.3.1 Oil and Gas Production

Immediately south of NPR-1 is NPR-2. The federal government owns about one-third of the 30,000-acre NPR-2 site, and most of the rest is owned by major oil companies. NPR-2 land owned by the federal government is leased in 17 separate units, with the lessees responsible for all development and production operations. The surface characteristics and land use patterns on NPR-2 are essentially the same as those on NPR-1. Several large and extensively developed oil fields, each covering thousands of acres, are located east, south and west of the NPR-1 (e.g., Coles Levee, Midway Sunset, and Cymric oil fields, respectively), with additional petroleum development occurring on a smaller scale to the north (Bureau of Land Management 1978). Elements of the infrastructure associated with petroleum production (e.g., drilling rigs, access roads, storage tanks, pipelines, and power lines) are found throughout this area.

3.7.3.2 Agriculture and Open Space

Much of the area surrounding NPR-1 consists of agricultural land and open space, with oil extraction occurring as a compatible use. Intensive irrigated agriculture is practiced to the north and east of the site near the California Aqueduct. Numerous canals, ditches, drains, and wells serve the farms in this area. Sheep and cattle are grazed to the south and west of the site on lands that are not irrigated for crop production. The Bureau of Land Management's landholdings in the area (about 5,100 acres) are leased for grazing. In addition, numerous oil extraction facilities coexist with these agricultural activities.

Although various portions of open space have been impacted by grazing, some parcels remain in a relatively unspoiled condition and are being sought by the Nature Conservancy for habitat reclamation. These lands have been zoned by Kern County as resource areas (Kern County Planning Commission 1988), and future commercial or residential development would be discouraged. Also, the Williamson Act of 1965 provides tax relief for lands that are dedicated solely to agricultural or open space purposes. Long-term trends are for increasing amounts of land in the San Joaquin Valley portion of Kern County to be dedicated to irrigated agriculture (California Department of Water Resources 1986).

3.7.3.3 Water Banking

The Kern Water Bank Plan is part of the California State Water Project for recharging, extracting, and storing State Water Project water. The Kern Fan Element of the project consists of approximately 20,000 acres which is located near the eastern border of NPR-1. Only a small amount of this land will be used for long-term recharge. A substantial portion of the remaining acreage may be used for intermittent recharge of local flood flows and habitat conservation including the restoration of native habitat suitable for threatened and endangered wildlife species.

About two-thirds of the lands within the Kern Fan Element Project area are currently devoted to agriculture, and the remaining one-third is covered in native vegetation (with less than 1% located within urban-industrial areas). Oil extraction occurs and is expected to continue on about two-thirds of the native vegetation area. It is anticipated that use of the area for petroleum extraction would continue at about its present rate, while some irrigated cropland would be taken out of production (California Department of Water Resources 1986). The California Chapter of the Nature Conservancy has formed a consortium with the State of California and other organizations to reclaim a large part of the agricultural leases expiring within the next 5 years. Several other water districts in the vicinity of NPR-1 currently are developing plans to join the Kern Water Bank.

3.7.3.4 Parks and Recreation

The two major parks in the vicinity of NPR-1 are the 1,585-acre Kern County Buena Vista Aquatic Recreation Area and the 955-acre Tule Elk State Reserve. Buena Vista Park is an extremely popular local recreational area, featuring boating on two lakes, camping, picnicking, swimming, and fishing. Fishing also occurs along portions of the California Aqueduct and the Kern River. A 165-acre golf course and park complex is located west of the recreational area at the edge of Elk Hills. The Buena Vista Recreation Area received 336,000 visits during FY 1988 and is nearing carrying capacity. The Tule Elk State Reserve shelters a small herd of elk and is considered ecologically sensitive, with most of the area closed to public access. The reserve contains a small viewing and picnicking section that receives about 30,000 visits per year.

Several small parks are located in the communities of Taft, Buttonwillow, McKittrick, Derby Acres, Valley Acres, Ford City, and Fellows. Kern County's Scenic Highway Plan includes a scenic route consisting of Elk Hills Road extending north and south through the center of NPR-1, State Route 119, and various county roads that border the eastern half of the site (Kern County Planning Commission 1974). However, this scenic route is ranked low in the recommended order of implementation.

3.7.3.5 Local Community Development

Development surrounding NPR-1 includes the incorporated area of Taft and numerous unincorporated areas, such as the rural communities of Tupman, Buttonwillow, Derby Acres, McKittrick, Dustin Acres, and Valley Acres. The city of Taft and the surrounding developed areas of South Taft, Taft Heights, and Ford City have an estimated population of 14,500 and cover an area of about 2,000 acres. Taft is largely residential, with some commercial and light industrial development. A small airfield is located nearby. Except for the rural community of Buttonwillow (population 1,700), the remaining communities mentioned are surrounded by lands zoned for resource use (e.g., agriculture, mineral and petroleum development, open space) by the county. Some of these areas are considered to be hazardous (e.g., floodplain, landslide area, seismic area), and future development is likely to be limited.

3.7.4 Ongoing Non-Federal-Connected Actions

Major third-party actions at NPR-1 initiated prior to and during the preparation of this document include the construction, operation and maintenance of two new third-party pipelines: SoCal and Santa Fe (see Section 1.4). SoCal construction which has been essentially completed, disturbed about 180 acres of land, 75 acres of which were in 10 sections along the western and southwestern edges of NPR-1. All 180 acres were revegetated.

The Santa Fe project disturbed about 12 acres of saltbush/grassland habitat, 4 acres of which were on NPR-1 (EG&G/EM 1988). Except for a narrow strip along the construction corridor occupied by the pipeline itself, all disturbances are to be revegetated.

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*Copies of correspondence and unpublished documents cited in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California, 93276.

3.8 SOCIOECONOMICS

The following subsections contain a socioeconomic description of Kern County, the location of NPR-1. Included is information on population, income and employment, trade, housing, transportation, public services and utilities, and public finances. Special emphasis has been placed on the southwestern areas of the county near NPR-1. When possible, separate information has been included for Bakersfield and Taft, the communities most likely to be affected by operations at the site.

3.8.1 Population

The population of Kern County, currently just over 500,000, increased by 74% from 1960 to 1987. During the 1980's, population grew at an annual rate of 3.2%; growth is expected to continue, but at a slower rate, between 1987 and 2010 (Table 3.8-1). Compared with 1987, total population is expected to be 52% higher in 2010.

Table 3.8-2 lists the 1980 and 1988 populations of Kern County cities and unincorporated areas. In both years, more than half of the county's residents lived in unincorporated areas. Bakersfield had the highest concentration of population of any incorporated area, with almost 31% of the county's 1988 total. Ridgecrest is second with just over 5% of the population, and Taft accounts for only 1.2% of the county's population. The population distribution by city within the county remained about the same throughout the 1980's.

In 1980, the median age of Kern County residents was 28.2 years, with 55% of the population being between 20 and 64 years old. School-age children (5-19 years old) made up 26% of the population, preschool children (under 5) 9%, and the elderly (65 and older) 10% (Kern Council of Governments undated). About 70% of the county's population consisted of non-Hispanic whites, 22% Hispanics, 5% Blacks, and 3% others.

3.8.2 Income and Employment

Table 3.8-3 shows that real median household income in Kern County increased by less than 1% from 1970 to 1980 but increased more than 8% from 1980 to 1986. The 1986 median household income for Kern County was approximately 17% lower than the U.S. median of $24,897 (U.S. Bureau of the Census 1987).

In absolute terms, the number of Kern County residents below the poverty level decreased by 4% from 1970 to 1980 but increased 22% from 1980 to 1986 (Table 3.8-3). Most of the increase in absolute terms was due to a general increase in population. The portion of residents under the poverty level decreased from about 16% in 1970 to about 12% both in 1980 and 1986. The percentage of the Kern County residents below the poverty level in 1986 was lower than the overall U.S. percentage of 13.6% (U.S. Bureau of the Census 1987).

TABLE 3.8.1 Kern County Population Growth Trends

Year	Total Population	Population Density (persons/mi^2)	Average Annual Rate of Increase (%)
1960	291,984	36	
1970	330,234	40	1.2
1975	355,808	44	1.5
1980	403,089	49	2.5
1985	479,500	59	3.5
1987	504,200	62	3.2[a]
1990	539,600	66	2.4[b]
1995	602,100	74	2.2
2000	662,600	81	1.9
2005	715,400	88	1.5
2010	766,000	94	1.4

[a]1980 to 1987
[b]1985 to 1990

Source: Kern Council of Governments undated.

TABLE 3.8-2 Kern County Population by City, 1980 and 1988

City	1980	1988	Percent of 1988 County Total
Arvin	6,863	8,550	1.7
Bakersfield	105,611	157,400	30.8
California City	2,743	3,760	0.7
Delano	16,491	20,050	3.9
Maricopa	946	1,240	0.2
McFarland	5,151	6,350	1.2
Ridgecrest	15,929	26,850	5.3
Shafter	7,010	7,625	1.5
Taft	5,316	6,350	1.2
Tehachapi	4,126	5,175	1.0
Wasco	9,613	11,150	2.2
Unincorporated areas	223,290	257,000	50.3
County Total	403,089	511,325	

Source: California Employment Development Department (EDD) 1988.

TABLE 3.8-3 Trends in Kern County Household Income and Poverty Level (in constant 1986 dollars)

Category	1970	1980	1986
Income Level			
Median household income ($)	18,974	19,088	20,722
Mean household income ($)	23,681	23,137	-[a]
Per capita income ($)	6,721	8,156	-
Poverty Level			
Persons below poverty level	52,051	49,904	60,754
Percent below poverty level	15.8	12.4	12.3

[a]Data not available.

Source: Kern Council of Governments undated.

Employment trends in Kern County are shown in Table 3.8-4. The total labor force and the number of employed persons increased by about 48% from 1970 to 1980. Between 1980 and 1986, however, the labor force grew by 24%, while the number of employed persons increased only by 19%. The difference is reflected in the increase in the county's unemployment rate, which rose from 7.7% in 1980 to 11.8% in June 1986. Some of the increase in unemployment was due to structural changes in the economy of Kern County during this period (Table 3.8-5). From 1980 to September 1987, there was an overall increase of 17% in employment; however, some industries grew rapidly (such as construction, up 36%) while others decreased (such as wholesale trade, down 8.6%). Mining (which includes oil and gas production) and agriculture, two traditionally strong industries in Kern County, had employment growth rates of 12% and 3%, respectively. Construction, retail trade, finance, insurance, real estate, and service industries each experienced employment growth rates of more than 25% from 1980 to 1987.

With more than $1.2 billion in farm sales and about $4 billion in oil and gas wellhead revenues every year, Kern County is a major exporter of farm goods and petroleum to the rest of California and the rest of the United States. Many workers in Kern County support export industries. Table 3.8-6, which summarizes the findings of a location-quotient analysis conducted for this study, identifies industries with substantial export employment (more than 800 jobs) in Kern County. Individual industries with fewer than 800 export jobs each represent less than 0.5% of total employment in Kern County. The entire matrix of employment by Standard Industrial Classification (SIC) and the location quotients calculated from the analysis are presented in Appendix F.

Table 3.8-6 reveals that Kern County has a broad base of export industries, but it is unclear how much of export employment is based on petroleum and natural gas extraction. The level of wholesale and retail trade jobs is due to Kern County's (especially Bakersfield's) central location and may not have anything to do with oil and gas production. Trucking and warehousing export employment is probably due to agricultural production. Setting those categories aside, special trades (SIC category 17) may be the single largest category of export employment dependent on oil and gas extraction. However, export employment in this category is only about 1% of total employment in Kern County.

Table 3.8-7 summarizes findings of a shift-share analysis conducted for this document to examine the competitive position of Kern County's basic industries relative to the rest of the country. The technique examines changes in the structure of employment for the country as a whole, over time, and then compares those trends with changes in the local economy. Although shift-share analysis does not explain why changes are occurring, it is used as an indicator that changes are taking place in employment patterns and that jobs are being lost in specific sectors.

Between 1980 and 1984, Kern County lost jobs in 13 SIC categories and gained employment in 27 others. The only SIC categories losing more than 200 jobs were (1) manufacturing and (2) transportation and public utilities (SICs 20-49). However, Kern County's employment

TABLE 3.8-4 Employment Trends in Kern County

Category	1970 Average	1980 Average	1986 June
Total labor force	122,167	180,410	224,085
Number employed	109,539	162,190	192,400
Number unemployed	7,851	13,489	25,800
Percent unemployed	6.7	7.7	11.8

Source: Kern Council of Governments undated

TABLE 3.8-5 Kern County Employment Trends by Industry

Industry	1975	1980	1985	1987[a]	Percent Change 1980-87
Agriculture	23,640	31,600	26,500	32,522	2.9
Mining	8,310	11,900	16,400	13,274	11.5
Construction	4,010	7,300	9,000	9,940	36.2
Manufacturing	8,010	9,300	10,400	10,370	11.5
Transportation and public utilities	6,610	7,700	8,300	7,630	-0.9
Wholesale trade	6,310	7,900	7,600	7,222	-8.6
Retail trade	19,920	25,700	31,000	32,082	24.8
Finance, insurance, and real estate	3,710	4,800	5,800	6,318	31.6
Services	16,530	23,600	28,900	30,965	31.2
Government	30,050	33,000	36,000	39,380	19.3
Other industries			225		
All industries	127,100	162,800	180,125	189,703	16.5

[a]September 1987.

Sources: Kern Council of Governments undated; California EDD 1988.

TABLE 3.8-6 Selected Export Employment in Kern County Compared with U.S. Export Employment, 1984 Data

			Kern County Employment	
SIC	Description	U.S. Employment (%)	(%)	Export Jobs
17	Special trade	3.18	5.82	2,422
42	Truck and warehousing	1.64	2.56	844
50	Wholesale trade	3.8	5.01	942
54	Food stores	3.30	5.24	1,775
55	Auto	2.35	4.11	1,613
58	Eating and drinking	6.68	11.65	4,545
59	Miscellaneous retail	2.67	3.86	1,087
73	Business services	5.07	6.76	1,551

Sources: U.S. Bureau of the Census 1986; University of Florida 1977.

TABLE 3.8-7 Changes in Selected Categories of Employment in Kern County Compared with Changes in U.S. Employment, 1980-1984

			Kern County Employment	
SIC	Description	U.S. Employment (%)	(%)	Export Jobs
17	Special trade	2.5	19.5	868
32	Stone, glass	(13.8)	118.8	394
49	Electric, gas service	9.0	159.1	735
54	Food stores	12.3	30.6	1,125
58	Eating and drinking	12.5	28.0	2,331
73	Business services	28.2	46.8	1,979
86	Membership organizations	24.1	47.4	594

Sources: U.S. Bureau of the Census 1986; University of Florida 1977.

increased by more than 200 jobs in the categories of general contractors (SIC 15), special trades (SIC 17), stone, glass, and clay (SIC 32), trucking and warehousing (SIC 42), utility services (SIC 45), all SIC categories in wholesale trade (SIC 50 et al), food stores (SIC 54), miscellaneous retail trade (SIC 59), hotels and lodging (SIC 70), business services (SIC 73), health services (SIC 80), special services (SIC 83), and membership organizations (SIC 86).

Employment at NPR-1 totaled between 1,300 and 1,800 in 1987. The NPR-1 management and operating contractor, BPOI, employs about 700 persons. Chevron U.S.A. (CUSA), co-owner of the site with DOE, employs almost 30 persons, depending upon seasonal factors, special projects, and other factors. About 60 persons are employed by the DOE. Employment by other subcontractors at NPR-1 includes 12-15 persons employed each by EG&G Energy Measurements, Inc. (EG&G/EM) and Research Management Consultants, Inc. (RMCI). Because BPOI relies heavily on subcontractors for such major activities as construction and drilling, the number of subcontractor employees in the trades working on NPR-1 at any one time may range from 500 to 1,000 people. Each material subcontractor uses labor to best fit his own needs, and there are no records or systematic procedure to estimate person-years of effort employed for many field activities. Acknowledging the range for direct and indirect employment, NPR-1 may account for up to 10% of all Kern County employment in mining and oil and gas extraction.

3.8.3 Trade

Kern County is one of the top three agricultural producing counties in the United States. In 1985, the value of all farm production in the county exceeded $1.2 billion, consisting of about one-third fruit and nut crops, one-third field crops, and one-third miscellaneous crops, livestock, and poultry. Kern also is the leading petroleum producing county in California and the leading county for oil production in the entire United States. The four largest employers are government (38,000 workers), services (38,000), retail trade (32,000), and agriculture (26,000). Gravel mining and petroleum extraction account for only about 10,000 employees. The total value of minerals, oil, and natural gas production in the County exceeded $6.5 billion in 1985 (California Employment Development Department [EDD] 1988, p. 3; Kern County Board of Trade 1988, p.25).

Table 3.8-8 summarizes oil and gas statistics for NPR-1, Kern County, and California. Two of every three barrels of oil produced in California are from Kern County, and two of the largest fields in Kern County set new production records in 1987, despite falling oil prices. In 1987, the Kern County oil-production rate was about 675,000 barrels/day, more than twice that of the entire state of Oklahoma. This amount is equivalent to about 222 million barrels/year, which is down somewhat from the 256 million barrels/year in 1985 (California EDD 1988, p. 29). County oil production is expected to increase with a new cogeneration plant being built in the Kern River field. That plant will ultimately recover millions of barrels of heavy crude and produce significant amounts of electricity in the process (California EDD 1988, p. 16). Cogeneration facilities permit coproduct sales of electricity,

TABLE 3.8-8 Summary of Oil and Gas Production for NPR-1, Kern County, and California

Production Category/Product	NPR-1 FY 1987[a]	Kern County 1985[b]	California 1985[c]
Cumulative Production[d]			
Crude (10^6 bbl)	556.0	-[e]	20,800
Natural gas liquids (10^6 bbl)	45.7	-	1,199
Natural gas (10^9 ft^3)	1,026.0	-	30,919
Proven Reserves			
Crude (10^6 bbl)	361.0[f]	2,740	26,601
Natural gas liquids (10^6 bbl)	-	-	1,357
Natural gas (10^9 ft^3)	1,678.1[f]	-	26,543
Production			
Crude (10^6 bbl)	39.8	256	407
Natural gas liquids (10^6 bbl)	5.4	6	11
Natural gas (10^9 ft^3)	125.0	165	469

[a]DOE 1988.
[b]Data provided by Kern County Assessor's Office.
[c]Independent Petroleum Association of America 1987, pp. 24-25.
[d]For NPR-1, cumulative production values are for the period since 1976.
[e]"-" indicates data not available.
[f]After July 1, 1988 (Jerry R. Bergeson & Assoc. 1988).

Source: California Department of Conservation 1985, p.3.

which offset the costs of producing oil, thereby increasing the economic life and total production of the oil fields.

The availability of land for development in Kern County, which is relatively close to the Los Angeles area, suggests long-term potential for future growth. The state's Economic Development Department foresees future growth in the tourism industry, which could have significant impact on the area's retail sales, hotels, restaurants, services, recreation, travel, and entertainment businesses (California EDD 1988, p. 15).

3.8.4 Housing

Characteristics of the Kern County, Taft, and Bakersfield housing markets are summarized in Table 3.8-9. Bakersfield contains about 33% of all housing units in Kern County, Taft about 1.5%. Taft's portion of the county's total units ranges from about 1% to 2% for all categories -- single-family, multifamily, and mobile homes. Bakersfield has only about 10% of Kern County's mobile homes but almost 57% of all multifamily complexes greater than five units each. Vacancy rates are somewhat higher in Taft and lower in Bakersfield relative to the county as a whole. The absolute difference in vacancy rates between Taft and Bakersfield is about 3%. Vacancy rates for rental units were not reported separately.

According to the Kern Council of Governments (undated), the total number of housing units in the county increased 20% to 184,660 units between 1980 to 1986 and is expected to increase by almost 70,000 units, or about 40%, from 1986 to 2000. This is approximately the same rate of growth experienced in the Kern County housing market between 1970 and 1980. Trends in the composition of housing from 1970 to 1980 indicate a 10% relative decline in single-family homes, offset by a 6% relative increase in multiplex units and a 4% relative increase in mobile homes.

3.8.5 Transportation

Access to the NPR-1 site is principally from the Taft-Bakersfield Highway (State Highway 119) (Figure 3.7-1). Other points of access are from Tupman, via Tupman Road; McKittrick, via Skyline Road; and Elk Hills Road, which intersects Skyline near the center of NPR-1. Payroll records indicate that 85% of NPR-1 employees commute from Bakersfield, 14% from Taft, and the remaining 1% from a variety of other local areas, such as Oildale, Tupman, McKittrick, or unincorporated areas in Kern County. It appears that a larger portion of professionals employed at NPR-1 live in the Bakersfield area than Taft, but the reverse is true for clerical staff and field workers, including contractors and their employees.

3.8.6 Public Services and Utilities

Public services and utilities are affected directly by NPR-1 operations at the site, as well as indirectly by population growth induced throughout Kern County. In general, the most

TABLE 3.8-9 Kern County Housing Characteristics, January 1987

Location	Total Units	Single-Family	2-4 Units	5 or More Units	Mobil Homes	Occupied Units	Vacancy Rates (%)
Taft	2,648	1,865	153	474	156	2,373	10.4
Bakersfield	61,811	38,811	6,890	14,326	1,803	57,206	7.5
Kern County	188,679	125,831	17,997	25,184	19,667	172,138	8.8

Source: California Department of Finance 1987.

significant ongoing socioeconomic effects of NPR-1 operations are those associated with the population and economic activity created by the project, as opposed to those directly resulting from the operation of the facility. Because the population-related effects are dispersed throughout the county (primarily in the cities of Bakersfield and Taft and unincorporated areas of Kern County), the effects of NPR-1 operations on the public services and utilities are difficult to isolate and are not likely to tax existing capacities.

3.8.6.1 Police Services

Police services are provided in the unincorporated areas of Kern County by the county sheriff. In FY 1988-89, the Kern County Sheriff's Department had about 450 positions; about two-thirds of these positions are sworn officers. In addition, the Sheriff's Department also operates the county's detention facilities. These facilities require a staff of approximately 500 employees (Kern County 1988). In Taft, the city police department has 12 sworn officers and 10 reserve officers (City of Taft 1986).

3.8.6.2 Fire Protection

Quick-response fire protection services at the NPR-1 site are provided by on-site safety personnel during working hours. Additional fire protection services are provided by the Kern County Fire Department and the City of Taft Fire Department.

The Kern County Fire Department operates 44 year-round stations and has 666 authorized full-time positions. The Kern County stations at Buttonwillow, McKittrick, and Taft would provide initial response fire protection services for NPR-1. The Buttonwillow station employs a fire captain, one fire engineer, and one fire fighter. The McKittrick station employs a fire captain and one fire fighter. The Taft station would provide an initial response force consisting of three fire engines, two patrol vehicles, and up to nine, fire-fighting personnel.

Currently, the Taft Fire Department employs a fire chief, one fire marshall, three fire captains, two fire engineers and two fire fighters.

3.8.6.3 Schools

As indicated above, a majority of NPR-1 employees live in Bakersfield and their children attend school there, with the remainder spread throughout the westside area of the county. Education is provided in Kern County by 37 elementary school districts, 7 unified districts, 4 high school districts, and 2 community college districts. California State University, Bakersfield, is the region's 4-year university (Flaim 1989).

Table 3.8-10 shows that all of the Taft area schools have excess capacity and could accommodate additional student enrollment. Increases in enrollment could, however, require additional staffing and operating funds.

TABLE 3.8-10 Taft Area School Enrollments and Capacities, April 1988

School District	Enrollment	Capacity[a]
Taft Union High	850	> 1,000
Taft City Elementary	2,088	3,025
Maricopa Unified[b]	457	1,000
Midway	177	225
McKittrick	40	80
Elk Hills	102	200
Belridge	67	120
Buttonwillow Union[c]	376	465
Lost Hills Union	335	380

[a]Capacity without switching to year-round schools, double-sessions, or larger classes.
[b]Includes elementary and high school students.
[c]High School students attend Shafter High School.

Source: Data provided by City of Taft

Elementary schools in Bakersfield have been experiencing steady growth. In 1987-88, about 21,000 students attended in the Bakersfield elementary school system (Flaim 1988).

Although children of NPR-1 employees are concentrated somewhat in the Panama Elementary School District in southwestern Bakersfield, the general distribution of students throughout the city schools means that the effects of NPR-related population growth are small relative to the capacities of the school systems.

3.8.7 Public Finances

Table 3.8-11, which summarizes Kern County's sources of financing for FY 1988, shows that about 45% ($200 million) of the county's revenue comes from intergovernmental sources, principally the state of California and the federal government. Property taxes ($132.1 million) account for about 30% of the county revenues. Total taxes and fees collected within the county (including licenses, permits, fines, forfeitures, penalties, charges for services, and miscellaneous revenues) total $234 million. The table lists only those property taxes collected within Kern County that are allocable to the county budget. Table 3.8-12 lists the distribution of all $343 million in property taxes collected in the county. The county and the school districts share about equally, 36% and 37%, respectively. Special districts governed by local boards account for 15% of the total, and the cities account for about 9%. The assessed value of CUSA's portion (about 22%) of NPR-1 totaled about $1.5 billion in 1987.

Table 3.8-13 shows how Kern County's budget was spent during the 1987-88 budget year. Public protection (the courts, police, and similar services) accounted for about $138 million (31%); public assistance for $151 million (34%); general government for $64 million (14%); health and sanitation for $34 million (8%); and public ways and facilities for $27 million (6%). The categories of education, recreation and cultural services, and reserves each accounted for 3% or less of the total.

TABLE 3.8-11 Summary of Kern County Financing for Budget Year 1987-88

Source of Funds	Amount ($ million)	Percent of Total
Fund balance from prior year	6.5	2
Current property tax allocation	132.1	30
Taxes other than property taxes	26.8	5
Licenses and permits	5.5	1
Fines, forfeitures, and penalties	6.5	2
Revenues from use of money and property	5.6	1
Intergovernmental revenues	200.1	45
Charges for services	51.7	12
Miscellaneous	5.8	1
Other financing	1.8	1
Total	443[a]	100

[a]Total is rounded.

Source: Jackson 1988.

TABLE 3.8-12 Summary of Kern County Property Tax Billing for Budget Year 1987-88

Allocation	Amount ($ million)	Percent of Total
County Budget	121.8	36
Special Districts-Local Boards	51.6	15
Special Districts-Board of Supervisors	2.6	1
School Districts	127.9	37
Special Education Programs	6.9	2
Cities	32.2	9
Total	343	100

Source: Jackson 1988.

TABLE 3.8-13 Summary of Kern County Budget Allocations for Budget Year 1987-88

Application	Amount ($ million)	Percent of Total
General Government	64.0	14
Public Protection	138.0	31
Public Ways and Facilities	27.4	6
Health and Sanitation	34.3	8
Public Assistance	150.7	34
Education	8.4	2
Recreation and Cultural Services	8.7	2
Reserves	11.2	3
Total	443[a]	100

[a]Total is rounded.

Source: Jackson 1988.

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3.9 RISK ASSESSMENT

This section compares/discusses risks at typical petroleum-production facilities with those at NPR-1.

Two major types of risks are inherent in petroleum-production facilities: (1) fire and explosion (which threaten primarily personnel and property and, secondarily, the environment); and (2) spills (which threaten primarily the environment). Because the hazards of dealing with large quantities of oil, gas, and natural gas liquids are well recognized at petroleum-production facilities, standards and precautions to prevent spills and accidents are highly developed, as are the capabilities of coping with such events should they occur. Despite precautions, a degree of risk remains, which is discussed as follows:

3.9.1 Historical Risks - National and NPR-1

One of the notable risks associated with oil-field operations is that of oil spills. Spills and leaks are inevitable in the transfer, processing, and storage of large quantities of crude oil. Historically, about 3% of nationally reported oil-field spills have involved less than 100 gallons (2.4 barrels); 82% have involved 100-10,000 gallons (2.4-240 barrels); and 15% have involved more than 10,000 gallons (240 barrels) (Ritchie et al. 1973). The major cause (about 80% of the cases) of reported spills was pipe failure, which in turn was caused primarily by external corrosion (46% of the cases). Other factors causing spills included ruptures, external corrosion, and failures of valves and pumps.

As required by law in recognition of the potential for spills, NPR-1 instituted a spill prevention, control and countermeasure plan (SPCC) in 1989 which, among other things, led to the installation/enhancement of prevention and containment facilities throughout the site. The SPCC has recently been updated as required by Part 112 of 40 CPR (BPOI 1992). At NPR-1, most piping is above the ground, and the majority of releases resulted from internal corrosion.

Records of the number and volume of spills at NPR-1 have been maintained since July 1976. Table 3.9-1 summarizes reported spills from 1979 through 1988. The number of spills involving less than 100 barrels has fluctuated from 17 to 33/month, averaging about 22 spills/month. Although the total quantity spilled/volume produced appears to be fairly constant with time (except for 1982), the number of incidents has increased steadily since 1983. This increase may be attributed, in part, to increasing corrosion associated with aging equipment and more stringent reporting requirements.

Spills of greater than 100 barrels have occurred on NPR-1 at an average rate of 6.5 spills/year. The average size of the spill has decreased appreciably since 1983. With few exceptions, the oil spilled has been contained, and recovery has approached 65% overall. Spilled oil is recovered by use of vacuum trucks and then placed into the 27R oil recovery sump. Spilled oil that cannot be recovered is contained within secondary

TABLE 3.9-1 NPR-1 Oil Spill History

Category[a]	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	Totals
Minor Spills											
Total incidents	-[b]	298	209	213	201	218	253	284	390	523	-
Barrels spilled	2,452	2,557	1,995	1,616	1,619	1,348	1,395	1,379	2,421	2,584	16,782
Barrels recovered	633	895	1,034	598	620	627	627	645	1,237	923	9,500
Major Spills											
Total incidents	0	2	4	7	6	9	7	7	5	9	
Barrels spilled	0	500	632	14,807	1,817	2,091	1,303	3,004	907	2,152	27,213
Barrels recovered	0	430	579	11,304	1,519	1,595	985	2,791	840	1,710	21,753
Total											
Barrels spilled	2,452	3,057	2,627	16,423	3,436	3,439	2,698	4,383	3,328	4,736	46,579
Barrels recovered	633	1,325	1,613	11,902	2,139	2,222	1,612	3,436	2,077	2,633	29,592
Barrels not recovered	1,819	1,732	1,014	4,521	1,297	1,217	1,086	947	1,251	2,103	16,987

[a]Minor spills are those involving less than 100 barrels; major spills are those involving 100 barrels or more.
[b]Data not available.

containment facilities or contained within NPR-1 site boundaries by use of berms and diversions. To mitigate oil spills, NPR-1 has ongoing corrosion control and pipeline monitoring/inspection/replacement programs. See Section 1.2.2.22 and Table 1.2-10 (Projects P40301A, P40302, P40301B, P48767A, P49314, P48724, and P49703) for corrosion control and pipeline replacement projects included in the proposed action.

Only limited data exist on the occurrence of accidents involving fire or explosion in oil-field facilities; however, some information is available on well blowouts. Based on data taken from the 1979 EIS (DOE 1979), the calculated blowout rate for new wells is 0.8 blowouts/1,000 wells drilled and the estimated blowout rate for remedial actions on wells is 0.3 blowouts/1,000 actions. Since the mid-1970's, NPR-1 has actually experienced six blow-outs, or similar conditions: one in connection with drilling approximately 1,100 wells; three performing perhaps 15,000 (guesstimate) remedial and workover actions; and two related to day-to-day well operations (non-drilling and non-remedial/workover). This translates into actual experience factors of 0.9 blowouts/1,000 wells drilled and 0.2 blowouts/1,000 remedial/workover actions. The blowout conditions experienced in connection with day-to-day well operations cannot be statistically correlated with industry experience. However, it is anticipated that current and future risks would be relatively insignificant compared to past risks because reservoir pressures have fallen significantly (and will continue to fall).

3.9.2 Identification of Potential Risks Associated with Operations at NPR-1

Risk has two major components--frequency and magnitude. Table 1-5 in the 1979 Final NPR-1 EIS (DOE 1979) provides a rating of the risks associated with various systems and components of the operations at NPR-1. These risks have been rated according to frequency of occurrence and magnitude of the consequences. Unacceptable risks are generally identified as those that either occur too frequently, even though the consequences are fairly minor, or those for which the magnitude of consequences is so great that occurrence can be tolerated only in terms of millennia. The primary risks of concern are discussed below.

Because major spills can create serious environmental impacts, large tanks (usually 10,000 barrels or larger) at NPR-1 are individually diked to limit the extent that oil could spread in case of a spill and to facilitate cleanup and recovery. Many smaller tanks are afforded the same protection. Containment provisions are based on Division of Oil and Gas regulations and requirements set forth in the Porter-Cologne Water Quality Act and 40 CFR, Part 112. Some smaller tanks (usually less than 1,000 barrels) are currently protected by contingency catch basins located in drainage channels downhill of tank settings. Studies have been completed and others are underway or planned to determine the feasibility of enhancing secondary containment at these tank settings. As the result of the completed studies, a project is in progress to enhance secondary containment at approximately 25 tank settings. Contingency catch basins also are located strategically throughout NPR-1 to contain oil spills from sources other than tank settings, including drilling operations, broken pipes, and leaking valves. All diked areas at NPR-1 meet the 100-year rainfall capacity requirements. Where capacity is limited, two or more catch basins may be placed in a drainage channel in series.

With the exception of road crossings, the great majority of pipelines at NPR-1 run above the ground and are supported by structural members where necessary. Pipelines typically transport various liquid and gaseous hydrocarbons and water at pressures ranging from vacuum up to 3,500 pounds psig. At road crossings, pipelines are installed underground and are protected against corrosion and damage from vehicles or other heavy equipment. Pipelines are labeled at strategic locations to assist in responding to accidents and emergencies, such as ruptures that can cause pipelines to whip around causing additional damage and/or the release of flammable hydrocarbons. Plans are to study the feasibility of enhancing the existing pipeline labeling system so that risks are more immediately obvious following accidents and during emergencies.

Operation of compressor stations is one of the more hazardous operations at NPR-1. Closed spaces at these stations are potential locations where leaking gas can accumulate to form explosive mixtures. Four explosions have occurred at enclosed compressor stations at NPR-1 since MER production began in the mid-1970's, the last of which was in 1985. No injuries resulted from these explosions. Portions of LTS-1, LTS-2, HPI, 35R and 33S are enclosed, while 36R, 33R, 30R, 17R, and 7R are all open. The enclosed stations and some open stations have fire and gas detection equipment installed. Most open compressor stations are not provided with detection equipment.

About 630,000 gallons/day of natural gas liquid products (NGL) were produced at NPR-1 gas plants in 1987 -- 38% propane, 31% butane, and 31% natural gasoline. This amounts to about 5.5 million barrels/year, which is about half of the total NGL production in California. These NPR-1 products are moved to market in MC-330 and MC-331 tank trucks on public highways. Given that NGL's are highly flammable, this represents a potentially significant risk to the public. Hence, an analysis was undertaken to determine the number of vehicle accidents that might occur "off-site" while transporting NPR-1 NGL's.

On the basis of the analysis, it was estimated that 13 vehicle accidents/year could be expected based on an estimated 37,230 one-way tank truck shipments (0.00035 accidents/one-way trip). This estimate assumed 150 one-way trips/day during the summer and 50-58/day during the winter. In addition, the estimate was based in part, on an analysis reported in Appendix C of the 1979 EIS (DOE 1979) of 40 accidents involving tank trucks hauling products similar to NGL's (1.8-6.3 accidents/million miles for trucks depending on highway type). Although there are no known cases of spills associated with tank trucks transporting NPR-1 NGL's, based on a severe accident frequency of 9% (Jones et al. 1973), one of the 13 accidents could be severe (i.e. fuel-air detonation).

Despite the heavy traffic, the "on-site" safety record at NPR-1 facilities where NGL products are stored and transported is excellent; accidents have been few and very minor.

Wet gas, as taken from the wellhead, always contains trace amounts of radioactive gas, primarily radon. During gas processing, radon can become concentrated in the gas plant in the ethane and propane fractions. Studies have shown that radon can produce slight, but possibly significant, short-term hazards to workers and consumers (DOE 1979, Appendix C). The radon level in California wet gas is well within the normal limits reported from other gas-producing areas in the nation. However, liquid petroleum gas (LPG) produced and sold in California has the highest radon content of any state, possibly due to the rapid movement of the produced LPG to market (radon-222 has a half-life of 3.8 days). In recognition of the risks, naturally occurring radioactive material (NORM) surveys, including radon, have been performed at NPR-1 to establish baseline conditions and to identify areas of concern. The results of the survey are being evaluated for appropriate action. It is anticipated that within the next 1-2 years, among other protective measures, a monitoring program will be established, signs will be posted, and storage times will be monitored/controlled.

Recordable occupational injury rates at NPR-1 (DOE, contractors and subcontractors) for the period 1982-1990 are provided by Table 3.9-2. Injuries per 200,000 man-hours worked during this period ranged from 2.48 in 1986 to 8.50 in 1982. During this same period the average injury rate experienced by the oil and gas extraction industry according to the Bureau of Labor Statistics (BLS) ranged from 7.50 in 1989 to 12.0 in 1982. The NPR-1 injury rate was below that reported by BLS in each year during the indicated period. The most hazardous activities at NPR-1 are those associated with drilling operations.

There have been a total of five fatalities at NPR-1 since 1979, the last of which occurred in July 1988. Fatality incidents are reported to Cal-OSHA, County of Kern and DOE Emergency Operations Center.

NPR-1 reported an average of 525 vehicles in use and 3,748,000 miles of travel/year during the period 1983-1987. That level of vehicle use resulted in a total of 41 reported vehicle accidents and $52,000 in vehicle losses. Thus, the vehicle accident rate for the period was 2.2 accidents/million vehicle miles, which is 35% lower than the DOE average of 3.4 accidents/million vehicle miles.

During 1982, NPR-1 reported 37 vehicle accidents, which resulted in a vehicle accident rate of 6.0 accidents/million vehicle miles. During 1988, 18 reportable accidents were recorded for nearly 4 million vehicle miles driven. This resulted in a frequency rate of 4.5 reportable accidents/million vehicle miles. This was about 32% higher than the DOE-wide average of 3.4 accidents/million vehicle miles. About 62% of the NPR-1 accidents involved pickups. Automobiles were listed in 17% of the accidents and 8% of the losses, while heavier trucks accounted for 15% of the accidents and 22% of the vehicle losses.

TABLE 3.9-2 NPR-1 Recordable Occupational Injury Rates[a] Compared with Bureau of Labor Statistics (BLS) for Oil and Gas Extraction Industry

Year	NPR-1					BLS
	Drilling	Production	Gas Processing	Other[b]	Overall	
1982	12.86	6.66	5.70	5.61	8.50	12.0
1983	16.65	5.37	4.47	1.27	5.19	9.6
1984	6.40	4.38	7.58	.96	3.87	11.7
1985	4.50	2.23	3.09	1.79	2.55	10.0
1986	6.19	3.61	3.48	.80	2.48	8.0
1987	6.82	8.07	4.52	2.24	4.55	8.2
1988	10.35	6.75	7.12	.99	4.75	8.1
1989	5.39	4.38	7.59	1.03	3.42	7.5
1990	3.22	3.90	6.15	1.27	3.01	N/A[c]

[a]Recordable accidents/200,000 man hours worked.
[b]Engineering, Administrative, etc.
[c]Data not available.

3.9.3 References*

Bechtel Petroleum Operations, Inc., 1992, Spill Prevention Control and Countermeasure Plan (SPCC), Naval Petroleum Reserve No. 1, Elk Hills, Tupman, California, December.

DOE -- See U.S. Department of Energy.

Jones, G. P., et al., 1973, Risk Analysis and Hazardous Materials Transportation, Vol. 1, Institute of Aerospace Safety and Management, University of Southern California, Los Angeles, March.

Ritchie, J. E., Jr., et al., 1973, Petroleum Systems Reliability Analysis: A Program for Prevention of Oil Spill Using an Engineering Approach to a Study of Offshore and Onshore Crude Oil Petroleum Systems, U.S. Environmental Protection Agency Report EPA-R2-73-280B, Washington, DC, August.

U.S. Department of Energy, 1979, Final Environmental Impact Statement, Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California, U.S. Department of Energy Report DOE/EIS-0012, Washington, DC, August.

*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California 93276.

4.0 ENVIRONMENTAL IMPACTS OF PROPOSED ACTION AND ALTERNATIVES

4.1 PROPOSED ACTION

The impacts of the proposed action are those that are associated with the continuation of existing operations (see Section 3.0) plus those that are associated with new development included in the proposed action as described below.

4.1.1 Geology and Soils

4.1.1.1 Construction Impacts

The disturbance and development of approximately 1,569 acres on and off of NPR-1 over the next 30 years (see Table 1.3-2) associated with construction projects would increase the potential for soil erosion. However, any increase should be relatively short-lived and should not result in significant adverse impacts, if appropriate erosion-control and site-rehabilitation measures are implemented. Measures planned include those applied in the past (see Section 1.2.2.12 and 1.3) using Amimoto (1977) and the Soil Conservation Service (1985) as guidelines (see Section 1.2.2.19 for more information). In addition, as part of the proposed action, approximately 1,045 acres of development on and off of NPR-1 would be subject to erosion control measures pursuant to revegetation activities (see Table 1.3-2).

4.1.1.2 Operational Impacts

Potential geologic impacts from the operational phase of the proposed action include surface subsidence and induced seismicity.

Surface subsidence could be caused by withdrawal of oil and gas from the producing zones and by pumping water from the Tulare Formation for enhanced petroleum-recovery operations. However, based on an evaluation of geologic characteristics (see Section 3.1.2.4), plans to reduce Tulare withdrawals for waterflooding by recycling produced water and plans to continue the ongoing and proposed water and gas injection programs (see Section 1.2.2.1 and 4.1.4.2.2), the potential magnitude of surface subsidence attributable to the proposed action should not be sufficiently large to cause damage to critical structures. Nevertheless, because of the uncertainties inherent in predicting subsidence, it is possible that subsidence could occur.

Seismic events that could be induced by activities associated with the proposed action are not expected to cause significant impacts to structures at NPR-1 or nearby areas. Although oil and gas withdrawals have been known to stimulate seismic events of magnitudes up to 4.6, such an earthquake would unlikely produce sufficient motion and be of sufficient duration to affect properly designed structures.

Earthquake design loads for buildings and other structures are determined in accordance with the procedures contained in the latest edition of the Uniform Building Code. The subject code identifies NPR-1 as a seismic Zone 4 area (Uniform Building Code 1991). A site-specific geotechnical and earthquake engineering study of NPR-1 has been completed which will be used for the design of more critical structures (Woodward-Clyde 1991). One facility that is under review is the 35R gas plant which was constructed in the early 1950's. It is anticipated that the review will result in projects to enhance the structural integrity of some components of this plant.

Based on an evaluation of historical natural seismic activity (see Section 3.1.2.5), it appears that this does not present a major hazard to the NPR-1. NPR-1 is located on sandstone and mudstone bedrock of the Tulare Formation and also on alluvial fan deposits that extend onto the site. Possible damage due to a major earthquake on either the White Wolf or the San Andreas fault would tend to be greatest to any facilities located on the alluvial fan and in Buena Vista Valley, where ground cracking, densification, and liquefaction are most likely to occur. Thus, the design and construction of any oil and gas storage and shipping facilities located in these areas would require careful attention. Well-constructed facilities in the elevated portion of the NPR-1 should be safe, even in the event of a large earthquake on the nearby active faults. The maximum estimated earthquake magnitude for a fault near NPR-1 is 7.5-8.0 on the San Andreas fault (Woodward-Clyde 1991).

4.1.1.3 References*

Amimoto, P.Y., 1977 (reprinted 1981), Erosion and Sediment Control Handbook, Division of Mines and Geology, California Department of Conservation, Sacramento, California.

Soil Conservation Service, 1985, Guides for Erosion and Sediment Control in California, U.S. Department of Agriculture, Davis, California, p. 114.

Uniform Building Code, 1991, International Conference of Building Officials, Whittier, California.

Woodward-Clyde Consultants, 1991, Geotechnical and Earthquake Engineering Study, Naval Petroleum Reserve No. 1, Elk Hills, California, Oakland, California, February 27.

*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval petroleum Reserves in California, Tupman, California 93276.

4.1.2 Waste Generation

Reauthorization of the Resource Conservation and Recovery Act (RCRA) is being considered by Congress at this time. Oilfield production and exploration wastes currently exempted from Subpart C of RCRA may become regulated wastes in the reauthorized legislation. Should this occur, RCRA hazardous waste streams at NPRC will increase substantially. However, current management practices are already in place which manage these waste streams under state hazardous waste regulations.

Implementation of the proposed action would have several impacts: e.g., those associated with the current operations described in Section 3.2, and other impacts associated with intensifying enhanced recovery techniques in response to field maturation and natural production declines. The most noteworthy impact would be an increase in wastewater due to waterflood and steamflood operations. Other impacts would decline, such as those from well drilling. A more comprehensive discussion of potential impacts and associated mitigation are presented below.

4.1.2.1 Continuation of Current Oil and Gas Operations

Under the proposed action, 259 wells (production and injection) would be drilled, redrilled or deepened in the Stevens and SOZ zones over the period 1989-1995. This is an average of about 36 wells/year, compared with an average of 70 wells/year over the period 1974-1988. These same types of well projects would be completed at a rate of about 4/year over the period 1996-2025. Thus, the proposed action would sharply reduce well-drilling activity, which, in turn, would reduce the volume of spent drilling fluids requiring disposal. The reduction in the number of well projects through 1991 has shown a resulting 45% reduction in the volume of drilling wastes disposed (700,000 barrels/year in 1987 versus 315,000 barrels/year in 1990.) The toxicity of current drilling fluids is also much reduced because chromium and other hazardous additives are no longer utilized (see Section 3.2.3). Therefore, the overall impacts from spent drilling fluid, which is a major waste stream, would be sharply reduced; eventually, they would probably become insignificant.

As the implementation of various secondary oil recovery projects continues, the volume of another principal waste on NPR-1 -- produced wastewater -- would increase substantially. Currently, about 100,000 -110,000 barrels/day of produced wastewater are generated on NPR-1. This volume is projected to increase to approximately 181,000 barrels/day (see Table 1.2-1). Impacts related to handling and disposal of wastewater are discussed in Sections 4.1.4.2.1 and 4.1.4.2.2.

MER is expected to decrease steadily over the next 10 years. The occurrence of episodic waste releases (e.g., oil spills, leaking storage facilities, wastes from process chemicals) would be expected to parallel the rate of oil production. Thus, impacts from these types of wastes should decline. In the near term (the next 10 years), the increasing age of equipment is not expected to be a serious problem. While the oil-production level is still relatively high, profits would be optimized by good management practices, such as quickly replacing old equipment with new.

As the oil field matures and profits decline, good maintenance practices must steadily receive a higher priority, otherwise leaks from corrosion, valve and equipment failure, and similar sources could cause increased amounts of wastes to be released to the environment. In recognition of this, the intensity of corrosion-monitoring activities has increased substantially over the past few years and is expected to increase further in the future.

4.1.2.2 Planned Facility Development

Some facility construction and operational activities included in the proposed action have the potential to cause adverse environmental impacts through the generation and subsequent disposal of wastes. These facilities and operations include (1) 24Z/29R closed-loop gas-lift, (2) a fourth gas-processing plant, (3) cogeneration plant, (4) butane isomerization plant, (5) Stevens and SOZ waterflood expansion, and (6) SOZ steamflood expansion.

Although each of the above facilities is a major construction effort, the total volume of non-hazardous construction wastes generated would comprise only a minor fraction of the approximately 24,000 cubic yards/year of non-hazardous solid wastes currently generated at NPR-1. Table 4.1.2.2-1 provides an estimate of the total amount of non-hazardous construction-related waste volumes for the six planned facility projects. The construction debris from these projects would be collected as nonhazardous solid waste and disposed of off-site at the Kern County landfill near Taft.

It is expected that a small amount of hazardous waste would also be generated during construction of each project. This waste would include various solvents, paints, sealants, adhesives, waste lubricants, and the containers of these products. It is expected these hazardous wastes would increase only slightly the site's current annual 19,800 pound (9,000 kilograms) hazardous waste stream.

Operation-related wastes are discussed below for each of the facilities and summarized in Table 4.1.2.2-2 for reference. As a result of operation of planned facilities, NPR-1's overall hazardous waste stream is not expected to increase significantly.

24Z/29R Closed-loop Gas-Lift

The closed-loop gas-lift projects are expected to have very little waste-related impact on the environment. Three large air compressor engines would generate a small amount of used motor oil each year. This facility would include a glycol dehydration system to remove water from the incoming gas. Wet gas (containing water) causes substantial corrosion to gas manifolds and piping. If unchecked, this corrosion could lead to eventual failure of the system, resulting in release of liquids and gases to the environment. The glycol dehydration system would reduce corrosion in the gas lines, and thus, reduce the potential for a large hydrocarbon release to the environment. Spills and leaks of glycol would be minimized and addressed through the Spill Prevention, Control, and Countermeasure (SPCC) plan. No significant waste-related impacts are anticipated from construction or operation of this facility.

TABLE 4.1.2.2-1 Estimated Volumes of Construction Related Non-hazardous Solid Waste Generation for Planned Facility Development Projects[1]

PROJECT	TOTAL QUANTITIES OF WASTE ESTIMATED TO BE GENERATED DURING CONSTRUCTION		
	CONCRETE (cubic yards)	CRATING & PAPER (cubic yards)	SCRAP METAL (tons)
Closed-loop gas-lift	1	10	1
Gas processing plant	3	30	3
Cogeneration plant	3	30	3
Butane isomerization plant	3	30	3
Waterflood expansion	1	10	1
Steamflood expansion	1	5	2
TOTAL	12	115	13

[1]Data represents best estimates available.

Source: BPOI 1991

TABLE 4.1.2.2-2 Estimated Volumes of Operational Waste Generation For Planned Facility Development Projects[1]

PROJECT TYPE	WASTE TYPE		
	LIQUID	SOLID	HAZARDOUS
Closed-loop gas-lift	360 gallons/year used motor oil	([1])	([1])
Gas processing plant	120-640 gallons/day[2]	50-100 pounds/day	12 cubic yards/year used glycol filters[3]
Cogeneration plant 13.H-2	412 barrels/day[4] 171 barrels/day[5] 450 barrels/day[6]	([1]) 13.H-2	([1])
Butane/isomerization plant	120-640 gallons/day[7]	50-100 pounds/day	([1])
Stevens/SOZ Waterflood expansion	([1])	50-100 pounds/day	([1])
Steamflood expansion	8,500-35,000 barrels/day([8])	50-100 pounds/day	([1])

[1]It is expected that nominal quantities of all waste types would be generated during operations and maintenance activities.
[2]Wastewater stream would be from cooling tower blowdown and spent caustics.
[3]Assumed to weigh 810 lbs/yd^3. Annual volume equates to 9,720 lbs (4,418kg).
[4]Demineralizer system regeneration waste. 13.H-2
[5]Potable water wastes (domestic wastewater).
[6]Miscellaneous non-hazardous wastewater from heat recovery steam generator blowdown for system losses.
[7]Wastewater would comprise cooling tower blowdown.
[8]Produced wastewater from steam-injection activities.
Source: BPOI 1991

Fourth Gas-Processing Plant

Construction of a fourth gas-processing plant represents a major expansion of gas-processing capacity at NPR-1. In addition to wastewater, it is expected that 50-100 pounds/day of non-hazardous solid waste and 12 cubic yards/year of hazardous waste would be generated during operation of the gas-processing plant. Potential waste-related impacts from this plant would be minimized by the following mitigation measures: (1) there would be no direct waste discharges from this plant to unlined sumps or drainages; (2) drainage from the plant would flow through lined concrete ditches into lined collection ponds used for evaporation; (3) all process chemical and production storage would be subject to secondary containment; and, (4) waste minimization would be achieved through bulk chemical storage (see Section 3.2). Waste released from this facility, as a result of spills or leaks, should, therefore, be minimal. Spills and leaks would be managed through the SPCC plan.

Cogeneration Plant

Operation of the proposed cogeneration plant in Section 35R would provide most of the electricity needed at NPR-1. Small amounts of antiscaling and biocide agents, exact type to be determined in the project design process, may be required to be added to the condensate feedwater for the system. Caustics and acids (sodium hydroxide and sulfuric acid) would be used at this plant as the anion and cation exchangers in a demineralizer system for treating the make-up water. The regeneration of the demineralizer system every 24 hours would produce approximately 412 barrels of demineralizer system regeneration liquid waste/day (see Table 4.1.2.2-2). This waste would be collected in a waste neutralization tank. The wastewater would be neutralized to an alkaline pH (7.0 - 8.5). The neutralized wastewater is estimated to have a TADS content of approximately 9,600 parts/million (BPOI 1993). It is expected that this wastewater would meet Class II injection fluid criteria pursuant to the provisions of the July 31, 1987 Final Policy for Class II Wells (EPA 1987). Accordingly, plans for disposal of this wastewater into NPR-1 Class II Wells would be proposed to the Division of Oil and Gas. Disposal by injection into Class II wells would be in accordance with all applicable regulatory procedures. Significant adverse environmental effects to groundwater are not anticipated as a result of this disposal method. Refer to Section 4.1.4.2 and Appendix D for a detailed discussion of potential groundwater impacts as a result of disposal by injection. Treatment of the wastewater in the neutralization tank as an integral part of the cogeneration system process would not require a RCRA treatment permit. However, this waste treatment process prior to disposal would be conducted in accordance with all applicable regulatory procedures of State of California Assembly Bill 1772, Permit By Rule Reform.

In addition to the demineralizer system wastes, small amounts of domestic wastewater, (approximately 171 barrels/day), and miscellaneous non-hazardous liquid wastes from the heat recovery steam generators, i.e., blowdown and system losses of approximately 450 barrels/day (see Table 4.1.2.2-2), would be generated from the operation of the cogeneration plant. The domestic liquid wastes would be disposed of in an on-site septic system. If the existing septic system capacity at the LTS-1 plant in Section 35R is inadequate to dispose of these volumes, a new on-site septic system would be provided. The miscellaneous liquid wastes would be disposed of by injection into NPR-1 Class II Wells in accordance with the above Class II Well Policy.

Butane Isomerization Facility

The butane isomerization facility is expected to generate some volumes of waste. Cooling tower blowdown water and sludges containing water treatment additives, such as antiscaling and biocide agents, would be collected and tested prior to disposal in accordance with applicable regulations. The quantities and types of water-treatment additives would be determined in the project design process. Processing and disposal would be conducted in accordance with regulated procedures. Caustics such as sodium hydroxide used in the process would be collected, tested, neutralized as required and injected into on-site Class II wastewater disposal wells (BPOI 1991). Spent hydrochloric acid from this process would be injected into on-site disposal wells as part of the well stimulation process (BPOI 1991). Spent catalysts would be regenerated in an on-site regeneration unit to reduce the volume of waste requiring disposal. As with the foregoing projects, secondary spill containment, bulk chemical storage and spill response in accordance with the SPCC plan would be integral parts of the project.

Stevens and SOZ Waterflood Expansion

The Stevens and SOZ waterflood expansion would increase injection water needs from approximately 148,000 barrels/day (1989) to approximately 254,500 barrels/day (1995) (BPOI 1989). These additional water requirements are planned to be supplied by recycling produced wastewater currently disposed of by injection into the Tulare. Environmental impacts should be minimal since very little increase in waste generation is expected (except produced wastewater, which is discussed in Section 4.1.4).

Steamflood Expansion

Many of the new wells to be drilled under the proposed action would be part of the expansion of the SOZ steamflood project. A total of approximately 148 new wells (both production and injection) would be drilled, redrilled or deepened in this project area over approximately 30 years. This amount of well drilling activity would not generate volumes of drilling fluid wastes requiring disposal in the landfarms on site above the volumes experienced in 1987 (700,000 barrels/year). Site-wide, the amount of drilling activity has been on the decrease since 1989. This has resulted in a downward trend of drilling wastes generated each year (see Sections 3.2.1 and 4.1.2.1). Existing landfarm facilities have sufficient capacity to accept the volumes of drilling wastes that would be generated from this project.

As many as 10 new steam generators would be operational if the full expansion of the steamflood project is achieved. Small amounts of chemical additives (quantities and types to be determined in the project design process) such as water softening, antiscaling and biocide agents would be added to the condensate feedwater of the steam generators. It is not anticipated these chemicals or the wastewater would be released into the environment except as a result of leaks or spills. As mentioned in the foregoing project discussions, secondary containment, response in accordance with the SPCC Plan and wastewater collection, handling, processing, and disposal in accordance with regulated procedures should reduce the potential impacts from such releases. The volume of produced wastewater is expected to increase significantly as the SOZ steamflood project is expanded. This issue is discussed in Sections 4.1.4.1.2.1 and 4.1.4.2.2.

4.1.2.3 General Mitigation

Environmental concerns at NPR-1 focus on compliance with federal, state, and local laws and regulations, as well as DOE Orders. DOE Orders address such programs as the pollution prevention awareness program, waste minimization/recycling program, environmental protection implementation plan, hazardous waste management plan, and the environmental protection policy statement; typically, these programs supplement legal and regulatory requirements through the implementation of good management practices, which represents significant mitigation activity.

In the course of planning, designing, approving, funding and implementing site activities, the scope of the activities will be reviewed to determine if their scope has changed sufficiently, in comparison to the scope described herein, to require additional NEPA assessments. Additional assessments would be conducted as appropriate. In addition, proposed action activities would be required to undergo NPR-1's pollution prevention, waste minimization and recycling program reviews.

Potential increases to the site's annual volume of hazardous waste generation as a result of the proposed facilities would require careful facility planning, engineering controls, and hazardous waste minimization and management practices review. This process and opportunities to reduce such waste streams during design would be addressed during the future project-specific environmental analyses.

State regulatory programs, such as the state's Hazardous Waste Reduction and Management Review Act of 1989 (SB14) would also be complied with. Compliance with this Act would be required if NPR-1's annual hazardous waste stream exceeds 12,000 kilograms.

Other mitigation activities focus on remediating impacts associated with past and current operations. These activities are included in the LRP and the proposed action. The principal initiatives are listed below, and the listing is followed by a more detailed discussion.

- Chromium cleanup,
- Inactive waste site characterization and remediation,
- Programs to minimize wastewater sumping (line sumps, and shut-down sumps and replace them with tankage),

- Cleanup/closure of inactive wastewater sumps,
- Calderon Bill mandated solid-waste facility characterization,
- Spill minimization and cleanup,
- Drainage reclamation,
- 25S dehydration facility tank repair/replacement/relocation,
- 2-25S Stevens tank setting surge tank repair/replacement,
- Tank setting secondary containment project,
- 27R hazardous waste site closure,
- 3G gas plant demolition,
- 35R asbestos/removal program,
- Recycling wastewater for waterflood use (PWI projects),
- Waste-minimization/recycling program, and
- Pollution-prevention awareness program.

Past and current chromium-cleanup activities are discussed in <u>Section 3.2</u>. Additional actions include continuing a visual program to monitor other potential sites.

Several inactive waste sites have been identified, some of which contained hazardous substances such as arsenic; these are discussed in <u>Section 3.2.4</u>. These sites are to be reviewed, characterized, remediated and closed in accordance with appropriate requirements, including DOE Orders.

NPR-1's objective is to minimize sumping of wastewater by providing additional tankage at sump locations so as to reduce the need for sumping to only occasional off-normal situations. Furthermore, sumps that are not needed are to be eliminated altogether and formally closed. Necessary sumps in sensitive areas are to be lined, to preclude infiltration.

Wastewater sumps that have been abandoned, or are no longer needed, are to be identified and reviewed, characterized, remediated, and closed in accordance with appropriate requirements, including DOE Orders. An example of a sump project is the 35R sump. The drainage effluent from the existing 35R gas plant and LTS-1 compressor building was collected at 35R sump until October 1989. The project eliminated the use of this sump by providing surface tankage to collect the drainage. The project also provided facilities to transport the drainage to the oil/water production collection system. The 35R sump is no longer in use and is scheduled to be formally closed.

Another example is the 27R sump project. The 27R sump replacement project is designed to replace the four oil-recovery and truck-washout sumps with environmentally appropriate aboveground tankage facilities. Three sumps will then be formally closed, and the fourth will be used as an emergency catch basin backup for the tankage during unexpected off-normal situations (such as tank overflows). Emergency catch basins are to be managed in accordance with the SPCC program.

The characterization program for all Calderon bill regulated solid-waste facilities includes site characterization and reporting of results to regulatory agencies of all active and inactive landfarms, landfills, surface dumps, and any other solid-waste facilities (Section 3.2).

Spills are minimized through a comprehensive corrosion monitoring and facility replacement program. In addition, spill and overflow scenarios are considered in the course of facility design to ensure facilities are adequate to prevent/minimize and contain spills. When spills do occur they are addressed in accordance with the SPCC plan.

A drainage-reclamation program is planned, primarily to address historical inactive drilling fluid sumps that might have been abandoned in natural drainages. This issue will be addressed in accordance with CCR Title 14 Section 1716.

The 25S dehydration facility and Stevens tank setting projects are to shutdown, repair, replace, or relocate various tanks and equipment used in the separation of oil and produced water. These tanks have been subject to corrosion and weathering for a number of years, thus creating a potential for oil leaks and spills in an area that is near the Tulare/Alluvium contact, the California Aqueduct, and the Kern Water Bank Project.

The secondary containment project is to enhance secondary containment provided for storage tanks field-wide, as required to ensure that spills and leaks do not leave NPR-1 or cause adverse impacts to the environment.

A project is in progress to formally close the 27R hazardous waste trench. A borehole was drilled to 1,000 feet to test for and characterize underlying groundwater. Water to this depth was not detected. A closure plan to clay cap and monitor the site was released for public comment. Closure activities required to obtain a post-closure permit have been completed.

The 3G gas plant project includes demolition of the inactive 3G gas plant and removal of the associated cooling tower. The level of copper contained in the cooling tower is above the California TTLC limit. Debris from the demolition of the cooling tower would be considered hazardous waste and would be disposed of in accordance with applicable regulations.

The asbestos program involves the phased removal of all asbestos-containing insulation from NPR-1 facilities and equipment. The overwhelming majority of asbestos at NPR-1 is at the 35R gas plant constructed in the early 1950's. Typically, removal projects would be initiated in conjunction with projects that disturb existing asbestos. Until it is removed, friable asbestos would be encapsulated. Airborne asbestos particulate is and would continue to be monitored. Reinsulation would be carried out as necessary with appropriate nonhazardous materials.

The most significant waste minimization/recycling and pollution-prevention program planned is to utilize produced wastewater as source water for waterflood operations, in lieu of using Tulare water (PWI projects); this will reduce the quantity of wastewater requiring disposal significantly, which is discussed in more detail in <u>Sections 4.1.4.2.1 and 4.1.4.2.2</u>. Other programs in place that would be continued include drum recycling, paper recycling, spent lead-acid battery recycling, and recycling spent acids, as previously discussed in <u>Section 3.2</u>.

4.1.2.4 References*

Bechtel Petroleum Operations, Inc., 1989 NPRC FY 1989 - 1995 Long Range Plan, Naval Petroleum Reserves in California, Tupman, California.

Bechtel Petroleum Operations, Inc., 1991, Memorandum from R. L. Donahoe to J. C. Killen, Responses to DOE/HQ Comments on the SEIS, November 8.

Bechtel Petroleum Opertions, Inc., 1993, Memorandum from R. L. Donahoe to Danny A. Hogan, Water and Wastewater Study, Elk Hills Cogeneration Facility, Tupman, California, January 15.

BPOI - See Bechtel Petroleum Operations, Inc.

EPA - See U.S. Environmental Protection Agency

U.S. Environmental Protection Agency, 1987, Classification of Wells Used to Inject Air Scrubber Waste or Water Softener Regeneration Brine Associated with Oil Field Operations, Final Policy, Office of Water, Washington DC, July 31.

*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California 93276.

4.1.3 Air Resources

Current levels of air pollutant emissions from NPR-1 sources are summarized in Section 3.3.2.2. The following sections discuss the atmospheric emissions that are expected to occur under the proposed action, compare those emissions to the existing conditions, and assess potential impacts on ambient air quality.

4.1.3.1 Future Atmospheric Emissions

The new sources of atmospheric emissions to be installed at the NPR-1 site for the proposed action include (1) 10 gas-fired, 62.5-million-Btu/hour heat-input steam generators; (2) 18 gas-fired compressor engines (4-5,500-horsepower units, 8-1,500-horsepower units, and 11-1,000-horsepower units); (3) 2 gas-turbine-driven, 21-megawatt cogenerators; (4) 2 gas-fired, 41.5-million-BTU/hour heat-input heaters; and (5) 2 flares (1 low-pressure unit with 31 million cubic foot/day capacity and 1 high-pressure unit with 92 million cubic foot/day capacity). The planned locations of these proposed new emission sources are shown in Figure 3.3-1. Estimated average emissions from new sources for the year 1996 are summarized in Table 4.1.3-1. Details of the emission estimates for the proposed new sources are provided in Table B.22 of Appendix B. The year 1996 was chosen for analysis because it corresponds to the projected peak level of activity for the proposed steamflood expansion project and, therefore, to the maximum level of atmospheric emissions.

The sources listed in Table 4.1.3-1 include new pieces of equipment that would be installed between now and 1996. Not all of the items of equipment listed in Table 4.1.3-1 would be used directly in connection with the steamflood expansion project. For example, the cogenerators located at the 35R facilities also would be used to meet the heating requirements currently provided by existing boilers and heaters. About 70% of the new compressor capacity would be installed for the proposed fourth gas plant. The equipment emission estimates in Table 4.1.3-1 are based primarily on manufacturers' data and should be considered fairly accurate. However, the accuracy of fugitive emission estimates must be considered rather uncertain. The largest contributions to new emissions of ROG, NO_x, and CO would be the compressor engines. The quantities of new emissions of particulates from the compressor engines, steam generators, and cogenerators would be relatively small.

As described in Section 1.2, new construction projects planned between 1989 and 1996 include those for the steamflood expansion, a fourth gas plant, cogenerators, compressors, a butane isomerization unit, a closed-loop gas-lift system, and several third-party actions. Table 4.1.3-2 summarizes the temporary emissions produced by (1) fugitive dusts and engines of construction machines from site-preparation activities and (2) vehicular traffic associated with the additional construction workers and delivery of construction material. Details of the emission estimates for these construction activities are provided in Table B.23 of Appendix B.

The emission estimates presented in Table 4.1.3-2 for temporary construction activities are in most cases for the year 1990, when such activities, including third-party actions, would be at

TABLE 4.1.3-1 Summary of Projected Emissions from Proposed New Sources at NPR-1 (Proposed Action and Alternative 2)

Source Category	Total Capacity	Emission Rate (lb/h)[a]						
		ROG[b]	NO_x	CO	SO_2[c]	TSP	PM_{10}	H_2S
Compressor engines	37,500 hp	122.6	82.7	345.0	0.2	1.4	1.4	0
Steam generators and heaters	708 x 10^6 Btu/h	1.1	28.3	10.3	0.3	3.0	3.0	0
Cogenerators	42 MWe	5.3	7.8	10.6	0.2	1.1	1.1	0
Flares	123 x 10^6 ft^3/day	0.3	5.4	1.1	0	0.3	0.3	0
Fugitive emissions	-	4.3	0	0	0	0	0	1 x 10^{-4}
Totals[d]								
Proposed Action		133.6	124.2	367.0	0.7	5.8	5.8	1 x 10^{-4}
Alternative 2[e]		90.4	63.3	242.6	0.2	1.3	1.3	1 x 10^{-4}

[a]Annual average values for projected level of peak activity in 1996; multiply by 4.38 to convert to units of tons/year.
[b]Emissions of C_6H_6 included in ROG emissions are estimated to be negligible.
[c]5% of SO_2 is estimated to be emitted as SO_4.
[d]Individual values may not add up to totals because of rounding.
[e]Excludes emissions from steam generators and heaters, cogenerators, and 70% of compressor engines.

TABLE 4.1.3-2 Summary of Projected Temporary Emissions Associated with New-Source Construction Activities at NPR-1

Source Category	Emission Rate (1b/h)[a]					
	ROG[b]	NO_x	CO	SO_2[c]	TSP	PM_{10}
Construction[d]	0.6	7.5	1.6	0.5	3.8	1.1
Vehicular traffic[e]						
On-site	0.1	0.6	0.3	0.1	62.0	24.3
Off-site	0.5	3.8	1.8	0.8	6.3	3.1
Total	1.2	11.9	3.7	1.4	72.1	27.4

[a]Annual average values for 1990 unless otherwise noted; multiply by 4.38 to convert to units of tons/year.
[b]Emissions of C_6H_6 included in ROG emissions are estimated to be negligible.
[c]5% of SO_2 is estimated to be emitted as SO_4
[d]Based on the disturbance of 64 2.2-acre sites during 1990, when the construction activities at NPR-1, including third-party projects, were projected to be at peak level..
[e]Associated with the peak construction work force and delivery of construction material in 1992.

their peak level at NPR-1. Construction-related emissions during other years would be substantially less than those shown in the table. For example, the emissions in 1995, when construction activities would be limited to the steamflood expansion project, would be less than 20% of the values listed in the table. The emission estimates listed in Table 4.1.3-2 for the vehicular traffic are for the year 1992, when the on-site construction work force was projected to be at its peak level of 300 people. In 1995, the vehicular emissions associated with the construction activities would be only one-third of the 1992 levels.

Compared with the new stationary source emissions, the temporary emissions from the construction activities and associated vehicular traffic would be relatively small, except for SO_2 and particulate matter.

Table 4.1.3-3 lists (1) total current emissions from existing sources; (2) projected changes in emissions from currently existing sources for the year 1996; (3) net changes in emissions between the period 1987-1989 and 1996; and (4) the projected total 1996 emissions. Further details are presented in Tables B.24 through B.26. The emission changes listed in Table 4.1.3-3 are based on associated activity projections supplied by BPOI, as indicated in the footnotes to Table B.24. For example, NO_x emissions associated with well-pump engines are projected to decrease, because up to 80% of current NO_x emissions must be eliminated pursuant to KCAPCD Rule 427 (see Section B.2.2). The net emission changes between the period 1987-1989 and 1996 represent the sums of the proposed new emissions and the projected changes in existing emissions. The projected total 1996 emissions are the sums of existing emissions and net emission changes between now and 1996. As can be seen from the data, some net increases are expected in emissions of CO, TSP, and PM_{10}; while net decreases are projected for ROG, NO_x, and SO_2 emissions as a result of the proposed action. The net increase in CO emissions would be due primarily to the new compressor engines. The net increases in TSP and PM_{10} emissions would be due primarily to increased truck traffic delivering liquid products associated with increased production at the new fourth gas plant.

Currently, the NPR-1 emission sources subject to KCAPCD Rule 210.1 (standards for an authority-to-construct permit) are permitted under three different stationary sources: (1) light-oil-production stationary source; (2) gas-processing stationary source; and (3) gasoline-dispensing stationary source. All 10 new steam generators and three 1,500-horsepower compressors would belong to the light-oil-production stationary source; the remaining 15 new compressors, the 2 cogenerators, 2 heaters, and 2 flares would belong to the gas-processing stationary source. Emission increases from these proposed new sources would be offset by the emission offset credits accumulated through previous emission-reduction programs at NPR-1, and the emission offset credits to be obtained through future emission-reduction programs at NPR-1 pursuant to the requirements of KCAPCD Rule 210.1 (New Source Review), and the State and Federal Clean Air Acts (including the conformity provisions of the FCAA).

Table 4.1.3-4 lists the cumulative net changes in emissions for all three stationary sources at NPR-1 for the period December 28, 1976, through May 2, 1989. The cumulative net changes

TABLE 4.1.3-3 Summary of Emissions for Existing and Proposed New Sources, Projected Changes, Net Changes, and Projected 1996 Sources

Category	Emissions Rate (lb/h)[a]						
	ROG	NO_x	CO	SO_2[b]	TSP	PM_{10}	H_2S
Existing emissions	1,524	1,451	1,312	14.8	743	304	0.03
Proposed new emissions	134	124	367	0.7	6	6	0
Projected changes in existing emissions	-388	-768	-10	-1.0	66	25	0
Net emission changes[c,d]	-255	-644	357	-0.3	72	31	0
Projected 1996 emissions[d,e]	1,270	807	1,669	14.5	815	335	0.03

[a]Existing emissions of C_6H_6 (0.30 lb/h) and Pb (0.01 lb/h) are not expected to change; multiply by 4.38 to convert to units of tons/year.
[b]5% of SO_2 is estimated to be SO_4.
[c]Net emission changes = proposed new emissions + projected changes in existing emissions.
[d]Individual values may not add up to totals because of rounding.
[e]Projected 1996 emissions = existing emissions + net emission changes.

TABLE 4.1.3-4 Cumulative Net Emission Rate Changes at NPR-1, December 28, 1976, through May 2, 1989[a]

Source	Emission Rate (1b/d)					
	ROG	NO_x	CO	SO_2	SO_4	PM_{10}[b]
Light-oil-production stationary source	-13,370.08	-3,011.57	2,387.27	0.90	0.00	7.88
Gas-processing stationary source	-16,358.29	-9,260.06	-51,218.40	1.64	0.48	28.89
Gasoline-dispensing stationary source	1.51	0	0	0	0	0
Totals	-29,726.86	-12,271.63	-48,831.13	2.54	0.48	36.77

[a]Adjusted for authorities to construct issued after December 28, 1976.
[b]TSP emissions included in cumulative net emission changes prior to May 2, 1989, are considered to be the same as PM_{10} emissions.

Source: Chun 1989.

for this period, net increases in emissions from the proposed new sources, and the cumulative net changes adjusted for the new source emissions are listed in Tables 4.1.3-5 and 4.1.3-6 for the light-oil-production stationary source and the gas-processing stationary source, respectively. As shown in these tables, all new emission sources would result in increased emissions. Therefore, Section V.A of KCAPCD Rule 210.1 (requirement of best available control technology) would apply to these sources with respect to all air contaminants for which there is a NAAQS (excluding CO) or any precursor of such contaminants (i.e., ROG, NO_x, SO_2, and PM_{10}).

If the cumulative net emission change for any contaminant listed in Tables 4.1.3-5 and 4.1.3-6 equals or exceeds the *de minimis levels* specified in Section 111.C of KCAPCD Rule 210.1*, the requirement of lowest achievable emission rate and mitigation (Section V.B of KCAPCD Rule 210.1) would be applicable. The cumulative net emission changes of all air contaminants listed in Tables 4.1.3-5 and 4.1.3-6 are estimated to be less than the *de minimis levels*, except for CO at the light-oil-production stationary source and PM_{10} at both the light-oil-production and gas-processing stationary sources. Although the cumulative net emission change for CO at the light-oil-production stationary source would be greater than the *de minimis level*, the source would be exempt from Section V.B of KCAPCD Rule 210.1 (requirement of lowest achievable emission rate and mitigation). The reason for the exemption is that air quality modeling has demonstrated that CO air quality impacts due to the new emission sources at the light-oil-production stationary source would not cause or contribute to a violation of NAAQS for CO, in accordance with Section V.B.1.b, as shown in Figures B.26 and B.27 (see Section B.5, Appendix B).

Because the cumulative net emission changes in PM_{10} would be greater than the *de minimis* level and because NPR-1 is located in a PM_{10} serious nonattainment area, the cumulative net emission increases would be offset by reducing road dust emissions from the paved and unpaved roads above and beyond the emission reductions that would be required by the Fugitive Dust Control Regulations for the San Joaquin Valley Air Basin. (These regulations have been proposed in early 1990 as a component of the San Joaquin Valley Air Basin Air Pollution Control District's PM_{10} nonattainment plan).

For the purposes of new-source review, EPA Region IX considers the entire NPR-1 as a single stationary source (BPOI 1991). In addition, the net emission changes are calculated on the basis of only those emission increases or decreases that occur between the following two dates: (1) the date 5 years before construction of the particular change commences, and (2) the date that the increase from the particular change occurs. To be creditable for the calculation of net emission changes, actual emission decreases have to meet several conditions, including the

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*80 pounds/day for PM_{10} and 150 pounds/day of any other air contaminant for which there is an NAAQS (except for CO); no net increase (0 pounds/day) of emissions of any nonattainment pollutant (currently O_3 and PM_{10}) or its precursors, effective July 1, 1991; and 550 pounds/day for CO.

TABLE 4.1.3-5 Cumulative Net Emission Rate Changes for the Light-Oil-Production Stationary Source at NPR-1, Adjusted for Proposed Action[a]

Category	Emission Rate (1b/d)					
	ROG	NO_x	CO	SO_2	SO_4	PM_{10}[b]
Cumulative net change, Dec. 28, 1976 - May 2, 1989	-13,370.08	-3,011.57	2,387.27	0.90	0	7.88
Increases in emissions from proposed new sources	277.44	838.32	894.24	6.19	0.31	73.68
Cumulative net change after new source installation	-13,092.64 (-2,389.41)[b]	-2,173.25 (-396.62)	3,281.51 (598.88)	7.09 (1.29)	0.31 (0.06)	81.56 (14.88)

[a]Cumulative net changes from Table 4.1.3-4 adjusted for emissions from new sources included in the proposed action.
[b]Values in parentheses are tons/year.

TABLE 4.1.3-6 Cumulative Net Emission Rate Changes for the Gas-Processing Stationary Source at NPR-1, Adjusted for Proposed Action[a]

Category	Emission Rate (1b/d)					
	ROG	NO_x	CO	SO_2	SO_4	PM_{10}
Cumulative net change, Dec. 28, 1976 - May 2, 1989	-16,358.29	-9,260.06	-51,218.40	1.64	0.48	28.89
Increases in emissions from proposed new sources	2,929.68	2,142.96	7,912.08	10.51	0.53	65.04
Changes in emissions from eliminating existing sources x 0.9[b]	-10.80	-541.20	-135.12	-2.30	-0.12	-11.52
Net increases in emissions	2,918.88	1,601.76	7,776.96	8.21	0.41	53.52
Cumulative net change after new source installation	-13,439.41 (-2,452.69)[c]	-7,658.30 (-1,397.64)	-43,441.44 (-7,928.06)	9.85 (1.80)	0.89 (0.16)	82.41 (15.04)

[a]Cumulative net changes from Table 4.1.3-4 adjusted for increases in emissions from new sources included in the proposed action and decreases in emissions from eliminating existing sources.
[b]To account for a 10% emission reduction to be preserved for Small Source Siting Allowance (KCAPCD Rule 210.1, IV.E).
[c]Values in parentheses are tons/year.

following: (1) the old level of actual emissions or the old level of allowable emissions,whichever is lower, exceeds the new level of actual emissions; (2) the decrease is federally enforceable at and after the time that actual construction of the particular change begins; (3) the decrease has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and (4) the decrease has not been relied upon in obtaining a permit under Prevention of Significant Deterioration (PSD) regulations.

The emission changes for all NPR-1 facilities since October 1, 1985 (5 years before the construction of the steamflood expansion project was to commence) are shown in Table 4.1.3-7. The table lists the emission changes that are potentially creditable in determining the applicability of the new-source and PSD reviews. The net emission changes, after adding the emission increases from the new sources included in the proposed action, are also shown in Table 4.1.3-7. The resulting adjusted net changes would be less than zero for NO_x, and CO. Although the adjusted net change in both ROG and SO_2 emissions would be less than the significant levels defined by the EPA (100 tons/year for ROG and 40 tons/ year for SO_2), such changes in TSP emissions would be greater than the significant level defined by the EPA (25 tons/year for TSP). However, the particulate matter emission increase above the significant level (0.86 tons/year) would be offset by the reduction in road dust emissions from the paved and unpaved roads as described earlier in this section. Therefore, the proposed action would not qualify as a major modification, and would not be subject to the new-source review or PSD review. All emission increases associated with the proposed action would be offset pursuant to the requirements of the New Source Review (KCAPD Rule 210.1) in compliance with the conformity provisions of the 1990 Amendments to the Federal Clean Air Act.

To meet the above emission-control technology requirements, the new compressor engines would be equipped with the low NO_x emission precombustion chambers, and the steam generators, heaters, and cogenerators also would be equipped with appropriate low NO_X combustion technology (i.e., low NO_x burners and flue gas recirculation for the steam generators and heaters and selective catalytic reduction system for the cogenerators). The emissions of NO_x and SO_2 from the cogenerators would meet applicable federal new-source-performance standards for new gas turbines applicable to all stationary gas turbines with a peak heat input at peak load equal to or greater than 100 million BTU/hour (40 CFR 60 Subpart GG).

4.1.3.2 Air Quality Impacts

Upon release from their sources, the plumes containing air pollutants may rise above the point of their release due to buoyancy, be transported by wind, and then be transformed into other pollutant species. Simultaneously, air pollutants are dispersed through diffusion and turbulent motion of the atmosphere, contributing to the ground level pollutant concentration levels.

To determine compliance with applicable ambient air quality standards and other criteria, air quality impacts of the emissions from the existing sources and future sources at NPR-1 were estimated with computerized dispersion models recommended by the EPA (1986). The models

TABLE 4.1.3-7 Cumulative Net Emission Rate Changes at NPR-1, October 1, 1985, through May 2, 1989, Adjusted for Proposed New Sources

Category	Emission Rate (lb/d)					
	ROG	NO_x	CO	SO_2	SO_4	PM_{10}[a]
Cumulative net change, since Oct. 1, 1985[b]	-3,816.56	-12,932.84	-50,690.39	1.44	0.48	14.51
Net increases in emissions from proposed new sources	3,196.32	2,440.08	8,671.20	14.40	0.72	127.20
Cumulative net change after new source installation	-620.24 (-113.19)[c]	-10,492.76 (-1,914.93)	-42,019.19 (-7,668.50)	15.84 (2.89)	1.20 (0.22)	141.71 (25.86)

[a]TSP emissions included in cumulative net emission changes prior to May 2, 1989, are considered to be the same as PM_{10} emissions.
[b]As of May 2, 1989.
[c]Values in parentheses are tons/year.

and the model input data are described in Section B.5 of Appendix B. Air quality modeling was performed for NO_2, CO, SO_2, PM_{10}, H_2S, and C_6H_6. Air quality impacts were not modeled for O_3 according to advice from CARB (BPOI 1991).

The electric power to be generated by the two new cogenerators (42 megawatt total) would provide electric power that would otherwise be purchased from the Pacific Gas and Electric Co. (PG&E). Therefore, air pollutant emissions resulting from the generation of the equivalent amount of electricity would be eliminated from the PG&E generating system. (About 80% of air pollutants emitted by the cogenerators would be attributed to electric power generation and the remaining 20% to heat-recovery steam generation.)

Air quality impacts estimated for the construction period and for the operational period corresponding to the year 1996 are described below.

Construction Period

Several activities during the construction period would result in fugitive pollutant emissions and thus would affect ambient air quality. Fugitive dust would be generated by site preparation for steam generators, cogenerators, the fourth gas plant, compressors, new wells, and roadways, and by the third-party actions. Various combustion-product pollutants would be emitted from the operation of diesel engines used in site clearing and drilling and from the increased vehicular traffic on NPR-1 during the construction period. All such fugitive emissions are expected to be temporary, confined within relatively small areas, and dissipated within short distances from the sources. Unless they are produced close to or outside the site boundary, these emissions are not expected to cause any significant impacts outside the NPR-1 boundary. The conservatively high estimate of the maximum 24-hour mean PM_{10} concentration contribution due to fugitive dust emissions from site-clearing activities located some distance away from the site boundary is less than 1 microgram/cubic meter at the NPR-1 site boundary (Figure B.29). The corresponding value for the annual averaging period is negligible. However, third-party construction activities located close to or outside the site boundary could result in significant impacts on ambient PM_{10} concentrations.

Since NPR-1 is an operating oil field, use of diesel-powered construction equipment would occur concurrently with use of other diesel-powered equipment for day-to-day operation of the oil field. Therefore, the emissions from diesel-powered construction equipment were included in the air quality modeling for the operational period described below.

Operational Period

Because the magnitudes of all net emission increases from the proposed new sources would be, after emission offsets, less than the significant levels defined by KCAPCD and EPA, no significant additional air quality impacts are anticipated from the proposed modifications of operations at NPR-1.

The maximum estimated ground-level air pollutant contributions on the site and at the NPR-1 boundary (or at Elk Hills Road) by the existing sources and future (1996) sources (including the proposed new sources) are summarized in Tables 4.1.3-8 and 4.1.3-9. These tables also show the maximum ground-level ambient concentrations estimated by adding background concentrations (including the effects of vehicular emissions at Elk Hills Road and Skyline Road) to the contributions attributable to the NPR-1 sources. In Table 4.1.3-8, the estimated maximum on-site ambient concentrations are compared with permissible exposure limits (PELs) established by the Occupational Safety and Health Administration (29 CFR 1910). The estimated maximum ambient air quality levels at the site boundary (or at Elk Hills Road) listed in Table 4.1.3-9 are compared with applicable California and National Ambient Air Quality Standards (CAAQS and NAAQS). As shown in the tables, the estimated on-site ambient levels of all pollutant species modeled are less than the applicable PELs. The tables also show that the maximum ambient levels (estimated at the site boundary or at Elk Hills Road) of all pollutants modeled are less than the applicable CAAQS and NAAQS, except for the maximum 24-hour PM_{10} concentration. The impacts of individual pollutants are discussed below.

Ozone. Emissions of O_3 precursors from the existing sources at NPR-1 are about 1,500 pounds/hour each for NO_x and ROG. Some increases in the emissions of O_3 precursors [ROG (134 pounds/hour) and NO_x, (124 pounds/hour)] are expected from the proposed new sources at NPR-1. However, because of anticipated reductions in other activities at NPR-1, a net reduction in emissions of ROG (-255 pounds/hour) and NO_x (-644 pounds/ hour) are expected between now and the year 1996. Therefore, no increases are expected in ambient ozone concentrations in the vicinity of NPR-1 as a result of the proposed action.

Releases from the stack vents at tank settings during upset conditions constitute one of the major sources of ROG at NPR-1. This is the single largest source of hydrocarbon emissions at NPR-1, accounting for about 52% of the total current emissions of ROG. NPR-1 completed a study to reduce emissions from the tank settings with high release records and is committed to eliminating 80-90% of the emissions through the addition of gas compression, facility modifications, and other activities to increase operator awareness of the importance of decreasing releases (BPOI 1988). Operator awareness activities are in progress. Gas compression additions and other facility modifications are to be completed in accordance with the proposed action schedules included herein.

Another potential source of ROG at NPR-1 is the release of these pollutants from anode bed wells. There are approximately 650 anode beds field-wide. Each anode bed consists of several anode rods vertically stacked in wells approximately 400 feet below ground surface. Each anode bed provides corrosion protection for a 300 foot radius, and typically are placed in the center of several producing and/or injection wells. The emissions from the anode bed wells consist primarily of methane, which is non-reactive. The anode beds also release small amounts of reactive organic gases (ROG's), which are estimated to constitute about 2% of NPR-1's total current emissions of ROG. However, the uncertainty associated with these estimates is very large. Emissions from anode bed wells are known to decrease as the level of soil moisture

TABLE 4.1.3-8 Maximum On-Site Ground-Level Air Quality Concentration Contributions and Ambient Concentrations Estimated for the Existing and Future Emission Sources at NPR-1

Pollutant	Averaging Time	Concentrations						
		Existing Sources Only	Future Sources Only	Existing Sources Plus Background[a]	Future Sources Plus Background[a]	Applicable PEL[b]		
						TWA[c]	STEL[d]	CL[e]
NO_2 (ppm)	1 hour	0.281	0.174	0.293	0.179	-[f]	1	-
	Annual	0.021	0.011	0.035	0.025			
CO (ppm)	1 hour	1.43	1.41	4.63	4.61	35	-	200
	8 hours	0.49	0.49	2.09	2.09			
SO_2 (ppm)	1 hour	0.027	0.027	0.157	0.157	2	5	-
	3 hours	0.015	0.015	0.120	0.120			
	24 hours	0.003	0.003	0.042	0.042			
	Annual	<0.001	<0.001	0.008	0.009			
SO_4 ($\mu g/m^3$)	24 hours	0.44	0.44	15.9	15.9	-	-	-
PM_{10} ($\mu g/m^3$)				46.9[g]	50.4[g]	-	-	-
	24 hours	9.2	9.2	15.8[g]	16.9[g]			
	Annual	1.0	1.1					
Pb ($\mu g/m^3$)	30 days	h	h	0.13	0.13	50	-	-
	Calendar quarter	h	h	0.12	0.12			

TABLE 4.1.3-8 Maximum On-Site Ground-Level Air Quality Concentration Contributions and Ambient Concentrations Estimated for the Existing and Future Emission Sources at NPR-1 (Cont'd)

Pollutant	Averaging Time	Concentrations						
		Existing Sources Only	Future Sources Only	Existing Sources Plus Background[a]	Future Sources Plus Background[a]	Applicable PEL[b]		
						TWA[c]	STEL[d]	CL[e]
H_2S (ppm)	1 hour	0.009	--[i]	--	--	10	15	-

[a]Includes the background concentration and the effects of vehicular emissions along Elk Hills Road and Skyline.
[b]Permissible exposure limits established by OSHA.
[c]Time-weighted-average (TWA) is the employee's average airborne exposure in any 8-hour work shift of a 40-hour work week which shall not be exceeded.
[d]Short-term exposure limit (STEL) is the employee's 15-minute time-weighted average exposure which shall not be exceeded at any time during a work day.
[e]Ceiling limit (CL) is the employee's exposure which shall not be exceeded during any part of the work day.
[f]"-" indicates limit not established.
[g]Includes the effects of vehicular emissions and road dusts along Elk Hills Road and Skyline Road, but not the background concentration.
[h]Negligible.
[i]"--" indicates value not estimated.

TABLE 4.1.3-9 Maximum Site-Boundary Ground-Level Air Quality Concentration Contributions and Ambient Concentrations Estimated for the Existing and Future Emission Sources at NPR-1

Pollutant	Averaging Time	Concentrations at Site Boundary or at Elk Hills Road				Applicable Ambient Air Quality Standards	
		Existing Sources Only	Future Sources Only	Existing Sources Plus Background[a]	Future Sources Plus Background[a]	California	National
NO_2 (ppm)	1 hour	0.242	0.166	0.246	0.170	0.25	-[b]
	Annual	0.021	0.011	0.035	0.025	-	0.05
CO (ppm)	1 hour	1.10	1.10	4.30	4.30	20	35
	8 hours	0.49	0.49	2.09	2.09	9	9
SO_2 (ppm)	1 hour	0.010	0.009	0.140	0.139	0.25	-
	3 hours	0.006	0.006	0.111	0.111	-	0.5[c]
	24 hours	0.001	0.001	0.040	0.040	0.05	0.14
	Annual	<0.001	<0.001	0.008	0.009	-	0.03
SO_4 ($\mu g/m^3$)	24 hours	0.13	0.11	15.7	15.7	25	-
PM_{10} ($\mu g/m^3$)	24 hours	2.7	2.4	46.9[d]	50.4[d]	50	150
	Annual	0.2	0.2	15.8[d]	16.9[d]	30	50
Pb ($\mu g/m^3$)	30 days	e	e	0.13	0.13	1.5	-
	Calendar quarter	e	e	0.12	0.12	-	1.5

TABLE 4.1.3-9 Maximum Site-Boundary Ground-Level Air Quality Concentration Contributions and Ambient Concentrations Estimated for the Existing and Future Emission Sources at NPR-1 (Cont'd)

Pollutant	Averaging Time	Concentrations at Site Boundary or at Elk Hills Road				Applicable Ambient Air Quality Standards	
		Existing Sources Only	Future Sources Only	Existing Sources Plus Background[a]	Future Sources Plus Background[a]	California	National
H_2S (ppm)	1 hour	0.003	--[f]	--	--	0.03	-

[a]Includes the background concentration and the effects of vehicular emissions along Elk Hills Road and Skyline Road.
[b]"-" means no standard established.
[c]Secondary standard.
[d]Includes the effects of vehicular emissions and road dusts on Elk Hills Road and Skyline Road, but not the background concentration.
[e]Negligible.
[f]"--" indicates value not estimated.

saturation increases. Anode beds are watered frequently to maintain a high degree of soil moisture saturation and thus minimize ROG emissions.

Nitrogen Dioxide. Air quality modeling indicates that NO_x emissions from existing and future sources at NPR-1 would result in maximum 1-hour ambient NO_2 concentrations of about 98% and 68%, respectively, of CAAQS for NO_2 (0.25 ppm) at the junction of Elk Hills Road and Skyline Road (Table 4.1.3-9 and Figure B.24). The highest annual mean ambient NO_2 concentrations estimated at Elk Hills Road are less than 0.04 ppm, well below the applicable NAAQS for NO_2 (Table 4.1.3-9 and Figure B.25).

Carbon Monoxide. The current CO emissions at NPR-1 are estimated to result in a maximum 1-hour ambient CO concentration of 4.3O ppm (Table 4.1.3-9 and Figure B.26), with background concentrations contributing 3.2 ppm and the NPR-1 sources contributing only 1.10 ppm. No increase in the maximum 1-hour ambient CO concentration is expected at the site boundary between now and 1996, and no changes are expected in the maximum 8-hour mean CO concentration (Figure B.27). All of these concentrations are only a fraction of applicable CAAQS and NAAQS, and no problem is anticipated in maintaining the ambient standards.

Sulfur Dioxide. Sulfur dioxide emissions from the existing sources at NPR-1 are small (about 15 pounds/hour), and a small increase in SO_2 emissions from new sources included in the proposed action would be more than offset by the reduction in emissions from other activities at NPR-1, such as drilling. Air quality modeling indicates that the current ambient SO_2 concentrations at the site boundary for all averaging periods are well below applicable standards and that there would be no measurable changes in these levels between now and the year 1996 (Table 4.1.3-9 and Figure B.28).

Sulfate. A small fraction (about 5%) of sulfur compounds from combustion sources is estimated to be emitted as SO_4. Therefore, SO_4 emissions at NPR-1 are estimated to be less than 1 pound/hour. Since a small net decrease in SO_2 emissions is expected between now and 1996, SO_4 emissions also are expected to decrease. In addition, conversion of SO_2 to SO_4 during travel of the air mass over the NPR-1 site is expected to be insignificant. Therefore, no significant impacts of SO_4 from the existing sources at NPR-1 are anticipated, and no significant changes in SO_4 impacts are expected as a result of the proposed action. The maximum contributions from the NPR-1 sources to the ambient 24-hour ground-level SO_4 concentrations at the site boundary are estimated (based on SO_2 modeling results) to be negligible, i.e., about 0.1 microgram/cubic meter for both the existing and future conditions (Table 4.1.3-9).

Nitrate. Nitrates in the atmosphere are derived primarily from the atmospheric chemical reactions of NO_x. The NO_x emissions from the NPR-1 sources are subject to these chemical reactions and contribute to the regional levels of atmospheric nitrate. However, a net decrease in the emission of NO_x is expected as a result of the proposed action. Therefore, a net decrease in impacts is expected.

Particulate Matter. Most (94%) of the PM_{10} emissions occurring throughout the year at NPR-1 are road dusts; combustion source stacks and vehicle exhausts contribute the rest of the PM_{10} emissions. An intermittent, but important, PM_{10} emission source of short duration (lasting for a 10-day period each April) is maintenance of the firebreak that extends around and just inside the NPR-1 boundary. The emission rate of PM_{10} for this work is small on an annual basis, but is large while occurring. The maximum 24-hour and annual mean PM_{10} concentration contributions estimated at the site boundary are 2.7 micrograms/cubic meter and 0.2 micrograms/cubic meter, respectively, for combustion source emissions only, and about 47 micrograms/cubic meter and 16 micrograms/cubic meter respectively, when the impacts from vehicular emissions, including road dusts, are added. Since a small increase (31 pounds/hour) in PM_{10} emissions is projected between now and the year 1996, the contributions of NPR-1 to total concentrations are expected to increase only slightly (Table 4.1.3-9 and Figures B.30 and B.31).

Although these estimated concentration contributions from NPR-1 sources do not by themselves exceed the applicable NAAQS or CAAQS, the maximum 24-hour mean concentration contribution (50 micrograms/cubic meter) is equal to the corresponding CAAQS. When background PM_{10} concentrations are included, the total concentrations would exceed the 24-hour CAAQS, and possibly the 24-hour NAAQS (150 micrograms/ cubic meter) and annual CAAQS and NAAQS. Contributions from the firebreak maintenance work are likely to increase the probability of causing the 24-hour standards to be exceeded. However, the maximum total PM_{10} concentration levels at the site boundary cannot be estimated with a reasonable degree of accuracy until measurements are made of on-site ambient levels. The road dust emission reductions that would be required by the proposed Fugitive Dust Control Regulations for the San Joaquin Valley Air Basin and the additional reductions required to bring down the cumulative net emission changes in PM_{10} to zero at NPR-1 (see Section 4.1.3.1) would contribute significantly to reducing the ambient PM_{10} concentration levels at NPR-1. Initiatives at NPR-1 to comply with the Regulations are in various stages of planning and implementation, and they include instituting an employee van pool program (approximately 27 eight or fifteen passenger vans), improving on-site roads, modifying vehicles, and addressing on-site ridership. These and other initiatives are to be included in a Transportation Management Plan and a PM_{10} Control Plan which, among other things, will specifically address long-term compliance with the State and Federal Clean Air Acts.

Lead. No emissions of lead are expected from any of the equipment that would be installed for the proposed steamflood expansion project.

Hydrogen Sulfide. Very conservative estimates indicate that the maximum ambient H_2S concentrations from stack vent stacking releases at NPR-1 tank settings are about 10% of the appropriate CAAQS (Table 4.1.3-9 and Figure B.32). Some increases in H_2S concentration of raw gas produced at NPR-1 are expected as a result of proposed steamflood recovery operations. However, the ambient air concentration is expected to remain well within the standards.

Benzene. The only source of benzene emissions at NPR-1 that may result in any significant ambient concentrations is evaporation from oil spills (0.26 pounds/hour annual average for 1987). Emissions from other sources, e.g., the benzene in the ROG releases from the relief valves at tank settings and LACT tanks (<0.02 pounds/hour), and that in ROG fugitive emissions throughout NPR-1 (less than 0.02 pounds/hour), are small and diffuse. Therefore, no significant air quality impacts are expected from these sources.

The benzene component of an oil spill is estimated to evaporate completely within about 1 hour after the spill (Stiver et al 1989). The maximum 1-hour ambient concentrations of benzene for that 1-hour period are estimated to be about 66 ppm and 90 ppm at the downwind boundaries of a minor spill (10 barrels) and a major spill (250 barrels), respectively. For a worker standing at these locations, those concentrations are equivalent to about 11 and 8 ppm as 8-hour, time-weighted, mean concentrations. These levels are higher than the OSHA's standard for benzene permissible exposure limits (PEL's) [8-hour, time-weighted average (TWA) of 1 ppm and 15-minute time-weighted, short-term exposure limit (STEL) of 5 ppm]. However, oil and gas activities are exempt from these standards (29 CFR 1910.1028, VI). The applicable standard for benzene PEL's for oil and gas activities is 10 ppm (8-hour TWA) and 25 ppm (STEL) (29 CFR, 1910.1000, IV). To avoid an exposure above the benzene PEL's, an oil-spill cleanup procedure has been implemented that requires oil-spill cleanup crews to begin cleanup operations from the upwind side of the spill. Protective clothing and equipment will be provided if benzene levels exceed OSHA standards (BPOI 1992).

Visibility. Impairment of visibility is caused by the scattering and absorption of light by suspended particles and gases in the atmosphere. The most important man-made causes of degraded visual air quality are fine solid or liquid particles (atmospheric aerosols) and to a lesser extent NO_2 (EPA 1979). The current emissions at NPR-1 of fine suspended particles and NO_2, and their precursors (e.g., ROG, NO_x, SO_2), would contribute to visibility impairment in the vicinity of NPR-1 and the southern San Joaquin Valley. However, the proposed action would actually result in significant net decreases (ROG, NO_x, and SO_2) or small net increases (PM_{10}) of such emissions. Therefore, the proposed action is expected to have only minimal adverse impacts on visibility in the vicinity of the NPR-1 site.

4.1.3.3 Acoustical Impacts

Under the proposed action, new audible-noise sources at NPR-1 would include 18 compressors with a total rated capacity of 37,500 horsepower, 10 additional steam generators rated at 62.5-million BTU/hour each, 2 heaters rated at 41.5-million BTU/hour each, and 2 gas-turbine-driven cogenerators each rated at 21 megawatts and equipped with exhaust-heat recovery steam generators. Table 4.1.3-10 lists the relative acoustic-power- emission levels of the noisiest pieces of equipment in use.

The State of California (1972) requires that each community have a general plan containing, among other items, a noise element (California Government Code, Division 1, Planning and Zoning, Chapter 3 - Local Planning, Article 5, Section 65302). This requirement is met by the

TABLE 4.1.3-10 Typical Acoustic Power of NPR-1 Noise Sources

Equipment	Acoutic Power (watts)[a]
21-MW gas-turbine system	8.0[b]
5,500-hp compressor engine	2.6[c]
466-hp drilling rig engine	1.0[b]
62.5 x 10^6-BTU/h steam generator	0.72[d]
Heavy truck (accelerating)	0.32[e]

[a]A-weighted spectrum.
[b]Measured performance data obtained from the manufacturer.
[c]Derived from field measurements (Hanna 1989), using American Gas Association (1969) model.
[d]Derived from the steam generator design specification data using the Heitner (1968) model.
[e]Field measurement data (Sharp and Donavan 1979).

noise element of the Kern County General Plan issued by the Kern County Department of Planning and Development Services, the Tupman Rural Community Plan, the Dustin Acres Rural Community Plan, and the Valley Acres Rural Community Plan. Collectively, these documents define a requirement for a proposed new facility to provide plans for mitigating noise emissions if the proposed action is likely to cause outdoor noise levels in the community to exceed 55 decibels, community noise equivalent level (CNEL) or day-night sound level (L_{dn}). This corresponds to about a 48-decibel residual level for these kinds of acoustical environments (Conner 1978; Bishop 1979; Fidell et al 1981; and U.S. Air Force 1987).

Analyses have been made of both baseline (existing) ambient noise environments and worst-case intrusive (future) noise emissions to the residential communities nearest to the NPR-1 property lines for all phases of the proposed NPR-1 steamflood expansion project through the year 1996. The probability of hearing increased drilling, steam injection, gas-compression, power-generation, and associated trucking activities was investigated using the Fidell probabilistic detectability model (Fidell and Horonjeff 1982). These are the only major sources that would be audible at the residential communities. Noise from other, smaller sources would not be audible at the distances under consideration. Variables in the acoustic model included terrain effects (groundcover and hill-shielding), as well as the fundamental attenuation mechanisms of spreading, atmospheric absorption, and scattering losses due to air turbulence (BB&N 1984).

Three community locations were selected for analysis (Figure 4.1.3-1). These locations are the residential sites closest to the areas within the NPR-1 where the greatest concentrations of noise-producing activities would occur during any phase of the proposed action. Table 4.1.3-11 lists the distances between those activity locations that are closest to the community and, in turn, the residential locations selected because they are closest to the NPR-1 noise-producing activities. This approach to the selection of source and receiving locations results in conservative numerical results. Distances from sources to receptors of interest are mostly in the range from 2 to 7 kilometers. Sound attenuation over such distances is very large (typically 90 to 150 decibels in the middle of the audible-frequency range).

The results of the modeling analyses indicate that only insignificant increases in A-weighted residual noise level would occur in any of the three communities as a result of the proposed action: about 3 decibels maximum in Tupman (in the year 2000), 3 decibels maximum in Dustin Acres (in 1991), and about 1 decibel maximum in Valley Acres (in 1996). These increases in the residual environmental noise levels would result in no CNEL or L_{dn} levels greater than about 48 decibels in any community. Therefore, no noticeable impacts are foreseen.

FIGURE 4.1.3-1 LOCATIONS OF NEAREST RESIDENCES TO MAJOR NOISE SOURCES AT NPR-1

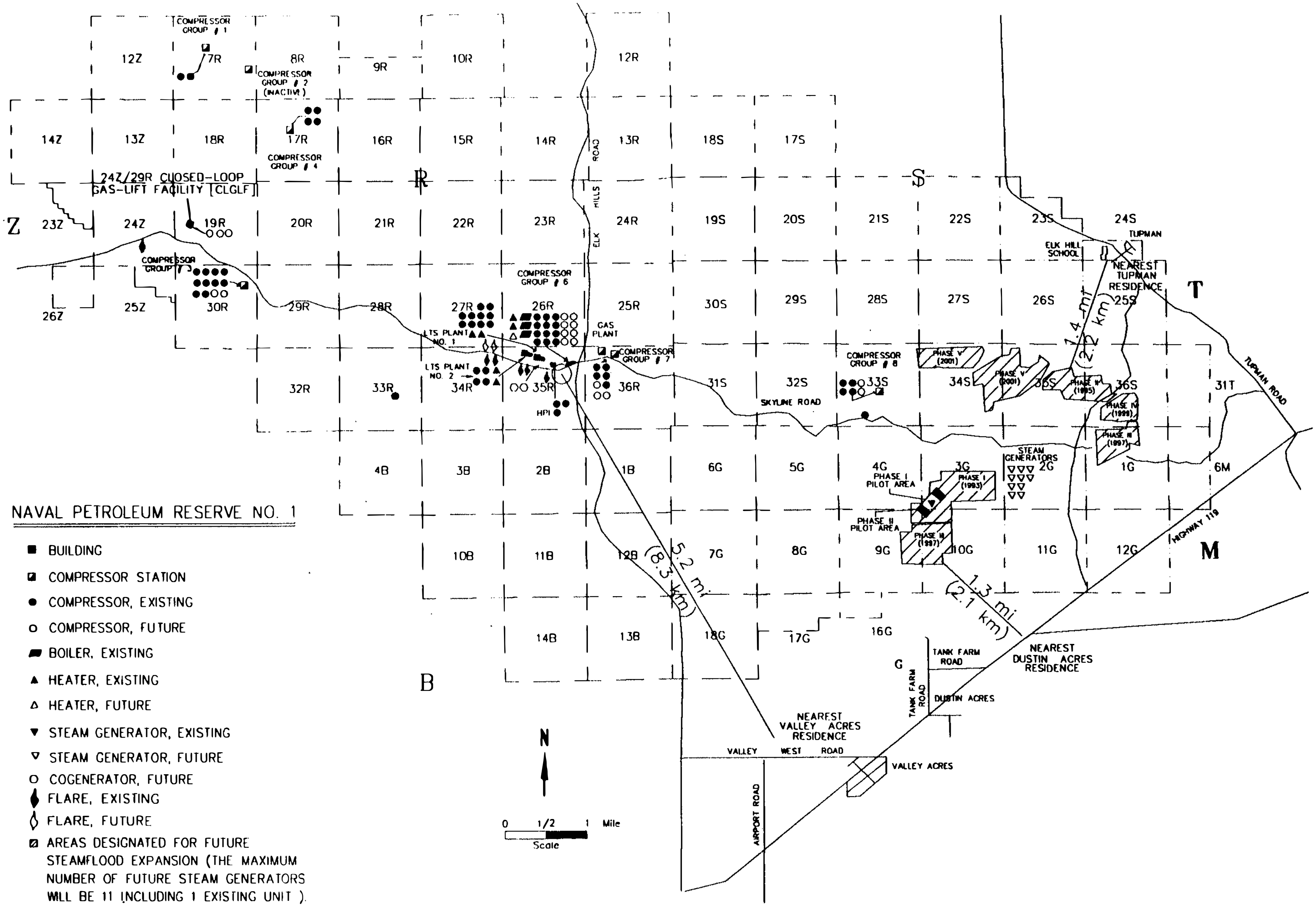

TABLE 4.1.3-11 Average Distance between *Worst-Case* (shortest-path) Combinations of Noise-Source and Residential Locations Selected for Analysis

Noise Source	Distance to Residential Sites (km)		
	Tupman	Dustin Acres	Valley Acres
Phase I Wells (3G)	5.9	2.6	6.0
Phase II Wells (35S)	2.2	4.4	9.3
Phase III(A) Wells (9/10G)	5.9	2.1	4.3
Phase III(B) Wells (1G)	3.2	3.7	7.0
Phaes IV Wells (36S)	2.7	4.5	7.8
Phase V Wells (34/35S)	2.7	4.4	7.0
Gas-turbine generator (35R)	11.0	10.4	8.3
Compressor group (33S)	5.1	5.3	7.0

4.1.3.4 References*

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*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California 93276.

4.1.4 Water Resources

4.1.4.1 Surface Water

Data presented in Section 3.4.1 indicate that because of the arid conditions of the area, only a small amount of surface-water runoff leaves Elk Hills. Except for a few days each year when excess precipitation occurs, the stream channels draining the flanks of the hills do not carry natural runoff. Given these circumstances, the actions proposed for future development at NPR-1 should cause few, if any, significant adverse impacts to the existing surface-water resources.

Although some surface disturbances will occur during the construction of new surface structures, access roads, well pads, and other facilities, significant impacts to the surface-water resources are not likely because of the lack of surface-water features on the site and the limited ability of the surface-water system to transmit water and materials any appreciable distance off the site. Even if a major runoff-producing storm were to occur during the period where surface disturbance was at a maximum, or following some major accidental release of contaminants, the potential for adverse impacts to off-site surface-water resources should be minimal.

Several measures have been taken to prevent any runoff from entering the California Aqueduct along the northern and northeastern perimeter of the Elk Hills. The western side of the aqueduct has been constructed with a high berm to divert runoff, and overshoots have been constructed at various locations to carry runoff water across the aqueduct for discharge into the Kern River Flood Canal. Southeast of the Elk Hills at the eastern terminus of Buena Vista Creek, a dike was constructed to divert flow away from the aqueduct and into Buena Vista Lakebed. In addition, NPR-1 has plans to implement a drainage reclamation program that addresses historical drilling sumps that may have been abandoned in natural drainages as a mitigative measure for surface water quality protection.

As discussed in Section 3.4.1 and Appendix J, 33 sites are identified on draft U.S. Fish and Wildlife Service National Wetland Inventory Maps of NPR-1. Based on a preliminary field evaluation (Fries 1993), 17 of these sites were determined to be produced water sumps; 8 were man-made obstructions to control the spread of potential oil spills; 1 was a diked area; 6 were ephemeral stream channels, and 1 was a lowland area associated with the historic channeling of the Buena Vista Slough. The evaluation concluded that the 17 produced water sumps do not meet wetland criteria the 8 man-made obstacles and the 1 diked area probably do not meet wetland criteria and need to be evaluated further in the springtime to confirm this; and the remaining 7 sites may qualify for wetland designation and need to be evaluated in accordance with 33 CFR Part 328.3 and the 1987 U.S. Army Corps of Engineers Wetland Delineation Manual (Corps of Engineers 1987). These recommendations will be followed. In the interim the 7 sites that may qualify as wetlands will be protected from operations and development activities.

4.1.4.2 Groundwater

Unmitigated, the proposed action has the potential of affecting groundwater resources in several ways. The primary considerations are increased quantities of wastewater to dispose of as the result of more intense enhanced recovery operations and higher water cuts associated with the continued production of a mature oil field. Intensified enhanced recovery operations would also increase the need for source water for waterflood and steamflood initiatives.

The discussion of groundwater impacts, and potential impacts, is presented below in three Sections: continuing current operations, planned facility development, and planned mitigation. Each Section is further divided into eight impact areas that are considered to be the ones that are the most significant. These areas are: (1) hydrocarbon, equipment lubricant, and fuel spills; solid wastes; and surface soil contamination; (2) producing well cellars; (3) wells; (4) disposal of fluids associated with drilling, degreasing, and equipment washing; (5) dehydration/LACT stations and associated storage facilities; (6) injection of fluids associated with enhanced hydrocarbon recovery; (7) disposal of oil production wastewater; and (8) fresh water activities. These eight impact areas were also discussed in Section 3.4.2.4 in terms of the existing environment; reference is made to these discussions for additional information.

4.1.4.2.1 Impacts from Continuation of Current Oil and Gas Activities

This section addresses the impacts of the proposed action that are associated with current operations and not related to development facility projects. These impacts are expected to continue, and are discussed as follows:

Hydrocarbon, Equipment Lubricant, and Fuel Spills; Solid Wastes; and Surface Soil Contamination

As the field matures, oil production would decline significantly as previously discussed (see Table 1.2-1). This is expected to reduce the frequency and volume of spills correspondingly. To reduce the effects of corrosion and lengthen life-cycles of pipelines and equipment, DOE implemented an aggressive corrosion control program in 1986. DOE also has begun a planned proactive maintenance program that will sustain high standards of equipment reliability and plant availability. A strategic plan for implementing a total quality planned maintenance program is now being implemented (DOE 1992). This program will enable DOE to effectively manage the requirements of its equipment inventory. This should reduce soil contamination significantly, as well as potential impacts to groundwater resources.

The combination of oil and produced water production are expected to increase in the short term (declining oil production is expected to be more than offset by increasing water production--see Table 1.2-1). This should result in some increase in the volume of some solid wastes, such as tank bottom sediments. In comparison to current operations, this increase is not expected to be significant, and these wastes will be disposed of by the environmentally sound methods discussed in Section 3.2.

Drilling activity is expected to be significantly less than in the past. This should result in a substantial reduction in spent drilling fluids which is one of the most significant waste streams on the site. Drilling fluids are discussed further under the topic of disposal of drilling fluids below.

Well Cellars

Risks associated with well cellars (see Section 3.4.2.4) should decline as production declines and wells are taken out of production.

Wells

Wells have the potential of impacting groundwater, as explained in Section 3.4.2.4 -- i.e., wells could leak into overlying groundwater aquifers. As the result of the drilling program included in the proposed action (see Section 1.2.2.4 and Table 1.2-3), the total number of wells at NPR-1 is expected to increase by approximately 382--from 2,315 to 2,697 (BPOI 1989).

In recognition of the risks posed by wells (see Section 3.4.2.4), stringent laws and regulations have been put in place to govern the completion of new wells that are drilled, the operation/monitoring of active and idle wells, and the abandonment of wells when their economic life has expired. These regulations are followed closely and minimal impact to groundwater resources is expected.

As production declines, wells will be taken out of production. Therefore, the risks associated with active wells would decline correspondingly.

Generally, wells that have been removed from production remain in an idle status until they can be evaluated for stimulation and/or enhanced recovery opportunities; this, and subsequent periods of reactivation, usually take place over an extended period of time. When idle wells are eventually determined to have no further economic benefit, they are abandoned. Idle wells pose a potential risk for communication of fluids between producing zones if the wells have casing leaks. Because of this potential, NPR-1 routinely checks idled wells for integrity and takes necessary corrective action as required. Abandoned wells are fully "plugged" with a cement slurry to prevent any movement of fluids within the well. In the long term, as more idle wells are abandoned, the risks associated with idle wells should decrease and eventually become insignificant.

As abandonments occur, the risks associated with abandoned wells will increase. Given that abandoned wells are permanent components of the environment, the regulations that govern this activity provide for an increased level of environmental protection; accordingly, the risks associated with abandoned wells are less than those associated with active and idle wells. Therefore, as time passes, and active and idle wells are converted into abandoned wells, the potential for impacting groundwater should decrease correspondingly.

As of the end of FY 1988, the total number of active and idle wells was approximately 2,055. Under the proposed action, abandonments planned are 180 and 900 for the periods FY 1989-1995 and FY 1996-2025, respectively, which is a total of 1,080. As explained above, 382 new wells are planned to be drilled during the same period. On this basis, active and idle wells are expected to decline to 1,357 (2,055 - 1,080 + 382 = 1,357), which represents a reduction of 698 (2,055 - 1,357 = 698). For additional information pertaining to abandonments refer to Section 1.2.2.14 and Table 1.2-8.

Disposal of Fluids Associated with Drilling, Degreasing, and Equipment Washing

Spent drilling fluids are the most significant waste streams at the site, and therefore they have the greatest potential for impacting groundwater. Drilling activity is expected to be significantly less than in the past which should reduce the volume of spent drilling fluid requiring disposal proportionally (see Section 4.1.2.1). Current drilling fluids no longer contain the chromium compounds that were added to some drilling fluids prior to 1983 (see Section 3.2.3.1) and which now pose an environmental removal problem at NPR-1. Overall, risks to groundwater associated with drilling operations are expected to be reduced substantially.

Waste fluids that are generated from other operations, such as degreasing and equipment washing, should decrease over time as production declines and equipment is taken out of service and/or used on a less frequent basis.

Dehydration/ LACT Stations and Associated Storage Facilities

Declining production should lower risks associated with spills, overflows, etc. at these kinds of facilities. On the other hand, as the age of these facilities increases, the risk of leaks should increase correspondingly. Projects to address these risks are included in the proposed action, and they are identified in the Section 4.1.4.3 pertaining to mitigation.

Injection of Fluids Associated with Enhanced Hydrocarbon Recovery

Enhanced recovery activities such as waterflood, steamflood, and gas injection are expected to continue and intensify. Accordingly, the risks these operations pose to groundwaters should increase correspondingly: i.e., leaking injection wells could provide a mechanism for producing formations to leak into groundwaters. Reference is made to Section 3.4.2.4 for additional information.

Currently, there are 151 injection wells at NPR-1 (132 Stevens waterflood, 14 Stevens gas, 3 SOZ gas and 2 SOZ waterflood). Waterflood injection is approximately 148,000 barrels/ day into the Stevens Zone areas shown by Figure 3.4-5. Gas injection is currently approximately 188.2 million cubic feet/day into the Stevens Zone areas shown by Figure 3.4-6. The steamflood project is currently injecting approximately 3,100-5,200 barrels/day of fresh water as steam into the SOZ in the area shown by Figure 1.2-2 (Phase I). The continuation of the enhanced recovery programs should pose only a minimal risk to groundwater. This is because the injection wells are completed and monitored in accordance with the stringent laws, regulations, and DOE Orders that govern this activity, and because injection zones are deep and groundwater aquifers are relatively shallow, thus minimizing the potential for communication in the event the injection systems fail. The groundwaters at risk (i.e, those that are penetrated by the injection wells) are in UIC exempt aquifers where the quality of the groundwater is not suitable for use for potable water supplies.

As indicated above, plans are to intensify enhanced recovery operations. The impacts of these initiatives are discussed in Section 4.1.4.2.2 (planned facility development) under the enhanced recovery discussion.

Produced Water Disposal

As the field matures, continued production results in producing proportionally larger quantities of water. As a result of these circumstances and increases in waterflood injection quantities (described in Section 4.1.4.2.2), produced water is expected to increase from the current level of approximately 100,000-110,000 barrels/day to approximately 181,000 barrels/day in FY 1994 (see Table 1.2-1).

Disposal of produced water is currently being carried out in accordance with applicable laws, regulations and DOE Orders, under the authorities described in Section 3.4.2.4. Produced wastewater is disposed of primarily by injection into the Tulare Zone; currently this is approximately 80,000-100,000 barrels/day. Additional wastewater is disposed of by deep injection into producing zones - currently approximately 10,000 barrels/day. Some wastewater is disposed of by percolation/evaporation in open, lined and unlined sumps/secondary containment during off-normal situations (currently approximately 1,000-2,000 barrels/day). If these disposal methods continue to be utilized, given the quantities of wastewater forecast for the future, the impact on NPR-1 and adjacent groundwaters could be significant.

This is especially true for NPR-1 groundwaters in the Tulare Zone where wastewaters are being injected and sumped. However, even though the impact on NPR-1 groundwaters could be significant, the result is unlikely to be consequential since these groundwaters are in UIC exempt aquifers which are not known to have any beneficial uses other than as a potential source for oil-field waterflood operations (Smith 1986).

In addition to NPR-1 groundwater impacts, there is a potential that usable groundwaters along the periphery of the site could be affected. If wastewaters currently being released to unlined sumps (which overlie the Tulare Formation) have a flowpath above the water table to usable groundwaters near the margins of the site, and/or if the relatively poor quality NPR-1 groundwaters can flow into these usable groundwaters, then there is a possibility that past and/or ongoing wastewater disposal practices could degrade usable groundwaters. (NPR-1 groundwaters have and continue to receive wastewaters by injection into the Tulare and by sumping. In the past, some sumping was into unlined sumps near the Tulare/Alluvium contact). For additional information pertaining to NPR-1 groundwater impacts, and the potential for groundwater impacts near the boundaries of NPR-1, reference is made to Section 3.4.2.4 and Appendix D where these issues are discussed in greater detail.

In recognition of the foregoing impacts and risks, projects have been initiated to address them. These projects are explained in Section 4.1.4.2.2 under enhanced recovery and produced water disposal discussions, and in Section 4.1.4.3 pertaining to mitigation. Generally, the objective of these projects is to minimize, or eliminate, injection into the Tulare; to continue reducing releases into unlined sumps; and to evaluate NPR-1 groundwater regimes for the purpose of assessing and acting on the effects of past and ongoing operations, as appropriate. It is anticipated that implementation of the planned mitigation will preclude any significant adverse impacts.

Fresh Water Activities

In FY 1988, fresh water consumption was approximately 29,000 barrels/day (Filley 1989) (see Section 3.4.2.4). These requirements have been increasing, primarily as the result of increases in gas processing and well remediation. This trend is expected to continue, but the increases are not expected to have any adverse impacts. This is primarily because existing systems should be capable of providing requirements associated with the continuation of current operations.

Most of the projected increase associated with continuing operations will be due to increased gas processing as the result of a projected short-term increase in gas production (see Table 1.2-1). In the long term, gas rates are expected to decline in a manner similar to oil rates; therefore, increased fresh water requirements as the result of gas processing should be temporary. Additional water will also be required to support an intensified well remediation program which will be needed to offset natural production declines and maintain MER production. Eventually, well remediation opportunities will decline, and associated water requirements should decline correspondingly (see Table 1.2-4). Increases in the amount of water required for gas processing and well remediation should be partly offset by a decrease in water required for the drilling program (see Section 4.1.2.2).

4.1.4.2.2 Impacts from Planned Facility Development

This Section addresses the impacts of the proposed action that are the result of development facility initiatives. These impacts are discussed as follows:

Hydrocarbon, Equipment Lubricant, and Fuel Spills; Solid wastes; and Surface Soil Contamination

Disposal of Fluids Associated with Drilling, Degreasing, and Equipment Washing

The facility projects that comprise the proposed action, including future third-party projects, are expected to generate spills, solid wastes, and fluids which could require disposal and which could contaminate soils and degrade underlying and peripheral groundwaters. These spills, solid wastes, and fluids are expected to be relatively small, and programs are in place to address them in an effective manner (see planned mitigation activities in Section 4.1.4.3); therefore, impacts should not be significant. Some examples of the projects included in the proposed action that have the greatest potential for these types of impacts are the closed-loop gas-lift projects, the gas operations expansion project (fourth gas plant), the cogeneration project, the butane isomerization project, the SOZ steamflood project, and waterflood projects. Mitigation activities are presented in Section 4.1.4.3.

Water used to hydrostatically test equipment, including future third-party projects, could impact groundwater resources. Hydrostatic test water is typically fresh water that is pressured into new and clean pipelines. Following the completion of the tests, these waters require disposal. Given that normally the water is fresh and the equipment is clean, it is anticipated that whatever the means of disposal, risks should be minimal. Nevertheless, special precautions will be taken. More specific plans are identified in Section 4.1.4.3. It is anticipated that these measures will preclude any significant adverse impacts.

Producing Well Cellars, and Wells

These operations are not included in planned facility development; they were covered in the preceding Section on the continuation of current operations.

Dehydration/LACT Stations and Associated Storage Facilities

As mentioned in Section 4.1.4.2.1, dehydration/LACT facility operations have the potential of causing overflows and/or leaks which could degrade underlying groundwater; this includes related activities that intensify the use of these kinds of facilities, such as activities associated with third-party pipelines that connect to LACT facilities. The 25S area is particularly important because of aging facilities that are situated near the California Aqueduct and the Tulare/Alluvium contact adjacent to the proposed Kern Water Bank Project in the vicinity of usable groundwater. In recognition of the risks posed by these facilities, the proposed action includes projects to appropriately repair, or replace, or relocate, or remove the components of the 25S dehydration/LACT and tank setting facilities. Additional information pertaining to this initiative is presented in Table 1.2-10, Section 1.2.2.14, and Section 4.1.4.3. The proposed action also includes a site-wide project (including the 25S area), which is in progress, to enhance secondary containment facilities; this will provide additional protection for groundwater resources. Additional information regarding the secondary containment project is included in Table 1.2-10.

Injection of Fluids Associated with Enhanced Hydrocarbon Recovery

Of the estimated 148 new wells planned for the SOZ Steamflood (see Table 1.2-3), approximately 60 are injectors. In addition, approximately 5-10 additional injectors are planned for the Stevens waterflood, plus 10-15 additional injectors for the SOZ SS-2 Mulinia waterflood. Additional Stevens gas injectors are expected to be 2-5 wells. Another 5-15 gas injectors could be needed for gas injection into the SOZ. If the SOZ SS-1 is waterflooded, this could require

25-60 additional water injectors which would be in lieu of all or a part of the SOZ steamflood injectors previously mentioned. In total, there could be a need for as many as 105 additional injectors (steamflood, waterflood and gas injection).

Within a few years, waterflood injection is expected to increase from the current level of approximately 148,000 barrels/day to approximately 254,500 barrels/day (see Section 1.2.2.7 and Table 1.2.-1); this is an increase of approximately 106,500 barrels/day, and is to include the SOZ and the Stevens Zone. New projects that have been conceptualized to date include a 20,000 barrels/day increase in the existing 24Z Stevens waterflood (see Figure 3.4-5), and a new 24,000 barrels/day waterflood project in the south flank of the SOZ in the SS-2 Mulinia (see Figure 3.4-5). An evaluation is also in progress to determine the benefits of waterflooding all or portions of the SOZ SS1 as an alternative to steamflooding. The affected areas are shown by Figure 3.4-5.

Gas injection is projected to increase from 188.2 million cubic feet/day to approximately 271.5 million cubic feet/day, or an increase of 83.3 million cubic feet/day (see Section 1.2.2.8 and Table 1.2-1); this increase will be due to an increase in Stevens injection and new injection initiatives involving the SOZ. It is anticipated that for the most part the increase can be accommodated utilizing existing wells and facilities in the areas denoted by Figure 3.4-6.

Steam injection into the SOZ is anticipated to increase from approximately 3,100-5,200 barrels/day of water as steam (see Section 1.2.2.6 and Table 1.2-1) by approximately 32,805-34,478 barrels/day (see Tables 1.2-1 and 1.2-6) by FY 1994, or an increase to approximately 35,905-39,678 barrels/day. For more information pertaining to the SOZ steam project, refer to Section 1.2.2.6. The areas proposed for steamflooding are shown by Figure 1.2-2.

The risks these enhanced recovery projects pose to groundwater are the same as those that were explained in Section 4.1.4.2.1. For the reasons given, it is not anticipated that these risks are significant.

The expansion of the waterflood and steamflood projects would also increase the need for source water for these initiatives. The source water for the steam project would be fresh water which is a separate topic of discussion below. As previously mentioned, the additional water required for the waterflood program is 106,500 barrels/day. For this program, plans are to provide the additional water by recycling produced wastewater; this is referred to as the Produced Water Injection (PWI) Project. The project would have the dual benefit of providing water for the waterflood program and reducing wastewater requiring disposal. The wastewater disposal component of this initiative is presented separately in the produced water disposal discussion presented below and in the mitigation discussion in Section 4.1.4.3. Additional information pertaining to the source water component is discussed as follows.

Recently, construction was completed on a project to recycle approximately 50,000 barrels/day of wastewater for use in the existing waterflood; currently, this project is in the start-up phase and is being evaluated. It has not been possible to begin recycling operations because the quality of the water produced by the project does not meet current waterflood source water specifications for quality. As designed, the project would reduce by 50,000 barrels/day the amount of Tulare water currently being withdrawn as source water for the existing waterflood. Additional projects to accomplish the same objective are planned, pending the results of the first project. Assuming it proves technically and economically possible to recycle all wastewater for use as waterflood source water, this could involve recycling up to 181,100 barrels/day (see Table 1.2-1). Since the waterflood projects are projected to require up to 254,500 barrels/day (see Table 1.2-1), it would be necessary to obtain the balance of 73,400 barrels/day from the Tulare (254,000-181,100= 73,400).

Currently, the full amount of the waterflood of 148,000 barrels/day is provided from the Tulare. Therefore, it is possible that Tulare withdrawals could be reduced by as much as 74,600 barrels/day (148,000-73,400=74,600).

Source Water Withdrawal

If the PWI projects are unsuccessful, Tulare withdrawals would need to be increased from approximately 148,000 barrels/day to a maximum of approximately 254,500 barrels/day. Disposal of produced wastewater into the Tulare Formation would be a maximum of approximately 181,000 barrels/day. The resulting Tulare drawdown would be approximately 73,500 barrels/day (254,500 - 181,000 = 73,500). As discussed in Section 3.4.2.4 and Appendix D, Section D.4.2.2, this is comparable to historic operations which have been observed to have had no significant impact on the level or quality of the Tulare aquifer underlying NPR-1 or adjacent alluvial aquifers within the Alluvium in Buena Vista Valley.

Produced Water Disposal

As mentioned in Section 4.1.4.2.1, the waterflood and steamflood would contribute to increasing the amount of wastewater requiring disposal. This poses the same risks to groundwater that were discussed in that Section: i.e., the impact to NPR-1 groundwater is expected to be significant, but these waters are in a UIC exempt aquifer, they are poor quality, and except for oil-field waterflood operations, they have no known beneficial uses. In addition to impacts to NPR-1 groundwaters, there is also some possibility that wastewater disposed of on-site could migrate into usable groundwaters along the site periphery (see Section 3.4.2.3 and Appendix D). In recognition of this possibility, the following mitigation actions are in progress: to eliminate or minimize Tulare injection; to continue minimizing releases into unlined sumps; and, to evaluate NPR-1 groundwater regimes for the purpose of assessing and acting on the effects of past and ongoing activities, as appropriate. Discussion on the initiative to eliminate/reduce Tulare injection follows.

As mentioned in the enhanced recovery discussion above, the proposed action includes a project that has been constructed to recycle approximately 50,000 barrels/day for the purpose of reducing wastewater requiring disposal and to provide source water for future waterflood projects; this project is in the start-up phase which is expected to require an extended period of time. When start-up is completed, injection into the Tulare would be reduced by approximately 50,000 barrels/day from the current level of 80,000-100,000 barrels/day. This would result in a continuing need to dispose of approximately 30,000-50,000 barrels/day by injection into the Tulare. Produced water is expected to peak within a few years at approximately 181,000 barrels/day (see Table 1.2-1). Therefore, future wastewater quantities available for recycling are estimated to be on the order of 131,000 barrels/day (181,000-50,000=131,000). Additional projects to pursue this opportunity are planned as part of the proposed action (PWI projects).

If it is possible to recycle all wastewater (as described in the enhanced recovery discussion above), sumping and Tulare injection would eventually be reduced essentially to zero; this is the objective of the proposed action. Having stated this objective, however, it should be noted that recycling all wastewater may not be technically possible. This is primarily due to difficulties associated with filtering and cleaning produced water for use in waterflood applications. To the extent it is not possible to recycle all produced waters, some sumping and Tulare injection might continue to be necessary. It is anticipated, however, that whatever sumping and Tulare injection might continue, it should be considerably less than the current practice. Additional discussions on the recycling initiative are presented in the description of the proposed action in Section 1.2.2.7, and in Section 4.1.4.2.1 under produced water disposal discussions.

Fresh Water Activities

As indicated in the enhanced recovery discussion above, and the description of the proposed action in Section 1.2.2.6, if all five phases of the SOZ project are completed, the project could increase fresh water requirements by approximately 32,805-34,478 barrels/day. This, together with smaller requirements from other facility projects, such as the butane isomerization project, cogeneration plant project, and the continuation of existing operations (see Section 4.1.4.2.1), could result in a peak requirement of approximately 74,800 barrels/day within several years (see Section 1.2.2.16). Estimates of the fresh water and system capacity requirements for each phase of the project will be made during detailed engineering design studies. West Kern Water District anticipates having sufficient water supplies to meet the NPR-1 fresh water requirement for all five phases of the SOZ project (BPOI 1991).

As explained in Section 1.2.2.6, the SOZ steamflood project is planned to proceed one phase at a time with each successive phase being dependent on the economic success of the preceding phase. Given the economic uncertainties associated with enhanced recovery projects (particularly steam projects), it is a realistic possibility that the SOZ steam project may not be fully developed, or it may develop over a period of time that is much longer than currently projected. Accordingly, it is possible that added fresh water capacity may not be needed. Whatever the outcome, it is not anticipated that fresh water initiatives taken by themselves pose a significant threat to NPR-1 groundwater resources. The manner in which fresh water is used could adversely impact NPR-1 (e.g., by injection into the subsurface and increasing the production of wastewater requiring disposal), but these have already been discussed.

Based on the foregoing uncertainties, and unavailability of off-site information, it is not possible to assess off-site impacts at this time. If fresh water requirements exceed the current contract limit of 48,000 barrels/day, additional NEPA assessments would be completed as appropriate.

4.1.4.3 Mitigation

Water resource impacts would be minimized through the implementation of programs that comply with legal, regulatory, and permit requirements, as well as the myriad of DOE Orders that go beyond these requirements into good management practices. These include Orders that establish requirements in the areas of waste minimization/recycling, pollution prevention awareness, environmental protection implementation planning, groundwater protection planning and implementation, etc. Specific mitigative measures that are included as part of the proposed action are discussed as follows:

Hydrocarbon, Equipment Lubricant, and Fuel Spills; Solid Wastes; and Surface Soil Contamination

- Spills would be minimized, cleaned up and disposed of in accordance with the site's approved SPCC plan, which incorporates legal and regulatory requirements, as well as applicable DOE Orders.

- Inadvertent spills would be contained through the use of proper secondary containment. Pursuant to this, the proposed action includes a field-wide program to upgrade secondary containment facilities. A project is currently underway that addresses secondary containment at the 25 highest priority facilities. Additional similar projects are planned.

- Prior to disposal, wastes would be tested to determine if they are hazardous or non-hazardous. Non-hazardous wastes would be disposed of on-site in accordance with all requirements. Hazardous wastes would be disposed of off-site at permitted hazardous waste facilities.

- Projects are in progress, and others are planned, to identify, clean and formally close all historical inactive waste sites.

Producing Well Cellars

- Producing well cellars on or near the Alluvium would be monitored daily. All other wells ordinarily would be monitored daily, and no less often than weekly. If fluids are observed in the cellars, the fluids would be disposed of expeditiously in a manner that is consistent with the procedures described above for spills and wastes. In addition, corrective actions would be implemented to prevent reoccurrences.

Wells

- Well completions, operations, maintenance, monitoring, and abandonments would be carried out in strict conformance with all requirements.

- Instances of suspected well leakage, such as unexplained surface water observations, would be evaluated to determine potential sources. Evaluation results would be used to design and implement appropriate corrective actions.

Disposal of Fluids Associated with Drilling, Degreasing, and Equipment Washing

- Drilling and other fluid wastes would be minimized in accordance with the applicable DOE Orders.

- Drilling fluids would be designed to be nonhazardous, and they would be tested to confirm this after use and before disposal. Fluids that are confirmed to be nonhazardous would be disposed of on-site at permitted landfarms in strict accordance with Waste Discharge Requirements (see Section 3.2.3.2). In the rare instances when drilling fluids could test hazardous, they would be disposed of off-site at permitted hazardous waste facilities.

- Other waste fluids would be disposed of in accordance with requirements by methods that cause minimal impacts. For example, the proposed action includes initiatives to minimize sumping. One such initiative that is in progress is to install additional tankage at the truck washout facility at the 27R waste management facility. This tankage would be used to contain washwaters that previously were disposed of on a regular basis in two open unlined sumps. The wastewater collected in the tankage would be disposed of in the produced wastewater system. One sump would be cleaned and formally closed. The other sump would be retained for use as an emergency catch basin during off-normal situations, such as infrequent system failures like a tank overflow. Additional similar projects are in progress, or are being planned. Emergency catch basins would be managed in accordance with the SPCC plan.

- Hydrostatic test activities would be designed to minimize wastewater requiring disposal. To the extent practical, this would involve testing the systems in smaller units (e.g., different segments of third party pipelines) and reusing the water in each individual unit to minimize total water requirements. Wastewater releases to the surface would be contained in the general area of the test. To the maximum extent possible, only fresh water would be used for tests, and equipment would be cleaned beforehand. Wastewater would not be released to alluvial soils.

Dehydration/LACT Stations and Associated Storage Facilities

- 25S LACT/dehydration and tank setting facilities would either be relocated to less sensitive areas, or they would be inspected and repaired, or replaced, or removed from service, as appropriate.

• Secondary containment facilities would be upgraded field-wide. Projects are in progress to address the most sensitive areas--such as facilities in Section 25S.

• Third-party pipeline connections to LACT facilities would be controlled through the NPR-1 third-party permitting process. This provides a structured mechanism to ensure that connections granted have a beneficial need, and that they are designed, constructed, operated, and maintained in a manner that is environmentally safe, conforming to all environmental requirements.

Injection of Fluids Associated with Enhanced Hydrocarbon Recovery

• Well completions, operations, maintenance, monitoring, and abandonments would be carried out in strict conformance with all requirements. Particular attention would be paid to injection pressures to ensure they do not exceed safe levels, as needed to protect the producing injection formations from fracturing and potentially providing a flow path to overlying groundwaters.

• Instances of suspected well leakage, such as unexplained surface water observations, would be evaluated to determine potential sources. Evaluation results would be used to design and implement appropriate corrective actions.

• As explained in Sections 4.1.4.2.1 and 4.1.4.2.2, the impacts of the projected increase in waterflood source water requirements (which are currently provided by withdrawal from the Tulare Zone) would be minimized through the implementation of the wastewater recycling program (PWI projects). The proposed action includes a project to recycle approximately 50,000 barrels/day of produced wastewater. This project is in the start-up phase; when it goes on-line, Tulare source water withdrawals would be reduced by the 50,000 barrels/day figure. Additional similar projects are planned as part of the proposed action, with the objective being to recycle as much wastewater as is technically and economically possible, up to the amount of waste water produced (which is expected to peak at approximately 181,000 barrels/day within a few years).

Produced Water Disposal

• Wastewater quantities would be minimized pursuant to the requirements of applicable DOE Orders. Specific objectives and projects to accomplish this have been identified. These were discussed in Section 4.1.4.2.1 and 4.1.4.2.2 above. In summary, a project is in the start-up phase which, when complete, would recycle 50,000 barrels/day of produced wastewater for use as waterflood source water, thus reducing wastewater requiring disposal by that amount. Additional projects for the same purpose are planned, with the objective being a recycling program that eventually eliminates, or substantially reduces, the disposal of wastewater by traditional sumping and Tulare injection methods.

• Wastewater requiring disposal would be disposed of in strict accordance with requirements by acceptable injection and sumping methods that pose minimal threats to underlying and peripheral groundwaters.

● Releases of wastewater to sumps would be restricted to off-normal situations. Off- normal situations would be minimized through contingency initiatives that minimize the need to resort to surface disposal. For example, the proposed action includes a project to install additional wastewater tankage at the 18G dehydration/LACT facility for the purpose of reducing the potential for sump releases and eliminating and formally closing one of the two sumps situated there; this project is in the construction phase. The proposed action includes other similar projects which are in progress, or are being planned.

● Wastewater sumps at facilities located near the Tulare/Alluvium contact would continue to be lined.

● Inactive wastewater sumps that are no longer required would be formally closed. Formal closure includes testing for contamination, remediation if necessary, regrading and revegetation.

● In accordance with DOE Order 5400.1, a Groundwater Protection Management Plan has been approved and put in place; implementation of this plan is included in the proposed action. One of the elements of this plan addresses the fact that the potential is not fully understood for past and ongoing sumping and Tulare injection to degrade usable groundwaters on the periphery of the site. Accordingly, plan implementation includes an initiative to evaluate and attempt to understand underlying groundwater regimes. The first step in this initiative is to characterize groundwater hydrology to the maximum extent possible based on existing data (principally well data from drilling operations). The information collected from existing data will be reviewed to determine the need for additional data required to complete a comprehensive risk analysis of NPR-1 operations with respect to on-site and off-site groundwater resources. A draft groundwater monitoring plan in this regard has recently been developed for NPR-1 (Golder 1990) and is currently being reviewed. Construction and operation of groundwater monitoring wells is being contemplated for the northeast portion of the site.

● Initiatives to coordinate and cooperate with government agencies and organizations involved in local water matters will continue.

4.1.4.4 References*

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U.S. Department of Energy, 1992, Total Planned Quality Maintenance Plan, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California, June.

*Copies of correspondence and unpublished documents cited in this list are available upon request from James C. Killen, Manager, Technical Assurance, U.S. Department of Energy, Tupman, California 93276.

4.1.5 Terrestrial Biota

This section discusses the impacts of the proposed action on plant and animal communities, including threatened and endangered species.

As indicated by Table 1.3-2, numerous federal facility projects are anticipated to result in the disturbance of approximately 878 acres of NPR-1 lands, or about 2.1% of the remaining undeveloped habitat. Although exact project locations have not been specified, most will be dispersed throughout the developed portions of the site in Townships G, R, and S; some development will occur in other areas, including those that are currently undeveloped. Most disturbances should occur prior to the year 1998; some, however, will continue to take place over a longer period of time (perhaps until the year 2020-2025). In addition to the 878 acres to be disturbed, 625 acres associated with abandoned facilities, or 1.5% of the remaining undeveloped habitat, are to be revegetated (Table 3.5-1). This results in a 253-acre net increase in developed areas on NPR-1, or 0.6% of the remaining undeveloped habitat.

Disturbances associated with non-federal projects (third-party projects) are expected to be approximately 691 acres: 101 acres on NPR-1 (or about 0.2% of the remaining undeveloped habitat) and 590 acres off of NPR-1. These disturbances should take place on both developed and undeveloped lands (see Table 1.3-2), and they should occur periodically throughout the economic life of the NPR-1 project. Of the 691 acres to be disturbed, 420 acres are to be revegetated following construction completion: 60 acres on NPR-1 and 360 acres off NPR-1. This results in a 271-acre net increase in development; 41 acres on NPR-1 and 230 acres off NPR-1.

Total federal and non-federal disturbances on NPR-1 are projected to be about 979 acres (878 + 101 = 979), or approximately 2.3% of the remaining undeveloped habitat. Of this, 685 acres are to be revegetated (625 + 60 = 685), which results in an increase of 294 acres of development (979 - 685 = 294), or 0.7% of the remaining undeveloped habitat.

Total on-site and off-site disturbances are estimated to be 1,569 acres (979 + 590 = 1,569). Total on-site and off-site revegetation is estimated to be 1,045 acres (625 + 420 = 1,045). This results in an on-site and off-site increase in development of 524 acres (1,569 - 1,045 = 524).

Another 6,780 acres could be temporarily affected over the next 30 years as the result of non-federal third-party geophysical (seismic) surveys. It is anticipated that approximately one-half of this acreage, or about 3,390 acres, would be dispersed over both developed and undeveloped portions of NPR-1; the remainder would be on developed and undeveloped areas off-site. Seismic surveys should occur periodically throughout the economic life of the NPR-1 project.

A more complete discussion of impacts is presented below.

4.1.5.1 Plant Communities

Impacts of the proposed action on plant communities are expected to be qualitatively similar to those that have occurred on NPR-1 in the past (see Section 3.5.1). The most important impact will be the removal of vegetation from the 1,569 acres associated with construction activities.

All proposed federal facilities (approximately 878 acres) and all aboveground non-federal third-party projects (approximately 120 acres) would permanently displace vegetation for the life of the respective projects. The major portions of approximately 571 acres disturbed by underground third-party projects would cause only temporary impacts to vegetation. This is because all construction areas not needed for operations and maintenance activities, such as corridors for underground pipelines, would be revegetated following construction. It is estimated that of the 571 acres, 420 acres would be revegetated.

About 226 acres/year, or 6,780 acres over 30 years, are expected to be affected during seismic surveys. This activity would result in the crushing of some vegetation along the survey route; however, since the vegetation is not actually removed, adverse impacts are expected to be temporary. In some cases, small, widely spaced areas would need to be graded for placement of dynamite charges used in survey activities. Impacts would be minimized by adjusting survey routes to avoid endangered species and by revegetating graded areas.

NPR-1 soils are often loose and prone to erosion (Soil Conservation Service undated). However, erosion should be minimized by revegetation and mulch placement following construction, which are part of the existing reclamation program (discussed below). Soil erosion could occur nevertheless if major precipitation events occurred during construction of facilities, especially if construction occurred on steep or unstable slopes. Under these circumstances, if construction activities exposed saline soils, erosion could transport this material and result in death or inhibit the growth of intolerant species.

Operations and maintenance of proposed facilities would have relatively minor, localized impacts. Spills of oil and other oil-field chemicals could be expected at a rate comparable to that of current operations (see Section 4.1.9). Uncontained oil spills could result in the death of plants within the spill area. Plants also could be adversely affected by uptake from contaminated soils or by changes in soil chemistry (O'Farrell and Mitchell 1985).

Operations and maintenance of the proposed facilities could occasionally cause accidental fires (see Section 4.1.9). Such fires would cause changes in vegetation structure, especially the loss of shrubs, but would be expected to have little long-term effect because herbaceous annuals resprout during the following growing season (Heady 1977; O'Farrell and Mitchell 1985).

The impacts of construction, operation, and maintenance of proposed facilities on plant communities would be lessened because of the general location of facilities. Most development would occur in areas previously subjected to extensive development.

A program to reclaim previous disturbances that are no longer needed for operations (abandoned facility sites, roads, etc.) is in progress to compensate, in part, for MER disturbances (see Section 3.5.1, Table 3.5.1, and Section 3.5.3). Approximately 690 acres have undergone reclamation to date and another 625 acres are planned through 1998.

4.1.5.2 Animal Communities

The impacts of the proposed action on NPR-1 animal communities are expected to be similar to those that have occurred in the past (see Section 3.5.2). Most impacts would result from the construction of proposed facilities, including third-party pipeline projects and seismic surveys. Approximately 1,569 acres are expected to be disturbed over the next 30 years as a result of the construction of facilities, and a proportionate reduction in carrying capacity is anticipated. Animals within construction areas would be killed during construction or would disperse to other areas; dispersing individuals tend to have a lower survivorship (Emlen 1984; Ralls et al 1986). Soil erosion resulting from construction activities could destroy or alter habitat, or decrease the productivity of forage plants (see Section 4.1.5). Seismic surveys would result in temporary disturbance of animal communities on a total of about 6,780 acres over the next 30 years. This disturbance should be limited to the period of time the surveying activities are actually in progress. It is estimated that each survey will affect an average of 113 acres over a period of 2 to 8 weeks (see Table 1.2-9).

Operations and maintenance activities should have relatively minor effects on animal communities. Anticipated impacts include accidental spills of oil and other oil-field chemicals (e.g., barium). Animals occasionally could become trapped in spilled oil (O'Farrell et al 1986), or they could ingest oil-field chemicals present in sumps or assimilated by forage which might cause or contribute to death, disease or diminished ability to avoid predation. Road kills/harassment are also expected, especially in construction areas (see Section 3.8). Accidental fires could affect animal communities if animals are harassed, burned or killed, or if fires reduce forage.

Impacts associated with proposed new facilities are expected to be limited to the immediate vicinity of the facilities. Impacts associated with the continuation of existing operations will be more widespread, but mostly in previously developed upland areas. Impacts associated with the Endangered Species Program will be positive. The impacts of new facilities and continued operations will be minimized through the implementation of portions of the Endangered Species Program such as the Wildlife Management Plan (see Section 4.1.5.4).

4.1.5.3 Threatened and Endangered Species

In accordance with Section 7(a)(2) of the Endangered Species Act, in 1991, DOE prepared a Biological Assessment to initiate formal consultation with FWS on the effects of continued petroleum production at NPR-1 (DOE 1991). Pursuant to 40 CFR Part 1505.21, incorporated by reference into this FSEIS is the "Biological Assessment of the Effects of Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California, on Threatened and Endangered Species", U.S. Department of Energy, Naval Petroleum Reserves in California. The document is available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, P.O. Box 11, Tupman, California, 93276. Much of the discussions on impacts to listed species following in this section were summarized from the 1991 Biological Assessment (DOE 1991).

Plants

As discussed in <u>Section 3.5.3.1</u>, one plant species federally listed as threatened has been observed in the lowland areas of NPR-1 along the periphery of the site (Hoover's wooly-star) (EG&G/EM 1990b) and at a few isolated areas in the uplands (EG&G/EM unpublished data). Suitable habitat exists in the lowland areas for two other plant species that are federally listed as endangered (Kern mallow and San Joaquin woolly-threads), and a federal Category 2 plant species was observed (Lost Hills saltbush), but its location was not confirmed to be on NPR-1. Four State of California plant species of special concern have been observed (cottony buckwheat, Temblor buckwheat, Kern tarplant and gypsum-loving larkspur). The cottony buckwheat and gypsum-loving larkspur are widely distributed in the upland areas of the site. Kern tarplant is encountered only rarely in the lowland areas. Little information is available on the distribution of the Temblor buckwheat on NPR-1.

Approximately 878 acres are expected to be disturbed as the result of the construction of federal facilities on NPR-1 (see <u>Table 1.3-2</u>). Almost all of these disturbances are anticipated to be in the developed upland areas. Another estimated 691 acres are expected to be disturbed on and off NPR-1 during construction of third-party pipelines, about one-half of which should be in undeveloped lowland areas. In addition, third-party seismic surveys will affect about 6,780 acres on and off NPR-1 over the next 30 years, about two-thirds of which could be in undeveloped lowland areas.

NPR-1 projects are sited based on preactivity surveys. With rare exceptions, projects would be sited to avoid impacts. In those rare instances where avoidance is not possible, any plants within project areas would be destroyed, or crushed. Even in these cases, however, impacts would be minimized by designing and implementing initiatives to maximize reestablishment (e.g., reuse of the same topsoil containing seed remnants, prevention of soil erosion, and scheduling of work to occur when plants are not flowering).

Animals

Three animal species that are federally listed as endangered are likely to be affected by the proposed action. These include the San Joaquin kit fox, giant kangaroo rat, and blunt-nosed leopard lizard. Several federal Category 2 species and species that are listed by the state as threatened or of special concern also may be affected (San Joaquin antelope squirrel, short-nosed kangaroo rat, and four blister beetles). The Tipton kangaroo rat, a federally endangered species present only within Section 23S of NPR-1, should not be affected because this area is not currently developed, and future development is unlikely.

San Joaquin Kit Fox.

Impacts on the San Joaquin kit fox that could result from the proposed action are similar to those described by O'Farrell et al (1986) for impacts of past NPR-1 activities. These impacts, or potential impacts, include direct mortality, loss of dens, loss or alteration of habitat, harassment, or ingestion of oil-field chemicals. The apparent role of each was discussed in Section 3.5.3.2.

Most of the proposed activity would occur within the central hills of the site. Most kit foxes are now found in undeveloped areas along the site periphery, away from most activity (see Section 3.5.3.2). This is only the current situation, however, at a time when kit fox numbers on NPR-1 are relatively low compared to the early 1980s. Developed upland areas also represent important habitat because as recently as 1984, kit foxes were widespread over the site and occurred in all of the areas where activities are proposed (O'Farrell and Mathews 1987).

Activities in upland areas of NPR-1 should have little effect on the existing kit fox population; however, the carrying capacity and the prospects for future recolonization of these areas could be affected by the types of impacts that have occurred in the past, such as documented vehicle mortality (see Section 3.5.3.2) (O'Farrell and Mathews 1987; O'Farrell and Sauls 1987).

Activities that take place in the undeveloped lowlands areas, such as third-party pipeline projects, have a greater potential for impacting kit fox populations. As previously stated, this is because these habitats currently support most of the remainder of the NPR-1 kit fox population. It is estimated, for example, that third-party pipeline construction, operation and maintenance will disturb 691 acres (101 acres on NPR-1), of which about 304 acres are in undeveloped areas (22 acres on NPR-1) where most kit foxes now live. This could result in direct mortality, destruction of dens, habitat loss or alteration, human harassment, and ingestion of oil-field chemicals. The magnitude of impacts would depend on the location of pipeline routes.

Third-party seismic surveys are expected to affect a total of about 6,780 acres during the projected 30-year active life of NPR-1 (3,390 acres on NPR-1). Of this, about 4,590 acres are expected to be in undeveloped areas where many foxes now live (2,880 acres on NPR-1). Although seismic surveys do not involve construction, and thus no permanent habitat disturbance is expected, impacts to the kit fox could result from the collapse of dens and human harassment along the survey route. The magnitude of impacts would depend on the location of the survey routes.

It is anticipated that with few exceptions, all site activities would be designed to avoid direct contact with kit fox dens, based on information from preactivity surveys (see Section 4.1.5.4). In addition, spills would be cleaned up immediately in accordance with the SPCC plan, thus minimizing, if not eliminating, the risk of exposure or ingestion of oil-field chemicals. These actions should essentially preclude impacts associated with den destruction and spills. Vehicle mortality could still occur, but this would be mitigated by controlling speed limits and minimizing night driving. Approximately 1,569 acres of habitat on and off NPR-1 would be lost, but a successful program to reclaim approximately 1,045 acres associated with abandoned facilities (between 1989-1998) would compensate for a large portion of the loss. Some inadvertent human harassment would continue.

Activities associated with the Endangered Species Program may result in the deaths of protected animal species. Trapping and radiocollaring kit foxes will continue and will carry the risk of inadvertent harassment or death (see Section 3.5.3.2). However, efforts have been and will continue to be taken to mitigate this risk. Kit fox traps now used are of a smaller mesh size to reduce mouth injuries. Lighter radiocollars with shorter antennas are now being used and trapping methodologies have been designed to minimize if not eliminate loss or injury to the animal. Kit fox trapping is authorized under permit from the U.S. Fish and Wildlife Service and Memorandum of Understanding with the Department of Fish and Game. Trapping efforts follow guidelines established by both agencies.

Additional mitigation measures to reduce potential effects to protected species are described in Section 4.1.5.4.

Giant Kangaroo Rat.

Active burrow systems of the giant kangaroo rat have been found on 30 sections of NPR-1 (see Section 3.5). While high concentrations of burrow systems occur mostly in the Buena Vista Valley and northeast portions of NPR-1, isolated burrow systems also have been found in the developed, upland portions of NPR-1. Potential impacts to the giant kangaroo rat as the result of construction, operations and maintenance activities, could include (1) inadvertent harassment, (2) destruction of burrow systems, (3) removal of food sources (annual and perennial grasses that produce seed), (4) alteration of soil conditions that increases the difficulty in constructing burrows, and (5) ingestion of oil-field chemicals inadvertently released to the environment (e.g., spills).

Most activities are anticipated to be in upland developed areas which should have little effect on the giant kangaroo rat. This is because giant kangaroo rats are relatively uncommon in these areas. Exceptions to this include construction of well pads and associated roads and third-party facilities and seismic surveys, some of which are planned in portions of developed upland areas where giant kangaroo rats have been observed, or in the undeveloped lowland areas where populations of giant kangaroo rats are greatest.

New oil-well pads and associated roads are planned throughout the upland portions of NPR-1. A total of about 579 acres of disturbances are anticipated. Some of these disturbances are expected to be in Sections 20R, 28R, 25R, 32S, 27S, 26S, 6G, 7G, and 14R where burrow systems have been observed. In these instances, the impacts described above could occur. The magnitude of the impacts would depend on the specific location of the pads and roads. Preactivity surveys and flexibility in citing well pads, roads and other facilities should minimize impacts (Kato 1986; Kato et al 1985). Where burrow systems exist in the vicinity of existing well pads, O'Farrell et al (1987) found that 99% were located more than 300 feet away. This could be an indicator of the tolerance level that giant kangaroo rats have for site activity, which to the maximum extent practical would be taken into account in siting decisions.

Third-party pipelines have the greatest potential for direct impacts on giant kangaroo rats. The magnitude of impacts would depend on the specific location of each pipeline. Total disturbances are expected to be 691 acres (101 acres on NPR-1), of which 304 acres are in undeveloped areas (22 acres on NPR-1) where most giant kangaroo rats live. These areas represent important habitat for giant kangaroo rat populations. For example, O'Farrell et al (1987) estimated that Section 8B, which the authors state as representative habitat in the Buena Vista Valley, contained 28.2 giant kangaroo rat burrows/acre. Pipelines that are located in the undeveloped lowlands could have any of the adverse impacts described above.

Third-party seismic surveys are expected to disturb 6,780 acres (3,390 acres on NPR-1) over the next 30 years, of which 4,590 acres are expected to be in undeveloped areas (2,880 acres on NPR-1). In undeveloped areas, these activities could adversely affect giant kangaroo rat populations. Although no construction is involved, and thus no permanent disturbance to habitats is expected, impacts could result from the collapse of burrows and harassment along survey routes. The magnitude of impacts would depend on the location of the survey routes.

Preactivity surveys and flexibility in siting well pads, roads and other facilities should minimize impacts (Kato 1986; Kato et al 1985) (see Section 4.1.5.4). It is anticipated that, with few exceptions, these projects and all operations and maintenance activities can and would be designed to avoid direct contact with the giant kangaroo rat. In addition, spills are cleaned up immediately, thus minimizing, if not eliminating the risk of exposure to or ingestion of oil-field chemicals. These activities should essentially preclude impacts associated with burrow systems and spills. Habitat would be unavoidably lost, but a successful program to reclaim lands (previously explained) would compensate for a large portion of the loss. Some inadvertent human harassment would continue.

Live trapping of giant kangaroo rats, an activity associated with the Endangered Species Program, may result in the death of some animals. However, efforts have been made to minimize this impact. Baiting is done in late afternoon and trapping is not done during periods of extreme temperatures. Trapping of giant kangaroo rats and other small mammals is done under a Memorandum of Understanding from the California Department of Fish and Game.

Additional mitigation measures to reduce potential effects to protected species are described in Section 4.1.5.4.

Blunt-nosed Leopard Lizard.

Surveys conducted between 1979 and 1981 located blunt-nosed leopard lizards on 28 sections containing alluvial areas or washes that penetrate the central hills of the site (Kato et al 1987). Of the 83 blunt-nosed leopard lizards found during the survey, 70% were located in flat areas (Kato et al 1987). Densities in upland areas have been estimated at less that 0.5 lizard/acre (FWS 1985).

Potential impacts to the blunt-nosed leopard lizard as the result of proposed activities (construction, including federal and non-federal projects, seismic surveys, operations and maintenance) are expected to include (1) vehicle and other direct mortality, (2) destruction of small mammal burrows used by the lizard (Kato and O'Farrell 1987), (3) habitat loss or alteration, (4) accidental oil spills or wastewater discharges into drainages or washes comprising preferred habitat could drown blunt-nosed leopard lizards, coat them with oil or other oil-field chemicals, or contaminate portions of their habitat or food supply, and (5) inadvertent harassment as the result of human activity. As in the case of the kit fox and the giant kangaroo rat, the nature and the magnitude of the impacts are dependent on the specific location of the proposed activity. Since most activities are planned to take place in the developed upland areas, and since very few lizards are in these areas, most components of the proposed action should have little or no impact. Activities that take place in the undeveloped lowland areas, however, and especially those in the vicinity of the washes along the periphery of the central hills and in valley areas, could have the adverse impacts described above. The nature and magnitude of these impacts are expected to be similar to those previously described for the kit fox and the giant kangaroo rat.

As in the case of the kit fox and the giant kangaroo rat, with few exceptions, activities would be sited to maximize avoidance through the use of preactivity surveys (Kato 1986; Kato et al 1985). The other mitigative measures that are applicable to the kit fox and the giant kangaroo rat are also applicable to the blunt-nosed leopard lizard (vehicle control, spill cleanup, habitat reclamation, etc.). In addition, used pipeline hydrostatic test water will be released very slowly to minimize the possibility of flooding washes; washes will be monitored during releases to ensure the effectiveness of this measure.

There has been only one known case of mortality or harassment to the blunt-nosed leopard lizard as a result of research activities carried out under the Endangered Species Program. Future activities will maintain the same precautions taken in previous years to avoid death or injury to blunt-nosed leopard lizards.

Additional mitigation measures to reduce potential effects to protected species are described in Section 4.1.5.4.

Candidate Species and Species of Special Concern.

Several federal Category 2 species and state species of special concern are known to occur on NPR-1, or suitable habitat for these species exists (see Section 3.5.3.2).

The San Joaquin antelope squirrel and the short-nosed kangaroo rat are the Category 2 species most likely to be affected by proposed development. The San Joaquin antelope squirrel is relatively common on the site and is known to occur in areas where development of proposed facilities will occur (EG&G/EM 1988b and 1990a). The short-nosed kangaroo rat is common also, especially within areas of the Buena Vista Valley (EG&G/EM 1988b). Third-party pipeline projects have the greatest potential to affect this species because these projects are most likely to occur in their preferred valley floor habitats.

Impacts to the San Joaquin antelope squirrel and the short-nosed kangaroo rat that could result from the proposed action include direct mortality, reduction of carrying capacity, exposure to spills of oil and other chemicals, and harassment. The impacts of seismic surveys should be more temporary and should be limited to the possibility of direct mortality, harassment and soil erosion. The significance of impacts of all proposed projects would depend on the location of projects. Preactivity surveys would determine if species are present within project areas, and to the maximum extent possible, direct impacts would be avoided. Impacts are not expected to be significant because of the relative abundance and widespread distribution of these species.

Live trapping small mammals on NPR-1 to monitor population trends will continue and may result in the inadvertent injury or death of San Joaquin antelope squirrels and the short-nosed kangaroo rat. However, efforts have been made to minimize this impact. Baiting is done in the late afternoon and trapping is done during periods of extreme temperatures. Also trapping is done under a Memorandum of Understanding from the California Department of Fish and Game.

Suitable habitat for the four Category 2 blister beetles is thought to exist in Sections 7R, 18R, and 28R (EG&G/EM 1988b), where wells and other development are planned. In surveys conducted to date, these species have not been observed; however, their presence would continue to be investigated in future preactivity surveys, and if they are observed, they would be avoided to the maximum extent practical.

The effects of the proposed action on other Category 2 species and species of special concern (see Table 3.5-3 for a list of these species) would be similar to those described in Section 4.1.5.2. Their presence would continue to be investigated in preactivity surveys, and direct contact would be avoided to the maximum extent practical.

Additional mitigation measures to reduce potential effects to protected species are described in Section 4.1.5.4.

4.1.5.4 Mitigation

Programs to mitigate the effects of NPR-1 activities on the terrestrial biota have been in effect for a number of years, and all personnel, including contractors, subcontractors, third parties, etc., are required to comply with applicable requirements. The principal programs include an initiative to reclaim abandoned sites, a contemporaneous revegetation program, and a wildlife-management plan. These programs would continue under the proposed action, and they are explained as follows:

Reclamation of Abandoned Sites

The goal of this program is to minimize erosion and reestablish vegetation on disturbed areas of the site where facilities are no longer needed and have been abandoned (O'Farrell and Mitchell 1985). This program has been in operation since 1985 and has resulted in reclamation activities on approximately 690 acres through 1989 (EG&G/EM 1989a). From 1981 to 1983, a series of field trials were conducted on NPR-1 to evaluate reclamation techniques (O'Farrell and Mitchell 1985). The following criteria are currently used in selecting sites for reclamation: (1) the site is abandoned; (2) the site is not contaminated: i.e., there are no factors that would limit plant growth such as oil or salt water contamination; (3) there are no factors that limit site access; and (4) there are no plans to use the site in the future (EG&G/EM 1989a).

NPR-1 reclamation techniques are similar to those used in other areas of the arid west. Site preparation includes (1) cleanup of man-made debris and spills; (2) ripping and discing of compacted soils; (3) replacement of removed topsoil; (4) erosion control and recontouring; and (5) amendment of soils with fertilizers (EG&G/EM 1989a). Prepared sites are mulched and then seeded with a mix of species that depends on the topographic position of the site (e.g., slopes, flats) and soil conditions (e.g., high salt content) (Wolfe 1986a, 1986b; EG&G/EM 1989a). Species used for revegetation include a variety of shrubs and annual grasses, such as desert saltbush, buckwheat (*Eriogonum fasciculatum*), smooth brome (*Bromus mollis*), and foxtail fescue (*Festuca megalura*) (Anderson 1987; EG&G/EM 1989a). Sites where reclamation activities have occurred are monitored after the first, second and fifth growing season. In the fifth year, cover and shrub density are compared to control sites to determine the success and progress of reclamation efforts.

Additional information on monitoring and success evaluation are provided as follows:

Monitoring of reclamation success consists of a subjective (qualitative) evaluation in combination with quantitative evaluations of key vegetation parameters. The program has been in operation since 1987. Reclamation sites are monitored qualitatively after the first, second, and fifth growing season by a plant ecologist. In the fifth year, sites most likely to meet revegetation success criteria (as determined from the subjective evaluations) are monitored quantitatively. If the fifth year is a below normal precipitation year (defined as one standard deviation below the mean), sampling occurs in the first normal precipitation year after the fifth year.

A site is considered successfully revegetated when total plant cover and shrub density are at least 70% of the average plant cover and shrub density of undisturbed reference areas. Sites meeting reclamation success criteria after five growing seasons are released from monitoring and considered reclaimed. Sites unlikely to meet the success criteria in the fifth year receive remedial revegetation work or are deferred for re-evaluation in 5 more years. Results to date are summarized as follows:

- In FY 1985, 115 acres were reclaimed (148 sites). Average plant cover in 1991 was 28% for 61 sites most likely to meet success criteria. Control sites averaged 35% in FY 1991.

- In FY 1986, 130 acres were reclaimed (272 sites). Average plant cover in 1991 was 30% for 98 sites most likely to meet success criteria. Control sites averaged 35% in FY 1991.

- In FY 1987, 130 acres were reclaimed (191 sites). Average plant cover in 1992 was 55% for 105 sites most likely to meet success criteria. Control sites averaged 71% in FY 1992.

- In FY 1988, 200 acres were reclaimed (396 sites). Average plant cover in 1992 was 50% on a subsample of the 396 sites. Control sites averaged 71% in FY 1992. Revegetation through FY 1988 was 690 acres (see Table 3.5.1).

- In FY 1989, 116 acres were reclaimed (173 sites). Average plant cover in 1992 was 49% on a subsample of the 173 sites. Control sites averaged 71% in FY 1992.

- In FY 1990, 72 acres were reclaimed (166 sites). Average plant cover in 1992 was 50% on a subsample of the 166 sites. Control sites averaged 71% in FY 1992.

- In FY 1991, 84 acres were reclaimed (198 sites). Average plant cover in 1991 was 48% on a subsample of the 198 sites. Control sites averaged 71% in FY 1992.

As of FY 1992, approximately 850 acres of disturbed land on NPR-1 have been revegetated.

Plant cover and shrub density at all sites revegetated between FY 1985 and FY 1987 (approximately 375 acres) were compared with data from reference sites. At present, 26% of the sites (91 acres) reclaimed between FY 1985 and FY 1987 have met the criteria for successful revegetation in spite of the drought conditions that existed. Additional sites are likely to meet the success criteria, when they are reevaluated in future years. Given that NPRC receives relatively little precipitation and that two of the last five years had precipitation far below average, the success of revegetation on NPR-1 is encouraging.

Contemporaneous Revegetation Program

This program, which was instituted in 1988, is similar to the abandonment reclamation program, but instead of abandoned sites, it addresses contemporary construction disturbances on lands that are not required for ongoing operations and maintenance activities. It is anticipated that as much as 50-100 acres will be revegetated under this program each year. Limited results to date appear to be comparable with those of the abandonment program.

Wildlife-Management Plan

The plan is directed primarily at conserving threatened and endangered species on the site, but it also serves to minimize the impacts of operations on other species (O'Farrell and Scrivner 1987). The plan consists of the following actions: (1) perform preactivity surveys to determine the presence of threatened and endangered species and their habitat; (2) revegetate areas disturbed by past actions (see preceding descriptions of reclamation programs); (3) monitor abundance, health, mortality, reproductivity, and other information on selected animal populations; (4) monitor the success of the reclamation programs; (5) control populations of coyotes; (6) protect raptors, migratory birds, and other species of concern; (7) implement operating guidelines that will contribute to conservation of animals and their habitat; (8) study animal conservation and habitat restoration techniques; (9) develop an information and education program; and (10) participate in endangered species recovery programs. These elements of the wildlife-management plan are discussed in the following paragraphs. In addition, impacts to wildlife are considered during the design phase of project development (BPOI 1989), including siting projects to maximize avoidance and erosion control.

Preconstruction/preactivity surveys have been conducted on NPR-1 since 1980. The objectives of preactivity surveys include (1) minimize the extent of habitat loss, (2) conserve San Joaquin kit fox dens, (3) minimize damage to washes used by blunt-nosed leopard lizards, (4) conserve giant kangaroo rat burrow systems, (5) prevent impacts to eagles, and (6) protect other species of concern (e.g., federal Category 2 species, and state endangered, threatened and special concern species) (Kato et al 1985; Kato and O'Farrell 1987; O'Farrell and Scrivner 1987). Site design, the amount of undisturbed habitat in the area, and the type of disturbance is evaluated for each project. Recommendations are then made to minimize the loss of habitat, including measures to control erosion. Areas where kit fox or giant kangaroo rat dens or burrows are found are avoided if possible, and the project is relocated a sufficient distance from these dens or burrows to minimize indirect impacts. Attempts are made to minimize any disturbance of broad sandy washes, which are the preferred habitat of the blunt-nosed leopard lizard. Impacts to eagles and other species of concern are avoided by redesigning or relocating projects when these species are found in the project area. Surveys are conducted after a project is completed to ensure that mitigation recommendations were followed (Kato and O'Farrell 1987). Currently, specific mitigation plans for Category 2 species have not been formalized; however, investigations have been conducted in anticipation of the need for mitigation plans in the future (O'Farrell and Mathews 1987; EG&G/EM 1988b and 1990a) and avoidance measures are implemented informally as practical. These and other actions would be formalized in the future as appropriate.

Since implementation of preactivity surveys, only five cases of inadvertent destruction of kit fox dens have been documented (O'Farrell et al 1986), despite the fact that several thousand acres were disturbed within the kit fox's range over this same time period. Plans to continue preactivity surveys would significantly reduce impacts of the proposed action. Past operations have probably had little effect on giant kangaroo rat habitat. Most such habitat is located in areas of limited petroleum activities. For blunt-nosed leopard lizard populations, preactivity surveys resulted in project changes that reduced impacts to leopard lizard habitat. Only one large wash has been disturbed by past activities (Kato 1986).

An extensive monitoring program has been in operation on NPR-1 since 1980. This program focuses primarily on the monitoring of reclamation success and populations of several endangered species (O'Farrell and Scrivner 1987). The kit fox is the most intensively studied species on the site; monitoring for this species has been conducted each year since 1980 and includes determinations of (1) population trends; (2) reproductive success; (3) sources and rates of mortality; (4) movement patterns and dispersal; (5) density of dens; (6) abundance trends of prey, especially lagomorphs; and (7) abundance trends of predators, especially coyotes. The giant kangaroo rat and blunt-nosed leopard lizard were monitored on NPR-1 in the early 1980s. Monitoring efforts for these species have included evaluations of distribution, habitat requirements, and relative density. Category 2 species have also been studied on NPR-1 to determine their relative abundance (EG&G/EM 1988b).

The coyote control program, implemented to protect the kit fox from predation, was in operation from 1985 to May of 1990 (Scrivner and Harris 1986; O'Farrell and Scrivner 1987; Scrivner 1987). Coyotes have been removed annually by denning, trapping, and shooting. The program is implemented by the U.S. Department of Agriculture, Division of Animal Damage Control, in accordance with a cooperative agreement with DOE. The program was discontinued in 1990 pending evaluation of its effectiveness.

The protection of raptors on NPR-1 focuses on the adoption of design specifications for electric power poles that would reduce the probability of electrocution of birds using these poles for perches (O'Farrell and Scrivner 1987). Raptors and other species of concern are protected by additional actions, such as hawk silhouettes on windows, screening of oil sumps, sump elimination, nest and egg protection, the SPCC plan, and environmental training. In addition, raptor and other species benefit from reclamation and other activities adopted to protect endangered and threatened species.

Operating guidelines on NPR-1 that are pertinent to wildlife protection include the following: (1) maintenance of speed limits to reduce the incidence of road kills; (2) prevention and cleanup of oil and other spills; (3) restriction of off-road vehicle travel; (4) covering of sumps that may receive oil; (5) fire protection program to prevent and suppress accidental and naturally occurring fires; (6) prohibition of hunting, trapping, livestock grazing, agricultural activities, and casual public access; and (7) restriction of the use of insecticides, rodenticides, and other potentially toxic substances.

As a means of compensating for impacts that cannot be otherwise offset or fully mitigated, such as habitat losses, several studies of endangered species are being conducted on NPR-1 to refine conservation techniques (EG&G/EM 1989b) and to provide information that could contribute to recovery; other studies are being planned. Ongoing studies include (1) techniques for increasing carrying capacity of developed habitats for the kit fox, such as artificial dens and reintroduction of kit foxes, (2) the influence of food supplies on the kit fox, and (3) reclamation of habitat for giant kangaroo rats. These are long term studies that are still in progress.

Threatened, endangered, candidate or species of special concern may be impacted by trapping and/or radiocollaring activities carried out under the Endangered Species Program. Efforts have been and will continue to be taken to mitigate this risk. Trapping kit foxes and small mammals is authorized either under permit from the U.S. Fish and Wildlife Service and Memorandum of Understanding with the California Department of Fish and Game. Trapping efforts follow guidelines established by both agencies. Endangered Species Program activities outside the scope of this document that may be implemented in future years will receive a full environmental review prior to implementation.

An education/training program has been implemented to promote worker awareness of the requirements of the NPR-1 endangered species and wildlife conservation programs. This program focuses on teaching workers about wildlife (especially endangered species), impact recognition and avoidance, and impact reporting. This program is given to all permanent NPR-1 employees, subcontractors and third-party contractors.

Section 7 Consultation

As discussed in Section 3.5.3, the FWS rendered a nonjeopardy Biological Opinion for the continued operation and development of Naval Petroleum Reserve No. 1 at the maximum efficient rate of production in 1987 (see Appendix I.3). On October 9, 1991, DOE reinitiated Section 7 consultation with FWS for MER production, due to the proposal to implement recovery strategies and efficiency projects that would be more aggressive than were originally planned. FWS issued a partial draft Biological Opinion on December 19, 1992, and a final draft Biological Opinion on May 28, 1993, for this action which also concluded nonjeopardy (see Appendix I.1). This consultation is still in progress and when it is completed, DOE will comply with all requirements contained in FWS's new Biological Opinion. Until the new Biological Opinion is finalized, DOE will comply with all requirements of the 1987 Biological Opinion (See Appendix I.2). In addition, projects with impacts that are not covered by the 1987 Biological Opinion will not be initiated until they have been appropriately subjected to consultation under Section 7 of the Endangered Species Act.

To further reduce potential adverse impacts to listed species on NPR-1, DOE would continue to implement an endangered species program including, but not limited to, the following mitigation activities that are addressed in the 1993 final draft Biological Opinion: (1) continue the endangered species worker education/training program; (2) continue to conduct preactivity surveys to minimize habitat disturbances and harm or mortality to listed species; (3) to the extent feasible, avoid sensitive habitats such as San Joaquin kit fox dens, giant and Tipton kangaroo rat burrows, and burrows potentially utilized by blunt-nosed leopard lizards; (4) refrain from destroying San Joaquin kit fox dens that cannot be avoided until approval is obtained from FWS; (5) continue to implement a habitat reclamation program to reclaim disturbed areas that are no longer needed for oil-field operations; (6) restrict unauthorized off-road vehicle travel; (7) prohibit employees from bringing pets onto NPR-1; (8) clean up oil and chemical spills in accordance with the Spill Prevention Control and Countermeasure Plan; (9) continue to evaluate sumps and catch basins to identify potential hazards to the extent practicable; (10) continue to evaluate and, to the extent practicable, remediate well cellar covers posing hazards to wildlife; (11) continue utilizing biological monitors with stop-work authority during very critical portions of construction projects to ensure that impacts to protected species and their habitats are minimized; and (12) continue to prepare an annual report on the status of the endangered species program.

In the 1993 final draft Biological Opinion, the FWS proposed setting aside 5,058 acreas of undisturbed habitat on NPR-1 for protected species as one method of compensating for habitat losses occurring since 1976 when MER activities commenced. DOE is currently evaluating this method of habitat compensation as well as other compensation alternatives.

4.1.5.5 Cumulative Impacts

The San Joaquin Valley has undergone considerable development in the past, especially in connection with agriculture (Morrell 1975; FWS 1983). It was estimated that in 1979 only 6.7% of the habitat in the southern San Joaquin Valley remained undeveloped (FWS 1985); this figure is probably less now because development has continued since 1979.

NPR-1 is regionally significant because, based on the 1979 estimate, it contains 8% of the remaining undeveloped habitat in the southern San Joaquin Valley (FWS 1985). NPR-1 habitat is also high quality (O'Farrell et al 1986); only NPR-2, the Buena Vista Valley, the Elkhorn Plain, and the Carrizo Plain are comparable (O'Farrell et al 1980; O'Farrell and McCue 1981; Kato 1986; O'Farrell et al 1986). Habitat quantity and quality make NPR-1 an important ecological resource.

NPR-1 is approximately 47,409 acres. To date, development has taken place on 6,546 acres, 1,689 of which have undergone reclamation (see Table 3.5-1). This results in an existing developed area of approximately 4,857 acres (6,546 - 1,689 = 4,857), which leaves approximately 42,552 acres (about 90% of the site) in a relatively undeveloped state. The proposed action would result in the permanent disturbance of an additional 979 acres on NPR-1 (see Table 1.3-2). Assuming a successful habitat reclamation program, the proposed action should also result in reclaiming an additional 685 acres on NPR-1: 625 acres associated with abandonments and 60 acres associated with third-party projects (see Tables 1.2-9, 1.3-2 and 3.5-1). The net result is that over approximately 30 years, developed areas will increase by 294 acres (979 - 685 = 294) from 4,857 acres to 5,151 acres, and undeveloped areas will decrease correspondingly from 42,552 acres to 42,258 acres (about 89% of the site). The 294 acres represents 0.6% of all NPR-1 lands, 0.7% of undeveloped

NPR-1 lands, and 0.05% of the undeveloped lands within the southern San Joaquin Valley in 1979.

In addition to NPR-1 development, the proposed action would result in the development of another 590 acres off-site (see Table 1.3-2); of this, 360 acres would be revegetated. Therefore, the proposed action would increase off-site developed areas and decrease undeveloped areas by a total of 230 acres (590 - 360 = 230). Adding this to the on-site increase, the total increase is 524 acres (294 + 230 = 524), which represents 0.1% of the undeveloped habitat within the southern San Joaquin Valley in 1979. Exclusive of the 1,045 acres to be reclaimed (685 + 360 = 1,045), total development is expected to be 1,569 acres (524 + 1,045 = 1,569), which represents 0.3% of the remaining undeveloped habitat in the southern San Joaquin Valley in 1979.

In addition to the impacts of the NPR-1 proposed action, several state and private projects within the San Joaquin Valley are planned. These include urban development, mineral development, wind-energy development, and reservoir construction (Kobetich 1989a). FWS believes that these projects will result in significant cumulative effects to the kit fox, blunt-nosed leopard lizard, and giant kangaroo rat (Kobetich 1989a).

Federal projects within the San Joaquin Valley include the recently completed Mojave-Kern River pipelines certified by the Federal Energy Regulatory Commission (FERC), which passes near NPR-1, and the proposed Taft, California, Federal Correction Institution, approximately 9 miles south of NPR-1. The San Joaquin kit fox and blunt-nosed leopard lizard are found in both project areas, but the giant kangaroo rat is found only within the area of the proposed pipelines. The FWS issued Biological Opinions on the impacts of these projects in 1990 (FWS 1990) and 1989 (Kobetich 1989b), respectively. They determined that construction of the proposed pipelines and the correction institution would not jeopardize the continued existence of the San Joaquin kit fox, blunt-nosed leopard lizard, and the giant kangaroo rat.

Prior to the 1970's, extensive development occurred on NPR-2 (adjacent to NPR-1); development since then has been relatively insignificant because NPR-2 reservoirs are essentially depleted. Nevertheless, some of the existing facilities on NPR-2 will continue to be operated for the foreseeable future until the reservoirs are entirely depleted. The types of impacts, or risk of impacts, associated with past and future NPR-2 operations should be similar to those that were presented in Section 3.5 for NPR-1. The cumulative magnitude of NPR-2 impacts has not been characterized (almost all NPR-2 development and operations occurred many years ago). The magnitude of future NPR-2 impacts should be relatively small because the magnitude of future development and operations are expected to be relatively small.

In summary of the foregoing, the past impacts of NPR-1 operations, and the past and future impacts of other activities in the San Joaquin Valley, have been significant. The proposed NPR-1 action would contribute to these impacts incrementally in the manner that has been presented.

4.1.5.6 References*

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*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Manager, Technical Assurance, U.S. Department of Energy, Tupman, California 93276.

4.1.6 Cultural Resources

4.1.6.1 Impacts and Mitigation

The proposed action includes a variety of land-disturbing activities that could adversely affect archaeological sites. These activities are described in Section 1.2 and include operations and maintenance activities, seismic surveys (including third-party seismic surveys), well drilling, and construction of production facilities (including steamflood facilities), access roads, compressor facilities, water injection and pumping facilities, cogeneration facilities, gas processing facilities, gas compression and injection facilities, and pipelines (including third-party pipelines). Table 1.3-2 provides a summary of land disturbances associated with each major development activity. Over the estimated 30 year economic life of NPR-1 it is anticipated that 1,569 acres would be disturbed on and off of NPR-1 as the result of operation and maintenance, drilling, and construction. Another 6,780 acres on and off of NPR-1 would be temporarily affected in conjunction with seismic surveys. Adverse impacts would be mitigated in accordance with a comprehensive cultural resource management plan which is currently being developed in consultation with the California State Historic Preservation Office (SHPO).

Archaeological remains (artifacts and features) deposited on or near the surface of disturbance areas could be displaced, damaged, or destroyed during site activities. Most of the potentially affected areas are located in upland areas, where the known distribution of archaeological remains suggests that sites are largely confined to surface lithic scatters. Surficial deposits in the Elk Hills are of pre-Holocene age (i.e., greater than 10,000 bp), with limited potential for burial of remains. Therefore, surface impacts are the primary concern in upland areas. The sparse vegetative cover on NPR-1 allows high surface visibility. Previously undisturbed areas along the periphery of the uplands are more likely to have remains that are buried. In these areas, the proposed action has a greater potential for subsurface impacts.

The design of the NPR-1 cultural resource management plan is based on the existing cultural resource surveys (see Section 3.6). Peak's 1991 survey, the most comprehensive to date, was designed in consultation with the SHPO. Following survey completion, additional consultations with the SHPO are to be conducted to formulate the specific components of the management plan. It is anticipated that the primary mitigation activity will be resource avoidance, which would be maximized through the continued use of preactivity surveys. Prior to commencing new land disturbance activities, preactivity surveys would be conducted in a manner that appropriately takes into account the resource inventory in the proposed project area. To the maximum extent practical, resources identified in project areas would be avoided by siting projects in previously disturbed areas (such as installing new pipelines in existing right-of-ways). When it is not practical to site new projects in previously disturbed areas, siting flexibility makes it possible, with few exceptions, to locate projects a sufficient distance away from significant cultural resources to avoid impacts. Additional matters that are being considered during the process of developing the management plan include evaluating sites for inclusion in the National Register of Historic Places; the appropriate scope of preactivity surveys (e.g., surveyor qualification requirements, subsurface testing, etc.); and data recovery, evaluation and reporting of potential impacts (individual and cumulative) that are unavoidable.

Other major federal projects that have been completed or are proposed within the San Joaquin Valley include development of the Mojave-Kern River pipelines near NPR-1, certified by the Federal Energy Regulatory Commission (FERC), and the Taft, California, Federal Correction Institution, approximately 9 miles south of NPR-1. An inventory and evaluation of the California portion of the pipelines has been completed (McGuire 1990). The proposed correctional institution's cultural resource impacts were addressed in the environmental impact statement of that project (U.S. Department of Justice 1989). Cultural resource surveys conducted for this project identified 23 loci and 4 sites requiring evaluation for inclusion in the National Register of Historic Places.

Some operations, maintenance and development activities are anticipated on government property on NPR-2 (adjacent to NPR-1). Given that NPR-2 reservoirs are essentially depleted, these activities are expected to be comparatively infrequent and small in scope. As new projects are proposed on government NPR-2 property, affected resources would be identified and impacts mitigated in consultation with the SHPO. Appropriate planning and mitigative actions are expected to preclude significant impacts to any cultural resources that exist on government NPR-2 property. For example, during the period 1988-1990, 11 projects on government NPR-2 property were evaluated, 9 of which were accomplished in consultation with the SHPO. The evaluations resulted in identifying 1 site within the project areas that is not eligible for the National Register of Historic Places, 78 sites that are probably not eligible, and 1 site that potentially is eligible. Of the 80 sites that were identified, 78 were historic oil-field development structures/sites (such as wells, brick scatters and trash dumps) which are in excess of 50 years old (oil production activities at NPR-2 began in the early part of the century) and the other 2 sites are prehistoric flake scatters. The evaluations concluded that the projects would affect only 1 of the 80 sites . In consultation with the SHPO it was determined that the threatened site was ineligible for inclusion in the National Register.

4.1.6.2 References*

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*Copies of correspondence and unpublished documents included in this list may be obtained upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves In California, Tupman, California 93276.

4.1.7 Land Use

4.1.7.1 Discussion

To date, approximately 6,546 acres of NPR-1 (13.8% of the site) have been disturbed since development began in the early part of the century (see Table 3.5-1); 3,306 acres of this (7.0% of the site) occurred as the result of MER production that began in the mid-1970's. Revegetation activities have been completed, or are in progress, on 1,689 acres of these disturbances (3.6% of the site). Therefore, the existing environment consists of 4,857 acres of development (6,546 - 1,689 = 4,857) (10.2% of the site).

The proposed action would result in the development of approximately 979 additional acres on NPR-1 (2.0% of the site) over the next 30 years (see Table 1.3-2) for federal and non-federal facilities. The proposed action also includes the revegetation of all land associated with facilities that have been, or would be, abandoned because they are not needed for operations. This has been estimated to be 625 acres through the year 1998 (see Table 3.5-1). In addition, another 60 acres would be revegetated on NPR-1 over the next 30 years in conjunction with third-party pipeline projects (see Table 1.3-2, footnote e). Therefore, total revegetation included in the proposed action is 685 acres (1.4% of the site). This results in a net increase in developed area on NPR-1 of 294 acres (979-685 = 294)(0.6% of the site). Land requirements of individual initiatives are summarized in Table 1.3-2, and a more detailed description of each initiative, including project locations, are provided in Section 1.2.2.

The proposed action would result in the development of approximately 590 acres off of NPR-1 over the next 30 years, pursuant to the construction of non-federal facilities (see Table 1.3-2); 360 of these acres would be revegetated as part of the respective construction projects (see Table 1.3-2, footnote j). This results in a net increase in development of 230 acres off of NPR-1 (590 - 360 = 230).

Total disturbances on and off NPR-1 are estimated to be 1,569 acres (979 + 590 = 1,569). Total revegetation on and off of NPR-1 is estimated to be 1,045 acres (685 + 360 = 1,045). This results in a net increase in developed area of 524 acres on and off of NPR-1 (1,569 -1,045 = 524).

The proposed action is expected to temporarily affect another 226 acres per year in connection with seismic surveys. Over a 30-year period this amounts to 6,780 acres, approximately 50% of which should be on NPR-1.

Historically, oil exploration and production have been conducted on NPR-1 and the surrounding area since the mid-to-late 1800's (Maher et al. 1975). The proposed action would be consistent with this tradition and with the provisions of the Naval Petroleum Reserves Production Act of 1976. Construction and operational activities associated with the proposed action would be consistent with current land use on and around the site and with planning objectives stated in the Kern County General Plan (Kern County Planning Commission 1988).

It is anticipated that petroleum development, urban development, agricultural irrigation, and sheep and cattle grazing would continue on lands surrounding the site. The continued use of NPR-1 for petroleum development might, in turn, result in some minor increase in commercial or industrial development in nearby local communities (see Section 4.1.8). Proposed site activities are not expected to adversely affect the surrounding recreational resources, such as the Buena Vista Aquatic Recreation Area, or open space and natural areas, such as the Tule Elk State Reserve. Although the increased amount of construction activities and production facilities would result in additional visual degradation, these impacts would be only incremental in nature, with a minimal number of off-site views affected.

While few direct adverse impacts to land uses are anticipated, potential risks to groundwater and further loss of wildlife habitat could have some indirect impacts. Groundwater and wildlife issues are presented in Sections 3.4, 3.5, 4.1.4, 4.1.5, Appendix D, and Appendix E.

4.1.7.2 References*

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*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California, 93276.

4.1.8 Socioeconomics

This section discusses potential impacts on population, employment, and trade from implementation of the proposed action at NPR-1. All of the socioeconomic impacts identified would be neutral or positive. Continued conventional development and expanded enhanced recovery at NPR-1 would stabilize otherwise declining petroleum industry employment at the site, which in turn would serve to stabilize the tax base, housing market, and trade sectors of Kern County. Impact on income, normally a major focus of socioeconomic analyses, is not addressed in detail because most of the oil and gas produced at NPR-1 is exported to other areas of California, and about 80% of the revenues from all wellhead sales are remitted to the U.S. Treasury. (CUSA's share of NPR-1 product sales that is spent in Kern County has been accounted for in Section 4.1.8.3).

The results of input-output impact analyses summarized below must be considered within the context of several special circumstances. First, a return to the baseline conditions against which the proposed action is compared would result in lower production and employment levels at NPR-1. Without additional development, the petroleum resources of the site would be depleted, wells would be abandoned, and direct and indirect employment would decline. Second, the proposed action requires hiring few additional permanent employees at NPR-1, although temporary construction labor could increase total workers on the site by an additional 250 persons from 1991 to 1993. Third, even if additional employment were planned, there appears to be sufficient surplus labor available for field operations and professional petroleum activities. Fourth, most temporary construction workers on the site would likely come from outside Kern County because of special skill requirements for these projects. Even if all additional workers lived in Kern County, this is still less than a 1% change in total employment and not more than a 2% change in any specific industry.

4.1.8.1 Population

Although the proposed action would not substantially increase operational employment at NPR-1, it would help stabilize conditions by preventing a decline in employment levels that would occur if there were no additional production development (see input-output analyses in Appendix F). It should be noted, however, that even if such a reduction in the NPR-1 employment level were to occur, the effects would be absorbed by other growth in Kern County, resulting only in a reduced rate of population growth, not an actual decline in population.

4.1.8.2 Housing and Public Facilities

The proposed action would not adversely affect housing, transportation, utilities, or other public services and facilities in the vicinity of NPR-1 because only temporary increases in employment are anticipated. Although potential increases up to 30% of the temporary workforce might be realized, the housing market and public facilities in local communities appear to have sufficient excess capacity to accommodate such growth.

4.1.8.3 Employment and Trade

This section summarizes the results of an analysis in which input-output (I-O) multipliers were used to estimate the induced socioeconomic impacts of the additional expenditures that would result from the proposed action (Table 4.1.8-1 and Appendix F). Although NPR-2 expenditures are not reported separately and thus are included in the baseline used here, they constitute only a small portion of the total.

For this analysis of impacts, it has been assumed that 75% of the increased facility costs for the steamflood expansion would be expended in Kern County, and 25% would be expended outside the county. These proportions are assumed to reverse for all other investments included in the proposed action. The varying proportion of expenditures in Kern County from year to year is attributable to different mix of investments between these two categories (steamflood and other).

The results of the I-O analyses, summarized in Appendix F, show small positive increases in Kern County output, earnings, and employment from the proposed action. The multipliers used in the analyses were generated for Kern County using the U.S. Department of Commerce's Regional Input-Output Modeling System (RIMS II) (U.S. Department of Commerce 1988). The limitation of this type of analysis is that it assumes that the structure of the local economy (i.e., the relative proportions of the industries in the county) remains approximately the same throughout the forecast period. The projected increases, however, are relatively small compared with the county's economy. Moreover, the forecast period is relatively short. On this basis, use of I-O multipliers was decided to be an appropriate modeling technique for determining regional impacts of the proposed action.

In summary, the proposed action at NPR-1 would have a small, positive incremental impact on the region in terms of increases in induced industrial output, household income, and employment. The I-O analyses summarized above suggest that in Kern County, the proposed action would induce incremental increases of less than 1% in output values and of less than 0.1% in employment. If the trend of decreasing Kern County incremental expenditures (Table 4.1.8-1) is extended beyond 1994, there would be no additional expenditures in the county from the proposed action within 5 years. This means that the projected incremental increases in output and employment would decrease with time, reaching zero by 1999.

TABLE 4.1.8-1 NPR-1 Total Development Case, Maintenance Case, and Incremental Expenditures in Kern County

	Expenditures ($1,000)				
Year	Total Development Case	Maintenance Case	Proposed Action	Estimated Kern County Increment	Kern County Portion of Total Expenditures (%)
1989	172,293	167,078	0	0	-
1990	187,384	146,191	0	0	-
1991	232,217	147,666	26,680	8,810	33
1992	327,036	147,291	107,630	29,111	27
1993	219,470	139,706	6,570	3,893	59
1994	228,029	139,688	2,300	1,725	75
1995	224,622	137,988	930	698	75

Source: BPOI 1989

4.1.8.4 References*

Bechtel Petroleum Operations, Inc., 1989, NPRC 1989-1995 Long Range Plan, Naval Petroleum Reserves in California, Tupman, California.

U.S. Department of Commerce, 1988, Regional Input-Output Modeling System (RIMS II), Regional Economic Analysis Division, Bureau of Economic Analysis, Washington, DC.

*Copies of correspondence and unpublished documents included in this list are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California, 93276.

4.1.9 Risk Assessment

Because the proposed action would be similar to past and current operations, the types and magnitudes of risks associated with future operations would probably be similar to those described in Section 3.9. Experiences over the past approximate 5 years would be particularly applicable. It is generally predictable that oil spills, pipeline and tank leaks, fires/explosions, well blowouts, vehicle accidents, and other common types of industrial accidents occasionally could occur. A discussion of the most significant risks and mitigation measures follows.

If the blowout data and experience presented in Section 3.9.1 is applied to the activities comprising the proposed action (e.g. 382 new wells to be drilled, 2,663 remedial and workover actions, etc.), then 1-2 blowouts could occur during the period 1990-2025. In addition, a fourth gas plant and additional compressors could increase the possibility of a gas explosion. This increase should be offset by the safety precautions that have been put in place as the result of formal investigations of past explosions. Given that permanent staff levels, budgets, etc. would remain essentially at current levels, other risks such as occupational accidents, vehicle accidents, etc., should be essentially unchanged. Aging equipment could increase the risk of oil spills. This increase would probably be offset by declining oil production.

Some of the primary programs that are in-place to mitigate risks include:

- The SPCC program (see Section 3.2).

- DOE Orders and other requirements providing for formal reporting systems, internal investigations, and development and implementation of corrective actions for occupational accidents and near misses, vehicle accidents, fires/explosions, and unusual occurrences.

- DOE Orders and other requirements providing for formal independent investigations, and development and implementation of corrective actions for any of the foregoing incidents that are particularly significant.

- DOE Orders and other requirements providing for periodic formal Technical Safety Appraisals, Environmental Surveys, and Tiger Team Assessments (safety and environmental) sponsored by DOE headquarters, and development and implementation of corrective actions.

- DOE Orders and other requirements providing for internal inspections, audits, and vulnerability assessments of all operational, safety, and environmental activities to determine the level of compliance with requirements and to develop and implement appropriate corrective actions. Example activities include self-assessments of compliance with OSHA requirements, fire and explosion prevention requirements, emergency response requirements, general safety requirements, and environmental self-assessments.

- Comprehensive quality assurance and quality control programs, pursuant to DOE Orders, including, among other things, a Performance Indicator System which tracks/trends safety and environmental performance indicators. A Comprehensive Corrective Action System to track completion of all identified corrective actions is also in place.

4.2 ALTERNATIVES

4.2.1 Alternative 1: No Future Development (No Action)

This alternative would continue operation, maintenance and production of existing facilities without provision for any potential future development (based on LRP "maintenance case"). The impacts of the no action alternative are based on those that are described in Section 3.0 (Description of Existing Environment) for the continuation of existing operations (see Sections 2.1 and 3.0). These impacts would continue in the near term, but would be expected to decrease as hydrocarbon production declines over time. Environmental and safety compliance programs and ongoing environmental restoration activities would continue (see Table 1.2-10).

4.2.1.1 Geology and Soils

Construction Impacts

Implementation of this alternative would result in the disturbance and development of approximately 50 acres on NPR-1 for the maintenance and replacement of facility pipelines (Table 1.3-2). An additional 691 acres of land disturbance on and off NPR-1 are anticipated in association with non-federal third-party pipeline actions. Erosion control measures as outlined in Amimoto (1977) and Soil Conservation Service (1985) would be followed to minimize the impacts of all pipeline projects. As with the proposed action, approximately 1,045 acres of development on and off of NPR-1 would be subject to erosion control measures in conjunction with revegetation activities (Table 1.3-2).

Operational Impacts

The potential for subsidence and induced seismic activity would be somewhat less than for the proposed action. Under this alternative, up to 500 million barrels of oil and 250 billion cubic feet of gas would not be recovered. In addition, source water withdrawal from the Tulare Formation would remain at 148,000 barrels/day, the current level of withdrawal.

As in the case of the proposed action, projects to enhance the structural integrity of the 35R gas plant would be undertaken if needed.

4.2.1.2 Waste Generation

The amount of waste generated under this alternative would be limited to the wastes that result from current operations as discussed in Section 3.2 but without any new petroleum development drilling or facility construction activities. The three largest waste streams currently generated at NPR-1 are nonhazardous produced wastewater (37 million barrels/year), spent drilling fluids and solid wastes (315,000 barrels/year), and nonhazardous solid wastes (24,000 cubic yards/year). NPR-1 currently generates only about 19,800 pounds/year (9,000 kilograms/year) of hazardous wastes.

Generation of produced wastewater is anticipated to increase in the future in an unknown amount, even without the drilling of new production wells. This is because the water to oil ratio of a maturing oil field increases with age. Future use of drilling fluids would be limited to well remedial workovers, well abandonments, and groundwater monitoring well drilling projects. The amount of spent drilling fluid wastes requiring disposal should be significantly reduced, thereby reducing the risks posed by this activity. Generation of nonhazardous solid wastes would be no more than current quantities generated. The amount of hazardous waste generated as a result of future operations under this alternative should also be somewhat reduced, given future waste minimization program initiatives.

The NPR-1 waste minimization program, which emphasizes source reduction, product substitution and recycling of hazardous wastes as a means of reducing the volume and toxicity of the waste, would be continued. Programs initiated to investigate and characterize solid waste landfills, surface dumps, and wastewater sumps on NPR-1 would continue. Likewise, characterization activities and possible future removal actions would continue for the hexavalent chromium spill sites, 23S saltwater disposal sumps, 1A-6M well pad and sumps, 3G gas plant cooling tower and drainageways, 18R drilling fluid tanks, 36R abandoned gas plant, and various miscellaneous NPR-1 sumps.

4.2.1.3 Air Quality and Noise

The current level of air pollutant emissions from stationary combustion sources, drilling and construction-related sources, noncombustion and oil and gas production sources, and vehicular sources are summarized in Table 3.3-3. Total capacity of stationary combustion sources and associated emissions would not increase under this alternative. Emissions associated with drilling and construction-related sources would be reduced as a result of the cessation of any additional production well drilling and construction activity. Noncombustion oil and gas source emissions would be expected to decline as hydrocarbon production declines over time. Vehicular source emissions would be reduced as a result of the need for fewer subcontract personnel on-site for construction and drilling-related activities.

Emission-control programs and practices currently in place at NPR-1 would be continued. This includes the use of vapor-recovery systems on major storage tanks at tank settings, LACT units, and liquid product loading facilities; the inspection/maintenance (I/M) program to control fugitive emissions from pipeline connections, valves, seals and other components; tank setting inspections to minimize hydrocarbon leaks; flaring of gas from LTS 1, LTS 2, and 35R/HPI during upset conditions, rather than direct venting of the gas to the atmosphere; and the use of watering to control fugitive dust emissions.

The impact of audible-noise sources within NPR-1 on nearby communities has been to increase the residual environmental noise levels to the range of 40-45 decibels (DOE 1978). Implementation of this alternative could result in slightly reduced noise levels on these nearby communities due to the elimination of additional production well drilling and construction activity, and reduced traffic levels.

4.2.1.4 Water Resources

Surface Water

As discussed in Section 4.1.4.1, stream channels draining the flanks of the Elk Hills do not carry natural runoff except for a few days each year when excess precipitation occurs. Data is available from only a single surface water sample taken at an ephemeral stream flowing off the northeast flank of Elk Hills in Section 19S. The total dissolved solids (TDS) concentration of this sample was 1,300 milligrams/liter. It is believed this water is typical of water draining from the Elk Hills (See Section 3.4.1.3).

Implementation of this alternative would eliminate construction of future surface structures, well pads, and other facilities. Gradually declining hydrocarbon production at NPR-1 would further reduce the potential impact of a major accidental release of contaminants followed by a runoff-producing storm. NPR-1's plan to implement a drainage reclamation program that addresses historical drilling sumps that may have been abandoned in natural drainages would be continued under this alternative.

Groundwater

The facilities and activities at NPR-1 that have the greatest potential of impacting groundwater resources are described in Section 3.4.2.4. Implementation of this alternative would result in roughly the same level of potential impacts as currently exists, with the following exceptions. As discussed in Section 4.2.1.1, the amount of drilling fluids requiring disposal would be reduced significantly, thereby reducing risks associated with that practice correspondingly. On the other hand, the amount of produced wastewater requiring disposal is expected to increase beyond the current level of 100,000-110,000 barrels/day to as much as 130,000 barrels/day as the NPR-1 oil field matures, even without the drilling of new production wells. This will further increase the risk of potential impacts to on-site and off-site groundwaters from wastewater disposal practices beyond that which already exists.

NPR-1 is obligated by DOE Order 5400.1 to implement a groundwater management protection program which is to include the development of a groundwater monitoring plan. It is anticipated that implementation of the groundwater monitoring plan will provide for the detection of significant impacts to groundwater resources caused by NPR-1 activities. The groundwater management protection program would provide management controls for appropriate response, investigation and corrective actions for any significant groundwater impacts detected.

4.2.1.5 Terrestrial Biota

As outlined in Section 3.5, the principal NPR-1 development impacts to the terrestrial biota have been loss of habitat, vehicle mortality, harassment, and the possible adverse effects of oil-field chemicals. As of 1989, 3,306 acres of NPR-1 have been disturbed as the result of

MER (Table 3.5-1). Loss of habitat may have contributed to declines in the NPR-1 lagomorph populations, the primary prey of the San Joaquin kit fox (Figure 3.5-7). Impacts to kit foxes known to have been caused by NPR-1 operations during the period 1980-1990 include 37 mortalities, 34 of which were the result of collisions with vehicles, and the destruction of 25 kit fox dens and potential dens. Oil, oil-field chemicals, and oil-field wastewater have been spilled or released on NPR-1 (see Section 3.2) and may have been inhaled or ingested by kit foxes through contaminated drinking water or prey. A toxicology study to determine the extent to which oil-field chemicals may have contributed to the decline of kit foxes on NPR-1 has been completed (Suter 1992)(see Section 3.5.3.2). Based on the results of the study, it is unlikely that oil-field chemicals were responsible for the decline in the NPR-1 kit fox population that occurred in the early 1980s.

Implementation of this alternative would limit future NPR-1 habitat disturbances and development to approximately 50 acres on NPR-1 for the maintenance and replacement of facility pipelines, and an additional 691 acres of land disturbance on or off NPR-1 in connection with non-federal third-party pipeline actions. In addition, this alternative would also temporarily affect approximately 226 acres/year in connection with seismic surveys. Over a 30-year period this amounts to 6,780 acres, approximately 50% of which would be on NPR-1. Vehicle mortality rates to NPR-1 site wildlife, including the San Joaquin kit fox, would likely decrease as a result of reduced traffic on NPR-1 primary and secondary roads. Inadvertent den destruction and intentional den excavations should occur at diminished rates in the absence of future production well drilling and construction activity. The potential for impacts associated with oil-field chemicals should also be less than in the past due to the use of non-toxic drilling muds and decreasing reliance upon surface sumping to dispose of produced wastewaters. Listed, candidate, and species of special concern could still be impacted by trapping and/or radiocollaring activities carried out under the Endangered Species Program. All trapping is conducted in strict accordance with permits and guidelines issued by the California Department of Fish and Game and the FWS.

Mitigation measures agreed upon with the U.S. Fish and Wildlife Service (FWS) during consultations pursuant to the Endangered Species Act in 1980 and 1987 would continue to be practiced. This includes the continued implementation of the NPR-1 Wildlife Management Plan (see Section 4.1.5.4). As required in the 1980 Biological Opinion, NPR-1 committed to avoid impacts to the San Joaquin kit fox and the blunt-nosed leopard lizard to the maximum extent practical, reclaim disturbed habitat, offset loss of habitat through compensation and mitigation, study the San Joaquin kit fox, and study the blunt-nosed leopard lizard. As a result of the 1987 Opinion, NPR-1 implemented an aggressive habitat reclamation program, expanded "preconstruction" surveys that only address construction projects to "preactivity" surveys that address all land disturbances, undertook studies to investigate the effects of oil-field chemicals on kit foxes, and reopened consultations in conjunction with the development and release of this SEIS.

All mitigation measures mentioned above, as well as additional measures agreed upon with FWS as part of the ongoing Section 7 consultation, would be continued and/or implemented as part of this alternative.

4.2.1.6 Cultural Resources

As a result of cultural resource surveys conducted between 1973-1991, combined with a review of existing file data, it has been determined that 40 recorded archaeological sites are located on NPR-1 (Peak 1991). None of the sites on NPR-1 are currently listed in the National Register of Historic Places (NRHP), although 12 archaeological sites possibly satisfy the criteria for inclusion in the NRHP. These sites will undergo formal evaluation to determine if they are eligible for listing in the NRHP. No historic sites are currently listed in the NRHP for NPR-1, although several sites (associated with the development of the local petroleum industry) located near the site are listed in the state files (BPOI 1986). A total of 101 historic sites have been recorded on NPR-1. Although important paleontological localities are situated near NPR-1 (most notably the McKittrick oil seeps), a broad surface reconnaissance conducted during 1980 found few fossil exposures on the site (Repenning unpublished data).

Implementation of this alternative would have little or no additional adverse impacts on cultural resources. This alternative would result in the disturbance of approximately 50 acres on NPR-1 for the maintenance and replacement of facility pipelines, 691 acres on and off NPR-1 in connection with non-federal third-party pipeline actions and 6,780 acres on and off NPR-1 in connection with seismic surveys. NPR-1 is currently in the process of implementing a cultural resource management plan which stresses avoidance of cultural resources. This plan is being designed in consultation with the SHPO on the basis of a comprehensive inventory of site resources. The management plan would be implemented under this alternative.

4.2.1.7 Land Use

Of the 47,409 acres that comprise NPR-1, approximately 6,546 acres (13.8% of the site) have been disturbed as a result of petroleum extraction activities begun in the early part of the century (Table 3.5-1). The remaining 40,863 acres (86.2% of the site) are relatively undisturbed lands that serve as natural habitat to several threatened and endangered species in the southern San Joaquin Valley, including the San Joaquin kit fox and the blunt-nosed leopard lizard. Adjacent land uses include oil and gas production, agriculture and open space, water banking, parks and recreation, and local community development (see Section 3.7).

As previously stated, this alternative would result in the development of approximately 50 acres on NPR-1 for the maintenance and replacement of facility pipelines, and an additional 691 acres on and off NPR-1 associated with non-federal third-party pipelines. As a part of this alternative, approximately 1,045 acres of development on and off NPR-1 would be revegetated (Table 1.3-2). The net result would be a 304-acre decrease in developed lands on and off NPR-1.

4.2.1.8 Socioeconomics

Implementation of this alternative would result in a return to the baseline conditions discussed in Section 3.8 and Section 4.1.8. Without additional development, the petroleum resources of the site would be depleted, wells would be abandoned, and direct and indirect employment would decline. This would result in a slightly negative impact to Kern County in terms of employment and trade. Implementation of this alternative would have a significant impact to the Federal Government as the revenues received from sale of NPR-1 hydrocarbons would continually decline from current levels.

4.2.1.9 Risk Assessment

As discussed in Section 3.9 the principal types of risks inherent in the operation of petroleum-production facilities are fire and explosion (which threaten primarily personnel and property) and spills (which threaten primarily the environment). Other risks include occupational injury and vehicle accidents.

Four explosions have occurred at enclosed compressor stations at NPR-1 since MER production began in the mid-1970's. The "on-site" safety record at NPR-1 facilities, where flammable natural gas liquids are stored, is excellent. Oil spills involving less than 100 barrels have averaged about 22/month, while spills of greater than 100 barrels have occurred at a rate of about 6.5/year. Injuries per 200,000 man-hours worked during the period 1982-1990 ranged from a low 2.48 in 1986 to a high of 8.50 in 1982. During 1982 NPR-1 had a vehicle accident rate of 6.0 accidents/million vehicle miles. For the period 1983-1987, NPR-1 had a vehicle accident rate of 2.2 accidents/million vehicle miles.

Implementation of the no action alternative would result in declining hydrocarbon production and concomitant site activities in the future. This fact, in conjunction with improved safety and operation programs at NPR-1 (see Section 4.1.9), should result in reduced risks in all of the above categories.

4.2.2 Alternative 2: Proposed Action Excluding SOZ Steam Expansion, Gas Processing Expansion, and Cogeneration Project

As explained in Section 2.2, this alternative provides for the same activity included in the proposed action, except that it excludes the SOZ steam expansion (see Section 1.2.2.6), the expansion of gas processing capacity (fourth gas plant) (see Section 1.2.2.11), and the cogeneration plant (see Section 1.2.13). The impacts of this Alternative are those that are associated with the continuation of existing operations (see Section 3.0), plus those that are associated with new development included in this Alternative (see Section 2.2). Accordingly, the impacts of this alternative would be approximately the same as those described for the proposed action, less the impacts of excluded projects. An impact discussion follows.

4.2.2.1 Geology and Soils

Construction Impacts

As in the case of the proposed action, construction activities would increase the potential for soil erosion, but adverse impacts should be insignificant as the result of measures planned to control erosion and rehabilitate construction sites (see Section 4.1.1.1). To the extent this alternative would cause adverse impacts, they should be less than those of the proposed action by an amount that is approximately proportional to differences in construction disturbances. Construction disturbances associated with the proposed action would be 1,569 acres on and off of NPR-1 over the next 30 years (see Table 1.3-2). This compares to 1,119 acres for this alternative (see Table 2.2-1), or 71% of the proposed action. Both the proposed action and this alternative would include measures to implement erosion control on approximately 1,045 acres to be revegetated (see Tables 1.3-2 and 2.2-1).

Operational Impacts

As in the case of the proposed action, potential geologic impacts (surface subsidence and induced seismicity) from the operational phase of this alternative should be relatively insignificant (see Section 4.1.2.2). However, to the extent there are risks, they should be somewhat less for the alternative than for the proposed action, primarily due to the exclusion of the fourth gas plant. If implemented, this project would accelerate gas withdrawals from the Stevens Zone by as much as approximately 50 million cubic feet/day, which could increase the risk of geologic impacts. By not implementing the fourth gas plant, the alternative would eliminate this risk.

The implementation of the SOZ steam expansion should have little or no effect on geologic structures over the long term. This is because fluid injection (steam) should be roughly equal to fluid withdrawal (hydrocarbons and water).

The cogeneration project is not expected to impact geologic structures.

4.2.2.2 Waste Generation

The impacts of this alternative on waste generation, handling, and disposal would be the same as those described for the proposed action, except they would not include the impacts of the SOZ steam expansion, the fourth gas plant, or the cogeneration facility (see Section 4.1.2). The impacts of these initiatives are discussed as follows:

The wastes requiring disposal which would be avoided if the SOZ steam expansion is not implemented primarily include construction debris, spent drilling fluids (and other drilling wastes), and produced water associated with the expansion. The proposed action provides for a 382-well drilling program, 148 of which are associated with the SOZ steam expansion (see Table 1.2-6) for the SOZ steam expansion, spent drilling fluids, and other drilling wastes would be reduced accordingly (approximately 39% reduction).

The proposed action includes the generation of approximately 100,100-181,000 barrels/day of produced water during the period FY 1990-1995 (see Section 4.1.4.2.1 and Table 1.2-1). These quantities include an estimated 8,505-34,478 barrels/day between the years 1991 and 2003 (see Table 1.2-6) for the SOZ steam expansion. By not implementing the SOZ steam expansion, produced water quantities would be reduced accordingly.

With the exception of the generation of potentially hazardous waste that would require disposal, impacts avoided by not constructing and operating the fourth gas plant or the cogeneration facility would be insignificant. This is because the proposed action would essentially mitigate all significant impacts associated with these projects (see Sections 4.1.2.2 and 4.1.2.3).

4.2.2.3 Air Quality and Noise

Construction Emissions

Construction pollutants and noise for the alternative would be qualitatively similar to those that were described or the proposed action in Section 4.1.3.2. The magnitude of these impacts should be approximately proportional to the magnitude of the respective disturbances. For the proposed action, development and/or temporary disturbances would occur on approximately 8,349 acres in connection with construction and seismic survey activities (see Table 1.3-2). For this alternative, the corresponding disturbances would occur on approximately 7,899 acres (see Table 2.2-1). On this basis, disturbances related to this alternative would be approximately 95% of those of the proposed action. Assuming the same relationship for construction emissions, this alternative would result in construction emissions that are approximately 95% of those that are shown for the proposed action by Table 4.1.3-2.

Noise levels associated with the proposed action are expected to increase residual noise levels in nearby communities by only 3 decibels maximum (see Section 4.1.3.3). Due to the exclusion of the major facility projects in this alternative residual noise level increases on nearby communities should be 3 decibels or less.

Operational Emissions

Table 4.1.3-1 shows operational emission levels for the proposed action and the alternative. As the table indicates, emission levels associated with this alternative would be less than the expansion, the fourth gas plant, and the cogeneration plant.

4.2.2.4 Water Resources

Surface Water

The impacts of this alternative on surface water resources would be qualitatively similar to those that were described in Section 4.1.4.1 for the proposed action, but somewhat smaller in magnitude due to the exclusion of the SOZ steam expansion, the fourth gas plant, and the cogeneration project. Given that surface water impacts for the proposed action were determined to be insignificant (primarily due to the arid conditions at NPR-1), they also would be insignificant for the alternative.

Groundwater

The impacts of this alternative (actual and potential) on groundwater resources would be qualitatively similar to those that were described in Section 4.1.4.2 for the proposed action; however, the magnitude of these impacts would be somewhat smaller than the proposed action due to the exclusion of the SOZ steam expansion, the fourth gas plant, and the cogeneration project. The effects of excluding these projects are discussed as follows:

SOZ Steam Expansion

- The proposed action, which includes the implementation of the SOZ steam expansion, would result in 100,000-181,000 barrels/day of produced water during the period FY 1990-1995 (see Table 1.2-1). To the extent it is technically and economically possible, plans are to dispose of this waste by recycling it for use as source water in the Stevens Zone and SOZ waterfloods. Wastewater that cannot be recycled would be disposed of by injection into the Tulare Formation. Current disposal by injection into the Tulare is approximately 80,000-100,000 barrels/day. Assuming the recycling initiative were fully successful, injection into the Tulare could be reduced to zero. Waterflood source water requirements in excess of that available from the wastewater system would be obtained by withdrawal from the Tulare Formation. Current withdrawals are approximately 148,000 barrels/day. If the recycling project were fully successful, withdrawals could be reduced to approximately 74,600 barrels/day. For additional explanations or information pertaining to the foregoing strategies and impacts, refer to the discussion on Injection of Fluids et al and Produced Water Disposal in Sections 1.2.2.7, 3.4.2.4, 4.1.4.2.1, 4.1.4.2.2, and 4.1.4.2.3.

The expansion of the SOZ steam project could result in generating 8,505-34,478 barrels/day of produced water requiring disposal during the period 1991-2003 (see Table 1.2-6). If the expansion were not implemented, as this alternative proposes, the produced water and Tulare injection quantities described in the preceding paragraph would decrease correspondingly, along with a corresponding increase in Tulare withdrawal quantities; associated impacts would change accordingly.

- As explained in the Fresh Water Activities discussions in Sections 1.2.2.16, 3.4.2.4, 4.1.4.2.1, 4.1.4.2.2, and 4.1.4.2.3, fresh water requirements for the proposed action would be expected to increase from the current level of approximately 29,000 barrels/day to a peak of approximately 74,800 barrels/day in 1995, if the SOZ steam expansion were fully implemented along with facility projects including the cogeneration plant. The fresh water requirements of the SOZ steam expansion are estimated to be 8,505-34,478 barrels/day during the period 1991-2003 (see Table 1.2-6). The fresh water requirements of the cogeneration plant are estimated to be approximately 6,500 barrels/day (see Section 1.2.2.13). These quantities would not be required if the SOZ steam expansion and cogeneration plant were not implemented, as this alternative proposes. Accordingly, fresh water requirements from the West Kern Water District and associated impacts for the alternative would be reduced in comparison to the proposed action.

- The proposed action consists of a 382 well drilling program (see Table 1.2-3), 105 of which could be injection wells (see the discussion on Injection of Fluids et al under Section 4.1.4.2.2). The drilling and operation of these wells could result in leaks from producing formations into overlying groundwater aquifers (see the discussion on Wells in Sections 3.4.2.4, 4.1.4.2.1, 4.1.4.2.2, and 4.1.4.2.3). This is particularly true of injection wells which are typically operated at higher pressures.

The SOZ steam expansion, which is included in the proposed action, consists of drilling 148 wells, 60 of which would be injectors. If the SOZ steam expansion were not implemented, these wells would not be drilled and operated, and the risk of leaks from producing formations into overlying groundwater aquifers described for the proposed action in the preceding paragraph would be reduced accordingly.

4.2.2.5 Terrestrial Biota

The impacts of this alternative on the terrestrial biota, including plant and animal communities and threatened and endangered species, would be qualitatively similar to those described for the proposed action in Section 4.1.5; however, impacts related to development area would be smaller in magnitude for the alternative by an amount corresponding to respective development area differences. These differences are explained as follows:

The proposed action would result in the development of 1,569 acres over the next 30 years: 979 acres on NPR-1 (2.3% of the remaining undeveloped habitat) and 590 acres off of NPR-1 (Table 1.3-2). It also would result in revegetating approximately 1,045 acres: 685 acres on NPR-1 and 360 acres off of NPR-1. This would result in a net decrease in undeveloped area of 524 acres: 294 acres on NPR-1 (0.7% of the remaining undeveloped habitat) and 230 acres off of NPR-1.

In comparison, the alternative to the proposed action would result in the development of approximately 1,119 acres on and off of NPR-1 over the next 30 years: 529 acres on NPR-1 (or 1.2% of the remaining undeveloped habitat) and 590 acres off of NPR-1 (Table 2.2-1).

In addition, the alternative would result in a net decrease of 74 acres in undeveloped area: a 156-acre increase on NPR-1 (0.4% of the remaining undeveloped habitat) and a 230-acre decrease off of NPR-1.

Based on area of development on and off of NPR-1, the alternative would disturb approximately 71% of the acreage that would be disturbed by the proposed action (1,119/1,569 = 71%). Based on NPR-1 only, the alternative would disturb approximately 54% of the acreage that would be disturbed by the proposed action (529/979 = 54%). The NPR-1 revegetation program and the other mitigation requirements from the FWS, including the NPR-1 Wildlife Management Plan, would continue under this alternative. Additional mitigation measures agreed upon with FWS during the ongoing Section 7 consultation would be implemented as part of this alternative.

4.2.2.6 Cultural Resources

The potential for cultural resource impacts is dependent upon the magnitude of disturbance areas and resource distribution. As explained in Section 4.2.2.3 under the Construction Emissions discussion, total disturbance areas associated with the alternative are approximately 95% of those associated with the proposed action. In addition, the disturbance areas of the SOZ steam expansion, the fourth gas plant, and the cogeneration facility (the only projects that are included in the proposed action but are not included in this alternative) are all in the developed upland areas of NPR-1 where prehistoric cultural resources are least likely to be encountered. Disturbances in the lower flatland areas on and off of NPR-1 (primarily due to third-party projects and geophysical surveys), where most prehistoric cultural resources appear to be located, would be approximately the same for both the proposed action and this alternative. Given these circumstances, impacts associated with the alternative should be approximately the same as those described for the proposed action in Section 4.1.6. For both the proposed action and Alternative 2, impacts would be mitigated through the implementation of a cultural resource management plan which stresses avoidance by taking advantage of inherent project siting flexibility and preactivity surveys. This plan is being designed in consultation with the SHPO on the basis of a comprehensive inventory of site resources.

4.2.2.7 Land Use

Land requirements for this alternative would be the same as described for the proposed action in Section 4.1.7, except that 450 acres of land for the SOZ steam expansion, the fourth gas plant, and the cogeneration facility would not be developed. Land requirements for the alternative and the proposed action are summarized by Table 2.2-1 and Table 1.3-2, respectively. Total development for the alternative over the next 30 years on and off of NPR-1 would be approximately 1,119 acres; this compares to 1,569 acres for the proposed action. In addition, both the alternative and the proposed action provide for the revegetation of approximately 1,045 acres of disturbed lands on and off of NPR-1 over the next 30 years. The activities comprising the alternative would be consistent with current land use patterns and should not result in significant adverse impacts.

On NPR-1, the alternative would result in the development of an additional 529 acres (1.1% of the site) over the next 30 years for federal and non-federal facilities. As in the case of the proposed action, this alternative also includes the revegetation of all land associated with facilities that have been, or will be, abandoned because they are not needed for operations (see Section 4.1.7). This has been estimated to be 685 acres on NPR-1 (1.4% of the site). The net result is that on NPR-1 the alternative would return approximately 156 acres of land to its original condition (0.3% of the site). In comparison, the proposed action would result in a net 294 acre increase in development on NPR-1 (0.6% of the site)(see Section 4.1.7).

Off of NPR-1, the impacts that would result from this alternative and the proposed action are the same: both would result in the disturbance of an additional 590 acres over the next 30 years, pursuant to the construction of non-federal facilities, and 360 acres of this would be revegetated as part of the respective construction projects. The net result is that developed areas off of NPR-1 wold be increased by approximately 230 acres.

In addition to the foregoing disturbances, this alternative would also temporarily affect approximately 226 acres/year in connection with seismic surveys. Over a 30-year period this amounts to 6,780 acres, approximately 50% of which would be on NPR-1.

4.2.2.8 Socioeconomics

The socioeconomic impacts of the alternative would be the same as those described for the proposed action in Sections 3.8 and 4.1.8, less the impacts of the SOZ steam expansion, the fourth gas plant, and the cogeneration facility. The total budget for drilling, construction, operations, and maintenance for the proposed action is anticipated to increase from approximately $172 million in FY 1989 to approximately 225 million in FY 1995. The great majority of these expenditures would induce incremental output, earnings and employment for Kern County. The same expenditures for the SOZ steam expansion, the fourth gas plant, and the cogeneration facility during the period 1991-2025 would be approximately $700-$750 million. If these projects are not implemented, then output, earnings, and employment would be reduced correspondingly.

4.2.2.9 Risk Assessment

The risks associated with this alternative would be the same as those described for proposed action in Sections 3.9 and 4.1.9, less risks directly associated with the SOZ steam expansion, the fourth gas plant, and the cogeneration facility. The most significant risks are discussed as follows.

The most notable difference between the alternative and the proposed action pertains to blowouts during the conduct of drilling operations. As indicated in Section 4.1.9, it appears that the proposed action could result in 1-2 blowouts during the period 1990-2025 as the result of drilling, remedials, workovers, and well operations. The proposed action includes a program to drill 382 wells, 148 of which are associated with the SOZ steam expansion. If the SOZ steam expansion is not implemented, then the drilling program would be reduced by 148 wells, and the risk of incurring blowouts would be reduced correspondingly. The expected blowout rate based on published data and actual experience is 0.8-0.9 blowouts/1,000 wells drilled (Section 3.9).

Under the proposed action, there would be six closed or partially closed major compressor facilities (LTS-1, LTS-2, 35R, fourth gas plant, HPI and 33S) of the types where all past explosions have occurred. Under this alternative, there only would be five such facilities with the exclusion of the fourth gas plant. In addition, gas processing and handling under this alternative would be less than the proposed action by up to approximately 50 million cubic feet/day for approximately 15 years. Given the circumstances, the risk of explosions would be less under the alternative than under the proposed action.

If the SOZ steam expansion, the fourth gas plant, and the cogeneration facility are not constructed and operated, the risk of occupational accidents would be somewhat less than otherwise. This would be especially applicable with regard to drilling the 148 SOZ steam expansion wells, given that accident rates at NPR-1 are highest for drilling operations (see Table 3.9-2).

Given that oil production rates would be somewhat less for the alternative than for the proposed action, the risk of oil spills would be reduced correspondingly. The anticipated production rates for the proposed action are shown by Table 1.2-1. These would be reduced by approximately 8,000-12,000 barrels/day of oil if the SOZ steam expansion and the fourth gas plant projects are not implemented.

Mitigation activities planned for the alternative would be the same as those described for the proposed action in Section 4.1.9.

4.2.3 Alternative 3: Nonsteamflood Tertiary Oil-Recovery Strategies

This alternative has been considered and dismissed without further analysis for the reasons given in Section 2.3.

4.2.4 References*

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*Copies of correspondence and unpublished documents included in this list may be obtained upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California 93276.

5.0 UNAVOIDABLE ADVERSE IMPACTS

5.1 PROPOSED ACTION

Unavoidable, adverse impacts and risk of impacts (i.e., those significant impacts that cannot be avoided with planned mitigation) are presented as follows:

- Some soil erosion would occur, especially in areas of new construction if major storms were to occur before soil stabilization measures take effect.

- There is some potential for subsidence as the result of withdrawal of oil, gas and water from underlying geologic structures.

- Inadvertent releases of oil or other oil-field chemicals that are not entirely recovered on a timely basis could, over a period of time, migrate into and degrade groundwater aquifers.

- Small net increases in the emissions of CO and particulate matter could occur, resulting in marginal, and probably unmeasurable, changes in ambient concentrations of these pollutants in western Kern County.

- There would be unavoidable adverse impacts associated with habitat disturbances. These would be the adverse impacts associated with disturbing approximately 1,569 acres over a 30-year period due to new construction (approximately 979 acres on NPR-1, or 2.3% of the remaining undeveloped habitat), less the favorable impacts of revegetating approximately 1,045 acres (685 acres on NPR-1, or 1.6% of the remaining undeveloped habitat) through the year 1998, taking into account the period of time required for revegetation to take full effect.

- Loss of habitat, exposure to hydrocarbons and oil-field chemicals and site activities would result in the death, injury and displacement of some plants and animals, including threatened and endangered species. Of particular concern are incremental impacts to the federally endangered San Joaquin kit fox which currently exist on the site in relatively small numbers.

- If the program to recycle produced water for use as waterflood water does not eliminate the need to dispose of produced water into the Tulare Formation, then there is a possibility that such wastewater could degrade usable off-site groundwaters. The proposed action includes the implementation of a Groundwater Protection Management Program that will address the potential risks to off-site groundwater resources that may result from all NPR-1 operations.

5.2 Alternatives

As discussed in Section 4.2.1, Alternative 1 (no action) would continue the impacts associated with the existing NPR-1 operation. Significant, unavoidable impacts that would occur under Alternative 1 include habitat disturbance of 741 acres on and off NPR-1 (reduced from 1,569 acres), from construction activities related to maintenance, replacement, or installation of NPR-1 and third-party facilities necessary for NPR-1 oil and gas product deliveries under this alternative; loss of an estimated 1.2 billion dollars in federal revenues; and slight increases over time in the volume of produced wastewater that would require disposal. As discussed in Section 4.2.2, significant, unavoidable impacts that would occur under Alternative 2 (proposed action excluding SOZ steam expansion, fourth gas plant and cogeneration project) would be essentially the same as described in Section 5.1 above, with the exception that habitat disturbances from new construction on NPR-1 would be reduced from 1,569 acres to 1,119 acres over the next 30 years. As discussed in Sections 2.3 and 4.2.3, proposed Alternative 3 (nonsteamflood tertiary oil-recovery strategies) was eliminated from detailed analysis.

6.0 RELATIONSHIP BETWEEN SHORT-TERM USE OF THE ENVIRONMENT AND LONG-TERM PRODUCTIVITY

Given the extensive loss of wildlife habitat in the San Joaquin Valley over the past several decades, the best long-term utilization of NPR-1 would probably be as wildlife habitat (or some other compatible human use). This was the primary use of the site prior to beginning hydrocarbon extraction in the early part of the century, and it has continued to be an important use even while hydrocarbon extraction has been carried out, especially during the time when petroleum production activities were comparatively limited.

Under the proposed action, the primary short-term use of NPR-1 would be for hydrocarbon extraction, which has been the case for most of this century, and especially since MER production began in the mid-1970's. This is expected to continue for 25-30 years, depending on economic conditions and technological advancements. As explained in the previous sections of this document, under the proposed action NPR-1 would continue to be an important ecological resource even while MER production activities are being carried out. The great majority of the site would continue to be undisturbed. Disturbed areas that are not needed for future operations would be revegetated; soil conservation practices would continue to be implemented; off-road driving would be prohibited; grazing would continue to be prohibited; site access would be controlled; and avoidance would continue to be the cornerstone of development activities with respect to threatened and endangered species. Given this strategy, the site would eventually be returned to long-term use as wildlife habitat, and therefore, short-term and long-term uses should be compatible. This notwithstanding, the impacts of the proposed action on NPR-1 habitat would be significant for a relatively long period of time. This could result in permanent, or long-term changes in the quality of the habitat which could affect the productivity of the site for use by wildlife (e.g., wildlife populations could change). Of particular concern would be any impacts on the habitat that would adversely affect its use by the federally endangered San Joaquin kit fox.

Current fresh water requirements are about 30,000 barrels/day. Short-term requirements for fresh water could increase to as much as 74,800 barrels/day if the proposed steamflood projects are fully implemented in accordance with the indicated schedule along with smaller contributions from other facility projects, such as the butane isomerization project, cogeneration project, and continuation of existing operations. As explained, the scope and schedule of the steamflood projects are uncertain, and it is reasonable to anticipate that fresh water requirements may never exceed the current on-site and off-site capability and contract amount of 48,000 barrels/day.

In addition to fresh water, there also will be a need for waterflood source water. Currently this is about 148,000 barrels/day and is obtained from the Tulare groundwater aquifer underlying NPR-1. If the Produced Water Injection (PWI) projects are fully implemented, Tulare source water withdrawals would be reduced to 73,500 barrels/day. If the PWI projects are totally unsuccessful, Tulare source water withdrawals could increase to

254,000 barrels/day within several years. In either event, source water withdrawals would decline to zero within the economic life of the field (about 2010-2025).

In addition to using the Tulare aquifer for waterflood source water, the aquifer also could be used to dispose of produced wastewater. Currently, 100,000-110,000 barrels/day of wastewater are disposed of into the Tulare. If the PWI projects are fully successful, this would be reduced to zero within a few years. If the PWI projects are totally unsuccessful, this could increase to approximately 181,000 barrels/day.

Based on studies and observations, there have been no significant impacts on the Tulare aquifer, on or off NPR-1, as the result of on-site wastewater disposal practices or waterflood source water withdrawals. Therefore, no adverse long-term effects on Tulare aquifer productivity is anticipated to result from the proposed action.

7.0 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

As stated in Section 6, the short-term commitment of NPR-1 to petroleum production as proposed would not necessarily preclude concurrent use of the site for other purposes, such as wildlife habitat (the principal predevelopment use, along with livestock grazing). Also, the site could largely be returned to predevelopment uses and/or other human uses through proper reclamation activities as oil operations decelerate and eventually come to an end. Thus, NPR-1 land resources would not be irreversibly or irretrievably committed by implementation of the proposed action.

Three significant irreversible and irretrievable commitments of resources would occur with implementation of the proposed action: (1) consumptive use of energy (i.e., electricity and fossil fuels) for construction and operation of production facilities; (2) extraction, sale, and consumptive use of oil and natural-gas products from NPR-1; and (3) consumptive use of fresh water. A portion of the equipment and materials used in fabrication of project operating and transport facilities would also be lost, but much could be salvaged as these facilities were phased out over time. The commitment of extracted fossil fuels to sale and ultimate consumption would, of course, render them irretrievable for use in the future. Commitment of these resources has been mandated by the Naval Petroleum Production Act of 1976 -- Public Law 94-258.

8.0 PREPARERS/CONTRIBUTORS

8.1 DOCUMENT PREPARATION

This Supplemental Environmental Impact Statement (SEIS) has been prepared by the U.S. Department of Energy (DOE), Naval Petroleum Reserves in California (NPRC), based on a preliminary draft of the document (PDSEIS) prepared by the Environmental Assessment and Information Sciences Division of Argonne National Laboratory (ANL 1990), and review comments provided by the staffs of DOE-NPRC, Chevron U.S.A. Inc. (CUSA), Bechtel Petroleum Operations, Inc. (BPOI), EG&G Energy Measurements, Inc. (EG&G/EM), Research Management Consultants, Inc. (RMCI), and other interested agencies and parties. The project was managed by DOE-NPRC with coordination and technical assistance provided by RMCI. The primary preparers/contributors are listed below:

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The majority of the information provided in this document was developed by ANL and presented in the ANL PDSEIS. A complete list of ANL contributors is included in the PDSEIS, a copy of which will be provided upon request.

8.2 REFERENCES*

Argonne National Laboratory, Environmental Assessment and Information Sciences Division, 1990, Revised Preliminary Draft Supplement to Final Environmental Impact Statement (Issued 1979), Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California, June.

*Copies of this document are available upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California (NPRC), Tupman, California 93276. Copies are also available for review in the NPRC reading room.

APPENDIX A:

DESCRIPTION OF CURRENT FACILITIES AND OPERATIONS

This appendix describes the production facilities and related support systems, services, and operation and maintenance activities currently in place at NPR-1. Summary descriptions are provided for production zones and product streams, production-well development, injection systems, oil- and gas-gathering systems, product-processing and storage facilities; enhanced oil-recovery systems; waste-handling procedures and facilities; support systems and facilities; and operations and maintenance activities.

A.1 PRODUCTION ZONES AND PRODUCT STREAMS

Approximately 82% of all present Unit hydrocarbon production is from the Stevens Zone, 17% is from the Shallow Oil Zone (SOZ), and the remaining 1% or less is from the Carneros and Dry Gas Zones (DGZ). The government also owns 100% of Asphalto and Railroad Gap properties, which produce small amounts of oil and gas.

Reservoir pressure has been severely depleted in the SOZ, and artificial lift with pumping units is required. Approximately 100 Stevens wells flow freely and do not require artificial lift, while the remaining 300 or so wells require pumping units, electrical submersible pumps, or artificial lift by means of gas lift. As pressure is depleted in the Stevens reservoirs, more and more of the free-flowing wells will require some means of artificial lift. Estimates of the percentages of flowing wells for specific reservoirs are as follows: Main Body B (MBB) 25-30%, C/D shales 10%, and 29R 5%. Other zones yield only gas and water, and the production streams require separation into gas and liquid components after withdrawal.

Hydrocarbon and water production from individual wells enters a tank setting through a manifold header. Production then enters a series of separators where liquids (oil and water) and gas are separated. The liquids are separated to production tanks and eventually gravitated or pumped to dehydration/lease automatic custody transfer (LACT) facilities. The water is separated from the oil and currently is disposed of in the Tulare Formation. The pipeline-quality oil is sent through the LACT meter, where ownership is transferred to the purchaser (DOE 1989).

The gas stream is subsequently separated in a gas-processing facility into gas liquids that are sold and dry gases (primarily methane and ethane) that either are sold, or injected into wells of the oil-production zones to maintain reservoir pressure. Gas produced primarily from the DGZ is either sent to a gas-processing facility, used as a fuel to run engines for gas compression, or is sometimes sent directly to the sales line.

A.1.1 Dry Gas Zone

The Dry Gas Zone (Figure A.1) consists of thin, channel-like sand bodies within the Mya member of the Pliocene San Joaquin Formation. Included are 17 stratigraphic intervals with identified gas resources and 57 mapped pools. The zone is being developed with compression from 35 wells; 26 are producing and 9 are shut in.

A.1.2 Shallow Oil Zone

The SOZ (Figure A.1) consists of about 17 identifiable sands. In general, the younger sands are productive in the eastern portion of the 31S structure, and the older sands of the Etchegoin Formation are productive to the west. A pilot steamflood project for the SS-1 sand (one of the oil-producing sands in the SOZ) was initiated in Section 3G during FY 1987. The 59-acre phase I of the project consists of 12 production wells, 5 injectors, and 3 observation wells (wells drilled to obtain data on changes in temperature and pressure and to help determine steam and oil front movement).

A.1.3 Stevens Zone

The Stevens Zone (Figure A.2) consists of 11 major pools and is the most significant source of crude oil reserves in the Elk Hills. The five most productive pools are the Main Body B/Western 31S (MBB/W31S) sands, 26R sand, 24Z sand, Northwest Stevens (NWS) A1-A3, and the NWS A4-A6 sands. The MBB/W31S interval consists of four sands that together cover the entire 31S structure (the major anticlinal oil reservoir in the region). Both the MBB and W31S sands are produced under a peripheral waterflood project. Currently the project consists of approximately 280 wells, including 69 water injectors and 6 gas injectors.

The 26R sand is a submarine fan channel sand approximately 1 mile wide on the southwestern limb of the 31S structure. Fifty completed wells produce from the 26R sand, and gas is being injected through eight wells to maintain pressure.

The 24Z sand is a channel sand about 1 mile wide and up to 1,000 feet thick crossing the 29R structure in Sections 24Z and 13Z (Figure A.2). Currently the 24Z pool has 12 active producing wells, 2 gas injectors, and 3 water injectors. A peripheral waterflood was initiated in the 24Z pool in FY 1987.

The production zone of the Northwest Stevens structure consists of thick, massive, deepwater channel sands (the A sands, T sands and N shales). The A1-A2 sands are pressure-maintained by gas injection. The A3-A6 sands are under peripheral water injection to maintain reservoir pressure and are produced by 59 wells.

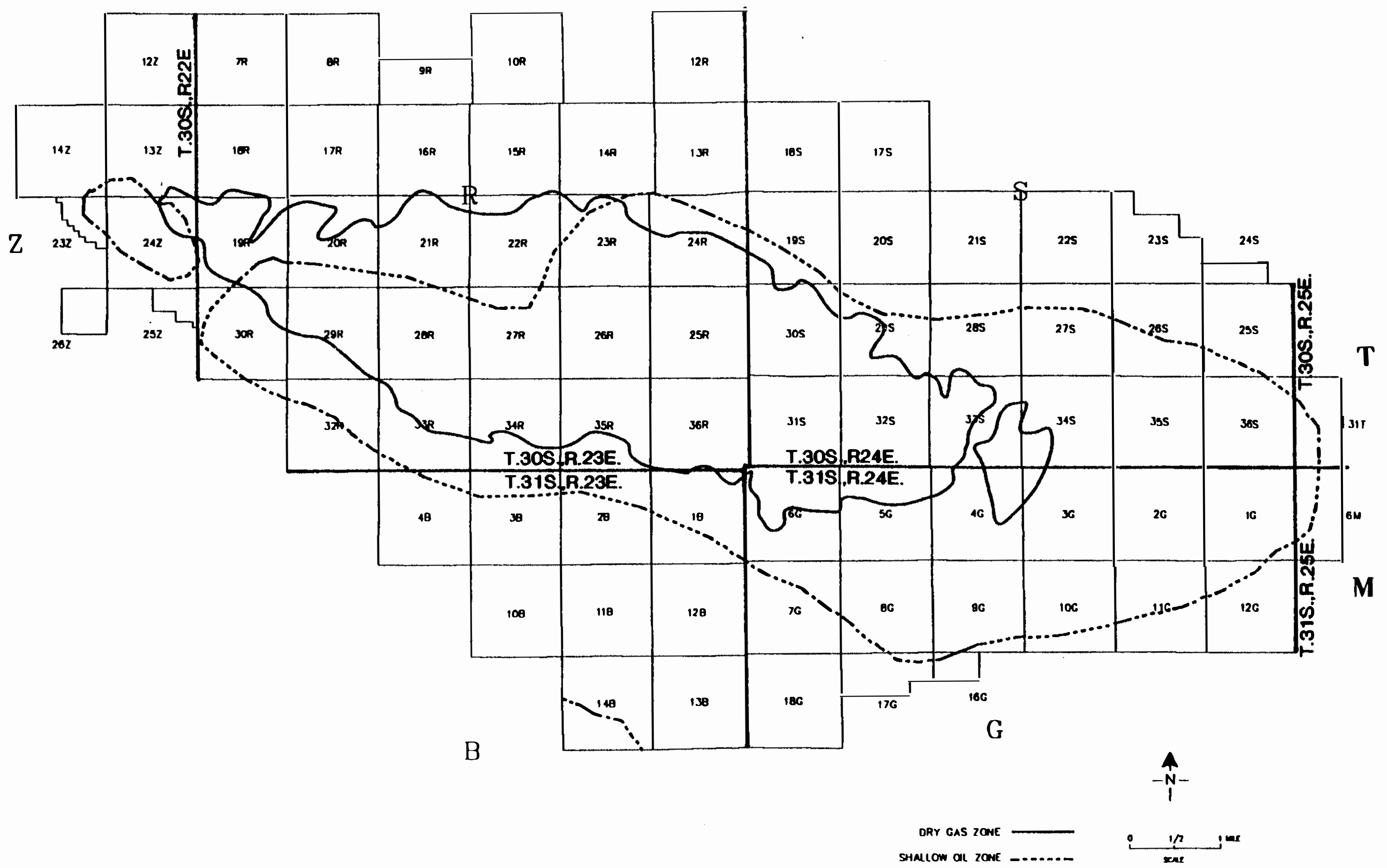

FIGURE A.1 SUBSURFACE LOCATIONS OF DRY GAS ZONE AND SHALLOW OIL ZONE RELATIVE TO NPR-1 SECTIONS

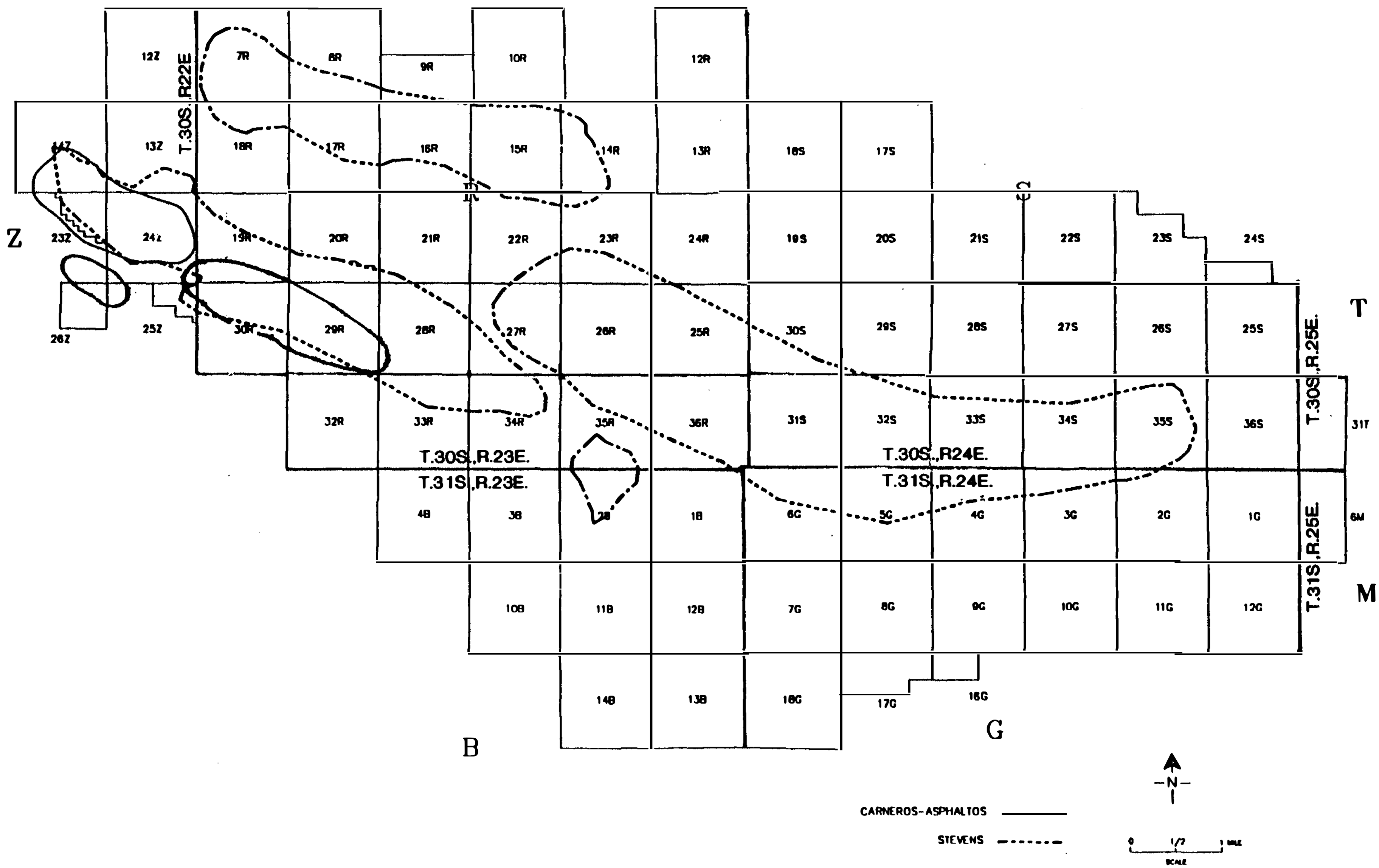

FIGURE A.2 SUBSURFACE LOCATIONS OF STEVENS AND CARNEROS ZONES RELATIVE TO NPR-1 SECTIONS.

A.1.4 Asphalto Zone

The Asphalto reservoir is in an advanced stage of depletion (approximately 70% of the estimated original oil-in-place has been removed). This reservoir is an extension of the Stevens 24Z sand and extends outside the southwestern boundary of NPR-1. Production comes from the northeastern quarter of Section 26Z at the southwestern edge of the Reserve. Currently there are 11 wells producing about 160 barrels/day of oil.

A.1.5 Carneros Zone

The Carneros Zone (Figure A.2) consists of three sands containing oil, gas, and gas condensate. The accumulation of gas and oil in the Carneros Zone is controlled primarily by the 29R structure (an anticlinal trap) and secondarily by the pinching out of the sands to the east.

A.2 PRODUCTION WELLS

Before inception of the *Total Capability Development Program* (implemented in 1974 to open the NPR-1 for commercial production), about 1,279 wells had been drilled at the Elk Hills; 1,036 more wells were drilled between 1974 and FY 1988.

During the primary development period (1974 through FY 1983), 926 development wells were drilled, an average of 93 wells per year. Since then, about 26 development wells per year (average) have been drilled for infill, replacement, waterflood, and steamflooding. Forty exploration wells have been drilled during that same period, with the number drilled each year decreasing as the field becomes fully developed.

The importance of the primary production zones at NPR-1 is indicated by the distribution of the 29 development wells completed in FY 1987. Twenty-four of the wells are producers -- 20 in the Stevens Zone and 4 in the SOZ. In addition, five water-injection wells were drilled in the Stevens Zone as part of a waterflood program. Table A.1 lists the number of development wells drilled each year from 1974 through FY 1987.

By the end of FY 1988, a total of 2,315 wells had been completed since establishment of NPR-1. Of those wells, 1,252 were operational -- 1,079 were active producers, 117 were water source/injection wells, 15 were water-disposal wells, 17 were gas-injection wells, and 4 were steam-injection wells. Shut-in (idle) and abandoned wells totaled 1,055. Table A.2 presents an inventory of existing wells at NPR-1 at the end of FY 1988.

TABLE A.1 Number of Development Wells Drilled at NPR-1, 1974 through FY 1987

Period	Tulare	Dry Gas	Shallow Oil	Olig	Stevens	Carneros	Total
1974-1976	0	12	163	0	81	2	258
FY 1977	0	5	99	0	63	1	168
FY 1978	0	6	65	0	47	2	120
FY 1979	2	3	34	0	43	0	82
FY 1980	2	0	16	0	46	0	64
FY 1981	4	0	0	0	42	0	46
FY 1982	8	0	31	1	61	0	101
FY 1983	0	0	25	0	62	0	87
FY 1984	4	0	10	0	15	1	30
FY 1985	4	0	8	0	10	0	22
FY 1986	0	0	12	0	10	0	22
FY 1987	1	0	4	0	24	0	29
Total	25	26	467	1	504	6	1,029

Source: DOE 1988.

TABLE A.2 Inventory of Completed Wells at NPR-1 as of September 30, 1988

Zone	Well Type				
	Producer/ Supply	Injection/ Disposal	Shut-in[a]	Abandoned[b]	Total
Dry Gas	28	0	9	0	37
Shallow Oil	623	5	535	255	1,418
Stevens	393	134	257	6	790
Carneros	10	0	4	1	15
Other					
Asphalto	11	0	6	0	17
Tulare	11[c]	14[d]	0	0	25
Railroad Gap	3	0	10	0	13
Total	1,079	153	821	262	2,315

[a]Temporarily removed from production because of field operating requirements.
[b]All abandoned wells are plugged.
[c]Four wells are water source wells and seven are idle production wells.
[d]Fourteen wells are designated for disposal of wastewater, and 13 are currently used for this purpose.

A.3 INJECTION SYSTEM

The injection system at NPR-1 consists of the gas- and water-injection elements described as follows:

A.3.1 Gas Injection

After processing and extraction of liquids, approximately 205 million cubic feet/day of dry gas (consisting primarily of methane and ethane) is compressed to 3,500 pounds per square inch gauge (psig) through the high-pressure injection (HPI) system and reinjected into selected pools in the Stevens Zone. The gas is injected into approximately 17 wells in pools for reservoir pressure maintenance. Approximately 13 wells take gas from this system, in which the pressure is dropped to approximately 1,500 psig for artificial gas-lift use. Compression capacity totals 270 million cubic feet/day at 3,500 psig. The HPI system has in service six KVR compressors rated at 5,500 horsepower each and three KVR compressors rated at 4,000 horsepower each. Three Clark compressors rated at 888 horsepower each also can provide injection capacity, if required. All of these compressors are located at the 35R gas complex (DOE 1989).

A.3.2 Water Injection

All injection water for waterflooding the Stevens Zone is supplied from the Tulare Formation. Approximately 148,000 barrels/day of Tulare water are pumped from approximately five source wells in the south flank of the reservoir to the 33S and 17R waterflood plants. The water is free of oil and only requires slight chemical treatment with corrosion inhibitors and biocides. The 33S waterflood plant supplies water to the MBB waterflood, and the 17R waterflood plant supplies water to the NWS and 24Z waterflood.

Approximately 100,000-110,000 barrels/day (4.2 million gallons/day) of produced water are removed from oil at the dehydration/LACT facilities. Approximately 80,000-100,000 barrels/day of this are disposed of by injection into the Tulare, the SOZ and the Olig; most is into the Tulare. Approximately 6,500 barrels/day are disposed of into three wells south of the 24Z reservoir to maintain a pressure barrier and prevent migration of Stevens Zone crude oil into the Asphalto field (DOE 1989).

A.4 OIL- AND GAS-GATHERING SYSTEMS

Hydrocarbons produced throughout the site first enter tank settings, where oil and gas are separated. The wet gas is then collected into vacuum, low-pressure, and high-pressure gas-gathering systems. All of this gas is transported to the 35R gas complex, with the exception of gas used for fuel and gas lost due to shrinkage. The gas is then processed, with liquids such as propane, butane, and natural gasoline being extracted and sold. The residue gas containing primarily methane with some ethane is both sold and reinjected into the Stevens Reservoir.

Oil and water volumes separated at the tank settings are gathered in oil and water collection lines. The liquids are then either gravitated or pumped to the nearest dehydration/LACT facilities. Water is removed and disposed of, and the pipeline-quality oil is metered through the LACT unit, where ownership is transferred to DOE purchasers or CUSA. Current gross liquid production is approximately 200,000 barrels/day. Gross liquid production is expected to peak at about 250,000 barrels/day. Oil currently is shipped off the site through one of five dehydration/LACT facilities and then through five pipelines to be marketed via common carrier pipelines. Table A.3 lists the section locations and operators of pipelines shipping crude oil off of NPR-1. Some crude oil product is shipped off-site in trucks.

Each of the five dehydration/LACT facilities includes a production tank, a settling tank, a shipping tank, LACT monitoring and metering equipment, and a LACT pump. The LACT units automatically meter and record oil volume as it enters the purchaser's pipeline. If too much water is present, it will be sensed by a resistance probe and the oil will be rejected to the production tank, where the dehydration process starts over. Dehydration/LACT facilities are located in Sections 10G, 18G, 25S, 24Z, and 26Z. LACT meters also are located in Sections 30R and 35R, but hydrocarbons are only metered for accounting purposes; no transfer of outside ownership takes place at these two locations.

Additional LACT units may be added, if required. At peak MER, a total of about 150,000 barrels/day of water would be separated from oil at the dehydration/LACT facilities. Crude oil from each of the four oil-producing zones is sent to separate dehydration/LACT facilities to keep the oil segregated. Carneros production is metered through a LACT at 30R and is commingled with Asphalto and Railroad Gap production at the Asphalto production tank setting in Section 2-26Z. Here, oil from the three zones is metered through the 26Z LACT unit and sold to the purchaser (DOE 1989). Characteristics of the two major types of crude oil from the SOZ and Stevens Zone are presented in Appendix B of the 1979 Final EIS (DOE 1979).

A.5 GAS-PROCESSING AND -STORAGE FACILITIES

The gas-collection, -processing, -injection, and -sales-distribution systems collect gas produced from oil and gas wells, process the gas to remove water and natural gas liquids (NGL), and pressurize and distribute the gas for injection or sales to customers. Total nominal process capacity available is 300 million cubic feet/day. An off-site contract facility can handle an additional 60 million cubic feet/day. Current gas production at NPR-1 is about 360 million cubic feet/day.

Typically, the gas is separated from the oil/water/gas stream at the tank settings and transported by pipeline for processing at the gas plant complexes in Sections 35R and 17Z. Before processing, this gas is commonly referred to as *wet* gas. Some wet gas is used as fuel for field operations, and the wet gas that condenses into a liquid is removed by the condensate-collection system. Wet gas is also reinjected into some wells to stimulate the production of oil (gas-lift wells). The remaining wet gas is processed at the gas plants.

TABLE A.3 Pipelines Shipping Crude Oil off NPR-1

Section Location	Number of Pipelines	Operator
25S	2	CUSA/DOE
10G	1	4 Corners Pipeline Co./Arco
18G	4	CUSA
	1	4 Corners Pipeline Co./Arco
	2	Texaco
	1	Santa Fe Energy
24Z	3	Chevron
	1	Texaco
	1	Anchor Petroleum
26Z	1	4 Corners Pipeline Co./Arco

Source: BPOI 1989.

The condensate-collection system is a network of piping that parallels the gas piping system. Liquid hydrocarbons that condense in the gas-collection systems are removed through traps (or boots) into the condensate-collection system. Stevens Zone condensate is gathered throughout the reservoir and is pumped behind the 35R Lean Oil Absorption Plant to storage vessels. Here it is stabilized and pumped to a nearby tank setting, where it is commingled with Stevens Zone production. The condensate eventually is sold with Stevens Zone oil at the 18G dehydration/ LACT facility. The capability also exists to process this condensate at the gas plants for recovery of NGL products, depending on market conditions.

At MER, total production of natural gas liquids would be about 650,000 gallons/day. Two gas-processing plants, LTS-1 and LTS-2, include facilities to extract gas liquids from the rich gas at low temperatures and separate them into propane, butane, and natural gasoline products for sale. The third gas-processing plant, 35R, uses an absorption process to accomplish the separation. This on-site gas-processing complex has a nominal capacity of 300 million cubic feet/day. In addition, off-site gas processing and storage is available at Chevron's McKittrick gas plant, located in Section 17Z. Table A.4 lists the capacity of the on-site gas-processing system and the current rate of production.

The gas-sales system includes facilities and equipment to dehydrate (if required), compress, transport through a pipeline system, and meter produced gas for sales. Two basic sales systems exist for produced natural gas -- the Stevens system (which handles Stevens [Asphalto], Carneros, and SOZ gas) and the Dry Gas Zone system. Both systems compress and dehydrate the gas, which then is transported by pipeline to the sales-metering stations for marketing. The capacities of these two sales systems relative to current production are shown in Table A.5.

Propane, butane, and natural gasoline from NPR-1 gas plants are stored on the site and loaded for truck shipment. Storage, loading, and transportation facilities are also associated with the CUSA gas plant.

The NGL products are transferred to storage tanks and delivered to contractors through a tanker truck loading facility. Product fractions are transferred from accumulation vessels at the processing plant site through dedicated 3-inch and 4-inch steel pipelines to pressure vessels outside of the plant boundaries. These storage vessels, located in two separate areas of Section 35R, can hold approximately three days of production. Table A.6 lists the on-site NGL product storage capacities by product and location. The storage and loading configurations are estimated to be capable of servicing up to 200 tankers/day.

All liquids currently recovered by the existing on-site processing plants are shipped from NPR-1 via tanker-trucks with capacities of about 10,000 gallons each. The typical amount of liquid hauled per truck is 7,500-10,000 gallons. Peak traffic is about 58 trucks/day during summer and 150/day during winter.

TABLE A.4 Capacities of Gas-Processing Systems

System	Nominal Capacity (10^6 ft^3/day)	Current Production (10^6 ft^3/day)
Processing (35R & 17Z)	360	365
Gas injection	273	195
Gas Sales Compression	140	137
Low-pressure compression	217	176
Vacuum compression	35	18
High pressure Systems	450	369

Source: BPOI 1988.

TABLE A.5 Capacities of Gas Sales Pipeline Systems

System	Capacity (10^6 ft^3/day)	Current Production (10^6 ft^3/day)
Dry Gas Zone	21	20
Stevens	161	119
Total	182	139

Source: BPOI 1988.

TABLE A.6 NGL Product Storage Capacities at NPR-1 (Gallons)

Product	Number of Vessels	Operational Capacity of Each	Total Operational Capacity
LTS Storage			
Propane	10	77,850	778,500
Mixed Butane	6	77,850	467,100
Natural gasoline	4	77,850	311,400
Subtotal	20		1,557,000
35R Storage			
Propane	5	25,950	129,750
Mixed butane	6	25,950	155,700
Natural gasoline	2	51,900	103,800
Subtotal	13		389,250
Emergency Storage			
Mixed Butane	1	103,800	103,800
Mixed butane or natural gasoline	2	77,850	155,700
Subtotal	3		259,500
Grand Total	36		2,205,750

Source: BPOI 1988.

A.6 ENHANCED RECOVERY SYSTEMS

The NPR-1 development program includes several secondary and tertiary (enhanced) oil recovery projects. Secondary recovery is achieved by injecting water into injection wells that are perforated at or near oil-production intervals. The water is displaced through the reservoir at high pressures, and this displaces the oil towards producing wells. This displacement of water in the reservoir is referred to as waterflooding and can recover significant incremental amounts of oil that otherwise might not be removed.

Tertiary, or enhanced oil recovery is used to recover residual oil remaining in the reservoir after primary and secondary methods have been exhausted. Enhanced oil recovery can be achieved by several mechanisms, one of which is steamflooding. Steam is produced on the surface by heating very clean water through a steam generator and injecting it through insulated piping into a shallow well, some 1,000-2,500 feet deep. Heat from the steam significantly reduces the viscosity of the oil and increases its mobility. The oil is then displaced toward producing wells. Steamflooding is used principally for reservoirs that have heavy oil with gravities between 8 and 18 degrees API. The SOZ oil for the pilot steamflood has a lighter gravity of approximately 28 degrees API. Steamflooding lighter oils such as these is termed light-oil steamflooding (LOSF).

Currently, three waterflood projects and a pilot steamflood project are being operated at NPR-1. The 33S waterflood plant can provide 140,000 barrels/day of water for the Stevens MBB/W31S waterflood. This project involves about 100 injection wells and 225 production wells. The production wells are on 20-acre spacing, with present operations for infill drilling some wells to 10-acre spacing. Currently, approximately 94,000 barrels/day are being injected into the MBB/W31S. The 17R waterflood plant provides 18,000 barrels/day of water for the Stevens A3-A6 waterflood, also referred to as the Northwest Stevens waterflood. The A3-A6 project consists of approximately 60 producers and 20 injectors. The 17R waterflood plant also supplies 36,000 barrels/day of water for the 24Z waterflood. The 24Z project consists of approximately 12 producers and 12 injectors. The total capacity of the 17R waterflood plant is 60,000 barrels/day.

The SOZ pilot steamflood project was placed into production in FY 1987. The facilities include injection of steam through 5 injection wells and production facilities to handle the oil, water, and gas from 12 producing wells. The installation consists of a 62.5-million-BTU/hour steam generator, water-treatment facilities, flow lines, test and production separators, tanks, and shipping pumps. The oil is pumped into the SOZ gravity line near the 10G dehydration and sales facilities. The gas goes into the SOZ gathering system near the vacuum compressors in Section 3G.

A.7 WASTE-HANDLING SYSTEMS

Liquid-waste-disposal facilities at NPR-1 include (1) sanitary-sewage-disposal facilities (septic tanks, leach fields, and percolation wells), (2) water-injection facilities for produced waters, and (3) percolation/evaporation ponds for a portion of produced waters and all process wastewaters.

Stevens and SOZ wastewater are disposed of into 12 Tulare Zone disposal wells. Eight of the disposal wells are clustered near the 18G LACT facility. The remaining four wells are in Sections 24Z and 26Z. The Tulare Zone disposal well in Section 26Z was recompleted into the Olig in 1992. Stevens wastewater generated at the 24Z dehydration/LACT facility is disposed of as source water for the Stevens 24Z pool (south flank) water injection project and into the Tulare Zone disposal wells in Section 24Z. Asphalto wastewater generated at the 26Z dehydration/LACT facility is disposed of into a disposal well completed in the Olig Formation. Carneros wastewater generated at the gas plant complex in Section 35R is commingled into the Stevens/SOZ wastewater system for disposal with other waters. The other disposal wells, one each in 15G and 16G, are also used to dispose of SOZ and Stevens wastewater.

Wastewater disposal is currently reaching existing disposal capacity. In response to this, projects are in various stages of planning, evaluation, construction and start-up to recycle wastewater for use as source water for waterflood projects (in lieu of using Tulare water for source water), thus reducing or eliminating the need to dispose of wastewater into the Tulare (BPOI 1989).

Solid and liquid/solid wastes (such as tank bottom sediments, drilling fluids, and similar waste materials generated by well-drilling and production operations) are disposed of at one of the two existing state-regulated disposal sites on NPR-1 (landfarms in Sections 10G and 27R). Since mid-1990, the 10G landfarm has not received wastes due to the reduced level of drilling activity. Other solid wastes are collected at two solid-waste transfer stations located in Sections 36S and 35R. Wastes are placed in 40-cubic yard dumpsters, which are removed when filled and then dumped at the Kern County landfill off the NPR-1 site. Current waste-management facilities are described in Section 3.2.5.

A.8 SUPPORT SYSTEMS AND FACILITIES

A.8.1 Road Network

Three primary roadways dissect NPR-1. Skyline Road extends east and west across the field for 13 miles, and Elk Hills Road (which is maintained by the county) extends north and south for a distance of about 8 miles. On the eastern end of the hills, the North/South Access Road extends for about 4 miles, for a total of 25 miles of primary road. NPR-1 also has about 100 miles of secondary roads and nearly 1,000 miles of tertiary (unpaved) access roads. The primary roads require routine maintenance and localized resurfacing. Secondary and tertiary (access roads) are maintained as necessary to permit access. Abandoned roadways are reseeded and reclaimed as part of the site-wide reclamation program.

A.8.2 Water Supply

Water required for producing at MER is provided by three major systems: (1) freshwater system, (2) wastewater system, and (3) Tulare water system. The freshwater supply system provides water for fire-fighting and process needs. The wastewater supply system provides supplemental water needed for oil zone injection and reservoir pressure maintenance. The Tulare system provides water to meet injection needs.

The freshwater system has an overall capacity of 1.6 million gallons/day and consists of two parallel pipelines, one main pump station, two booster stations, and five storage tanks (one each in Sections 35S, 32S, and 18R, and two in Section 28S) with a total storage capacity of 1 million gallons. About 630,000 gallons/day of water will be required to meet operational water demands through 1994. Currently, fresh water is purchased from the West Kern Water District, which is under contract to deliver up to 1.7 million gallons/day at the eastern end of the site.

The wastewater supply system is being developed so that the water separated from oil (production water) in the LACT systems can be reused for waterflooding.

Water is provided for the three waterflood operations from the Tulare Formation. Approximately five source wells drilled in the south flank of the reservoir in Sections 13B, 14B, and 18G provide 148,000 barrels/day of water. A fourth source well was completed in 1987 in the Tulare Formation in the northwest area of the reservoir in Section 8R. This well has not performed acceptably and is shut in.

A.8.3 Power Supply

NPR-1 has its own electrical power transmission and distribution system, with the power being purchased from Pacific Gas and Electric Co. (PG&E). The main intake power supply is from a unit-owned metering and service facility at the 35R substation, where PG&E delivers power at 115 kilovolts. At the 18G and 35R main area substations, power is transformed from 115 kilovolts to the field distribution voltage of 12 kilovolts. The other main area substations at Section 33S serve the 33S waterflood plant and the 4G closed-loop gas-lift facilities, and at Section 17R serve the 17R waterflood plant and the Northwest Stevens closed-loop gas-lift facilities. Power at both these locations is stepped down to 4,160 volts. Other, less significant, power supplies from PG&E also serve some miscellaneous facilities (e.g., 3G and 4G). The field distribution at 12 kilovolts is via overhead lines on wooden poles to the various utilization locations, where it is transformed to lower voltages.

The existing electrical system at NPR-1 consists of a connected capacity of 80 megawatts, with a current running load of approximately 24 megawatts. After waterflood injection and additional gas-lift compression is increased and more electrically-driven pumping wells are added, loads are expected to be about 50 megawatts. The electrical service facility at NPR-1 is basically a single integrated system.

The principal users of electric power throughout the facility are the gas plants and compressor stations (LTS 1, LTS 2, HPI, 35R, 33S, and 30R); water source wells; some of the oil-producing wells; the water injection facilities; cathodic protection operations; and offices and workshop facilities. Natural gas from gas-processing plants is used as fuel to power the plants and compressor stations.

A.8.4 Telephone

Telephone service is provided and maintained by Continental Telephone Co. of California. The main lines run underground along the North/South Access Road.

A.8.5 Security

The great majority of 47,409 acres of the site are fenced. Areas that are not fenced typically have barriers that would significantly impede attempts of unauthorized entry. All critical areas such as gas plants, loading facilities, etc., are in fenced areas. All roads providing access to NPR-1 have locked gates and signs indicating the boundaries of the site. Two main gates controlled by security guards provide access to NPR-1 24 hours/day. Four other main gates, also controlled by security guards, provide access during daylight hours only. Roving security guards patrol the site 24 hours/day.

A.8.6 Fire Protection

Fire protection is provided to NPR-1 primarily through the Kern Country Fire Department, with stations at McKittrick, Taft, Buttonwillow, and Bakersfield. NPR-1 has fire-response capability and a general training program in fire protection and fire-fighting, but the Kern County Fire Department is the primary responsible fire-fighting agency; the NPR-1 capability is primarily one of containment until County resources are in-place. The Taft substation of the Kern County Fire Department has a patrol for fighting grass fires and one truck capable of fighting oil fires, with provisions for long-distance delivery of both foam and water, and the ability to pump large volumes of water considerable distances. An additional engine capable of fighting oil fires is available at the Fellows Substation (Station 23). The response time from McKittrick to the 24Z area is under 5 minutes. Response time to NPR-1 is approximately 25 minutes from the Taft and Buttonwillow stations and more than 45 minutes from Bakersfield. The Kern County Foam Cooperative, operated by the Kern County Fire Department, also can respond to fires at the site.

NPR-1 has a separate fire-water system for fighting fires. In addition, wastewater from the production system can be used to fight fires. Fire water is commonly stored in tanks at several locations. In Section 24Z, only wastewater is available for fighting fires. Additional sources are being investigated. The wastewater system is not tied into the freshwater system at any location on NPR-1.

The potential for a fire to spread from matches or cigarettes thrown from vehicles along primary roads through and bordering the site is minimized by fire breaks constructed parallel to the roads. These firebreaks, which were initially about 30 feet wide, are now 12-20 feet wide and total about 53 miles long. They are disced annually, if appropriate, and abandoned firebreaks are being reclaimed. Firebreaks encompass a total area of about 91 acres.

A.9 OPERATION AND MAINTENANCE

Production activities and facilities operation and maintenance are conducted by the management and operating contractor (currently BPOI). Storage and transfers of liquid products are controlled through the LACT units and the storage and loading facilities associated with the gas-processing plants. Gas-processing plants are operated on a continuous basis by staff on routine shift assignments. The flow of all major product streams into and out of each plant is metered and sampled for analysis.

The LACT units, liquid storage, and loading areas are operated continuously, and incoming and outgoing liquid products are metered. Metering equipment and controls are maintained, tested, and calibrated on a periodic basis. Special considerations for a variety of abnormal operating conditions (e.g., pipeline rupture, explosion) are discussed in Section 3.9 (Risk Assessment).

Operation of wells and tank settings is primarily automated. Whenever the crude oil tanks at any tank setting become full, an alarm is sent to a control center and an operator is notified (overflow is directed into associated tanks). When an overpressure condition occurs, the associated feed wells are designed to shut down automatically. Field operators are on duty at the site around the clock. Operators perform periodic tests at each tank setting, LACT, well and other facilities to determine gas and oil production rates. Equipment is maintained according to established schedules.

Emergency operating procedures include shutdown and isolation of facilities in the event of explosions, fires, or product spills, as well as monitoring, containment, and collection of product spills and restoration of affected areas. Emergency problems are the responsibility of operations personnel.

Operating and maintenance personnel include subcontractor employees involved in maintenance, repair, and the provision of goods and services, as well as the contractor personnel performing operational functions. Operating personnel include some individuals working at facilities that have 24-hour/day operations with three rotating shifts. The government, CUSA, and NPRC contractor work forces total about 800 people (Table A.7). In addition, vendor and subcontractor personnel providing construction maintenance, repair, and other services average about 400-500 people per day.

A.10 FACILITY MOTHBALLING AND ABANDONMENT

Facilities that become temporarily unnecessary or undesirable before expiration of the useful life of the facilities or depletion of the reservoir are secured for later reactivation; such securing is called mothballing. Typical mothballing procedures may include shutting in wells; emptying storage tanks, pipelines, and equipment of all products; refilling the pipelines and storage tanks with water containing a corrosion inhibitor; and draining and removing pump seals and refilling with vapor inhibitor to prevent corrosion. Facilities or equipment that becomes unnecessary or inoperable (at the end of the useful life of the facilities or upon depletion of the oil reservoir)

TABLE A.7 Current and Projected Staffing Requirements for NPR-1*

Employer	Fiscal Year						
	1989	1990	1991	1992	1993	1994	1995
BPOI	708	740	744	755	758	762	765
DOE (FTE)	61	61	63	63	65	65	65
Contract/service vendors	425	400	400	400	400	400	400
Construction	100	150	200	300	250	100	100
Total	1,294	1,351	1,407	1,518	1,473	1,327	1,330

*Exclusive of CUSA, EG&G/EM, and RMCI (formerly SMS). Add approximately 50-60 personnel for these organizations.

Source: BPOI 1989

are abandoned. Abandoned wells are plugged in accordance with appropriate state regulations. Following surplus designation, such facilities or equipment are sold and removed, if determined to have a real salvage value exceeding the cost of removal, or they are scrapped prior to abandonment and site reclamation.

A.11 REFERENCES*

Bechtel Petroleum Operations, Inc., 1988, Naval Petroleum Reserves in California, Long Range Plan, FY88 - FY94, Tupman, California, February.

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U.S. Department of Energy, 1979, Final Environmental Impact Statement, Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California, U.S. Department of Energy Report DOE/EIS-0012, Washington, DC

U.S. Department of Energy, 1988, Naval Petroleum and Oil Shale Reserves, Annual Report of Operations, FY 1987, Washington, DC

U.S. Department of Energy, 1989, Surface Facilities at Naval Petroleum Reserve No. 1 in California, U.S. Department of Energy Engineering Division, Tupman, California, August.

*Copies of correspondence and unpublished documents included in this list may be obtained upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California, 93276.

APPENDIX B:

CLIMATE, METEOROLOGY, AND AIR QUALITY

B.1 CLIMATE AND METEOROLOGY

This section provides (1) recent meteorological and climatological data representative of the NPR-1 site area that has become available since 1979 and (2) additional information that has been developed using that recent data. Included is information on wind direction and speed, atmospheric stability, and mixing-height. These data are necessary to conduct an air quality impact analysis of the proposed action.

Information from the following four data bases was used in developing the materials presented in this section:

- Hourly wind data (direction and speed) measured at seven of eight air quality and meteorological monitoring stations in western Kern County operated by the West San Joaquin Area Monitoring Group of the Kern County Westside Operators for the period 1983-1988 (Woodward-Clyde Consultants 1984-1989) (the Westside Operators is a consortium formed by a group of private oil firms operating in western Kern County);

- Hourly surface observations of meteorological data collected at the National Weather Service station at Meadows Field Airport in Oildale (northwest of Bakersfield) for the period 1958-1987;

- Mixing-height data at one of the eight monitoring stations operated by the Westside Operators; and

- Aircraft sounding data measured at the National Weather Service station at Meadows Field (1981-1987).

Figure B.1 shows the locations of the eight monitoring stations operated by the Westside Operators* and the National Weather Service station at Meadows Field. The approximate topography of western Kern County near the eight monitoring stations and their elevations are shown in Figure B.2. Table B.1 lists the meteorological parameters measured at the monitoring stations operated by the Westside Operators.

*Three stations were closed during 1988 and one station was relocated.

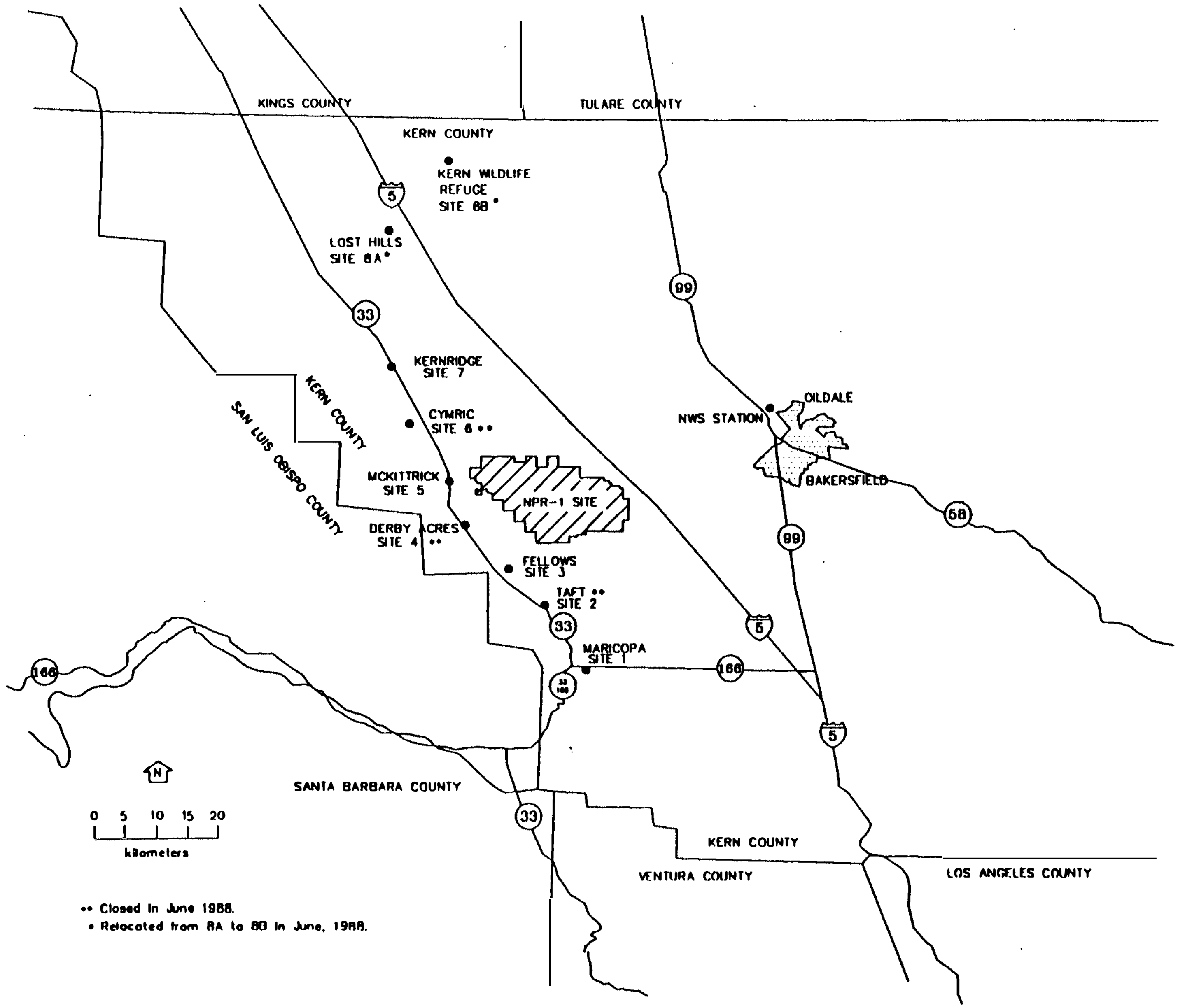


FIGURE B.1 LOCATIONS OF NATIONAL WEATHER SERVICE STATION NEAR BAKERSFIELD AND OF AIR QUALITY AND METEOROLOGICAL MONITORING STATIONS OPERATED IN WESTERN KERN COUNTY BY WESTSIDE OPERATORS (SOURCE: MODIFIED FROM WOODWARD-CLYDE CONSULTANTS 1988)

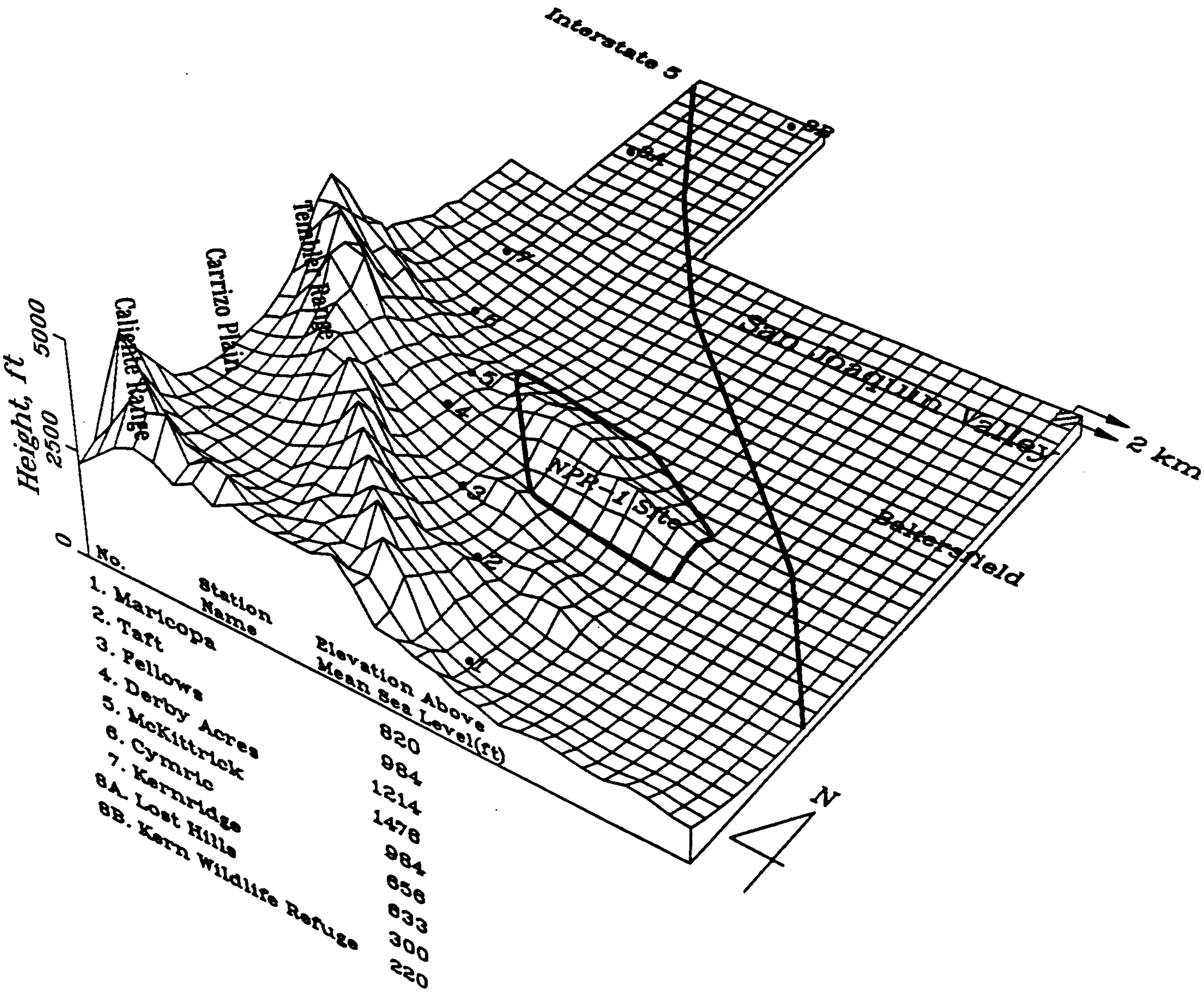


FIGURE B.2 TOPOGRAPHY OF WESTERN KERN COUNTY NEAR THE NPR-1 SITE AND WESTSIDE OPERATORS' METEOROLOGICAL AND AIR QUALITY MONITORING STATIONS (SOURCE: BASED ON USGS 7.5 MINUTE SERIES TOPOGRAPHIC MAPS; WOODWARD-CLYDE CONSULTANTS 1988)

TABLE B.1 Meteorological Parameters Measured at Monitoring Stations in Western Kern County Operated by Westside Operators[a]

Station Number[b]	Station Location	Wind Direction	Wind Speed	Mixing Height
1	Maricopa	X	X	
2	Taft[c,d]			
3	Fellows	X	X	X
4	Derby Acres[d]	X	X	
5	McKittrick	X	X	
6	Cymric[d]	X	X	
7	Kernridge	X	X	
8A	Lost Hills[e]	X	X	
8B	Kern Wildlife Refuge[e]	X	X	

[a]An "X" indicates that a given parameter is measured at the indicated station.
[b]Station numbers are keyed to locations shown in Figure B.1.
[c]No meteorological data are measured at this station.
[d]Closed in June 1988.
[e]Relocated from 8A to 8B in June 1988.

Source: Woodward-Clyde Consultants 1987.

B.1.1 Wind

B.1.1.1 Wind Direction and Speed

The Westside Operators measure wind direction and speed at the 10-m level at all the monitoring stations they operate in western Kern County except for the Taft station (site 2 in Figure B.1). Figure B.3 shows wind roses based on 5 years (1983-1987) of data from the Maricopa, Fellows, and Lost Hills stations and on 16 years (1965-1980) of data from Meadows Field. At the three monitoring stations run by Westside Operators the wind direction distribution is approximately bimodal, with primary directions being from the western and northern quadrants. At the Fellows site, which is one of the stations closest to NPR-1, the prevailing wind is from the west-southwest. Flow from the quadrant centered on that direction is primarily indicative of nocturnal drainage winds originating from higher terrain west and southwest of the monitoring station. Northerly winds represent the prevailing daytime *down-valley* flow observed at most locations in the southern San Joaquin Valley. Figures B.4 and B.5 present nighttime and daytime wind roses, by season, computed from data collected at the Fellows station. As shown later in this section, stable atmospheric conditions are associated primarily with the nighttime drainage winds, and unstable and neutral conditions are associated primarily with the daytime, down-valley flows.

At Meadows Field, located toward the eastern side of the valley, the prevailing winds are the daytime, down-valley flows from the north and northwest. The nighttime drainage winds from the eastern slope are somewhat less prevalent.

The windflow patterns at the western and eastern sides of the southern San Joaquin Valley correspond to the windflow patterns illustrated for the Kern County area in Figure B.6. The flow patterns shown in the figure suggest that there is little exchange of air mass (and consequently air pollutants) between the western and central regions of the Kern County. This is one of the main reasons for dividing the San Joaquin Valley Air Basin portion of Kern County into two regions (western Kern County and central Kern County) for air quality control planning purposes.

Wind data for an entire year are not available for the NPR-1 site, but hourly measurements were obtained at a central location on NPR-1 for an 8-day period during the summer of 1987 (Mark Group 1987). Although certain features of the wind roses for the 8-day period at the NPR-1 site appear to be most analogous to those at the Fellows station among all the Westside Operators' meteorological monitoring stations, the measurement period at NPR-1 was too short to draw any meaningful conclusions. Topographical features surrounding the Westside Operators' monitoring stations (Figure B.2) do not provide any basis to determine which station could best represent the wind conditions at the NPR-1 site. Evaluation of the wind roses for the seven western Kern County monitoring stations and Meadows Field in relation to the windflow patterns illustrated in Figure B.6 suggests that the wind patterns at the NPR-1 site may best be represented by those at the Fellows monitoring station. The

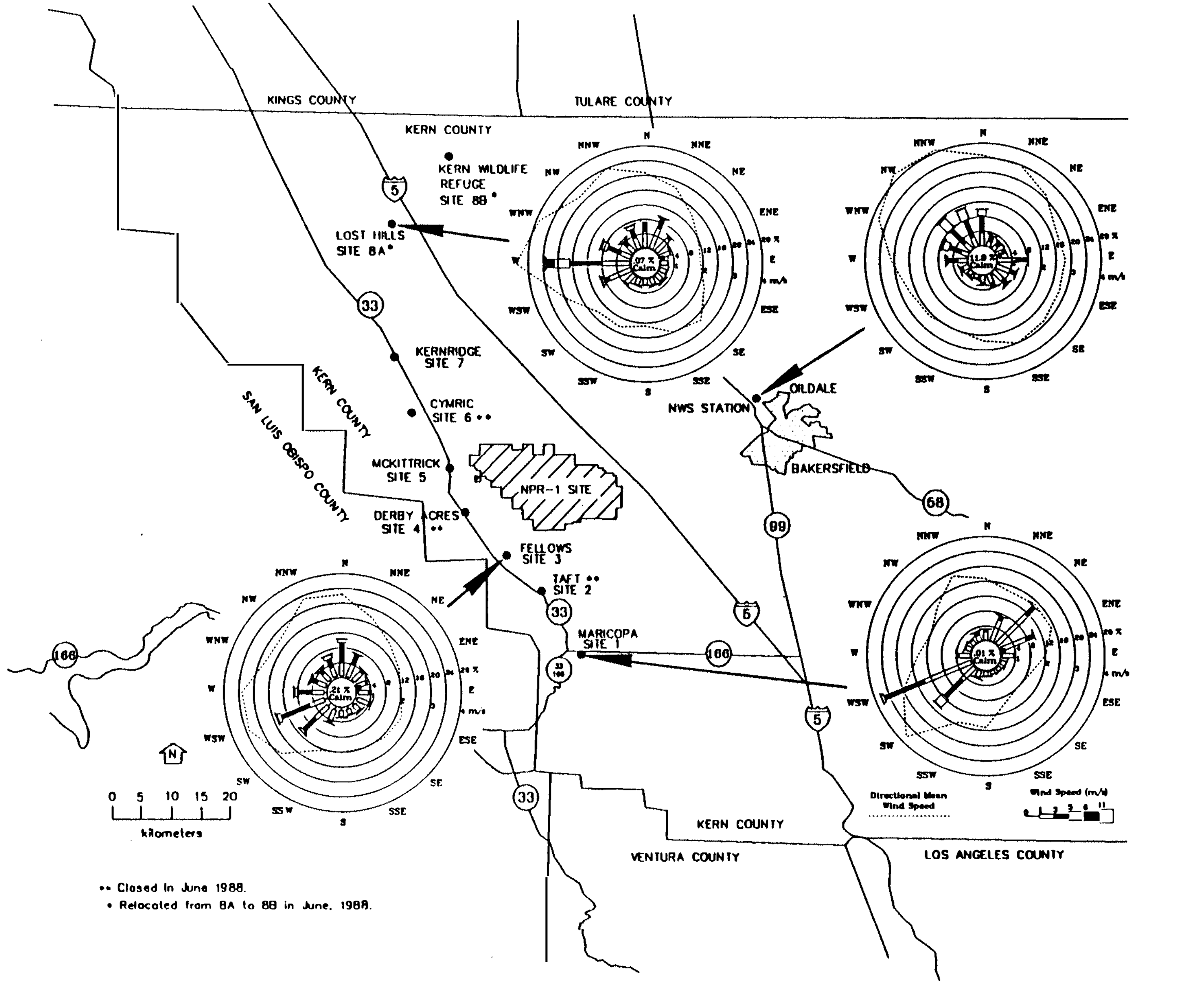


FIGURE B.3 WIND ROSES AT SELECTED MONITORING STATIONS IN WESTERN KERN COUNTY OPERATED BY THE WESTSIDE OPERATORS AND AT MEADOWS FIELD (NORTHWEST OF BAKERSFIELD) (SOURCE: BASED ON WOODWARD-CLYDE CONSULTANTS 1988; NATIONAL CLIMATIC CENTER 1988)

WIND ROSE FOR FELLOWS, CA

PERIOD : 010183 – 123187 (NIGHT)

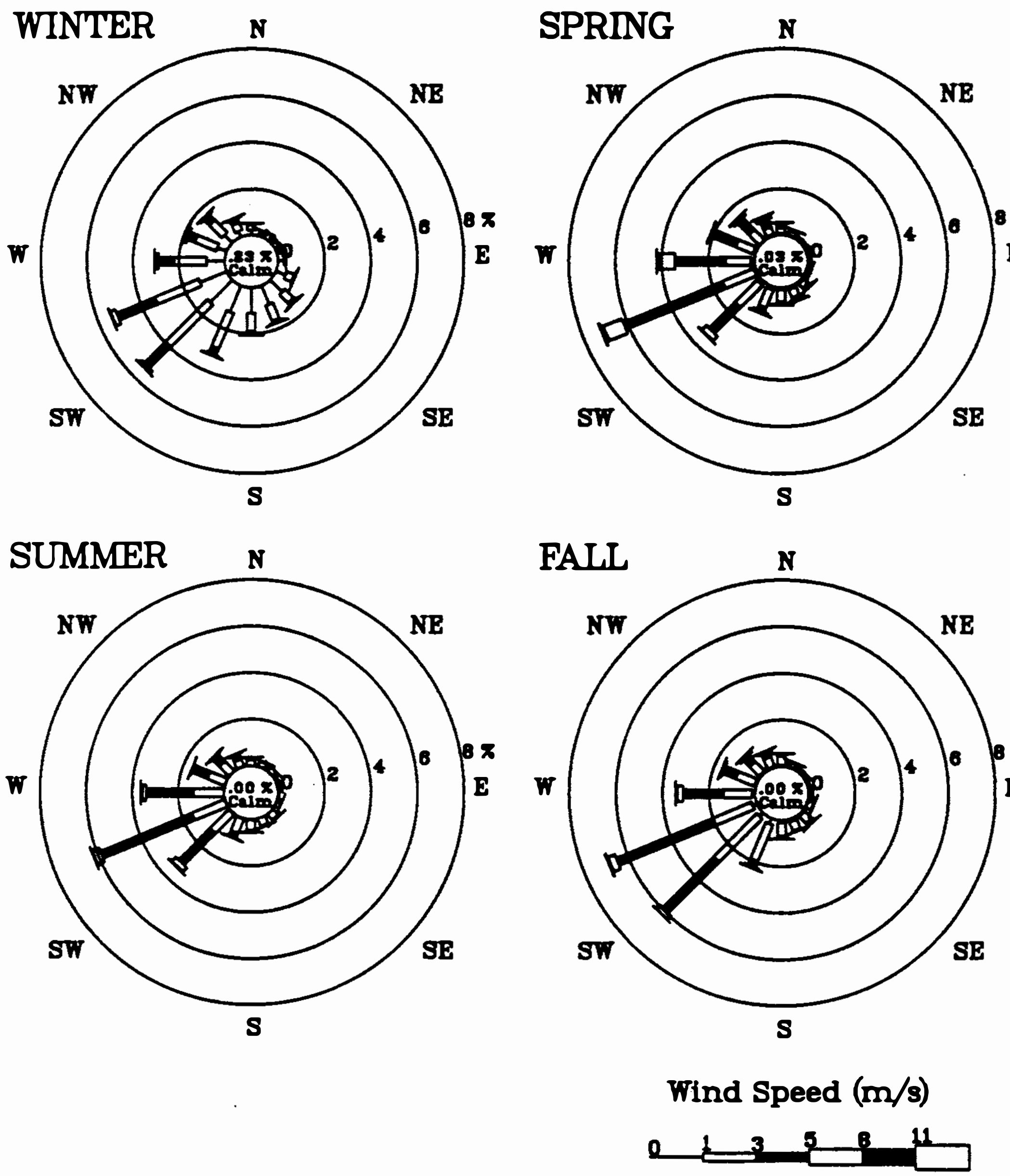


FIGURE B.4 NIGHTTIME WIND ROSES BY SEASON AT THE FELLOWS SITE IN WESTERN KERN COUNTY (SOURCE: DEVELOPED FROM WOODWARD-CLYDE CONSULTANTS 1988)

WIND ROSE FOR FELLOWS, CA
PERIOD : 010183 – 123187 (DAY)

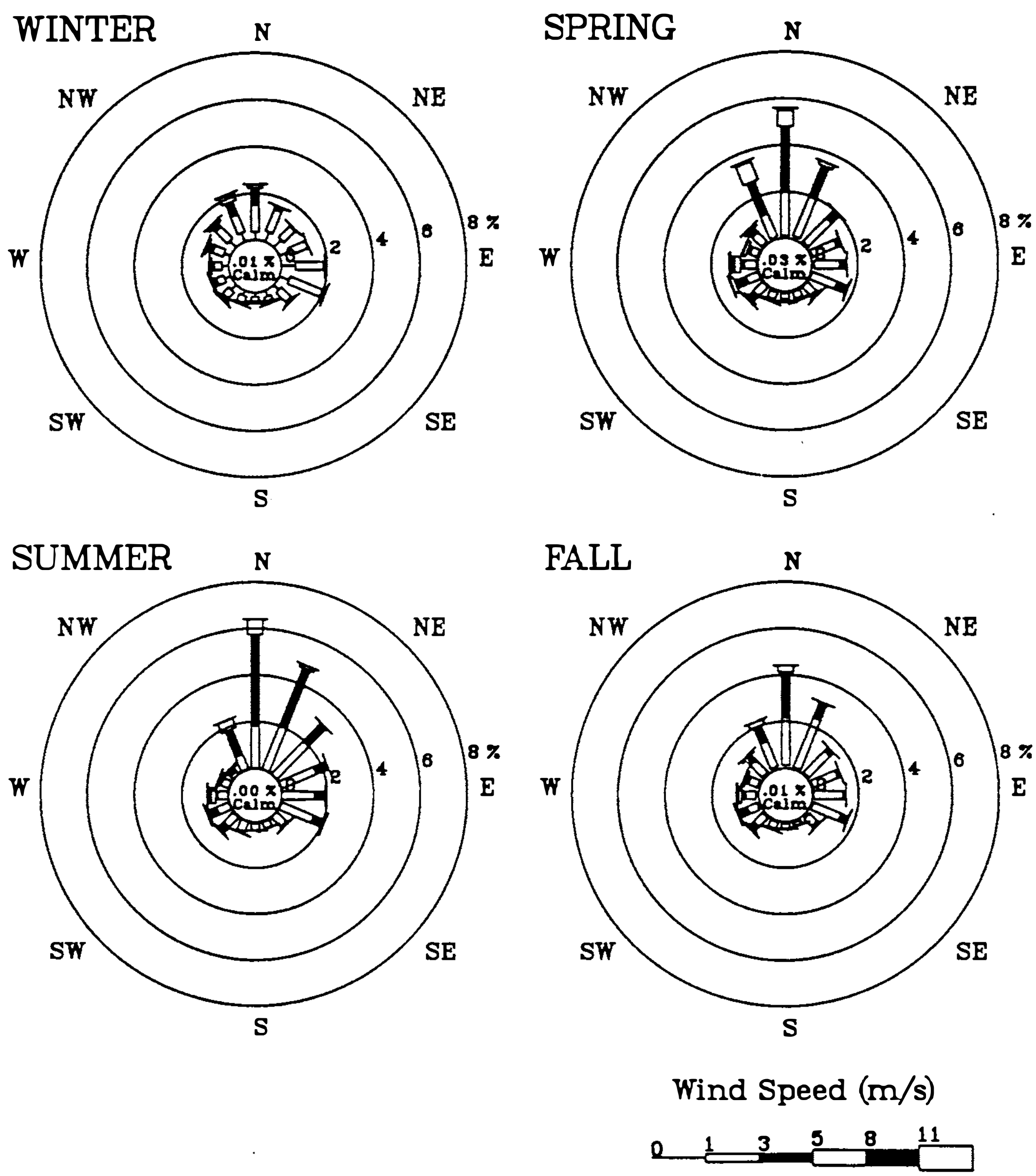


FIGURE B.5 DAYTIME WIND ROSES BY SEASON AT FELLOWS SITE IN WESTERN KERN COUNTY (SOURCE: DEVELOPED FROM WOODWARD-CLYDE CONSULTANTS 1988)

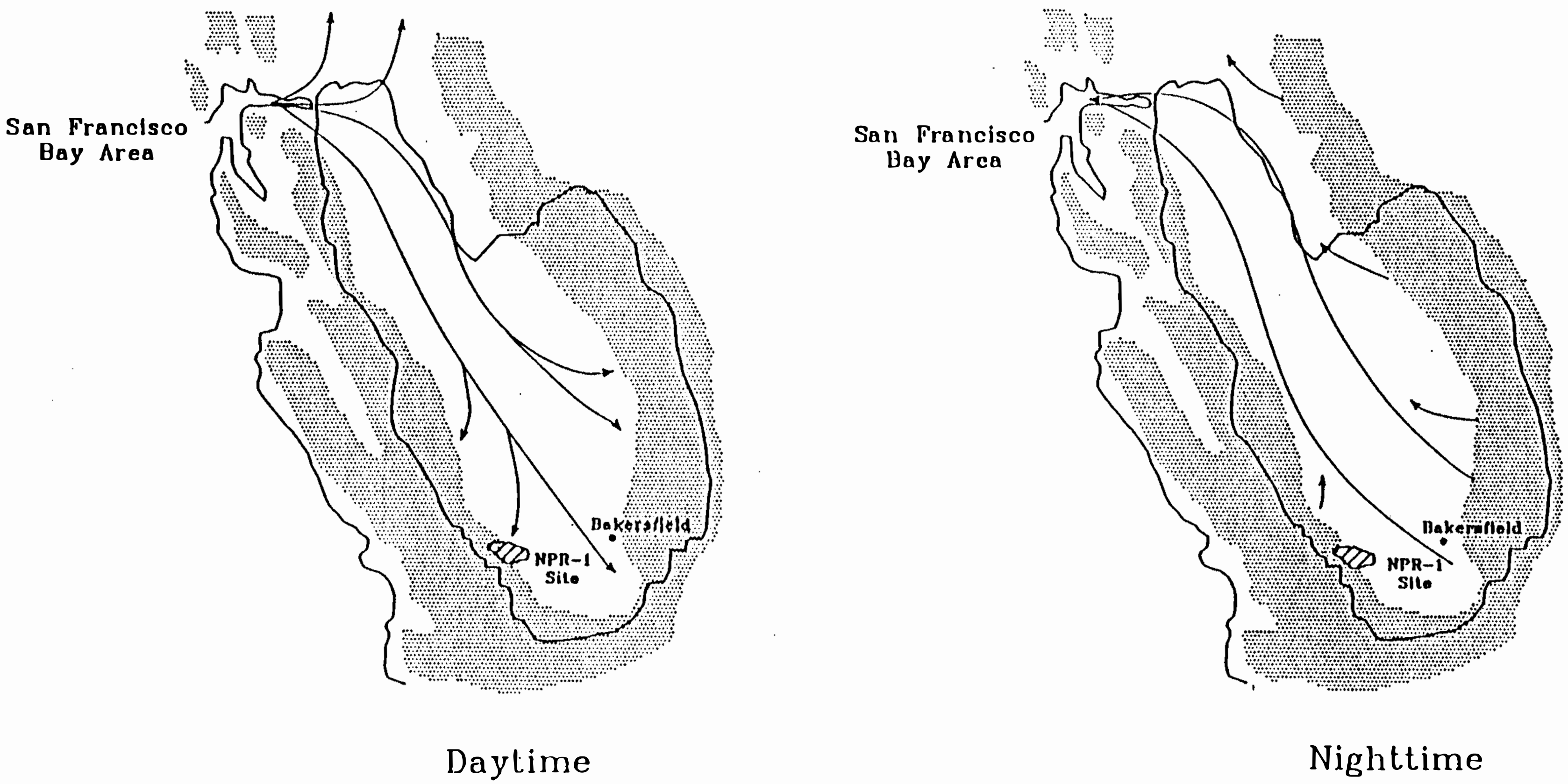


FIGURE B.6 DAYTIME AND NIGHTTIME WIND FLOW PATTERNS IN SOUTHERN SAN JOAQUIN VALLEY
(SOURCE: MODIFIED FROM HAYES ET AL 1984)

Fellows station is one of the stations closest to NPR-1. Thus, the wind data at the Fellows monitoring station are used to describe those at the NPR-1 site in the following sections.

B.1.1.2 Wind Persistence

Table B.2 shows the frequency distributions of wind direction persistence at the Fellows monitoring station for the period 1983-1987. The distributions indicate that the predominant west-southwesterly winds persist for longer periods than any other wind direction. Westerly winds persist 2 hours or more 10% of the annual period, and for as long as 12 consecutive hours. Winds from the north, which is the dominant direction during the daytime, last 2 or more consecutive hours 7% of the time. The maximum persistence of the northerly wind was 16 hours.

Frequency distributions of wind speed persistence at the Fellows station are shown in Table B.3. Wind speeds between 1 and 3 m/s are the most common (occurring 47% of the time) and persist for the longest periods (up to 24 or more consecutive hours). Wind speeds in excess of 11 m/s rarely occur but have been observed to persist for as long as 9 consecutive hours during the 5-year period.

B.1.2 Atmospheric Stability

The stability of the atmosphere relates to its tendency to resist or enhance vertical motion, or alternatively to suppress or augment existing turbulence. The degree of atmospheric turbulence depends primarily on the vertical temperature gradient, although it is also influenced by terrain roughness, wind speed, and wind shear.

Meteorological parameters needed to determine atmospheric stability (such as the temperature gradient in the surface layer) have been measured in the past in western Kern County. Stability data estimated at Belridge (approximately 10 miles northwest of NPR-1) were described in the 1979 EIS for NPR-1 (DOE 1979). Measurements of the temperature gradient at Belridge were terminated in the early 1980s.

Stability data have been developed for use in air quality simulation modeling in conjunction with recent wind and mixing height data that are more representative of the NPR-1 site. The stability data were computed by applying the Turner's objective method (Turner 1964) to the wind data from the Fellows monitoring site and the ceiling height and cloud cover data measured at the National Weather Service station at Meadows Field (National Climatic Center 1988). Figure B.7 shows the annual distributions of various stability classes thus determined. Stable conditions (stability classes E, F, and G) occur most frequently (43% of the time); unstable conditions (stability classes A, B, and C) and neutral conditions (stability class D) occur 31% and 26% of the annual period, respectively.

TABLE B.2 Wind Direction Persistence at the Fellows Monitoring Site, 1983-1987

	Frequency[a] of Persistent Wind by Direction (%)								
Persistence (Hours)	N	NNE	NE	ENE	E	ESE	SE	SSE	S
1	10.41	7.13	4.37	3.46	3.76	4.65	3.15	2.62	2.94
2	6.90	3.60	1.62	1.14	1.48	2.43	1.07	0.72	0.94
3	4.42	1.73	0.51	0.27	0.53	1.24	0.40	0.21	0.37
4	2.70	0.70	0.19	0.05	0.17	0.63	0.10	0.07	0.14
5	1.49	0.30	0.07	0.01	0.04	0.31	0.04	0.04	0.05
6	0.87	0.15	0.03	0.01	0	0.15	0	0.04	0.03
7	0.51	0.09	0.02	0	0	0.10	0	0.04	0
8	0.34	0.06	0	0	0	0.06	0	0.04	0
9	0.20	0.02	0	0	0	0.02	0	0.02	0
10	0.12	0	0	0	0	0.02	0	0	0
11	0.09	0	0	0	0	0	0	0	0
12	0.07	0	0	0	0	0	0	0	0
13	0.04	0	0	0	0	0	0	0	0
14	0.04	0	0	0	0	0	0	0	0
15	0.04	0	0	0	0	0	0	0	0
16	0.04	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0
>25	0	0	0	0	0	0	0	0	0

TABLE B.2 (Cont'd)

Frequency[a] of Persistent Wind by Direction (%)								
Persistence (Hours)	SSW	SW	WSW	W	WNW	NW	NNW	ALL
1	5.05	11.20	15.01	9.21	5.32	4.79	6.91	100.00
2	2.27	7.23	10.49	4.93	2.06	2.09	3.57	52.74
3	1.12	4.88	7.16	2.80	0.85	1.07	2.11	29.67
4	0.51	3.17	4.97	1.53	0.28	0.50	1.28	17.01
5	0.26	2.18	3.55	0.80	0.13	0.35	0.81	10.44
6	0.17	1.53	2.48	0.32	0.02	0.25	0.46	6.52
7	0.17	1.09	1.70	0.14	0.02	0.09	0.23	4.19
8	0.12	0.80	1.14	0.11	0.02	0.02	0.16	2.87
9	0.08	0.61	0.78	0.05	0	0	0.10	1.89
10	0.06	0.41	0.54	0.03	0	0	0.08	1.26
11	0.06	0.31	0.27	0.03	0	0	0.06	0.82
12	0.03	0.21	0.09	0.03	0	0	0.06	0.48
13	0	0.06	0	0	0	0	0	0.10
14	0	0	0	0	0	0	0	0.04
15	0	0	0	0	0	0	0	0.04
16	0	0	0	0	0	0	0	0.04
17	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0
>25	0	0	0	0	0	0	0	

[a]In percent of all observations.

Source: Derived from Woodward-Clyde Consultants 1988.

TABLE B.3 Wind Speed Persistence at the Fellows Monitoring Site, 1983-1987

	Frequency[a] of Persistent Wind by Direction (%)							
Persistence (Hours)	Calm	0-1	1-3	3-5	5-8	8-11	>11	Total
1	0.21	10.50	47.29	34.56	6.06	1.10	0.27	100.00
2	0.15	8.27	43.31	30.50	4.58	0.82	0.19	87.81
3	0.08	6.54	38.16	26.00	3.25	0.54	0.11	74.68
4	0.07	5.36	33.41	21.82	2.26	0.36	0.06	63.34
5	0.03	4.60	29.15	17.65	1.47	0.23	0.03	53.17
6	0.03	3.85	24.52	14.32	0.99	0.21	0.02	43.95
7	0.03	3.40	20.22	11.61	0.57	0.13	0.02	35.98
8	0.03	3.02	16.63	9.34	0.33	0.10	0.02	29.47
9	0.03	2.75	13.52	7.66	0.17	0.08	0.02	24.23
10	0.03	2.46	10.86	5.88	0.13	0.06	0	19.42
11	0.03	2.22	8.81	3.78	0.10	0.03	0	14.97
12	0.03	2.00	7.23	2.43	0.08	0.03	0	11.81
13	0	1.80	5.15	1.35	0.05	0.03	0	8.38
14	0	1.61	3.69	0.94	0.05	0.03	0	6.31
15	0	1.47	2.80	0.77	0.05	0	0	5.08
16	0	1.29	1.96	0.62	0.05	0	0	3.91
17	0	1.09	1.37	0.54	0.05	0	0	3.05
18	0	0.93	1.08	0.42	0.05	0	0	2.47
19	0	0.71	0.95	0.24	0.05	0	0	1.94
20	0	0.57	0.90	0.20	0	0	0	1.67
21	0	0.32	0.71	0	0	0	0	1.03
22	0	0.22	0.45	0	0	0	0	0.67
23	0	0.11	0.34	0	0	0	0	0.46
24	0	0.06	0.12	0	0	0	0	0.18
>25	0	0	0	0	0	0	0	0

[a]In percent of all observations

Source: Derived from Woodward-Clyde Consultants 1988.

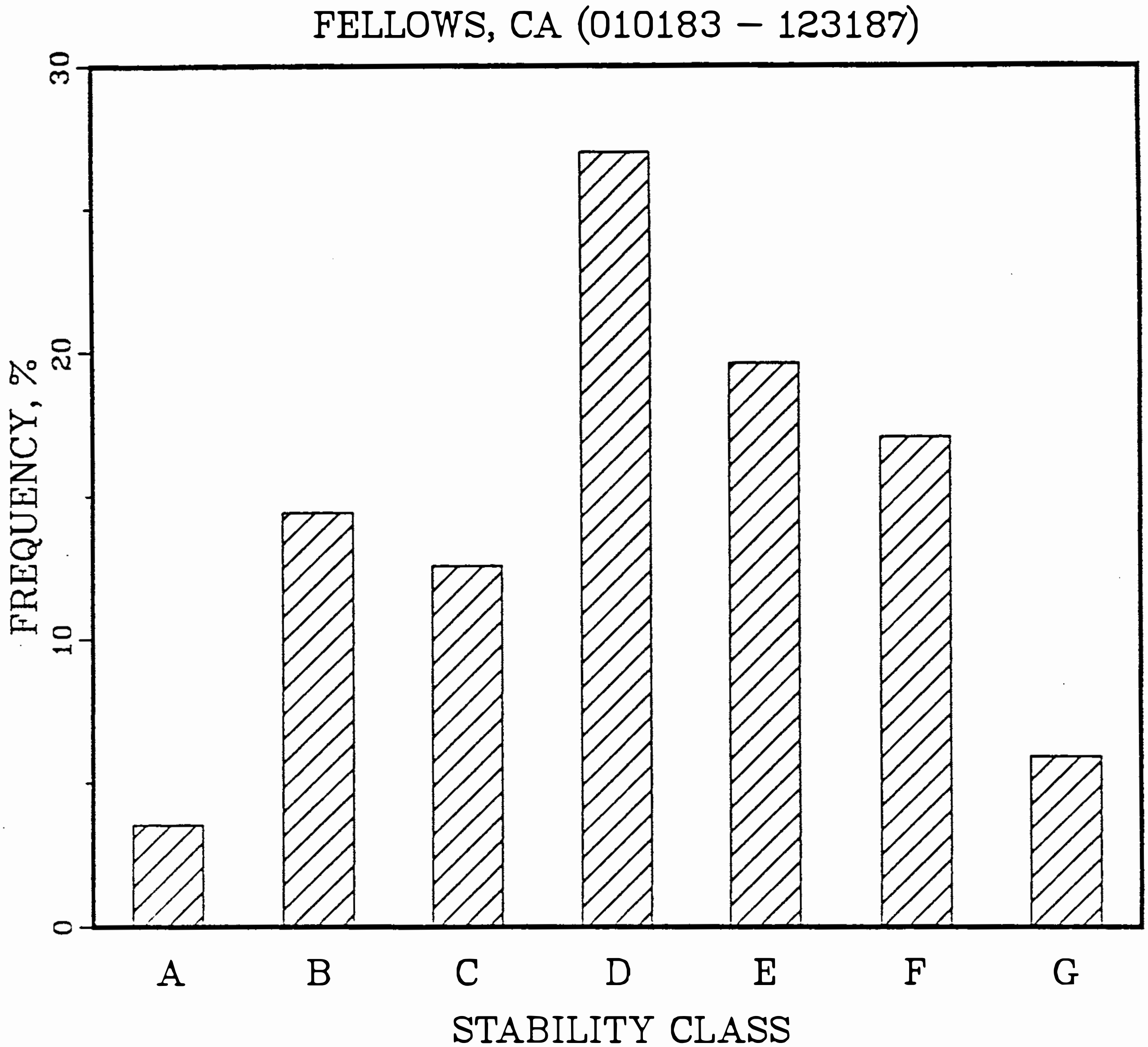


FIGURE B.7 FREQUENCY DISTRIBUTION OF ATMOSPHERIC STABILITY CLASSES AT THE FELLOWS MONITORING SITE, 1983-1987 (SOURCE: DEVELOPED FROM WOODWARD-CLYDE CONSULTANTS 1988; NATIONAL CLIMATIC CENTER 1988)

B.1.3 Diurnal Trends and Joint Frequency Distributions of Wind Speed, Wind Direction, and Atmospheric Stability

Table B.4 shows diurnal variations in the most frequent wind directions, their average speeds, and most frequently associated stability classes. Stable drainage flow from the west-southwest is most frequently experienced during nocturnal hours. During early morning hours, wind flow exhibits a short transitional period as wind patterns shift from a westerly to a northerly flow. This shift is caused by the development of a down-valley flow stimulated by surface heating effects along the valley floor. As shown in Table B.4, stability conditions also undergo a transition from stable to neutral during this period. Concurrently, wind speeds tend to decrease while this directional change occurs.

During late morning and afternoon hours, winds are typically down-valley flow from the northern quadrant, with moderate speeds of 2-3 m/s. During the daylight hours, the prevailing atmospheric stability class at the Fellows site is moderately unstable (Class B).

Atmospheric conditions undergo another transition during the early evening hours. Just after sunset, the atmosphere stabilizes, and the wind changes from the down-valley flow into drainage flow from the western quadrant. Wind speeds decrease somewhat during this transitional period but increase with time as the drainage wind gains momentum. The three-way joint frequency distribution of stability, wind direction, and wind speed at the Fellows site for the period 1983-1987 is presented in Table B.5.

B.1.4 Mixing Height

The mixing-height is the height above the earth's surface through which relatively vigorous vertical mixing of air occurs. Convection at the surface caused by solar heating can be inhibited at higher elevations by the presence of stable layers or subsiding air from the upper atmosphere. Thus, the entire troposphere is not available for dilution and transport of pollutants released near the surface; only the lower atmosphere defined by mixing-height serves this function.

Three potential data sources exist for mixing height in the vicinity of NPR-1 and the southern San Joaquin Valley Air Basin: (1) hourly mixing-height data estimated from the measurements by an acoustic sounder at the Westside Operators' Fellows monitoring station near the NPR-1 site (Figure B.1); (2) seasonal mean mixing-height data interpolated for the NPR-1 area from Holzworth's climatological mixing-height isopleths over the contiguous United States (Holzworth 1972); and (3) daily morning and afternoon mixing-height data estimated from the aircraft temperature-sounding data measured every morning at Meadows Field near Bakersfield (CARB 1988a).

Because the maximum mixing-height measured at Fellows is limited to 1,000 meters and because a substantial fraction of hourly data is missing, the Fellows site mixing-height data are not considered reliable. Mixing-height values interpolated from the Holzworth's

TABLE B.4 Diurnal Trends of Wind Direction, Wind Speed, and Atmospheric Stability at the Fellows Monitoring Site, 1983-1987

Local Time	Most Frequent Wind Direction	Averaged Wind Speed (m/s)	Most Frequent Stability Class
Midnight	WSW	3.2	Moderately stable (F)
1 a.m.	WSW	3.0	Moderately stable (F)
2 a.m.	WSW	2.8	Moderately stable (F)
3 a.m.	WSW	2.7	Moderately stable (F)
4 a.m.	WSW	2.6	Moderately stable (F)
5 a.m.	WSW	2.5	Moderately stable (F)
6 a.m.	WSW	2.4	Neutral (D)
7 a.m.	SW	2.0	Neutral (D)
8 a.m.	ESE	2.0	Neutral (D)
9 a.m.	N	2.1	Moderately unstable (B)
10 a.m.	N	2.3	Moderately unstable (B)
11 a.m.	N	2.5	Moderately unstable (B)
Noon	N	2.7	Moderately unstable (B)
1 p.m.	N	2.9	Moderately unstable (B)
2 p.m.	N	3.2	Moderately unstable (B)
3 p.m.	N	3.4	Moderately unstable (B)
4 p.m.	N	3.4	Slightly unstable (C)
5 p.m.	N	3.4	Neutral (D)
6 p.m.	N	3.2	Neutral (D)
7 p.m.	N	3.0	Slightly stable (E)
8 p.m.	WSW	2.9	Slightly stable (E)
9 p.m.	WSW	3.2	Slightly stable (E)
10 p.m.	WSW	3.3	Slightly stable (E)
11 p.m.	WSW	3.3	Slightly stable (E)

Source: Derived from Woodward-Clyde Consultants 1988; National Climatic Center 1988.

TABLE B.5 Three-Way Joint Frequency Distribution of Atmospheric Stability, Wind Direction, and Wind Speed at the Fellows Monitoring Site, 1983 - 1987

	Frequency[a] by Wind Speed (m/s) Class							
Wind Direction	0-1	1-3	3-5	5-8	8-11	>11	Mean[b]	All
Stability Class A								
N	7 (0.02)	180 (0.44)	22 (0.05)	0 (0.00)	0 (0.00)	0 (0.00)	2.6	209 (0.51)
NNE	10 (0.02)	251 (0.61)	22 (0.05)	0 (0.00)	0 (0.00)	0 (0.00)	2.5	283 (0.69)
NE	6 (0.01)	258 (0.63)	10 (0.02)	0 (0.00)	0 (0.00)	0 (0.00)	2.5	274 (0.67)
ENE	10 (0.02)	210 (0.51)	14 (0.03)	0 (0.00)	0 (0.00)	0 (0.00)	2.4	234 (0.57)
E	11 (0.03)	164 (0.40)	11 (0.03)	0 (0.00)	0 (0.00)	0 (0.00)	2.3	186 (0.45)
ESE	8 (0.02)	107 (0.26)	8 (0.02)	0 (0.00)	0 (0.00)	0 (0.00)	2.4	123 (0.30)
SE	2 (0.00)	29 (0.07)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	2.2	32 (0.08)
SSE	0 (0.00)	6 (0.01)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	2.0	7 (0.02)
S	1 (0.00)	5 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.9	6 (0.01)
SSW	0 (0.00)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	2.6	1 (0.00)
SW	0 (0.00)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	2.2	1 (0.00)
WSW	0 (0.00)	2 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	2.6	2 (0.00)
W	1 (0.00)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.8	2 (0.00)
WNW	1 (0.00)	7 (0.02)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	2.2	8 (0.02)
NW	2 (0.00)	4 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.5	6 (0.01)
NNW	5 (0.01)	57 (0.14)	4 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	2.4	66 (0.16)
CALM	1 (0.00)							
ALL	65 (0.16)	1283 (3.13)	93 (0.23)	0 (0.00)	0 (0.00)	0 (0.00)	2.4	1441 (3.52)

TABLE B.5 (Cont'd)

Wind Direction	Frequency[a] by Wind Speed (m/s) Class 0-1	1-3	3-5	5-8	8-11	>11	Mean[b]	All
Stability Class B								
N	34 (0.08)	585 (1.43)	719 (1.76)	12 (0.03)	0 (0.00)	0 (0.00)	2.9	1350 (3.30)
NNE	38 (0.09)	674 (1.65)	435 (1.06)	2 (0.00)	0 (0.00)	0 (0.00)	2.6	1149 (2.81)
NE	32 (0.08)	485 (1.18)	220 (0.54)	0 (0.00)	0 (0.00)	0 (0.00)	2.4	737 (1.80)
ENE	31 (0.08)	414 (1.01)	124 (0.30)	1 (0.00)	0 (0.00)	0 (0.00)	2.2	570 (1.39)
E	36 (0.09)	431 (1.05)	110 (0.27)	1 (0.00)	0 (0.00)	0 (0.00)	2.1	578 (1.41)
ESE	20 (0.05)	411 (1.00)	120 (0.29)	4 (0.01)	0 (0.00)	0 (0.00)	2.3	555 (1.36)
SE	6 (0.01)	76 (0.19)	13 (0.03)	1 (0.00)	0 (0.00)	0 (0.00)	2.0	96 (0.23)
SSE	8 (0.02)	27 (0.07)	2 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.7	37 (0.09)
S	5 (0.01)	11 (0.03)	1 (0.00)	1 (0.00)	0 (0.00)	0 (0.00)	1.7	18 (0.04)
SSW	6 (0.01)	11 (0.03)	2 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.5	19 (0.05)
SW	4 (0.01)	14 (0.03)	2 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.6	20 (0.05)
WSW	5 (0.01)	15 (0.04)	5 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	1.9	25 (0.06)
W	6 (0.01)	15 (0.04)	8 (0.02)	0 (0.00)	0 (0.00)	0 (0.00)	2.1	29 (0.07)
WNW	12 (0.03)	33 (0.08)	12 (0.03)	0 (0.00)	0 (0.00)	0 (0.00)	1.9	57 (0.14)
NW	22 (0.05)	101 (0.25)	27 (0.07)	0 (0.00)	0 (0.00)	0 (0.00)	2.0	150 (0.37)
NNW	33 (0.08)	268 (0.65)	200 (0.49)	9 (0.02)	0 (0.00)	0 (0.00)	2.6	510 (1.25)
CALM	1 (0.00)							
ALL	299 (0.73)	3571 (8.72)	2000 (4.89)	31 (0.08)	0 (0.00)	0 (0.00)	2.5	5901 (14.42)

TABLE B.5 (Cont'd)

Wind Direction	Frequency[a] by Wind Speed (m/s) Class 0-1	1-3	3-5	5-8	8-11	>11	Mean[b]	All
Stability Class C								
N	42 (0.10)	366 (0.89)	706 (1.72)	117 (0.29)	4 (0.01)	0 (0.00)	3.5	1235 (3.02)
NNE	39 (0.10)	287 (0.70)	302 (0.74)	16 (0.04)	1 (0.00)	0 (0.00)	2.9	645 (1.58)
NE	44 (0.11)	204 (0.50)	86 (0.21)	4 (0.01)	0 (0.00)	0 (0.00)	2.3	338 (0.83)
ENE	49 (0.12)	185 (0.45)	40 (0.10)	3 (0.01)	0 (0.00)	0 (0.00)	2.0	277 (0.68)
E	66 (0.16)	225 (0.55)	46 (0.11)	4 (0.01)	0 (0.00)	0 (0.00)	2.0	341 (0.83)
ESE	53 (0.13)	303 (0.74)	102 (0.25)	7 (0.02)	0 (0.00)	0 (0.00)	2.3	465 (1.14)
SE	33 (0.08)	149 (0.36)	29 (0.07)	7 (0.02)	0 (0.00)	0 (0.00)	2.1	218 (0.53)
SSE	25 (0.06)	38 (0.09)	6 (0.01)	1 (0.00)	1 (0.00)	0 (0.00)	1.7	71 (0.17)
S	14 (0.03)	29 (0.07)	8 (0.02)	1 (0.00)	2 (0.00)	0 (0.00)	2.1	54 (0.13)
SSW	12 (0.03)	26 (0.06)	11 (0.03)	5 (0.01)	0 (0.00)	0 (0.00)	2.3	54 (0.13)
SW	16 (0.04)	44 (0.11)	19 (0.05)	4 (0.01)	2 (0.00)	1 (0.00)	2.6	86 (0.21)
WSW	14 (0.03)	71 (0.17)	28 (0.07)	5 (0.01)	0 (0.00)	0 (0.00)	2.4	118 (0.29)
W	28 (0.07)	64 (0.16)	21 (0.05)	14 (0.03)	6 (0.01)	0 (0.00)	2.6	133 (0.32)
WNW	29 (0.07)	83 (0.20)	30 (0.07)	19 (0.05)	0 (0.00)	0 (0.00)	2.5	161 (0.39)
NW	40 (0.10)	152 (0.37)	61 (0.15)	14 (0.03)	0 (0.00)	0 (0.00)	2.4	267 (0.65)
NNW	42 (0.10)	223 (0.54)	318 (0.78)	91 (0.22)	1 (0.00)	0 (0.00)	3.4	675 (1.65)
CALM	2 (0.00)							
ALL	548 (1.33)	2449 (5.96)	1813 (4.43)	312 (0.76)	17 (0.02)	1 (0.00)	2.8	5138 (12.55)

TABLE B.5 (Cont'd)

Wind Direction	Frequency[a] by Wind Speed (m/s) Class 0-1	1-3	3-5	5-8	8-11	>11	Mean[b]	All
Stability Class D								
N	74 (1.18)	337 (0.82)	515 (1.26)	225 (0.55)	23 (0.06)	5 (0.01)	3.7	1179 (2.88)
NNE	85 (0.21)	285 (0.70)	247 (0.60)	55 (0.13)	1 (0.00)	0 (0.00)	2.9	673 (1.64)
NE	82 (0.20)	173 (0.42)	63 (0.15)	7 (0.02)	0 (0.00)	0 (0.00)	2.1	325 (0.79)
ENE	76 (0.19)	164 (0.40)	23 (0.06)	4 (0.01)	0 (0.00)	0 (0.00)	1.7	267 (0.65)
E	110 (0.27)	222 (0.54)	28 (0.07)	5 (0.01)	0 (0.00)	0 (0.00)	1.7	365 (0.89)
ESE	128 (0.31)	353 (0.86)	88 (0.21)	23 (0.06)	2 (0.00)	1 (0.00)	2.1	595 (1.45)
SE	176 (0.43)	279 (0.68)	88 (0.21)	40 (0.10)	5 (0.01)	0 (0.00)	2.2	588 (1.44)
SSE	169 (0.41)	189 (0.46)	48 (0.12)	37 (0.09)	12 (0.03)	4 (0.01)	2.1	459 (1.12)
S	159 (0.39)	151 (0.37)	39 (0.10)	35 (0.09)	15 (0.04)	9 (0.02)	2.4	408 (1.00)
SSW	140 (0.34)	207 (0.51)	57 (0.14)	42 (0.10)	17 (0.04)	9 (0.02)	2.6	472 (1.15)
SW	153 (0.37)	248 (0.61)	246 (0.60)	93 (0.23)	48 (0.12)	14 (0.03)	3.4	802 (1.96)
WSW	153 (0.37)	264 (0.64)	392 (0.96)	253 (0.62)	71 (0.17)	31 (0.08)	4.1	1164 (2.84)
W	143 (0.35)	266 (0.65)	164 (0.40)	299 (0.73)	143 (0.35)	27 (0.07)	4.7	1042 (2.55)
WNW	121 (0.30)	306 (0.75)	166 (0.41)	123 (0.30)	24 (0.06)	0 (0.00)	3.1	740 (1.81)
NW	141 (0.34)	296 (0.72)	189 (0.46)	119 (0.29)	21 (0.05)	4 (0.01)	3.1	770 (1.88)
NNW	110 (0.27)	271 (0.66)	361 (0.88)	313 (0.76)	36 (0.09)	2 (0.00)	3.9	1093 (2.67)
CALM	48 (0.12)							
ALL	2068 (5.05)	4011 (9.80)	2714 (6.63)	1673 (4.09)	418 (1.02)	106 (0.25)	3.2	10942 (26.85)

TABLE B.5 (Cont'd)

Wind Direction	Frequency[a] by Wind Speed (m/s) Class 0-1	1-3	3-5	5-8	8-11	>11	Mean[b]	All
Stability Class E								
N	16 (0.04)	138 (0.34)	71 (0.17)	7 (0.02)	0 (0.00)	0 (0.00)	2.6	232 (0.57)
NNE	11 (0.03)	102 (0.25)	31 (0.08)	1 (0.00)	0 (0.00)	0 (0.00)	2.4	145 (0.35)
NE	8 (0.02)	80 (0.20)	5 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	2.1	93 (0.23)
ENE	7 (0.02)	32 (0.08)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.7	40 (0.10)
E	12 (0.03)	32 (0.08)	2 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.6	46 (0.11)
ESE	14 (0.03)	64 (0.16)	7 (0.02)	2 (0.00)	0 (0.00)	0 (0.00)	2.0	87 (0.21)
SE	28 (0.07)	98 (0.24)	32 (0.08)	6 (0.01)	0 (0.00)	0 (0.00)	2.2	164 (0.40)
SSE	31 (0.08)	109 (0.27)	33 (0.08)	10 (0.02)	0 (0.00)	0 (0.00)	2.3	183 (0.45)
S	46 (0.11)	137 (0.33)	43 (0.11)	7 (0.02)	0 (0.00)	0 (0.00)	2.1	233 (0.57)
SSW	42 (0.10)	216 (0.53)	108 (0.26)	6 (0.01)	0 (0.00)	0 (0.00)	2.5	372 (0.91)
SW	58 (0.14)	304 (0.74)	1025 (2.50)	112 (0.27)	0 (0.00)	0 (0.00)	3.7	1499 (3.66)
WSW	61 (0.15)	302 (0.74)	2081 (5.08)	155 (0.38)	0 (0.00)	1 (0.00)	3.8	2600 (6.35)
W	50 (0.12)	251 (0.61)	778 (1.90)	74 (0.18)	0 (0.00)	0 (0.00)	3.5	1153 (2.82)
WNW	23 (0.06)	163 (0.40)	261 (0.64)	25 (0.06)	0 (0.00)	0 (0.00)	3.3	472 (1.15)
NW	20 (0.05)	163 (0.40)	189 (0.46)	28 (0.07)	0 (0.00)	0 (0.00)	3.2	400 (0.98)
NNW	14 (0.03)	144 (0.35)	129 (0.32)	16 (0.04)	0 (0.00)	0 (0.00)	3.0	303 (0.74)
CALM	11 (0.03)							
ALL	452 (1.11)	2335 (5.72)	4796 (11.71)	449 (1.08)	0 (0.00)	1 (0.00)	3.4	8022 (19.60)

TABLE B.5 (Cont'd)

Wind Direction	Frequency[a] by Wind Speed (m/s) Class 0-1	1-3	3-5	5-8	8-11	>11	Mean[b]	All
Stability Class F								
N	7 (0.02)	17 (0.04)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.6	25 (0.06)
NNE	2 (0.00)	16 (0.04)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.8	18 (0.04)
NE	6 (0.01)	12 (0.03)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.4	19 (0.05)
ENE	7 (0.02)	12 (0.03)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.4	19 (0.05)
E	6 (0.01)	16 (0.04)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.3	22 (0.05)
ESE	15 (0.04)	34 (0.08)	3 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	1.5	52 (0.13)
SE	29 (0.07)	85 (0.21)	16 (0.04)	2 (0.00)	0 (0.00)	0 (0.00)	2.0	132 (0.32)
SSE	47 (0.11)	140 (0.34)	18 (0.04)	0 (0.00)	0 (0.00)	0 (0.00)	1.8	205 (0.50)
S	55 (0.13)	195 (0.48)	22 (0.05)	0 (0.00)	0 (0.00)	0 (0.00)	1.9	272 (0.66)
SSW	66 (0.16)	508 (1.24)	113 (0.28)	1 (0.00)	0 (0.00)	0 (0.00)	2.3	688 (1.68)
SW	90 (0.22)	891 (2.18)	566 (1.38)	2 (0.00)	0 (0.00)	0 (0.00)	2.6	1549 (3.78)
WSW	68 (0.17)	834 (2.04)	936 (2.29)	1 (0.00)	0 (0.00)	0 (0.00)	2.8	1839 (4.49)
W	54 (0.13)	580 (1.42)	537 (1.31)	1 (0.00)	0 (0.00)	0 (0.00)	2.8	1172 (2.86)
WNW	23 (0.06)	329 (0.80)	238 (0.58)	0 (0.00)	0 (0.00)	0 (0.00)	2.6	590 (1.44)
NW	19 (0.05)	174 (0.43)	94 (0.23)	0 (0.00)	0 (0.00)	0 (0.00)	2.5	287 (0.70)
NNW	8 (0.02)	69 (0.17)	17 (0.04)	1 (0.00)	0 (0.00)	0 (0.00)	2.1	95 (0.23)
CALM	10 (0.02)							
ALL	512 (1.24)	3912 (9.57)	2562 (6.25)	8 (0.00)	0 (0.00)	0 (0.00)	2.6	6984 (17.04)

TABLE B.5 (Cont'd)

Wind Direction	Frequency[a] by Wind Speed (m/s) Class							
	0-1	1-3	3-5	5-8	8-11	>11	Mean[b]	All
Stability Class G								
N	5 (0.01)	7 (0.02)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.1	12 (0.03)
NNE	4 (0.01)	8 (0.02)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.1	12 (0.03)
NE	5 (0.01)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	0.7	6 (0.01)
ENE	3 (0.01)	3 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	0.9	6 (0.01)
E	7 (0.02)	3 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	0.8	10 (0.02)
ESE	12 (0.03)	21 (0.05)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.3	33 (0.08)
SE	27 (0.07)	38 (0.09)	2 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.2	67 (0.16)
SSE	43 (0.11)	71 (0.17)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.2	114 (0.28)
S	76 (0.19)	139 (0.34)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.2	215 (0.53)
SSW	151 (0.37)	304 (0.75)	0 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.3	455 (1.11)
SW	147 (0.36)	478 (1.17)	5 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	1.4	630 (1.54)
WSW	117 (0.29)	286 (0.70)	3 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	1.3	406 (0.99)
W	56 (0.14)	169 (0.41)	4 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	1.4	229 (0.56)
WNW	28 (0.07)	102 (0.25)	2 (0.00)	1 (0.00)	0 (0.00)	0 (0.00)	1.4	133 (0.32)
NW	8 (0.02)	59 (0.14)	1 (0.00)	0 (0.00)	0 (0.00)	0 (0.00)	1.5	68 (0.17)
NNW	9 (0.02)	15 (0.04)	3 (0.01)	0 (0.00)	0 (0.00)	0 (0.00)	1.5	27 (0.07)
CALM	11 (0.03)							
ALL	709 (1.76)	1704 (4.17)	20 (0.04)	1 (0.00)	0 (0.00)	0 (0.00)	1.3	2423 (5.91)

[a]The numbers before parentheses are hours of occurrence; numbers in parentheses are percent of the time.
[b]Mean wind speed for the stability and wind direction indicated.

Source: Derived from Woodward-Clyde Consultants 1988; National Climatic Center 1988.

isopleths are not considered representative of the conditions in the southern San Joaquin Valley because they are based on temperature-sounding data measured outside the southern San Joaquin Valley. Thus, the mixing-height data based on the Meadows Field temperature-sounding measurements are considered most reliable and representative of the NPR-1 site. Figure B.8 shows seasonal and annual morning and afternoon mean mixing-height values estimated from the Meadows Field temperature-sounding data (CARB 1988a) using a method formulated by Holzworth (1972).

B.2 AIR QUALITY STANDARDS AND REGULATIONS

The 1979 EIS (DOE 1979) described the ambient air quality standards and other federal, state, and local air quality regulations applicable at this time. However, a number of changes have occurred in the standards and other air pollution control regulations since then. These changes are briefly summarized below.

B.2.1 Ambient Air Quality Standards

The primary and secondary National Ambient Air Quality Standards (NAAQS) were promulgated by the U.S. Environmental Protection Agency (EPA) in 1971 (EPA 1971). The primary standards were established to protect the public health with an adequate margin of safety, and the secondary standards were intended to protect the public welfare from any known or anticipated adverse effects of a pollutant. Several changes have been made to the NAAQS since publication of the 1979 NPR-1 EIS. Significant changes include (1) an increase in the level of the 1-hour O_3 standard from 0.08 ppm to 0.12 ppm, (2) replacement of total suspended particulates (TSP) as the indicator for particulate matter with PM_{10} (suspended particulate matter with an aerodynamic diameter equal to or less than a nominal 10 μm); (3) deletion of nonmethane hydrocarbon standards; and (4) addition of lead (Pb) standards.

The current NAAQS and California Ambient Air Quality Standards (CAAQS) are listed in Table B.6. The California standards were initially established by CARB as goals to protect the most sensitive populations -- particularly children, the elderly, and individuals suffering from lung and heart diseases. However, the California Clean Air Act of 1988 established them as standards to meet.

B.2.2 Attainment Plans

The Clean Air Act of 1970 required the attainment of the NAAQS no later than July 1, 1977. Because most areas of the nation were unable to attain those standards by the deadline, the Clean Air Act Amendments of 1977 were passed, setting rigorous additional requirements for the nonattainment areas to ensure timely attainment of NAAQS. These requirements included a deadline for submission of state implementation plans (SIPs). The SIPs outline additional controls on existing sources and define the review procedures and emission limits that are necessary in order for new sources to attain the standards by the end

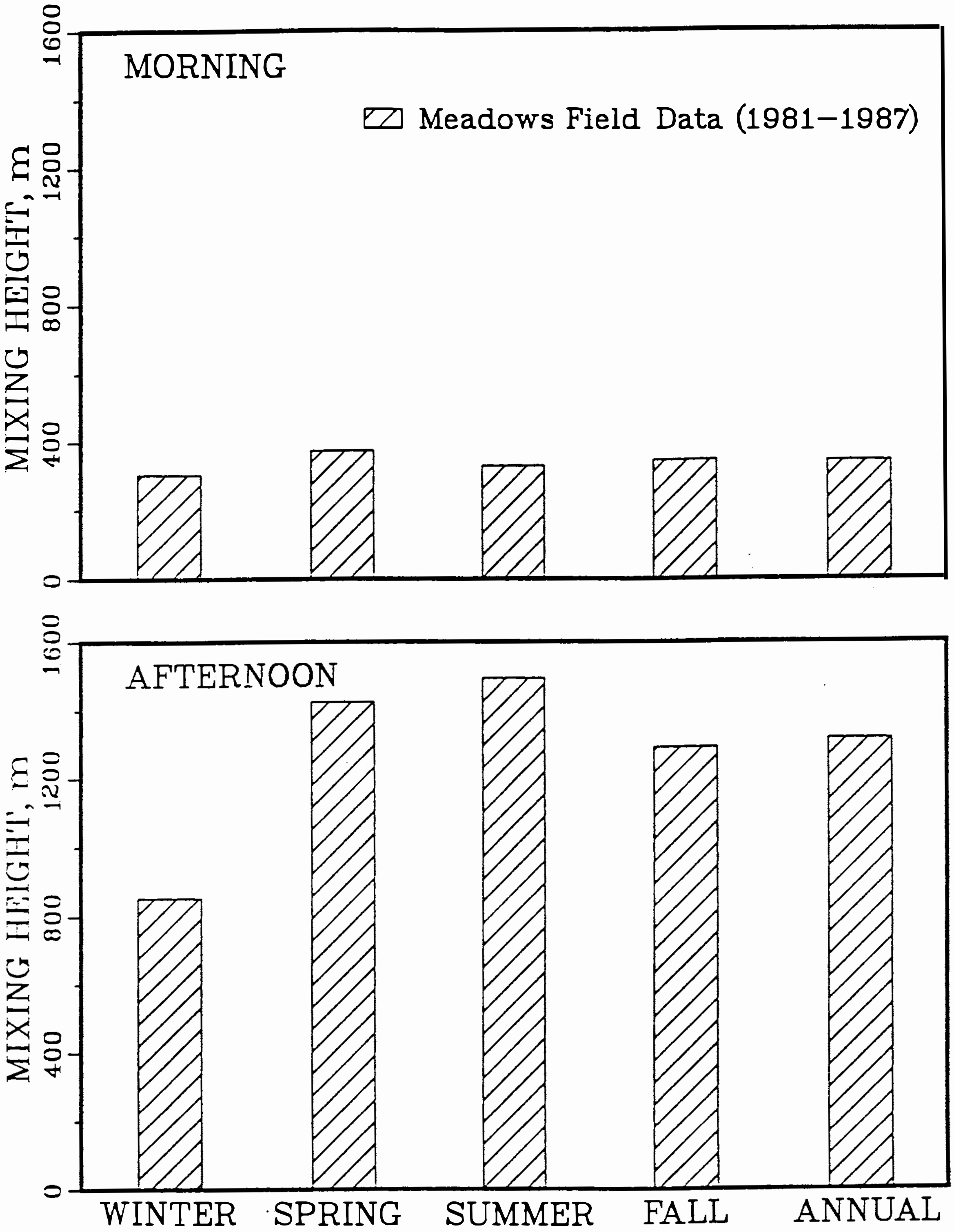


FIGURE B.8 MORNING AND AFTERNOON MIXING-HEIGHT VALUES BY SEASON ESTIMATED FOR SOUTHERN SAN JOAQUIN VALLEY (SOURCE: CARB 1988a)

TABLE B.6 Ambient Air Quality Standards Applicable in Kern County, California

Pollutant	Averaging Time	California Standards[a]	Federal Standards[b]	
			Primary	Secondary
Oxidant	1 hour	0.09 ppm (180 $\mu g/m^3$)[c]	-	-
Ozone	1 hour	-	0.12 ppm (235 $\mu g/m^3$)	Same[d]
Carbon Monoxide	8 hours	9.0 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	Same
	1 hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	
Nitrogen dioxide	Annual	-	100 $\mu g/m^3$ (0.05 ppm)	Same
	1 hour	0.25 ppm (131 $\mu g/m^3$)	-	
Sulfur dioxide	Annual	-	80 $\mu g/m^3$ (0.03 ppm)	-
	24 hours	0.05 ppm (131 $\mu g/m^3$)	365 $\mu g/m^3$ (0.14 ppm)	-
	3 hours	-	-	1300 $\mu g/m^3$ (0.5 ppm)
	1 hour	0.25 ppm (131 $\mu g/m^3$)	-	-
Suspended particulate matter (PM_{10})	Annual	30 $\mu g/m^3$[e]	50 $\mu g/m^3$[f]	Same
	24 hours	50 $\mu g/m^3$	150 $\mu g/m^3$	
Sulfates	24 hours	25 $\mu g/m^3$	-	-
Lead (particulate)	30 days	1.5 $\mu g/m^3$	-	-
	Calendar quarter	-	1.5 $\mu g/m^3$	Same
Hydrogen sulfide	1 hour	0.03 ppm (42 $\mu g/m^3$)	-	-
Vinyl Chloride (chloroethene)	24 hours	0.010 ppm (26 $\mu g/m^3$)	-	-

TABLE B.6 (Cont'd)

Pollutant	Averaging time	California Standards[a]	Federal Standards[b]	
			Primary	Secondary
Visibility-reducing particles	1 observation	In sufficient amount to reduce the prevailing visibility to less than 10 miles when the relative humidity is less than 70%	-	-

[a]National standards, other than oxidant, carbon monoxide, sulfur dioxide (1 hour), nitrogen dioxide, and particulate matter (PM_{10}) are values that are not to be equaled or exceeded. The oxidant, carbon monoxide, sulfur dioxide (1 hour), nitrogen dioxide, and particulate matter (PM_{10}) standards are not to be exceeded.

[b]National standards, other than ozone, particulate matter (PM_{10}) and those based on annual averages, are not to be exceeded more than once a year. The ozone standards are attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one. The 24-hour particulate matter (PM_{10}) standards are attained when the expected number of days with a 24-hour average concentration above the standard is equal to or less than 1. The annual arithmetic mean particulate matter (PM_{10}) standards are attained when the expected annual arithmetic mean concentration is less than or equal to the standard.

[c]ppm = parts per million; $\mu g/m^3$ = micrograms per cubic meter.

[d]Same as Primary Standard.

[e]Geometric mean of all reported values taken during the year.

[f]Arithmetic mean of the quarterly arithmetic means for the four calendar quarters of the year.

Sources: California Code of Regulations, Title 17, Section 70200; Code of Federal Regulations, Title 40, Part 50.

of 1982, with a possible extension to the end of 1987 for O_3 and CO. To meet these requirements, the Kern County Air Pollution Control District (KCAPCD) adopted an attainment plan in 1979 and a more stringent, revised plan in 1982. Implementation of these plans has resulted in steady improvements in several air quality parameters, except for concentrations of O_3 and suspended particulate matter. To attain the NAAQS for O_3 and CO, the KCAPCD plan was revised again in 1986, and later updated in 1987. However, the plan was not approved by EPA, and the O_3 standard was not met. Another revised plan with provisions for attainment of PM_{10} standards is due in mid-1993. Carbon monoxide is now an attainment pollutant in the NPR-1 area.

The 1987 revised Kern County SIP contains an important provision that is directly relevant to operation of NPR-1. That provision is to impose KCAPCD Rule 427 on western Kern County (Kern County west of Highway 5) in the event that it is needed. The KCAPCD Rule 427 requires a more effective NO_x-control strategy for existing internal combustion engines with ratings greater than 50 hp. The rule would be imposed if implementation of existing precursor-control measures fails to attain the NAAQS for O_3. The standard would be deemed not attained if O_3 concentrations exceed 0.12 ppm on more than 3 separate days during the 3-year period 1988-1990. The additional NO_x control measures would be imposed, however, at anytime during those 3 years that a fourth exceedance of the standard occurred. The 3-day period was exceeded in October 1988. The application of Rule 427 to western Kern County and the requirement for additional NO_x emission reduction from existing internal combustion engines became effective in April 1989.

Currently, SIP's are developed only for attainment of the NAAQS; however, the California Clean Air Act of 1988 requires that attainment plans also be developed by each air pollution control district for the attainment of more stringent CAAQS and be submitted by December 31, 1990. The attainment plans will require more stringent emission-control strategies to attain and maintain the CAAQS than would be required for NAAQS attainment. The attainment plan will require reduction of emissions of nonattainment pollutants in each district by 5% per year using the district's emissions as of December 31, 1987, as a baseline. Mandatory control strategies required to attain and maintain the CAAQS will depend on the severity of nonattainment. The most stringent control strategies would be required in air basins with "severe" air pollution, and would include (1) no net increase in emissions of nonattainment pollutants or their precursors from any new or modified stationary source, (2) application of the best available retrofit control technology to existing sources, and (3) additional measures to control emissions from vehicular sources. Severe air pollution is defined for an area where attainment is not expected until after December 31, 1997, or an attainment date cannot be identified. These requirements parallel those outlined in the 1990 Amendments to the FCAA.

B.2.3 Regulations for Toxic Air Contaminants

Although not subject to the CAAQS or NAAQS, a number of noncriteria air pollutants are designated by EPA as hazardous air pollutants according to Section 112 of the Clean Air

Act (40 CFR 61 Subpart A), or are identified by CARB as toxic air contaminants (CARB 1989). Hazardous air pollutants thus designated or identified are listed in Table B.7. National emission standards have been established by EPA for the designated hazardous air pollutants, and control measures have been developed or are under development by CARB for the identified toxic air contaminants. These regulations were modified by the 1990 Amendments to the FCAA.

Benzene, a compound that may be contained in the hydrocarbon emissions at NPR-1, is designated as a hazardous air pollutant by EPA and as a toxic air contaminant by CARB. The national emission standards for equipment leaks of benzene and of volatile hazardous air pollutants apply only to the equipment that either contains or contacts a fluid (liquid or gas) that is at least 10% by weight benzene or volatile hazardous air pollutant.

Another California regulation on toxic air contaminants (Air Toxics "Hot Spot" Information and Assessment Act of 1987 [Assembly Bill 2588]) requires all emission sources with criteria pollutant emissions above 25 tons per year (according to the 1985 CARB emissions-inventory) to submit emissions-inventory data for any of the more than 300 listed compounds. The list of compounds includes benzene, toluene, and xylene, which are present in the crude oil produced at NPR-1. The emissions-inventory data submitted are to be used in assessing health risks associated with potential emissions and in developing control measures, if deemed necessary.

B.3 TRENDS IN AMBIENT AIR QUALITY

B.3.1 Introduction

This section describes trends in ambient air quality in the southern San Joaquin Valley Air Basin for O_3 and in the Kern County portion of the air basin for other air quality parameters. This analysis is based on data from the monitoring networks operated by (1) state and local agencies (California Air Resources Board 1978-1988) and (2) the Westside Operators (Woodward-Clyde Consultants 1984-1989). Locations of the air quality monitoring stations operated in the San Joaquin Valley Air Basin by the state and local agencies during 1988 are shown in Figure B.9. Monitoring stations operated in western Kern County by the Westside Operators are shown in Figure B.1. Air quality parameters measured at these monitoring stations during 1988 are listed in Table B.8.

Trends in levels of O_3, NO_2, and CO up to 1985 for the Kern County portion of the San Joaquin Valley Air Basin are described in a report by the Kern County Air Pollution Control District and Kern Council of Governments (1986). These trends were constructed by plotting 3-year moving averages of county-wide data summarized by the CARB from the monitoring network operated by state and local agencies. This section contains updated trends reflecting the additional data collected up to 1988 for O_3, NO_2, and CO and the trends for other air pollutants.

TABLE B.7 Hazardous Air Pollutants Designated by EPA and Toxic Air Contaminants Identified by CARB

Hazardous Air Pollutants Designated by EPA[a]	Toxic Air Contaminants Identified by CARB[b]
Asbestos	Asbestos
Benzene	Benzene
Beryllium	Cadmium
Coke oven emissions	Chlorinated dioxins and dibenzofurans (15 species)
Inorganic arsenic	Chromium (VI)
Mercury	Ethylene bromide
Radionuclides	Ethylene dichloride
Vinyl Chloride	Carbon tetrachloride
Hexavalent Chromium	Ethylene oxide
Inorganic Arsenic	
Trichloroethylene	
Chloroform 13.A-4	

[a]Designated according to Section 112 of the Clean Air Act (Code of Federal Regulations, Title 40 Part 61). Although not formally designated, there are 25 additional compounds or classes of compounds, including toluene, for which a Federal Register notice has been published that included consideration of serious health effects. An additional 189 chemicals have been identified for future consideration as toxic air contaminants by EPA pursuant to Title V of the 1990 Amendments to the Federal Clean Air Act. 13.A-4

[b]Identified pursuant to the provisions of California's air toxics law (California Health and Safety Code Section 39650 et seq.). Thirty-two additional compounds or classes of compounds are currently under review. Seventeen additional compounds or classes of compounds are also listed for which health effects information is limited or not yet sufficient to support review (CARB 1989).

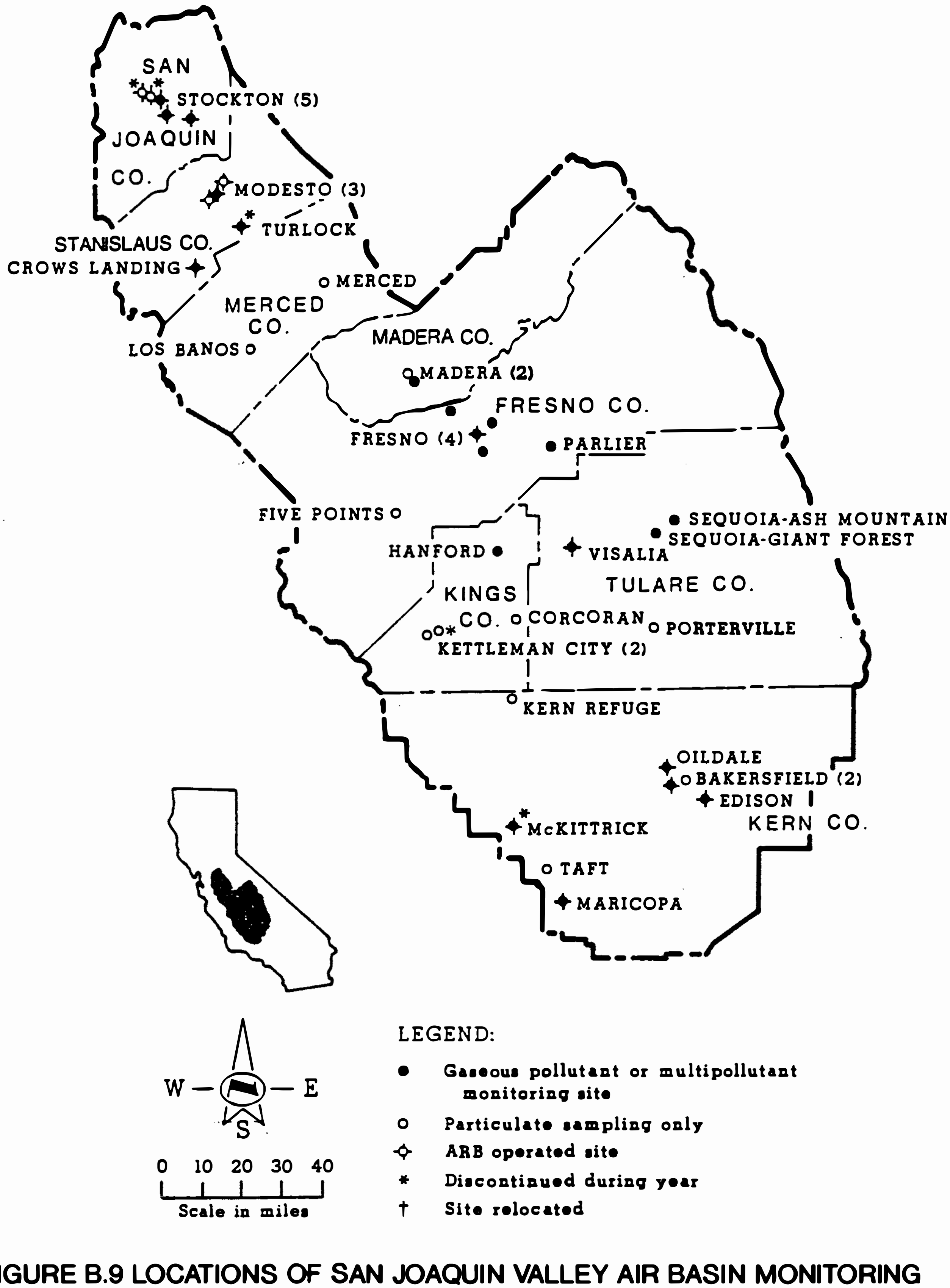


FIGURE B.9 LOCATIONS OF SAN JOAQUIN VALLEY AIR BASIN MONITORING STATIONS OPERATED BY STATE AND LOCAL AGENCIES DURING 1988 (SOURCE: CARB ANNUAL REPORT FOR 1988)

TABLE B.8 Air Quality Parameters Measured at Monitoring Stations in Western and Central Kern County During 1988.

Monitoring Station[a]	Air Quality Parameters[b,c]											
	O_3	CO	NO_2	SO_2	TSP	PM_{10}	Pb	TSP-SO_4	PM_{10}-SO_4	TSP-NO_3	PM_{10}-NO_3	HC
Western Kern County												
Kern Wildlife Refuge[d,e]	X		X	X		X		X				
Lost Hills[d,e]			X	X								
Kernridge$_{d}$	X[f]	X	X	X	X[f]	X[f]		X[f]	X[f]			
Cymric$_{d,e}$				X								
McKittrick[d]		X[f]	X[f]	X	X[f]	X[f]		X[f]	X[f]			X[f]
McKittrick[d]	X	X	X	X	X			X		X		
Derby Acres[d,f]			X	X	X			X				
Fellows[d]		X[g]	X[g]	X	X[g]	X[g]		X[g]				
Taft[d,f]	X											
Taft					X	X	X	X	X	X	X	
Maricopa[d]	X		X		X			X				
Maricopa	X											
Central Kern County												
Kern Refuge					X		X	X		X		
Oildale	X	X	X	X	X	X		X	X	X	X	
Bakersfield - Chester	X	X	X	X	X	X	X	X	X	X	X	
Bakersfield - Flower					X		X	X		X		
Edison	X		X[g]									

[a]Monitoring stations operated by state or local agencies unless otherwise noted.
[b]Only air quality parameter of primary interest, not all parameters measured, are listed here.
[c]An "X" indicates that a given parameter was measured at the indicated station.
[d]Monitoring stations operated by the Westside Operators.
[e]Relocated from Lost Hills to Kern Wildlife Refuge during 1988.
[f]Closed during 1988.
[g]Monitors installed during 1988.
Source: CARB Annual Report for 1988; Woodward-Clyde Consultants Annual Report for 1988.

Information on the current visibility parameter (visual range) in the Kern County portion of the San Joaquin Valley Air Basin is derived from data measured at the NWS station at Meadows Field, near Bakersfield. The visibility data base used in this analysis was obtained from the National Climatic Data Center in the Weather Bureau-Air Force-Navy (WBAN) hourly surface observation format for the 30-year period 1958-1987.

B.3.2 Ozone

The spatial distribution of ambient ozone (O_3) concentrations in the southern San Joaquin Valley Air Basin and the seasonal and diurnal variations in those concentrations are described in detail in the 1979 NPR-1 EIS (DOE 1979) based on data collected before 1978. These features, which essentially depend on the precursor emissions in upwind areas and on diurnal variation in solar intensity, should remain unchanged. More up-to-date information on some of these features is provided later in this section.

Table B.9 lists the 1988 annual summary statistics of the ambient O_3 concentrations over the southern San Joaquin Valley Air Basin. Data for the Kern County portion of the San Joaquin Valley Air Basin are presented separately for central and Western Kern County because these two segments of the county are affected by different air flow patterns that influence the transport of O_3 precursors. Data for other air quality parameters in the subsequent tables are presented in the same manner because the data from western Kern County better represent the NPR-1 site than do the central Kern County data.

Table B.9 shows that the NAAQS for O_3 (0.12 ppm as a 1-hour average) was exceeded on a number of days at most of the monitoring stations (e.g., 5 days at Bakersfield and 54 days at Edison). The number of occurrences from April through October peaked in July through September (Table B.10). Ozone concentrations were generally higher in the eastern and southern portions of the valley and in areas downwind of major metropolitan areas, such as Fresno and Bakersfield. Figure B.10 shows the spatial distribution of the mean daily maximum 1-hour O_3 concentrations during August 1987, and Table B.9 shows the number of days that the NAAQS was exceeded during 1988.

The highest and the second-highest 1-hour O_3 concentrations measured in 1988 at monitoring stations in central and western Kern County were 0.17 ppm and 0.16 ppm, respectively. These O_3 levels have changed little over the last 8 years. The plots of 3-year moving averages of these concentrations in central and western Kern County are shown in Figure B.11. The number of hours and the number of days that exceeded the NAAQS for O_3 (0.12 ppm) in central Kern County and corresponding numbers that exceeded the California standard for O_3 (0.09 ppm) seem to have increased somewhat during the last 5 years but are only slightly greater than those 10 years ago (Figure B.12). The number of hours and the number of days that exceeded the NAAQS for O_3 at Maricopa in western Kern County and the corresponding numbers that exceeded the California standard for O_3 appear to have decreased slightly during the last 5 years (Figure B.13). (Table B.11 shows

TABLE B.9 1988 Annual Summary Statistics for Ambient Ozone Concentration at Monitoring Stations in Southern San Joaquin Valley Air Basin

County and Monitoring Station[a]	Daily Max. 1-hour Conc. (ppm)		Annual Mean Conc. (ppm)		Annual Number of Occurrences with 1-hour Conc.				Number of 1-hour Samples
					>0.09 ppm[b]		>0.12 ppm[c]		
	First Highest	Second Highest	All Hours	Daily Maximum Hour	Hour	(day)	Hour	(day)	
Fresno County									
Fresno-Sierra	0.15[d]	0.14[d]	0.036[d]	0.069[d]	220	(60)	16	(8)	6,927
Fresno-Drumm	0.19	0.17	0.030	0.063[d]	161	(56)	19	(11)	7,927
Fresno-Olive	0.16	0.16	0.028	0.061	147	(53)	17	(9)	8,125
Fresno-Cal. State	0.16	0.16	0.039	0.074	325	(84)	50	(27)	7,881
Parlier	0.15[d]	0.15[d]	0.040[d]	0.077[d]	406	(95)	44	(26)	7,554
Tulare County (Visalia)	0.15	0.13	0.034	0.067	263	(77)	5	(4)	8,013
Kern County - Central									
Oildale	0.14	0.13	0.043	0.072	300	(73)	5	(5)	7,939
Bkrsfld-Chester	0.14	0.14	0.031	0.068	289	(76)	8	(5)	7,922
Edison	0.17[d]	0.17[d]	0.045[d]	0.083[d]	562	(125)	100	(54)	7,491
Kern County - Western									
Kern Wildlife Refuge[c,f]	0.11[d]	0.10[d]	0.024[d]	0.055[d]	3	(3)	0	(0)	4,163
Kernridge[c,g]	0.10[d]	0.10[d]	0.032[d]	0.052[d]	5	(3)	0	(0)	4,065

TABLE B.9 1988 (Cont'd)

County and Monitoring Station[a]	Daily Max. 1-hour Conc. (ppm)		Annual Mean Conc. (ppm)		Annual Number of Occurrences with 1-hour Conc.				Number of 1-hour Samples
	First Highest	Second Highest	All Hours	Daily Maximum Hour	>0.09 ppm[b]		>0.12 ppm[c]		
					Hour	(day)	Hour	(day)	
Kern County - Western									
McKittrick	0.12[d]	0.11[d]	0.038[d]	0.060[d]	9	(2)	0	(0)	1,644
Taft[e,g]	0.08[d]	0.07[d]	0.026[d]	0.040[d]	0	(0)	0	(0)	4,258
Maricopa School	0.14[d]	0.14[d]	0.048[d]	0.069[d]	321	(69)	13	(6)	6,996
Maricopa[e]	0.16	0.16	0.044[d]	0.067	359	(76)	30	(8)	8,366

[a]Monitoring stations operated by state or local agencies unless otherwise noted.
[b]California 1-hour ambient air quality standard for oxidant.
[c]National 1-hour primary and secondary ambient air quality standard for ozone.
[d]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness.
[e]Monitoring stations operated by Westside Operators.
[f]Ozone monitor installed during 1988.
[g]Monitoring terminated during 1988.

Sources: CARB Annual Report for 1988; Woodward-Clyde Consultants' Annual Report for 1988.

TABLE B.10 Number of Days Ambient Ozone Standards Were Exceeded Per Month in 1988 at Selected Monitoring Stations in the San Joaquin Valley

Ambient Ozone Standard	Monitoring Station	Number of Days with 1-hour Concentrations Higher than Ambient Standard												
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
California (0.09 ppm)	Fresno-Olive	0	1	0	1	4	6	13	9	12	7	0	0	53
	Parlier	0	1	2	6	7	14	25	19	20	-[a]	1	0	95
	Visalia	0	2	1	0	5	13	16	9	17	14	0	0	77
	Bkrsfld-Chester	0	1	1	1	5	10	17	12	12	17	0	0	76
	Edison	0	2	2	5	11	12	22	28	21	21	1	0	125
	McKittrick	0	2	0	-	-	-	-	-	-	-	-	-	2
Federal (0.12 ppm)	Fresno-Olive	0	0	0	0	0	1	1	2	4	1	0	0	9
	Parlier	0	0	0	1	1	2	11	7	4	-	0	00	26
	Visalia	0	0	0	0	0	1	0	2	1	0	0	0	4
	Bkrsfld-Chester	0	0	0	0	1	0	2	0	1	1	0	0	5
	Edison	0	0	1	1	2	5	13	11	11	10	0	0	54
	McKittrick	0	0	0	-	-	-	-	-	-	-	-	-	0

[a]Data not available

Source: CARB Annual Report for 1988.

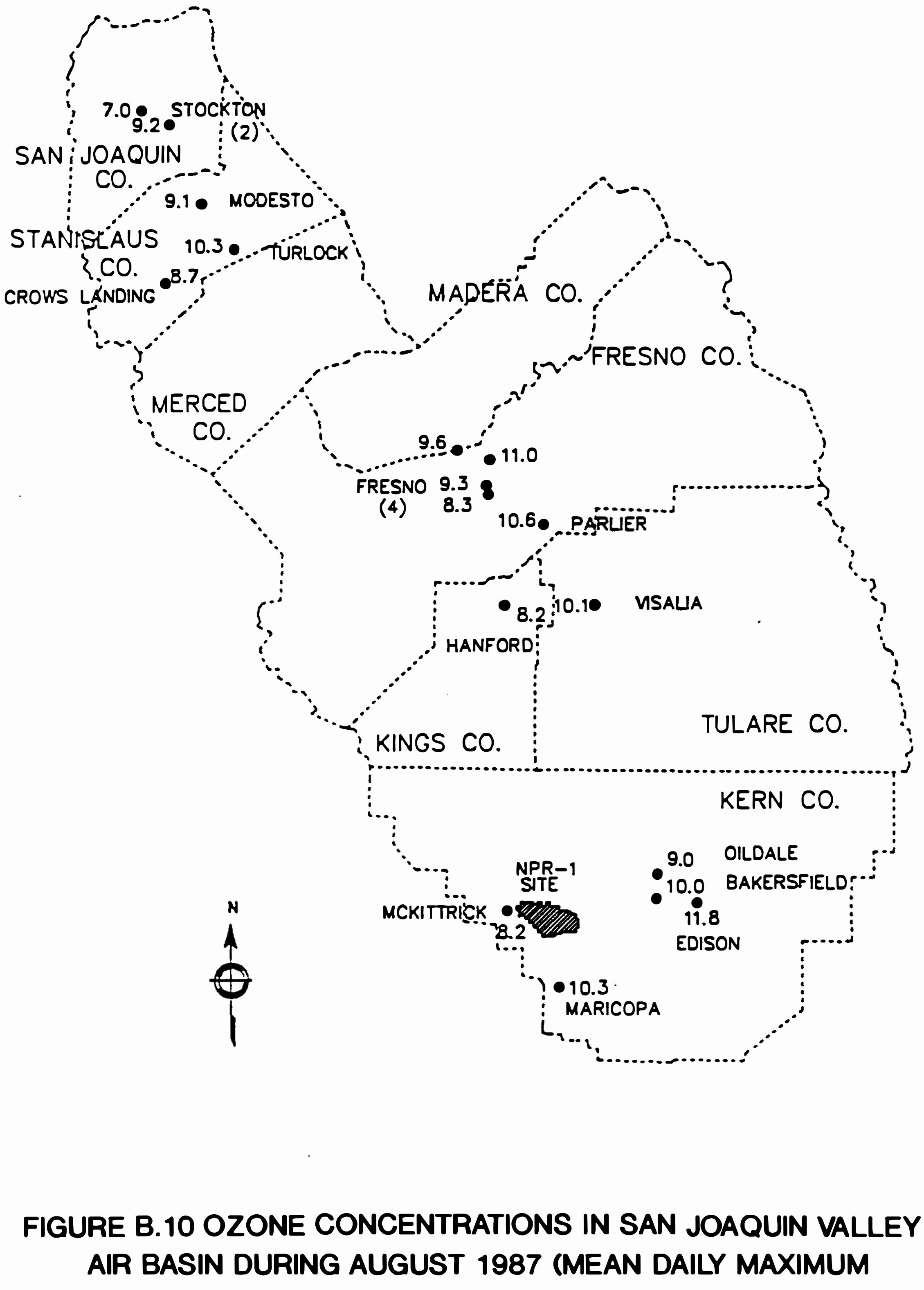
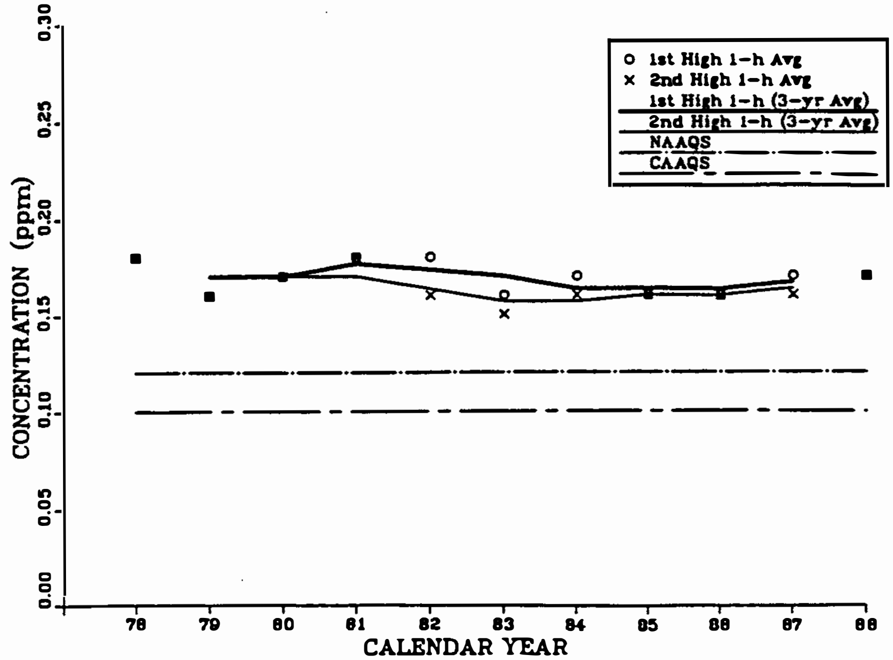


FIGURE B.10 OZONE CONCENTRATIONS IN SAN JOAQUIN VALLEY AIR BASIN DURING AUGUST 1987 (MEAN DAILY MAXIMUM CONCENTRATIONS IN PPHM) (SOURCE: BASED ON CARB 1987)



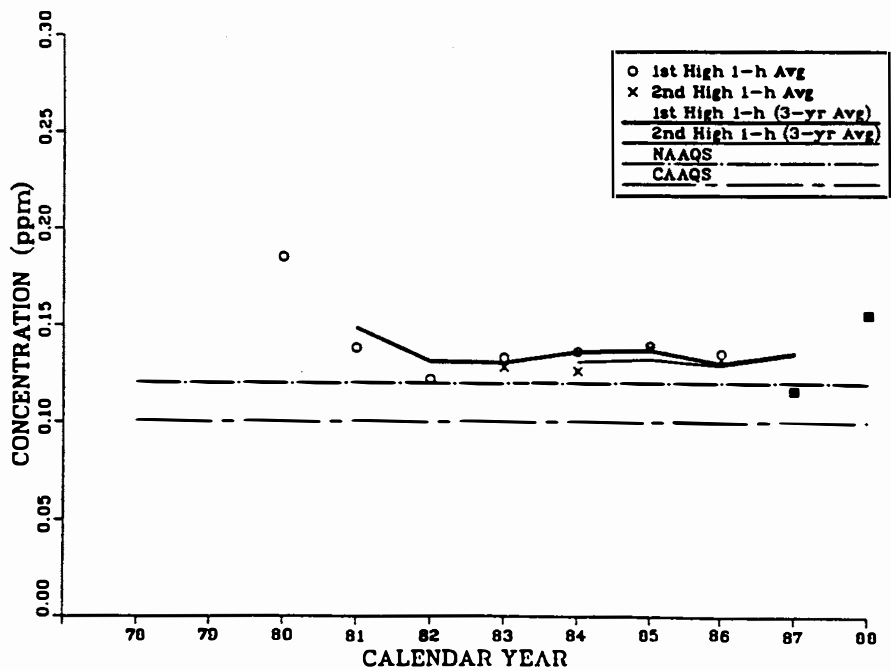
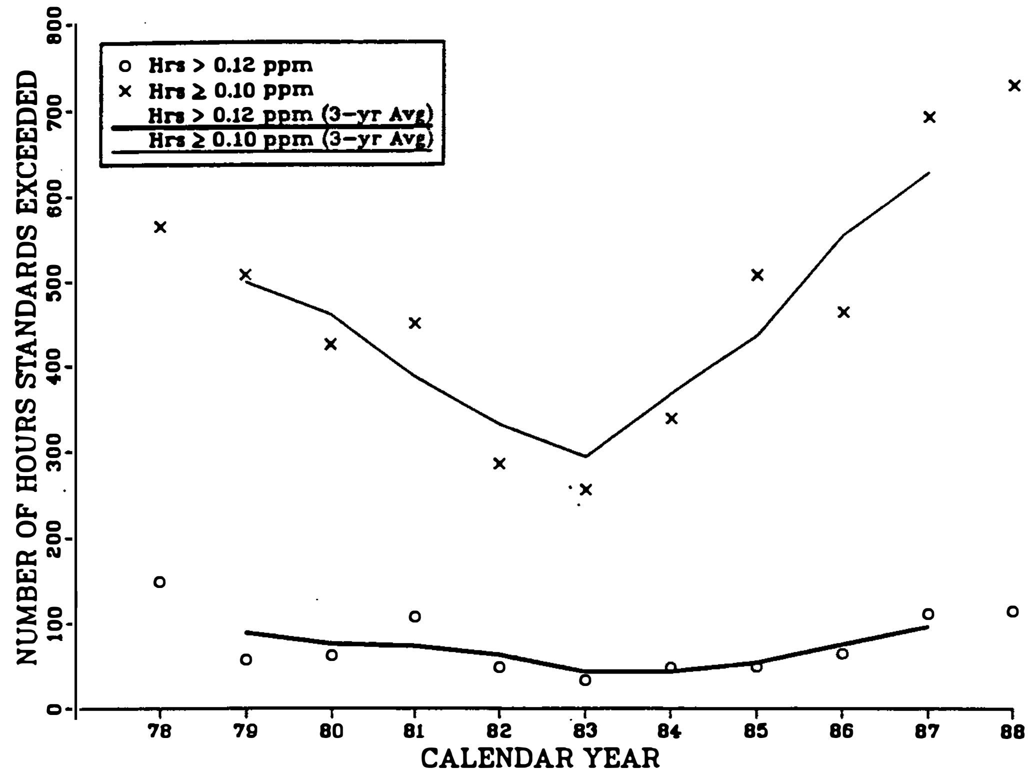


FIGURE B.11 TRENDS IN THE MAXIMUM 1-HOUR OZONE CONCENTRATIONS IN CENTRAL (TOP) AND WESTERN (BOTTOM) KERN COUNTY (SOURCE: DEVELOPED FROM CARB 1987-1988 AND WOODWARD-CLYDE CONSULTANTS 1984-1989)



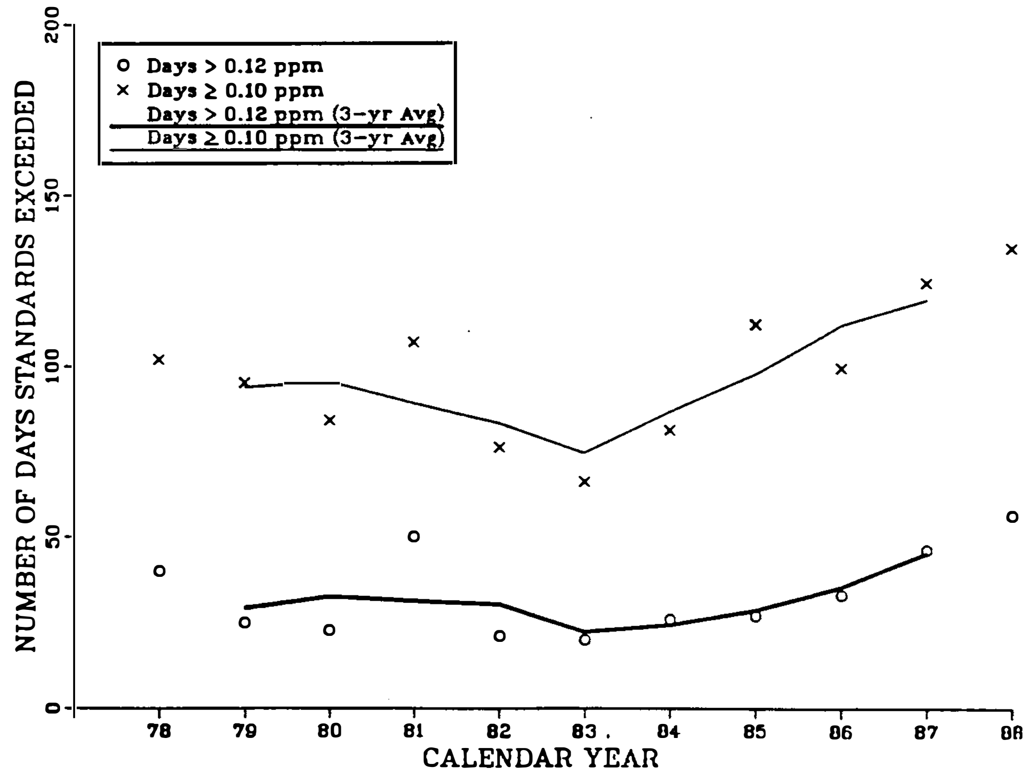
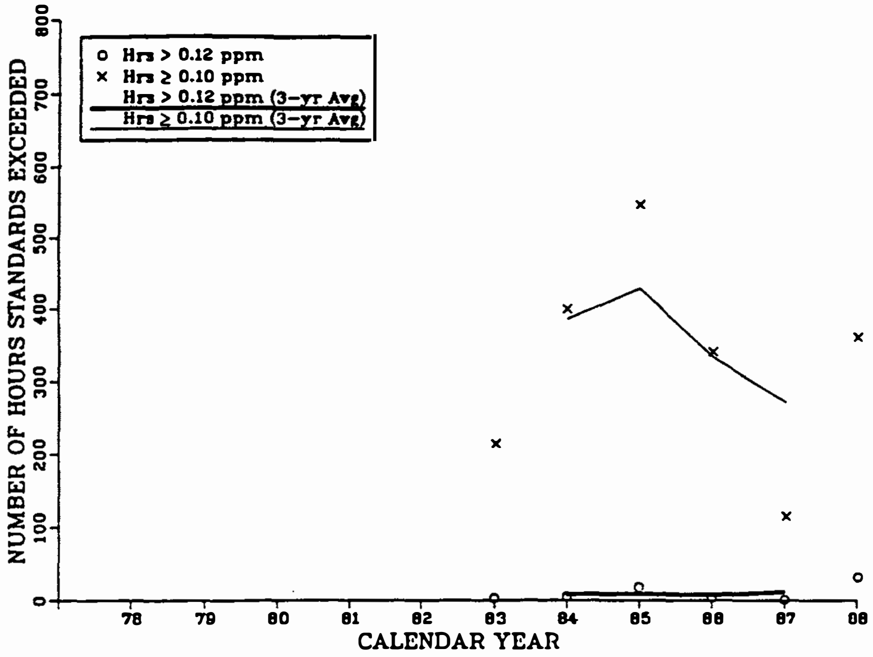


FIGURE B.12 TRENDS IN THE NUMBER OF HOURS (TOP) AND DAYS (BOTTOM) WHEN THE NAAQS OR CAAQS FOR OZONE WAS EXCEEDED IN CENTRAL KERN COUNTY (SOURCE: DEVELOPED FROM CARB 1978-1988)



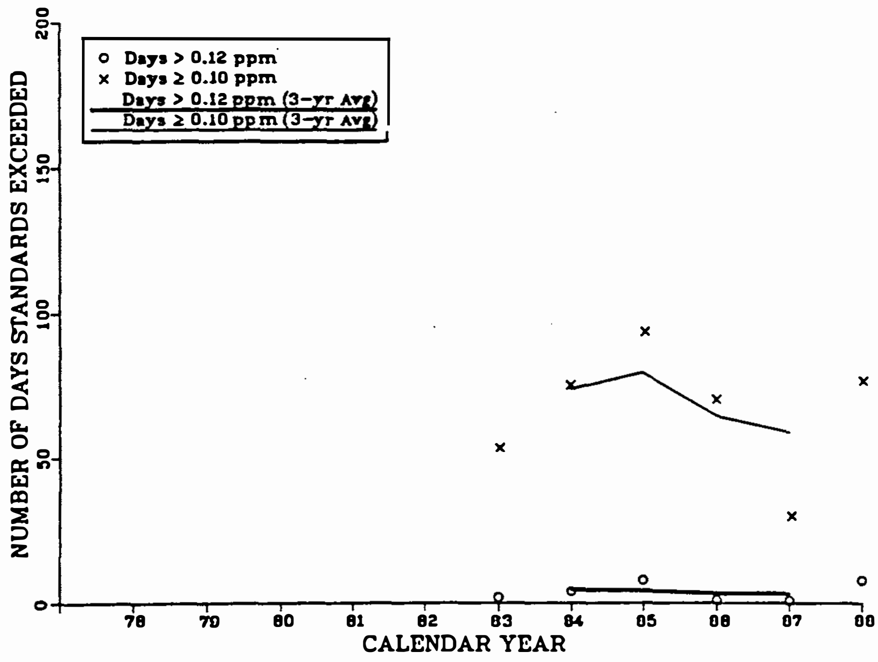


FIGURE B.13 TRENDS IN THE NUMBER OF HOURS (TOP) AND DAYS (BOTTOM) WHEN THE NAAQS OR CAAQS FOR OZONE WAS EXCEEDED IN WESTERN KERN COUNTY (SOURCE: DEVELOPED FROM WOODWARD-CLYDE CONSULTANTS 1984-1989)

TABLE B.11 Number of Days Ambient Ozone Standards Were Exceeded per Year at Selected Monitoring Stations in San Joaquin Valley, 1978-1988

Ozone Standard	Monitoring Station	Number of Days with 1-hour O_3 Concentrations Higher than Ambient Standard										
		1978	1979	1980	1981	1982	1983	1984	1985	1985	1987	1988
California												
(0.09 ppm)	Fresno-Olive	36	36	55	26	21	23	5	42	26	67	53
	Parlier	0[a]	-[b]	-	-	-	-	91[a]	74[a]	71[a]	107	95[a]
	Visalia	18	38	77	54	43	46[a]	46	38	95	90	77
	Bkrsfld-Chester	77	36	61	47	45	50	39[a]	62	68	68	76
	Edison	-	-	-	100[a]	68	36[a]	57[a]	104[a]	78	110	125[a]
Federal	Fresno-Olive	9	7	14	5	1	2	0	7	6	12	9
(0.12 ppm)	Parlier	0[a]	-	-	-	-	-	18[a]	11	21[a]	27	26[a]
	Visalia	2	8[a]	10	2	3	4[a]	2	1	12	8	4
	Bkrsfld-Chester	15	4	7	7	7	7	2[a]	5	7	10	5
	Edison	-	-	-	50[a]	19	17[a]	23[a]	24[a]	28	43	54[a]

[a]Data presented are valid but incomplete in that an insufficient number of data points were collected to meet EPA or CARB criteria for representativeness.
[b]Data not available.

Source: CARB 1978-1988.

a similar trend for the number of days that the ambient O_3 standard was exceeded at other monitoring stations in the southern San Joaquin Valley Air Basin.)

Ambient O_3 plays an important role in conversion of nitrogen oxide (NO) to nitrogen dioxide (NO_2) and other nitrogen compounds of higher oxidation state. Seasonal maximum hourly O_3 concentrations and corresponding NO_2 concentrations measured at the monitoring stations in western Kern County have been analyzed. (These data were used in ambient NO_2 modeling incorporating the ozone-limiting method, as described in Section B.5.) Figure B.14 plots seasonal maximum and mean hourly O_3 and NO_2 concentrations at the Westside Operators' Maricopa station for the period 1983-1987. The following seasonal and diurnal patterns are illustrated in the figure: (1) higher O_3 levels in warmer seasons and during daytime, (2) higher NO_2 concentrations during the colder winter season, and (3) higher NO_2 concentrations and corresponding dips in O_3 levels during the morning and afternoon rush hours. The seasonal maximum hourly O_3 concentrations and corresponding NO_2 concentrations are shown in Figure B.15 for the Maricopa station. Comparison of Figures B.14 and B.15 indicates that NO_2 levels corresponding to the seasonal maximum O_3 concentrations are, in general, similar to or slightly lower than the seasonal mean hourly NO_2 concentrations, but are significantly lower than the seasonal maximum hourly NO_2 concentrations. Ozone data from other monitoring stations in western Kern County operated by the Westside Operators or CARB show seasonal and diurnal patterns to be generally similar to those at the Maricopa station, but with somewhat lower concentration levels.

B.3.3 Suspended Particulate Matter

Table B.12 presents the 1988 annual summary statistics for 24-hour ambient suspended particulate matter (PM_{10}) concentrations measured in the Kern County portion of the San Joaquin Valley Air Basin. The table includes the levels of 24-hour concentrations (the highest, the second highest, and the lowest), annual mean concentrations (geometric and arithmetic), and the number of 24-hour samples that exceeded the California and national standards.

The annual NAAQS for PM_{10} (50 $\mu g/m^3$ as an arithmetic mean) was exceeded in 1988 at all three monitoring stations listed where samplers were in operation throughout the year. The standard was exceeded by about 20% or more at these stations. The three stations exceeded the California annual standard of 30 $\mu g/m^3$ (as a geometric mean) by substantial margins. Both the 24-hour NAAQS for PM_{10} (150 $\mu g/m^3$) and the California standard 50 $\mu g/m^3$) were exceeded at all three monitoring stations.

The PM_{10} samples were not collected at the monitoring stations listed in Table B.12 before 1984. No increasing or decreasing trend of PM_{10} levels could be identified from the limited period of available data.

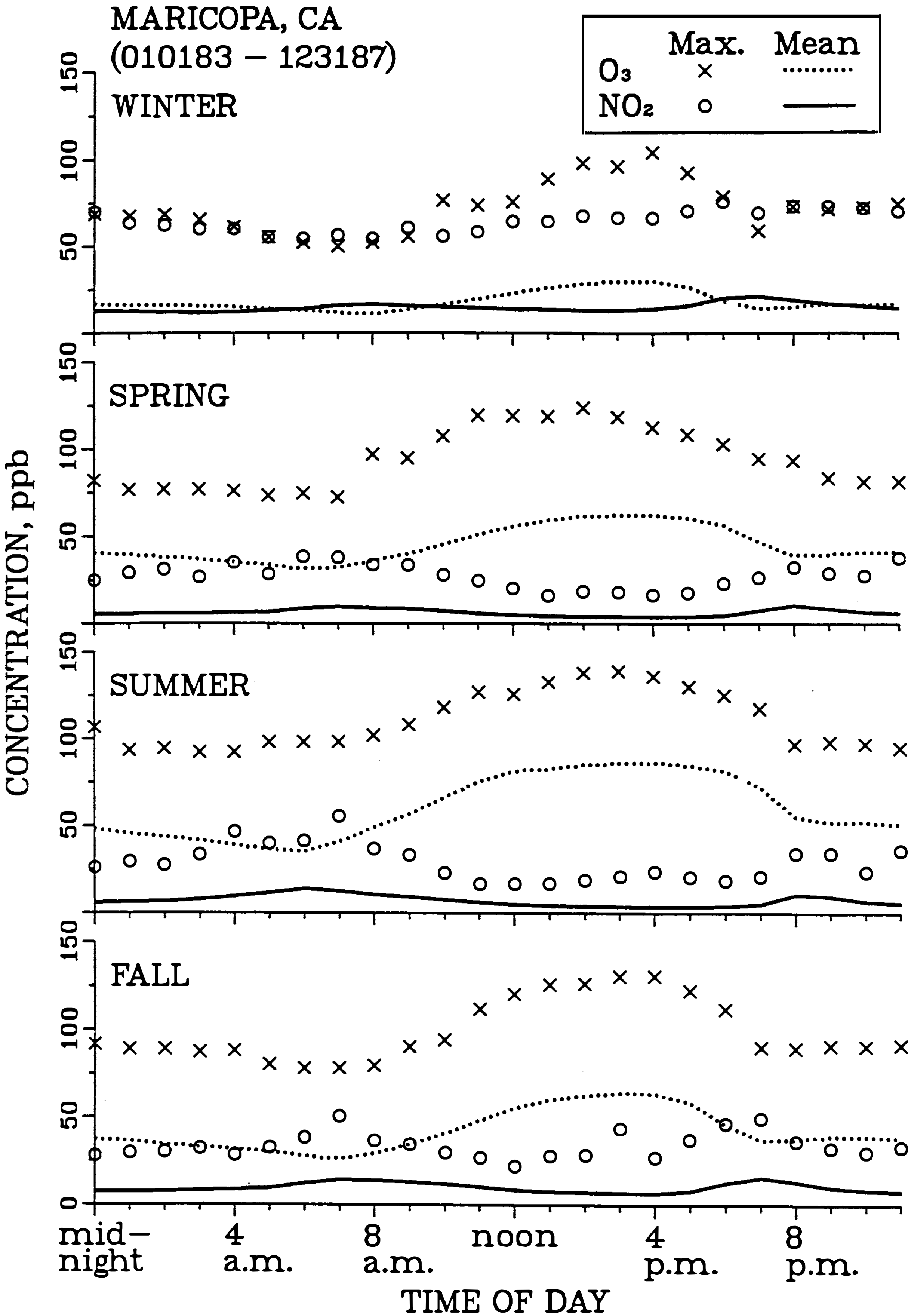


FIGURE B.14 SEASONAL AND DIURNAL VARIATIONS IN THE MAXIMUM AND MEAN HOURLY O_3 AND NO_2 CONCENTRATIONS IN MARICOPA, CALIFORNIA, 1983-1987 (SOURCE: DEVELOPED FROM WOODWARD-CLYDE CONSULTANTS 1988)

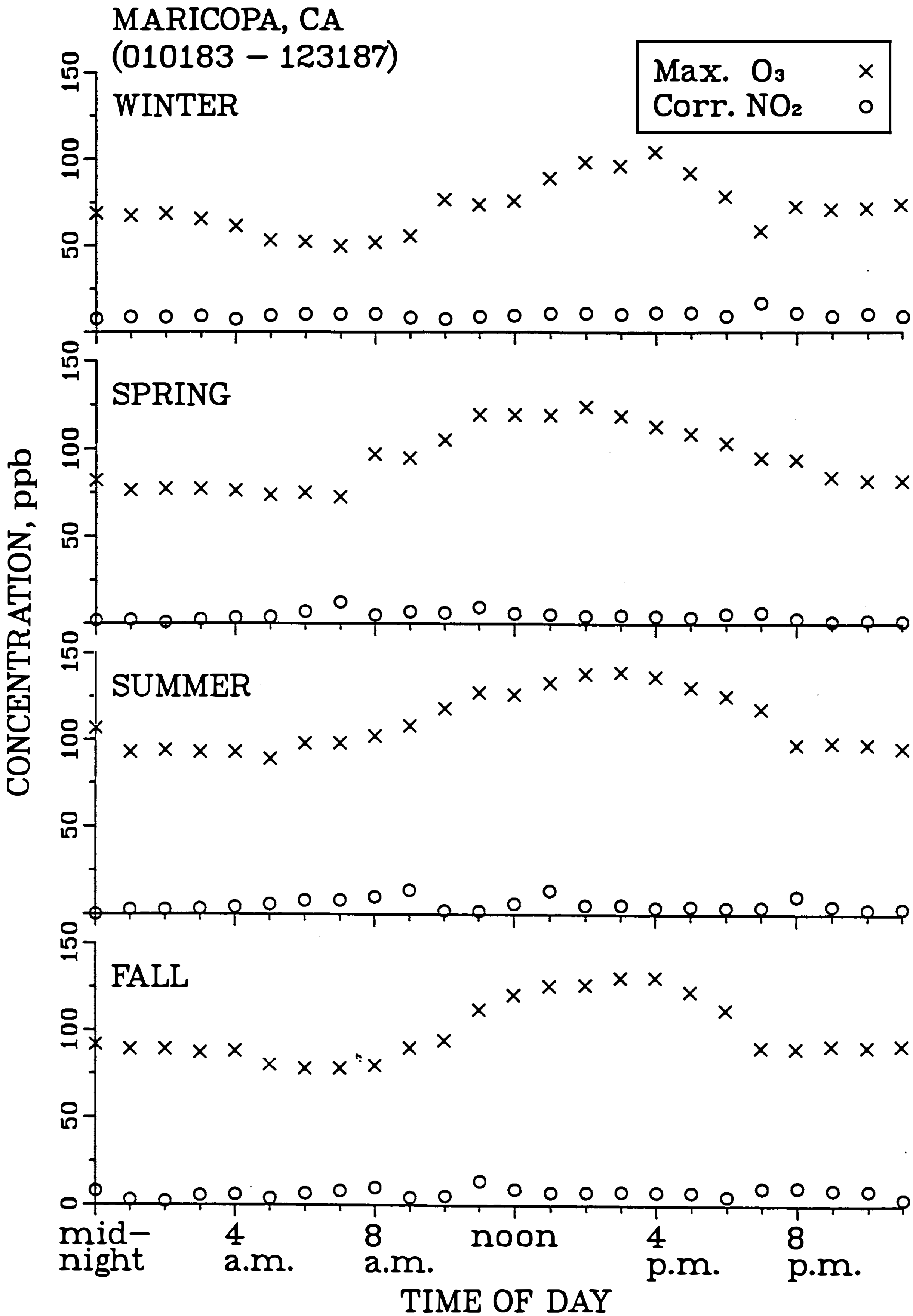


FIGURE B.15 SEASONAL MAXIMUM HOURLY O_3 CONCENTRATIONS AND CORRESPONDING NO_2 CONCENTRATIONS IN MARICOPA, CALIFORNIA, 1983-1987 (SOURCE: DEVELOPED FROM WOODWARD-CLYDE CONSULTANTS 1988)

TABLE B.12 Summary Statistics for ambient Suspended Particulate Matter (PM[10]) Concentrations at monitoring Stations in Kern County

Monitoring Station[a]	24-hour Concentration ($\mu g/m^3$)					Number of 24-hour Samples		
	First Highest	Second Highest	Lowest	Annual Mean				
				Geometric[b]	Arithmetic[c]	>50[d] $\mu g/m^3$	>150[e] $\mu g/m^3$	Total
Central Kern County								
Oildale	216	206	12	65.4	77.8	37	5	56
Bkrsfld-Chester	173	172	12	64.6	73.3	41	4	56
Western Kern County								
Kern Wildlife Refuge[f,g]	122	111	17	60.1[i]	67.9[i]	18	0	28
Kernridge[f,h]	393	281	14	85.4[i]	109.7[i]	22	6	29
McKittrick[f,g]	151	144	9	45.9[i]	53.6[i]	11	1	27
Fellows	247	118	19	62.6[i]	72.1[i]	20	1	26
Taft	244	151	11	50.5	59.6	30	2	57

[a]Monitoring stations operated by the state or local agencies unless otherwise noted.
[b]California ambient air quality standard for PM_{10} concentration is 30 $\mu g/m^3$.
[c]National ambient air quality standard for annual PM_{10} concentration is 50 $\mu g/m^3$.
[d]California 24-hour ambient air quality standard for PM_{10}.
[e]National 24-hour ambient air quality standard for PM_{10}.
[f]Monitoring stations operated by the Westside Operators.
[g]PM_{10} sampler installed during 1988.
[h]Sampling terminated during 1988.
[i]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness.

Sources: CARB Annual Report for 1988; Woodward-Clyde Consultants Annual Repoort for 1988.

B.3.4 Carbon Monoxide

Table B.13 shows the highest and the second highest values of 1-hour concentrations and 8-hour moving average concentrations of carbon monoxide (CO) measured in 1988 in central and western Kern County. Annual mean concentrations also are listed. As indicated, CO concentrations were substantially lower in western than in central Kern County.

The highest 1- and 8-hour CO concentrations measured at Bakersfield in central Kern County (12.0 ppm and 8.9 ppm) were both below the NAAQS (35 ppm for 1 hour and 9 ppm for 8 hours) and the California standard (20 ppm for 1 hour and 9 ppm for 8 hours).

The trends in the highest and second highest 1-hour concentrations and in the 8-hour moving mean concentrations (Figure B.16) show that the CO concentrations in central Kern county decreased steadily during the first half of the last decade and then leveled off after 1984. All the CO data used in constructing the trend lines came from the monitoring station in Bakersfield. Limited data available from the monitoring stations in western Kern County indicate the CO levels at these stations have remained unchanged or decreased slightly over the past several years (Woodward-Clyde Consultants 1988).

B.3.5 Nitrogen Dioxide

Table B.14 lists the highest and the second highest ambient 1-hour nitrogen dioxide (NO_2) concentrations measured in 1988 at stations in central and western Kern county, along with the annual mean concentration levels. The data show the NO_2 levels are lower in the western portion of the county. The highest annual mean NO_2 concentrations observed in 1988 were 0.032 ppm at Bakersfield in central Kern County and 0.012 ppm at Kernridge in western Kern County. The 0.012 ppm value is less than half the annual NAAQS for NO_2. The highest 1-hour NO_2 concentrations measured in 1988 in central and western Kern County were equal to or less than 0.12 ppm, which is also less than one-half of the California 1-hour standard for NO_2 (0.25 ppm).

The trends in the ambient NO_2 concentrations in central Kern County are shown in Figure B.17. The highest and the second highest 1-hour concentrations and the annual mean concentration have decreased steadily over the last 10 years. However, ambient NO concentrations have changed little during the most recent 5 years in both central and western Kern County.

B.3.6 Sulfur Dioxide

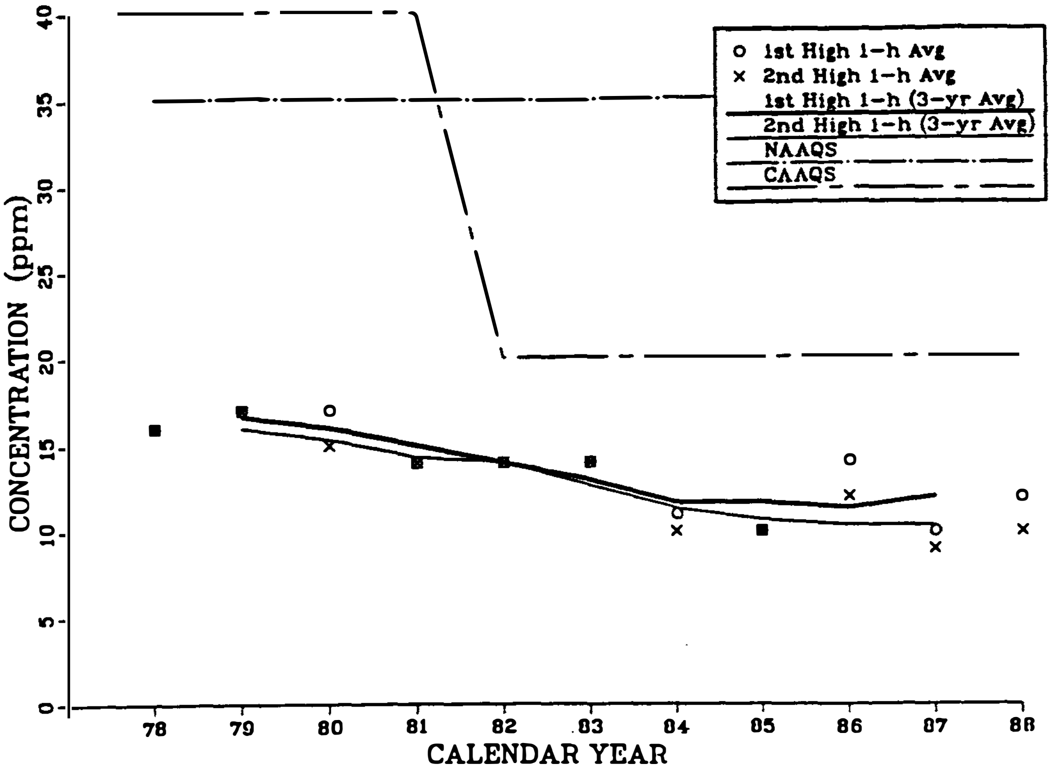
The annual summary statistics for sulfur dioxide (SO_2) concentrations measured in 1988 at monitoring stations in central and western Kern County are presented in Table B.15. Included are the highest and second highest values for 1-, 3-, and 24-hour mean concentrations and the annual mean concentrations.

TABLE B.13 Annual Summary Statistics for Ambient CO Concentrations at Monitoring Stations located in Kern County

Monitoring Station[a]	Concentration (ppm)						Number of 1-hour Samples
	1-hour[b]		8-hour Moving Mean[c]		Annual Mean		
	First Highest	Second Highest	First Highest	Second Highest	All Hours	Daily Maximum Hour	
Central Kern County							
Oildale	4.0	4.0[a]	2.7	2.4	0.63	1.33	8,207
Bakersfield-Chester	12.0	10.0	8.9	7.4	1.27	3.08	8,199
Western Kern County							
Kernridge[d]	3.7	2.5	1.3	1.3	0.37	0.72	8,386
McKittrick	2.0[g]	2.0[g]	1.1[g]	1.0[g]	0.13[g]	0.79[g]	1,605
McKittrick[d,e]	1.4[g]	1.3[g]	1.0[g]	1.0[g]	0.44[g]	0.76[g]	4,185
Fellows[d,f]	2.4[g]	2.3[g]	1.3[g]	1.3[g]	0.45[g]	0.82[g]	3,542

[a]Monitoring stations operated by the state or local agencies unless otherwise noted.
[b]California and national 1-hour ambient air quality standards for CO are 20 ppm and 35 ppm respectively.
[c]California and national 8-hour standards for CO are both 9.0 ppm.
[d]Monitoring stations operated by the Westside Operators.
[e]Monitor installed during 1988.
[f]Monitoring terminated during 1988.
[g]Data presented are valid but incomplete in that an insufficient number of valid data points were collected to meet EPA or CARB criteria for representativeness.

Sources: CARB Annual Report for 1988; Woodward-Clyde Consultants Annual Report for 1988.



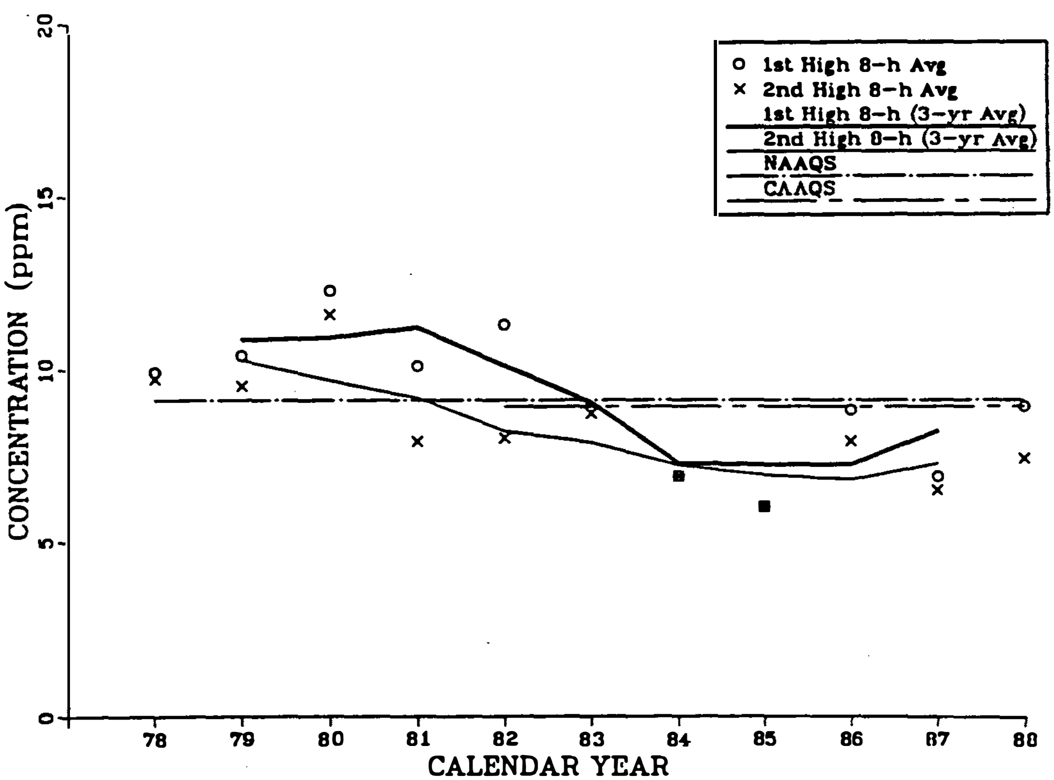


FIGURE B.16 TRENDS IN THE MAXIMUM 1-HOUR (TOP) AND 8-HOUR MOVING AVERAGE (BOTTOM) CO CONCENTRATIONS IN CENTRAL KERN COUNTY (SOURCE: DEVELOPED FROM CARB 1987-1988)

TABLE B.14 1988 Annual Summary Statistics for Ambient NO_2 Concentrations at Monitoring Stations in Kern County

Monitoring Station[a]	Concentration (ppm)				
	1-Hour[b]		Annual Mean[c]		
	First Highest	Second Highest	All Hours	Daily Max. Hour	Number of 1-hour Samples
Central Kern County					
Oildale	0.11	0.09	0.023	0.044	8,029
Bakersfield-Chester	0.12	0.12	0.032	0.063	8,219
Western Kern County					
Kern Wildlife Refuge[d,e]	0.04[g]	0.04[g]	0.007[g]	0.016[g]	4,674
Lost Hills[d,f]	0.06[g]	0.05[g]	0.009[g]	0.023[g]	3,505
Kernridge[d]	0.08	0.08	0.012	0.029	8,372
McKittrick	0.06[g]	0.05[g]	0.011[g]	0.028[g]	1,273
McKittrick[d,f]	0.06[g]	0.06[g]	0.009[g]	0.023[g]	3,980
Derby Acres[d,f]	0.06[g]	0.06[g]	0.010[g]	0.024[g]	4,066
Fellows[d,e]	0.08[g]	0.07[g]	0.017[g]	0.038[g]	3,503
Maricopa[d]	0.07	0.05	0.0011	0.024	8,030

[a]Monitoring stations operated by the state or local agencies unless otherwise noted.
[b]California 1-hour ambient air quality standard for NO_2 is 0.25 ppm.
[c]National annual ambient air quality standard for NO_2 is 0.05 ppm.
[d]Monitoring stations operated by the Westside Operators.
[e]Monitor installed during 1988.
[f]Monitoring terminated during 1988.
[g]Data presented are valid but incomplete in that an insufficient number of valid data points were collected to meet EPA or CARB criteria for representativeness.

Sources: CARB Annual Report for 1988; Woodward-Clyde Consultants Annual Report for 1988.

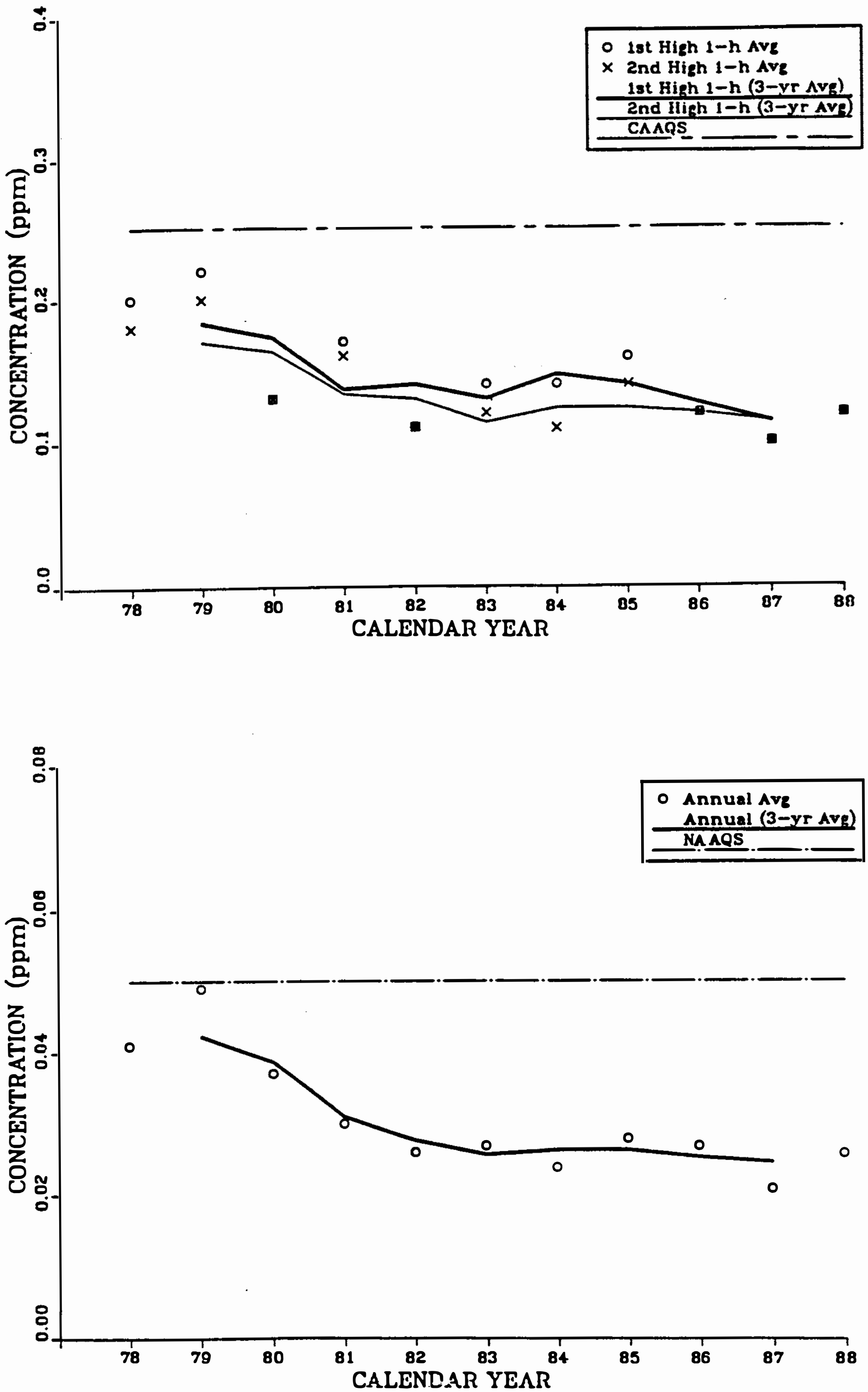


FIGURE B.17 TRENDS IN THE MAXIMUM HOURLY (TOP) AND ANNUAL (BOTTOM) MEAN NO_2 CONCENTRATIONS IN CENTRAL KERN COUNTY (SOURCE: DEVELOPED FROM CARB 1978-1988

TABLE B.15 1988 Annual Summary Statistics for Ambient SO^2 Concentrations at Monitoring Stations in Kern County

Monitoring Station[a]	Concentration (ppm)[b]					Number of 1-hour Samples
	1-hour	3-hour	24-hour	Annual Mean		
				All Hours	Daily Maximum Hour	
Central Kern County						
Oildale	0.07/0.07[c]	-[d]	0.017/0.017	0.005	0.019	7,911
Bakersfield-Chester	0.04/0.03	-	0.025/0.022	0.005	0.013	8,118
Western Kern County						
Kern Wildlife Refuge[e,f]	0.02/0.01[g]	0.014/0.014[g]	0.011/0.011[g]	0.003[g]	0.005[g]	3,669
Lost Hills[e,h]	0.03/0.02[g]	0.025/0.019[g]	0.011/0.011[g]	0.003[g]	0.006[g]	3,392
Kernridge[e]	0.12/0.10	0.082/0.080	0.027/0.027	0.005	0.020	8,135
Cymric[e,h]	0.08/0.07[g]	0.074/0.069[g]	0.028/0.028[g]	0.003[g]	0.010[g]	3,828
McKittrick[e]	0.09.0.07	0.068/0.049	0.026/0.026	0.003	0.015	8,315
McKittrick	0.06/0.04[g]	-	0.017/0.012[g]	0.002[g]	0.013[g]	1,603
Derby Acres[e,h]	0.13/0.12[g]	0.105/0.098[g]	0.036/0.036[g]	0.005[g]	0.021[g]	4,240
Fellows[e]	0.12/0.12	0.081/0.080	0.029/0.029	0.009	0.033	8,044

[a]Monitoring stations operated by the state or local agencies unless otherwise noted.
[b]California ambient air quality standards for SO_2 are 0.25 ppm for 1-hour concentration and 0.05 ppm for 24-hour concentrations. National ambient air quality standards for SO_2 are 0.14 ppm and 0.03 ppm for 24-hour and annual concentrations, respectively (primary standards), and 0.5 ppm for 3-hour concentration (secondary standard).
[c]Values such as 0.07/0.07 represent the first and second highest concentrations.
[d]Data not available.
[e]Monitoring stations operated by the Westside Operators.
[f]Monitor installed during 1988.
[g]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness.
[h]Monitoring terminated during 1988.

Sources: CARB Annual Report for 1988; Woodward-Clyde Consultants Annual Report for 1988.

The SO_2 concentrations measured both in central and western Kern County were all well below applicable national and California standards. The highest annual mean concentration of 0.009 ppm observed at the Fellows station was only a fraction of the applicable primary NAAQS of 0.03 ppm. The highest 24-hour mean concentration of 0.029 ppm measured at Fellows also was well below the applicable primary NAAQS of 0.14 ppm and the CAAQS of 0.05 ppm. The maximum 3-hour concentration (0.082 ppm) was less than one-fifth of the applicable secondary NAAQS (0.5 ppm), and the maximum 1-hour concentration (0.12 ppm) was about one-half the applicable California standard (0.25 ppm).

Sulfur dioxide concentrations in central Kern County have decreased steadily over the last 10 years. Figure B.18 shows the trends in the highest and second highest 24-hour mean SO_2 concentrations measured in central Kern County. Similar trends are shown by the highest annual mean SO_2 concentration and the highest annual mean value of daily maximum 1-hour concentrations. Data for a more limited period at the monitoring stations in western Kern County indicate that ambient SO_2 concentrations have remained unchanged or decreased slightly during the last 9 years (Woodward-Clyde Consultants 1988).

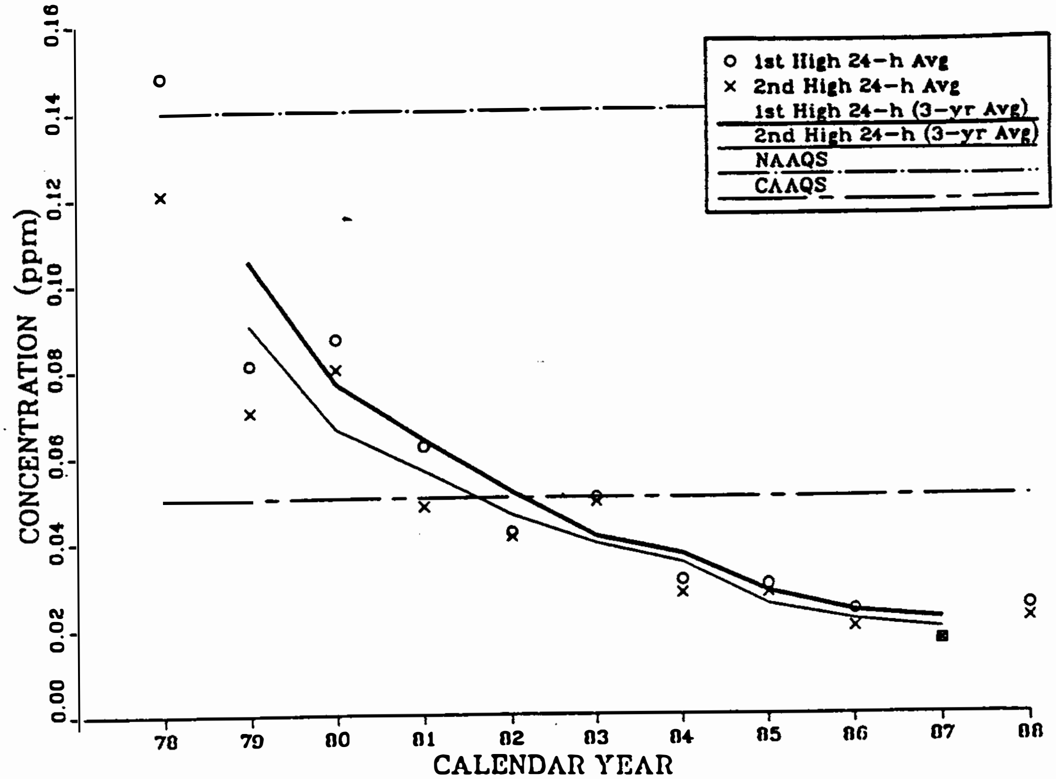
B.3.7 Hydrogen Sulfide

Although a California standard for hydrogen sulfide (H_2S) has been established no formal stations have been established to monitor H_2S in the Kern County portion of the San Joaquin Valley Air Basin.

B.3.8 Lead

The monthly and quarterly mean concentrations of lead (Pb) (associated with total suspended particulates) measured in 1988 at monitoring stations in central and western Kern county are listed in Table B.16. The highest quarterly mean Pb concentration observed was 0.13 $\mu g/m^3$ in western Kern County. This value is a small fraction of the applicable NAAQS (1.5 $\mu g/m^3$). The highest monthly mean Pb concentrations are similar to the highest quarterly mean concentrations, which are again only a small fraction of the applicable California state standard (1.5 $\mu g/m^3$).

The trend of decreasing Pb concentrations in central Kern County over the last decade is illustrated in Figure B.19, which plots the highest quarterly Pb concentrations from 1978 through 1988 and a line connecting their 3-year moving mean values. During the early 1980s, Pb concentrations in western Kern County were only a fraction of the levels measured in central Kern County. Western Kern County concentrations decreased slightly in the early 1980s and have remained almost constant at about 0.1 $\mu g/m^3$ (quarterly mean value) (CARB 1978-1988).



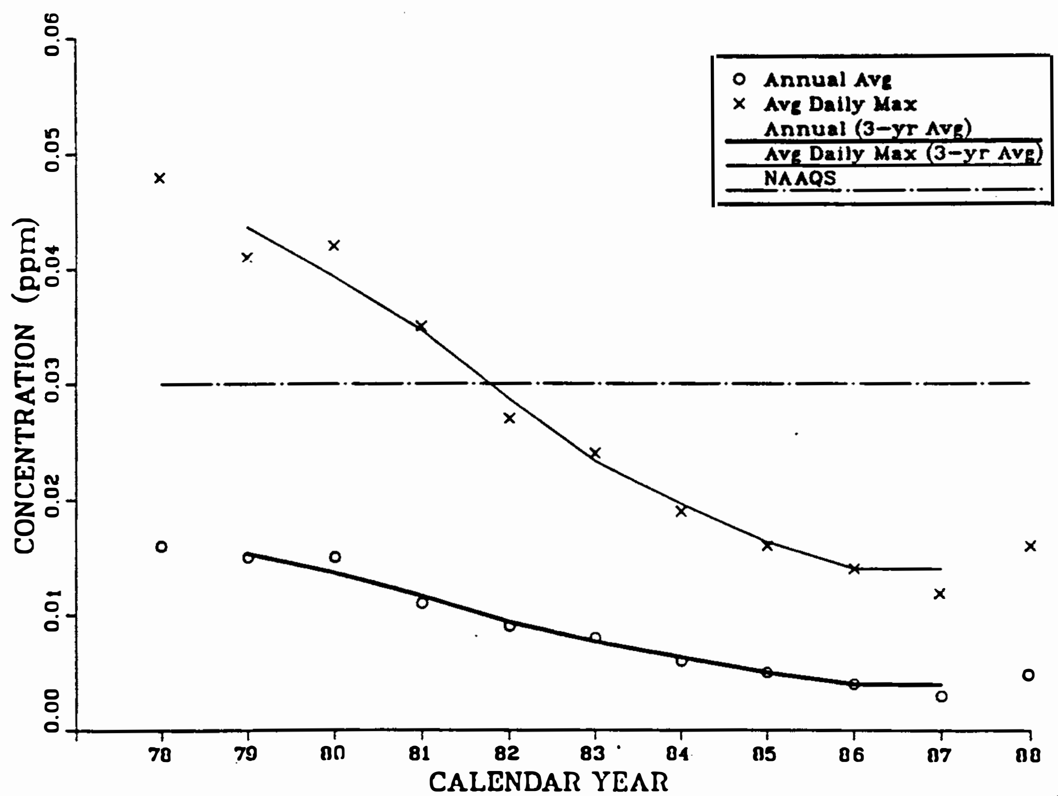


FIGURE B.18 TRENDS IN THE MAXIMUM 24-HOUR (TOP) AND ANNUAL (BOTTOM) MEAN SO_2 CONCENTRATIONS IN KERN COUNTY (SOURCE: DEVELOPED FROM CARB 1978-1988)

TABLE B.16 1988 Monthly and Quarterly Means of Ambient Lead Concentrations at Monitoring Stations in Kern County

Monitoring Station[a]	Concentration ($\mu g/m^3$)[b]						Number of 24-hour Samples
	Monthly Mean		Quarterly Mean				
	First Highest	Second Highest	First	Second	Third	Fourth	
Central Kern County							
Kern Refuge	0.13	0.12	0.12	0.12	0.12[c]	0.12[c]	52
Bksfld-Chester	0.06	0.06	0.05[c]	0.04[c]	0.05	0.06	51
Bksfld-Flower	0.12	0.12	0.12	0.11[c]	0.12[c]	0.11	52
Western Kern County (Taft)	0.13	0.13	0.12	0.12	0.13[c]	0.12	54

[a]All monitoring stations are operated by the state or local agencies.

[b]California ambient air quality standard for the monthly mean lead concentration and national ambient air quality standard for quarterly mean lead concentration are both 1.5 $\mu g/m^3$.

[c]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness.

Source: CARB Annual Report for 1988.

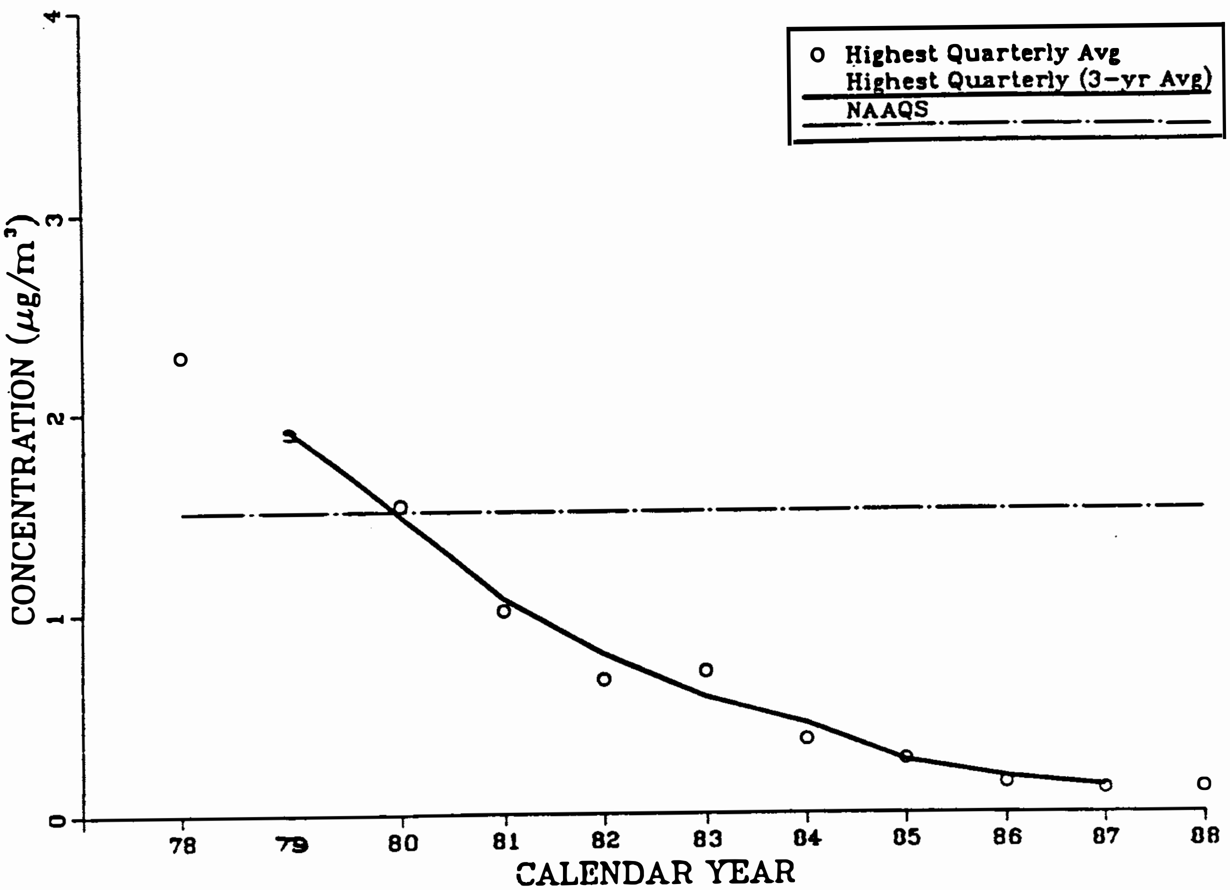


FIGURE B.19 TREND IN THE MAXIMUM QUARTERLY MEAN Pb CONCENTRATION IN CENTRAL KERN COUNTY (SOURCE: DEVELOPED FROM CARB 1978-1988)

B.3.9 Sulfate

No national ambient air quality standard exists for suspended sulfates (SO_4) associated with either PM_{10} or TSP. However, a California state standard does exist. The standard is for sulfate associated with the 24-hour standard for TSP measured using a high-volume sampler (25 $\mu g/m3$). The highest 24-hour total suspended sulfate concentration measured in 1988 in central and western Kern County (19.9 $\mu g/m^3$) was about 80% of the state standard Table B.17). The California state sulfate standard was exceeded in Kern County until 1985 (Figure B.20). However, decreasing sulfate concentrations during the past several years have reduced the ambient levels to below the state standard for three consecutive years (1986-1988), both in central and western Kern County.

Although no ambient air quality standards exist for sulfate anions associated with PM_{10}, these anions do contribute to the PM_{10} concentration. Table B.18 shows the 1988 summary statistics for ambient sulfate concentrations associated with PM_{10} at the monitoring stations in central and western Kern County. The highest 24-hour concentration of PM_{10} sulfate in 1988 was about 20 $\mu g/m^3$, or about 40% and 13%, respectively, of the state and national standards for the 24-hour PM_{10} concentration. Annual geometric and arithmetic mean concentrations of PM_{10} sulfate ranged from 3 to 6 $\mu g/m^3$, which amount to about 15% and 10% of the CAAQS and NAAQS, respectively.

B.3.10 Nitrate

Ambient air quality standards have not been established for nitrate (NO_3) anions associated with either TSP or PM_{10}. However, NO_3 has been identified as perhaps one of the most widespread and dominant of the secondary PM_{10} constituents in California. The 1988 annual statistics for ambient PM_{10} nitrate concentrations at monitoring stations in central and western Kern County are presented in Table B.19.

The highest PM_{10} nitrate concentrations in 1988 were on the order of 70 $\mu g/m^3$ in central Kern County and 50 $\mu g/m^3$ in western Kern County. These levels amount to about 140% and 50% of the CAAQS and NAAQS for the 24-hour PM_{10} concentration, respectively, for central Kern County; and about 100% and 30%, respectively, for western Kern County. Annual geometric mean concentrations of PM_{10} nitrate were about 5 $\mu g/m^3$ in central Kern County and 3 $\mu g/m^3$ in western Kern County. These levels correspond to 10-15% of the CAAQS for PM_{10}. The annual arithmetic mean concentration of PM_{10} nitrate was about 9 $\mu g/m^3$ in central Kern County and about 6 $\mu g/m^3$ in western Kern County. These concentration levels are 10-20% of the NAAQS for PM_{10}. However, these values must be evaluated carefully because PM_{10} nitrate sampling is subject to substantial positive or negative artifact information.

TABLE B.17 1988 Annual Summary of Statistics for Ambient Total Suspended Particulate Sulfate Concentrations at Monitoring Stations in Kern County

Monitoring Station[a]	24-hour Concentration ($\mu g/m^3$)[b]				Number of 24-hour Samples
	First Highest	Second Highest	Lowest	Annual Geometric Mean	
Central Kern County					
Kern Refuge	9.5	8.6	0.8	3.87[c]	52
Oildale	19.9	16.2	2.9	7.32[c]	50
Bakersfield-Chester	15.3	12.7	2.6	6.39[c]	51
Bakersfield-Flower	14.5	11.8	3.9	6.15[c]	52
Western Kern County					
Kernridge[d,e]	18.9	14.8	1.5	5.79[c]	29
McKittrick[e]	7.6	7.1	6.2	6.94[c]	3
McKittrick[d,e]	12.5	12.1	1.1	3.05[c]	28
Derby Acres[d,e]	11.7	6.8	1.3	3.23[c]	30
Fellows[d,e]	14.0	9.9	2.3	4.99[c]	25
Taft	19.6	14.9	3.6	7.88[c]	54
Maricopa[d]	13.2	6.0	0.7	3.02	60

[a]Monitoring stations operated by the state or local agencies unless otherwise noted.
[b]California ambient air quality standard for 24-hour sulfate concentration is 25 $\mu g/m^3$. There is no national standard for sulfate.
[c]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness.
[d]Monitoring stations operated by the Westside Operators.
[e]Sampling terminated during 1988.
[f]Sampler installed during 1988.

Sources: CARB Annual Report for 1988; Woodward-Clyde Consultants Annual Report for 1988.

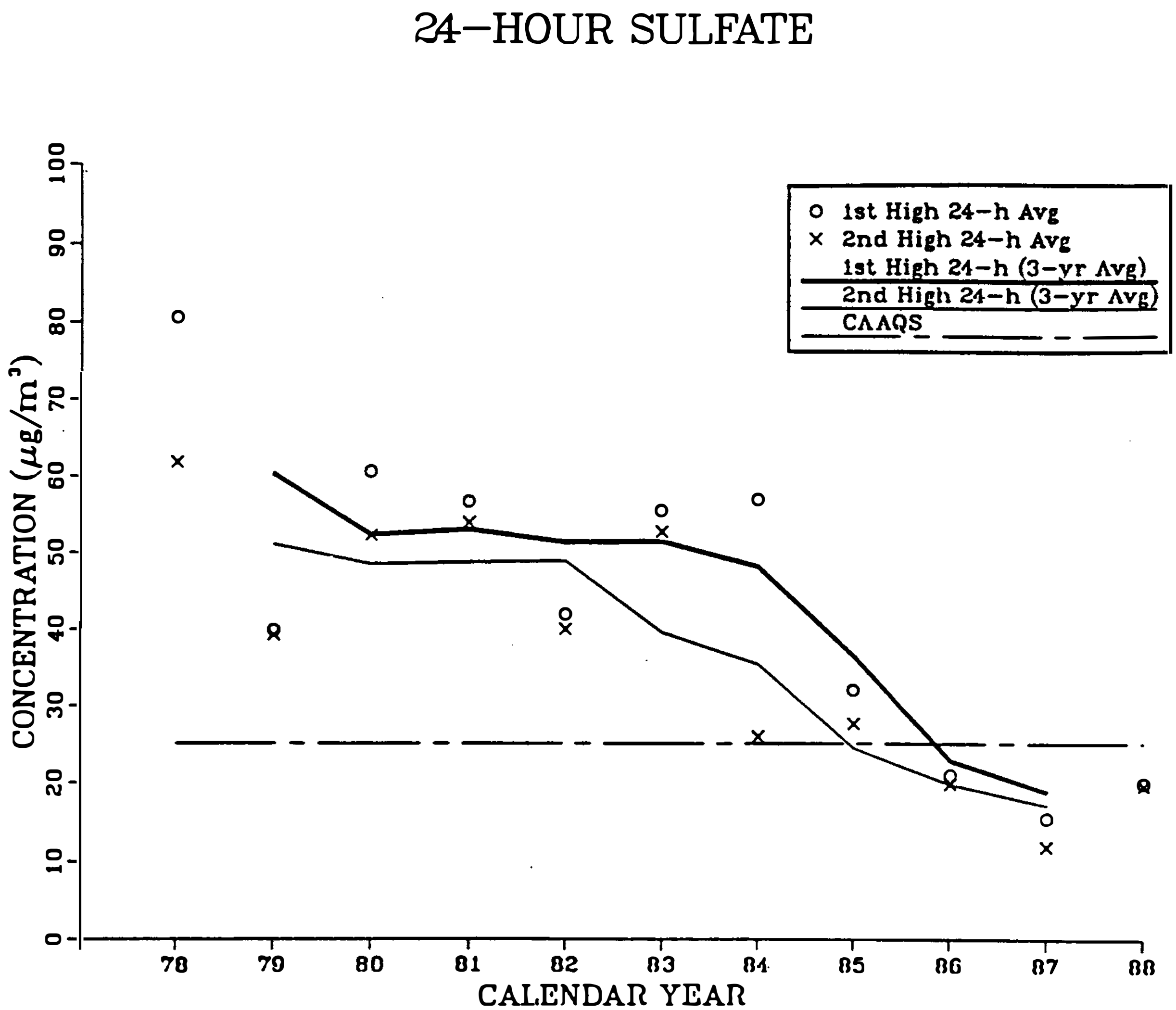


FIGURE B.20 TRENDS IN THE MAXIMUM 24-HOUR SULFATE CONCENTRATION IN CENTRAL KERN COUNTY (SOURCE: DEVELOPED FROM CARB 1978-1988)

TABLE B.18 1988 Annual Summary Statistics for Ambient 10-μm Particulate (PM^{10}) Sulfate Concentrations at Monitoring Stations in Kern County.

Monitoring Station[a]	24-hour Concentration ($\mu g/m^3$)					Number of 24-hour Samples
	First Highest	Second Highest	Lowest	Annual Geometric Mean	Annual Arithmetic Mean	
Central Kern County						
Oildale	14.6	13.2	1.3	4.31[b]	5.06[b]	56
Bakersfield-Chester	9.9	9.8	1.6	3.65[b]	4.08	56
Western Kern County						
Kern Wildlife Refuge[c,d]	9.3	6.4	1.0	2.82[b]	3.32[b]	28
Kernridge[c,e]	20.3	16.3	1.6	5.24[b]	6.18[b]	29
McKittrick[c,e]	13.1	12.5	1.1	2.79[b]	3.69[b]	27
Fellows[c,d]	13.6	8.8	2.2	4.96[b]	5.33[b]	26
Taft	14.7	11.1	1.6	4.06	4.64	57

[a]Monitoring stations operated by the state or local agencies unless otherwise noted.
[b]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness.
[c]Monitoring stations operated by the Westside Operators.
[d]Sampler installed during 1988.
[e]Sampling terminated during 1988.

Sources: CARB Annual Report for 1988; Woodward-Clyde Consultants Annual Report for 1988.

TABLE B.19 Annual Summary Statistics for Ambient 10-μm Particulate (PM_{10}) Nitrate Concentrations at Monitoring Stations in Kern County

Monitoring Station[a]	24-hour Concentration ($\mu g/m^3$)					Number of 24-hour Samples
	First Highest	Second Highest	Lowest	Annual Geometric Mean	Annual Arithmetic Mean	
Central Kern County						
Oildale	71.7	59.1	0.6	4.52[b]	9.21[b]	54
Bakersfield-Chester	52.2	48.8	1.1	4.87[b]	8.86[b]	56
Western Kern County						
Taft	49.0	37.0	0.6	3.19[b]	6.02	55

[a]Monitoring stations operated by the state or local agencies.
[b]Data presented are valid but incomplete in that insufficient data points were collected to meet EPA or CARB criteria for representativeness.

Sources: CARB Annual Report for 1988; Woodward-Clyde Consultants Annual Report for 1988.

B.3.11 Toxic Air Contaminants

Ambient concentrations of toxic air contaminants or hazardous air pollutants (see Table B.7) are not routinely measured at the air quality monitoring stations operated by the Westside Operators or by state or local agencies. However, ambient concentrations of a number of toxic air contaminants (identified by CARB and designated by EPA) and other organic compounds were measured at several solid-waste disposal sites on NPR-1 during the summer of 1987. Table B.20 lists the 24-hour mean ambient concentrations of these compounds measured upwind and downwind of the disposal sites, the detection limits of the measurement methods used, and 8-hour time-weighted average (TWA) threshold limit values (TLVs) for these compounds.

Detectable amounts of benzene (0.4 to 21 ppb) and carbon tetrachloride (0.07 to 0.1 ppb) were found at all four sites; however, chloroform, 1,2-dichloroethane, and ethylene dibromide were not detected at any site. Other compounds listed in Table B.20 were detected at some sites but not at others. The detected concentrations are all very low, at least more than an order of magnitude smaller than the applicable TWA TLVs.

B.3.12 Visibility

The topographical and climatic features that affect the visibility in the southern San Joaquin Valley are discussed in detail in the 1979 EIS for NPR-1 (DOE 1979). Haze and smog, which are caused by the accumulation of aerosols in the southern San Joaquin Valley, often obscure the views from NPR-1. In addition, dense fogs that often occur on the valley floor during the winter also obstruct views and reduce visibility. The closest National Weather Service station where visibility is routinely measured is at Meadows Field near Bakersfield, about 20 miles east of NPR-1. During 1987, visibility there was 6 miles or less about 15% of the time and 15 miles or less about 65% of the time. Although climatic conditions at the National Weather Service station are comparable to those at the NPR-1 site, localized visibilities experienced in the vicinity of NPR-1 probably vary somewhat from those at Meadows Field.

Trends in visibility at several National Weather Service stations in the San Joaquin Valley have been discussed in detail by CARB (Duckworth and Kinney 1978; Kinney and Grauman 1986). The indicator used by CARB to show these trends was the percent of time when the prevailing visibilities did not meet the California state standard (termed adverse visibility). Adverse conditions occur when the concentration of visibility-reducing particles is sufficient to lower the prevailing visibility to less than 10 miles when relative humidity is less than 70%. The trend of visibility conditions at Meadows Field up to 1987 is shown in Figure B.21. The indicator used in the figure is the percent of time with prevailing visibility of less than 6 miles (rather than 10 miles) at 1 p.m. when the relative humidity is less than 70%. For Meadows Field, the 6 miles visibility value is considered a much more accurate indicator than the 10 miles value used in defining adverse visibility. The reasons for this are that (1) there are no good markers between 7 and 10 miles from the observer location; and

TABLE B.20 Ambient Concentrations of Toxic Air Contaminants and Other Organic Compounds at Several Solid-Waste Disposal Sites[a] on NPR-1

Compound	24-hour Mean Ambient Concentration (ppb)								Method Detection Limit (ppb)[d]	8-hour Time-Weighted Threshold Limit Value (ppm)
	Site 26S East[e]	Site 26S West[e]	Site 27R[b]				Site 35R			
			Upwind	Downwind						
				Site 1	Site 1A[c]	Site 2	Upwind	Downwind		
Benzene	0.4	1.6	0.4	14	21.0	1.0	0.9	0.7	1.0	10
Carbon Tetrachloride	0.07	0.1	0.1	ND	0.1	0.07	0.05	0.08	0.07	5
Chloroform	ND[f]	ND	ND	ND	ND	ND	ND	ND	0.09	10
1,2 dichloroethane	ND	ND	ND	ND	ND	ND	ND	ND	0.1	200
Ethylene dibromide	ND	ND	ND	ND	ND	ND	ND	ND	0.06	-
Methylene chloride	ND	ND	ND	2.0	2.4	ND	98	4.2	1.00	50
Tetrachloroethylene (PCE)	ND	ND	ND	ND	0.08	0.1	0.2	0.2	0.1	50
1,1,1-trichloroethane (TCA)	ND	1.3	0.2	0.5	0.6	0.6	2.3	1.8	0.08	10
Trichloroethylene (TCE)	0.2	0.4	ND	ND	0.1	ND	0.9	0.4	0.09	50
Vinyl Chloride	ND	35.0	ND	ND	ND	ND	ND	ND	0.2	5

[a]Figure 4.1.2-1 shows the sections where these solid waste diposal sites are located.
[b]Maximum values for three measurements made during three consecutive days.
[c]Duplicate measurements for site 1.
[d]Largest among the values given for several different measurements.
[e]Downwind
[f]ND = Not Detected

Source: Mark Group 1987; Anthrosphere 1987a-c.

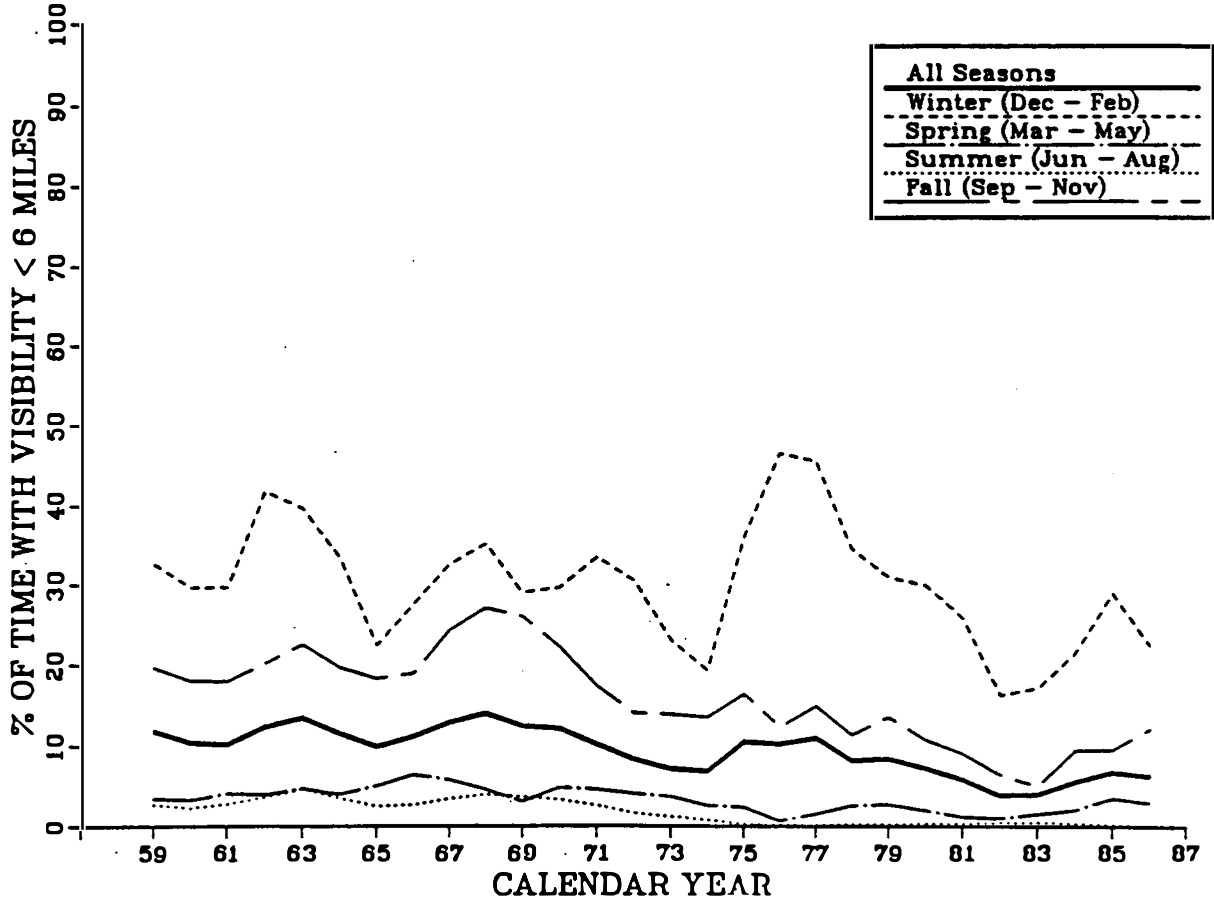


FIGURE B.21 TRENDS IN VISIBILITY AT THE BAKERSFIELD AIRPORT (3-YEAR MOVING AVERAGE OF THE PERCENT OF TIME WITH MIDDAY VISIBILITY LIMITED TO LESS THAN 6 MILES) (SOURCE: DEVELOPED FROM NATIONAL CLIMATIC CENTER 1988)

(2) all visibility data equal to or greater than 7 miles were recorded as 7 miles during the 1978-1979 period. The visibility at 1 p.m. was selected because the midday period provides the most data with relative humidity less than 70%. The 3-year moving means of the selected indicator for each season and annual period show that visibility may have been improving somewhat during the last decade.

B.4 ATMOSPHERIC EMISSIONS AT NPR-1

Table B.21 lists, by source, the current estimated atmospheric emissions of ROG, NO_x, CO, SO_2, TSP, and PM_{10} at NPR-1. To the extent possible, the table given is the general location (by section designation) of each source; the number of units of each equipment type, and the overall capacity or level of activity. Emission rates are given in pounds per hour and represent annual average values that were obtained from total annual emission divided by 24 x 365 = 8,760 h/yr. The emission estimates shown in Table B.21 reflect the most recent activities and up-to-date information on emission factors that could be obtained. The activity data used in the calculation of these estimates is, for the most part, characteristic of the period 1987-1989.

An attempt was made to make the compilation of emissions at NPR-1 as comprehensive as possible. Consequently, many sources listed in the table are not currently subject to permitting requirements for either Kern County or the EPA. The sources listed include those that are currently in continuous or intermittent use and those that are not currently used but that could be brought into use quickly and for which there are no immediate plans for removal. Other sources that have been considered in the past but are no longer operable (the old 3G gas plant, for example) or that are reserve units currently in storage are not included in Table B.21.

Although the emission estimates in Table B.21 are based on the best and most recent information available, the inherent uncertainties are not necessarily small or uniform across source types. The quality of the emission factors used varies from good to poor, depending on the type of source. Significant variations in emissions can be found in test results on otherwise apparently identical sources. In this case, the total estimated emissions from a large number of sources is more accurate than the emissions estimated for an individual source. Also, the relevant level of activity at NPR-1 was well-known in some cases, but more uncertain in others.

The emission estimates in Table B.21 are based where possible on actual emission test results or an actual gas-metering data, as appropriate; this is the case for NO_x, ROG, and CO emissions from the compressor engines involved in the NPR-1 NO_x-reduction program. When direct emission measurements were not available, permitted limits or manufacturer's data were used if possible. This is important when, as in the case of the low NO_x burner used in the 3G steam generator, some type of emission-control technology is being used. If none of the above information was available, the emission factors tabulated by the EPA (1985) were used.

TABLE B.21 Existing Source Emissions at NPR-1

PART A: Stationary Combustion Sources[a]

Source Category	Capacity	Emission Rate (lb/h)					
		ROG	NO_x	CO	SO_2	TSP	PM_{10}
Compressor engines							
7R (2)	2,000[b]	4.92	48.50	220.46	0.008	0.040	0.040
17R (4)	2,950[b]	7.17	38.79	26.01	0.013	0.065	0.065
30R (10)	10,000[b]	24.60	176.40	88.20	0.040	0.200	0.200
33R (1)	650[b]	1.57	15.76	8.60	0.003	0.015	0.015
33S (5)	9,000[b,c]	19.76	35.28	88.20	0.032	0.160	0.160
35R HPI (3)	12,000[b]	46.35	52.92	132.27	0.048	0.231	0.228
35R gas plant (13)	17,490[b]	56.31	324.86	111.78	0.073	0.349	0.347
35R LTS 1 (4)	18,500[b]	69.20	81.57	203.94	0.074	0.355	0.355
35R LTS 2 (4)	18,500[b]	69.20	81.57	203.94	0.074	0.355	0.355
35R Area (6)	4,000[b]	9.84	38.82	44.08	0.016	0.084	0.084
36R (5)	5,000[b]	12.30	61.74	44.10	0.020	0.100	0.100
Subtotals	100,090[b]	321.22	956.21	1,171.58	0.401	1.954	1.949
Boilers and heaters							
35R gas plant							
Boilers (3)	136[d,c]	0.10	5.23	1.31	0.022	0.112	0.111
Regen. heater (1)	1[d]	0.01	0.10	0.02	0.001	0.003	0.003
Rich oil heaters (2)	38[d]	0.09	5.06	1.27	0.022	0.109	0.108
35R LTS 1 process heaters (2)	55[d]	0.15	7.33	1.83	0.031	0.157	0.156
35R LTS 2 process heaters (2)	55[d]	0.15	7.33	1.83	0.031	0.157	0.156

TABLE B.21 (Cont'd)

PART A (Cont'd)

Source Category	Capacity	Emission Rate (1b/h)					
		ROG	NO_X	CO	SO_2	TSP	PM_{10}
3G steam generator (1)	62.5[d]	0.10[f]	4.70	0.75	0.024	0.280	0.280
LACT even-flux heaters							
18G (6)	72[d]	0.11[f]	2.40	0.60	0.010	0.051	0.051
10G (1)	12[d]	0.02[f]	0.40	0.10	0.002	0.009	0.009
24Z (1)	12[d]	0.02[f]	0.40	0.10	0.002	0.009	0.009
Glyco reboilers (9)	6.7[d]	0.13[f]	0.64	0.13	0.004	0.019	0.019
Closed-loop gas-lift heaters							
8G (1)	0.585[d]	0.30[f]	0.06	0.01	0.000	0.002	0.002
33G (1)	1.320[d]	0.45[f]	0.13	0.03	0.001	0.004	0.004
Subtotals	452.1	1.63	33.78	7.98	0.150	0.912	0.908
Flares							
LTS LP (2)	62[g]	0.15	2.79	0.58	0.016	0.140	0.140
LTS HP (2)	184[g]	0.43	8.07	1.61	0.048	0.404	0.404
HPI (1)	50[g]	0.12	2.21	0.44	0.013	0.111	0.111
24Z (1)	0.015[h]	0.00	0.06	0.01	0.000	0.003	0.003
Subtotals		0.70	13.13	2.64	0.077	0.658	0.658

TABLE B.21 (Cont'd)

PART A (Cont'd)

Source Category	Capacity	Emission Rate (lb/h)					
		ROG	NO_x	CO	SO_2	TSP	PM_{10}
Pump engines							
35R gas plant (4)	900[b]	2.08[f]	21.60	2.79	0.004	0.022	0.022
3G Water injection (3)	1,290[b]	2.94[f]	30.96	4.00	0.005	0.028	0.028
Tank setting/LACT (24)	2,918[b]	1.82[f]	16.66	2.15	0.003	0.018	0.018
Wells (156)	12,887[b]	19.11[f]	185.57	23.97	0.031	0.191	0.190
Subtotal	17,995[b]	25.95	254.79	32.91	0.043	0.259	0.258
Miscellaneous field engines							
Gas-fired (6)	2,025[b,i]	0.04	0.09	0.01	0.000	0.000	0.000
Diesel (3)	930[b,i]	0.00	0.09	0.02	0.006	0.006	0.006
Gasoline (19)	122[b,j]	0.02	0.01	0.54	0.001	0.001	0.001
Subtotals	3,077	0.06	0.19	0.57	0.007	0.007	0.007
Fugitive emissions (compressor engines)							
7R		0.32					
17R		0.46					
30R		2.72					
33R		0.16					
33S		1.01					
35R HPI		1.27					
35R gas plant		9.96					
35R LTS 1		3.71					
35R LTS 2		3.71					

TABLE B.21 (Cont'd)

PART A (Cont'd)

		Emission Rate (1b/h)					
Source Category	Capacity	ROG	NO_x	CO	SO_2	TSP	PM_{10}
35R area		1.41					
36R		1.07					
Subtotals		25.80					
TOTAL (Part A)		375.36	1,258.10	1,215.68	0.678	3.790	3.780

Footnotes for Part A: Stationary Combustion Sources

[a]Total current hydrogen sulfide (H_2S) emissions are 0.001 1b/h from fugitive emissions.

[b]Horsepower.

[c]One 1,000-hp engine on standby only; four 2,000-hp engines run continuously

[d]10^6 Btu/h heat input.

[e]Two of the three boilers on standby only.

[f]ROG estimates include contributions from fugitive emissions.

[g]10^6 ft^3/day capacity; design operation time = 15 minutes per day.

[h]10^6 ft^3/day flared during 1987.

[i]Based on 16 hours of operation per year for testing purposes.

[j]Based on 1 % duty factor

TABLE B.21 (Cont'd)

PART B: Drilling, Construction[a], and Maintenance

Source Category	Capacity	Emission Rate (lb/h) ROG	NO_X	CO	SO_2	TSP	PM_{10}
New well drilling							
Equipment operation							
Deep STV/CAR	1,751[b]	3.3	43.3	9.3	2.9	3.1	3.0
Shallow STV	1,353[b]	2.6	33.4	7.2	2.2	2.4	2.3
SOZ	585[b]	1.1	14.5	3.1	1.0	1.0	1.0
Subtotal		7.0	91.2	19.6	6.1	6.5	6.3
Moving							
Deep STV/CAR	61.8[b]	0.2	1.9	0.4	0.1	0.1	0.1
Shallow STV	57.4[b]	0.1	1.8	0.4	0.1	0.1	0.1
SOZ	7.0[b]	0	0.2	0.1	0	0	0
Subtotal		0.3	3.9	0.8	0.3	0.3	0.3
Site Preparation							
Equipment operation	[c]	0.4	4.9	1.1	0.3	0.4	0.3
Fugitive dust	1.0[d]	0	0	0	0	2.0	0.4
Subtotal		0.4	4.9	1.1	0.3	2.4	0.7
Subtotals		7.7	100.0	21.5	6.7	9.2	7.3
Remedial work, new well completion, routine well pulling							
Equipment operation	2,888.6[b]	5.7	73.6	15.9	4.9	5.2	5.1
Moving	37.9[b]	0.1	1.2	0.3	0.1	0.1	0.1

TABLE B.21 (Cont'd)

PART B (Cont'd)

		Emission Rate (1b/h)					
Source Category	Capacity	ROG	NO_X	CO	SO_2	TSP	PM_{10}
Site preparation[c]							
Equipment operation	f	0.2	2.4	0.5	0.2	0.2	0.2
Fugitive dust	0.06[d]	0	0	0	0	1.0	0.2
Subtotals		6.0	77.2	16.7	5.2	6.5	5.6
Construction and maintenance							
New construction	g	0	0	0	0	0	0
Firebreak lane maintenance	h	0	0	0	0	0.4	0.1
Total (Part B)		13.7	177.2	38.2	11.9	16.1	13.0

Footnotes for Part B: Drilling, Construction, and Maintenance

[a]Based on 42 new wells and 155 remedial operations; estimated totals for FY 1988.
[b]Daily average total horsepower of equipment in use.
[c]158 daily average horsepower plus average of 10.4 miles driven per day.
[d]Average acres disturbed per site.
[e]Remedial operations only.
[f]79 daily average horsepower plus average of 5.2 miles driven per day.
[g]No new construction in FY 1988.
[h]190 acres of firebreak disced during 10-day period in April each year.

TABLE B.21 (Cont'd)

PART C: Noncombustion Oil and Gas Production[a]

		Emission Rate (lb/h)					
Source Category	Capacity	ROG	NO_x	CO	SO_2	TSP	PM_{10}
Active oil and gas wells							
Heads and cellars[b]	-[c]	207.5	-	-	-	-	-
Anode bed wells (32)	-	37.8	-	-	-	-	-
Subtotals	-	254.3	-	-	-	-	-
3G steamflood operation							
Process	-	0.7	-	-	-	-	-
Fugitive	-	0	-	-	-	-	-
Subtotals	-	0.7	-	-	-	-	-
Tank settings (79)							
Breathing/working	-	1.3	-	-	-	-	-
Relief valve	-	7.5	-	-	-	-	-
Drain tanks (128)	-	18.4	-	-	-	-	-
Fugitive	-	4.8	-	-	-	-	-
Subtotals	-	24.5	-	-	-	-	-
"Tankless" settings (57)	-	1.6	-	-	-	-	-
LACT units (5)							
10G							
Breathing/working	-	0	-	-	-	-	-
Relief valve	-	0.1	-	-	-	-	-
Slop tanks	-	0.5	-	-	-	-	-
Fugitive	-	0.6	-	-	-	-	-

TABLE B.21 Existing Source Emissions at NPR-1

PART C: Stationary Combustion Sources[a]

Source Category	Capacity	ROG	NO_X	CO	SO_2	TSP	PM_{10}
18G							
Breathing/working	-	0.4	-	-	-	-	-
Relief valve	-	1.8	-	-	-	-	-
Slop tanks	-	0	-	-	-	-	-
Fugitive	-	1.6	-	-	-	-	-
24Z							
Breathing/working	-	0	-	-	-	-	-
Relief valve	-	0.3	-	-	-	-	-
Slop tanks	-	0.3	-	-	-	-	-
Fugitive	-	0.1	-	-	-	-	-
25S							
Breathing/working	-	0.1	-	-	-	-	-
Relief valve	-	0.2	-	-	-	-	-
Slop tanks	-	0.1	-	-	-	-	-
Fugitive	-	0.6	-	-	-	-	-
26Z							
Breathing/working	-	0	-	-	-	-	-
Relief valve	-	0	-	-	-	-	-
Slop tanks	-	0	-	-	-	-	-
Fugitive	-	0	-	-	-	-	-
Subtotals	-	14.2	-	-	-	-	-
Condensate traps							
STV service (153)	-	8.2	-	-	-	-	-
S0Z service (14)	-	0.4	-	-	-	-	-
Subtotals	-	8.6	-	-	-	-	-

TABLE B.21 (Cont'd)

PART C (Cont'd)

Source Category	Capacity	Emission Rate (lb/h) ROG	NO_x	CO	SO_2	TSP	PM_{10}
Electric drive compressor fugitive emissions		10.6	-	-	-	-	-
35R product storage and handling							
Propane	185[d]	12.2	-	-	-	-	-
Butane	157[d]	3.6	-	-	-	-	-
Natural gasoline	146[d]	2.4	-	-	-	-	-
Fugitive	-	0.3	-	-	-	-	-
Subtotals	488[d]	18.5					
Gasoline storage tanks							
35R	-	0.0	-	-	-	-	-
36S	-	0.0	-	-	-	-	-
Percolation ponds	180[e]	4.1	-	-	-	-	-
3G weathering tanks	256[f]	6.2	-	-	-	-	-
Stack vent stacking releases	432[g]	792.0	-	-	-	-	-
Oil-spill related emissions	1,250[h]	2.1	-	-	-	-	-
Total (Part C)		1,128.4	0	0	0	0	0

TABLE B.21 (Cont'd)

Footnotes for Part C: Noncombustion Oil and Gas Production

[a]Total current H_2S emissions = -.031 1b/h; total current C_6H_6 emissions = 0.30 1b/h (0.26 1b/h from oil spills; 0.02 1b/h from tank relief valve emissions; and 0.02 1b/h from fugitive emissions).
[b]769 well heads with stuffing box/pump seals, 1053 oil production wells.
[c]"-" indicates not applicable.
[d]10^3 gal/day; 1987 average.
[e]10^3 ft^2; total area of ponds at 10G, 18G, 26Z.
[f]ft^2; total open surface area of two tanks.
[g]10^6 cubic feet of gas (1988).
[h]Bbl loss through spillage (1987); 1,183 bbl in minor spills (2,420 bbl spilled - 1,536 recovered), 67 bbl in major spills (907 bbl spilled - 840 bbl recovered).

TABLE B.21 (Cont'd)

PART D: Vehicular Traffic

		Emission Rate (lb/h)					
Source Category	Capacity	ROG	NO_x	CO	SO_2	TSP	PM_{10}
On-site (NPR-1)[a]							
Passenger vehicles							
Exhaust[b]	9.77[c]	0.5	1.0	5.1	0.078	0.2	0.1
Cold start	7.85[d]	0.8	0.2	10.2	0	0	0
Hot start	1.6[d]	0	0	0.2	0	0	0
Diur. evap.	7.05[c]	0.3	0	0	0	0	0
Hot soak evap.	9.45[d]	0.2	0	0	0	0	0
Road dust-paved	9.28[c]	0	0	0	0	169.0	65.9
-unpaved	0.49[c]	0	0	0	0	69.4	31.2
Light-duty trucks							
Exhaust[b]	7.48[c]	0.4	1.0	4.3	0.075	0.2	0.1
Cold start	3.40[d]	0.4	0.1	5.8	0	0	0
Hot start	3.40[d]	0	0.1	0.6	0	0	0
Diur. evap.	1.70[c]	0.1	0	0	0	0	0
Hot soak evap.	6.80[d]	0.2	0	0	0	0	0
Road dust-paved	5.61[c]	0	0	0	0	184.6	72.0
-unpaved	1.87[c]	0	0	0	0	76.0	34.2
Heavy-duty trucks							
Exhaust[b]	0.8[c]	0.2	1.3	0.6	0.256	0.2	0.2
Road dust-paved	0.8[c]	0	0	0	0	122.6	47.8
Subtotals	-	3.1	3.7	26.8	0.409	622.2	251.5

TABLE B.21 (Cont'd)

PART D (Cont'd)

		Emission Rate (lb/h)					
Source Category	Capacity	ROG	NO_x	CO	SO_2	TSP	PM_{10}
Off-site (Kern Co.)[f]							
Passenger vehicles							
Exhaust[b]	37.5[c]	1.8	3.7	19.5	0.300	0.7	0.3
Cold start	6.3[d]	0.6	0.2	8.1	0	0	0
Hot start	0	0	0	0	0	0	0
Diur. evap.	0	0	0	0	0	0	0
Hot soak evap.	6.3[d]	0.1	0	0	0	0	0
Road dust-paved	37.5[c]	0	0	0	0	87.5	30.5
Heavy-duty trucks							
Exhaust	4.8[c]	1.1	7.6	3.5	1.535	1.4	1.5
Road dust-paved	4.8[c]	0	0	0	0	11.2	3.9
Subtotals		3.6	11.5	31.1	1.835	100.8	35.9
Total (Part D)		6.7	15.2	57.9	2.244	723.0	287.4
Grand Total (Parts A-D)		1,524.2	1,450.5	1,311.8	14.8	742.9	304.2

Footnotes for Part D: Vehicular Emissions

[a]Total current lead (Pb) emissions = 0.002 lb/h from passenger vehicles.

[b]Includes contributions from tire wear.

[c]10^3 vehicle- miles traveled per day.

[d]10^2 trips per day.

[e]10^2 vehicles.

[f]Total current Pb emissions = 0.010 lb/h from passenger vehicles

Emission factors compiled by the American Petroleum Institute/Rockwell International (Eaton et al 1980) were used for all fugitive hydrocarbon (HC) emission estimates. Estimates for H_2S and benzene emissions that are released along with gaseous HC or crude oil were based on the measured concentrations of these constituents in HC or crude oil.

For vehicular emissions, the emission factors were derived from the 1987 vehicular emissions data and other traffic-related data for Kern County that were obtained from CARB (1988b). Seasonal emission factors were then developed after correcting for the mean temperature for each season using the temperature-correction factors obtained from CARB (1988c), and finally, composite annual mean emission factors were developed from these seasonal factors.

The overall quality of the emission estimates in Table B.21 is considered to be good, with the smallest relative uncertainties in the stationary combustion sources and the largest in the estimates for various fugitive and road dust emissions.

Details of the estimated emissions from the proposed new sources and those of temporary emissions produced by construction-site preparation and vehicular traffic caused by additional construction workers and delivery of construction material are provided in Tables B.22 and B.23. Details of the projected changes in emissions from the currently existing sources are provided in Table B.24. Net emission changes between the period 1987-1989 and 1996 are given for the major source categories in Table B.25; these values represent the sums of corresponding values from Tables B.22 and B.24. Finally, projected total emissions are given in Table B.26; these values are the sums of corresponding values from Tables B.21 and B.25.

B.5 AIR QUALITY IMPACT ANALYSIS

Air quality impacts of emissions from existing sources and from the proposed new sources at NPR-1 were estimated with air quality models recommended by the EPA. The air quality models relate source emissions, meteorological conditions, topography and nearby building dimensions, and chemical transformation to ground-level air pollutant concentrations. Air quality modeling was performed for NO_2, CO, SO_2, PM_{10}, H_2S, and C_6H_6. On advice from CARB, such modeling was not performed for O_3. The following subsections describe the air quality dispersion models used, input data, and modeling results.

B.5.1 Air Quality Models and Model Input Data

B.5.1.1 Air Quality Models

The three air quality models used in this analysis were selected from Version 6 of the Users Network for Applied Modeling of Air Pollution (UNAMAP) (Turner and Bender 1986; EPA 1986c). The models used were the most recent versions of the Industrial Source Complex-Short Term Mode (updated in December 1988), COMPLEX-I, and CALINE-3, all of which are recommended by the EPA (1986a, 1987).

TABLE B.22 Projected Emissions for New Sources at NPR-1[a]

		Emission Rate (lb/h)					
Source Category	Capacity	ROG	NO_x	CO	SO_2	TSP	PM_{10}
Stationary combustion							
Compressor engines							
19R (3)	4,500[b]	9.90	9.93	29.76	0.018	0.27	0.27
30R (2)	2,000[b]	4.92	4.40	13.22	0.008	0.12	0.12
33S (2)	2,000[b]	4.92	4.40	13.22	0.008	0.12	0.12
35R (8)	26,000[b]	95.52	57.32	268.96	0.104	0.66	0.66
36R (3)	3,000[b]	7.38	6.60	19.83	0.012	0.18	0.18
Subtotal	37,500[b]	122.64	82.65	344.99	0.150	1.35	1.35
Steam generators							
3G (10)	625[c]	0.90	25.00	7.50	0.240	2.80	2.80
Heaters							
35R (2)	83[c]	0.22	3.32	2.76	0.048	0.24	0.24
Cogenerators							
35R (2)	42[d]	5.32	7.82	10.58	0.226	1.13	1.12
Flares							
34R (2)	123[e]	0.29	5.43	1.10	0.032	0.27	0.27

TABLE B.23 Projected Emissions for New-Source Construction Activities at NPR-1

Source Category	Capacity	Emission Rate (1b/h)[a]					
		ROG	NO_X	CO	SO_2	TSP	PM_{10}
Construction-Site Preparation[b]							
Equipment operation	64[c]	0.57	7.47	1.62	0.50	0.54	0.51
Road dust	-[d]	-	-	-	-	0.10	0.04
Fugitive dust	-	-	-	-	-	3.11	0.59
Subtotals	-	0.57	7.47	1.62	0.50	3.75	1.14
Vehicular Traffic[b]							
On-site (NPR-1)							
Passenger vehicles[e]							
Exhaust	1.5[f]	0.07	0.15	0.78	0.01	0.03[g]	0.01[g]
Cold start	1.5[i]	0.14	0.04	1.95	-	-	-
Hot start	-	-	-	-	-	-	-
Diur. evap.	1.5[h]	0.05	-	-	-	-	-
Hot soak evap.	1.5[i]	0.04	-	-	-	-	-
Road dust--paved	1.5[f]	-	-	-	-	36.66	14.92
Heavy-duty trucks							
Exhaust	0.1[f]	0.02	0.16	0.07	0.03	0.02[g]	0.02[g]
Road dust--paved	0.1[f]	-	-	-	-	15.63	6.04
Subtotals	-	0.32	0.35	2.80	0.04	52.34	20.99

TABLE B.23 (Cont'd)

Source Category	Capacity	Emission Rate (lb/h)[a]					
		ROG	NO_x	CO	SO_2	TSP	PM_{10}
Off-site (Kern Co.)							
Passenger vehicles[j]							
Exhaust	9.0[f]	0.43	0.90	4.69	0.07	0.19[g]	0.09[g]
Cold start	1.5[i]	0.14	0.04	1.95	-	-	-
Hot start	-		-	-	-	-	-
Diur. evap.	-	-	-	-	-	-	-
Hot soak evap.	1.5[i]	0.04	-	-	-	-	-
Road dust--paved	9.0[f]	-	-	-	-	21.00	7.50
Heavy-duty trucks							
Exhaust	0.6[f]	0.13	0.95	0.44	0.19	0.18[g]	0.15[g]
Road dust--paved	0.6[f]	-	-	-	-	1.40	0.50
Subtotals	-	0.74	1.89	7.08	0.26	22.77	8.24
TOTALS	-	1.63	9.71	11.50	0.80	78.86	30.37

[a]Annual average value.
[b]During the construction period only.
[c]The number of 2.2-acre sites disturbed during 1990 when the construction activities, including the third-party projects, are at their peak level. In 1996, the emissions would be half the listed values.
[d]A dash (-) indicates not applicable.
[e]Total lead (Pb) emissions = 0.0004 lb/h from passenger vehicles.
[f]10^3 vehicle-miles traveled per day.
[g]Includes a contribution from tire wear.
[h]10^2 vehicles per day.
[i]10^2 trips per day.
[j]Total Pb emissions = 0.0002 lb/h from passenger vehicles.

TABLE B.24 Projected Changes in Emissions from Existing Sources

Source Category	Change in Emission Rate (lb/h)						FOOT NOTES
	ROG	NO_X	CO	SO_2	TSP	PM_{10}	
Stationary Combustion							
Compressor engines	0.0	-516.4	0.0	0.0	0.0	0.0	a
Boilers and heaters	-0.5	-25.1	-6.3	-0.1	-0.5	-0.5	b
Pump engines	0.0	-203.9	0.0	0.0	0.0	0.0	a
Field engines	0.0	-0.1	0.0	0.0	0.0	0.0	a
Total	-0.5	-745.5	-6.3	-0.1	-0.5	-0.5	
Drilling and construction							
New Well Drilling							c
Equipment operation	-2.2	-28.2	-6.1	-1.9	-2.0	-2.0	
Moving	-0.1	-1.2	-0.2	-0.1	-0.1	-0.1	
Site preparation							
Equipment operation	-0.1	-1.5	-0.3	-0.1	-0.1	-0.1	
Fugitive dust	0.0	0.0	0.0	0.0	-0.6	-0.1	
Subtotal	-2.4	-30.9	-6.6	-2.1	-2.8	-2.3	
Remedial work and new well completion							d
Equipment operation	0.2	2.5	0.5	0.2	0.2	0.2	
Moving	0.0	0.0	0.0	0.0	0.0	0.0	
Site preparation							
Equipment operation	0.0	0.0	0.0	0.0	0.0	0.0	
Fugitive dust	0.0	0.0	0.0	0.0	0.0	0.0	
Subtotal	0.2	2.5	0.5	0.2	0.2	0.2	
Construction	0.1	1.4	0.3	0.1	-1.9	0.2	e
Total	-2.1	-27.0	-5.8	-1.8	0.6	-1.9	
Noncombustion oil and gas production							
Active oil and gas wells	0.0	0.0	0.0	0.0	0.0	0.0	f
Tank settings	0.0	0.0	0.0	0.0	0.0	0.0	g
LACT Units	0.6	0.0	0.0	0.0	0.0	0.0	h
35R Product storage and handling	9.3	0.0	0.0	0.0	0.0	0.0	i
Stack vent stacking releases	-396.0	0.0	0.0	0.0	0.0	0.0	j
Total	-386.1	0.0	0.0	0.0	0.0	0.0	

TABLE B.24 (Cont'd)

Source Category	Change in Emission Rate (lb/h)						NOTES
	ROG	NO_X	CO	SO_2	TSP	PM_{10}	
Vehicular traffic							
Passenger vehicles	0.0	0.0	0.0	0.0	0.0	0.0	k
Heavy duty trucks							
On-site							l
Exhaust	0.1	0.6	0.3	0.1	0.1	0.1	
Road dust - paved	0.0	0.0	0.0	0.0	61.9	24.2	
Off-site							l
Exhaust	0.5	3.8	1.8	0.8	0.7	0.6	
Road dust- paved	0.0	0.0	0.0	0.0	5.6	2.5	
Total	0.6	4.4	2.1	0.9	68.3	27.4	
Grand Total	-388.1	-768.1	-10.0	-1.0	65.8	25.0	

[a]Compressor and other engine emissions reduced according to KCAPCD Rule 427.
[b]All existing 35R area boilers and heaters will be replaced by one cogenerator.
[c]Project 29 new wells for 1996, compared with a total of 42 for 1988.
[d]Project 176 remedial activities in addition to 29 new wells for 1996, compared with 155 remedial activities and 42 new wells for 1988.
[e]24 acres to be disturbed for developing 3 steam generator sites in 1996.
[f]Project about equal number of production wells in 1996 compared with 1988.
[g]Based on projected throughput changes supplied by BPOI.
[h]Installation of drain tanks at 18G and 26Z LACT units.
[i]Based on BPOI projections through 1995 considering additional productions based on 150×10^6 ft^3/day fourth gas plant employing expander process.
[j]Estimated 50% reduction from the current rate of releases.
[k]No change.
[l]40 additional trucks per day for delivery of liquid products from the fourth gas plant (expander process; 105×10^6 ft^3/day); each truck traveling 10 miles on the site and 60 miles off the site.

TABLE B.25 Net Emission Changes by Source Category

Source Category	Net Emission Change (1b/h)					
	ROG	NO_X	CO	SO_2	TSP	PM_{10}
Stationary combustion	133.1	-621.3	360.6	0.6	5.3	5.3
Drilling and Construction	-2.1	-27.0	-5.8	-1.8	-2.0	-1.9
Noncombustion oil and gas production	-386.1	0	0	0	0	0
Vehicular traffic						
On-site	0.1	0.6	0.3	0.1	62.0	24.3
Off-site	0.5	3.8	1.8	0.8	6.3	3.1
Total	-254.5	-643.9	356.9	-0.3	71.6	30.8

TABLE B.26 Projected Total 1996 NPR-1 Emission

Source Category	Emission Rate (1b/h)					
	ROG	NO_X	CO	SO_2	TSP	PM_{10}
Stationary combustion	508.5	636.8	1,576.3	1.3	9.1	9.1
Drilling, Construction, and Maintenance	11.6	150.2	32.4	10.1	14.1	11.1
Noncombustion oil and gas production	742.3	0	0	0	0	0
Vehicular traffic						
On-site	3.2	4.3	27.1	0.5	684.2	275.8
Off-site	4.1	15.3	32.9	2.6	107.1	39.0
Total	1,269.7	806.6	1,668.7	14.5	814.5	335.0

Industrial Source Complex Model

The Industrial Source Complex (ISC) model (EPA 1986b) is a steady-state Gaussian plume model than can be used to assess the effects of a variety of sources associated with an industrial complex such as NPR-1. Although the ISC model handles the effects of terrain in only a limited way, it is well suited for modeling emissions from the numerous sources scattered throughout the NPR-1 site, including those located at or near large buildings or structures. The limited treatment of terrain effects is not a significant drawback in the case of NPR-1 because most the large emission sources are located on or near the top of the Elk Hills.

For application of modeling analysis to the NPR-1, regulatory default options suggested in the EPA's guideline (EPA 1986a) and the rural option were used. A minor modification was employed in calculating the mixing-height values for the hours immediately after sunrise for the cases when stable conditions prevailed during the hour just before sunrise. The mixing-height for the hour just after sunrise was set to equal the mean value of (1) the mixing-height calculated by the model algorithm for this hour and (2) that for the next hour. This was done because the mixing-height calculated by the program for the hour immediately after sunrise in rural areas is an interpolated value between zero mixing-height at sunrise and the afternoon mixing-height value at 2 p.m.

Therefore, it is an instantaneous value at the beginning of the hour and is not an average mixing-height for a 60-minute period. Because the hourly air pollutant concentrations estimated with the model are to represent the hourly average concentrations, it is appropriate to use the hourly average mixing-height. Otherwise, ground-level concentrations would be estimated as zero for sources with plume heights slightly greater than the very restrictive mixing-height computed for the beginning of the hour immediately after sunrise under the rural option. This modification also reduces to more realistic values the artificially high ground-level concentrations estimated for those sources with plume heights just under the same restrictive mixing-height. For the multiple sources of NPR-1, many of which are located near large buildings or structures, ambient air quality impacts estimated by use of the ISC model are greater than those estimated by the use of the COMPLEX I model described below.

COMPLEX-I Model

COMPLEX-I is a modification of the Multiple Point Gaussian Dispersion Algorithm with Terrain Adjustment (MPTER) model that fully incorporates the effects of plume impaction on terrain. This model, without the option of including building downwash effects, is less resource-intensive than the ISC model. Therefore, it was used to model pollutants such as H_2S that are emitted from stacks that are scattered throughout the site but are located some distances away from large buildings or structures.

CALINE-3 Model

CALINE-3 (Benson 1979) is a steady-state Gaussian model designed to estimate the ambient concentrations of nonreactive pollutants from highway traffic. This model was used to estimate ground-level concentrations of pollutants emitted by the vehicles traveling on Elk Hills and Skyline roads.

B.5.1.2 Pollutant Emissions

Emissions from the following sources were considered in air quality modeling: (1) stationary combustion sources (compressors, boilers and heaters, steam generators, cogenerators, flares, and well pump engines); (2) diesel engines used in well drilling, remedial work, and routine well-pulling operations; and (3) vehicular traffic on Elk Hills and Skyline roads. To model primary PM_{10}, temporary construction fugitive dust emission sources and road dust emission sources were included. Annual average emission rates for the individual pieces or groups of devices are given in Tables B.21 and B.22. Of conservatism, devices associated with all activities except construction and vehicular traffic were assumed to be operating throughout the year and emitting pollutants at their hourly emission rates. The emissions from construction activities were assumed to be limited to the daytime 8-hour shift, and those from vehicular traffic were allocated to various hours based on the hourly traffic volume data observed at NPR-1 (BPOI 1989). To keep the number of emission sources to a manageable level, numerous sources scattered around the NPR-1 site, such as gas-fired well-pump engines, were grouped together and were assumed to be located at a central point for each group of sources. Large combustion sources also were grouped and located at a central point if they are located close to each other and their stack exhaust parameters are similar. Road dust emissions were allocated to each sector in proportion to the number of active wells in each sector, based on the assumption that the vehicle miles traveled during inspection, maintenance, and repair work would be proportional to the number of active wells.

The data on physical source characteristics (stack height, stack inside diameter, and exhaust-gas temperature and exit velocity) of the emission sources used in modeling were based primarily on (1) actual measured data obtained during emission testing periods (in the case of large compressors); (2) manufacturers' design data (in the case of steam generators, cogenerators, well pumps, and drilling engines); or (3) a combustion of the two data types in the case of boilers and heaters. Table B.27 lists these physical characteristics of typical emissions sources at NPR-1.

Emissions from other sources, such as seasonal heaters and miscellaneous field engines, were not included in modeling. They were not modeled because their emission rates are negligible or because preliminary modeling indicated that the impacts of these sources are not significant.

TABLE B.27 Physical Source Characteristics of Typical Emission Sources at NPR-1

Source Type	Capacity	Stack Height (ft)	Equivalent Stack Diameter (in.)	Exit Temperature (F)	Exit Velocity (ft/s)
Compressor	1,000 hp	15	12	800	130
Steam generator	62.5×10^6 Btu/h	22	74	330	10
Cogenerator	21 MW	50	60	290	135
Boiler	56.0×10^6 Btu/h	40	18	400	130
Heater	27.5×10^6 Btu/h	40	12	650	200
Pump engine	88 hp	10	5	1350	40
Drilling rig engine	380 hp	10	5	1000	250

It was determined during the preliminary modeling of combustion source emissions that high ground-level concentrations may result at Elk Hills Road (near the 35R gas plant), which is accessible to the public. To account for the diurnally varying effects of vehicular traffic emissions, hourly vehicle counts by vehicle type were taken during three consecutive weekdays in January-February 1989 at four locations near the junction of Elk Hills Road and Skyline Road (BPOI 1989). Hourly composite emissions factors were computed based on the CARB-supplied 1988 vehicular emissions and other traffic data for Kern County (CARB 1988b). The composites were used in conjunction with the mean hourly vehicle counts at Elk Hills Road and Skyline Road in the modeling (Figure B.22).

B.5.1.3 Meteorological and Climatological Data

Data on hourly wind speed and direction measured at the Fellows site by the Westside Operators during a 5-year period (1983-1987) were used in air quality modeling analysis. Atmospheric stability data were calculated from the hourly wind speed at the Fellows site and hourly ceiling height and sky cover data measured at Meadows Field near Bakersfield (for the same 5-year period). The mixing-height data used are the seasonal mean morning and afternoon mixing-height values derived from the morning temperature-sounding data obtained at Meadows Field during a 7-year period (1981-1987). (Details of these meteorological and climatological data are given in Section B.1.)

Preliminary modeling analyses of nonreactive pollutants using each of the 5 years of meteorological data indicated that the 1983 data produced the highest short-term ground-level concentrations. Therefore, all of the subsequent modeling analyses were conducted using the 1983 meteorological data.

B.5.1.4 Chemical Transformation

To model NO_2 concentrations, the ozone-limiting method (Code and Summerhays 1979) was used according to the EPA's air quality modeling guideline recommendation (EPA 1986a). The ozone-limiting method was applied after adding, at each receptor location, the NO_x concentration contributions from the point sources and vehicular traffic on Elk Hills and Skyline roads. The seasonal maximum hourly ozone concentrations measured at the Maricopa site during the period 1983-1987 were used for this. The Maricopa site showed the highest ozone concentrations among the three ozone-monitoring stations maintained by the Westside Operators. Details of the seasonal maximum hourly ozone concentrations at this monitoring station are described in Section B.3.2. The use of the seasonal maximum hourly ozone concentration in the application of the ozone-limiting method provides added conservatism in the estimation of NO_2 concentration.

The chemical transformation of SO_2 emitted from point sources or single industrial plants in rural areas is generally assumed to be unimportant when travel time is limited to a few hours. Because the time required for an air mass to traverse the NPR-1 site from its central

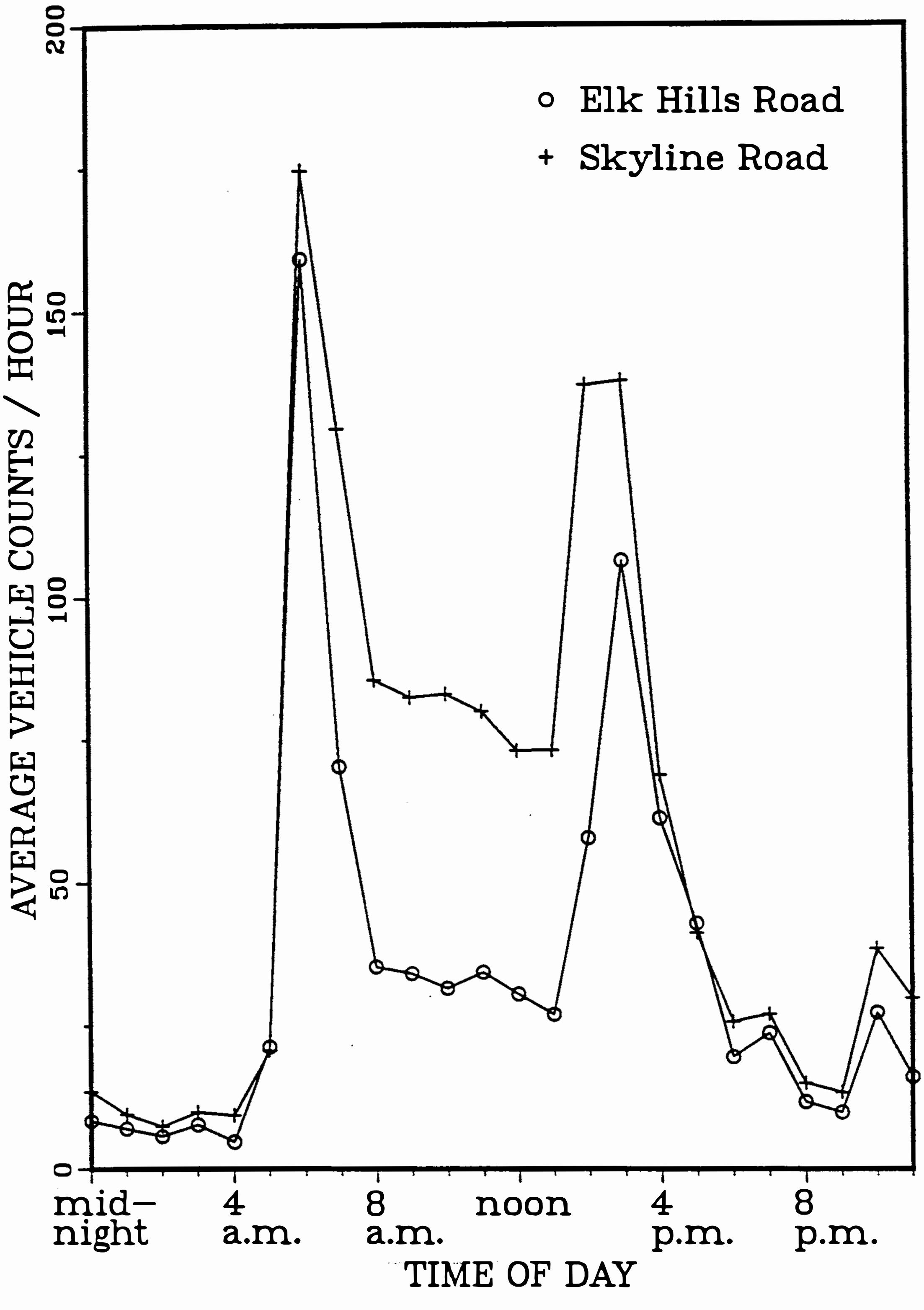


FIGURE B.22 MEAN HOURLY VEHICLE COUNTS ON ELK HILLS ROAD AND SKYLINE ROAD AT THEIR JUNCTION (SOURCE: DEVELOPED FROM BPOI 1989) location is on the order of a few hours even at a very low wind speed (e.g., 1 m/s), it was assumed that only a negligible amount of SO_2 is converted to SO_4 over the NPR-1 site.

B.5.1.5 Topography, Receptor Grid, and Receptor Locations

The size of the modeling domain selected for impact analysis was a rectangle 14 kilometers in the north-south direction and 25 kilometers in the east-west direction. Air quality impacts were estimated for receptor locations that were selected to adequately cover the areas near large emission sources, Elk Hills Road, and the site boundary. The basic grid size selected was 1 kilometer x 1 kilometer, except for the case of road dust modeling with a grid size of 1.6 kilometer x 1.6 kilometer. The elevation at each source and receptor location was obtained from the relevant USGS 7.5-minute series topographic maps. The approximate topography over the modeling domain, the NPR-1 site boundary, the locations of major existing and proposed new sources, major roadways, and the selected receptor locations are shown in Figure B.23.

B.5.1.6 Cumulative Effects

Background concentrations are essential components of the total air pollutant concentrations to be considered in determining source impacts. Background concentrations from existing nearby off-site sources and natural sources should be determined in the vicinity of the NPR-1 sources under consideration. Since the monitoring stations in western Kern County maintained by the Westside Operators are sufficiently close to the NPR-1 site (most are within a few miles of the NPR-1 boundary), air quality data obtained at these stations are considered to provide good estimates of background concentrations on the NPR-1 site. To be conservative, the maximum concentration levels measured for appropriate averaging time periods at these off-site monitoring stations during 1987* were used as the background levels. For the hourly NO_2 background concentrations, the seasonal mean hourly concentrations for the period 1983-1987 at the Maricopa site were used instead of the seasonal maximum hourly concentrations. This was done because the hourly NO_2 concentrations corresponding to the seasonal maximum hourly ozone concentrations used in the ozone-limiting method are, in general, equal to or slightly lower than the seasonal mean hourly NO_2 concentrations, but are substantially lower than the seasonal maximum hourly NO_2 concentration (Section B.3.2).

B.5.2 Air Quality Modeling Results

This section presents the modeling results from ground-level concentrations of NO_2, CO, SO_2, PM_{10}, H_2S, and C_6H_6 from existing and proposed new emission sources for various

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*Data from 1988 were not considered in determining the maximum concentration levels because monitoring at most of these stations was terminated in June 1988 due to closing or relocation.

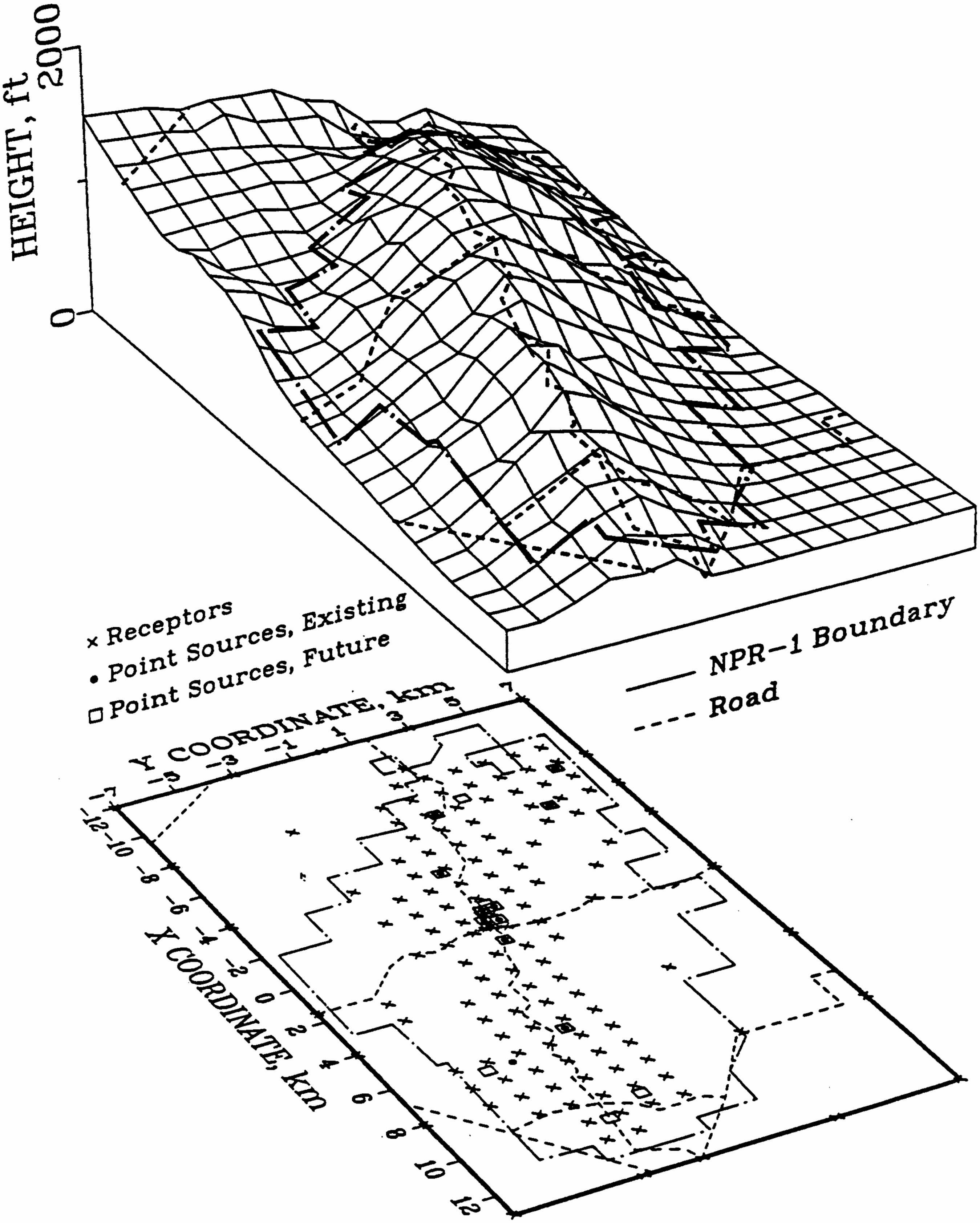


FIGURE B.23 TOPOGRAPHY OF THE MODELING DOMAIN AND THE LOCATIONS OF MAJOR EXISTING AND FUTURE POINT SOURCES, ROADWAYS, AND RECEPTOR LOCATIONS averaging time periods. Maximum ambient (ground-level) air pollutant concentrations estimated for within the NPR-1 site boundary are compared with applicable threshold limiting values (TLV) recommended by the American Conference of Governmental and Industrial Hygienists (1988). Maximum concentrations estimated for the site boundary or at Elk Hills Road are compared with applicable CAAQS or NAAQS (Table B.6).

B.5.2.1 Nitrogen Dioxide

Figure B.24 shows the isopleths of the maximum 1-hour ambient (ground-level) NO_2 concentrations estimated for the current conditions at NPR-1 and for anticipated conditions in 1996. The isopleths for 1996 take into account the proposed new source emissions and various expected emission changes at NPR-1. The highest maximum 1-hour NO_2 concentrations estimated for within the site boundary are 0.293 and 0.179 ppm for the existing and future estimated for within the site boundary are 0.293 and 0.179 ppm for the existing and future conditions, respectively. The points of highest concentration are located at the northwestern corner of the site and are attributable primarily to emissions from well-pump engines in the area. These highest concentrations are partially due to the artificial effects of lumping emissions from a number of well pump engines at a central location. Actual concentrations should be substantially lower than indicated. Even these conservatively high estimates of the maximum 1-hour concentrations are only a small fraction of the 8-hour time-weighted TLV of 3 ppm for NO_2.

The highest maximum 1-hour ambient NO_2 concentrations estimated at the site boundary or at Elk Hills Road are 0.246 and 0.170 ppm for the existing and future conditions, respectively. The highest concentrations, both located at the junction of Elk Hills and Skyline Roads, are mainly due to emissions from the compressors at the 35R Gas Plant. The concentration decrease from the existing to future conditions at the location of the maximum concentrations is 0.076 ppm, or 143 $\mu g/m^3$, which is primarily due to the emission reductions from the existing compressors (see Section B.2.2), according to KCAPCD Rule 427. The meteorological conditions associated with these estimated values are a westerly wind blowing at about 7 m/s and neutral atmospheric stability in early afternoon during a summer month. These highest estimate ambient concentrations are slightly below the 1-hour CAAQS of 0.25 ppm NO_2.

Figure B.25 shows the isopleths of the annual mean ambient (ground-level) NO_2 concentrations estimated for the current and anticipated 1996 conditions at NPR-1. The highest annual mean ambient NO_2 concentrations estimated for any location on the site or at the site boundary and Elk Hills Road are 0.035 ppm (65.7 $\mu g/m^3$) for existing conditions and 0.025 ppm (47.0 $\mu g/m^3$) for future conditions. (The concentration decrease from the existing to future conditions is 0.010 ppm, or about 19 $\mu g/m^3$.) These concentrations, both estimated for the junction of Elk Hills and Skyline Roads, are well below the applicable NAAQS for NO_2 (0.05 ppm).

Ambient Air Quality Standards

Pollutant	Averaging Time	California	National Pri	National Sec
NO_2	1 Hour	0.25	–	–

(Unit : ppm)

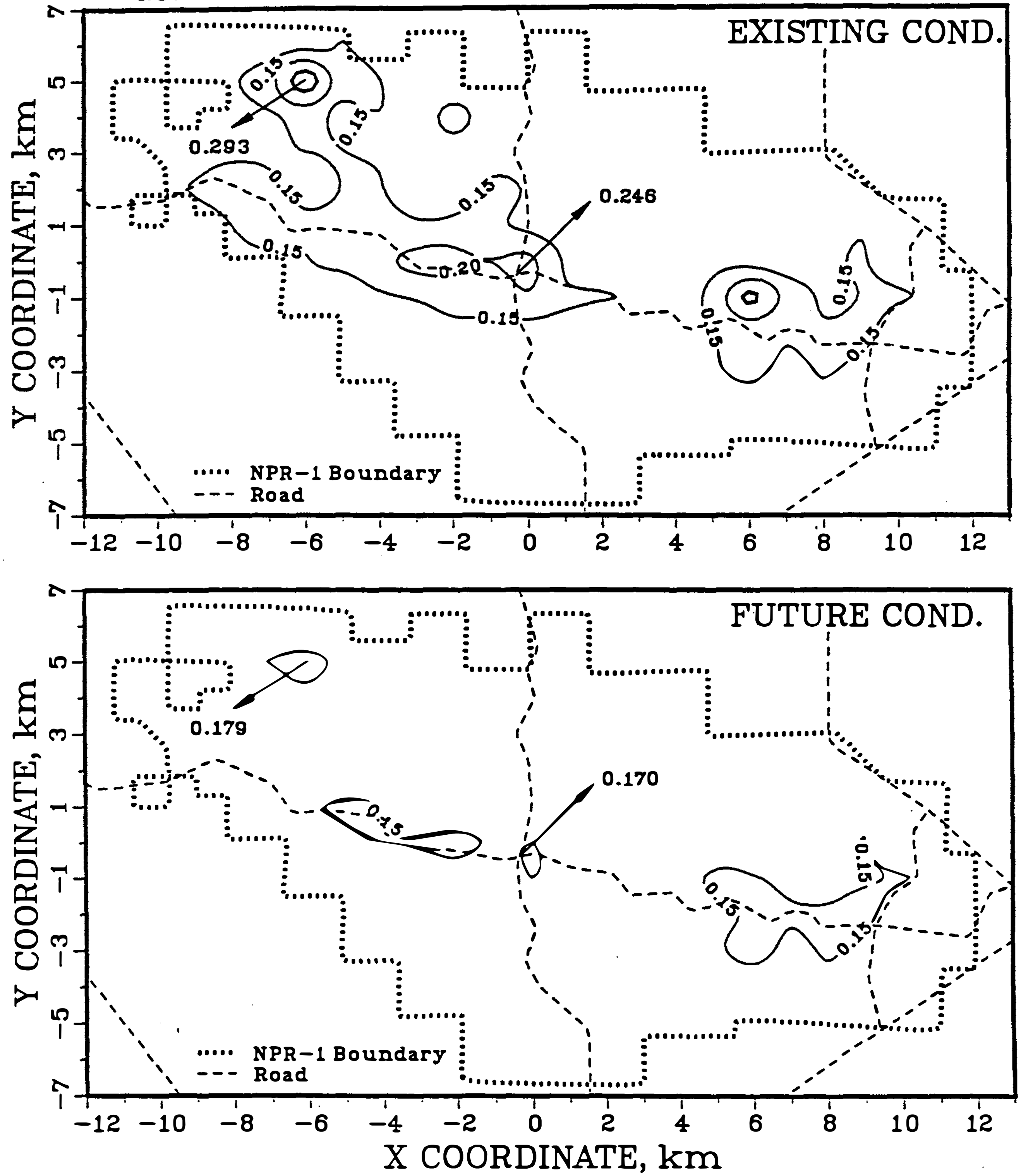


FIGURE B.24 ISOPLETHS FOR MAXIMUM 1-HOUR AMBIENT NO_2 CONCENTRATIONS ESTIMATED FOR EXISTING AND FUTURE CONDITIONS AT NPR-1

Ambient Air Quality Standards

Pollutant	Averaging Time	California	National Pri	National Sec
NO_2	Annual	–	100	100

(Unit : $\mu g/m^3$)

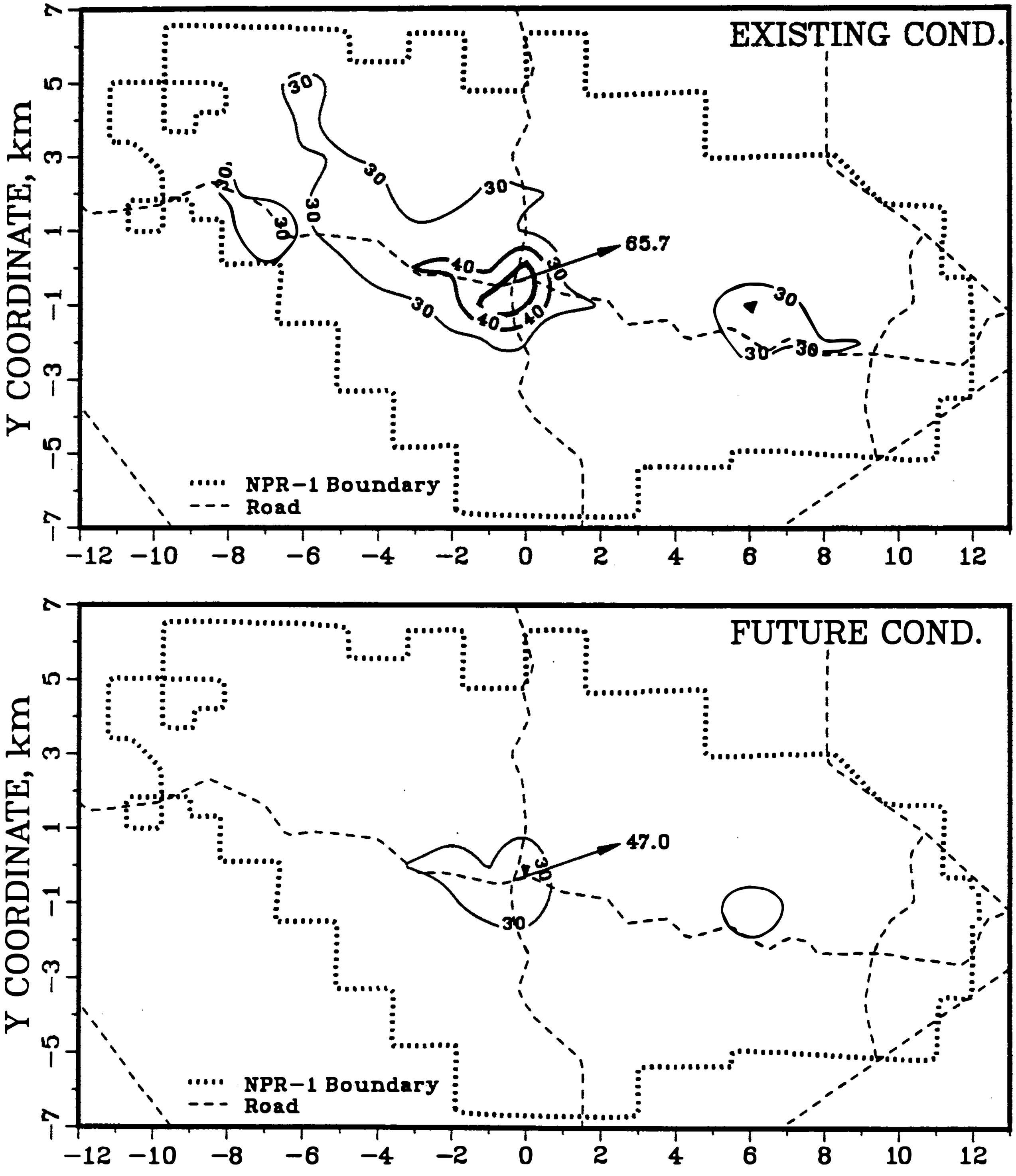


FIGURE B.25 ISOPLETHS FOR ANNUAL MEAN AMBIENT NO_2 CONCENTRATIONS ESTIMATED FOR EXISTING AND FUTURE CONDITIONS AT NPR-1

B.5.2.2 Carbon Monoxide

Figure B.26 displays isopleths of the maximum 1-hour ambient (ground-level) CO concentration contributions estimated for the existing and future emission sources at NPR-1. These isopleths reflect the impacts of the NPR-1 emission sources and the vehicular traffic along Elk Hills and Skyline Roads, but not the background concentration.

The highest maximum 1-hour CO concentration contributions estimated for within the site boundary are 1.43 and 1.41 ppm for the existing and 1996 emissions, respectively, with a decrement of 0.02 ppm. After adding the background concentration of 3.2 ppm (the maximum hourly concentration measured by the Westside Operators' monitoring network in 1987), the highest maximum 1-hour ambient CO concentrations estimated for within the NPR-1 boundary are 4.63 and 4.61 ppm for existing and future conditions, respectively. Both areas with these maximum concentrations occur west of the 35R area facilities, just north of Skyline Road. These maximum 1-hour ambient concentrations are less than 10% of the 8-hour time-weighted TLV of 50 ppm of CO.

The highest estimated maximum 1-hour CO concentrations at the site boundary or at Elk Hills Road are at the northwestern corner of the NPR-1 site, with concentrations of about 4.30 ppm for both existing and future conditions. These concentration levels are only a fraction of the applicable CAAQS and NAAQS of 20 and 35 ppm, respectively, for CO.

The isopleths of the maximum 8-hour mean ambient CO concentration contributions estimated for current and future (1996) emissions at NPR-1 are shown in Figure B.27. The isopleths for the 1996 conditions are virtually identical to those for the existing conditions except the areas surrounded by the same concentration isopleths are slightly larger for the future conditions. The highest maximum 8-hour CO concentrations estimated for within the boundary of NPR-1 are 2.09 ppm for both the existing and future conditions. Since 1.60 ppm represents the background concentration, the actual NPR-1 source contribution is only 0.49 ppm. These maximum concentration contributions, both estimated to occur at the junction of Elk Hills and Skyline roads, are primarily due to the emissions from the 35R Gas Plant. The highest maximum 8-hour CO concentrations are only a small fraction of the 8-hour time-weighted TLV of 50 ppm for CO.

The highest maximum 8-hour concentrations at the site boundary or at Elk Hills Road for the existing and future conditions also are estimated to occur at the junction of Elk Hills and Skyline roads.

B.5.2.3 Sulfur Dioxide

Figure B.28 shows the isopleths of the maximum 1-hour ambient (ground-level) SO_2 concentration contributions estimated for existing and future sources at NPR-1. As in the cases for CO, these isopleths reflect the impacts of the NPR-1 emissions sources and vehicular traffic on Elk Hills and Skyline roads, but not the background concentration. The

Ambient Air Quality Standards

Pollutant	Averaging Time	California	National Pri	National Sec
CO	1 Hour	20	35	35

(Unit : ppm)

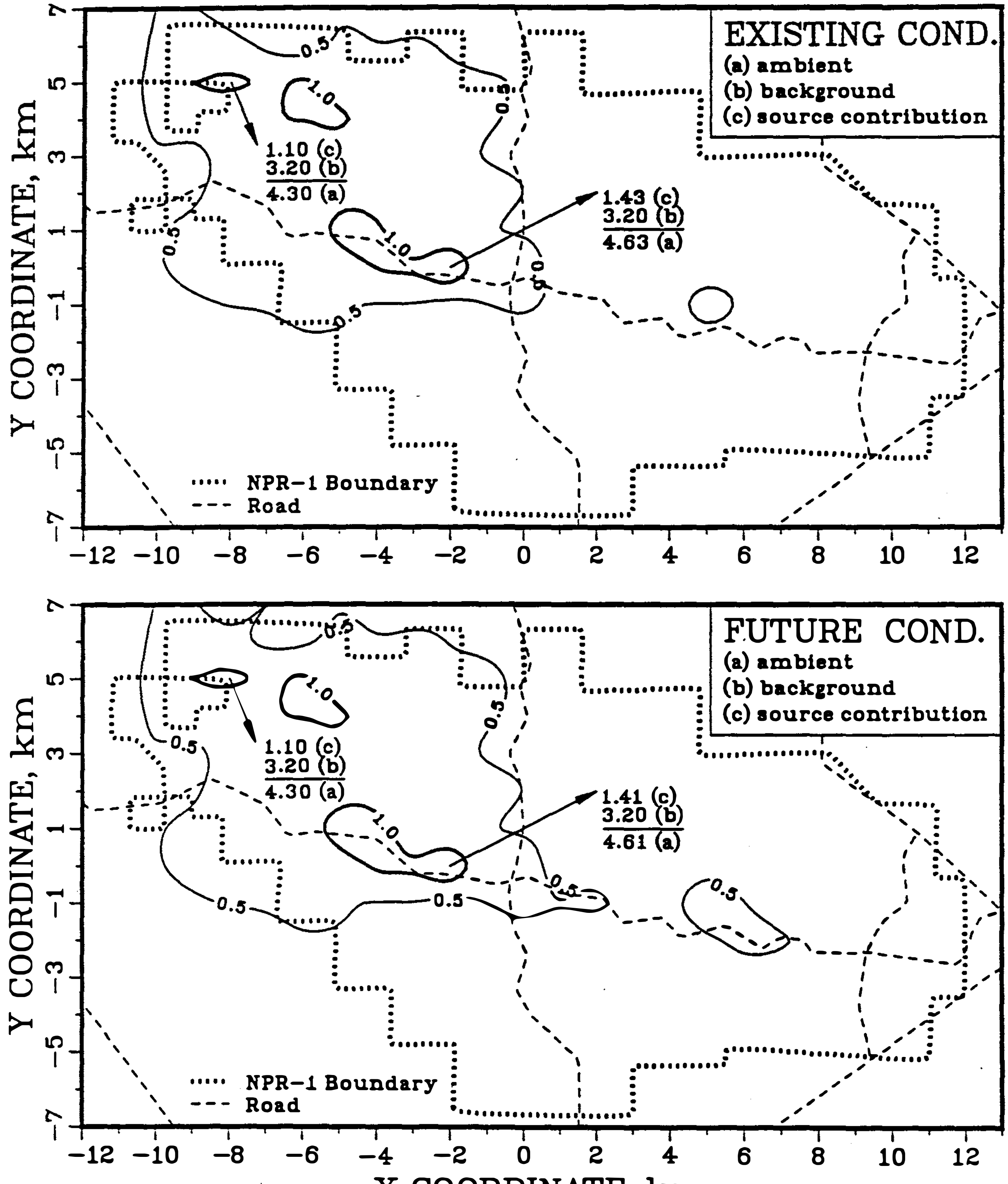


FIGURE B.26 ISOPLETHS FOR MAXIMUM 1-HOUR CO CONCENTRATIONS ESTIMATED FOR CONTRIBUTIONS FROM EXISTING AND FUTURE SOURCES AT NPR-1

Ambient Air Quality Standards

Pollutant	Averaging Time	California	National Pri	National Sec
CO	8 Hour	9	9	9

(Unit : ppm)

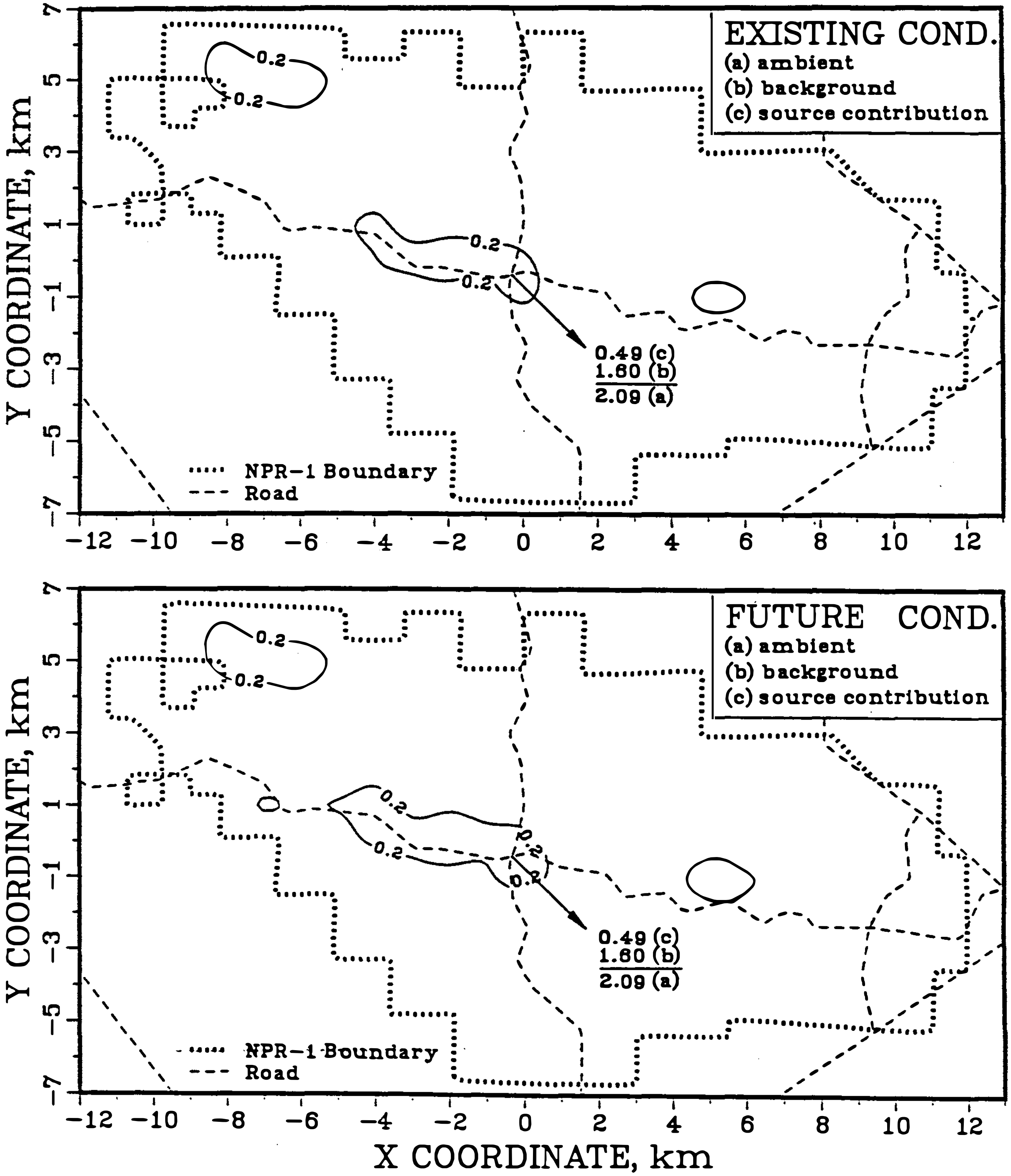


FIGURE B.27 ISOPLETHS FOR MAXIMUM 8-HOUR CO CONCENTRATIONS ESTIMATED FOR CONTRIBUTIONS FROM EXISTING AND FUTURE SOURCES AT NPR-1

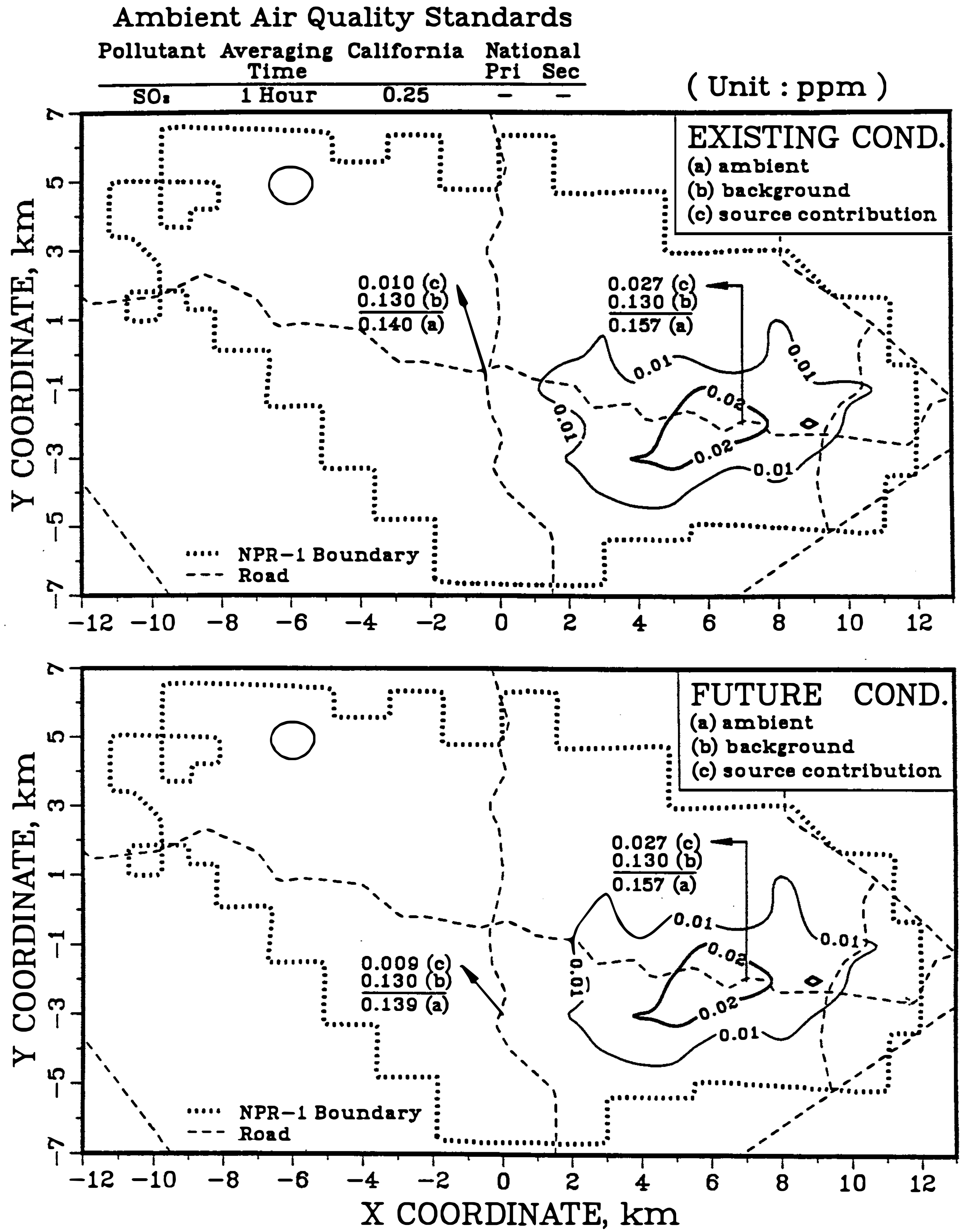


FIGURE B.28 ISOPLETH FOR MAXIMUM 1-HOUR SO_2 CONCENTRATIONS ESTIMATED FOR THE CONTRIBUTIONS FROM EXISTING AND FUTURE EMISSION SOURCES AT NPR-1 highest maximum 1-hour SO_2 concentration contribution estimated for within the NPR-1 site boundary is 0.027 ppm for both the existing and future emissions at NPR-1. Addition of the background concentration (0.13 ppm) increases the highest maximum 1-hour ambient SO_2 concentration within the NPR-1 site boundary to 0.157 ppm for both existing and future conditions. The area where these highest maximum 1-hour concentrations would occur is toward the southeastern corner of the NPR-1 site where most of the current and future drilling and remedial work activities are located. (Diesel engines used in these activities are small but constitute the largest source of SO_2 emissions on the site.) The maximum 1-hour SO_2 concentrations are less than 15% of the 8-hour time-weighted TLV of 2 ppm for SO_2.

The highest maximum 1-hour ambient SO_2 concentrations estimated at the site boundary or at Elk Hills Road are 0.140 and 0.139 ppm for existing and future conditions, respectively. These concentrations, estimated for a location at Elk Hills Road south of the junction of Elk Hills and Skyline Roads, are less than 60% of the applicable CAAQS of 0.25 ppm for SO_2.

Because existing CO_2 emissions at NPR-1 are small (14.8 lb/h) and because a small increase (1.5 lb/h) from the proposed new sources and additional vehicular emissions is expected to be offset by the reduction in SO_2 emissions from drilling activities in the future, ambient SO_2 concentrations are expected to remain at the current levels or decrease slightly in 1996. The small contributions to ambient SO_2 concentrations from the NPR-1 sources are expected to decrease even more when the CARB rule limiting the sulfur content of diesel fuel from the current average of 0.28% (by weight) to 0.05% (by weight) is extended to the entire state in October 1993 (California Code of Regulations, Title 13, Section 2555).

The highest maximum ambient SO_2 concentrations for other averaging periods (3 hours, 24 hours, and annual) estimated for the existing and future conditions, both on the site and at the site boundary, are all well below applicable TLVs or ambient standards.

The SO_2 concentrations increments contributed by the proposed new sources, as estimated for PSD review purposes, are negligible. The highest increments at the site boundary or at Elk Hills Road are less than 0.15 $\mu g/m^3$, 0.05 $\mu g/m^3$, and 0.005 $\mu g/m^3$ for the 3-hour, 24-hour, and annual averaging periods, respectively.

B.5.2.4 Particulate Matter

Air quality modeling for primary PM_{10} was performed for (1) temporary emissions of fugitive dust from site-preparation activities during the construction period, (2) stack emissions from combustion sources, and (3) emissions from vehicular traffic, including road dusts on the site and on Elk Hills Road.

Construction Fugitive-Dust Emissions

Figure B.29 shows the isopleths for the maximum 24-hour mean ambient PM_{10} concentration contributions estimated for temporary fugitive-dust emissions from two hypothetical sites that are simultaneously being prepared for construction. The two sites were assumed to be located at the centers of two adjacent sectors (2G and 3G) where substantial future construction activities are anticipated. For worst-case estimation, the maximum hourly emission rates for fugitive dusts during the initial stage of site preparation (i.e., the initial site-clearing period when water application for dust suppression may not be safe or practical) were considered for both sites. The highest maximum 24-hour mean PM_{10} concentration contributions thus estimated are about 10 $\mu g/m^3$ and less than 1 ug/m^3 within and at the site boundary, respectively. The corresponding values for the annual averaging period are about 0.3 $\mu g/m^3$ and 0.05 $\mu g/m^3$, respectively.

As illustrated in Figure B.29, construction fugitive-dust emissions dissipate within short distances from the sources and do not cause any significant impacts at or outside the boundary of NPR-1.

Combustion-Source Stack Emissions

The isopleths of the maximum 24-hour mean ambient primary PM_{10} concentration contributions from NPR-1 combustion sources estimated for current and 1996 stack emissions are shown in Figure B.30. The highest maximum 24-hour PM_{10} concentration contribution estimated within the NPR-1 site boundary is 9.2 $\mu g/m^3$ both for existing and future emissions. The area with the highest estimated maximum 24-hour concentration contribution is in the southeastern quarter of the site (as in the case of SO_2), where most of the current and future drilling and remedial work activities are expected.

The highest maximum 24-hour PM_{10} concentration contributions estimated for the site boundary or for Elk Hills Road are 2.7 and 2.4 $\mu g/m^3$ for existing and future combustion-source emissions, respectively. The slight decrease in the highest concentration contribution at Elk Hills Road is attributed to anticipated decreases in drilling activities east of the road.

Contributions from current and future NPR-1 combustion sources to annual ambient arithmetic mean PM_{10} concentrations are estimated to be small. The highest contribution on the site is about 1 $\mu g/m^3$ both for existing and future stack emissions, and the highest contribution at the site boundary or Elk Hills Road is less than 0.3 $\mu g/m^3$ both for existing and future emission sources.

All Emissions

Figure B.31 shows isopleths of the maximum 24-hour mean ambient PM_{10} concentration contributions estimated for all current and future (1996) emission at NPR-1. The emissions included in these isopleths are (1) construction fugitive dusts, (2) combustion-source stack

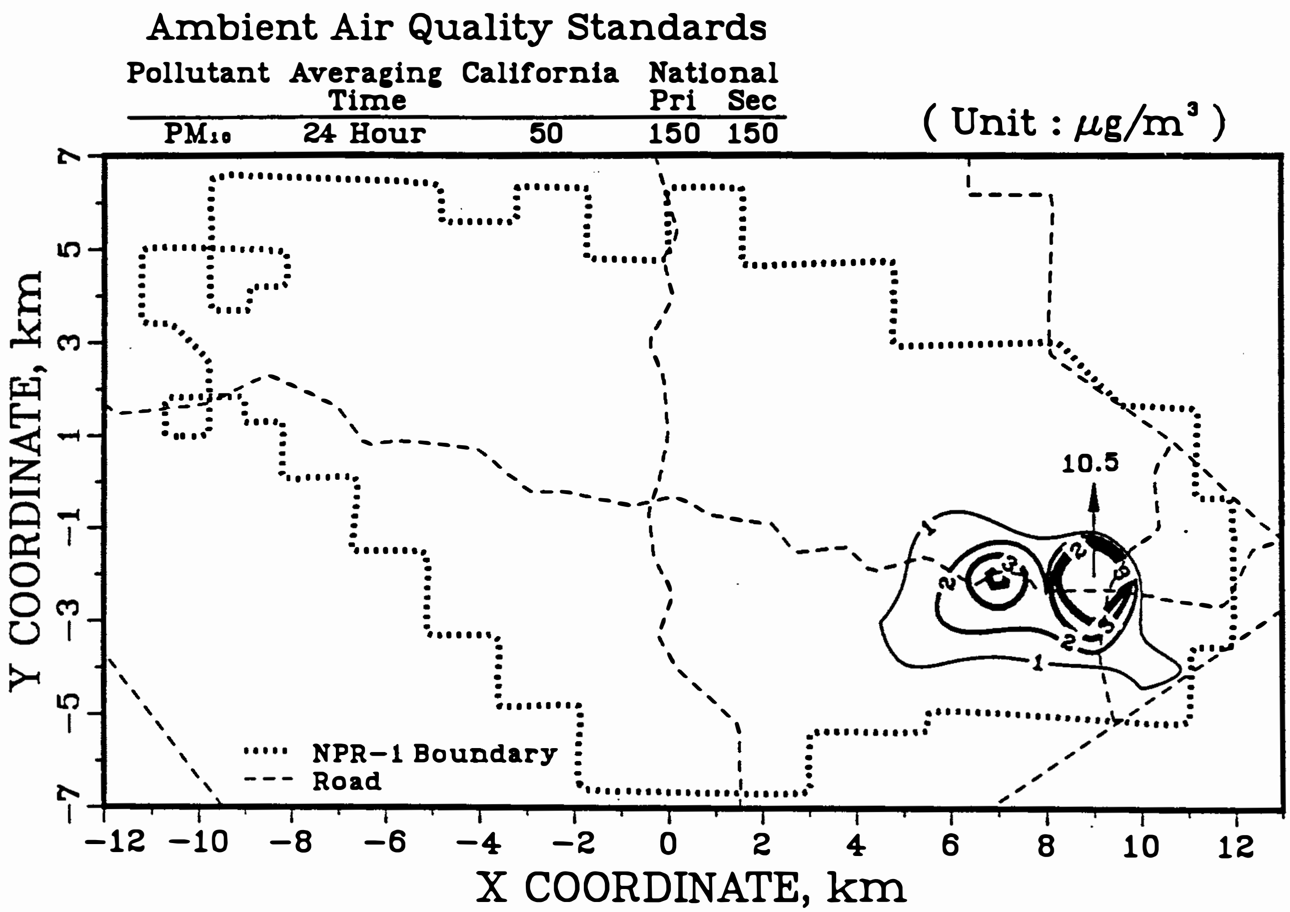


FIGURE B.29 ISOPLETHS FOR MAXIMUM 24-HOUR PM_{10} CONCENTRATIONS ESTIMATED FOR THE CONTRIBUTIONS FROM FUGITIVE-DUST EMISSIONS AT TWO ADJACENT LOCATIONS OF SITE PREPARATION ACTIVITIES

Ambient Air Quality Standards

Pollutant	Averaging Time	California	National Pri	National Sec
PM_{10}	24 Hour	50	150	150

(Unit : $\mu g/m^3$)

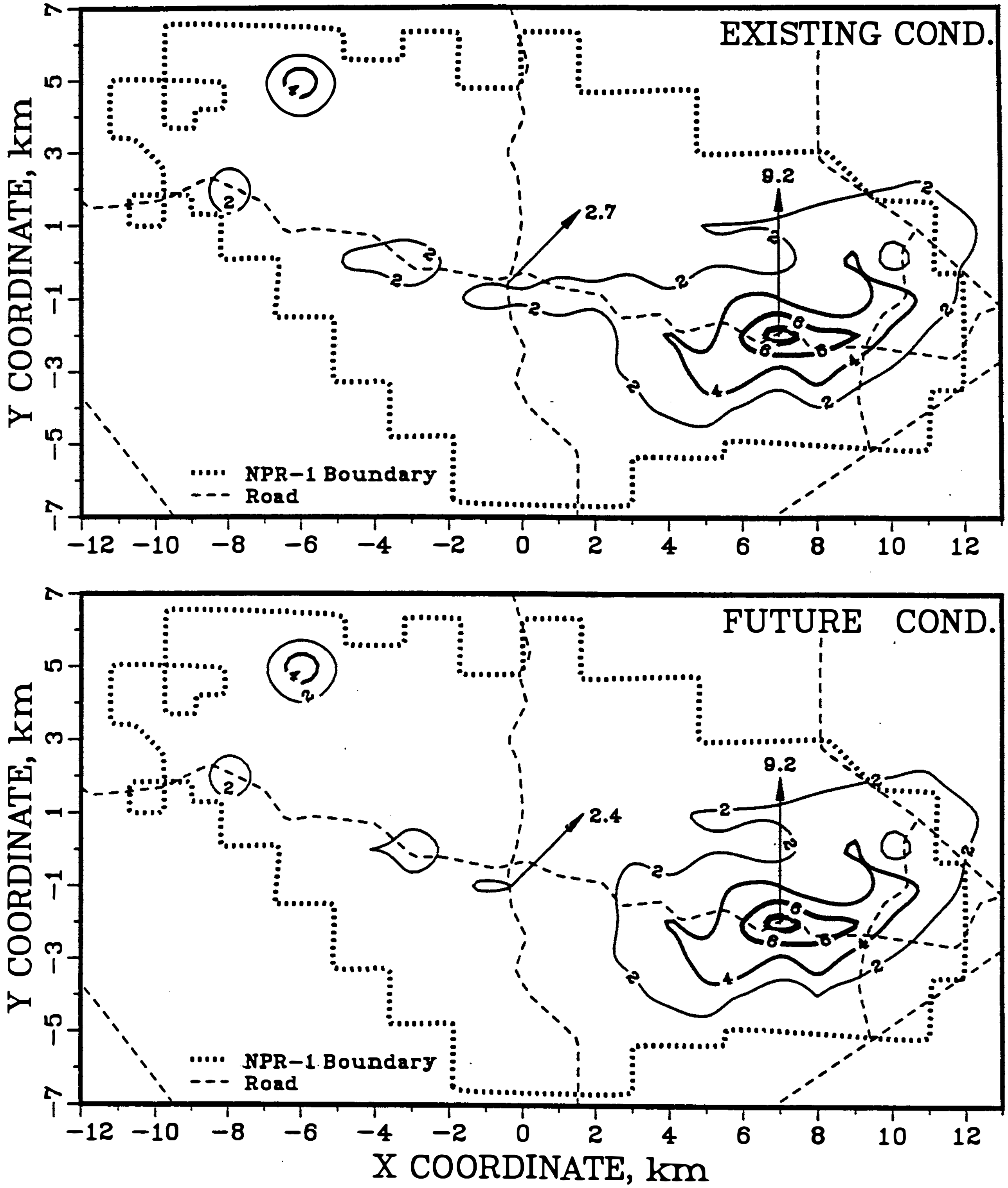


FIGURE B.30 ISOPLETHS FOR MAXIMUM 24-HOUR PM_{10} CONCENTRATIONS ESTIMATED FOR CONTRIBUTIONS FROM EXISTING AND FUTURE COMBUSTION-EMISSION SOURCES AT NPR-1

Ambient Air Quality Standards

Pollutant	Averaging Time	California	National Pri	National Sec
PM_{10}	24 Hour	50	150	150

(Unit : $\mu g/m^3$)

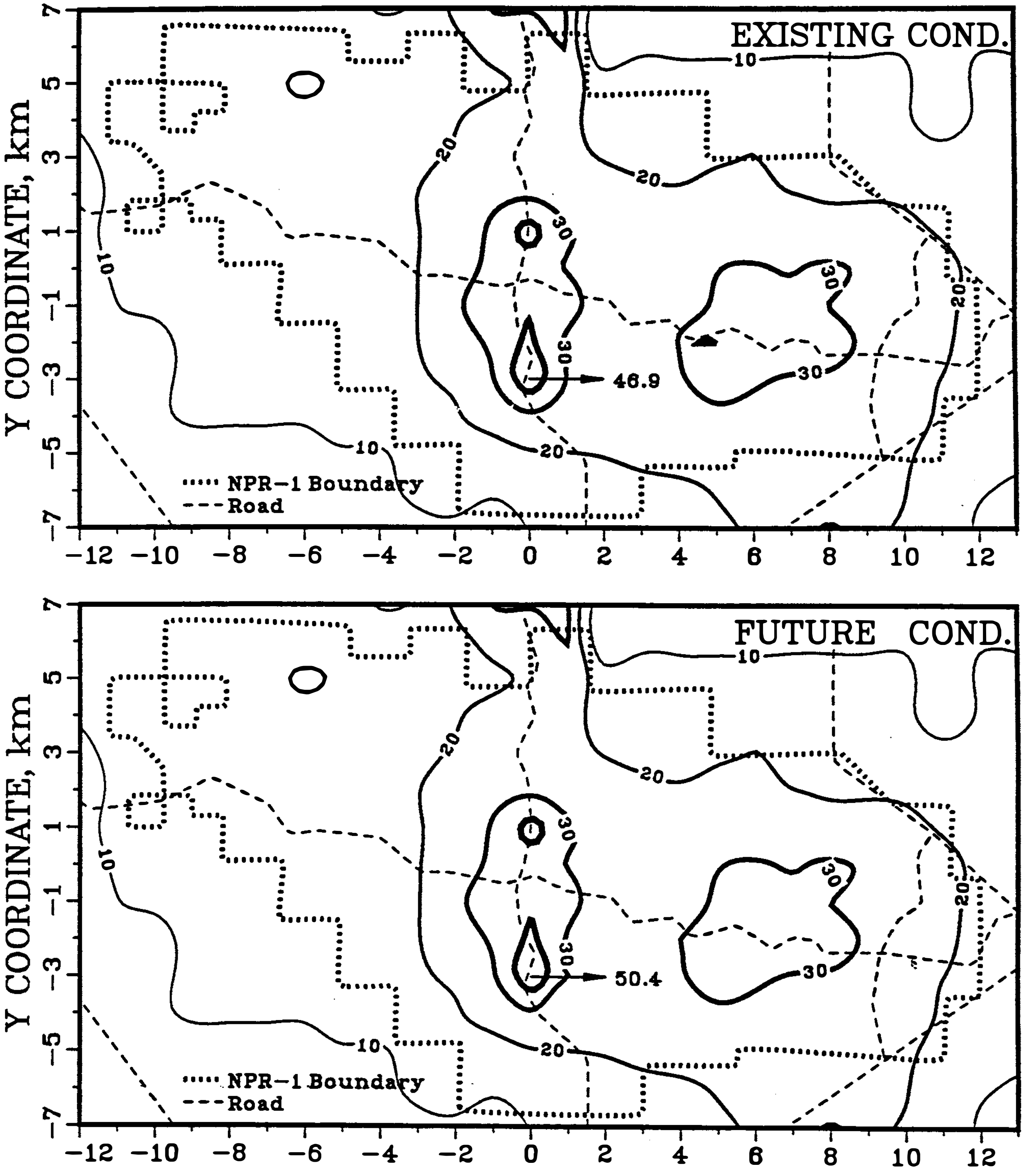


FIGURE B.31 ISOPLETHS FOR MAXIMUM 24-HOUR PM_{10} CONCENTRATION CONTRIBUTIONS ESTIMATED FOR THE EXISTING AND FUTURE PM_{10} EMISSION SOURCES AT NPR-1 (CONSTRUSTION FUGITIVE DUST, COMBUSTION SOURCES, AND ROAD DUST) emissions, and (3) exhaust and road dust emissions from vehicular traffic on the site (for commuting; construction materials and product delivery; and inspection, maintenance, and repair work) and on Elk Hills Road. These concentration isopleths were constructed by adding the maximum 24-hour concentration contributions estimated for the combustion-source emissions and vehicular exhaust emissions to those estimated for construction fugitive dusts and road dusts.

The highest maximum 24-hour PM_{10} concentration contributions estimated for within or at the site boundary are about 47 and 50 $\mu g/m^3$ for the existing and future emissions, respectively. The location of these highest maximum concentrations is at Elk Hills Road, south of the junction of Elk Hills and Skyline Roads. The estimated increase in the maximum 24-hour PM_{10} concentration at this location from the current to future conditions is about 3 $\mu g/m^3$.

Contributions from all existing or future emission sources at NPR-1 to annual arithmetic mean PM_{10} concentrations are estimated to be less than 40% of those for the 24-hour mean concentrations. The maximum annual arithmetic PM_{10} concentration contribution on Elk Hills Road, just north of the junction of Elk Hills and Skyline Roads, are about 16 and 17 $\mu g/m^3$ for the existing and future emissions at NPR-1, respectively. The estimated increase in the maximum annual PM_{10} concentrations from the current to future conditions is small (about 1 $\mu g/m^3$).

The ambient PM_{10} concentration contributions (for 24-hour and annual averaging periods) estimated above for all existing or future emission sources at NPR-1 (47 and 50 $\mu g/m^3$ for the 24-hour period, and 16 and 17 $\mu g/m^3$ for the annual period) are by themselves less than or equal to the corresponding CAAQS or NAAQS (50 $\mu g/m^3$ and 150 $\mu g/m^3$ for the 24-hour period, and 30 $\mu g/m^3$ and 50 $\mu g/m^3$ for the annual period). However, the highest maximum 24-hour PM_{10} concentrations of 47 and 50 $\mu g/m^3$ estimated for Elk Hills Road for the contributions from all existing and future emission sources at NPR-1, respectively, are quite close or equal to the California 24-hour ambient standard of 50 $\mu g/m^3$. The maximum ambient PM_{10} ambient concentrations measured in western Kern County during 1988 (at the Taft monitoring station, which is the only station in western Kern County where PM_{10} data were collected throughout the year) were 393 $\mu g/m^3$ for the 24-hour period and 59.6 $\mu g/m^3$ for the annual period (Table B.12). Both values exceeded the corresponding CAAQS and NAAQS. Since these concentrations would be heavily influenced by the local emission sources near the monitoring sites, they cannot be considered as realistic background concentrations near the NPR-1 site boundary. However, they cannot be lower than the natural background, which is usually on the order of 5-50 $\mu g/m^3$ (Junge 1963). When background concentrations are included, the total PM_{10} concentrations at the NPR-1 site boundary would exceed the 24-hour CAAQS for PM_{10}. The 24-hour NAAQS for PM_{10} and annual CAAQS and NAAQS for PM_{10} could also be exceeded, depending on the background level. However, the maximum total PM_{10} concentrations at the NPR-1 site boundary can not be estimated with a reasonable degree of accuracy until on-site ambient levels are measured.

B.5.2.5 Hydrogen Sulfide

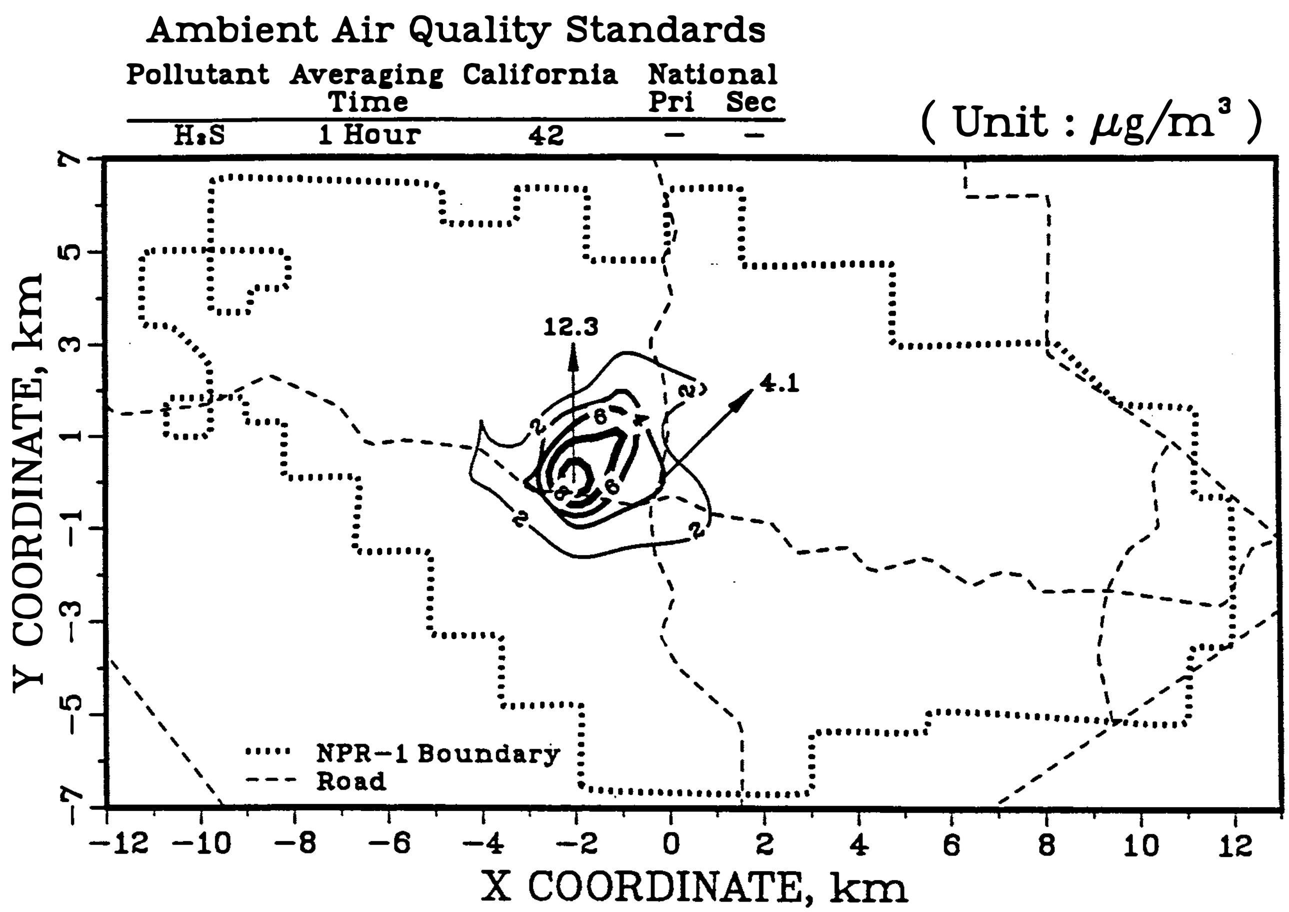
Figure B.32 shows the isopleths of maximum 1-hour H_2S concentration contributions for a hypothetical case of H_2S emissions from tank-setting stack-vent releases. The isopleths were developed based on the concentration contributions estimated using the COMPLEX-I model. The hypothetical case assumes that all four Stevens Zone tank settings in Section 26R, which has the highest combined H_2S release rate among all sections within the NPR-1 site boundary, are releasing H_2S simultaneously. The highest maximum 1-hour H_2S concentration estimated is 12.3 $\mu g/m^3$ at the southwestern corner of Section 26R, just north of Skyline Road. This hypothetical maximum 1-hour concentration is less than 0.1% of the applicable 8-hour, time-weighted TLV for H_2S (10 ppm or 13,900 $\mu g/m^3$).

The highest maximum 1-hour H_2S concentration estimated at Elk Hills Road is about 4 $\mu g/m^3$ (0.003 ppm) for the hypothetical case, which is less than one-tenth the applicable CAAQS for H_2S (42 $\mu g/m^3$ or 0.03 ppm). It is reasonable to conclude that ambient H_2S concentrations significantly greater than those estimated above are currently not expected at NPR-1 for the following reasons: (1) the H_2S emission rate assumed for the four tank settings in Section 26R is more than twice the combined rate for all tank settings in any other section; and (2) there are not other sections with any significant H_2S emission rate near Section 26R. Although H_2S concentrations in the NPR-1 raw gas may increase as the steamflood expansion project progresses, the extent of such an increase is not known at this time. However, there is substantial margin available between the currently estimated hypothetical maximum ambient H_2S concentration and the applicable CAAQS.

Hydrogen sulfide may accumulate inside crude oil tanks at tank settings and LACT facilities and then may be released to the atmosphere through relief valves or open gauge hatches. Measurements of H_2S concentration at the mouth of open gauge hatches of these tanks showed levels as high as 750 ppm. However, the concentrations 12 inches downwind of the open gauge hatch were less than or equal to 7 ppm, indicating that the rate of H_2S escaping from the open gauge hatches is small, and any escaping H_2S disperses rather quickly to levels below the TLV value for H_2S (10 ppm) within short distances downwind.

B.5.2.6 Benzene

The ambient concentrations of benzene (C_6H_6) resulting from two hypothetical cases of oil spills were estimated using the ISC model and treating the spills as area sources. The two hypothetical cases are typical minor and major oil spills at NPR-1, with a mean spill volume of 10 barrels and 250 barrels, respectively. It was also assumed that (1) oil is spilled on a flat ground, (2) the spill areas are 10 x 10 meters and 50 x 50 meters for the minor and major spill, respectively, with a mean thickness of 1.6 centimeters, and (3) all C_6H_6 contained in the spilled oil is evaporated within 1 hour after the spill. The last assumption was based on calculations using the formula developed by Stiver et al. (1989) and the



H2S SOURCES AT 26R–COMPLEX1

FIGURE B.32 ISOPLETHS FOR MAXIMUM 1-HOUR H_2S CONCENTRATIONS ESTIMATED FOR A HYPOTHETICAL CASE OF H2S EMISSION FROM STACK-VENT STACKING RELEASES assumed mean spill thickness of 1.6 centimeters. The total amount of C_6H_6 evaporated was based on the measured concentrations of C_6H_6 in crude oil produced at NPR-1 (Zalco Laboratories 1988) and the assumed spill volumes.

The maximum 1-hour ambient C_6H_6 concentrations for the hour immediately after a spill are estimated to be about 66 ppm and 90 ppm at the downwind boundaries of a minor spill and a major spill, respectively. These concentrations are equivalent to about 8 ppm and 11 ppm as 80 hour, time-weighted mean concentrations, because the C_6H_6 evaporation ceases after 1 hour. These concentration levels are higher than the OSHA's permissible exposure limits for C_6H_6 (8-hour, time weighted average [TWA] of 1 ppm and 15-minute, time-weighted, short-term exposure limit [STEL] of 5 ppm). The estimated maximum 1-hour C_6H_6 concentrations decrease to 32 ppm and 80 ppm within 10 meters downwind from the spill secondary for minor and major spills, respectively. The concentrations are equivalent to about 4 ppm and 10 ppm as 8-hour, time-weighted mean concentrations.

In real oil-spill situations, the thickness of the spill area might be much greater than the 1.6 centimeters assumed in this analysis, e.g., when the spill is collected in a depression. For a thicker spill, it would take longer for the same amount of C_6H_6 to evaporate. If it takes longer than 1 hour for most of C_6H_6 to evaporate, the maximum 1-hour ambient C_6H_6 concentrations would be lower than those estimated above for the hypothetical cases.

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APPENDIX C:

DESCRIPTIONS, PROPERTIES, AND EROSION OF ELK HILLS SOILS

C.1 SOIL DESCRIPTIONS

Twenty-six distinct soil map units have been identified for the Elk Hills. Table C.1 presents data on the surface area covered by each unit and lists the percentage of the total mapped area occupied by each unit. It is apparent from this tabulated information and the detailed descriptions given in a recent soil survey report by the Soil Conservation Service (SCS undated) that about six basic soils are present at the site -- (1) Cajon sandy loam, (2) Elk Hills sandy loam, (3) Elk Hills sandy loam, saline-sodic, (4) Garces fine sandy loam, (5) Kimberlina sandy loam, and (6) Torriorthents soils. The remaining map units are combinations or slight variants of these basic soils (such as eroded or very thin profile) that occur under varying slope conditions. Therefore, a reasonable understanding of the soil conditions of the site can be obtained from characteristics of the basic units, as summarized below. Definitions of the terms used in the following summary descriptions can be found in the text and glossary of the SCS report. Further details and quantitative estimates of the range for some variables normally expressed in qualitative terms (e.g., low, moderate, and high) are given in the U.S. Department of Agriculture's *Soil Survey Manual* (USDA 1951).

Cajon sandy loam is a very deep, somewhat excessively drained soil formed on alluvial fans. The present vegetation on this soil is mainly annual grasses, forbs, and scattered shrubs. Cheesebush is a common shrub in areas that have been disturbed. This soil occurs at elevations ranging from 300 to 720 feet and on slopes commonly between 2 and 5%. The surface layer of this unit is typically pale-brown sandy loam or loamy sand about 8 inches thick. The underlying material is stratified loamy sand or sand to a depth of 60 inches or more.

Permeability of the Cajon sandy loam is moderately rapid at the surface to rapid in the subsurface. Available water capacity is low or moderate, runoff is very slow, and the hazard of water erosion is slight. The hazard of wind erosion is moderate in the natural state and higher if the surface is disturbed. The hazard of flooding is rare.

Elk Hills sandy loam is a very deep, well-drained soil occurring on hills. The present vegetation growing on this soil is mainly annual grasses, forbs, and scattered shrubs. This soil is found at elevations of 400 to 1,380 feet. Slopes vary in steepness.

Typically the surface layer of this unit is a yellowish-brown sandy loam about 9 inches thick and is underlain by a layer of pale-brown sandy loam about 39 inches thick. Pale-brown loamy sand extends to a depth of 60 inches or more. In some locations, the surface may be loam, silt loam, or gravelly sandy loam.

TABLE C.1 Acreage and Proportionate Extent of Elk Hills Soils

Map Symbol	Map Unit	Acres	%
101	Cajon sandy loam, 2-5% slopes	205	0.4
102	Elk Hills sandy loam, 9-15% slopes	2,305	4.9
103	Elk Hills sandy loam, 15-30% slopes	3,685	12.1
104	Elk Hills sandy loam, 30-60% slopes	2,405	5.1
105	Elk Hills complex, 9-30% slopes	1,125	2.4
106	Elk Hills complex, 30-50% slopes	1,375	2.9
107	Garces fine sandy loam, 0-2% slopes	90	0.2
108	Kimberlina sandy loam, 0-2% slopes	200	0.4
109	Kimberlina sandy loam, 2-5% slopes	2,270	4.8
110	Kimberlina sandy loam, 5-9% slopes	2,035	4.3
111	Kimberlina-Cajon, occasionally flooded-Riverwash complex, 0-5% slopes	505	1.1
112	Kimberlina-Urban Land complex, 0-5% slopes	485	1.0
113	Torriorthents, thick, 9-15% slopes	470	1.0
114	Torriorthents, thick, 15-30% slopes	1,245	2.6
115	Torriorthents, thick, 30-50% slopes	830	1.8
116	Torriorthents, thin, 30-50% slopes, eroded	100	0.2
117	Torriorthents, very thin, 30-50% slopes, eroded	240	0.5
118	Torriorthents, thick-Elk Hills complex, 9-15%	195	0.4
119	Torriorthents, thick-Elk Hills complex, 15-30% slopes	5,510	11.8
120	Torriorthents, thick-Elk Hills complex, 30-50% slopes	3,745	7.9
121	Torriorthents, thick-Torriorthents, thin complex, 15-30% slopes	3,565	7.5
122	Torriorthents, thick-Torriorthents, very thin, eroded complex, 15-30% slopes	1,705	3.6
123	Torriorthents, thick-Torriorthents, very thin eroded-Elk Hills complex, 15-50% slopes	2,995	6.3
124	Torriorthents, thick-Torriorthents, thin complex, 30-60% slopes	2,035	4.3
125	Torriorthents, thick-Elk Hills-Torriorthents, thin, eroded complex, 30-60% slopes	1,280	2.7
126	Torriorthents, thick-Torriorthents, thin-Torriorthents very thin, eroded complex, 30-60%	4,645	9.8
	Total	47,245	100

Source: SCS undated.

The Elk Hills sandy loam unit is characterized by moderately rapid permeability and moderate to high available water capacity. Runoff tends to be medium on gentle slopes and increases to rapid on steeper slopes. Generally, the water erosion hazard is moderate; however, on steeper slopes ranging up to 60%, the erosion hazard increases to high. Wind erosion hazard is low if the surface is not disturbed, but increases following disturbance.

Elk Hills sandy loam, saline-sodic soil is intricately associated with the Elk Hills sandy loam in several map units. The sandy loam soil is often found on ridge tops and some northern aspects, while the saline-sodic type occurs on slopes of all aspects and a wide range of steepness. The saline-sodic soil is very deep, well drained, and supports vegetation that includes annual grasses, forbs, and scattered shrubs.

The surface layer of this unit is often yellowish-brown loam or sandy loam 7-11 inches thick. The next layer is generally pale-brown loam from less than 20 inches to about 50 inches thick and is underlain by stratified coarse sandy loam, sand, and gravelly coarse sand to a depth of 60 inches or more.

The permeability of this saline-sodic soil is moderately rapid, and available water capacity is low to moderate. Runoff is generally rapid, and water erosion hazard ranges from moderate on lesser slopes to high on steeper slopes. The hazard of wind erosion is low in the undisturbed state, but increases if the surface is disturbed.

Garces fine sandy loam is a very deep, well-drained saline-sodic soil found on basin rims. As with most other soils in the area, natural vegetation is mainly annual grasses, forbs, and scattered shrubs. This soil is generally found at elevations of 290 to 310 feet and on slopes ranging from 0 to 2%.

The surface layer of the Garces soil typically is pale-brown fine sandy loam, silt loam, or loam and is only about 2 inches thick. The subsoil is grayish-brown clay loam about 10 inches thick. The substratum extends to a depth of 60 inches or more and usually consists of grayish-brown loam, clay loam, or sandy clay loam.

This unit has a very slow permeability because of the presence of clay in the subsoil. Available water capacity is low to moderate, and runoff is very slow. The hazard of water erosion is slight, and that of wind erosion is low in the undisturbed state.

Kimberlina sandy loam is a very deep, well-drained soil found on alluvial fans at elevations ranging from 300 to 1,000 feet and on slopes of 0-9%. Present vegetation is mainly annual grasses, forbs, and scattered shrubs.

The surface layer of this unit is typically pale-brown to light yellowish-brown sandy loam or loamy sand about 6-12 inches thick. The underlying material to a depth of 60 inches or more is light yellowish-brown sandy loam.

The permeability of Kimberlina sandy loam is moderately rapid; available water capacity is moderate. Runoff ranges from very slow on flat to gentle slopes to medium on the steeper gradients. The hazard of water erosion is slight on gentle slopes, increasing to moderate at the upper range of slopes. In all slope conditions, the hazard of wind erosion is low for undisturbed soils.

Torriorthents soils on the Elk Hills have been distinguished as Torriorthents, thick, thin, or very thin, depending on the thickness of the surface soil layer. The thin and very thin Torriorthents have lost significant quantities of topsoil due to erosion. These soils all tend to be very deep, well-drained, and saline-sodic. They occur on hills ranging in elevation from about 400 feet to more than 1,500 feet and under slope conditions ranging from 9 to 60%.

The Torriorthents are highly variable in profile and tend to be intricately and complexly intermingled. They are saline-sodic below a depth of 12-40 inches A typical profile consists of a yellowish-brown loam, silt loam, or sandy loam surface layer about 8 inches thick (this varies depending on degree of erosion). This surface layer is underlain by a light yellowish-brown sandy loam about 20 inches thin, which, in turn, is underlain by a pale brown silt loam about 14 inches thick. The underlying material to a depth of 60 inches or more is light yellowish-brown loam. Specific profile characteristics may vary significantly from one location to another.

The Torriorthents are highly variable in profile and tend to be intricately and complexly intermingled. They are saline-sodic below a depth of 12-40 inches A typical profile consists of a yellowish-brown loam, or sandy loam surface layer about 8 inches thick (this varies depending on degree of erosion). This surface layer is underlain by a pale brown silt loam about 14 inches thick. The underlying material to a depth of 60 inches or more is light yellowish-brown loam. Specific profile characteristics may vary significantly from one location to another.

Permeability of the Torriorthents soils tends to be slow to moderate. Runoff ranges from medium to rapid due primarily to the range of slope conditions where these soils are found. Available water capacity is generally low or moderate. The hazard of water erosion varies from moderate to high, and the wind erosion hazard is mostly low if the soil is undisturbed.

C.2 SUMMARY OF GENERAL PROPERTIES OF ELK HILLS SOILS

Estimates of some characteristics and features that affect soil behavior are presented in Table C.2. Estimates are given for the major layers of each soil surveyed, and depths to the upper and lower boundaries of each layer are presented. The range in depth and other properties for individual soil layers can be found in the SCS report (undated). Other parameters and units of measure presented in the table are briefly discussed below.

TABLE C.2 Physical and Chemical Properties of the Elk Hills Soils[a]

Soil Map Symbol and Name	Depth (in.)	Clay (%)	Permeability (in./h)	Available Water Capacity (in./in.)	Hydrologic Group	Flooding Frequency	Soil Reaction (pH)	Salinity (mmho/cm)	Shrink-swell Potential	Soil Erodibility (K)	Wind Erodibility Group
101											
Cajon	0-8	8-18	2.0-6.0	0.09-0.12	A	Rare	7.4-8.4	<2	Low	0.28	3
	8-60	0-5	6.0-20	0.06-0.10			7.4-8.4	<2	Low	0.15	
102											
Elk Hills	0-48	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	48-60	5-18	2.0-6.0	0.07-0.12			7.4-8.4	<8	Low	0.28	
103											
Elk Hills	0-7	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	7-49	5-18	2.0-6.0	0.09-0.15			7.4-8.4	<4	Low	0.43	
	49-60	5-18	2.0-6.0	0.07-0.12			7.4-8.4	<8	Low	0.28	
104											
Elk Hills	0-26	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	26-50	5-18	2.0-6.0	0.09-0.15			7.4-8.4	<4	Low	0.43	
	50-60	5-18	2.0-6.0	0.07-0.12			7.4-8.4	<8	Low	0.28	
105											
Elk Hills	0-7	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<4	Low	0.37	6
	7-57	5-18	2.0-6.0	0.06-0.13			7.9-9.0	4-16	Low	0.43	
	57-60	5-18	2.0-6.0	0.05-0.10			7.9-9.0	4-16	Low	0.28	

TABLE C.2 (Cont'd)

Soil Map Symbol and Name	Depth (in.)	Clay (%)	Perme-ability (in./h)	Available Water Capacity (in./in.)	Hydro-logic Group	Flooding Frequency	Soil Reaction (pH)	Salinity (mmho/cm)	Shrink-swell Potential	Soil Erodi-bility (K)	Wind Erodi-bility Group
Elk Hills	0-14	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	14-60	5-18	2.0-6.0	0.09-0.15			7.4-8.4	<4	Low	0.43	
106											
Elk Hills	0-11	5-18	2.0-6.0	0.09-0.13	B		7.4-8.4	<4	Low	0.37	6
	11-57	5-18	2.0-6.0	0.06-0.13		None	7.9-9.0	4-16	Low	0.43	
	57-60	5-18	2.0-6.0	0.05-0.10			7.9-9.0	4-16	Low	0.28	
Elk Hills	0-12	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	12-52	5-18	2.0-6.0	0.09-0.15			7.4-8.4	<4	Low	0.43	
	52-60	5-18	2.0-6.0	0.07-0.12			7.4-8.4	<8	Low	0.28	
107	0-2	10-18	0.6-2.0	0.09-0.12	D	None	7.4-9.0	2-8	Low	0.43	5
Garces	2-12	27-35	<0.06	0.07-0.13			>8.4	>8	Moderate	0.43	
	12-60	10-27	0.2-0.6	0.05-0.14			>8.4	>4	Low	0.43	
108											
Kimberlina	0-12	6-18	2.0-6.0	0.10-0.13	B	Rare	6.6-8.4	<2	Low	0.32	6
	12-60	10-18	2.0-6.0	0.10-0.13			7.9-8.4	<4	Low	0.32	
109											
Kimberlina	0-4	6-18	2.0-6.0	0.10-0.13	B	Rare	6.6-8.4	<2	Low	0.32	6
	4-60	10-18	2.0-6.0	0.10-0.13			7.9-8.4	<4	Low	0.32	
110											
Kimberlina	0-6	6-18	2.0-6.0	0.10-0.13	B	None	6.6-8.4	<2	Low	0.32	6
	6-60	10-18	2.0-6.0	0.10-0.13			7.9-8.4	<4	Low	0.32	
111											
Kimberlina	0-10	6-18	2.0-6.0	0.10-0.13	B	Rare	6.6-8.4	<2	Low	0.32	6
	10-60	10-18	2.0-6.0	0.10-0.13			7.9-8.4	<4	Low	0.32	

TABLE C.2 (Cont'd)

Soil Map Symbol and Name	Depth (in.)	Clay (%)	Perme-ability (in./h)	Available Water Capacity (in./in.)	Hydro-logic Group	Flooding Frequency	Soil Reaction (pH)	Salinity (mmho/cm)	Shrink-swell Potential	Soil Erodi-bility (K)	Wind Erodi-bility Group
Cajon	0-4	0-8	6.0-20	0.06-0.09	A	Occasional	7.4-8.4	<2	Low	0.15	
	4-60	0-5	6.0-20	0.06-0.10			7.4-8.4	<2	Low	0.15	
Riverwash											3
112											
Kimberlina	0-8	6-18	2.0-6.0	0.10-0.13	B	None	6.6-8.4	<2	Low	0.32	
	8-60	10-18	2.0-6.0	0.10-0.13			7.9-8.4	<4	Low	0.32	
Urban Land											6
113							7.4-8.4				
Torriorthents	0-28	8-20	2.0-6.0	0.09-0.12	B	None	7.9-9.0	<4	Low	0.32	
	28-60	7-25	0.2-2.0	0.08-0.12				8-16	Low	0.24	
114											3
Torriorthents	0-5	8-20	0.6-2.0	0.13-0.15	B	None	7.4-8.4	<4	Low	0.43	
	5-36	12-35	0.2-2.0	0.09-0.14			7.4-9.0	<4	Moderate	0.37	
	36-60	7-25	0.2-2.0	0.09-0.12			7.9-9.0	8-16	Low	0.24	5

TABLE C.2 (Cont'd)

Soil Map Symbol and Name	Depth (in.)	Clay (%)	Perme-ability (in./h)	Available Water Capacity (in./in.)	Hydro-logic Group	Flooding Frequency	Soil Reaction (pH)	Salinity (mmho/cm)	Shrink-swell Potential	Soil Erodi-bility (K)	Wind Erodi-bility Group
115											
Torriorthents	0-10	8-20	2.0-6.0	0.09-0.12	B	None	7.4-8.4	<4	Low	0.32	3
	10-32	7-25	0.2-2.0	0.08-0.12			7.9-9.0	8-16	Low	0.24	
	32-60	25-60	0.06-0.6	0.06-0.12			7.9-9.0	>4	High	0.28	
116											
Torriorthents	0-5	8-20	0.6-2.0	0.13-0.16	B	None	7.4-8.4	<4	Low	0.43	5
	5-60	15-35	0.2-0.6	0.05-0.13			7.9-9.0	>8	Moderate	0.37	
117											
Torriorthents	0-9	10-27	0.6-2.0	0.06-0.13	B	None	7.4-9.0	>8	Low	0.43	4L
	9-60	25-60	0.06-0.6	0.04-0.12			7.9-9.0	>8	High	0.28	
118											
Torriorthents	0-35	8-20	0.6-2.0	0.13-0.15	B	None	7.4-8.4	<4	Low	0.43	5
	35-60	25-60	0.06-0.6	0.06-0.12			7.9-9.0	>4	High	0.28	
Elk Hills	0-31	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	31-60	5-18	2.0-6.0	0.07-0.12			7.4-8.4	<8	Low	0.28	
119											
Torriorthents	0-18	8-20	0.6-2.0	0.13-0.15	B	None	7.4-8.4	<4	Low	0.43	5
	18-37	12-35	0.2-2.0	0.09-0.14			7.4-9.0	>14	Moderate	0.37	
	37-60	25-60	0.06-0.6	0.06-0.12			7.9-9.0	>8	High	0.28	
Elk Hills	0-23	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	23-60	5-18	2.0-6.0	0.07-0.12			7.4-8.4	<8	Low	0.28	
120											
Torriorthents	0-5	8-20	0.6-2.0	0.13-0.15	B	None	7.4-8.4	<4	Low	0.43	5
	5-36	12-35	0.2-2.0	0.09-0.14			7.4-9.0	<4	Moderate	0.37	
	36-60	25-60	0.06-0.6	0.09-0.12			7.9-9.0	>4	High	0.28	
Elk Hills	0-5	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	5-60	5-18	2.0-6.0	0.09-0.15			7.4-8.4	<4	Low	0.43	

TABLE C.2 (Cont'd)

Soil Map Symbol and Name	Depth (in.)	Clay (%)	Perme-ability (in./h)	Available Water Capacity (in./in.)	Hydro-logic Group	Flooding Frequency	Soil Reaction (pH)	Salinity (mmho/cm)	Shrink-swell Potential	Soil Erodi-bility (K)	Wind Erodi-bility Group
121											
Torriorthents	0-8	8-20	0.6-2.0	0.13-0.15	B	None	7.4-8.4	<4	Low	0.43	5
	8-20	12-35	0.2-2.0	0.09-0.14			7.4-9.0	<4	Moderate	0.37	
	20-60	7-25	0.2-2.0	0.08-0.12			7.9-9.0	8-15	Low	0.24	
Torriorthents	0-8	8-20	2.0-6.0	0.08-0.11	B	None	7.4-8.4	<4	Low	0.32	3
	8-60	15-35	0.2-0.6	0.05-0.13			7.9-9.0	>8	Moderate	0.37	
122											
Torriorthents	0-6	8-20	2.0-6.0	0.09-0.12	B	None	7.4-8.4	<4	Low	0.32	3
	6-32	12-35	0.2-2.0	0.09-0.14			7.4-9.0	<4	Moderate	0.37	
	32-60	25-60	0.06-0.6	0.06-0.12			7.9-9.0	>4	High	0.28	
Torriorthents	0-3	10-37	0.6-2.0	0.06-0.13	B	None	7.4-9.0	>8	Low	0.43	4L
	3-46	15-35	0.2-2.0	0.04-0.12			7.9-9.0	>8	Moderate	0.32	
	46-60	25-60	0.06-0.6	0.04-0.12			7.9-9.0	>8	High	0.28	
123											
Torriorthents	0-28	8-20	2.0-6.0	0.09-0.12	B	None	7.4-8.4	<4	Low	0.32	3
	28-60	25-60	0.06-0.6	0.06-0.12			7.9-9.0	>4	High	0.28	

TABLE C.2 (Cont'd)

Soil Map Symbol and Name	Depth (in.)	Clay (%)	Perme-ability (in./h)	Available Water Capacity (in./in.)	Hydro-logic Group	Flooding Frequency	Soil Reaction (pH)	Salinity (mmho/cm)	Shrink-swell Potential	Soil Erodi-bility (K)	Wind Erodi-bility Group
Torriorthents	0-7	27-35	2.0-6.0	0.07-0.18	B	None	7.4-9.0	>8	Moderate	0.32	6
	7-44	10-27	0.6-6.0	0.05-0.12			7.9-9.0	>8	Low	0.43	
	44-60	25-60	0.06-0.6	0.04-0.12			7.9-9.0	>8	High	0.28	
Elk Hills	0-29	5-18	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	6
	29-49	5-18	2.0-6.0	0.09-0.15			7.4-8.4	<4	Low	0.43	
	49-60	5-18	2.0-6.0	0.07-0.12			7.4-8.4	<8	Low	0.28	
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Torriorthents	0-5	8-20	0.6-2.0	0.13-0.15	B	None	7.4-8.4	<4	Low	0.43	5
	5-25	12-35	0.2-2.0	0.09-0.14			7.4-9.0	<4	Moderate	0.37	5
	25-60	25-60	0.06-0.6	0.06-0.12			7.9-9.0	>4	High	0.28	
Torriorthents	0-4	8-20	0.6-2.0	0.13-0.16	B	None	7.4-8.4	<4	Low	0.43	3
	4-60	15-35	0.2-0.6	0.05-0.13			7.9-9.0	>8	Moderate	0.37	
125	0-4	8-20	2.0-6.0	0.09-0.12	B	None	7.4-8.4	<4	Low	0.32	
Torriorthents	4-15	12-35	0.2-2.0	0.09-0.14			7.4-9.0	<4	Moderate	0.37	6
	15-60	25-60	0.06-0.6	0.06-0.12			7.9-9.0	>4	High	0.28	
Elk Hills	0-21	5-15	2.0-6.0	0.09-0.13	B	None	7.4-8.4	<2	Low	0.37	
	21-46	5-18	2.0-6.0	0.09-0.15			7.4-8.4	<4	Low	0.43	5
	46-60	5-18	2.0-6.0	0.07-0.12			7.4-8.4	<8	Low	0.28	
Torriorthents	0-8	8-20	0.6-2.0	0.13-0.16	B	None	7.4-8.4	<4	Low	0.43	
	8-60	25-60	0.06-0.6	0.05-0.12			7.9-9.0	>8	High	0.28	

TABLE C.2 (Cont'd)

Soil Map Symbol and Name	Depth (in.)	Clay (%)	Perme-ability (in./h)	Available Water Capacity (in./in.)	Hydro-logic Group	Flooding Frequency	Soil Reaction (pH)	Salinity (mmho/cm)	Shrink-swell Potential	Soil Erodi-bility (K)	Wind Erodi-bility Group
126											
Torriorthents	0-13	8-20	0.6-2.0	0.13-0.15	B	None	7.4-8.4	<4	Low	0.43	5
	13-20	12-35	0.2-2.0	0.09-0.14			7.4-9.0	<4	Moderate	0.37	
	20-38	7-25	0.2-2.0	0.08-0.12			7.9-9.0	8-16	Low	0.24	
	38-60	25-60	0.06-0.6	0.06-0.12			7.9-9.0	>4	High	0.28	
Torriorthents	0-11	8-20	2.0-6.0	0.08-0.11	B	None	7.4-8.4	<4	Low	0.32	3
	11-34	8-20	2.0-6.0	0.05-0.09			7.9-9.0	8-16	Low	0.32	
	34-60	25-60	0.06-0.6	0.05-0.12			7.9-9.0	>8	High	0.28	
Torriorthents	0-10	27-35	0.2-0.6	0.07-0.18	B	None	7.4-9.0	>8	Moderate	0.32	6
	10-48	15-35	0.2-2.0	0.04-0.12			7.9-9.0	>8	Moderate	0.32	
	48-60	25-60	0.06-0.6	0.04-0.12			7.9-9.0	>8	High	0.28	

[a]See text for discussion of terms and units of measurement for each property.

Source: Adapted from SCS undated.

The estimated *clay content* of each major soil layer is presented as a percentage, by weight, of the soil that is less than 0.002 millimeters in diameter. The type and amount of clay affects fertility and physical characteristics of the soil. Among the properties influenced by clay content are cation absorption, moisture retention, shrink-swell potential, permeability, plasticity, and erodibility.

Permeability reflects the ability of the soil to transmit water or air. The tabulated estimates in inches per hour (in./h) indicate the rate of downward movement of water when the soil is saturated. Terms describing permeability are very slow (<0.06 in./h), slow (0.06-0.2 in./h), moderately slow (0.2-0.6 in./h), moderate (0.6-2.0 in./h), moderately rapid (2.0-6.0 in./h), rapid (6.0-20 in./h), and very rapid (greater than 20 in./h).

Availability water capacity refers to the quantity of water that the soil is capable of storing for use by plants. The parameter is measured in terms of inches of water per inch of soil (in./in.) for each major soil layer. Terms describing available water or moisture capacity are very low (0.0-2.5 in./in.), low (2.4-4.0 in./in.), moderate (5.0-7.5 in./in.), high (7.5-10.0 in./in.), and very high (>10.0 in./in.).

Hydrologic soil groups are used to estimate runoff from precipitation based on the intake of water when the soils are thoroughly wet and receive precipitation from long-duration storms (USDA 1951). Group A soils have a high infiltration rate (low runoff potential) and a high rate of water transmission when thoroughly wet. Soils of this group consist mainly of deep, well-drained to excessively drained sand or gravelly sand. Group B soils have moderate infiltration and water transmission rates when thoroughly wet. Most of the soils at Elk Hills fall within Group B. Soils with slow rates of infiltration and water transmission rates are placed in Group C. These soils have a layer that impedes downward water movement or they have a moderately fine to fine texture. Finally, Group D soils have very slow infiltration/water transmission rates (high runoff potential). Soils of this group typically have a large clay content.

Flooding refers to the temporary covering of the soil surface by flowing water derived from overflow from streams or runoff from adjacent slopes. Flooding frequency is expressed in Table C.2 as none, rare, occasional, and frequent. None means that flooding is not probable, rare means that the change of flooding in any year is 0-5%, occasional means that the change of flooding in any year is 5-50%. The chances of flooding for almost all of the soil map units at Elk Hills are categorized as none. This means that it is very unlikely that enough precipitation would occur in any given rainfall event in any given year to generate appreciable runoff in most of the mapped areas.

Soil reaction is a measure of the soil's acidity or alkalinity, expressed as a range in pH values. Most soils on the Elk Hills are mildly alkaline (pH of 7.4-7.8), moderately alkaline (7.9-8.4), or strongly alkaline (8.5-9.0).

Salinity is a measure of soluble salts in the soil at saturation and is expressed as the electrical conductivity of the saturation extract in millimhos per centimeter (mmho/cm) at 25 degrees centigrade. This property affects vegetative growth and the potential of the soil to corrode metal and concrete.

Shrink-swell potential is the potential for volume change in a soil because of moisture loss or gain. This property results from the interaction of clay minerals with water and varies with the type and amount of clay present in the soil. If the shrink-swell potential is rated moderate to very high, the magnitude of volume change can cause damage to buildings, roads, and other structures. Table C.2 indicates that many layers of the Torriorthents soils exhibit moderate to high shrink-swell potential, a problem not encountered in the other soils present on the Elk Hills.

The soil erodibility factor reflects the susceptibility of a soil to sheet and rill erosion. This factor, K, is one of the six variables used in the Universal Soil Loss Equation (USLE) to estimate the average annual rate of soil loss by sheet and rill erosion (see Section C.4.1 of this Appendix). Estimates of this parameter are based on primary soil characteristics, including the percentage of silt, very fine sand, sand, and organic matter, as well as soil structure and permeability (Wischmeier and Smith 1978). Values of K can range from 0.02 to 0.69 (SCS undated, p. 48), with larger values indicating increased susceptibility to erosion. The values of K shown in Table C.2 for most of the Elk Hills soils are larger than the midpoint (0.34) of this range but less than the value corresponding to 66% of the range (0.44). This suggests a moderate susceptibility to sheet and rill erosion. It should be noted also that the K values for the uppermost soil layers tabulated are the most important in evaluating sheet and rill erosion susceptibility. The values for subsoil would become important after the topsoil was removed and the subsoil was exposed at the surface.

Wind erodibility is a factor designed to group soils that have similar properties affecting their resistance to wind erosion. Factors taken into account include susceptibility to wind erosion, the amount of soil lost, and the difficulty of establishing crops. A key characteristic used in categorizing soils is the amount of stable aggregates 0.84 millimeters in size. Thus, two soils with similar surface textures may be classed differently because of differences in clay mineralogy that affect aggregate formation stability. The qualitative description of the wind erodibility of the various oil groups are (1) extremely erodible, (2) very highly erodible, (3) highly erodible, (4) erodible, (4L) moderately erodible, (5) slightly erodible, (6) very slightly erodible, and (7) not subject to wind erosion. Table C.2 indicates that the Elk Hills soils range from highly erodible (Group 3) to very slightly erodible (Group 6). Clearly this classification, although based on soil properties influencing erodibility, is qualitative and does not permit a direct estimate of quantities of soil lost.

Another soil parameter often measured but not included in Table C.2 is *organic matter content*. Organic matter is the plant and animal residue in the soil at various stages of decomposition. It usually is reported as a percentage, by weight, of the soil material less than 2 millimeters in diameter. This variable was reported by the SCS (undated) for the

Elk Hills soils, but was omitted from Table C.2 because all soils contain less than 1% by weight organic matter.

The SCS (undated) also presents data on several other soil properties that affect their use and management. These include engineering index properties, factors affecting building site development, location of construction materials, and several other characteristics.

C.3 CHEMICAL ANALYSES OF SOIL SAMPLES

Chemical elemental analyses have been conducted at the Elk Hills as part of a habitat reclamation program for 41 well sites disturbed by drilling operations (Anderson 1987). Soil concentrations of 17 elements and pH for samples collected at several locations around the Elk Hills site are presented in Tables C.3 and C.4. The prevalence and significance of these elements are briefly discussed below.

The data in Tables C.3 and C.4 were compiled from analytical results reported by Anderson (1987) from soil samples collected at disturbed well sites and at depth ranging to more than 60 inches. The tabulated values are for the upper intervals for a specific sample location reported by Anderson. The soil series identified with the disturbed areas included in the tables were approximated by overlaying a well location map (Figure C.1) on SCS soil survey field sheets (aerial photos, including map unit boundaries) (SCS undated).

The toxicity of a particular element to plants or animals often depends on the elemental form to which the organism is exposed. The following discussion of trace element behavior has been summarized from Dvorak et al (1978) and supplemented where noted by material from Chapman (1965). Additional information on this subject can be found in Gough et al (1979) and Kabata-Pendias and Pendias (1984).

Arsenic (As): Arsenic usually exists in the soil as a divalent anion resembling phosphate. It is converted from a readily available to a less available form in the soil by iron, aluminum, and calcium, and is more soluble under neutral and calcareous conditions. Although arsenic tends to be retained in the soil surface layer, it can be leached slowly to the lower soil horizons when in the soil solution. Total endogenous soil concentrations of arsenic generally range from 0.1 to 40 ppm, with an average of 6.0 ppm. Arsenic toxicity depends on its oxidation state; the pentavalent state, most common in aerated soils, is much less toxic than the trivalent state. Elemental arsenic is considered to be relatively nontoxic. Mean concentrations of arsenic ranged from 0.01 to 0.35 ppm for the soil mapping units of NPR-1.

Barium (Ba): Very little barium is present in soils in water-soluble form. Barium interacts with sulfates in the soil to form insoluble barium sulfate. Soils (notably acid soils) may become infertile if the exchangeable barium exceeds the exchangeable calcium and magnesium. Soluble barium compounds such as barium chloride, barium carbonate, barium sulfide, and barium oxide are highly toxic to animals when ingested. Endogenous soil

TABLE C.3 pH and Basic Elemental Composition in Disturbed Areas

Soil Mapping Unit and Slope	Well No.	pH	Composition (meq/l)		
			Ca	Mg	Na
Torriorthents Soils					
Thick, 15-50%	21-32S	7.4	49.40	19.09	102.80
	9-31T	8.0	32.49	1.38	538.90
	16A-6M	7.5	29.19	1.91	6.09
	87-1G	7.6	27.59	3.34	75.08
Very Thin, 30-50%	75-5G	7.8	39.82	6.57	208.80
Thick-Elk Hills complex, 15-30%	31-16G	8.0	34.23	2.16	134.30
	523-30R	7.6	6.79	0.54	1.75
Thick-Elk Hills Complex, 30-50%	17-34S	8.0	5.04	0.98	46.19
Thick-Torriorthents, Thin Complex, 15-30%	230-36S	7.5	30.74	1.58	47.67
	84-11G	7.8	33.63	1.76	101.90
	33-12G	7.8	4.57	0.38	12.70
	17-27S	7.5	30.14	4.15	46.37
	217-27S	7.7	38.82	3.42	48.81
Thick-Torriorthents, Very Thin Eroded Complex, 15-30%	15-34S	7.2	46.36	3.44	158.50
	16-34S	8.0	5.04	0.98	46.19
	38-35S	7.6	31.34	1.51	46.02
Thick-Torriorthents, Thin Complex, 30-60%	13-35S	7.6	31.14	2.65	42.02
	57-35S	7.2	40.37	3.11	13.40
	1-36S	7.2	42.27	2.25	24.75
	344-29R	7.9	27.69	3.64	66.73
	2D-1G	8.4	33.58	1.37	314.10
	1E-1G	7.2	255.6	15.55	388.90
	2E-1G	7.1	49.15	2.72	45.98
	2G-2G	7.2	42.81	3.50	18.14
	3G-2G	7.6	51.05	3.41	137.20
Thick-Elk Hills-Torriorthents, Thin, Eroded Complex, 30-60%	246-27S	7.8	39.67	3.19	96.09
	86-28S	7.5	36.33	2.96	34.41
	51-34S	7.3	58.88	5.03	83.43
Thick-Torriorthents, Thin Torriorthents, Very Thin, Eroded Complex, 30-60%	67-1G	7.6	29.69	4.94	206.50
	46-2G	7.4	44.21	0.99	2.74
	96-2G	7.7	30.19	3.26	130.90
	73-4G	7.8	26.25	2.99	150.40
	68-9G	8.5	28.69	1.09	252.70

TABLE C.3 (Cont'd)

Soil Mapping Unit and Slope	Well No.	pH	Composition (meq/l)		
			Ca	Mg	Na
Torriorthents Summary					
Average		7.64	38.87	3.51	110.0
Std. Dev.		0.34	35.97	3.85	119.8
Elk Hills Soils					
Elk Hills Sandy Loam, 15-30%	10-25S	7.7	39.17	1.76	30.14
Elk Hills Complex, 2-5%	24-27S	7.50	42.17	3.97	5.39
	57-27S	7.50	35.58	2.50	75.77
	10U-26S	7.6	44.96	3.59	91.08
	16U-26S	7.2	280.90	8.72	95.69
	316-26S	7.4	226.60	37.92	616.40
	21-27S	7.6	22.11	1.07	10.82
Elk Hills Summary					
Average		7.47	108.70	9.63	149.20
Std. Dev.		0.15	113.90	14.10	232.30
Kimberlina Sandy Loam, 2-5%	23S-Gate[a]	8.4	34.73	1.71	265.30

[a]Sample from undisturbed location.

Source: Based on data from Anderson 1987.

TABLE C.4 Trace Element Concentrations in Disturbed Areas

Soil Mapping Unit and Slope	Well No.	Concentrations (ppm)													
		As	Ba	B	Cd	Cr	Cu	Fe	K	Mn	Mo	Ni	Pb	Se	Zn
Torriorthents Soils Thick, 15-50%	21-32S	0.30	62.7	1.8	2.0	95.8	10.7	11,905	244	296.0	39.4	32.1	14.50	16.8	0.6
	9-31T	0.05	58.6	9.1	1.5	48.2	7.1	9,440	151	188.5	7.1	26.1	11.70	11.6	0.7
	16A-6M	0.02	18.6	1.3	0.8	33.8	4.6	6,025	66	105.0	<0.1	17.2	7.30	4.4	0.2
	87-1G	0.01	27.8	9.8	1.6	79.6	9.5	12,250	196	208.5	33.1	28.1	12.30	17.8	0.4
Very Thin, 30-50%	75-5G	0.02	55.9	11.3	2.4	79.0	10.1	9,075	218	250.5	8.2	28.6	11.90	3.8	0.3
Thick-Elk Hills Complex, 15-30%	31-16G	0.01	68.2	8.9	1.6	78.4	8.3	11,865	160	232.0	2.2	23.4	11.41	2.9	1.3
	523-30R	0.01	30.2	0.7	1.5	83.9	10.1	10,980	174	242.5	1.4	27.6	10.80	2.5	0.2
Thick-Elk Hills Complex, 30-50%	17-34S	1.30	92.2	29.8	2.8	71.4	9.2	11,050	173	331.5	11.3	27.2	14.40	10.2	0.4
Thick-Torriorthents, Thin Complex, 15-30%	230-36S	0.12	30.3	2.4	1.0	46.6	6.8	8,485	84	170.0	1.4	22.4	9.20	3.8	0.2
	84-11G	0.50	79.2	8.0	1.2	53.8	5.5	7,455	134	190.0	<0.1	14.2	8.40	0.3	0.2
	33-12G	0.10	63.8	2.8	2.7	117.5	15.8	14,635	261	270.5	5.5	41.4	15.50	3.9	0.4
	17-27S	0.50	18.4	6.0	0.9	63.4	6.0	8,160	1.05	123.2	0.1	18.3	9.10	6.3	1.0
	217-27S	0.15	57.6	3.3	1.2	63.2	8.4	7,660	116	240.5	0.1	19.2	10.80	11.8	0.5
Thick-Torriorthents, Very Thin, Eroded Complex, 15-30%	15-34S	0.35	45.3	23.4	1.7	75.8	9.5	10,330	680	208.0	<0.1	25.0	11.80	6.0	0.7
	16-34S	0.50	35.4	2.0	1.4	50.6	6.2	7,820	173	180.0	<0.1	16.8	12.90	6.4	0.7
	38-35S	0.50	27.0	25.0	1.3	72.2	5.4	7,485	100	132.0	14.7	15.6	8.80	4.2	0.5

TABLE C.4 (Cont'd)

Soil Mapping Unit and Slope	Well No.	As	Ba	B	Cd	Cr	Cu	Fe	K	Mn	Mo	Ni	Pb	Se	Zn
		Concentrations (ppm)													
Thick-Torriorthents Thin Complex, 30-60%	13-35S	1.5	18.7	5.4	1.7	67.8	8.0	11,230	132	217.5	1.2	25.0	19.1	5.7	0.9
	57-35S	0.55	32.3	1.5	1.0	44.6	8.3	8,095	193	171.0	<0.1	24.3	13.5	6.8	0.7
	1-36S	0.45	19.4	4.5	1.1	45.0	7.0	8,100	116	143.5	<0.1	22.2	10.7	5.6	0.3
	344-29R	0.2	38.4	9.6	1.5	71.0	7.5	9,935	132	181.5	12.8	19.6	10.5	2.8	0.2
	2D-1G	0.1	28.6	42.3	1.6	64.0	7.7	9,025	180	223.0	8.0	24.6	10.5	11.6	8.3
	1E-1G	0.15	98.8	9.6	2.0	50.8	6.5	6,690	116	195.5	5.3	23.2	12.8	13.7	0.4
	2E-1G	0.25	89.6	6.2	1.4	46.2	7.1	6,040	91	155.5	7.2	19.2	15.2	11.8	0.9
	2G-2G	0.01	26.1	3.2	0.8	40.2	4.6	4,490	100	104.0	7.3	15.0	10.7	6.7	0.8
	3G-2G	0.02	64.8	17.0	2.2	68.7	9.0	10,370	142	257.5	8.2	28.7	17.4	17.7	0.7
Thick-Elk Hills-Torriorthents, Thin, Eroded Complex, 30-60%	246-27S	0.8	59.4	18.7	2.7	86.0	18.8	12,155	245	315.5	30.0	26.9	17.4	20.4	0.5
	86-28S	0.2	39.9	8.4	1.3	82.0	8.6	10,505	163	218.5	15.7	24.8	10.4	9.6	0.4
	51-34S	0.7	32.4	8.0	1.7	61.2	8.5	9,155	103	202.5	10.7	18.2	11.3	5.5	0.5
Thick-Torriorthents, Thin-Torriorthents, Very Thin, Eroded Complex 30-60%	67-1G	0.2	50.9	8.9	1.2	48.4	5.6	6,800	124	124.5	15.2	17.9	9.7	0.2	0.0
	4G-2G	0.12	14.5	1.2	0.5	23.4	3.2	4,125	108	85.5	<0.1	10.0	7.6	0.2	11.1
	9G-2G	0.01	76.9	12.2	1.9	76.2	8.0	11,045	156	244.5	22.0	29.1	16.4	16.9	0.4
	73-4G	0.6	72.3	10.0	3.3	129.2	18.6	18,220	271	405.5	1.2	46.2	18.4	8.6	0.4
	68-9G	1.0	91.4	25.4	3.3	98.3	12.3	11,670	478	407.0	1.0	32.8	20.9	6.1	0.4

TABLE C.4 (Cont'd)

Soil Mapping Unit and Slope	Well No.	Concentrations (ppm) As	Ba	B	Cd	Cr	Cu	Fe	K	Mn	Mo	Ni	Pb	Se	Zn
Torriorthents Summary															
Average		0.34	49.26	10.23	1.7	67.16	8.56	9,463	178.3	212.8	8.2	23.97	12.52	7.96	1.1
Std. Dev.		0.38	24.84	9.60	0.7	22.91	3.54	2.854	118.5	77.8	10.2	7.46	3.44	5.51	2.3
Elk Hills Sandy Loam, 15-30%	10-25S	0.55	25.7	1.6	0.8	42.5	5.3	5,685	85.0	123.5	12.4	13.0	7.1	9.7	0.5
Elk Hills Complex, 2-5%	25-27S	0.10	27.6	4.0	1.4	65.6	8.1	9,405	196	202.5	5.5	19.4	8.7	4.5	0.5
	57-27S	0.50	46.0	10.0	1.0	54.9	7.9	9,215	183	179.5	1.4	19.0	12.1	8.0	0.7
	10U-26S	0.02	59.3	3.6	1.8	69.7	9.9	1,080	151	192.5	<0.1	23.2	11.4	9.4	0.4
	16U-26S	0.30	24.4	0.9	1.2	37.2	5.8	6,080	127	181.5	1.0	15.2	9.6	6.2	1.5
	316-26S	0.02	22.7	10.6	1.4	135.0	5.6	6,030	175	159.5	<0.1	15.3	7.7	5.4	0.6
	21-27S	0.01	22.6	0.7	1.1	37.0	3.7	5,145	37	101.0	7.1	10.0	5.6	4.0	0.2
Elk Hills Summary															
Average		0.16	33.77	4.97	1.32	66.57	6.83	6,159	144.8	169.4	2.5	17.02	9.18	6.25	0.65
Std. Dev.		0.2	15.33	4.35	0.29	36.24	2.22	3,057	58.26	36.5	3.0	4.55	2.40	2.09	0.45
Kimberlina Sandy Loam, 2-5%	23S-Gate[a]	0.07	57.4	24.9	1.1	58.8	8.0	9,495	255	200.5	7.6	42.9	8.5	6.3	0.3
Acceptable Range[b]		0.1-40	100-3,000		<3.7	<5-1,000	<20-100	Unknown	Unknown	100-4,000	<20	<5-500	<2-200	<80-90	<10-300

[a]Sample from undisturbed location.
[b]Based on data from Gough et al. 1979; Kabata-Pendias 1984.

Source: Based on data from Anderson 1987 except as noted.

Well Locations - Soil Samples Taken from Disturbed Areas

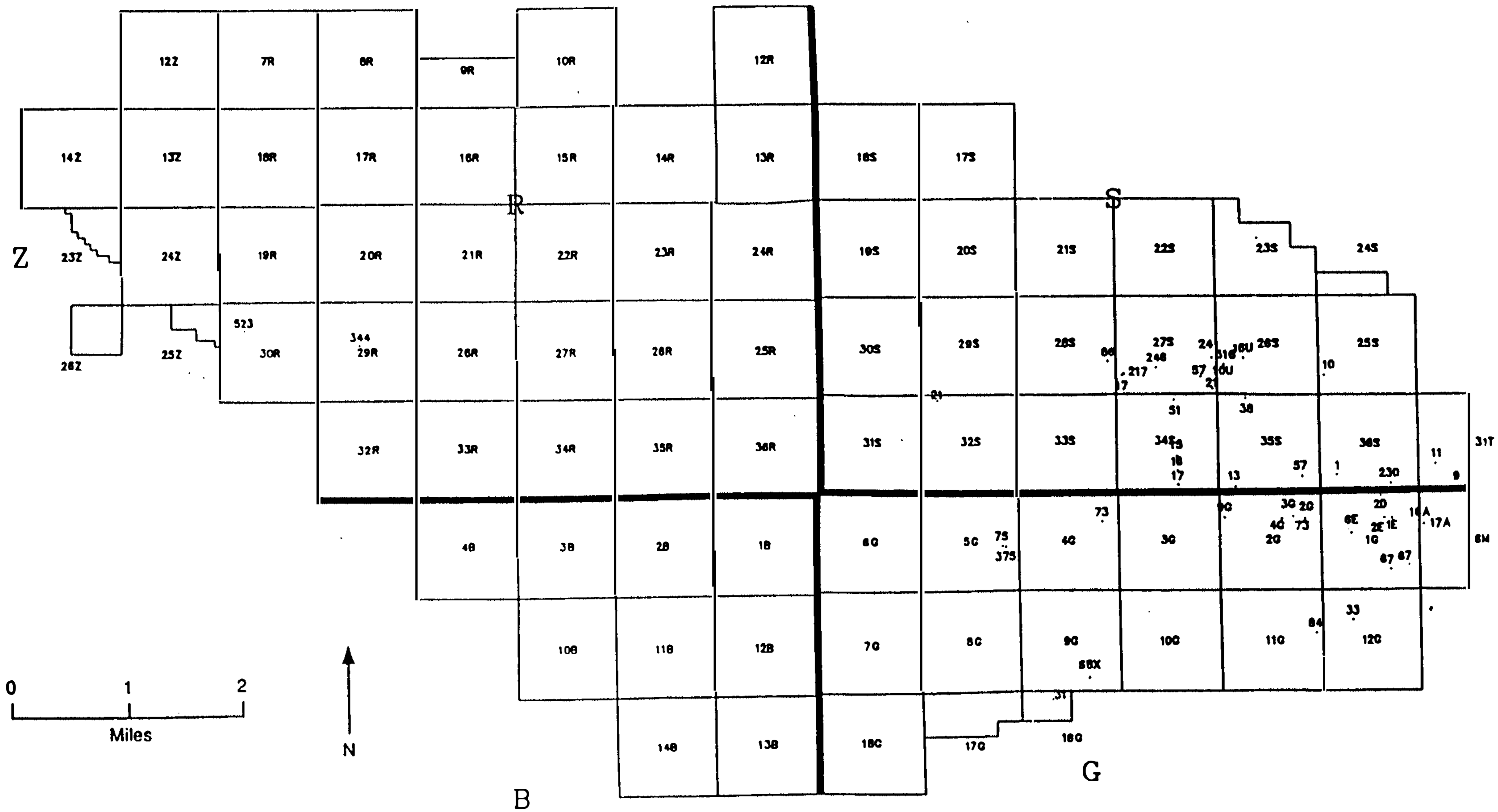

FIGURE C.1 WELL LOCATIONS - SOIL SAMPLES FROM DISTURBED AREAS concentrations of barium range from 100 to 3,000 ppm in most soils (Chapman 1965). Maximum barium concentrations measured in the disturbed areas listed in Table C.4 were 92.2 ppm.

Boron (B): Boron usually exists as undisassociated boric acid in soils of pH less than 8.5; thus it is leachable, although not as leachable as some chlorides, nitrates, or sulfates. the boron content of soil derived from igneous rocks is generally lower than in marine sediments (Chapman 1965). Boron is essential for plant growth, but there is only a very narrow margin between deficiency and toxicity . Some plants have an optimum boron level in solution culture of 15 ppm, whereas other species exhibit toxic symptoms at 0.5 ppm in solution culture. Mean boron concentrations in the soil mapping units of NPR-1 ranged from 2.58 to 15.2 ppm.

Cadmium (Cd): Cadmium is usually more available in acidic, sandy soils than in neutral or alkaline soils with large amounts of clay or organic matter. Cadmium occurs naturally in close association with zinc, usually in concentrations directly related to zinc levels. Cadmium-to-zinc ratios may vary for most soils and minerals from ratios of 1:1,000 to 1:12,000. In most uncontaminated soils, concentrations range from 0.01 to 7.0 ppm, with an average of 0.06. Cadmium is an accumulative poison in animals; levels of 15 ppm in food may be injurious to man. Mean cadmium concentration in the NPR-1 soil mapping units ranged from 0.87 to 2.58 ppm.

Chromium (Cr): Chromium usually exists in soils as insoluble oxides that are largely unavailable at a pH greater than 4.0. Chromium has oxidation states of 2+, 3+, and 6+. The divalent chromus compounds are readily oxidized and, therefore, are rarely encountered in the natural environment. Most of the more toxic hexavalent chromates are rare and unstable in soils. Chromium is widely distributed in soils, ranging in concentration from 5 to 1,000 ppm (Chapman 1965). Mean chromium concentrations in the soil mapping units at NPR-1 ranged from 51.4 to 97.5 ppm.

Copper (Cu): Copper is absorbed or bound more strongly to soil colloids than many other cations. Apparently, soluble complexing agents in the soil solution contribute significantly to the mobility of copper in soils. Copper complexes in the soil are more stable than those of lead, iron, nickel, manganese, cobalt, zinc, and magnesium and are held most securely at a pH range of 7.0-8.0. The water-soluble sulfates are more mobile than the insoluble sulfites. The ratio of copper in soil to available copper ranges from 2:1 to 100:1. The total content of copper in most soils ranges between 2 and 100 ppm (Chapman 1965). Mean copper concentrations ranged from 6.6 to 17.2 ppm in the major soil mapping units of NPR-1.

Iron (Fe): Iron is one of the more abundant constituents of soils, usually existing in the form of ferrous oxides. In soil solutions containing oxygen, these oxides are probably moved primarily as colloids partly stabilized by organic matter and by absorption on clay particles (Krauskof 1972). As the pH of the soil solution increases, absorption increases. In acid soils, iron usually is available to all plants, but in some neutral or alkaline soils it may be so insoluble that plants have difficulty absorbing sufficient amounts. Where excessive phosphates exist, iron may be made unavailable by being precipitated as insoluble iron phosphate. This condition is more likely in sandy than clay soils because clays tend to fix excess soluble phosphates. Under natural conditions, iron toxicity is extremely rare. Mean iron concentrations in the NPR-1 soil mapping units range from 8,088 to 14,067 ppm.

Lead (Pb): Most soil lead is relatively unavailable to plants and is strongly fixed by the humic fraction of soils. Lead is commonly only a minor constituent of soils. In general, soils contain from 0.5 to 5 ppm of available lead (Chapman 1965). The total lead content of agricultural soils may vary from 2 to 200 ppm, of which only a few ppm will be soluble. Mean lead concentrations in the soil mapping units of NPR-1 range from 8.2 to 17.5 ppm.

Manganese (Mn): Manganese usually occurs in soils in oxide forms (Chapman 1965). The more highly oxidized compounds of manganese, such as manganese dioxide, are of low availability to plants. Solubility of soil manganese decreases with decreasing acidity, and in many soils it is not available to plants above pH 6.5. Manganese is an essential element and is relatively less toxic than a number of other trace elements. Toxic concentrations occur in acidic or poorly aerated soils that favor the formation of the available divalent form over the unavailable higher oxides. Endogenous soil concentrations range from 100 to 4,000 ppm and average 850 ppm. Mean manganese concentrations in the soil mapping units of NPR-1 range from 155.5 to 310 ppm.

Molybdenum (Mo): Molybdenum is usually present in the soil as oxidized molybdates, which are fairly mobile under alkaline conditions. Availability is low in acidic soils. As an anion, molybdenum is strongly absorbed by soil minerals and colloids at pH levels below 6.0 (Chapman 1965). It is an essential element in some plants, and toxicity is rarely observed in the field. Of 400 samples analyzed throughout the United States, 95% ranged between 0.6 and 3.5 ppm molybdenum (Chapman 1965). Mean molybdenum concentrations in the soil mapping units of NPR-1 range from 0.09 to 29.28 ppm.

Nickel (Ni): Nickel seems to be fixed and less available in soils with a pH above 7.0 or below 6.5. Nickel interferes with the uptake of iron, and sufficient levels of iron appear to reduce the toxicity of nickel to plants. Nickel is not highly toxic to animals when ingested. Nickel carbonyl [$Ni(CO)_4$] is considered extremely toxic to man when inhaled or absorbed through the skin. Soils normally contain from 5 to 500 ppm of nickel, with an average of about 100 ppm; soils derived from igneous rocks may contain up to 500 ppm (Chapman 1965). Mean nickel concentrations in the NPR-1 soil mapping units range from 16.5 to 30.4 ppm.

Potassium (K): Plants need large amounts of potassium. Although most soils contain large quantities of high-potassium minerals, much of this essential substance remains insoluble and unavailable as a plant nutrient. Typically exchangeable potassium may constitute only 1% of the total potassium content of soils, and the amount of soluble potassium free to move with soil water is usually less than 5% of the exchangeable form. The supply of potassium to plants affects, and is affected by, the level of other elements. The relative proportions and availability of calcium, nitrogen, phosphorus, and sodium interact to influence potassium uptake. Potassium toxicity is rare and almost always results from excessive fertilization rather than from natural accumulation in the soil (Chapman 1965). Excessive potassium tends to induce manganese, zinc, and iron deficiencies in plants. Mean potassium values range from 121 to 331 ppm in the NPR-1 soil mapping units.

Selenium (Se): In acidic soils, selenium is usually fixed as insoluble ferric selenite and is largely unavailable to plants. In arid, alkaline soils (pH > 8), selenium is generally available to plants as soluble calcium selenite and soluble selenium compounds. Seleniferous soils are distributed from North Dakota south to Texas and west to the Pacific. They are generally alkaline, contain $CaCO_3$, and are located in areas receiving less than 20 inches annual rainfall. $CaSO_4$ and BaCl reduce selenium uptake in plants. Most soils contain less than 1 ppm selenium, although some have been reported as high as 80-90 ppm. Mean selenium concentrations in the soil mapping units of NPR-1 ranged from 4.4 to 17.5 ppm.

Zinc (Zn): Zinc is an essential element for all organisms, but can accumulate to toxic levels. This most often occurs in acid soils, soils developed from certain mineral ores, and soils in smelting regions. Total zinc in most soils varies from 10 to 300 ppm (Chapman 1965). Mean zinc concentrations range from 0.28 to 2.38 ppm in the major soil mapping units of NPR-1.

C.4 SOIL EROSION

Currently, it is possible to provide only general estimates of erosion rates and quantities for specific site conditions, and these estimates tend to be more reliable under certain climatic, pedologic, and land use conditions than under others. Erosion under arid to semiarid conditions, with significant surface disturbances and modifications, such as those from present and past activities at NPR-1, present the more difficult circumstances to quantify.

C.4.1 Soil Erosion by Water

The most widely used method of predicting soil loss in the United States by fluvial processes is application of the Universal Soil Loss Equation (USLE) (Wischmeier and Smith 1978). This equation is in the form:

$$A = RKLSCP \tag{C.1}$$

Where:

A = the computed soil loss per unit area, expressed in the units selected for K and for the period selected for R (in practice, these are normally selected so that A represents tons lost per acre per year);

R = the rainfall and runoff factor, which is the number of rainfall erosion index units, plus a factor for runoff from snowmelt or applied water, where significant;

K = the soil erodibility factor, which is the soil loss rate per erosion index unit for a specified soil as measured on a unit plot defined as a 72.6-foot length of uniform 9% slope continuously in clean-tilled fallow;

L = the slope-length factor, which is the ratio of soil loss from the field slope length being evaluated to that from a 72.6-ft length under otherwise identical conditions.

S = the slope-steepness factor, which is the ratio of soil loss from the field slope being evaluated to that from a 9% slope under otherwise identical conditions;

C = the cover and management factor, which is the ratio of soil loss from an area with specified cover and management being evaluated to that from an otherwise identical area in tilled continuous fallow; and

P = the support practice factor, which is the ratio of soil loss with a support practice such as contouring, stripcropping, or terracing to that with straight-row farming up and down the slope.

Several types of mechanisms of water erosion are known. These include raindrops, sheet and rill, gullies, and channels (see, for example, Beasley et al. 1984). The mechanisms, effectiveness, and quantities of soil erosion are different in each case. The USLE is an empirical relationship developed to estimate the long-term average annual soil loss from sheet and rill erosion of field-scale areas under a variety of conditions (Wischmeier 1976). Several modifications of the USLE have been proposed to improve the applicability of the equation to varying site conditions, as well as to allow estimates of sediment yields from small watersheds (Mitchell and Bubenzer 1980). Most such modifications are preliminary and lack substantial data verification.

It would be possible to estimate the long-term average annual sheet and rill erosion for selected areas on NPR-1 by using the USLE and values of the individual factors applicable to California and Kern County conditions (Amimoto 1977; Evans and Kalkanis 1977; SCS 1985). This would provide reasonably reliable results for those areas where soil/

vegetation conditions have been only little disturbed by human activities. Where significant disturbance has occurred, which is a large percentage of the total NPR-1 area, the results would be questionable and subject to increased error. Furthermore, this would provide no estimate of gully or channel erosion, which is clearly evident at the site. Given the level of uncertainties associated with a soil loss estimate obtained in this manner and with the utility of a long-term average annual value when human activities continue to change site conditions, the usefulness of such estimates for evaluating current environmental conditions at the NPR-1 seems limited.

C.4.2 Soil Erosion by Wind

The processes of erosion and transport of soil by wind are less well-known than those for fluvial actions. This is in large part due to the difficulty of obtaining accurate field measurements of the phenomena involved.

The major factors affecting wind erosion are climate, soil characteristics, surface roughness, vegetation and residue cover, and length of erodible surface along prevailing wind direction (Beasley et al 1984). Research on these factors led to the development of a wind erosion equation (Chepil and Woodruff 1963; Woodruff and Siddoway 1965) similar to the USLE for water erosion. The wind erosion equation is:

$$E = f(I', K', C', L', V) \tag{C.2}$$

where:

E = the potential erosion, expressed in tons per acre per year,

I' = a soil erodibility index related to cloddiness

K' = a soil ridge roughness factor,

C' = a local climatic factor related to wind velocity and soil moisture

L' = the median unsheltered field length along the prevailing wind erosion direction, and

V = the equivalent quantity of vegetation cover.

Charts, tables, and maps giving information relating to the distribution and magnitude of wind erosion forces and providing the necessary information for the solution of the wind erosion equation have been prepared by Skidmore and Woodruff (1968). Wilson and Cooke (1980) provide a good summary of wind erosion research and results.

As in the case of the USLE, the wind erosion equation could be used to obtain estimates of the average annual soil loss for selected parts of NPR-1. However, the same concerns as expressed above for estimates of fluvial erosion results would be appropriate for such estimates. Additionally, the error associated with the wind erosion estimates would probably be greater than those for fluvial erosion because fewer investigations of wind erosion have provided less understanding of, and data describing, these processes. Consequently, no estimates of wind erosion potential are calculated.

C.4.3 Current Site Erosion Conditions

In any study of soil erosion, it quickly becomes apparent that effective ground cover, usually in the form of vegetation, is the key to controlling soil loss. Although drainage basin sediment yield does not correlate exactly with the amount of soil erosion on hillslopes and methods exist to estimate erosion losses (Warner and Dysart 1980), sediment yield is considered in this discussion to reflect, at least qualitatively, an approximation of soil erosion within the watershed. Langbein and Schumm (1958) studied the influence of mean annual precipitation on suspended sediment yields using data from a number of stream sampling stations and reservoir sediment surveys. Graphical relationships between precipitation and runoff, adjusted for temperature, were used by Langbein and Schumm to obtain effective precipitation values from measured runoff data. Figure C.2 shows the relationships between sediment yield and precipitation, for the two data sets. Beginning with arid conditions of very limited precipitation, sediment yield increases rapidly with increasing precipitation. A peak in sediment yield occurs at an annual precipitation of about 10-14 inches Below this value, there is too little rain to produce large sediment yields; and above this value, increased vegetative cover reduces sediment yield despite increased erosion potential of the rainfall. Figure C.2 also shows that the peak sediment yield coincides roughly with the transition from desert shrubs to grassland.

Expanding upon the earlier findings of Langbein and Schumm (1958), Kirkby (1980) presented the generalized relationships between wind erosion, water erosion, precipitation, and vegetation. Assuming uncultivated conditions, progressively greater annual rainfall has two effects on soil erosion. Increased rainfall produces increased overland or subsurface runoff and more vegetation. Under arid or desert conditions, vegetation is so sparse that increasing precipitation/runoff results in increasing erosion. Wind erosion is greatest in deserts in absolute terms and appears proportionately dominant because water erosion rates are so low. However, many landform components in arid environments are fluvial in origin. When rainfall amounts are large enough to support semiarid vegetation, the increased vegetative cover does more to reduce water erosion than the increased runoff does to increase it; therefore, net erosion begins to decrease with increasing rainfall. This trend continues until a complete forest cover is obtained. While these data may not be directly applicable to the Elk Hills area, the pattern of variation of sediment yield with precipitation is important. Data from the Elk Hills area would plot somewhere to the left of and below the peak sediment yields of Figure C.2. If this relationship is true, then erosion (as expressed by sediment yield) is certainly less than the maximum that could be expected with

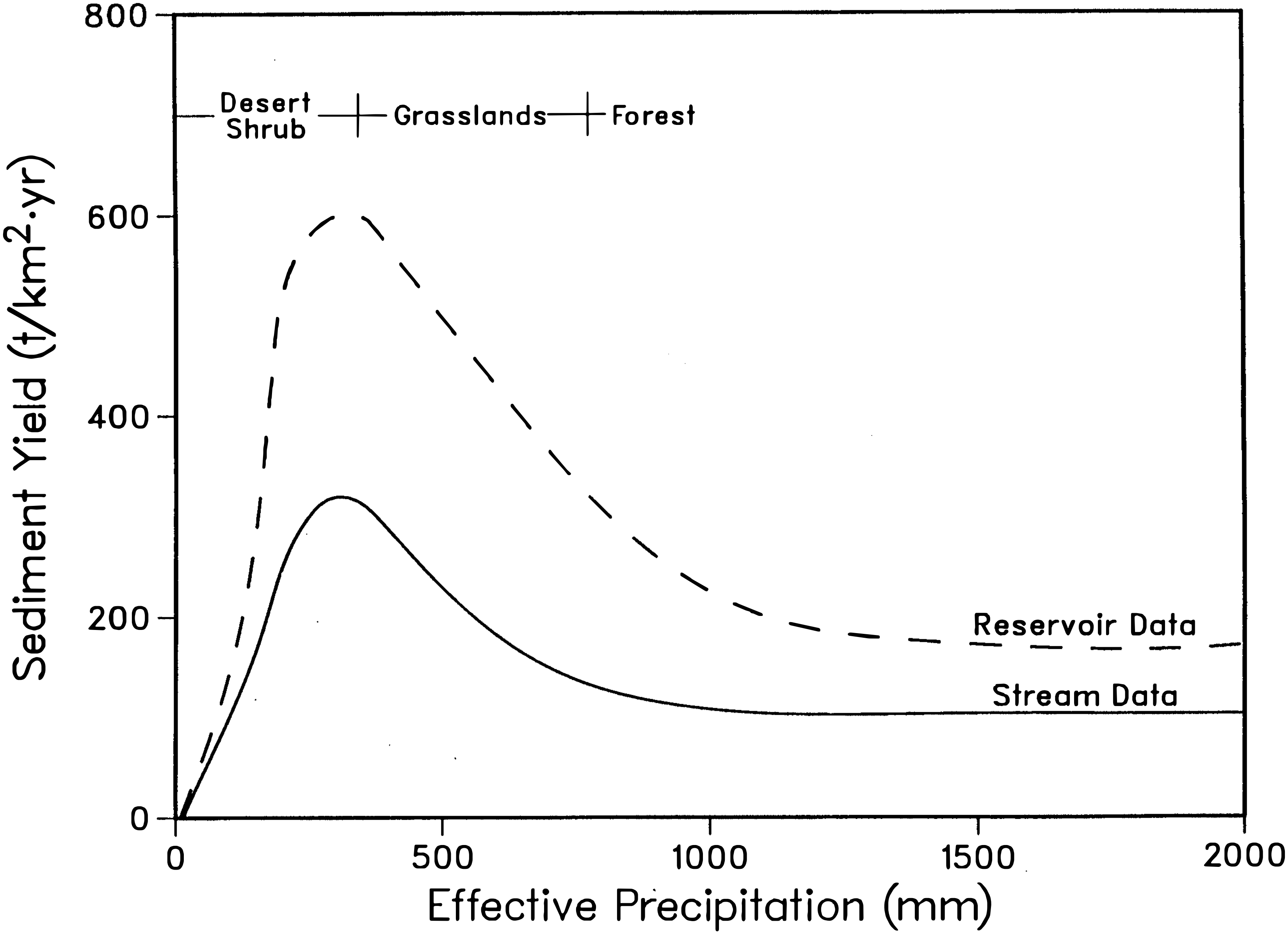

FIGURE C.2 VARIATION OF SEDIMENT YIELD WITH PRECIPITATION AND VEGETATION TYPE (SOURCE: BASED ON GREGORY AND WALLING 1973; LANGBEIN AND SCHUMM 1958) increased effective precipitation, but still significant compared to areas with less rainfall. This suggests that a significant amount of natural soil erosion could be expected for the conditions at the site, regardless of human activity. Wet or above-average precipitation years would increase short-term erosion even though vegetative cover might be better than average as well. During normal and below-average precipitation years, individual storms of high intensity would also be effective erosion agents. In all cases, erosion could involve gully and channel development in addition to sheet and rill processes. Such extensions of the drainage network would remain an observable part of the Elk Hills landscape. These arguments lead to the conclusion that the study area would experience a significant amount of natural erosion and landscape adjustment regardless of human activities. The same conclusion can be drawn from observations in any area of broadly similar climatic and geologic conditions.

The sequence, spatial distribution, and types of activities that have occurred since oil-field development began at NPR-1, as well as details of erosion-control and mitigative measures implemented, are only poorly known. Consequently, it is essentially impossible to segregate current and past erosion rates and consequences among those that would occur naturally and those resulting directly from petroleum development activities.

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*Copies of correspondence and unpublished documents included in this list may be obtained upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, Naval Petroleum Reserves in California, Tupman, California, 93276.

APPENDIX D:

GROUNDWATER

D.1 ENVIRONMENTAL SETTING

NPR-1 is located in the southwestern portion of the Central Valley of California. The Central Valley is a large sediment-filled structural basin lying between the Coastal Ranges and valleys to the west and the Sierra Nevada Range to the east. The aquifer system of the Central Valley consists of a heterogeneous mixture of continental alluvial sediments derived from the adjacent mountains. These sediments average approximately 2,900 feet thick in the San Joaquin Valley (Bertoldi and Sun 1986). The valley is about 50 miles wide at the northern border of Kern County but narrows to approximately 30 miles at its southern end. Within Kern County, valley elevations range from 250 feet above mean sea level (MSL) at the county's northern border to approximately 500 feet MSL at the surrounding foothills.

NPR-1 consists of approximately 47,000 acres and encompasses the Elk Hills, an elliptical foothill spur of the Temblor Range. The Elk Hills rise to approximately 1,550 feet MSL, about 1,000 to 1,200 feet above the valley floor. In the south, Buena Vista Valley separates Elk Hills from the Buena Vista Hills (Figure 3.1-2). In the west, the Elk Hills are separated from the main Temblor Range by Railroad Gap, a deeply dissected stream channel. To the east, the Elk Hills terminate at the valley floor in low stream cut bluffs where the Kern River channel enters the ancestral Buena Vista Lake. The California Aqueduct extends along the northeastern boundary of Elk Hills. Tupman, a small community established during the early 1900's, is situated on the valley floor near the northeastern flank of Elk Hills. Maher et al (1975) report that the shape and relief of the hills reflect the anticlinal structure of the subsurface sediments. The hills also contain many deep gullies carved by ephemeral streams.

The near-surface and surface sediments in the Elk Hills region are, in descending order, the Quaternary alluvium and the Tulare Formation. Maher et al (1975) state that Quaternary alluvium is present only on the border of the Elk Hills. The alluvium generally thickens to several hundred feet in the adjacent San Joaquin and Buena Vista valleys (Wilson and Zublin 1988, Plate 20; Rector 1983). The alluvium is described as a poorly sorted sand, silt, and clay mixture that is difficult to differentiate from the underlying Tulare Formation. The Corcoran clay, or E-Clay, or other confining clays, separate the unconfined and confined aquifers of the southern San Joaquin Valley. The areal extent of the E-Clay is not well understood. Page (1983) reports the clay is contained within the Tulare Formation in the vicinity of Kettleman Hills approximately 50 miles north of Elk Hills. Rector believes the E-Clay and the Maher middle clay (Amnicola), which underlies much of Elk Hills, are the same (Fries 1990). In their investigations adjacent to NPR-1, Kern County Water Agency (KCWA) did not observe the E-Clay extending onto the northeast flank of the site (KCWA 1990).

The Tulare Formation, which lies beneath the Alluvium, consists of a thick succession of nonmarine, poorly consolidated sands, conglomerates, and clays (Maher et al 1975). In the Elk Hills region, these sediments are from 600 to 2,150 feet thick.

The surface geology of the Tulare Formation at Elk Hills was mapped and described initially by Woodring in 1932 (Woodring et al 1932). On the basis of this work, Woodring divided the Tulare into Upper and Lower members based on color differences in the interbedded mudstones: light buff for the Upper member and olive gray for the Lower member. He also described a limestone he termed Limestone A near the interface of the Upper and Lower members.

The subsurface geology of Elk Hills was described by Maher in 1975 (Maher et al 1975). Maher's workwas based on his interpretation of well log data and Woodring's surface maps. Maher described an upper sandstone and conglomerate, a middle clay, and a lower sandstone and conglomerate. The upper sandstone and conglomerate is unconsolidated, medium-to-very-coarse grained sand with thin interbeds of siltstone and claystone. The lower sandstone and conglomerate is a poorly consolidated light olive-gray pyritic, very-fine to very-coarse grained sandstone. The sandstone beds are up to 50 feet thick and are separated by much thinner beds of siltstone and claystone. The middle clay, which separates the upper sandstone and conglomerate from the lower sandstone and conglomerate, is light olive-bluish and is slightly dolomitic.

Remsen (1990) demonstrated that Maher's subsurface interpretation of well log data correlates well with Woodring's description of surface geology. Remsen (1990) also demonstrated that Maher's upper sandstone and conglomerate, middle clay, and lower sandstone and conglomerate are all within Woodring's Lower Tulare member.

D.2 WATER REQUIREMENTS AND SUPPLIES

The extensive agricultural economy in Kern County requires large quantities of water for irrigation. Much of this irrigation water is obtained from groundwater resources; the rest is obtained from northern California through the California Aqueduct and the Friant-Kern Canal. In 1986, approximately 2,500,000 acre-feet of water were used to irrigate 813,900 acres in Kern County (KCWA 1987). Urban and industrial users of groundwater in Kern County required about 85,000 acre-feet. In addition to these groundwater resources, the KCWA distributes water obtained from the Kern River, Central Valley, and State Water Projects to 16 local water districts. In 1986, these additional sources amounted to approximately 3 million acre-feet. Within NPR-1, groundwater withdrawals total approximately 148,000 barrels/day. This groundwater is withdrawn from approximately five Tulare wells on the southern boundary of NPR-1 for injection into the Stevens Zone as part of an enhanced oil-recovery program. NPR-1 also purchased approximately 29,000 barrels/day of fresh water in 1988 from the West Kern Water District (WKWD) in Section 5M (see Section 3.4.2.4).

D.3 WATER RESOURCES

D.3.1 Groundwater Recharge

Groundwater is considered a valuable resource in the Kern County area, and conscious efforts are made to replenish these reserves through waterbanking programs. The West Kern Water District (WKWD) and Rosedale-Rio Bravo Water Storage District have recharge facilities near the Kern River flood canal. Here, water from both the Kern River and the California Aqueduct are spread on infiltration tracts. During 1979, 600,000 acre-feet of water was recharged in waterbanking programs (Kern County 1982). Water delivered to the KCWA by state programs is transported in unlined canals, where possible, or is spread on infiltration tracts in order to recharge the unconfined aquifer. The success of this recharge program prompted the State of California during 1988 to purchase a large tract of land on the western edge of the San Joaquin Valley to be used for groundwater banking. As shown in Figure 3.4-3, this tract of land is adjacent to the northeastern limit of NPR-1 (Fielden 1988).

The high temperatures and low humidity of the southern San Joaquin Valley produce very high evaporation rates. During 1986, approximately 70 inches of water were reported to have evaporated at a monitoring station in Bakersfield (KCWA 1987). Precipitation and evaporation records for a 13-year period (1970-1982) for the San Joaquin Water District, which includes the Elk Hills, show that evaporation exceeds precipitation by approximately 45 inches/year (average precipitation is 5-6 inches/year). During the 13-year period, only water year 1978 had an effective recharge to the groundwater surface by precipitation (Erlewine 1988).

During wet years, natural infiltration from the Kern River is considered the principal source of recharge in both the eastern and western parts of the valley. The bulk of the Kern River flow, however, is diverted in more eastern areas to irrigation canals. Other sources of recharge to the groundwater system include water from crop irrigation and oil field waste water disposal. Oil-field wastewaters may recharge the groundwater system through the waste disposal practices of sumping in unlined pits, discharging to natural drainageways, and underground injection. About 2,328 million barrels of petroleum-associated wastewater have been disposed of to-date in the Midway Valley and Buena Vista Valley vicinity through percolation, while 253 million barrels have been reinjected into subsurface formations (Wilson and Zublin 1988). Rector (1983) compiled data on volumes of wastewater production and disposal for the years 1970 and 1979. During 1979, the oil-field operations south of Tupman (adjacent to the northeastern flank of the NPR-1) disposed of approximately 6.9 million barrels of wastewater by surface methods. In the same year, it is estimated that NPR-1 disposed of an estimated 8.5 million barrels of wastewater by surface methods into several sumps at approximately 5-7 different locations on the site (the great majority being in Sections 10G and 24Z).

D.3.2 Groundwater Aquifers and Aquitards

Maher's middle clay behaves as an aquitard, hydraulically separating the Tulare Zone into an upper and lower part that probably do not communicate where the middle clay exists. In addition, there are multiple fine claystone and siltstone layers between the Tulare Limestone A and the middle clay that also are thought to act as aquitards (Fishburn 1990). Figure 3.4-2 schematically illustrates the vertical relationship between the various valley aquifers and NPR-1 sediments.

Historically, two principal water-bearing units have been indentified in the San Joaquin Valley; they are termed the unconfined and confined aquifers. The unconfined aquifer receives the bulk of the recharge discussed above and consists primarily of the surface alluvium. It is separated from the hydrogeologically confined portion of the Tulare Formation by the Corcoran clay, or E-Clay, or other confining clays (hereinafter referred to as the E-Clay) (see Figure 3.4-2). The E-Clay behaves hydraulically as an aquitard. Most of the sediments that form the unconfined aquifer were deposited by the ancestral Kern River over long periods of time. In the ancient river channels, permeable sand and gravel were deposited, while less permeable silt and clay form the more distant sediments. The Buena Vista lakebed is such an area where the unconfined aquifer has a larger clay content. Locally, the base of the unconfined aquifer (depth to the E-Clay) is generally less than 500 feet (Bean and Logan 1983). However, it has also been shown that it dips sharply to the south of NPR-1 with an observed depth of as much as 4,400 feet in the southern end of the San Joaquin Valley near Mettler (KCWA, 1990). The confined aquifer extends from the base of the E-Clay to the base of fresh water which is defined as 2,000 parts per million (ppm) total dissolved solids (TDS)(California Department of Water Resources and Kern County Water Agency [CDWR/KCWA] 1977; Bean and Logan 1983). More recently, KCWA has suggested a more complicated system consisting of an unconfined aquifer and more than one semi-confined aquifers (KCWA 1992).

In addition to the aquifers discussed here, a zone of perched groundwater lies at very shallow depths in places beneath the valley floor (KCWA 1987). This water is typically lower quality.

D.3.3 Groundwater Data and Flow Directions

D.3.3.1 Groundwater Zones

A number of investigators have provided groundwater elevation data and interpretations for the groundwater surfaces and flow directions in the various aquifer systems of the Elk Hills and adjacent valleys. Maher et al (1975, Figure 8) have provided a groundwater well location data base in the confined and unconfined aquifer systems in the valley floor along the northeastern margin of the NPR-1. Bean and Logan (1983, Figure 3-1) also have provided groundwater elevation data and made interpretations of the groundwater surface in the Buena Vista Valley. Rector (1983, Plate 19) has constructed groundwater surface elevation maps for the Elk Hills and westside area. KCWA (1987, Plates 1 and 4) published groundwater surface elevations for the confined, unconfined, and perched zones for both the San Joaquin Valley and Buena Vista Valley. Wilson and Zublin (1988, Plates 32a-c) compiled groundwater elevation data from the Buena Vista Valley and southern Elk Hills vicinity. Additional data on groundwater level for the Elk Hills are available from structural cross-section drawings developed from logs of Tulare production and wastewater injection wells (BPOI 1987a-d).

Bean and Logan (1983) report that groundwater levels in the confined aquifer are generally lower than those in the unconfined system. These groundwater elevation differences vary from between a few feet north of Buttonwillow to more than 100 feet in the Maricopa area.

The depth to groundwater in the San Joaquin and Buena Vista valleys within Kern County ranges from 50 feet beneath the Kern River and along the northeastern margin of the Elk Hills to more than 650 feet in the southern extremes of the valley near the White Wolf fault. Perched groundwater at depths shallower than 50 feet has been documented in the Buena Vista Lakebed (Bean and Logan 1983). KCWA (1987, Plate 1) found that depth to perched groundwater along the western margin of the San Joaquin Valley is typically no more than 20 feet beneath the ground surface. On NPR-1, the depth to groundwater is determined both by topography and subsurface structure. Data from NPR-1 Tulare production and waste disposal wells on the southern flank in Section 18G show a depth to water of about 400 feet (BPOI 1987a-d). On the northwestern flank of Elk Hills, NPR-1 water-supply well 61WS-8R had static and stressed water levels of about 400 and 700 feet, respectively. Withdrawal rates from this well were less than 10,000 barrels/day (this well is no longer in service).

Interpretation of these depths to saturation (as a representative groundwater surface) is complicated by the injection and production of water, which would serve to create mounds and valleys at these locations. Rector (1983, Plate 19) has constructed elevation surfaces of undifferentiated Tulare zone groundwater for the years 1975-1980 on the Elk Hills, as well as of the unconfined aquifer within the valley. These surfaces are generated from about 20 data points and show groundwater elevations within the Elk Hills varying from 150 to 680 feet MSL. The northern and northeastern periphery of the Elk Hills is within the San Joaquin Valley, where the depth to perched and unconfined groundwater ranges from 20 to 100 feet below ground surface (KCWA 1987, Plate 1).

As the result of tests conducted in 1987 (Mark Group 1987), groundwater was suspected at a depth of 60 feet in the vicinity of a truck washout sump at the 27R waste management facility. A subsequent study to characterize this water was unable to locate any saturated sediments (Kaman Tempo 1989). Surface water from unknown sources has been observed in sections 3G, 4G, and 35S areas. The 4G area has a well-established community of phreatophic (water-loving) plants. This suggests a long and constant period of flow (in excess of a year).

The Kern River has historically provided the largest amount of natural groundwater recharge in the valley. This is reflected in the groundwater surface map (Figure 3.4-3) in Section 3.4.2, which locates a northeast-southwest trending groundwater ridge in the valley following the trace of the Kern River. Groundwater typically flows away from ridges (high points) to areas of depressions (low points). Based on this interpretation, the principal direction of groundwater flow is away from the ridge in a northwest-southeast direction. The location of this groundwater high is also thought to coincide with the boundaries of the E-Clay (KCWA 1987). At the edge of the E-Clay, groundwater is thought to move downward and travel eastward within the confined aquifer (Bean and Logan 1983).

Groundwater highs may also indicate recharge due to irrigation (KCWA 1987), in addition to the presence of a confining or semiconfining bed at depth. Areas of extensive groundwater development and irrigation also influence groundwater surfaces by producing groundwater lows and highs, respectively. One such groundwater low is located along the northeastern margin of the NPR-1 near the town of Tupman (Figure 3.4-3). Many water production wells are clustered in this area, including several wells operated by the WKWD. It is possible that this area could capture groundwater flowing from both the Elk Hills and the San Joaquin Valley. Another low spot in the unconfined aquifer is the Buena Vista Lakebed area immediately southeast of NPR-1.

An area of groundwater mounding exists in the Buena Vista Valley along the southern margin of NPR-1. Both irrigation and oil-field wastewater disposal occur in the Buena Vista Valley (Bean and Logan 1983) and may be providing for groundwater recharge to this area. As in the case in the San Joaquin Valley, clay layers acting as aquitards could be contributing to the elevated groundwater positions in the Buena Vista Valley.

Rector (1983, Plate 19) shows groundwater moving from the Elk Hills into the adjacent valleys. He also suggests that groundwater in the Buena Vista Valley travels eastward. Maher et al (1975) and Waldron (1989) believe that groundwater in the Elk Hills and western Buena Vista Valley may have a source in the Temblors. This implies an easterly component of flow. Bean and Logan (1983, Figure 3-1) and KCWA (1987, Plate 4) show that groundwater elevations in the Buena Vista Valley are relatively higher in the eastern portions which suggests a westerly flow. KCWA (1990) has shown that the Buena Vista Valley subbasin is structurally separated from those of the San Joaquin Valley. If these separations are sufficiently developed, this could preclude hydraulic communication between the two valleys.

Very limited data exist that describe the hydraulic conductivity (permeability) of the sediments in the Elk Hills vicinity of the San Joaquin Valley. The California Department of Water Resources and Kern County Water Agency (CDWR/KCWA 1977) collaborated to numerically simulate the flow field of the southern San Joaquin Valley. The results of their model calibration provided estimates for the hydraulic conductivity of the confined and unconfined aquifers. The confined and unconfined aquifers were assigned hydraulic conductivities of 30 feet/day and 48 feet/day, respectively. No hydraulic conductivity data are known to be available for the principal clay zones; however, conductivity estimates of 10^{-6} to 10^{-4} feet/day have been made (Freeze and Cherry 1979). Rector (1983) has compiled groundwater data available from U. S. Geological Survey (USGS) publications for several valley wells. Eight of these analyses are reported from T31S/R25E close to the northeastern limit of the NPR-1 and show an average specific capacity of 40 gallons/minute/foot of drawdown. Generally, their screened interval (production interval) is located within the Alluvium.

D.3.3.2 Vadose Zones

The depth to saturated groundwater in the vicinity of Elk Hills ranges from a few tens of feet in the valley areas to in excess of 1,000 feet in the higher topographic elevations. Separating the ground surface and the groundwater surface is an unsaturated (vadose) zone. Infiltrating water in the unsaturated zone may be expected to move vertically unless heterogeneity is encountered in the subsurface sediments. When an infiltration event is of short duration or infrequent in occurrence, homogeneous, moisture-deficient sands overlying deep water tables can act as a buffer zone between infiltrating water and groundwater. If the infiltration event is of long duration, infiltration water could eventually communicate with the groundwater surface underlying the infiltration event, or those situated some distance away if migration along saturated clay layers occurs.

D.3.3.3 Water Chemistry

The groundwater basin in the Kern County portion of the San Joaquin Valley has no surface outflow, except in extremely wet years. This closed system causes salt magnification in the local groundwater. Surface water imported into the valley during the 1986 water year introduced approximately 435,000 tons of new salt into the groundwater basin (KCWA 1987). Data on TDS accumulated over a period of several years have been used to construct annual groundwater quality maps for the confined and unconfined aquifers of the valley. Maps released in 1987 (KCWA 1987, Plates 2 and 3) indicate that water quality is better in the confined system than in the unconfined. In part, this is thought to be because the confined systems were derived from pre-Corcoran (approximately 600,000 years ago) flood waters of lower mineral content than the salt-magnified waters that recharged the unconfined system more recently (Geological Society of America 1989). This is also thought to be because the E-Clay provides a seal that protects the confined aquifer from the lower quality waters of the unconfined aquifer.

The unconfined aquifer has received salt from both natural and artificial recharge. Perched groundwater in the San Joaquin Valley generally has a salt content that is higher than deeper groundwater, which makes it undesirable for agricultural uses (KCWA 1987). The confined aquifer has very low TDS, with the exception of the western valley margins (KCWA 1987, Plate 3). The water quality map of the unconfined aquifer, however, shows islands of high chemical concentration throughout the valley proper, as well as in the western margin area (KCWA 1987, Plate 2; Kern County 1982, Plate VIIIa). Confined and unconfined concentrations of TDS in the western margin area are higher than anywhere else in the valley. CDWR identified a small area near Tupman, California along the northeastern boundary of NPR-1 with elevated levels of groundwater TDS (CDWR, 1990). This finding is the source of other CDWR studies that are in progress pertaining to the Kern Water Bank.

There are two possible mechanisms that could be contributing to higher TDS levels in the margin areas. Waldron (1989) hypothesized that this is due to natural flow from the Temblors. It is also possible that low-quality artificial recharge is another contributing factor, such as oil-field wastewater and/or agricultural irrigation. Regardless of the source, it is possible that the poorer quality waters of the western margins are structurally confined (Page 1986 and KCWA 1990).

Groundwater chemical concentrations are affected by oil-field wastewater recharge and salts that dissolve in surface waters flowing over highly mineralized sediments of the Tulare and marine sedimentary rocks (Maher, 1975). Bean and Logan (1983) compared the chemistry of water produced in association with hydrocarbon production and seawater. The produced waters appear, in general, to have a chemistry similar to dilute sea water with low sulfate concentrations. The produced waters from the Buena Vista Valley and Elk Hills oil fields appear very similar to seawater in their total salt content. NPR-1 produced wastewater has been tested and found to have TDS levels between 20,000 to 40,000 ppm, with the dominant ionic species being chloride and sodium (Stuart 1987). Water taken from the Tulare Zone on the southern margin of NPR-1 as a source for waterflood operations has TDS levels between 3,000 and 6,000 ppm, with sodium, chloride, and sulfate providing approximately equal contribution of 1,000 ppm each.

NPR-1 surface waters have been studied and found in many cases to have high TDS when water flows over the Tulare and marine sediments in Buena Vista, Broad, and Sandy Creeks. These have been observed to have minimum TDS levels of 1,300 ppm and minimum sulfate-ion concentrations of 732 ppm (Maher 1975). TDS levels in Kern River surface waters are very low.

Bean and Logan (1983) report that few springs exist in the area. Those known are located away from the valley proper in the Temblor Range and have conductivity ranges (where conductivity correlates closely with TDS) between 1,200 and 3,530 micromhos/centimeter. Surface water has been observed at three locations on NPR-1: 3G, 4G, and 35S. Chemical analyses of surface water observed on numerous occasions in Section 4G indicate a TDS concentration of approximately 11,000 ppm. Sodium is the dominant cation and shows a concentration of approximately 3,000 ppm, while chloride and sulfate are the dominant anions and have concentrations of approximately 1,500 and 4,500 ppm, respectively (Reeder 1985). The conservative chloride ion concentration is similar to the 33S sump approximately a half mile away. This has caused suspicion that the sump could be the source of 4G surface water. This sump is used infrequently (pipeline pigging operations approximately once per year that generate approximately 500 barrels of waste water; and as drainage for runoff from the 33S waterflood facility and the 4G closed-loop gas-lift facility), which makes it difficult to correlate to the frequently observed surface water in 4G. In addition, the 4G surface water has a larger sulfate concentration than the 4G sump; however, this could be attributable to interaction with gypsum salts known to exist in the Tertiary sediments.

A historic spring on the Elk Hills was located in Section 35S near Well 223-35S (Maher et al 1975). A chemical analysis performed in 1956 indicates that with the exception of chloride, it's chemistry is similar to that of the 4G surface water. The existence of surface water in Section 3G that is not near a surface sump suggests that water is surfacing for reasons that are not associated with sumps. The TDS level of the 3G water was 7,650 ppm. Sodium, calcium, sulfate, and chloride were the dominant ionic species, with levels of 1,211, 585, 3,316 and 464 ppm, respectively. A recent study identifies leaking fresh water lines as the most probable source for the surface water observations (Nicholson 1989).

Water samples have been taken from two wells northwest of Tupman in T30S/R24E immediately off the northern flank of the Elk Hills (Bean and Logan 1983). Analyses of the water samples from these wells have shown variations by a factor of 10 in chloride concentration. Bean and Logan (1983) suggested that wastewater from oil fields, including NPR-1, could be responsible for this variation. Waldron (1989) reviewed the location of historic sumps on the northern flank of NPR-1 and believes they may not be located on a flow path that communicates with groundwater wells in T30S/R24E. Waldron also suggests that the chloride concentration variation could be due to the encroachment of poorer quality water from the Temblors.

The groundwater of the Buena Vista Valley is characterized by low bicarbonate and high sulfate and chloride. This groundwater, which is considered marginal for irrigation, has conductivities in the range of 25,000 to 11,000 micromhos/centimeter. The western portion of the Buena Vista Valley is thought to contain native groundwater, while groundwater in the eastern portion is thought to have been impacted by the disposal of oil-field wastewater. Analyses of water samples taken from irrigation wells located in the eastern part of the Buena Vista Valley (T31S/R24E) show large sporadic increases in conductivity, with sodium and chloride being the dominant ions.

The variability in groundwater chemistry, the similarity of some of the chemical properties of groundwater and oil-field wastewater, and the proximity of these observations to oil-field operations in the Buena Vista Valley, the western San Joaquin Valley, and on NPR-1, have suggested to some investigators that a relationship may exist between oil-field wastewater disposal practices and groundwater quality. This is best illustrated by maps compiled by Bean and Logan (1983, Plate 4-1) and Rector (1983, Plates 22 and 23) which show known oil-field sumps, disposal wells, and other facilities that existed up to 1983, in some cases for as many as 20 years. Several sumps on NPR-1 in T30S/R24E and T30S/R25S are close to the wells off the NPR-1 northeastern flank previously described as having saline water chemistry fluctuations.

In addition to oil-field operations, groundwater quality could be impacted by other sources. Waldron (1989) and Maher (1975) suggested that natural flow from the Temblors could be a prominent factor. Page (1986) and KCWA (1990) have suggested the existence of a structural trough along the western margin of the San Joaquin Valley in the same area off the northeastern flank of NPR-1 where Bean and Logan observed saline wells. In this area, natural flow from the Temblors may be mixing with groundwater recharge from the Sierra Nevada, thereby explaining the high TDS values observed. The existence of the structural trough also suggests the possibility that there could be hydrologic confinement to an area identified as the Buttonwillow subbasin by KCWA. It is also possible that agricultural irrigation is impacting groundwater quality.

Rector (1983, Plate 18) constructed a map showing areas of anomalous groundwater chemistry in the unconfined aquifer. Rector focused on boron, nitrate, calcium, chloride, and sulfate chemistry and considered concentrations greater than 1, 50, 500, 500, and 1,000 ppm, respectively, to be anomalous. The Buena Vista Valley and Buena Vista Lakebed areas appear to have concentrations at or above the anomaly thresholds for all chemical species. An area of anomalous chloride concentration occurs along the northeastern flank of the Elk Hills near the town of Tupman. Rector (1983, Plate 18) also delineated zones of anomalous TDS concentration above 2,000 ppm. One such zone is west of the California Aqueduct in the northeastern corner of NPR-1. KCWA (1987, Plate 2) indicates, with more complete data, that they observed this same anomaly east of the Elk Hills beyond the aqueduct, including groundwater beneath Tupman. Waldron (1989) has suggested that changes with time in the groundwater chemistry in the western areas of the San Joaquin Valley might be attributable to fluctuation in water surface elevation of the valley aquifers. During wet years, poorer quality groundwater located at the valley margins would be pushed away from the central valley by higher groundwater surface elevations. Dry years which provide less groundwater recharge, would permit poorer quality groundwater to move farther into the valley.

D.4 WASTEWATER

D.4.1 Wastewater Production and Disposal

Water produced in association with hydrocarbons is currently transported with oil to several separation (dehydration/LACT) facilities on NPR-1. These stations are located in Sections 18G, 10G, 25S, 26Z, and 24Z. After separation at the LACT stations, wastewater is transferred to several on-site disposal facilities. Approximately 100,000-110,000 barrels/day of wastewater are currently disposed of in the subsurface. The location of existing disposal wells is shown by Figure 3.4-7. Eleven wells are completed within the Tulare Formation and are located in the 7G, 8G, 18G, and 24Z areas (BPOI 1987a-d). Two wells are completed in the SOZ and are located in Sections 15G and 16G. Two wells are completed in the Olig Zone in 26Z. Four wells are completed in the Stevens Zone in 24Z; in addition to wastewater disposal, these wells serve the purpose of minimizing the flow of hydrocarbons off of NPR-1.

During off-normal situations (e. g., combinations of equipment breakdowns, disposal well failures, unforeseeable/uncontrollable water production surges, etc.) the wastewater disposal system is unable to accommodate the quantity of wastewater produced. This necessitates surface release of wastewater into evaporation/percolation ponds (sumps). In addition, wastewater is occasionally spilled into secondary containment, primarily at LACT and tank setting facilities.

Since approximately 1979, the principal wastewater sumps at NPR-1 have been in Sections 25S, 35S, 10G, 18G, 24Z, 26Z, 35R, and 27R/26R. The locations of these sumps are indicated on the map shown by Figure 3.4-8. When originally constructed (in some cases as early as the 1950's), these sumps were all unlined. The 25S, 10G and 35S sumps have been used for SOZ production water. The 25S sump was lined in 1988. The 24Z and 18G sumps have been used for Stevens water. One of the two 18G sumps was lined in 1990. The other sump has been taken out of service; it will either be lined, or included in the field-wide waste site cleanup/closure program, or utilized as an emergency catch basin and managed in accordance with the SPCC program. The 26Z sumps have been used for Asphalto water. All but one of the 26Z sumps were replaced with tanks in 1987 and formally cleaned and closed. One sump (unlined) was retained to serve as an emergency catch basin in the event of a tank overflow; it will be managed in accordance with the SPCC program. The tanks at 26Z have equipment that automatically shut down production if high tank levels occur. A sump located in Section 35R has, until recently, received drainage water and wastewater from the 35R gas processing plant and the LTS-1 compressor building; this sump has been taken out of service and is scheduled to be formally closed. Four additional sumps are used at the 27R waste management facility in connection with oil-recovery and a truck-washout facility. Two of these have been replaced with tanks and taken out of service. The same is scheduled for the other two. Three will be formally closed, and the fourth (unlined) will be used as an emergency catch basin in the event of a tank overflow and managed in accordance with the SPCC program.

Additional wastewater sumps in use prior to 1979 were identified by Rector (1983) and Bean and Logan (1983); these are shown by Figure 3.4-9. These sumps are included in the field-wide abandoned waste site cleanup/closure program. To date, they have been sampled and tested for chromium and arsenic. With the exception of one sample, these tests indicated nonhazardous levels of contamination. Additional reviews of these facilities are planned (see Section 3.2).

Before 1981, all produced wastewater was disposed of into two Stevens waterflood/ injection projects, an SOZ injection project, and into open, unlined sumps. Due to projected increases in wastewater quantities, beginning in 1981 the Tulare wastewater disposal well system was installed, and after that the great majority of wastewater was disposed of into the Tulare, SOZ and Stevens Zones; the primary use of sumps was during off-normal circumstances.

It has been estimated that from 1979 through 1989, average annual wastewater quantities released to sumps averaged 10,000 barrels/day field wide, ranging from 2,000 barrels/day to 21,000 barrels/day (McLemore 1990). Currently wastewater sumping is approximately 1,000-2,000 barrels/day field wide. The TDS level of wastewater is typically 30,000-40,000 ppm.

Sumping volumes at NPR-1 have not been measured directly. The quantities reported by BPOI were "field-wide" estimates based on calculations made in 1989 using an assortment of the best historical operating data available. The methodology employed to calculate "recent" sumping quantities is considered to result in estimates that are reasonably accurate. "Earlier" estimates are thought to be less precise. Data needed to calculate historical releases to "individual" sumps are not readily available. However, 10G and 24Z were normally the sumps of first resort, and it is believed that the overwhelming majority of surface releases took place at these locations.

NPR-1 is permitted to sump wastewater by Waste Discharge Requirement #58-491 issued by the State of California in 1958. This prohibits the release of wastewater into unlined sumps located on alluvial soils, if the wastewater exceeds 1,000 ppm TDS. The 18G and 25S sumps are located near the Tulare/Alluvium contact; therefore, releases at these locations could have been into alluvial soils. NPR-1 is permitted to sump wastewater at the 26Z sump by Waste Discharge Requirement #68-262 issued by the State of California in 1968. In recognition of this risk, these sumps were either lined or taken out of service as mentioned above. NPR-1 is in the process of updating the above Waste Discharge Requirement permits.

D.4.2 Fate and Transport of Disposed Water

D.4.2.1 Surface Disposal

Bean and Logan (1983), Rector (1983), and Wilson and Zublin (1988) have discussed how moisture-deficient sediments overlying deep water tables can buffer groundwater from infiltrating sump wastewater. Bean and Logan (1983) also hypothesized that heterogeneities (clay layers) in the sediment profile can resaturate and pond infiltrating water, thus directing it to move parallel to the groundwater surface. These authors cited this as a mechanism that might link sumps on the Elk Hills with brine-contaminated wells in the San Joaquin Valley. Fishburn (1990) suggested that the same clay layers, depending on their dip, geometry and character could act as an aquitard that would prevent migration of infiltration water off of NPR-1.

Figure 3.4-2 shows that the confined aquifer is present near the San Joaquin Valley/Elk Hills interface, but the character and depth of its base are not known. It also shows that infiltration water on Elk Hills will move along clay and shale units that are dipping down 20-30 degrees in the direction of the confined aquifer (Fishburn 1990). Hydrologic flow regimes and the precise geology in the vicinity of the interface are not known. If clay and shale unit dips are relatively shallow, it is possible that NPR-1 infiltration water could flow into the confined and/or unconfined valley aquifers. On the other hand, if the clay/shale units continue to dip downward sufficiently, infiltration waters could ultimately be separated at lower depths from the useable waters comprising the confined aquifer. It is also possible that the geometry and character of these clay/shale layers provide traps that could confine movement off of NPR-1. This is supported by the fact that in the western areas of NPR-1 oil and gas are known to be trapped above and below the middle clay (Fishburn, 1990). In addition, the DGZ, which is depositionally similar to the portions of the Tulare below Limestone A, is a trap for gas (Fishburn 1990).

The uncertainty of the hydraulic relationship between NPR-1 sediments and those on the valley floor is complicated further by the variable depth to the E-Clay marking the top of the confined aquifer, and the relationship between the E-Clay and the middle clay (Amnicola).

D.4.2.2 Subsurface Disposal

The existing south and northwest flank disposal wells currently are used for injection of wastewater into the Tulare Formation. Nicholson (1985) reported that the effects of this in the south flank wells should appear as groundwater chemistry changes in the water production wells (waterflood source water wells on the south flank) after approximately 2 years. These groundwater production wells are located in an apparent downgradient position approximately one mile away and completed in the same zones as the wastewater disposal wells. These chemistry changes have not been observed after approximately 7 years. This is consistent with Stuart (1987) who reviewed wastewater disposal operations at NPR-1 and concluded that there has been little or no migration away from the disposal wells. This conclusion was based on the small temporal chemistry changes of the nearby groundwater production wells. In reaching his conclusion, Stuart also acknowledged that it is possible that the injected wastewater may be bypassing the groundwater production wells and escaping detection. If this is the case, it is possible that NPR-1 wastewaters could be communicating with usable groundwaters in the Buena Vista Valley. It is also possible that heterogeneities and anisotropy present in the Tulare Formation may be preventing groundwater movements as suggested by Fishburn (1990).

In a continuing effort to better understand the risk associated with NPR-1 underground injection disposal, additional studies recently have been completed (Milliken 1992, Phillips 1992). Milliken (1992) investigated the relationship between NPR-1's south flank Tulare Formation geology and movement of produced water injected into the 7G/18G disposal wells (see Figure 3.4-7 for disposal well locations). Surface mapping, well log correlations, and water quality studies presented in this report indicate that the Tulare and Amnicola Clay are present in the subsurface and act as important geohydrological barriers (aquicludes) to the migration of disposed produced water into the Alluvium of Buena Vista Valley, from which agriculture water production is obtained.

Phillips (1992) investigated groundwater quality and elevation changes resulting from produced water disposal and source water withdrawal along the Elk Hills' south flank. Phillips (1992) references a study by Mele (1992) which examined groundwater quality data from four south flank source water wells from January 1984 to March 1992. This investigation concluded that the TDS concentration values for all source wells have remained relatively constant during this period (averaging between 4,700 ppm to 5,700 ppm). The only changes identified in Tulare Formation groundwater quality were: (1) a 600 ppm increase in chloride ion concentrations in well 86WS-18G; and (2) a higher baseline chloride concentration level in well 45WS-18G. Phillips (1992) also presents directly measured water quality data from NPR-1 source water wells, which show the Amnicola Clay forms an aquiclude between waters of distinctly different salinities (the quality of groundwater is significantly better above the Amnicola Clay than beneath it).

Phillips (1992) reports that the effect of continuous source water withdrawal in the south flank wells between 1980 and 1990 has been minimal; the only evident water level response has been a decline of 34 feet in a very small area at the west end of the south flank. This decline, together with the minimal response in the other areas of the south flank, does not represent a significant drop in the water level, given the steady substantial groundwater withdrawal rate. Phillips (1992) reports anomalously high groundwater elevations over the past 10 years within the 7G/18G disposal area, which suggests that NPR-1's disposed produced water is mounding and spreading laterally along strike (Milliken 1992).

D.5 REGULATORY CONSIDERATIONS PERTINENT TO GROUNDWATER

Benioff et al (1988) have compiled an overview of federal and California State water quality regulations. Information pertaining to drinking water standards has been obtained from that document.

D.5.1 Federal

DOE Order 5400.1 (DOE 1988) mandates that DOE facilities comply with all appropriate federal and state regulations. Under extenuating circumstances, DOE facilities may apply for exemption from Order 5400.1.

The national interim primary drinking water standards (40 CFR 141) set forth maximum contaminant levels (MCLs) for various chemicals. These MCLs are enforceable federal standards that may also be applicable to remedial action alternatives at hazardous and toxic waste sites. However, appropriate cleanup levels depend on the nature of the site (proximity to receptors, depth to groundwater, etc.) and are determined by considering all applicable federal, state, and local regulations.

Drilling fluids and water produced in association with hydrocarbons are specifically excluded from designation as hazardous wastes (40 CFR 261.4). The disposal of these fluids is, however, regulated.

Class II (oil-field) underground injection is covered under 40 CFR 144, 146, and 147. Part 146 sets forth the criteria and standards that must be met in permits for underground injection. In carrying out the mandate of the Safe Drinking Water Act (SDWA) it is provided that "no injection shall be authorized by permit or rule if it results in the movement of fluid containing any contaminant into underground sources of drinking water" (USDW) (40 CFR 146). A USDW may be exempted from this regulation if it can be shown that the USDW has "no real potential to be used as a drinking water source." Federal regulation of surface discharge is provided in 40 CFR 435, which stipulates that "there shall be no discharge of waste water pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling fluids, drill cuttings, and produced sand)".

D.5.2 STATE OF CALIFORNIA

D.5.2.1 Drinking Water

The State of California bases its drinking water standards on the National Interim Primary and Secondary Drinking Water Regulations (40 CFR 141, 143,). California requires (in 22 CCR 64401) that all public water systems owned and operated by federal agencies comply with regulation as set forth in 40 CFR 141.

D.5.5.2 Proposition 65

The Safe Drinking Water and Toxic Enforcement Act of 1986 (Proposition 65) provides that "no person in the cause of doing business shall knowingly release a chemical known to the state to cause cancer or reproductive toxicity into water or onto land where such chemical passes or probably will pass into any source of drinking water..." (26 CCR Safe Drinking Water and Toxic Enforcement Act of 1986, Supplement 11). Water disposed of into Class II disposal wells is exempted from Proposition 65.

D.5.2.3 Porter-Cologne Water Quality Control Act

The Porter-Cologne Water Quality Control Act attempts to organize the control and protection of the quality of waters in the state into a coherent whole. The act identifies the state and regional water quality control boards as the principal state agencies for control and coordination of water quality (California Water Resources Control Board 1987). Waste Discharge Requirements are also described in the Porter-Cologne Water Quality Control Act. Any person discharging or proposing to discharge must file a report with the appropriate regional board.

D.5.2.4 Tulare Lake Basin Plan

Federal Regulation 40 CFR 131.202 requires each state to submit water quality control plans for all basin planning areas within the state by July 1, 1975. The Tulare Lake Basin

Plan (TLBP) was developed in response to that regulation and it was adopted in August 1975 as a policy guidance document to be used in establishing requirements (California Water Resources Control Board 1975). Since then, several amendments to the plan have been accepted.

The TLBP establishes that "...all sumps overlying the groundwater body shall protect present beneficial uses and not degrade groundwater"; it provides that limits for "...wastewater in unlined sumps overlying the usable groundwater body will be 1,000 EC, 200 mg/l chlorides, and 1 mg/l boron;" and among other criteria it defines usable water as being 3,000 mg/l TDS or less. The TLBP cites Section 1750-1780 of the California Code of Regulations (Title 14), which define the environmental protection regulations relating to oil and gas operations. Section 1770 states that "...sumps for the collection of wastewater or oil shall not be permitted in natural drainage channels" and that "...unlined evaporation sumps, if they contain harmful waters, shall not be located over freshwater bearing aquifer."

California Code of Regulations, Title 23, Subchapter 15, Discharges of Waste to Land

In December 1984 Subchapter 15 was amended to provide that all waste management unit waste discharge permits be reviewed and revised appropriately to meet all Subchapter 15 requirements.

Sections 1724.6 through 1724.10 list the geologic, geochemical, and engineering data that must accompany an application for underground injection of fluids. Section 1724.10 requires that "sufficient surveys shall be filed with the California Division of Oil and Gas within 3 months after injection has commenced, once every year thereafter, after any significant anomalous rate or pressure change ... to confirm that the injection fluid is confined to the proper zone or zones."

D.5.3 Permits

Water resources underlying and adjacent to NPR-1 are protected through four basic types of permits; these are:

- Individual permits from the California Division of Oil and Gas for the operation of each of the various types of wells: hydrocarbon production, water production, steam/water/gas injection and wastewater disposal;

- Waste Discharge Requirements issued by the Central Valley Regional Water Quality Control Board in 1958 for field-wide wastewater sumping operations. These requirements prohibit sumping activities that would pollute adjacent surface and groundwater; they also prohibit sumping on alluvial soils if total dissolved solids exceed 1000 parts/million; chloride content exceeds 175 parts/million; or boron content exceeds 2 parts/million. A separate Waste Discharge Requirement for the 26Z area sumping operations (Asphalto Field) was issued by the Central Valley Regional Water Quality Control Board in 1968.

- Waste Discharge Requirements issued by the Central Valley Regional Water Quality Control Board in 1976 for the operation of the 27R waste management facility; and

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APPENDIX E:
TERRESTRIAL BIOTA

E.1 LIFE-TABLE ANALYSIS FOR SAN JOAQUIN KIT FOX ON NPR-1

Life tables are useful in determining the causes of population change (Pianka 1984; Begon and Mortimer 1981). Life tables are based on the fecundity and survivorship of females of each age in the population. Population parameters such as net reproductive rate, rate of increase, and generation time are calculated from these values.

E.1.1 Methods

The life-table analysis presented here for San Joaquin kit foxes on NPR-1 was developed from data on the survivorship of radiocollared kit foxes in the NPR-1 study area taken from Zoellick et al (1987). The analysis investigates average conditions during the period 1981-1988; no attempt has been made to-date to complete separate analyses for the period of population decline from 1981-1985 and the period of relative population stability from 1985 to 1989. Definitions of terms are based on those presented by Pianka (1984), and include:

- Fecundity - the number of female pups produced by females of breeding age each year;

- Survivorship - the proportion of female pups that survives to each subsequent age;

- Mortality - the proportion of females within each age group that dies before reaching the next age;

- Net Reproductive Rate - the average number of female offspring expected to be produced by each female born (for a population to be stable, net reproductive rate must average 1);

- Generation Time - the average time from birth of a female pup to the birth of her female offspring; and

- Rate of Increase - a measure of instantaneous rate of change of population size per individual.

Fecundity was determined from the percentage of females pregnant and the average litter size. These values were estimated from the occurrence and number of placental scars determined during necropsy (Zoellick et al 1987). An estimated 73.3% and 96.0% of yearling and adult females, respectively, were impregnated each year. Average litter size was estimated to be 3.92 for yearlings and 4.89 for adults.

Except for pups, the percentage of radiocollared foxes on NPR-1 of known age that survived to the next age class was used to determine age-specific survivorship. Survivorship of pups to weaning was estimated to be 27% for yearling mothers and 68% for adult mothers (Zoellick et al 1987). Survivorship from weaning to 1 year of age was based on the survivorship of radiocollared pups (30.3%). The product of these two survivorship values, adjusted for the percentages of yearlings and adults in the population (40% and 60 %, respectively) provided the overall estimate of 17.1 % (82.9% mortality) survivorship from birth to 1 year of age.

E.1.2 Results and Discussion

Table E.1-1 is the life table for the kit fox on NPR-1. Mean fecundity for all age classes was 2.2 for the period 1981-1988. Average mortality for this period ranged from a low of 0.432 for 2 year old foxes to 0.829 (17.1% survivorship) for foxes less than one year old. As a consequence, the net reproductive rate of the fox population was 0.56. Generation time was 2.0 years, and the rate of increase was -0.30. Figure E.1-1 shows predicted minimum population curves based on this rate of increase for summer and winter minimum populations in the NPR-1 study area during the period 1981-1988. This figure also shows the minimum populations that were actually observed. As indicated, the curves matched closely during the period 1981-1985. However, after 1985, when the population began to stabilize, the curves begin to diverge in a manner that suggests a population rate of increase that is near zero. An increase in survivorship of pups from the estimated 17.1 to 30.7% would result in a net reproductive rate of 1 and a stable population.

E.2 PRECIPITATION

Precipitation levels before and during the NPR-1 kit fox population decline are discussed as follows:

- During the 3-year period 1978-1980, immediately preceding 1981 when trapping on NPR-1 began, precipitation was significantly above average. This could have had significant effects on vegetative production. For the 3-year period 1978-1980, growing season precipitation was approximately 22.2 inches, or 7.4 inches/year. This compares to 17.4 inches during the first 3 years of trapping from 1981-1983 (at the outset of the observed kit fox population decline), or 5.8 inches/year. This represents a decline of approximately 21.7% over the 3-year periods.

- During the 5-year period immediately preceding the decline, from 1976-1980, growing season precipitation was approximately 27.3 inches, or an average of 5.5 inches/year. In comparison, for the 5-year period 1981-1985, when the population decline occurred, growing season precipitation was approximately 24.1 inches, or an average of 4.8 inches/year. This represents a decline of 2.3 inches (11.7 %) over the 5-year periods.

TABLE E.1-1 Life Table for San Joaquin Kit Fox on NPR-1, 1981-1988[a]

Age (years)	Survivorship (1_x)[b]	Fecundity (m_x)[c]	Mortality	$1_x * m_x$	$x * 1_x * m_x$
0	1.000	0.000	0.829	0.000	0.000
1	0.171	1.437	0.592	0.245	0.245
2	0.070	2.347	0.432	0.163	0.327
3	0.040	2.347	0.586	0.093	0.278
4	0.016	2.347	0.667	0.038	0.154
5	0.005	2.347	0.750	0.013	0.064
6	0.001	2.347	1.000	0.003	0.019
7	0.000	2.347	0.000	0.000	0.000
Sums				0.556	1.087

Net Reproductive Rate (R_0) = $\Sigma\ 1_x * m_x = 0.556$

Generation Time (T) = $(\Sigma\ x * 1_x * m_x)/R_0 = 1.087/0.556 = 1.956$

Rate of Increase (r) approximates $(\ln R_0)/T = \ln(0.556)/1.956$
$= -0.301$

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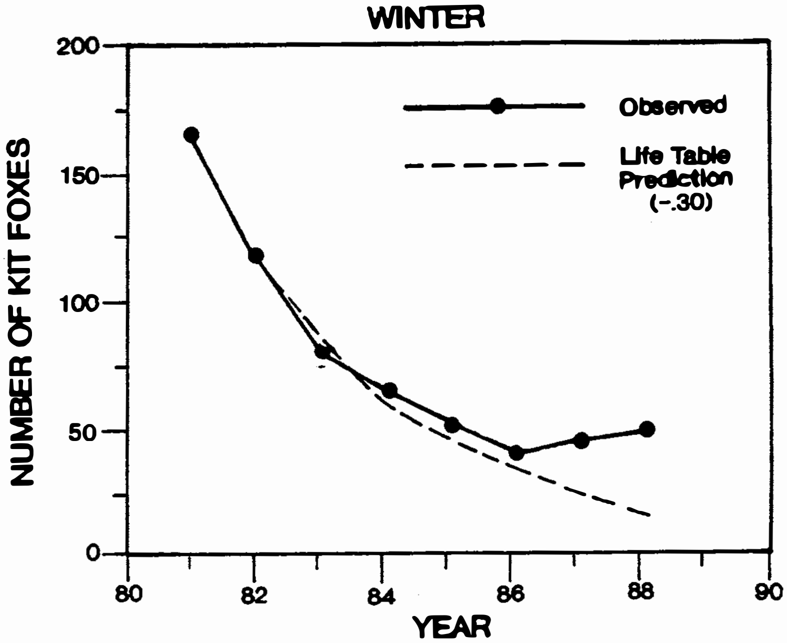
[a]Definitions of terms are provided in the text; formulas are from Pianka (1984).
[b]Calculated from data on survivorship of radiocollared foxes from 1981-1988.
[c]Calculated from data presented by Zoellick et al. 1987.

NUMBER OF KIT FOXES



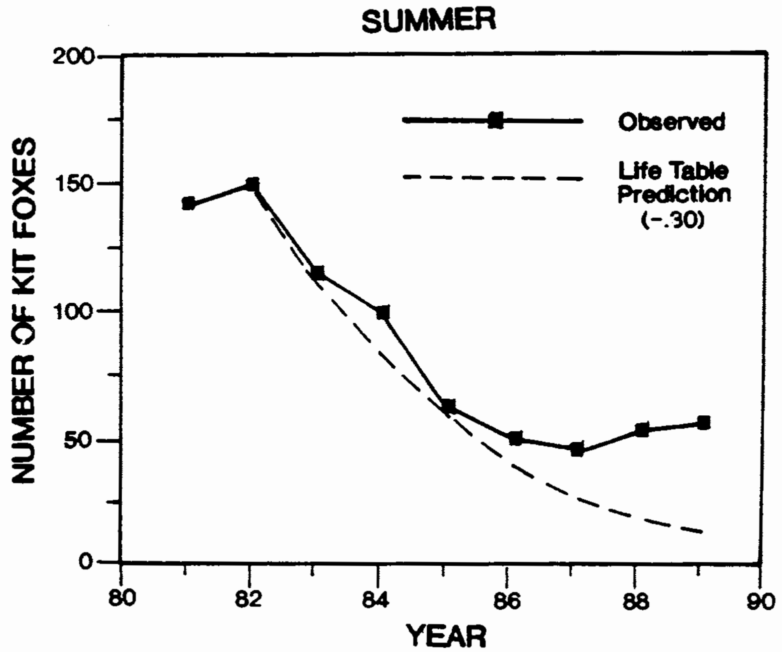


FIGURE E.1-1 NPR-1 STUDY AREA SAN JOAQUIN KIT FOX MINIMUM POPULATION KNOWN TO BE ALIVE AND ESTIMATED USING PARAMETERS FROM LIFE TABLE

- Growing season precipitation has been less than average during 6 years of the period 1981-1990, and 5 years of the period 1984-1990 (See Figure 3.5-4).

E.3 COYOTE CONTROL PROGRAM

The results of the coyote control program are being evaluated. Preliminary observations are as follows:

- Coyote abundance appears to have declined in a manner that parallels the implementation of the control program (see Table 3.5-2, Figure 3.5-1, and Figure 3.5-8). The decline in coyote abundance also parallels the decline in lagomorph abundance (see Figures 3.5-6 and 3.5-7), a primary food source for coyotes.

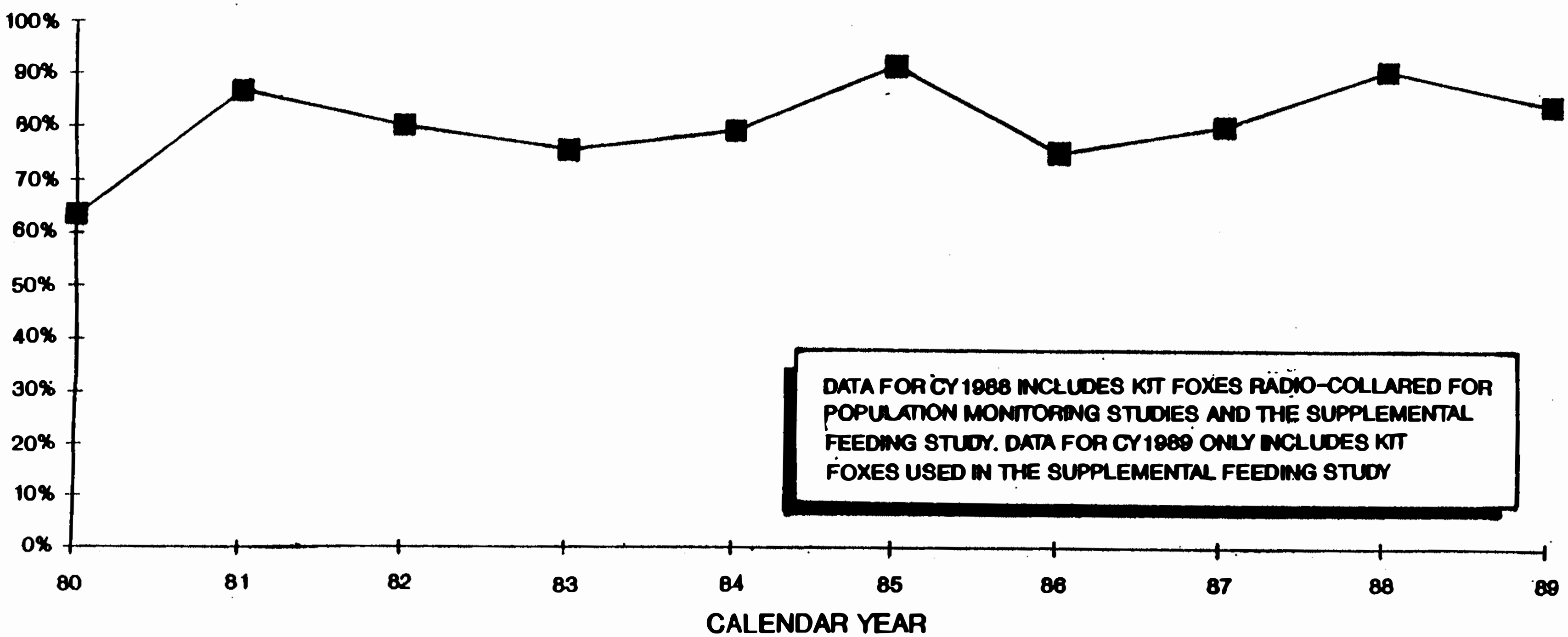
- The "rate" of kit fox mortality as the result of predation does not appear to have changed during the period of control (see Figure E.3-1). This could be because control was not effective, or it could be due to a decline in the relative number of deaths caused by factors other than predation.

- The kit fox population in the NPR-1 study area began stabilizing at or about the same time the control program was put in place during a period of deteriorating environmental conditions (5 of 7 years below average precipitation and declining lagomorph abundance). It is possible that under these conditions the kit fox population might have declined (instead of stabilizing) except for the possible favorable effect of the control program (see Figures 3.5-3, 3.5-4 and 3.5-7).

- In a kit fox supplemental feeding study it was observed that the survivorship of control pups was significantly higher in 1989 than in 1988. The intensity of the coyote control program was also significantly greater in 1989 than in 1988 (see Figure 3.5-8).

It is anticipated that an evaluation of the coyote control program will be completed in conjunction with the Section 7 consultation with the U.S. Fish and Wildlife Service regarding the continued operation of NPR-1 at Maximum Efficient Rate.

FIGURE E.3-1
PERCENTAGE OF KNOWN MORTALITY OF KIT FOXES DUE TO PREDATION ON NPR-1
SOURCE: EG&G/EM 1990b



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APPENDIX F:

SOCIOECONOMIC ANALYSES

This appendix contains the detailed matrices used for the location-quotient, shift-share, and input-output templates and analyses performed to assess current and projected socioeconomic impacts of NPR-1 in Kern County.

Tables F.1 and F.2 contain the elements used to calculate location-quotients for Kern County. The technique compares the percent of Kern County employment in each industry to the percent of total U.S. employment to determine how much employment in the county is attributable to export (outside the county) activities. The major findings of the location-quotient analysis are discussed in Section 3.8.2.

Tables F.3 and F.4 contain the elements used to calculate employment shift-shares for Kern County. The technique examines changes in the structure of employment for the country as a whole, over time, and then compares those trends against changes in the local economy. Although shift-share analysis does not explain why changes are occurring, it does serve as an indicator to reveal that jobs are being lost. The major findings of the shift-share analysis are discussed in Section 3.8.2.

Tables F.5, F.6, and F.7 provide the detailed input-output analysis (I-O) results that are summarized and discussed in Section 4.1.8.4. The multipliers (last column of Tables F.5, F.6, and F.7) were obtained from the Department of Commerce's Regional Input-Output Modeling System (1988). The impact numbers were calculated by multiplying the Kern County incremental expenditure figures (Table 4.1.8-1) by the multipliers in the last column. The impacts presented here represent the incremental increases in induced output, earnings, and employment by industry attributable to the proposed action.

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TABLE F.1 Location-Quotient Template - Employees by Industry, United States and Kern County, 1984

SIC Code/Industry	United States	Kern County
Contract Construction		7,931
15 General contractors	1,051,008	1,430
16 Heavy construction	698,745	1,170
17 Special trade	2,403,012	5,331
All others	0	0
Manufacturing		7,676
24 Lumber and wood products	661,454	321
27 Printing and publishing	1,355,907	805
28 Chemicals and allied products	851,573	192
32 Stone, clay, and glass	545,812	728
34 Fabricated metal products	1,468,937	348
35 Machinery except electrical	2,017,342	844
38 Instruments and related products	616,988	58
All others	11,807,339	4,380
Transportation and Public Utilities		6,322
42 Trucking and warehousing	1,238,332	2,343
47 Transportation services	254,001	175
48 Communication	1,286,751	1,461
49 Electric, gas, and sanitary services	810,386	1,197
All others	1,085,915	1,146
Wholesale Trade		8,471
50 Wholesale trade - durables	3,007,034	4,582
51 Wholesale trade - nondurables	2,104,639	3,329
All others	0	560
Retail Trade		29,384
52 Building materials and garden supply	553,355	1,103
53 General merchandise	1,868,903	2,963
54 Food stores	2,498,788	4,800
55 Auto dealers and service stations	1,779,133	3,766
56 Apparel and accessory stores	969,837	1,520
57 Furniture and home furnishings	586,822	1,024
58 Eating and drinking places	5,053,676	10,662
59 Miscellaneous retail	2,021,224	3,534
All others	0	12

TABLE F.1 (Cont'd)

SIC Code/Industry	United States	Kern County
Finance, Insurance, and Real-Estate		5,468
60 Banking	1,569,041	1,554
61 Credit agencies other than banks	699,673	922
63 Insurance carriers	1,241,324	569
64 Insurance agents, brokers, and service	523,339	592
65 Real Estate	1,051,474	1,158
All others	698,374	673
Services		26,280
70 Hotels and other lodging	1,200,435	1,470
72 Personal services	1,029,003	1,241
73 Business services	3,833,744	6,191
75 Auto repair, services, and garages	626,067	1,249
76 Miscellaneous repair	310,095	819
79 Amusement and recreation	739,514	1,004
80 Health services	6,202,435	8,125
81 Legal services	645,354	607
82 Education services	1,476,430	357
83 Social services	1,198,265	1,371
86 Membership organizations	1,507,452	1,847
89 Miscellaneous services	1,118,944	1,768
All others	461,584	231
Nonclassifiable Establishments	890,799	0
Total	75,620,259	83,601

TABLE F.2 Location-Quotient Analysis -- Employees by Industry, United States and Kern County, 1984

SIC Code/Industry	United States		Kern County		Employment for Local Requirements	Export Employment
	Employees	% of Total	Employees	% of Total		
Contract Construction						
16 Heavy construction	698,745	0.92	1,170	1.28	846	324
17 Special trade	2,403,012	3.18	5,331	5.82	2,909	242
All others	0	0.00	0	0.00	0	0
Manufacturing						0
24 Lumber and wood products	661,454	0.87	321	0.35	801	0
27 Printing and publishing	1,355,907	1.79	805	0.88	1,641	0
28 Chemicals and allied products	851,573	1.13	192	0.21	1,031	67
32 Stone, clay, and glass	545,812	0.72	728	0.80	661	0
32 Fabricated metal products	1,468,937	1.94	348	0.38	1,778	0
35 Machinery except electrical	2,017,342	2.67	844	0.92	2,442	0
38 Instruments and related products	616,988	0.82	58	0.06	747	0
All others	11,807,339	15.61	4,380	4.79	14,292	
Transportation and Public Utilities						
42 Trucking and warehousing	1,238,332	1.64	2,343	2.56	1,499	844
47 Transportation services	254,001	0.34	175	0.129	307	0
48 Communication	1,286,751	1.70	1,461	1.60	1,558	0
49 Electric, gas, and sanitary services	810,306	1.07	1,197	1.31	981	216
All others	1,085,915	1.44	1,146	1.25	1,314	0
Wholesale Trade						
50 Wholesale Trade - durables	3,007,034	3.98	4,582	5.01	3,640	942
51 Wholesale Trade - nondurables	2,104,639	2.78	3,329	3.64	2,547	782
All others	0	0.00	560	0.61	0	560

TABLE F.2 (Cont'd)

SIC Code/Industry	United States		Kern County		Employment for Local Requirements	Export Employment
	Employees	% of Total	Employees	% of Total		
Retail Trade						
52 Building materials and garden supply	553,355	0.73	1,103	1.21	670	433
53 General merchandise	1,868,903	2.47	2,963	3.24	2,262	701
54 Food stores	2,498,788	3.30	4,800	5.24	3,025	1,775
55 Auto dealers and service stations	1,779,133	2.35	3,766	4.11	2,153	1,613
56 Apparel and accessory stores	969,837	1.28	1,520	1.66	1,174	346
57 Furniture and home furnishings	586,822	0.78	1,024	1.12	710	314
58 Eating and drinking places	5,053,676	6.68	10,662	11.65	6,117	4,545
59 Miscellaneous retail	2,021,224	2.67	3,534	3.86	2,447	1,087
All others	0	0.00	12	0.01	0	12
Finance, Insurance, and Real Estate						
60 Banking	1,569,041	2.07	1,554	1.70	1,899	0
61 Credit agencies other than banks	699,673	0.93	922	1.01	847	75
63 Insurance carriers	1,241,324	1.64	569	0.62	1,503	0
64 Insurance agents, brokers, and service	523,339	0.69	592	0.65	633	0
65 Real estate	1,051,474	1.39	1,158	1.27	1,273	0
All others	698,374	0.92	673	0.74	845	0

TABLE F.2 Location-Quotient Analysis , (Cont'd)

SIC Code/Industry	United States		Kern County		Employment for Local Requirements	Export Employment
	Employees	% of Total	Employees	% of Total		
Services						
70 Hotels and other lodging	1,200,435	1.59	1,470	1.61	1,453	17
72 Personal services	1,029,003	1.36	1,241	1.36	1,246	0
73 Business services	3,833,744	5.07	6,191	6.76	4,640	1,551
75 Auto repair, services, and garages	626,067	0.83	1,249	1.36	758	491
76 Miscellaneous repair	310,095	0.41	819	0.89	375	444
79 Amusement and recreation	739,514	0.98	1,004	1.10	895	109
80 Health services	6,202,435	8.20	8,125	8.88	7,508	617
81 Legal services	645,354	0.85	607	0.66	781	0
82 Education services	1,476,430	1.95	357	0.39	1,787	0
83 Social services	1,198,265	1.58	1,371	1.50	1,450	0
86 Membership organizations	1,507,452	1.99	1,847	2.02	1,825	22
89 Miscellaneous services	1,118,944	1.48	1,768	1.93	1,354	414
All others	461,584	0.61	231	0.25	559	0
Nonclassifiable Establishments	890,799	1.18	0	0.00	1,078	0
Total	75,620,259	100.00	91,532	100.00	-	20,882

TABLE F.3 Shift-Share Template -- United States and Kern County Employees, 1980 and 1984

SIC Code/Industry	United States		Kern County	
	1980	1984	1980	1984
Contract Construction			7,009	7,931
15 General Contractors	1,257,780	1,051,008	1,200	1,430
16 Heavy construction	855,523	698,745	1,346	1,170
17 Special trade	2,344,302	2,403,012	4,463	5,331
All others	0	0	0	0
Manufacturing			8,141	7,676
20 Food and kindred products	1,515,593	1,420,436	0	0
24 Lumber and wood products	709,050	661,454	257	321
27 Printing and publishing	1,260,191	1,355,907	656	805
32 Stone, clay, and glass	633,138	545,812	334	728
35 Machinery except electrical	2,504,240	2,017,342	868	844
38 Instruments and related products	643,308	616,988	54	58
	13,899,177	12,707,413	5,972	4,920
Transportation and Public Utilities			5,947	6,322
42 Trucking and warehousing	1,284,308	1,238,332	2,113	2,343
47 Transportation services	213,051	254,001	104	175
49 Electric, gas, and sanitary services	743,184	810,386	462	1,197
All others	2,382,809	2,372,666	3,268	2,607

TABLE F.3 Shift-Share Template, (Cont'd)

SIC Code/Industry	United States		Kern County	
	1980	1984	1980	1984
Wholesale Trade			7,183	8,471
50 Wholesale trade - durables	2,962,331	3,007,034	4,132	4,582
51 Wholesale Trade - nondurables	1,986,772	2,104,639	2,905	3,329
All others	0	0	146	560
Retail Trade			25,326	29,384
53 General Merchandise	1,965,049	1,868,903	2,998	2,963
54 Food stores	2,225,209	2,498,788	3,675	4,800
55 Auto dealers and service stations	1,744,522	1,779,133	3,610	3,766
56 Apparel and accessory stores	943,841	969,837	1,750	1,750
57 Furniture and home furnishings	577,264	586,822	1,094	1,024
58 Eating and drinking places	4,492,287	5,053,676	8,331	10,662
59 Miscellaneous retail	1,914,092	2,021,224	3,223	3,534
All others	534,863	553,355	645	885
Finance, Insurance, and Real Estate			5,742	5,468
60 Banking	1,507,807	1,569,041	1,728	1,554
61 Credit agencies other than banks	587,632	699,673	934	922
63 Insurance carriers	1,237,429	1,241,324	574	569
65 Real estate	989,241	1,051,474	1,234	1,158
All others	972,566	1,221,713	1,272	1,265

TABLE F.3 Shift-Share Template, (Cont'd)

SIC Code/Industry	United States		Kern County	
	1980	1984	1980	1984
Services			21,554	26,280
70 Hotels and other lodging	1,085,973	1,200,435	1,250	1,470
72 Personal services	953,231	1,029,003	1,323	1,241
73 Business services	2,991,017	3,833,744	4,219	6,191
75 Auto repair, services, and garages	559,891	626,067	1,119	1,249
76 Miscellaneous repair	318,982	310,095	900	819
78 Motion Pictures	208,305	302,174	-	-
79 Amusement and recreation	706,048	739,514	900	1,004
80 Health services	5,258,027	6,202,435	6,895	8,125
81 Legal services	503,473	645,354	524	607
82 Education services	1,241,364	1,476,430	291	357
83 Social services	1,022,735	1,198,265	1,151	1,371
86 Membership organizations	1,214,858	1,507,452	1,253	1,847

TABLE F.4 Shift-Share Analysis -- Changes in Employment by Industry, United States and Kern County, 1980-1984

SIC Code/Industry	United States			Kern County		
	1980	1984	% Change	1980	1984	% Change
Part A						
Contract Construction						
15 General Contractors	1,257,780	1,051,008	-16.44	1,200	1,430	19.17
16 Heavy Construction	855,523	698,745	-18.33	1,346	1,170	-13.08
17 Special Trade	2,344,302	2,403,012	2.50	4,463	5,331	19.45
All others	0	0	0.00	0	0	0.00
Manufacturing						
20 Food and kindred products	1,515,593	1,420,436	-6.28	0	0	0.00
24 Lumber and wood products	709,050	661,454	-6.71	257	321	24.90
27 Printing and publishing	1,260,191	1,335,907	7.60	656	805	22.71
32 Stone, clay, and glass	633,138	545,812	-13.79	334	728	117.96
35 Machinery except electrical	2,504,240	2,017,342	-19.44	868	844	-2.76
38 Instruments and related products	643,308	616,988	-4.09	54	58	7.41
All others	13,899,177	12,707,413	-8.57	5,972	4,920	-17.62
Transportation and Public Utilities						
42 Trucking and warehousing	1,284,308	12,383,332	-3.58	2,113	2,343	10.88
47 Transportation services	213,051	254,001	19.22	104	175	68.27
49 Electric, gas, and sanitary services	743,184	810,386	9.04	462	1,197	159.09
All others	2,382,809	2,372,666	-0.43	3,268	2,607	-20.23
Wholesale Trade						
50 Wholesale trade - durables	2,962,331	3,007,034	1.51	4,132	4,582	10.89
51 Wholesale trade - nondurables	1,986,772	2,104,639	5.93	2,905	3,329	14.60
All others	0	0	0.00	146	560	283.56

TABLE F.4 Shift-Share Analysis, (Cont'd)

SIC Code/Industry	United States			Kern County		
	1980	1984	% Change	1980	1984	% Change
Retail Trade						
53 General Merchandise	1,965,049	1,868,903	-4.89	2,998	2,963	-1.17
54 Food stores	2,225,209	2,498,788	12.29	3,675	4,800	30.61
55 Auto dealers and service stations	1,744,522	1,779,133	1.98	3,610	3,766	4.32
56 Apparel and accessory stores	943,841	969,837	2.75	1,750	1,750	0.00
57 Furniture and home furnishings	577,264	586,822	1.66	1,094	1,024	-6.40
58 Eating and drinking places	4,492,287	5,053,676	12.50	8,331	10,662	27.98
59 Miscellaneous retail	1,914,092	2,021,224	5.60	3,223	3,534	9.65
All others	534,863	553,355	3.46	645	885	37.21
Finance, Insurance, and Real Estate						
60 Banking	1,507,807	1,569,041	4.06	1,728	1,554	-10.07
61 Credit agencies other than banks	587,632	699,673	19.07	934	922	-1.28
63 Insurance carriers	1,237,429	1,241,324	0.31	574	569	-0.87
65 Real estate	989,241	1,051,474	6.29	1,234	1,158	-6.16
All others	972,566	1,221,713	25.62	1,272	1,265	9.55
Services						
70 Hotels and other lodging	1,085,973	1,200,435	10.54	1,250	1,470	17.60
72 Personal services	953,231	1,029,003	7.95	1,323	1,241	-6.20
73 Business services	2,991,017	3,833,744	28.18	4,219	6,191	46.74
75 Auto repair, services, and garages	559,891	626,067	11.82	1,119	1,249	11.62
76 Miscellaneous repair	318,982	310,095	-2.79	900	819	-9.00
78 Motion pictures	208,305	202,174	-2.94	0	0	0.00
79 Amusement and recreation	706,048	739,514	4.74	900	1,004	11.56
80 Health services	5,258,027	6,202,435	17.96	6,895	8,125	17.84
81 Legal services	503,473	645,354	28.18	524	607	15.84

TABLE F.4 Shift-Share Analysis, (Cont'd)

SIC Code/Industry	United States			Kern County		
	1980	1984	% Change	1980	1984	% Change
82 Education services	1,241,364	1,476,430	18.94	291	357	22.68
83 Social Services	1,022,735	1,198,265	17.16	1,151	1,371	19.11
86 Membership organizations	1,214,858	1,507,452	24.08	1,253	1,847	47.41
89 Miscellaneous services	925,470	1,118,944	20.91	1,598	1,768	10.64
All others	28,231	32,911	16.58	131	231	76.34

TABLE F.4 (Cont'd)

SIC Code/Industry	National Growth	Industrial Mix	Competitive Share	Total Change
Part B				
Contract Construction				
15 General contractors	49	-246	427	230
16 Heavy construction	54	-301	71	-176
17 Special trade	181	- 69	756	868
All others	0	0	0	0
Manufacturing				
20 Food and kindred products	0	0	0	0
24 Lumber and wood products	10	-28	81	64
27 Printing and publishing	27	23	99	149
32 Stone, clay, and glass	14	-60	440	394
35 Machinery except electrical	35	-204	145	-24
38 Instruments and related products	2	-4	6	4
All others	242	-754	-540	-1,052
Transportation and Public Utilities				
42 Trucking and warehousing	85	-161	306	230
47 Transportation services	4	16	51	71
49 Electric, gas, and sanitary services	19	23	693	735
All others	132	-146	-647	-661
Wholesale Trade				
50 Wholesale trade - durables	167	-105	388	450
51 Wholesale trade - nondurables	118	55	252	424
All others	6	-6	414	414

TABLE F.4 (Cont'd)

SIC Code/Industry	National Growth	Industrial Mix	Competitive Share	Total Change
Retail Trade				
53 General merchandise	121	-268	112	-35
54 Food stores	1,249	303	673	1,125
55 Auto dealers and service stations	146	-74	84	156
56 Apparel and accessory stores	71	-23	-48	0
57 Furniture and home furnishings	44	-26	-88	-70
58 Eating and drinking places	337	704	1,290	2,331
59 Miscellaneous retail	130	50	131	311
All others	26	-4	218	240
Finance, Insurance, and Real Estate				
60 Banking	70	0	-244	-174
61 Credit agencies other than banks	38	140	-190	-12
63 Insurance carriers	23	-21	-7	-5
65 Real Estate	50	28	-154	-76
All others	51	274	-333	-7
Services				
70 Hotels and other lodging	51	81	88	220
72 Personal services	54	52	-187	-82
73 Business services	171	1,018	783	1,972
75 Auto repair, services, and garages	45	87	-2	130
76 Miscellaneous repair	36	- 61	-56	-81

TABLE F.4 (Cont'd)

SIC Code/Industry	National Growth	Industrial Mix	Competitive Share	Total Change
78 Motion pictures	0	0	0	0
79 Amusement and recreation	36	6	61	104
80 Health services	279	960	-8	1,230
81 Legal services	21	126	-65	83
82 Education services	12	43	11	66
83 Social services	47	151	22	220
86 Membership organizations	51	251	292	594
89 Miscellaneous services	65	269	-164	170
All others	5	16	78	100

TABLE F.5 Impacts on Output in Kern County by Project Year

	Increased Output ($\$10^3$)						
Industry	1989	1990	1991	1992	1993	1994	Multipliers
Agriculture, Forestry, and Fisheries							
Agricultural products and agricultural, forestry, and fishery services	0	0	23	76	10	4	0.0026
Forestry and fishery products	0	0	0	0	0	0	0
Mining							
Coal mining	0	0	0	0	0	0	0
Crude petroleum and natural gas	1	1	9,110	30,104	4,026	1,784	1.0341
Miscellaneous mining	0	0	4	12	2	1	0.0004
Construction							
New construction	0	0	0	0	0	0	0
Maintenance and repair construction	0	0	571	1,886	252	112	0.0648
Manufacturing							
Food and kindred products and tobacco	0	0	36	119	16	7	0.0041
Textile mill products	0	0	1	3	0	0	0.0001
Apparel	0	0	2	6	1	0	0.0002
Paper and allied products	0	0	2	6	1	0	0.0002
Printing and publishing	0	0	13	44	6	3	0.0015
Chemicals and petroleum refining	0	0	133	440	59	26	0.0151
Rubber and leather products	0	0	10	32	4	2	0.0011
Lumber and wood products and furniture	0	0	7	23	3	1	0.0008
Stone, clay, and glass products	0	0	19	61	8	4	0.0021
Primary metal industries	0	0	3	9	1	1	0.0003
Fabricated metal products	0	0	32	105	14	6	0.0036
Machinery, except electrical	0	0	66	218	29	13	0.0075
Electric and electronic equipment	0	0	1	3	0	0	0.0001
Motor vehicles and equipment	0	0	1	3	0	0	0.0001
Transportation equipment, except motor vehicles	0	0	3	9	1	1	0.0003

TABLE F.5 (Cont'd)

Industry	Increased Output ($\$10^3$)						Multipliers
	1989	1990	1991	1992	1993	1994	
Instruments and related products	0	0	1	3	0	0	0.0001
Miscellaneous manufacturing industries	0	0	1	3	0	0	0.0001
Transportation, Communication, and Utilities							
Transportation	0	0	79	262	35	16	0.009
Communication	0	0	55	180	24	11	0.0062
Electric, gas, water, and sanitary services	0	0	138	457	61	27	0.0157
Wholesale and Retail Trade							
Wholesale trade	0	0	143	472	63	28	0.0162
Retail trade	0	0	214	707	95	42	0.0243
Finance, Insurance, and Real Estate							
Finance	0	0	55	180	24	11	0.0062
Insurance	0	0	19	64	9	4	0.0022
Real estate	0	0	642	2,122	284	126	0.0729
Services							
Hotels, lodging places and amusements	0	0	21	70	9	4	0.0024
Personal services	0	0	26	84	11	5	0.0029
Business services	0	0	154	509	68	30	0.0175
Eating and drinking places	0	0	137	451	60	27	0.0155
Health services	0	0	83	274	37	16	0.0094
Miscellaneous services	0	0	85	282	38	17	0.0097
Households	0	0	1,675	5,534	740	328	0.1901
Total	1	1	11,887	39,279	5,253	2,328	1.3493

Source: BPOI 1989; U.S. Department of Commerce 1988.

TABLE F.6 Impacts on Earnings in Kern County by Project Year

	Increased Output ($\$10^3$)						
Industry	1989	1990	1991	1992	1993	1994	Multipliers
Agriculture, Forestry, and Fisheries							
Agricultural products and agricultural, forestry, and fishery services	0	0	8	26	4	2	0.0009
Forestry and fishery products	0	0	0	0	0	0	0
Mining							
Coal mining	0	0	0	0	0	0	0
Crude petroleum and natural gas	0	0	892	2,949	394	175	0.1013
Miscellaneous mining	0	0	1	3	0	0	0.0001
Construction							
New construction	0	0	0	0	0	0	0
Maintenance and repair construction	0	0	255	841	113	50	0.0289
Manufacturing							
Food and kindred products and tobacco	0	0	4	15	2	1	0.0005
Textile mill products	0	0	0	0	0	0	0
Apparel	0	0	0	0	0	0	0
Paper and allied products	0	0	0	0	0	0	0
Printing and publishing	0	0	4	15	2	1	0.0005
Chemicals and petroleum refining	0	0	5	17	2	1	0.0006
Rubber and leather products	0	0	3	9	1	1	0.0003
Lumber and wood products and furniture	0	0	2	6	1	0	0.0002
Stone, clay, and glass products	0	0	4	12	2	1	0.0004
Primary metal industries	0	0	1	3	0	0	0.0001
Fabricated metal products	0	0	8	26	4	2	0.0009
Machinery, except electrical	0	0	18	58	8	3	0.002
Electric and electronic equipment	0	0	0	0	0	0	0
Motor vehicles and equipment	0	0	0	0	0	0	0
Transportation equipment, except motor vehicles	0	0	1	3	0	0	0.0001

TABLE F.6 (Cont'd)

Industry	Increased Output ($\$10^3$) 1989	1990	1991	1992	1993	1994	Multipliers
Instruments and related products	0	0	0	0	0	0	0
Miscellaneous manufacturing industries	0	0	0	0	0	0	0
Transportation, Communication, and Utilities							
Transportation	0	0	34	114	15	7	0.0039
Communication	0	0	14	47	6	3	0.0016
Electric, gas, water, and sanitary services	0	0	12	41	5	2	0.0014
Wholesale and Retail Trade							
Wholesale trade	0	0	54	178	24	11	0.0061
Retail trade	0	0	103	341	46	20	0.0117
Finance, Insurance, and Real Estate							
Finance	0	0	17	55	7	3	0.0019
Insurance	0	0	8	26	4	2	0.0009
Real estate	0	0	15	49	7	3	0.0017
Services							
Hotels, lodging places and amusements	0	0	7	23	3	1	0.0008
Personal services	0	0	11	35	5	2	0.0012
Business services	0	0	70	233	31	14	0.008
Eating and drinking places	0	0	41	137	18	8	0.0047
Health services	0	0	47	154	21	9	0.0053
Miscellaneous services	0	0	29	96	13	6	0.0033
Households	0	0	6	20	3	1	0.0007
Total	0	0	1,675	5,534	740	328	0.1901

Source: BPOI 1989; U.S. Department of Commerce 1988.

TABLE F.7 Impacts on Employment in Kern County by Project Year

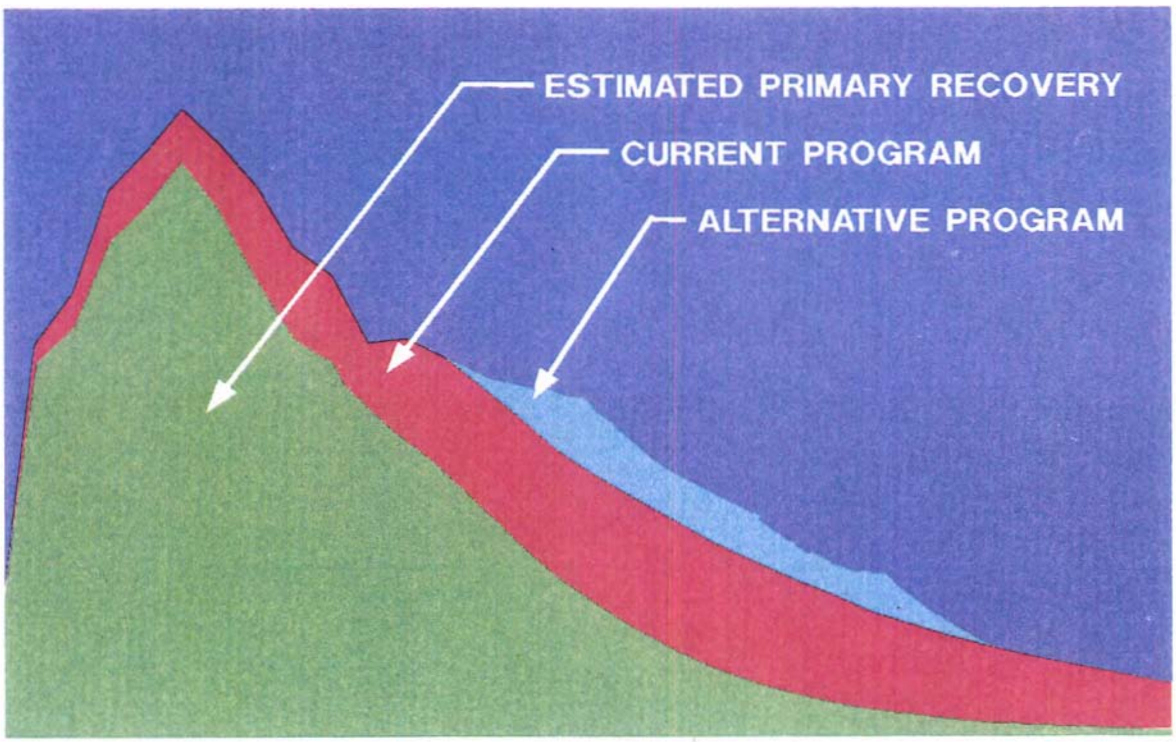
Industry	Increased Output ($\$10^3$) 1989	1990	1991	1992	1993	1994	Multipliers
Agriculture, Forestry, and Fisheries							
Agricultural products and agricultural, forestry, and fishery services	0	0	1	3	0	0	0.1
Forestry and fishery products	0	0	0	0	0	0	0
Mining							
Coal mining	0	0	0	0	0	0	0
Crude petroleum and natural gas	0	0	24	79	11	5	2.7
Miscellaneous mining	0	0	0	0	0	0	0
Construction							
New construction	0	0	0	0	0	0	0
Maintenance and repair construction	0	0	11	35	5	2	1.2
Manufacturing							
Food and kindred products and tobacco	0	0	0	0	0	0	0
Textile mill products	0	0	0	0	0	0	0
Apparel	0	0	0	0	0	0	0
Paper and allied products	0	0	0	0	0	0	0
Printing and publishing	0	0	0	0	0	0	0
Chemicals and petroleum refining	0	0	0	0	0	0	0
Rubber and leather products	0	0	0	0	0	0	0
Lumber and wood products and furniture	0	0	0	0	0	0	0
Stone, clay, and glass products	0	0	0	0	0	0	0
Primary metal industries	0	0	0	0	0	0	0
Fabricated metal products	0	0	0	0	0	0	0
Machinery, except electrical	0	0	1	3	0	0	0.1
Electric and electronic equipment	0	0	0	0	0	0	0
Motor vehicles and equipment	0	0	0	0	0	0	0
Transportation equipment, except motor vehicles	0	0	0	0	0	0	0

TABLE F.7 (Cont'd)

Industry	Increased Output ($\$10^3$) 1989	1990	1991	1992	1993	1994	Multipliers
Instruments and related products	0	0	0	0	0	0	0
Miscellaneous manufacturing industries	0	0	0	0	0	0	0
Transportation, Communication, and Utilities							
Transportation	0	0	1	3	0	0	0.1
Communication	0	0	0	0	0	0	0
Electric, gas, water, and sanitary services	0	0	0	0	0	0	0
Wholesale and Retail Trade							
Wholesale trade	0	0	3	9	1	1	0.3
Retail trade	0	0	7	23	3	1	0.8
Finance, Insurance, and Real Estate							
Finance	0	0	1	3	0	0	0.1
Insurance	0	0	0	0	0	0	0
Real estate	0	0	2	6	1	0	0.2
Services							
Hotels, lodging places and amusements	0	0	1	3	0	0	0.1
Personal services	0	0	1	3	0	0	0.1
Business services	0	0	4	15	2	1	0.5
Eating and drinking places	0	0	6	20	3	1	0.7
Health services	0	0	2	6	1	0	0.2
Miscellaneous services	0	0	2	6	1	0	0.2
Households	0	0	1	3	0	0	0.1
Total	0	0	67	221	30	13	7.6

Source: BPOI 1989; U.S. Department of Commerce 1988.

NPRC FY 1989 - 1995
LONG RANGE PLAN



NAVAL PETROLEUM RESERVES
IN
CALIFORNIA

NAVAL PETROLEUM RESERVES IN CALIFORNIA
LONG RANGE PLAN, FY 1989-1995

EXECUTIVE SUMMARY

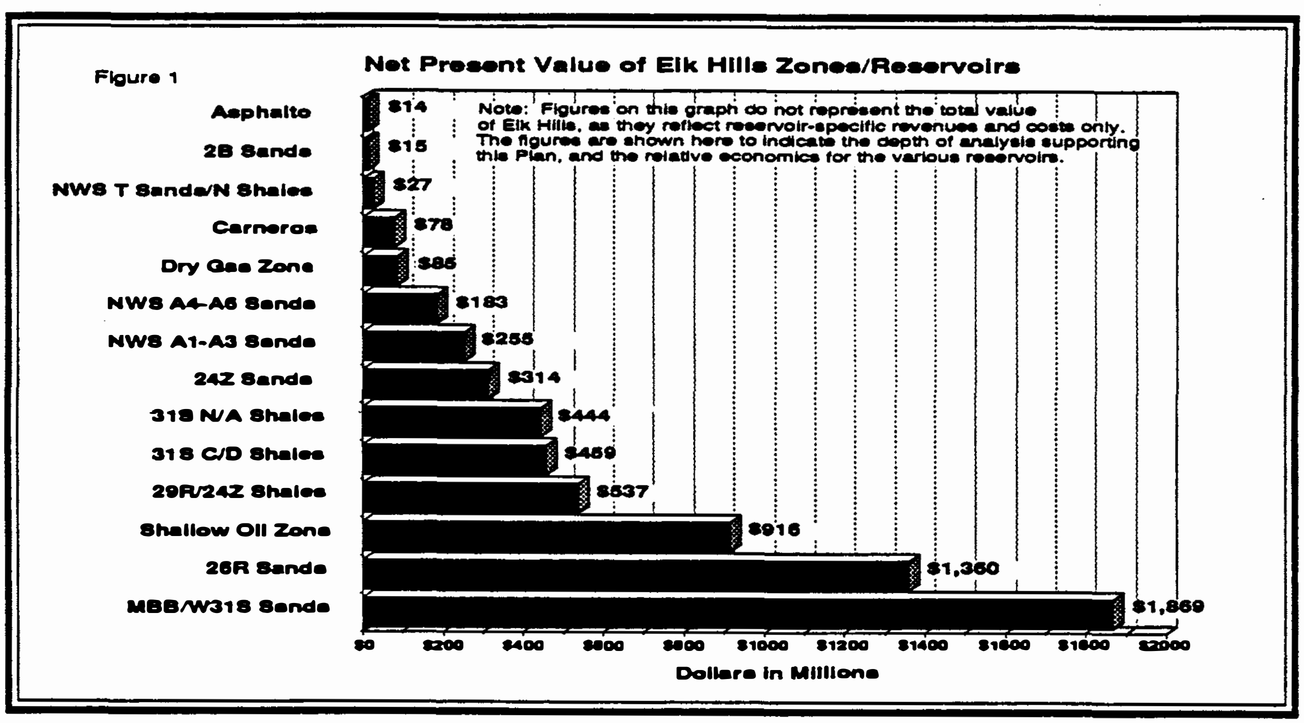
Introduction

The FY 1989-1995 Long Range Plan for the Naval Petroleum Reserves in California represents the most comprehensive effort to date toward articulating plans for all aspects of activity at Naval Petroleum Reserve No. 1 (Elk Hills). It also describes activity related to Naval Petroleum Reserve No. 2, although all the Government's known productive acreage in Naval Petroleum Reserve No. 2 has been leased since the 1920's, the Government's royalty oil from that field is now less than 200 barrels of oil per day, and the field requires minimal oversight.

Unlike the leasing arrangement at Naval Petroleum Reserve No. 2, Elk Hills is not leased, but is managed as a single unit by the Department of Energy on behalf of the U.S. Government (78 percent equity) and by Chevron U.S.A. Inc. (22 percent equity), and operated by Bechtel Petroleum Operations, Inc.

At almost 100,000 barrels of oil production each day (over 35 million barrels produced in FY 1988), Elk Hills ranks as the seventh largest oil field in the contiguous United States. It also contains natural gas reserves exceeding one-and-a-half trillion cubic feet, making it the largest gas field in California.

This Plan describes in some detail a seven-year blueprint for producing hydrocarbons from Elk Hills at maximum efficient rates, and pursuing economic opportunities which maximize its profitability. In that regard, net present values were calculated for each of the 14 designated reservoirs at Elk Hills based on reservoir-specific investments. (See Figure 1.) These values total about $6.6 billion dollars, of which the Government's share would be nearly $5 billion. If approved, non-reservoir-specific facility projects identified in this Plan could add substantially to these figures.



The Plan is grounded in optimum depletion strategies for each of the 14 producing reservoir groups designated at Elk Hills, the facility requirements needed to support production and sales, and plans for ensuring all activities are performed safely and in a way that protects the environment.

Production

Hydrocarbon production at maximum efficient rates is the primary objective at Elk Hills. In this Plan, hydrocarbon production is estimated for each reservoir under two scenarios: first, a baseline "Maintenance Case", which provides no additional investments for drilling or facilities and, second, a "Total Development Case" in which economic investments for additional drilling and new facilities are assumed.

The reservoirs from which the hydrocarbons will be produced and their volumes of production under the Total Development Case are shown in Figure 2 below. The Plan projects about 385 million barrels of oil plus 430 million barrels of oil-equivalent of natural gas and natural gas liquids (converted to oil on a Btu-equivalent basis) may be economically recovered from NPR-1 when produced to the end of its economic life around 2025.

The very large volumes of gas and natural gas liquids which exist at Elk Hills are just beginning to substantively affect depletion plans which have focussed primarily on oil recovery. This Plan takes a first step toward exploiting that opportunity for increased profitability and directs increased study toward reservoirs such as the 31S N/A Shales which have comparatively small oil reserves, but very large gas and natural gas liquid reserves.

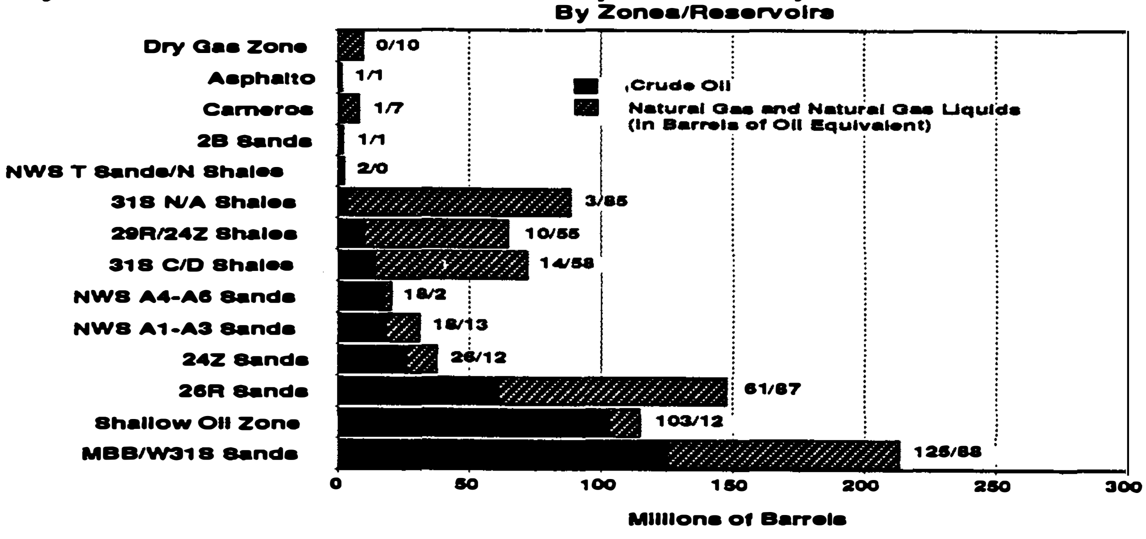
For the near-term, over the seven-year period of this Plan, it is estimated that oil production could be over 200 million barrels. As this Plan shows, production is directly related to investments in the field. Figure 3 on the next page compares crude oil production rates for the Total Development and Maintenance Cases for the seven-year period, with production shown both in thousands of barrels per day and millions of barrels per year. Figure 4 shows how crude oil production from Elk Hills would be shared by DOE and Chevron over the next seven years under the Total Development Case.

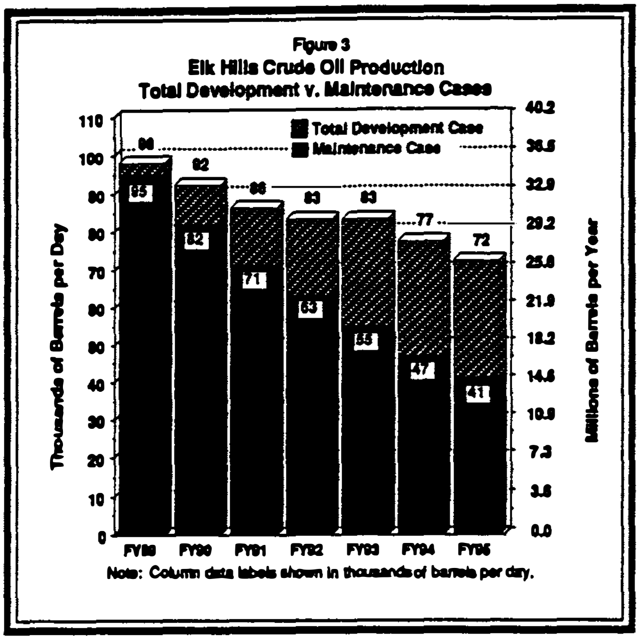
Reservoir Development

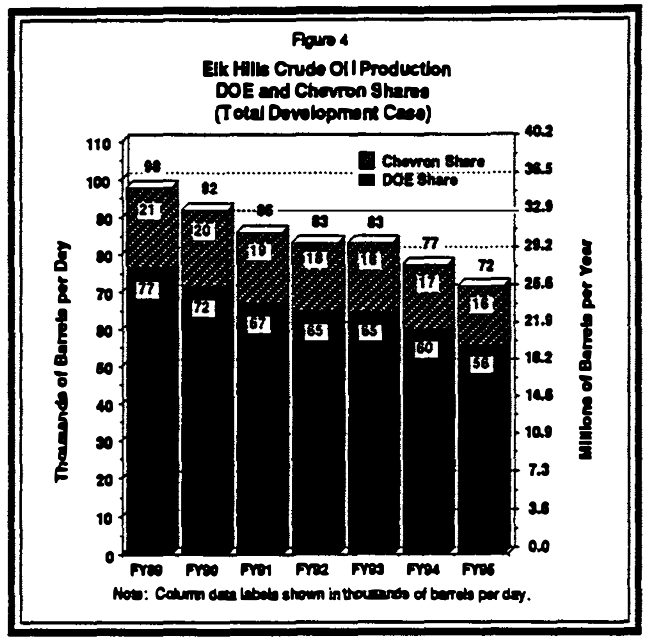
The 14 reservoir groups which have been identified at Elk Hills produce from four different stratigraphic zones. Three of these -- the Dry Gas Zone, the Shallow Oil Zone and the Carneros -- are

Figure 2

Estimated Recovery of Elk Hills Hydrocarbons
By Zones/Reservoirs







considered contiguous geologic formations which cover large areal portions of the field. The Stevens Zone, by contrast, produces from more distinct reservoirs, with varying degrees of communication between them.

Chapter 1 describes the exploratory efforts planned and underway to discover additional hydrocarbons at Elk Hills, generally in zones which lie beneath the Carneros. Of primary near-term interest is the testing of well 934-29R, the deepest well ever drilled in California, at 24,426 feet.

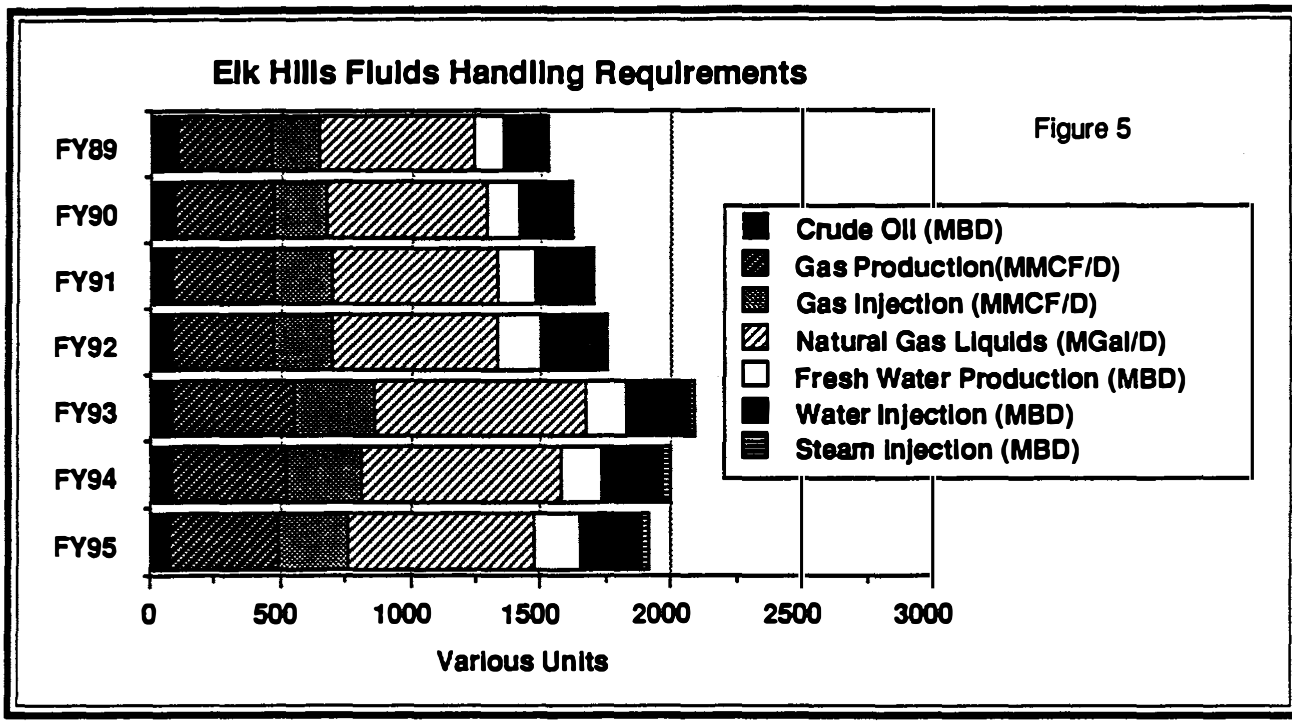
Chapter 2 provides for each reservoir group a general description, estimates of recovery, development activities and new economic projects which are contemplated. A section is also included which describes the potential for applying additional enhanced recovery processes at Elk Hills in the future.

Also, significant effort was made in the Plan to indicate the large geologic and petrophysical unknowns still remaining in these reservoirs. As a result of these unknowns, there is substantial analysis planned and under way to gain a better understanding of the reservoirs to improve future production rates and recovery efficiencies. In that regard, a comprehensive listing of all reservoir studies planned by DOE contractors and Chevron off-site offices are described in this Plan for the first time.

Facilities

This Plan describes in Chapter 3 each of the six major surface facility systems at Elk Hills, constructed for handling the petroleum products, water, and electricity. These systems now transport each day about 100,000 barrels of oil, 350 million cubic feet of gas, 600,000 gallons of natural gas liquids, almost 300,000 barrels of water, and 23 megawatts of electricity. Although crude oil production will decline, production of other fluids and electricity needs are forecast to increase. (See Figure 5 for total Elk Hills fluids production estimates.)

In addition to systems descriptions, Chapter 3 also identifies numerous facility requirements, with the costs and schedules of new facilities to replace worn-out facilities and to meet changing needs. In addition, facilities which would increase profitability are identified. The three major facilities resulting from the most recent planning process include those relating to gas operations expansion, cogeneration and butane isomerization. The table on the following page provides key information on these projects.



Gas Operations Expansion

Major Components
- Gas gathering system
- 100 MMCFD processing plant
- Gas injection system
- Gas liquids storage facilities
- Gas and gas liquids sales facilities

Economics
- Total Expected Cost: $80 million
- Net Present Value: $500+ million
- Payback Period: 1.3 years

Butane Isomerization

Major Components
- Deisobutanizer
- Isomerization section
- Stabilizer

Economics
- Total Expected Cost: $11 million
- Net Present Value: $71 million
- Payback Period: <1 year

Environment and Safety

Facility projects needed in response to specific safety and environmental concerns are included in Chapter 3. More comprehensive plans for the Elk Hills safety and environmental programs are described in more detail in Chapters 4 and 5, respectively.

Revenues

The Plan forecasts that 67-76 percent of revenues will continue to come from crude oil sales, with

Cogeneration Plant

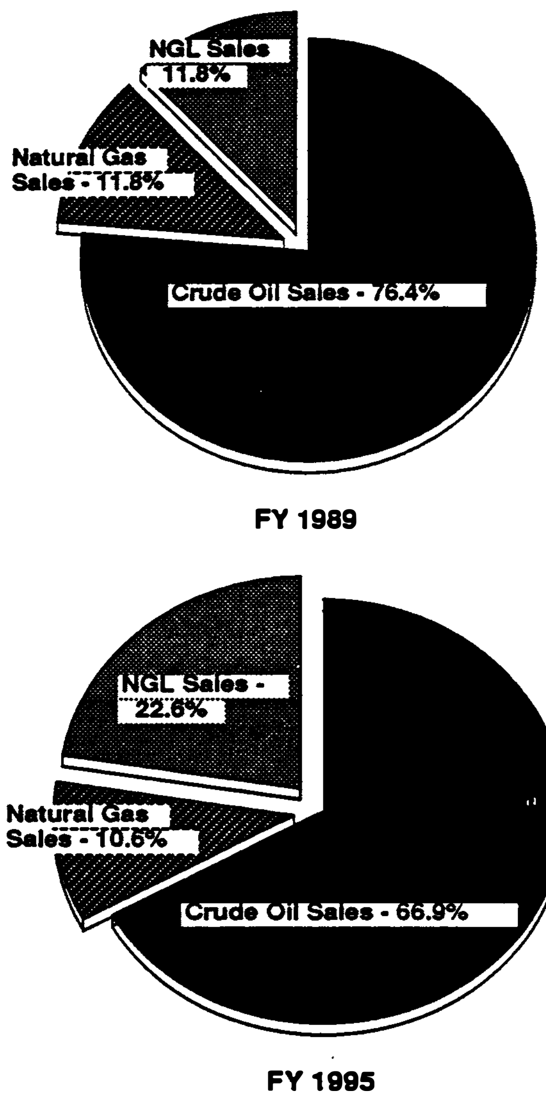
Major Components
- Two gas turbine powerplants
  - 42 megawatts electricity
  - 252,000 lb/hr process steam

Economics
- Total Expected Cost: $37 million
- Net Present Value: $64 million
- Payout Period: 4 years

about 11 percent from natural gas sales and 12-23 percent from the sale of natural gas liquids -- propane, butane and natural gasoline. As indicated in Figure 6, sales of natural gas liquids will contribute an increasingly larger share to total sales in the out-years, as larger volumes of gas are produced -- even as oil production declines.

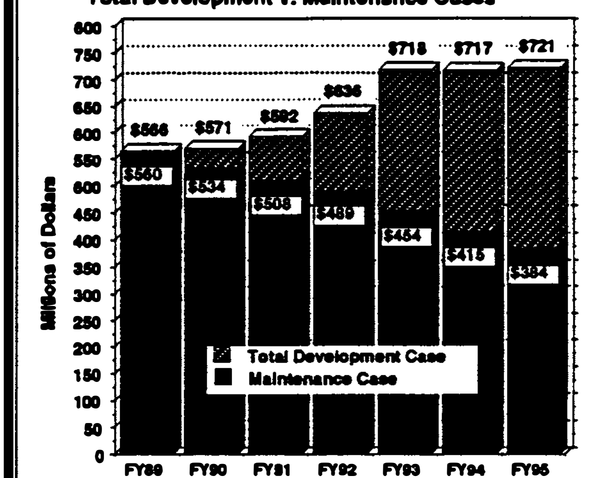
Figure 6

Percent Sales by Type Hydrocarbon FY 1989 v. FY 1995



The Plan forecasts that operations over the next seven-year period could result in revenues to the Government of more than $3 billion, with annual figures ranging between $385 and $725 million depending on which Case is pursued (see Figure 7). These dollar estimates, of course, depend on the accuracy of the petroleum prices forecast, the production estimates, and the accuracy of the cost requirements. It should also be noted that a portion of the value of Chevron's share of production also goes to the U.S. Government in the form of taxes.

Figure 7
Government Revenues from Hydrocarbon Sales
Total Development v. Maintenance Cases



The large increase in revenues beginning in FY 1993 results primarily from the sale of larger volumes of natural gas liquids. The addional liquids would be produced by the facilities project proposed to expand Elk Hills gas handling capacity by 100 million cubic feet per day. In addition to significantly increased revenues, the additional gas handling facilities will improve environmental compliance and safety, reduce the risk of shutting in oil production, and allow the other gas facilities to operate more efficiently. The butane isomerization project described earlier would also contribute substantially to out-year revenues.

Funding Requirements

Annual funding requirements to achieve the levels of revenues forecast in the Plan range between $160 and $340 million, stabilizing at about $200 million over the last four years of the Plan. Figure 8 shows the DOE share of these costs, by budget

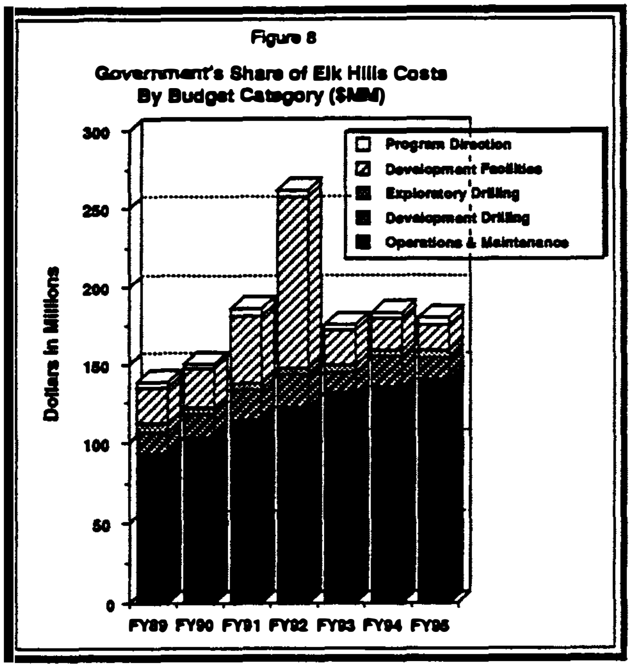


Figure 8
Government's Share of Elk Hills Costs By Budget Category ($MM)

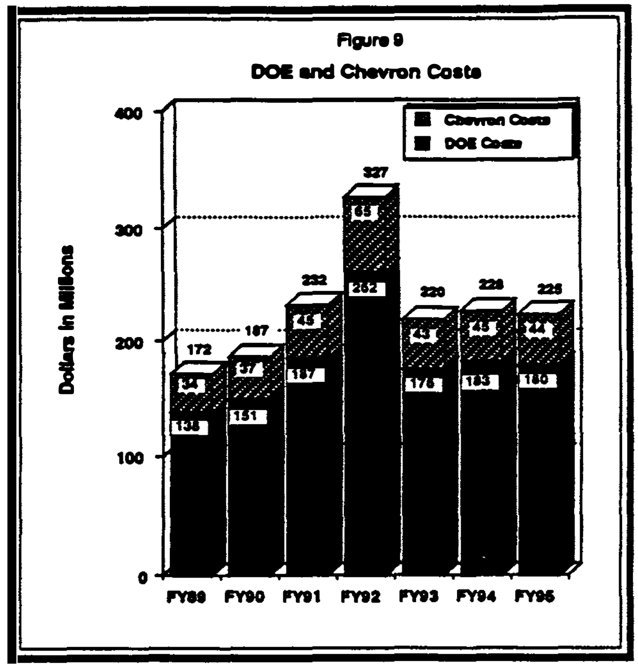


Figure 9
DOE and Chevron Costs

category -- that is, total costs less Chevron reimbursements. Figure 9 indicates total costs for the Total Development Plan and the manner in which they would be shared by DOE and Chevron. The large level of expenditures in FY 1991 is related primarily to the major facilities proposed in that year.

The Government's share of revenues and costs for the period of this Plan are summarized for both the Total Development Case and the Maintenance Case in the table below. Chevron's share would be about a quarter of the figures shown.

Administration

Elk Hills performs numerous administrative functions including procurement, sales (of petroleum products), administration of over 200 subcontracts, ADP, financial management including payroll and maintenance of accounting systems, quality assurance, security and others. These functions make an essential contribution to the success of the operation. While the Plan focussed this year on more technical areas, Chapter 6 provides some details regarding these functions, which will receive increased management review and analysis next year.

Conclusion

The Plan takes an aggressive approach to exploiting NPR-1 revenue enhancement opportunities and identifies numerous activities that will improve efficiency and result in greater field profitability for DOE and Chevron. It reflects the most comprehensive and coordinated effort to date by DOE, Chevron and Bechtel staff regarding exploration, development and production of the Elk Hills field. As such, it will provide the fundamental basis for operations this fiscal year, for the FY 1990 Annual Operating Plan, and for the FY 1991 Budget Request. It also provides a strong foundation for future long range planning efforts which are part of a continuing, dynamic process.

	Total Development Case							Maintenance Case						
($MM)	FY89	FY90	FY91	FY92	FY93	FY94	FY95	FY89	FY90	FY91	FY92	FY93	FY94	FY95
Revenue	$566	$571	$592	$636	$718	$717	$721	$560	$534	$508	$489	$454	$415	$384
Costs	138	151	187	262	176	183	181	134	118	119	119	113	113	111
Net Rev.	$428	$420	$405	$374	$542	$534	$540	$426	$416	$389	$370	$341	$302	$273

NAVAL PETROLEUM RESERVES IN CALIFORNIA
LONG RANGE PLAN, FY 1989 - 1995

MAY 1989

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CHAPTER 1 : EXPLORATION PLANS

The purpose of exploration is to find petroleum. The basic approach of an exploration program, whether field-wide or world-wide in scope, is the same, namely, to investigate areas which can be classified as possible or probable petroliferous areas. The discovery of new petroleum reserves is essential to all phases of the petroleum industry. Without a continued effort to find and develop new reserves, the end result is the liquidation of a company's or nation's assets through the pipeline.

The more complex the geologic history, the greater the potential for new petroleum reserves to exist. As seen on the accompanying cross-section of the San Joaquin Valley, the structural history at Elk Hills is extremely complex with major faulting and tightly folded anticlines. This, coupled with changing conditions in sand deposition, has created a multitude of potential trapping mechanisms for oil and gas. Elk Hills lies within one of the most petroliferous oil provinces in California and the exploratory risks are believed to be extremely favorable. Large areas exist within the NPR-1 boundary which have not been adequately evaluated and are postulated to contain oil and gas. Exploratory targets have shifted from the shallower horizons and are now concentrated in the Carneros and deeper zones where significant reserves are believed to exist at reasonable risks. However, shallow targets still exist.

The exploratory program at Elk Hills began in 1973, and has been maintained along with the development drilling program to fully develop the Reserve. The exploration emphasis has been directed at drilling deeper wells to suspected potential oil zones or in areas of postulated new structures and stratigraphic traps.

To the present time, 18 exploratory wells have been drilled to zones ranging in age from Pleistocene (one million years ago) to Cretaceous (70 to 135 million years ago). New pools have been discovered in the Tulare, Stevens, and Carneros zones. In addition to the rank exploratory work, step-out development drilling of an exploratory nature has extended the limits of the Dry Gas Zone, the Shallow Oil Zone, and the Stevens Zone. Approximately 105 million barrels of oil have been discovered in the Stevens Zone alone, with lesser amounts (compared to the Stevens) of gas and oil discovered in the shallower horizons.

Although a large number of wells have been drilled within the Reserve boundary, there remain large areas of land which have not been fully explored. These areas are considered to be highly prospective.

Hydrocarbon exploration is a complex process requiring the integration of available data with geologic theory. Among the data available at Elk Hills are electric logs and mud logs which permit the correlation of prospective horizons, core data from which reservoir quality can be predicted, dipmeter logs which provide structural information, drill stem tests which give an indication of zone productivity, geochemical data from which can be projected the depth at which certain hydrocarbons are likely to occur, and seismic data which allows the mapping of prospective horizons or structures where data quality is good. From these data, stratigraphic and structural models can be developed which permit the extrapolation of geologic potential into unexplored areas. Areas of greatest potential are then prioritized and additional data obtained to further delineate the prospects. Prospects with the greatest potential reserves and the greatest chance of success are then recommended for drilling.

EXPLORATION POTENTIAL BY ZONE

The Dry Gas Zone, the Shallow Oil Zone and large segments of the Stevens have been highly explored, but areas still remain that are attractive even in these zones. The Carneros and deeper zones are relatively unexplored to date and are considered ideal exploratory targets. Listed below in order of depth, from shallow to deep, are the exploration potential and future plans for each of the exploratory targets at Elk Hills:

Tulare

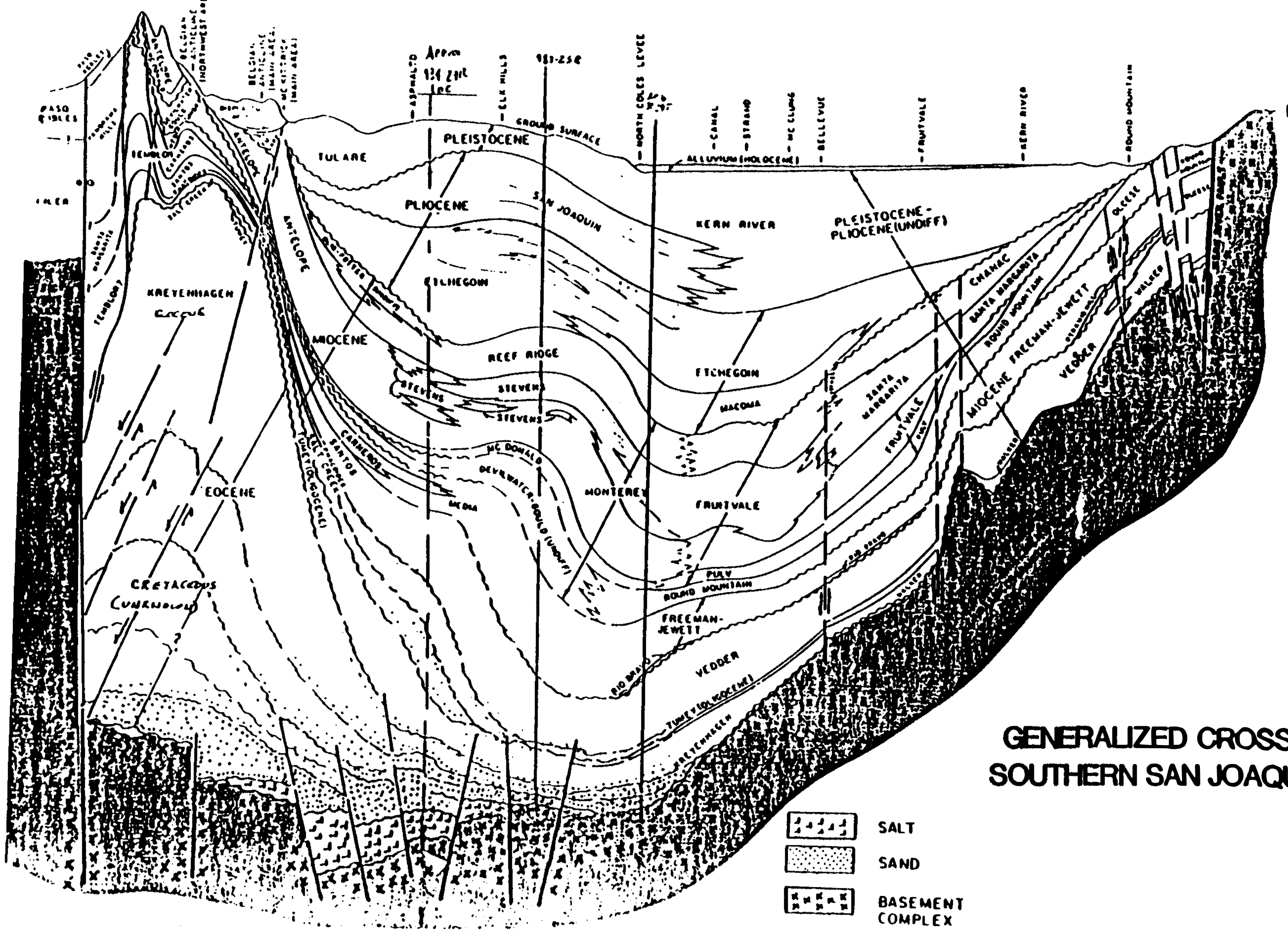
No major exploratory target remains.

Dry Gas Zone

Nearly all wells drilled at Elk Hills penetrate the Dry Gas Zone, yet additional areas exist that could prove to be productive. Although it is not a primary exploration target, as a matter of routine, wells drilled through this zone (exploratory or development) are programmed to evaluate any potential gas zone.

Shallow Oil Zone

No major exploratory areas remain in this zone. However, the western portion of Elk Hills contains numerous erratic sand zones that may be productive outside the



GENERALIZED CROSS SECTION
SOUTHERN SAN JOAQUIN VALLEY

currently known limits of production. As with the Dry Gas Zone, wells drilled in high potential areas are programmed to test the prospective sands.

Stevens Zone

The Stevens Zone is still a major exploratory target at Elk Hills. The potential thick sands and complex structural trapping mechanisms continue to offer attractive exploratory targets. Among the potential areas currently identified is a follow-up to the 384- 1G well which appears to have cut an oil/water contact in the Main Body 'B' Sand on a new structure south of the large 31S structure. Follow-up drilling is also warranted in Section 6G where a new structure was found but has not been fully evaluated. Another target occurs in the 1B-2B area where faulting may have trapped hydrocarbons in the 26R Sand southeast of the 2B Pool. Excellent potential exists along the North Flank of the 31S structure which is relatively untested and where large areas remain to be explored. Other potential exists in the fractured shales of the 14Z area, and the areas east of the Northwest Stevens structure.

Carneros Zone

The Carneros Sands also are a major exploratory target. The exploratory wells currently being tested (514-30R, 523-32S and 577- 34S, see FY'89 Major Activities) may lead to additional exploratory work in this zone. Furthermore, a follow-up or a redrill of 537-14R is considered a must. This well penetrated the Carneros and tested gas, but had a high water cut. An updip well may establish new production. The newly found Carneros structure in 34S will require additional exploratory work either as a step- out to 577-34S or to test this structure in a new area. Carneros potential also exists in Section 14Z where extreme structural complexity abounds. Additional potential may also be found in the 29R structure and in the deeper portions of the Northwest Stevens structure. The future evaluation of this zone will include these areas as targets.

Phacoides, Oceanic, Point of Rocks

These zones are extremely attractive exploratory targets but will require deep drilling and fairly large expenditures of money to fully evaluate the potential of these zones. Much of the geological thinking as to the best areas to explore awaits the testing of the deepest well in California, 934-29R. Generally speaking, the sands all exhibit low porosity and permeability. However, a better understanding of the deeper structure and the depositional history of these units will enable the geologists to pick the best locations to test them.

Phacoides (Lower Miocene)

This is an excellent target which is untested overall. Follow-up drilling on the 29R structure must be considered. The zone is potentially productive on the Northwest Stevens structure.

Oceanic (Oligocene)

This is another excellent target but has only been seen in 934-29R. The zone is a very good producer west of Elk Hills and follow-up drilling on the 29R and Northwest Stevens structures is very probable. This zone tested 791 MCFPD gas, 1568 BWPD water with some condensate and is an excellent candidate for a redrill in the 934-29R well if zones deeper prove to be uneconomical.

Point of Rocks (Eocene)

This, too, is considered an excellent target. It looked productive in 987-25R but was never tested due to pipe failure at a shallower depth. A follow-up well on the 31S structure, as well as a possible 34S well are considered to be definitely required. Additional drilling on the 29R structure as a follow-up to 934-29R is probably also required. Dips in the 934-29R well indicate that the Eocene is structurally higher to the north of 934-29R. Additional geologic work and testing is required to determine the best way to further explore this attractive sand.

Mesozoic (Cretaceous)

This zone is a definite unknown. It was encountered in the lowest portions of the 934-29R well and is scheduled to be tested during FY'89. This zone will have to be considered in any deep drilling on the western margins of Elk Hills.

MAJOR ACTIVITIES BY FISCAL YEAR

Major Activities (FY'89 Program)

Testing

Testing is currently underway on three previously drilled exploratory wells, 523-32S, 577-34S and 514-30R. The zones being tested are below the Carneros which is the deepest producing horizon at Elk Hills. Well 934-29R will begin testing of Cretaceous Sands during FY'89 as soon as a tie-back string has been run. It is expected that the testing of three zones (all below 17,000') in this well will carry into FY'90. The testing schedules for the above wells are shown on Figure 2 and Figure 3.

NPR-2 Exploration

Chevron recently drilled an exploratory test in NPR-2 (Buena Vista Hills) directly offsetting Department of Energy acreage. In the event that CUSA establishes commercial production, DOE will request funds to drill a sufficient number of wells to protect itself against drainage. Further disussion regarding NPR-2 is presented in chapter 7.

Major Activities (FY'90 Program)

Testing/Deepening

The testing of 934-29R will extend into FY'90 as three zones below 17,000' are being tested. The intervals being tested include the Cretaceous, the Point of Rocks and the Oceanic. Funds in the amount of $500,000 are planned for the testing of 373-18H, a well which was drilled off the nearby Buena Vista Hills Structure and encountered a thick series of Miocene sandstone.

New Well

The FY'90 program calls for the drilling of one new well at a cost of $4 million. Structural and stratigraphic analysis of data from existing exploratory wells will be initiated during FY'89. The purpose of this analysis is to identify prospective areas from which several prospects can be developed. From these prospects, the one which offers the most viable opportunity for the establishment of additional production will be selected.

Major Activities (FY'91 Program)

New Well

As the analysis of existing data continues, it is expected that a number of viable prospects will be generated, not only in the deeper zones of existing structures, but also along the flanks of those structures as well as separate structures on NPR-1 which have been previously mapped. The mapping of turbidite sand channels within the Stevens is also expected to provide a number of leads which will be further delineated through future seismic acquisition. It is proposed that either one new well be drilled during FY'91 at a cost of $4 million or that 934-29R be redrilled to test the updip Oceanic Sand if deeper production is not established. The cross-section on the following page (Figure 1) illustrates the redrill potential for 934-29R.

Testing

Testing funds of $500,000 are proposed for FY'91. These funds will be used for testing the exploratory wells drilled during FY'90 or FY'91 or for the additional testing of zones above 17,000' in 934-29R.

Seismic Reprocessing

The Elk Hills database has several line miles of seismic data. Over the crest of the main producing structures, data quality is extremely poor. Off the flanks of these structures, however, data quality ranges from fair to excellent. Advances in seismic processing in recent years make it possible to recover data from poor quality seismic records. Though not guaranteed, the use of accurate structural and stratigraphic models may allow the delineation of prospective areas through the reprocessing of existing data at a much lower cost than shooting new lines. For this reason, $100,000 has been earmarked in FY'91 to determine the feasibility of data reprocessing.

Major Activities (FY'92 Program)

New Well

The re-evaluation of existing and reprocessed seismic data is expected to add to the list of exploratory prospects. From this list, one prospect will be drilled at a cost of $4 million.

Testing

A total of $500,000 will be used for the testing of the well drilled during FY'92.

Seismic Acquisition

If the reprocessing of existing seismic data in FY'91 proves to be successful, it will probably be necessary to shoot several miles of new seismic to delineate leads generated in the previous year. Should the FY'91 project be unsuccessful, it will be necessary to experiment with data acquisition techniques in order to obtain seismic records that can be used in the generation of prospects. Funds in the amount of $250,000 are proposed for the acquisition of additional seismic data during FY'92.

Major Activities (FY'93-FY'95)

New Wells

The exploratory evaluation of Elk Hills conducted over the previous three years will provide several opportunities for exploratory drilling. With this in mind, one new exploratory well is planned for each of the remaining three years and will cost $4 million each.

Testing

A total of $500,000 per year is budgeted for the testing of each well drilled during the three year period FY'93-FY'95.

Seismic Acquisition/Processing

It is expected that by FY'94, the need will arise for either the reprocessing of seismic data or for the acquisition of new data. This information will be used for prospect delineation or for new prospect generation. In FY'94, $200,000 is proposed for the acquisition and/or reprocessing of seismic data.

Summation of funding for the Exploration Program is presented in the Administration Plan chapter under "Financial Management" - Fund 113.

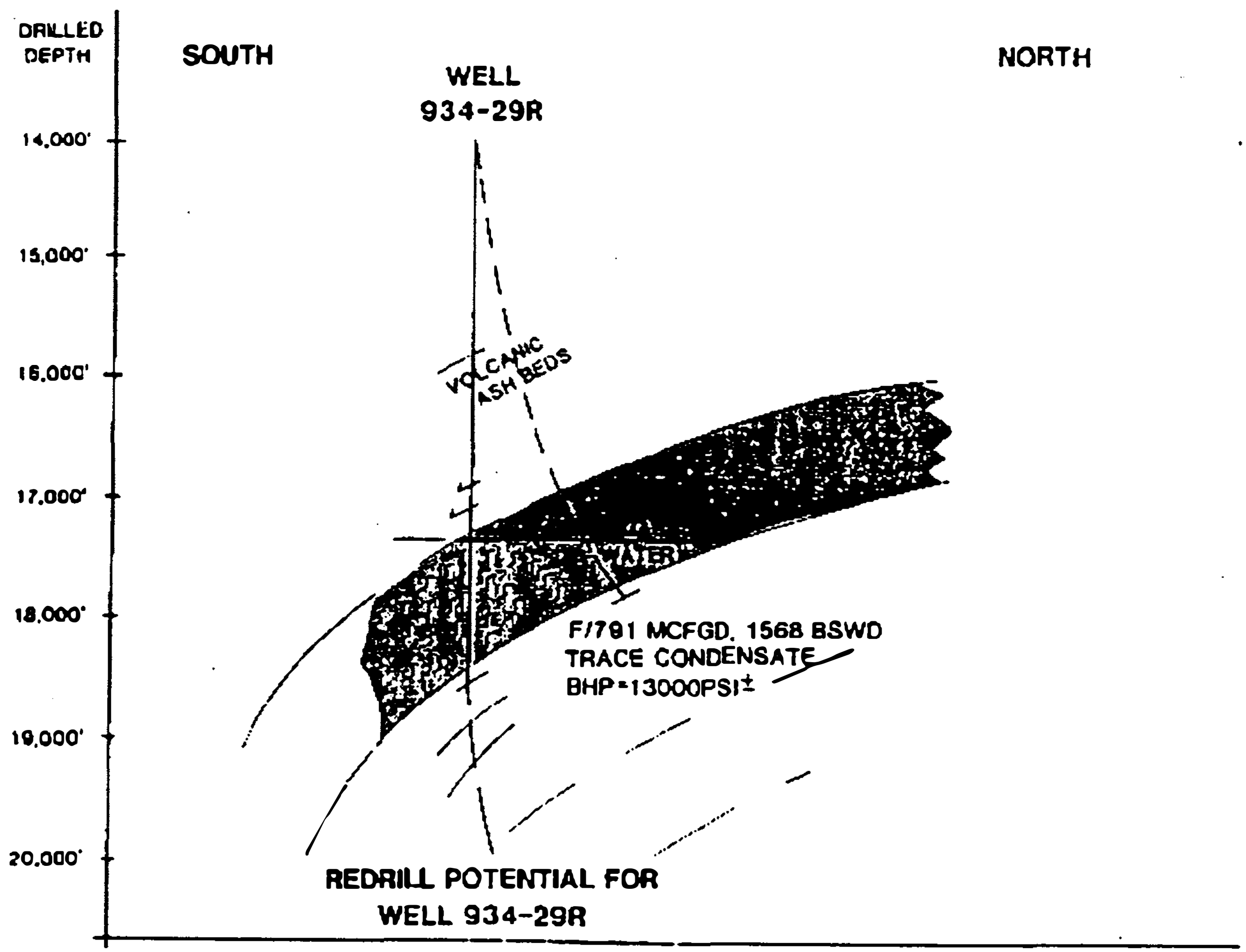
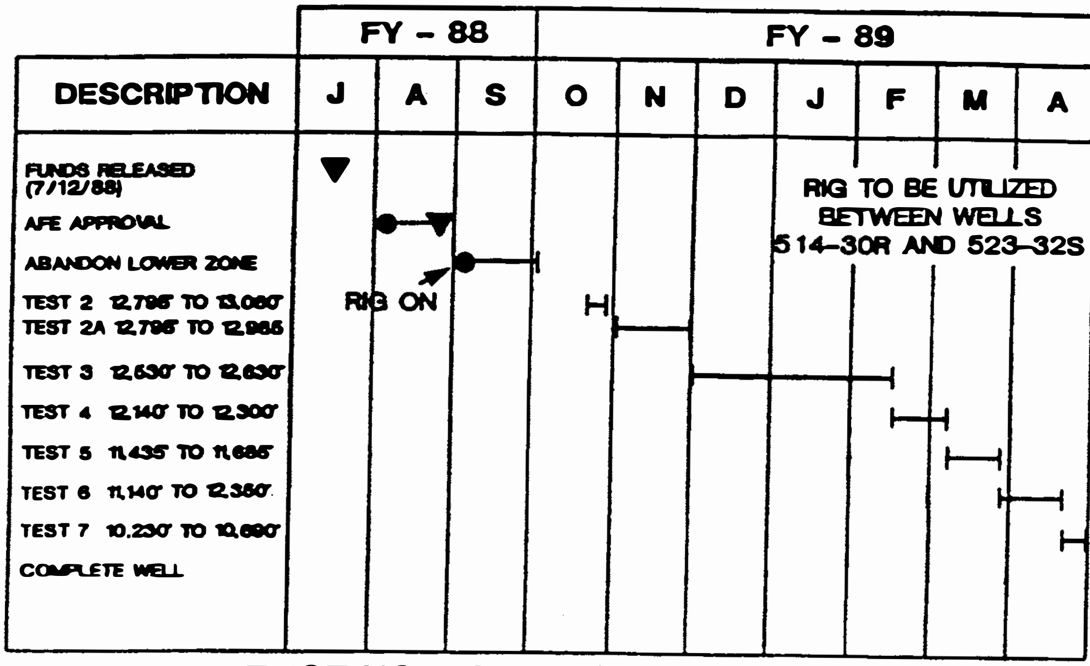
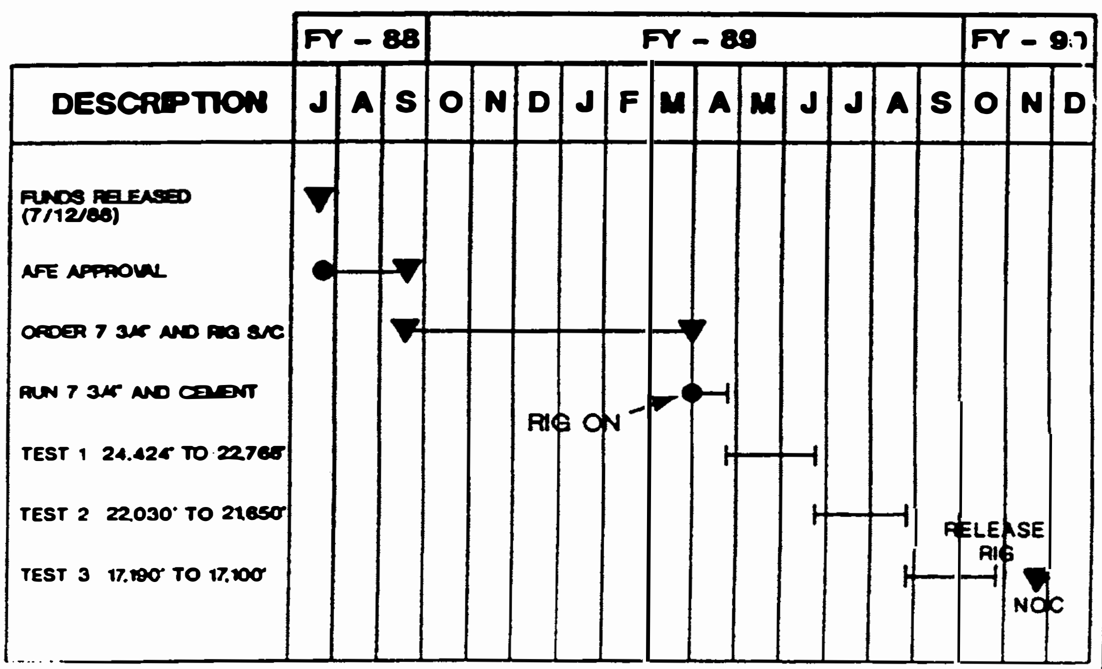


FIGURE 1

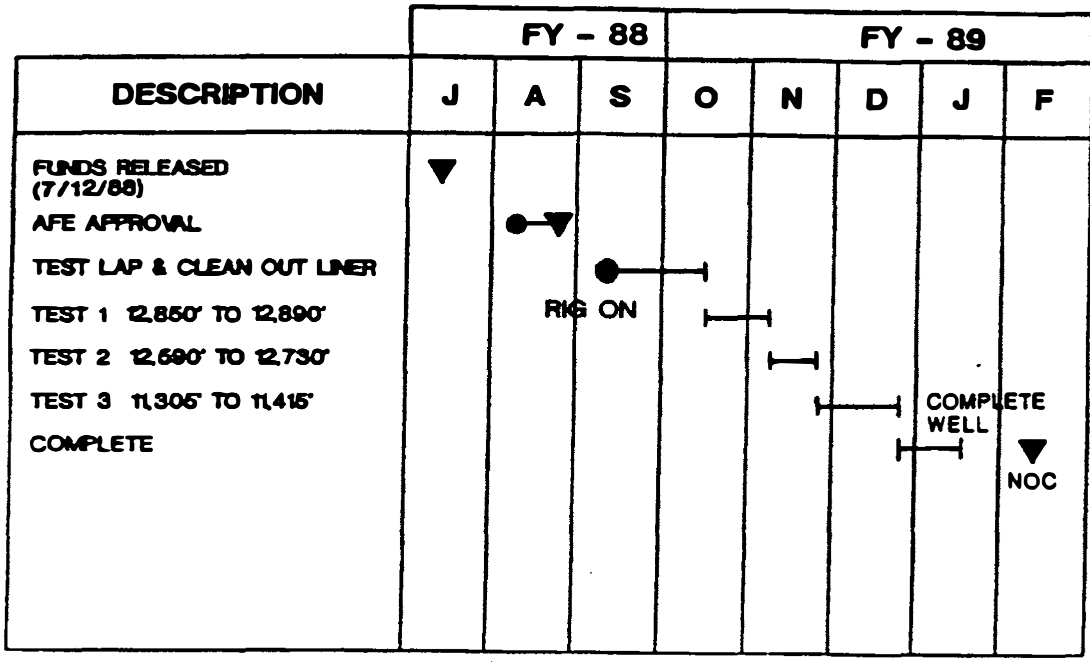


TESTING SCHEDULE 514 - 30R

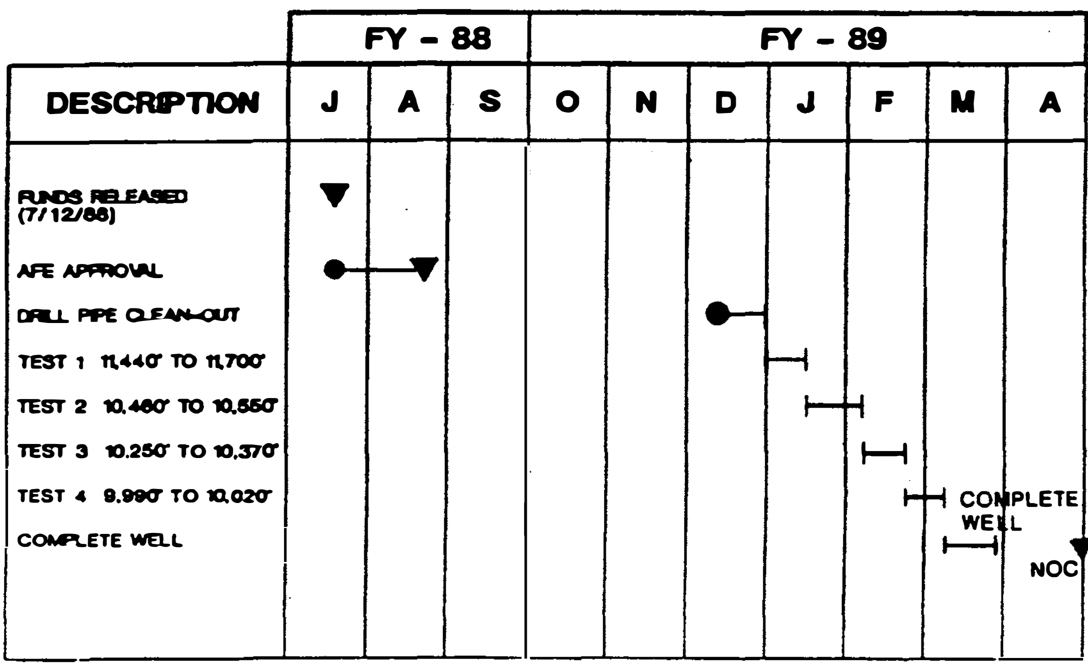


TESTING SCHEDULE 934 - 29R

Figure 2



TESTING SCHEDULE 523 - 32S



TESTING SCHEDULE 577 - 34S

Figure 3

Chapter 2: Reservoir Development

Introduction

The objective of NPR-1 operations is to produce oil and gas from reservoirs at the maximum efficient rate (MER), so that the profitability of operations is maximized. Production at MER is the result of optimizing both the physical and economic aspects of producing existing wells, drilling new wells, conducting improved recovery operations, and abandoning uneconomic wells. Integral to this are the capabilities of surface facilities for processing, sales, and injection. This chapter focuses on the individual reservoirs from which hydrocarbons are produced, describing activities needed to implement strategies for production at MER.

NPR-1 is situated in one of the world's most prolific petroleum producing areas, the southern San Joaquin Valley of California. It is considered a "giant" oil field, and ranked seventh in oil production in the U.S. in 1988. Within the many thousands of feet of subsurface rock from which oil and gas are produced, NPR-1 holds a very complex assemblage of geologic depositional systems and structural features. Figure 2.1 is a schematic view of the major producing zones at NPR-1, showing the areal extent of Stevens Zone and Shallow Oil Zone production. For reference, each of the 15 reservoirs described in this chapter is listed in Figure 2.1. The Dry Gas Zone, Carneros Zone, and Asphalto Zone are not shown, as these make relatively minor contributions to NPR-1 production. The Tulare Zone produced small quantities of oil in the past, and currently serves water supply and disposal functions.

Massive quantities of hydrocarbons remain to be economically produced from NPR-1, even though it is at a stage in which the majority of its primary development is completed. Oil and gas are produced from approximately 1,000 wells in 14 reservoirs. Nine reservoirs are under primary recovery, while pressure maintenance through waterflood and gas injection is being conducted in five reservoirs. Light-oil steamflood, an enhanced oil recovery (EOR) process, is being pilot-tested in the Shallow Oil Zone. Complementing continual production operations is a significant effort to characterize, model, and study the reservoirs in order to refine MER strategies. Strategies to produce NPR-1 reservoirs at their individual MERs are developed on both technical and economic bases, and are chosen on the basis of what is most efficient in terms of hydrocarbon recovery and economics. Resulting activities from these evaluations include remedial well work, drilling, improved recovery operations, and accompanying facilities requirements.

Economic Cases

The reservoir development plans detailed herein describe operating strategies and resultant production forecasts for two scenarios:

1. **Maintenance Case** - this involves the minimum activities required to operate reservoirs at their current rate of production decline, conducting only those remedial activities needed to maintain existing wells and facilities.
2. **Development Case** - Maintenance Case plus additional development activities required to achieve MER.

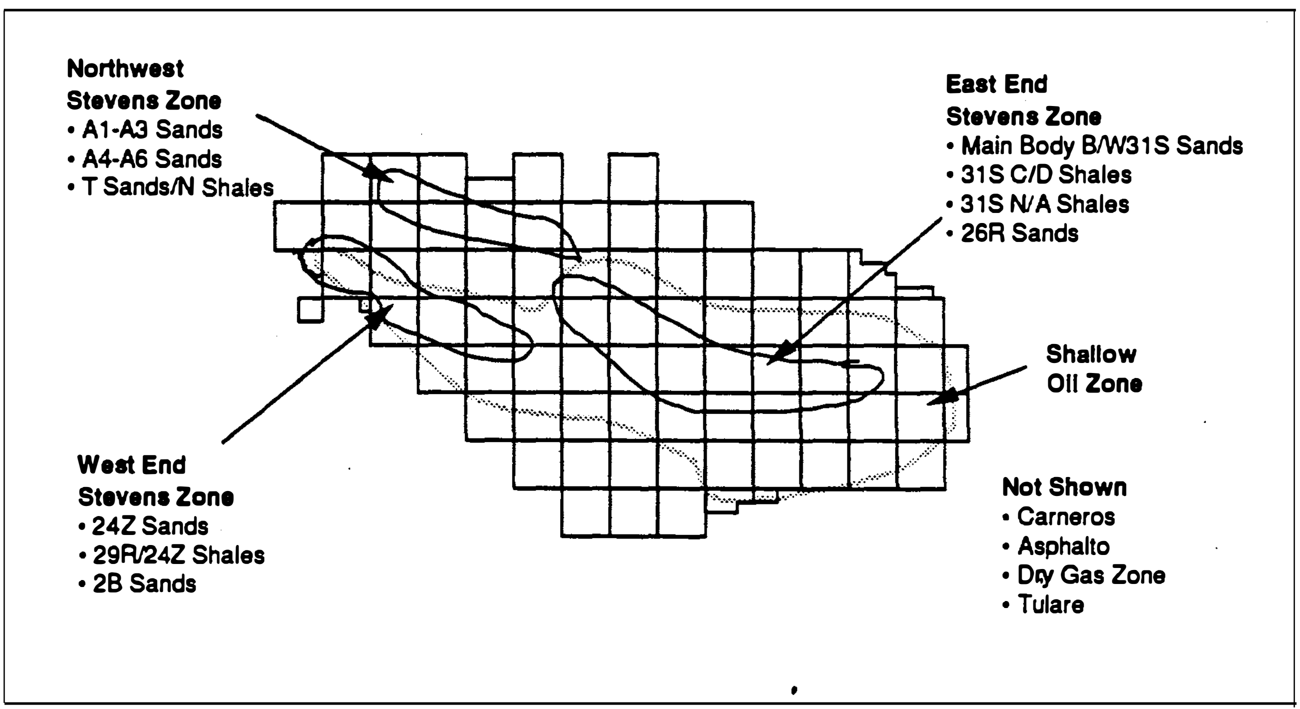


Figure 2.1. Areal extent of major producing zones at NPR-1.

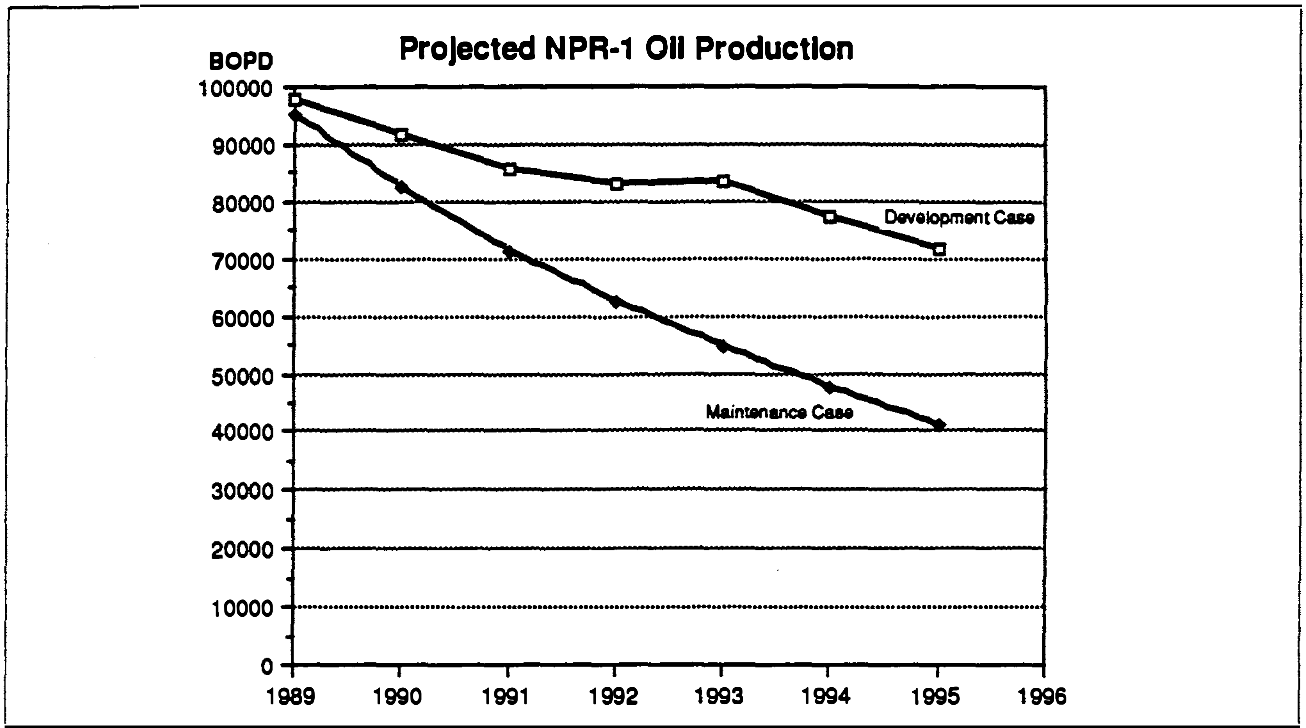


Figure 2.2. Total oil production forecast for the period FY 1989 to FY 1995.

Figures 2.2, 2.3, 2.4 and 2.5 illustrate the production of oil, gas, and natural gas liquids, respectively, which would result from implementing these cases during the period FY 1989 - FY 1995. As listed in Table 2.1, the Development Case is expected to provide a net present value (NPV) of over $3 billion during this period, and recover 298 million barrels of oil, on an equivalent BTU basis (MMBOE). Another measure of profitability shown in Table 2.1 is the estimated ratio of Net Revenue to Investment (NR/I). Development Case activities are projected to provide a NPV of over $6 billion during the remaining life of NPR-1, and to recover 816.0 MMBOE.

Development plans to maximize profitability and achieve production at MER are based on the expected economic life of each reservoir. Plans account for production of all hydrocarbon reserves, considering alternate development strategies. These alternatives are compared both on physical and economic bases. The most efficient alternative strategy is reflected in each development plan's activities. The resultant lifetime economic projection for each reservoir measures that reservoir's innate value. The relative lifetime profitabilities of the individual reservoirs are shown in Figures 2.6 and 2.7, which reflect NPV and NR/I, respectively. Table 2.2 summarizes this information.

Reservoir Development Activities

Activities which will be carried out to achieve production at MER during the period FY 1989 to FY 1995 will include routine production operations, remedial well work, drilling, and facilities work. Each reservoir development plan in this chapter describes these activities, and provides detailed cost estimates for routine operations as "reservoir operating costs." Additionally, costs for remedial well work, drilling, and facilities work are itemized. Chapter 3 gives details of all facilities projects. Comprehensive breakdowns of all costs are provided in the Exhibits at the

Table 2.1. Projected Results of Activities

FY 1989 - 1995 Case	Investments* $Millions	NPV* $Millions	NR/I* Ratio	Recovery, MMBOE
Maintenance	104.8	2,573.0	24.6	231.8
Projects	134.6	578.4	4.3	65.9
Development	239.4	3,151.4	13.2	297.7
FY 1989 to Economic Limit				
Case	Investments* $Millions	NPV* $Millions	NR/I* Ratio	Recovery, MMBOE
Maintenance	135.8	5,087.8	37.5	631.7
Projects	173.7	1,465.2	8.4	184.3
Development	309.5	6,553.0	21.2	816.0

*discounted at a rate of 10%

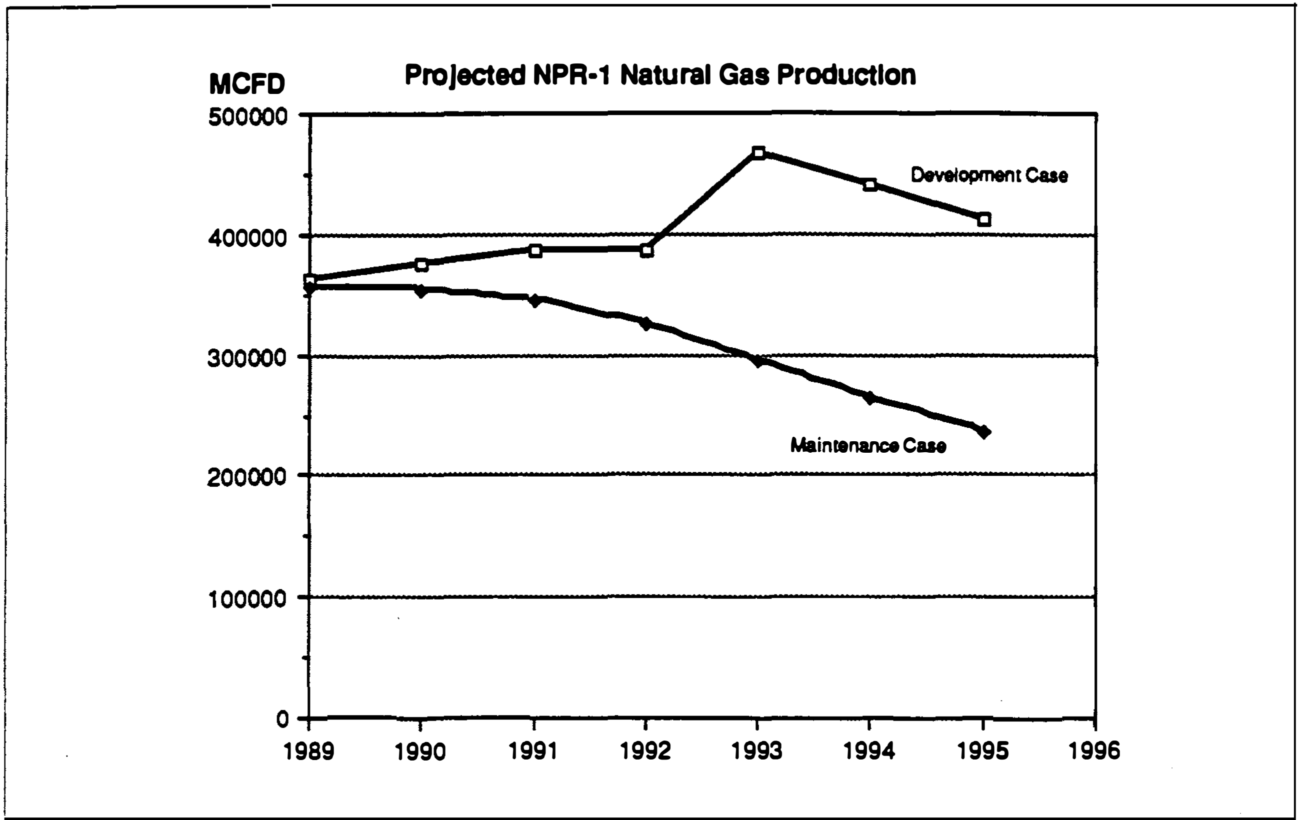


Figure 2.3. Total natural gas production forecast for the period FY 1989 to FY 1995.

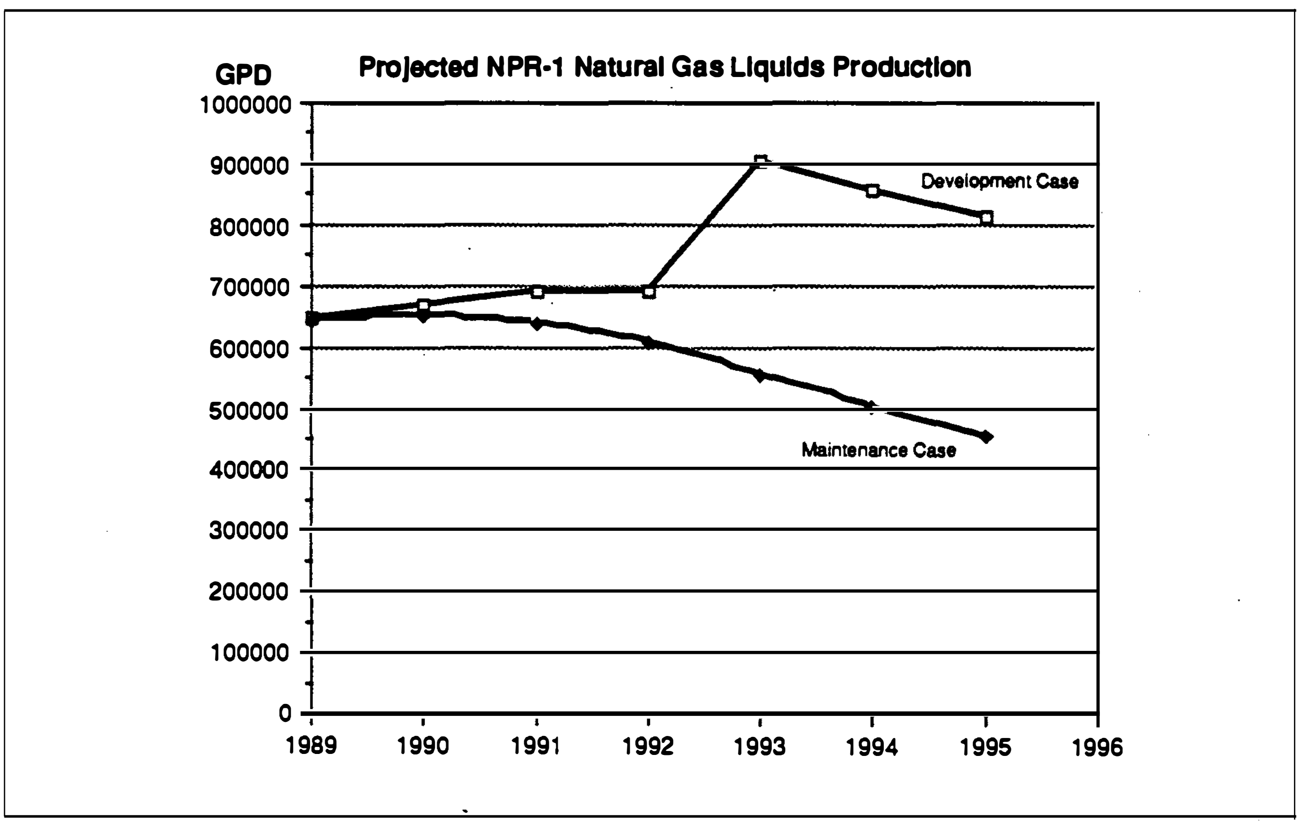


Figure 2.4. Total natural gas liquids production forecast for the period FY 1989 to FY 1995. This includes propane, butane (n-butane and iso-butane), and natural gasoline.

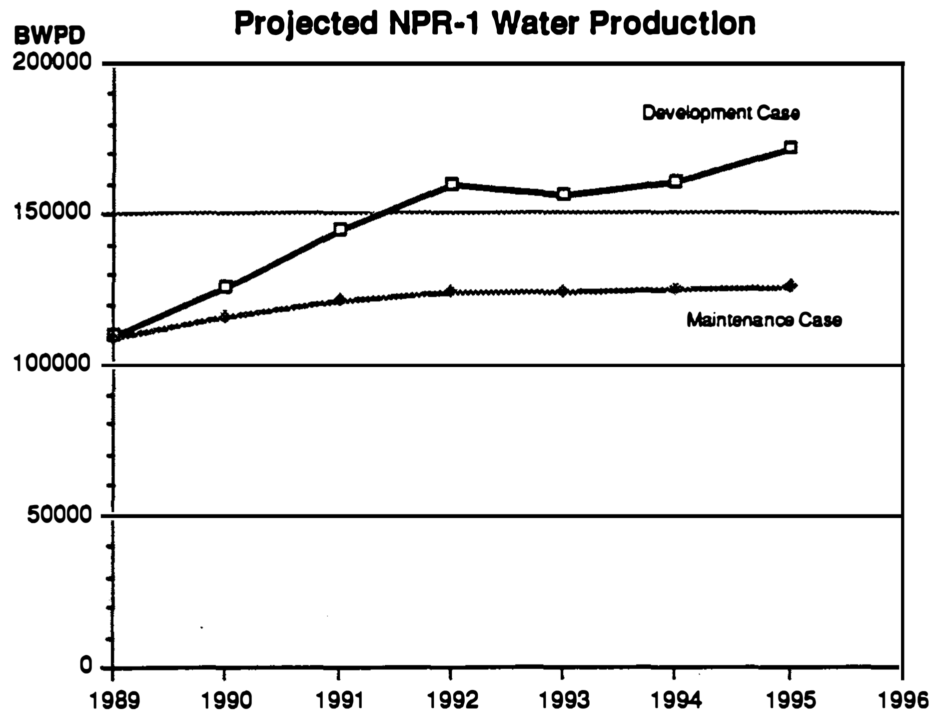


Figure 2.5. Total water production forecast for the period FY 1989 to FY 1995.

end of this Plan. The majority of the projected expenditures are associated with the development of Stevens Zone reservoirs, and plans for development of the Shallow Oil Zone Steamflood.

Investments projected for the seven-year period of this Plan in the three areas of remedial well work, drilling, and facilities total $343.5 million. This would be required to fund the necessary maintenance programs and the proposed projects which constitute the Development Case for the reservoirs.

In addition to the ongoing production requirements which constitute Maintenance Case activities, there are 19 spe-

Table 2.2. Projected NPR-1 Reservoir Profitabilities
Development Case: FY 1989 to Economic Limit

Reservoir	Investments*, $Millions	NPV*, $Millions	NR/I Ratio*	Recovery, MMBOE
MBB/W31S Sands	119.5	1,868.9	15.6	213.5
24Z Sands	9.7	314.3	32.3	37.6
2B Sands	1.5	14.8	10.1	2.2
29R/24Z Shales	15.7	536.9	34.3	65.3
26R Sands	19.5	1,359.9	69.7	148.1
31S C/D Shales	30.3	459.0	15.1	72.1
31S N/A Shales	6.9	443.6	64.5	88.5
NWS A1-A3 Sands	5.8	254.6	44.1	31.4
NWS A4-A6 Sands	13.0	183.0	14.1	20.3
NWS T Sands/N Shales	5.2	27.4	5.2	2.8
Shallow Oil Zone	73.4	915.8	12.5	114.8
Asphalto	0	13.6	-	1.8
Carneros	2.6	78.0	30.2	8.0
Dry Gas Zone	4.6	85.0	18.5	9.6
Tulare	1.8	-1.8	-1.0	0
TOTAL	**309.5**	**6,553.0**	**21.2**	**816.0**

* discounted at a rate of 10%

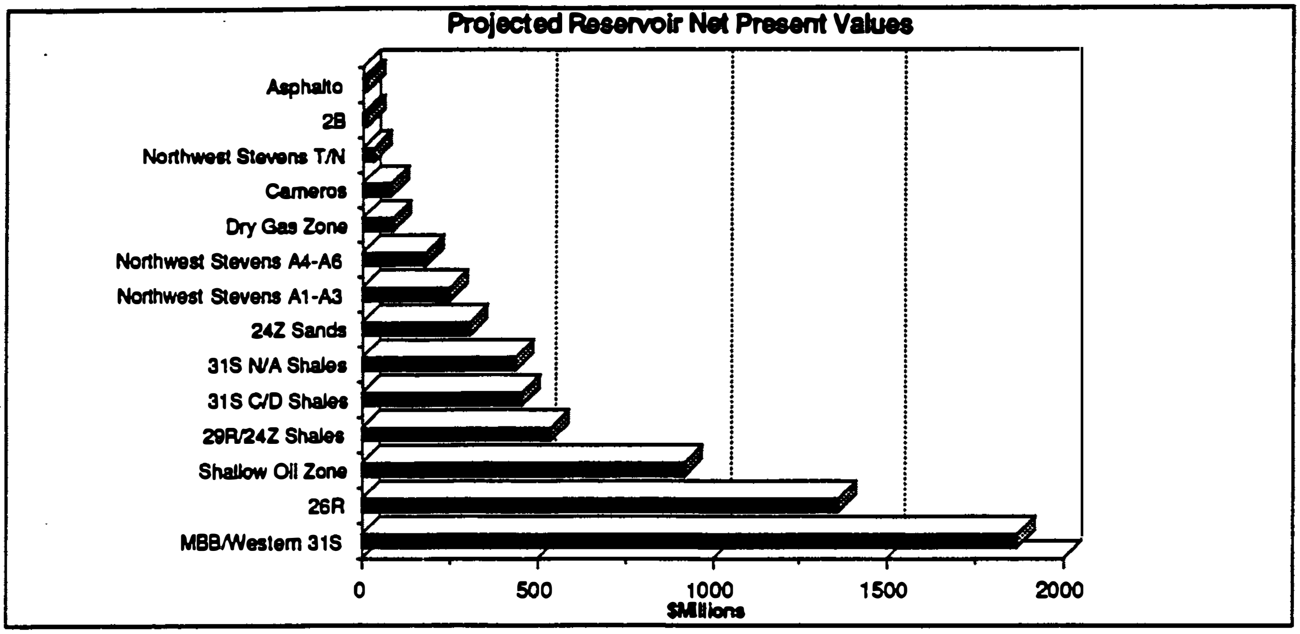


Figure 2.6. Comparative reservoir profitabilities as measured by NPV (@10%).

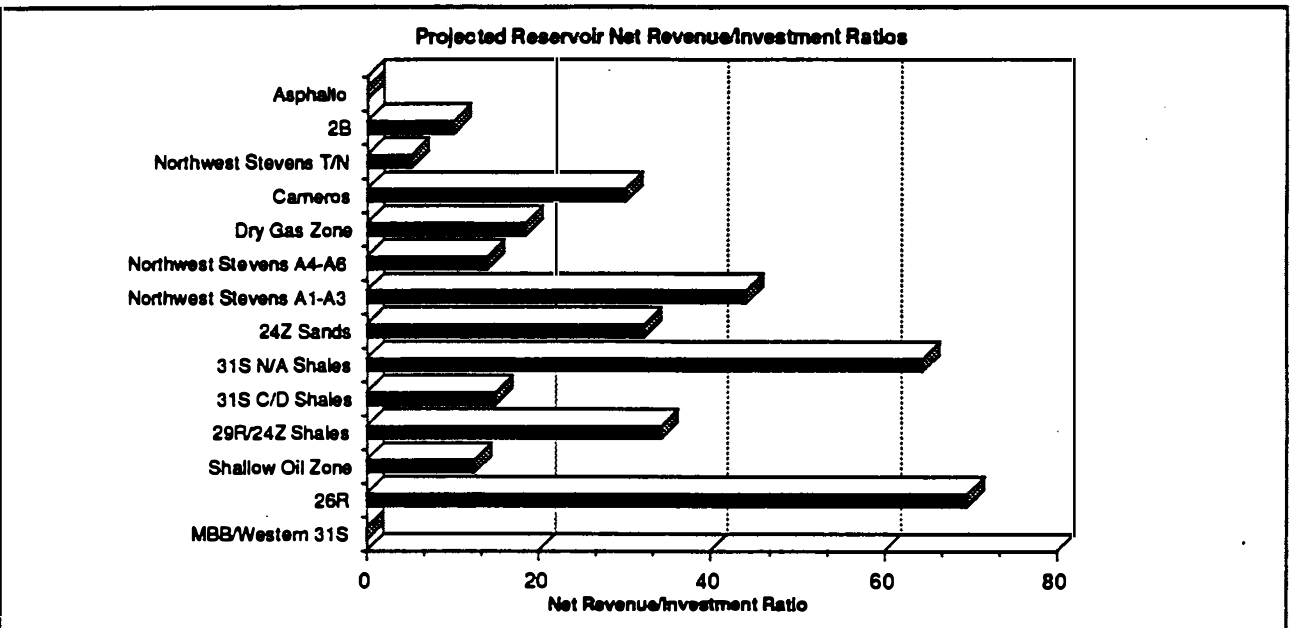


Figure 2.7. Comparative reservoir profitabilities as measured by the ratio of net revenue to investment (@10%).

cifically-identified projects described for the 15 reservoirs during the seven-year period. These consist of eight development drilling projects (including two horizontal drilling programs), five waterflood projects (pilot and expansion), two steamflood expansions, three remedial projects and one compressor installation. Nine of these recommended projects are scheduled for two reservoirs, the MBB/W31S Sands and the Shallow Oil Zone. Most of this work is forecast to be carried out in the early years of this Plan. Reservoir studies and evaluations will allow more definitive estimates of future opportunities, and will probably result in additional work. For example, various EOR processes will be evaluated; yet, there is insufficient information to project any investment in EOR at NPR-1 outside of steamflood in the Shallow Oil Zone (SOZ).

Remedial well work is a fundamental production function to ensure the producibility or injectivity of wells in the achievement of MER strategies. This work includes, but is not limited to, recompletions, stimulations, necessary well abandonments and maintenance. Table 2.3 summarizes expected remedial work during the period FY 1989 to FY 1995. Nearly half of the remedial jobs are planned for the Main Body B/Western 31S (MBB/W31S) Sands and the SOZ, to support projected waterflood and steamflood expansions. Similarly, the majority of the facility expenditures would be required for the MBB/W31S Sands ($25.5 million) and the Shallow Oil zone ($18.0 million).

Table 2.3. Summary of Projected Remedial Well Work
Development Case: FY 1989 to FY 1995

Reservoir Stevens	1989	1990	1991	1992	1993	1994	1995
MBB/W31S	53	50	56	55	57	56	58
24Z	10	10	8	7	3	4	2
2B	2	3	1	2	3	1	3
29R	16	15	11	13	14	18	16
26R	14	12	18	15	18	18	16
31S C/D	10	6	12	18	19	23	23
31S N/A	6	5	6	5	5	5	5
NWS A1-A3	7	5	4	3	3	3	3
NWS A4-A6	13	10	7	5	6	7	7
NWS T/N	6	8	7	5	5	4	5
Total Stevens	137	124	130	128	133	139	138
Other Zones							
SOZ	20	53	45	31	28	38	35
Asphalto	0	0	0	0	0	0	0
Carneros	1	1	3	4	2	0	0
Dry Gas Zone	5	9	7	7	1	1	1
Tulare	10	15	15	2	2	2	2
Abandonments	10	25	25	30	30	30	30
Total Remedials	**183**	**227**	**225**	**202**	**196**	**210**	**206**

Drilling is a vital element in a reservoir development and management strategy to achieve production at MER; additional wells are drilled for efficient drainage, as part of an improved recovery plan, and/or as replacement to existing wells which may no longer be productive due to mechanical conditions. Plans described in this chapter reflect development drilling being conducted in a logical, systematic manner so that each drilling investment provides optimal returns in increased efficiency and profitability. As itemized in Table 2.4, the bulk of the drilling activity in the reservoir development plans is forecast for three reservoirs: the MBB/W31S Sands (91 wells), the 31S C/D Shales (46 wells), and the Shallow Oil Zone (100 wells).

Significant development activities planned within the individual reservoirs are described in the following paragraphs.

Main Body B/Western 31S Sands. As illustrated in Figure 2.6, the MBB/W31S Sands have the greatest economic potential among NPR-1 reservoirs. Reservoir development plans assume that additional drilling of development wells or deepening of existing wells will occur. Further, continued expansion is planned for the existing waterflood in Sections 34S, 33S, and 32S. This Plan is based on 59 new wells and 32 deepening wells at a total investment of $69.0 million. Most of these wells would be located within the oil bank created by the waterflood. The Development Case requires a total investment of $139.4 million to generate a net present value of $1,058.5 million for the period FY 1989 to FY 1995. Two major reservoir studies are in progress on MBB/W31S Sands.

26R Sands. The26R Sands represent a pivotal resource for NPR-1, and will be the focus of significant evaluation during FY 1989 and 1990. Reservoir pressure in the 26R is currently being maintained by gas injection, and effective recovery of oil has occurred to date. Studies will concentrate on determining the most efficient strategy for future recovery of oil and massive volumes of natural gas within the Sands. To adequately drain this steeply-dipping reservoir, seven horizontal wells are planned from FY 1989 to FY 1992, for a total investment of $14.3 million; these plans are based on favorable results of an initial horizontal well drilled in the 26R in FY 1988. The Development Case for the 26R Sands reflects a total investment of $24.4 million yielding an NPV of $454.8 million between FY 1989 and FY 1995. A detailed reservoir simulation study with a fine grid model is in progress to aid in determining the optimum operating strategy for the reservoir.

Northwest Stevens A1-A3 Sands. Application of horizontal well technology is also planned to be utilized in the Northwest Stevens A1-A3 Sands to improve recovery efficiency and minimize gas cycling. The first horizontal well is planned for FY 1990, with the second projected for FY 1991; the total investment for these two wells would be

Table 2.4. Summary of Projected Drilling
Development Case: FY 1989 to FY 1995

Reservoir Stevens	1989	1990	1991	1992	1993	1994	1995
MBB/W31S	10	7	15	14	15	15	15
24Z	1	0	1	0	0	0	0
2B	0	0	0	0	0	0	0
29R	1	1	0	0	0	0	0
26R	1	2	2	2	0	0	0
31S C/D	0	2	11	9	8	8	8
31S N/A	0	0	0	0	0	0	0
NWS A1-A3	0	1	1	0	0	0	0
NWS A4-A6	0	1	1	0	0	0	0
NWS T/N	0	0	0	0	0	0	0
Total Stevens	13	14	31	25	23	23	23
Other Zones							
SOZ	7	14	6	33	6	28	6
Asphalto	0	0	0	0	0	0	0
Carneros	1	0	0	0	0	0	0
Dry Gas Zone	0	0	0	0	0	0	0
Tulare	0	0	0	0	0	0	0
Total Wells	**21**	**28**	**37**	**58**	**29**	**51**	**29**

* Includes new wells, redrills, deepening, and associated tests

$3.4 million. The Development Case for the Northwest Stevens A1-A3 Sands will cost $6.4 million and produce an NPV of $118.9 million between FY 1989 and FY 1995.

Northwest Stevens A4-A6 Sands. Two development wells are planned for this reservoir, one each in FY 1990 and FY 1991. These two wells are planned to adequately drain the A6 interval . The Development Case for the reservoir is projected to require investments of $13.2 million from FY 1989 to FY 1995 and generate an NPV of $147.3 million during this period.

31S C/D Shales. Studies indicate that considerable undeveloped reserves may be present in undrained portions of the 31S C/D Shales. To develop the potential in such areas, it is planned for all new MBB/W31S wells to be drilled to the 31S C/D Shales and tested for production. Three such wells are planned each year between FY 1991 and FY 1995. The total incremental costs of deepening and testing these wells in the 31S C/D Shales is $13.2 million. A pilot waterflood project is also planned for the zone. The projected investment required in the Development Case is $35.0 million, which is expected to provide an NPV of $196.0 million between FY 1989 and FY 1995.

Other Stevens Zone Reservoirs. Two development wells are planned for the 24Z Sands, one each in FY 1989 and one in FY 1991. The 29R/24Z Shales will be evaluated for additional recovery with two new wells, one in FY 1989 and one in FY 1990. No development activity is reflected in this Plan for the 31S N/A Shales, 2B Sands and Northwest Stevens T Sands/N Shales.

Shallow Oil Zone. The SOZ is the most extensive reservoir at Elk Hills and produces from nine sands. A large effort is underway to study this reservoir to refine strategies for production from its various areas and intervals. Several projects are planned for this reservoir, including a second phase of the existing Steamflood Pilot Project, a Steamflood Expansion Project, an SS-2/Mulinia Waterflood Project, a Hydraulic Fracturing Project, and a Development Drilling Project. If implemented, these projects would require the drilling of 100 wells at a total investment of $30.8 million between FY 1989 and FY 1995. The Development Case for the SOZ reservoir shows a total investment of $69.9 million and is expected to generate an NPV of $484.9 million between FY 1989 and FY 1995.

Other Reservoir Activities. The Carneros reservoir has one well projected for deepening to the Aqua Zone in Fy 1989 at a total cost of $0.9 million.

Following is a brief description of reservoir engineering and geologic studies planned for NPR-1 reservoirs. After that is a discussion of potential opportunities for increased recovery and profitability which may exist in the future, primarily in enhanced oil recovery (EOR) applications. Individual reservoir development plans for each reservoir are then provided, with detailed descriptions of activities necessary for continued production at MER.

RESERVOIR STUDIES

Elk Hills is typical of California oilfields as its productive formations are geologically young, highly faulted, relatively unconsolidated sands and tight shales. Highly folded, steeply dipping beds further complicate the geology.

As a result of the enormity and complexity of Elk Hills, much work remains to be done to properly describe the reservoirs geologically. As better understanding of the reservoirs occurs, more engineering must be undertaken to understand the movement of the entrained oil, gas and water to maximize recovery and revenues to the United States of America and Chevron USA.

A considerable number of reservoir studies are ongoing and planned by DOE, CUSA, and BPOI in an effort toward solving the complex reservoir problems. The following is a brief description of four groups of studies incorporated in this Long Range Plan. The first group represents those studies initiated and controlled by BPOI for which specific funds have been allocated as part of Fund Code 111. The second group is those studies being conducted by BPOI on a level of effort basis (LOE), as available funding permits. The third and forth groups are studies being performed on a 100% DOE basis and a 100% CUSA basis, respectively.

A. BPOI STUDIES (SSI)

26R Reservoir Study - Detailed 20-layer full field simulation to determine the best future operating strategy. Operating strategies to be investigated include full and partial pressure maintenance, waterflooding, infill drilling, and well completion variations.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	161	0	0	0	0	0	0
Schedule							
Start	Ongoing						
Complete	4Q						

31S Structure Comprehensive Reservoir Description
Develop a comprehensive geological and petrophysical database and a unified reservoir description for the Stevens interval. The database will be utilized for ongoing geologic and engineering analysis and be incorporated in the Reservoir Management System.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	806	0	0	0	0	0	0
Schedule							
Start	Ongoing						
Complete	3Q						

Localized Geological Studies - Develop detailed and specialized geological/petrophysical reservoir descriptions in areas with special requirements identified in the Comprehensive Reservoir Description.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	52	0	0	0	0	0
Schedule							
Start		1Q					
Complete		3Q					

C & D Shale Reservoir Study
Detailed 3D reservoir simulation study to determine the best future operating strategy. The present strategy of depletion by solution gas drive will be compared to pressure maintained operations.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	230	170	0	0	0	0	0
Schedule							
Start	3Q						
Complete		4Q					

Eastern Upper Main Body B Reservoir Study
Detailed 3D reservoir simulation study to determine the best future operating strategy. Strategies to be considered include continued peripheral waterflooding, pattern waterflooding, and gas injection for pressure maintenance.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	470	0	0	0	0	0
Schedule							
Start		1Q					
Complete			1Q				

Western Upper Main Body B Reservoir Study
Detailed 3D reservoir simulation study to determine the best future operating strategy. Strategies to be considered include continued peripheral waterflooding, pattern waterflooding and gas injection for pressure maintenance.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	0	520	0	0	0	0
Schedule							
Start			1Q				
Complete				1Q			

Lower Main Body B Reservoir Study - Detailed 3D reservoir simulation study to determine the best future operating strategy. Strategies to be considered include continued peripheral waterflooding, pattern waterflooding and gas injection for pressure maintenance.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	0	375	0	0	0	0
Schedule							
Start			1Q				
Complete				1Q			

Western 31S Reservoir Study - Detailed 3D reservoir simulation study to determine the best future operating strategy. Strategies to be considered include continued peripheral waterflooding, pattern waterflooding and gas injection for pressure maintenance.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	0	590	0	0	0	0
Schedule							
Start			1Q				
Complete				1Q			

N & A Shale Reservoir Study - Detailed 3D reservoir simulation study to determine the best future operating strategy. The study will consider the migration of fluids between 26R and N/A Shales and implications on current operating strategy.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	672	0	0	0	0	0
Schedule							
Start		1Q					
Complete			1Q				

Stevens Material Balance - Coarse grid simulation of all Stevens Zone Reservoirs as well as the regional aquifer. The study will investigate the plausibility of interstructure communication, the effect of the regional aquifer and their impacts on operating strategies.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	114	0	0	0	0	0	0
Schedule							
Start	Ongoing						
Complete	2Q						

24Z Reservoir Study - Detailed reservoir study including geological and petrophysical reservoir description and full field reservoir simulation to find the best operating strategy for the waterflood.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	264	102	0	0	0	0	0
Schedule							
Start	3Q						
Complete		4Q					

Comprehensive Reservoir and Surface Facility Model
Develop an engineering model for all NPRC reservoirs, pipelines and surface facilities to study the interaction between reservoirs and surface facilities, and optimize the total operation of the Reserve.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	0	0	600	400	0	0
Schedule							
Start				1Q			
Complete					4Q		

Enhanced Oil Recovery Studies

Develop and design EOR projects for reservoirs (blocks) with the best EOR potential.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	0	0	700	550	400	0
Schedule							
Start				1Q			
Complete						4Q	

Simulation Update Studies - The earlier studies will be updated to include new geologic, production and engineering information to improve operating strategies.

Cost/Schedule (FY'89 $)
($000)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95
Cost Estimate	0	0	0	0	650	1100	1500
Schedule							
Start					1Q		
Complete							4Q

B. BPOI STUDIES (LOE)

Eastern 31S Waterflood Performance Evaluation

Evaluate past and present performance of the eastern 31S waterflood to optimize operations and maximize ultimate reserve recovery.

Start: 1Q FY'89 Complete: 4Q FY'89

Western 31S Waterflood Performance Evaluation

Evaluate past and present performance of the western 31S waterflood to optimize operations and maximize ultimate reserve recovery.

Start: 1Q FY'90 Complete: 4Q FY'90

Evaluation of Secondary Recovery Potential of N, A, B, C and D Shales - Evaluate secondary recovery potential of the 31S shale reservoirs and recommend water injection operations as appropriate to enhance ultimate reserve recovery.

Start: 1Q FY'91 Complete: 4Q FY'94

"DD" Shale Development Potential - Investigate development potential of the DD Shale reserves.

Start: 1Q FY'91 Complete: 4Q FY'94

Evaluation of EOR Potential of 31S Reservoirs

Review of primary and secondary performance of the sands and shales of the 31S structure, and feasibility of implementing EOR processes to increase ultimate reserve recovery.

Start: 1Q FY'95 Complete: 4Q FY'95

Eastern SOZ Performance Evaluation - Develop a comprehensive reservoir description for fault blocks 7, 8 and 9 in the eastern portion of the SOZ. Evaluate past performance and predict future performance under primary and secondary operations in order to recommend the optimum means to maximize ultimate economic recovery.

Start: 1Q FY'89 Complete: 4Q FY'89

Western SOZ Performance Evaluation - Develop a comprehensive reservoir description for productive zones in the western portion of the SOZ. Evaluate past performance and predict future performance under primary and secondary operations in order to recommend the optimum means to maximize ultimate economic recovery.

Start: 1Q FY'90 Complete: 4Q FY'91

Production Operations Optimization - A study of the drilling, completion, and operation practices in the SOZ is recommended to ensure maximum inflow in this low pressure, high PI reservoir.

Start: 1Q FY'92 Complete: 4Q FY'92

Evaluate Secondary Performance and EOR Feasibility - Evaluate the secondary performance of the SOZ reservoirs in order to optimize secondary recovery and provide understanding to evaluate the economic feasibility of EOR processes.

Start: 1Q FY'93 Complete: 4Q FY'95

C. DOE STUDIES (100%)

Stevens Reservoirs - Of the 14 hydrocarbon producing reservoirs at Elk Hills, 10 are Stevens reservoirs. In order to produce their reserves of oil and gas, maximum efficient rates (MER) of production must be determined for each reservoir. The engineering procedures and methods for determining MER require extensive, in-depth reservoir engineering studies performed by expert geologists, petrophysicists, and petroleum engineers.

SOZ Reservoir Description - DOE requires an updated petrophysical interpretation for wells drilled in the last six years and for selected older wells to provide a sound basis for developing detailed reservoir description. The detailed reservoir descriptions will be used in analyzing alternative operating plans for specific fault blocks or/for equity considerations.

Gas Reservoirs - There are two major gas producing horizons at Elk Hills; the Dry Gas Zone and the Carneros Zone. In order to produce the gas and gas-liquid reserves from these zones, MER of production must be determined for each. The gas engineering procedures and methods for determining MER require in-depth reservoir engineering studies performed by expert geologists, petrophysicists, and petroleum engineers.

Simulator Case Runs - DOE requires making independent cases on the SSI developed simulation models for Stevens Zone Pools. These case runs are needed to support MER determination by DOE and to address Program Office requests or requirements.

Currently, DOE has a calibrated simulation model for the 26R Reservoir, the 24Z Reservoir, the Carneros Reservoir, the NWS Reservoir, and the 29R Reservoir. These models offer management a scientific alternative to traditional, decision models which in the past have generally rested on experience, instinct, or overriding judgements.

EOR Screening Studies - Apart from the Unit, the DOE Program Office requires EOR screening studies to determine the potential for EOR and to identify methods for maximizing ultimate recovery.

MER/Equity Projects - As a Unit Partner under the Unit Plan Contract (UPC), the DOE must perform geological, petrophysical, engineering duties pertaining to the determination and negotiation of equity or participating percentages. In support of this critical job role, the DOE calls upon expert, third-party petroleum consultants to provide required technical support. Additionally, the DOE must perform periodic MER reviews which require use of outside consultants and contractors.

BPOI/SSI Engineering Support - DOE requires on site, professional, reservoir engineering support to provide expert analysis and sound technical recommendations for projects typically beyond the purview of in-house engineers.

For example, projects handled to date include the NGL Storage Project, 26R PAR Analysis, Deep Test Formation Evaluation, ESOZ Study, etc., to name a few. In FY 1989, this engineering group shall address issues surrounding the SOZ LOSF, the SOZ proposed waterflood, the Stevens analogy reservoirs, non-Unit reservoirs, and equity or unitization matters.

Geological and Petrophysical Analysis

Log Analysis - DOE requires funds to perform log analyses independently of the Unit primarily for purposes of equity determinations, but also for non-Unit properties belonging to the Government.

Core Analysis - DOE requires funds to perform core analyses independently of the Unit primarily for purposes of equity determinations, but also for non-Unit properties belonging to the Government.

Geological - In support of log analyses and core analyses, geological consultation from third-party sources is required to pursue equity duties.

The following table reflects the projected cost of the 100% DOE Studies.

DOE-O&M
LONG RANGE PLAN
($000)

	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
1. Reservoir Studies							
A. Stevens Reservoirs	900	1,400	1,600	800	400	200	
B. SOZ Reservoirs	200	300	600	700	350	250	250
C. Gas Reservoirs	50	64	89	850	50	50	50
D. Simulation Case Run	102	267	328	391	456	466	500
E. Enhanced Oil Rec'y	125	534	467	486	228	100	150
F. MER/Equity Projects	0	1,921	1,370	1,408	1,029	1,050	1,000
2. BPOI/SSI Engr. Support	803	0	0	0	0	0	0
3. Petrophysical Analysis							
A. Log Analysis	52	52	54	55	56	58	60
B. Core Analysis	104	40	41	42	43	44	45
C. Geological	0	160	164	168	171	175	175

D. CUSA STUDIES (100%)

31S C/D Shales GOR Sensitivity (Chevron Geosciences) - Tank model study to investigate the effect of various GOR guidelines on ultimate oil recovery.

Main Body B Infill Drilling (CUSA-W.Region/ COFRAC) - Combined fractal geostatistical/ steamtube model of the eastern 31S Structure to investigate accelerated and incremental production from 10-acre infill drilling in Section 34S.

Stevens Material Balance (Chevron Geosciences) Coarse grid simulation of all Stevens Zone reservoirs, as well as the regional aquifer. The study will investigate interstructure communication, the effect of the regional aquifer and their effects on operating strategies.

Fractal Cross-Section of 26R (COFRC) Develop a cross-section of the 26R Reservoir, using fractal geostatistics for comparison to one developed using conventional cross- sectioning methods.

LOSF Simulation (COFRC) Fine grid, 3D, Three-phase numerical simulation of one-eighth of a five-spot currently being history matched. The study will aid in performance prediction for steamflood pilots and full scale projects.

LOSF Technical Service Project (COFRC) - Investigation of formation damage associated with water production in the steam flood. Upon identification of a damage mechanism a remedial stimulation method will be sought.

LOSF Expansion Geology (CUSA-W. Region) - Detailed geological study of potential steamflood expansion areas.

SOZ Equity (CUSA-W Region) - Detailed geological study for equity redetermination.

26R Compositional Simulation (Chevron Geosciences) - 2D reservoir simulation study to investigate the effects of gas cycling on NGL recoveries. To be initiated.

FUTURE OPPORTUNITIES

There are a number of opportunities that may be explored in the future to enhance NPR-1 revenues and hydrocarbon recoveries. No detailed engineering studies have been performed and most of the projects are not beyond a conceptual stage. This section will discuss these opportunities and identify the studies required to bring these ideas from the conceptual stage to project start-up. If cost estimates are available from previous feasibility studies, they will be included to show an order of magnitude of required funding to carry out these projects.

ENHANCED OIL RECOVERY PROJECTS

Currently, five reservoirs are undergoing fluid injection for pressure maintenance (MBB/W31S, 26R, NWS (A1-A3), NWS (A4-A6) and 24Z). These gas and water injection projects should increase hydrocarbon recovery and are discussed in the Reservoir Development Plans for each reservoir. For those reservoirs where the operating strategy is primary depletion, the opportunities for implementing fluid injection projects in the future are identified in their respective Development Plans. This section will concentrate on Enhanced Oil Recovery (EOR) Projects which permit recovery of residual oil unrecovered by more conventional secondary projects such as waterflooding. At the present time, the SOZ Light Oil Steamflood is the only EOR project which has been evaluated by the Unit. This project is covered in the SOZ Development Plan and will not be discussed here.

J. R. Bergeson and Associates, in their 1988 study of NPR-1 for the DOE, performed a screening of potential EOR projects for NPR-1 reservoirs. Since this study contains the best analysis done to date, we will use their data to discuss potential EOR projects. When risk analysis was applied to these projects, most of them failed to pass acceptable economic cut-offs. It would be emphasized that this study be used only as an initial screening tool to direct investigation of the most promising candidates. As further reservoir description and understanding of recovery mechanisms develops for each reservoir, and as oil prices fluctuate, the results of this type of screening study will change, making some projects more attractive and others less so. In the same light, cost and recovery numbers must be taken as very tentative, having a wide range of uncertainty, and being heavily dependent on the final project design.

In order to optimize EOR recoveries and economics, it is necessary to conduct detailed geological/engineering studies and pilot tests prior to implementation of commercial projects. The typical schedule for carrying out this work for each EOR project has been estimated as follows:

	Time (mos)	Elapsed Time (mos)
EOR Pilot design	12	12
Pilot installation	8	20
Pilot evaluation	24	44
Comm. proj.design	9	53
Comm. proj.installation	12	65

This schedule indicates that five years will elapse between a decision to initiate the engineering design of a pilot and start-up of the field commercial project. Due to the two-year budget lead time at NPR-1, funding estimates will be required prior to having detailed engineering design to firm up cost requirements. In order to speed up the process, the selection and design of the pilot projects should be made carefully so that several commercial projects may be started on the basis of one pilot.

CHEMICAL FLOOD (ASP)

The EOR process which Bergeson evaluated as having the widest range of applicability was an Alkaline-Surfactant-Polymer (ASP) Flood. This is a modification of the micellar-polymer process and involves the injection of large quantities of very dilute chemical concentrations instead of small slugs of highly concentrated chemical. This allows the project to behave more like a waterflood without the stringent control required to maintain the integrity of small slugs. Reservoir heterogenities tend to defeat efforts to maintain slug integrity and therefore cause most chemical floods to fail. The ASP approach is a relatively untested process which has conceptual appeal and would require careful pilot testing.

From the Bergeson analysis, an ASP project in the Eastern SOZ transition zone has potential to be an economic opportunity. Costs for engineering analysis, facilities and chemicals are shown in the following Table 1.

Additional costs totaling $95 million will also be required for the drilling of 154 injectors and 225 producers. This project is targeted at a resource base of 200 million barrels of oil.

The current SOZ study by the BPOI Task Force and Bergeson will investigate further the feasibility of the ASP process with the objective of recommending a location for a pilot by the end of FY'89. Design and laboratory studies could therefore begin in FY'90, although no funds have been identified in the FY'90 IRB.

CHEMICAL FLOOD (ASP)
ENGINEERING AND FACILITIES COSTS
(1989 THOUSANDS OF DOLLARS)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95	OUTYEARS
Pilot Design Lab/Engr Studies	-	330	470	-	-	-	-	-
Pilot Plant/Facilities	-	-	313	188	-	-	-	-
Pilot Chemical Costs	-	-	-	1,300	532	-	-	-
Commercial Scale Design, Pilot Evaluation	-	-	-	-	-	-	1,000	1,500
Commercial Plant/Facilities	-	-	-	-	-	-	-	3,800
Chemicals	-	-	-	-	-	-	-	225,000
TOTAL	0	330	783	1,488	532	0	1,000	230,300

Table 1

POLYMER FLOOD
ENGINEERING AND FACILITIES COSTS
(1989 THOUSANDS OF DOLLARS)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95	OUTYEARS
Pilot Design Lab/Engr Studies	-	250	350	-	-	-	-	-
Pilot Plant/Facilities	-	-	250	150	-	-	-	-
Pilot Chemical Costs	-	-	-	115	150	150	150	190
Commercial Scale Design, Pilot Evaluation	-	-	-	-	-	-	1,000	1,500
Commercial Plant/Facilities	-	-	-	-	-	-	-	2,500
Chemicals	-	-	-	-	-	-	-	92,000
TOTAL	0	250	600	265	150	150	1,150	96,190

Table 2

POLYMER FLOOD

A polymer flood in the Eastern SOZ transition zone was evaluated by Bergeson. The projected engineering, facilities and chemical costs for this project are given in the following table. The resource base targeted for this project was 28 million barrels of oil and required the drilling of 375 wells at a cost of $94 million. A risked evaluation resulted in unfavorable econonmics for this project. (See Table 2)

Furtherwork by the BPOI Task Force and Bergeson on the SOZ would be required to re-evaluate this process. At the current time, no further engineering study is anticipated due to the results of the previous scoping evaluation by Bergeson

INSITU COMBUSTION PROJECT

An insitu combustion project in the Eastern SOZ transition zone was evaluated by Bergeson to have acceptable economic indicators. A combustion proj-

INSITU COMBUSTION
ENGINEERING AND FACILITIES COSTS
(1989 THOUSANDS OF DOLLARS)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95	OUTYEARS
Pilot Design Lab/Engr Studies	-	-	330	470	-	-	-	-
Pilot Air Cost (Leased Compression)	-	-	-	-	145	190	190	430
Commercial Scale Design, Pilot Evaluation	-	-	-	-	-	-	-	2,500
Commercial Plant/Facilities	-	-	-	-	-	-	-	25,000
Air Cost (Leased Compression)	-	-	-	-	-	-	-	143,000
TOTAL	0	0	330	470	145	190	190	170,930

Table 3

ect is probably the highest risk EOR process that can be implemented. Factors that are extremely difficult to evaluate are the effects of the hot combustion front on downhole tubulars, corrosion effects on surface facilities, and the success of keeping the wells on production. Generally these difficulties are underestimated in the engineering design stage. Therefore, any preliminary scoping numbers should be viewed with appropriate skepticism. The projected engineering, facilities and air injection costs for the project are given in the following table (See Table 3). The resource base targeted for this project is 28 million barrels of oil and requires drilling 375 wells at a cost of $94 million.

Further work by the BPOI Task Force and Bergeson would be required to evaluate the process. The schedule assumes this work would not be initiated prior to FY'91.

CARBON DIOXIDE FLOODS (CO2)

Miscible floods using carbon-dioxide (CO2) are in widespread use, particularly in West Texas, where CO2 is available in large quantities by pipeline. Bergeson evaluated CO2 flooding in the NPR-1 Stevens reservoirs and did not obtain promising results. Based on the requirement to have a field-wide project to generate the economy of scale necessary to justify the cost of transporting CO2 to the Bakersfield area, Bergeson concluded this process was economically unattractive. The size of the potential CO2 projects at NPR-1, e.g., MBB/W31S, dictates the requirement for a large scale CO2 source. Smaller reservoirs such as 2B conceivably could be handled by trucking in CO2 as is done in other locations, e.g., North Coles Levee.

Further investigation of the feasibility of the CO2 miscible and immiscible processes would require laboratory tests, engineering and simulation study, market analysis of CO2 availability and potential demand and evaluation of the use of flue gas as an injection gas source. Funding for this work starting in FY'91 might be expected to amount to as much as $500 thousand per year for two to three years.

NITROGEN INJECTION

An alternative to injecting residue gas into 26R, NWS (A1-A3) and 24Z is the injection of nitrogen. Three benefits from such a change are release of residue gas to sales, the stripping effect nitrogen has on the residual oil saturation encountered as it moves through the reservoir and the elimination of corrosive agents in the injected gas. The benefits are offset by the requirement to manufacture the injected nitrogen onsite by cryogenic separation. In addition, the process requires investment to build a nitrogen rejection plant to process the produced gas and remove the nitrogen prior to gas sales. For a gas stream the size of 26R's, this would be a significant investment. The economics and engineering for this process have not been performed, but the estimated engineering, facilities and injection costs for this project are given in the following table (See Table 4).

NITROGEN INJECTION
ENGINEERING AND FACILITIES COSTS
(1989 THOUSANDS OF DOLLARS)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95	OUTYEARS
Pilot Design Lab/Engr Studies	-	-	500	1,500	-	-	-	-
Pilot Plant/Facilities	-	-	-	-	20,000	-	-	-
Pilot Chemical Costs	-	-	-	-	-	-	-	-
Commercial Scale Design, Pilot Evaluation	-	-	-	-	-	-	-	20,000
Commercial Plant/Facilities	-	-	-	-	-	-	-	200,000
TOTAL	0	0	500	1,500	20,000	0	0	220,000

Table 4

FLUID INJECTION NON-RATE SENSITIVE RESERVOIRS

True shales are composed to a large extent of clay particles which can swell and migrate when contacted by an aqueous fluid of a different chemical nature than the shales depositional fluid. Because of this phenomena, shales are not waterflooded. Recent studies of non-rate sensitive reservoirs at NPR-1 indicate that they are not true shales in the classic sense of the word. These reservoirs are more siliceous in nature than thought earlier and may be sufficiently insensitive to foreign fluids that they could be successfully injected. Because of the very significant amount of residual oil which could be unrecovered at the end of economic life by primary depletion, a pilot injection project followed by full scale expansion should be explored further. Opportunitis for specific projects are identified in the individual Reservoir Development Plans.

Projected engineering and facilities costs are given in the following table for two typical projects being considered, e.g., 29R waterflood at 30,000 BWPD and Eastern SOZ waterflood at 40,000 BWPD. The 29R project assumes 43 new producers and injectors at $850,000 each. The SOZ project assumes 50 new producers and injectors at $315,000 each. Pilot costs for each project are estimated at 10% of full project cost (See Table 5).

OTHER PROJECTS

INFILL DRILLING STUDIES

Reduction of well spacing by infill drilling may be an effective way of improving oil recovery and accelerating revenue in association with the waterflood projects ongoing and planned at NPR-1. It should be noted that infill drilling studies comprise only a part of developing an overall depletion plan for a particular reservoir, which is particularly true for reservoirs undergoing fluid injection. Prior to any infill drilling study, there must exist a detailed geological reservoir description for the subject reservoir. As noted below this geological precursor is just now being completed on several NPR-1 reservoirs.

FLUID INJECTION - NON-RATE SENSITIVE RESERVOIRS
ENGINEERING AND FACILITIES COSTS
(1989 THOUSANDS OF DOLLARS)

	FY'89	FY'90	FY'91	FY'92	FY'93	FY'94	FY'95	OUTYEARS
29R Shales								
Pilot								
Engineering	-	40	-	-	-	-	-	-
Wells	-	-	2,000	1,655	-	-	-	-
Facilities	-	-	230	-	-	-	-	-
Commercial								
Engineering	-	-	-	-	-	400	-	-
Wells	-	-	-	-	-	-	12,000	24,550
Facilities	-	-	-	-	-	-	2,300	
SUBTOTAL	0	40	2,230	1,655	0	400	14,300	24,550
Eastern SOZ								
Pilot								
Engineering	-	40	-	-	-	-	-	-
Wells	-	-	1,575	-	-	-	-	-
Facilities	-	-	180	-	-	-	-	-
Commercial								
Engineering	-	-	-	-	-	400	-	-
Wells	-	-	-	-	-	-	5,000	10,750
Facilities	-	-	-	-	-	-	1,800	-
SUBTOTAL	0	40	1,755	0	0	400	6,800	10,750
	=====	=====	=====	=====	=====	======	=======	======
TOTAL	0	80	3,985	1,655	0	800	21,100	35,300

Table 5

Analysis of the historical benefits of infill drilling can be made for two 10-acre areas of the MBB/W31S reservoirs in the eastern 31S Structure. The analysis would be in two phases, analytic followed by simulation. The elapsed time of the two-phase study of the combined two areas is estimated at 10 to 12 months and could be coordinated with the current studies of the BPOI Task Force and Bergeson and Associates.

The definition and evaluation of specific area infill programs for the Stevens sand reservoirs will need to follow the revised development completion/waterflood program for the MBB/W31S reservoirs and the Northwest Structure sands. Evaluation of the specific infill programs will require careful economic analyses integrated with simulation of the revised waterflood plan. An infill pilot test program is a likely approach.

The evaluation of infill drilling in the Stevens shales will need to be made when detailed geologic description and/or reservoir simulation studies are finished. The infill drilling analysis of the shales must be integrated with development of a completion/stimulation philosophy for these reservoirs. The 29R shales simulation study has identified five areas where infill drilling appears practical. The areas should be analyzed in detail using more detailed reservoir description and a fine grid simulation to evaluate the specific benefits of infill drilling. This analysis is not currently scheduled but could be completed in 9 to 12 months. The C/D Shales on the 31S Structure are to be the subject of an FY'89 geologic and simulation study to be completed in mid-FY'90. A detailed study of infill drilling could be completed in 6 to 9 months, finishing at the end of FY'90.

The projected engineering costs for this project are estimated at $300,000 per study area. Facilities costs already contained in the Facilities Project section under Stevens Tans Setting Modification and Produced Water Injection are sufficient to cover increased production due to infill drilling.

NGL STORAGE

The production of natural gas liquids (NGL) at NPR-1 reamins at a nearly constant rate year around. However, the market demand for NGL's is seasonal. There may be an opportunity to maximize revenues by storing NGL's during periods of low demand and releasing them from storage during periods of high demand. This question has received cursory analysis in the past. The effort has focused on technical considerations such as the feasibility of storing a given volume of NGL's in a particular reservoir. We are suggesting posing the question without restrictions: "Can revenues be enhanced by engaging in an NGL storage project?" The project would then be free to investigate all possibilities including offsite storage, and conduct a marketing analysis to determine the impact of selling significantly more than the current NPR-1 NGL stream in the peak demand periods.

INDIVIDUAL RESERVOIR DEVELOPMENT PLANS

This section contains plans for 15 reservoirs at Elk Hills.

MBB/W31S SANDS

The Main Body "B"/Western 31S (MBB/W31S) Sands are productive segments within the B Shale interval of the 31S Structure (See Location Map, Figure 1 and Cross Section, Figure 3). This interval consists of channel-like turbidite sands that cover the entire 31S Anticline.

The Total Development Case for MBB/W31S Sands is the sum of the Maintenance Case and four projects, as follows:

1. Development Drilling/Deepening Project
2. 34S Waterflood Expansion Project
3. 33S Waterflood Expansion Project
4. 32S Waterflood Expansion Project

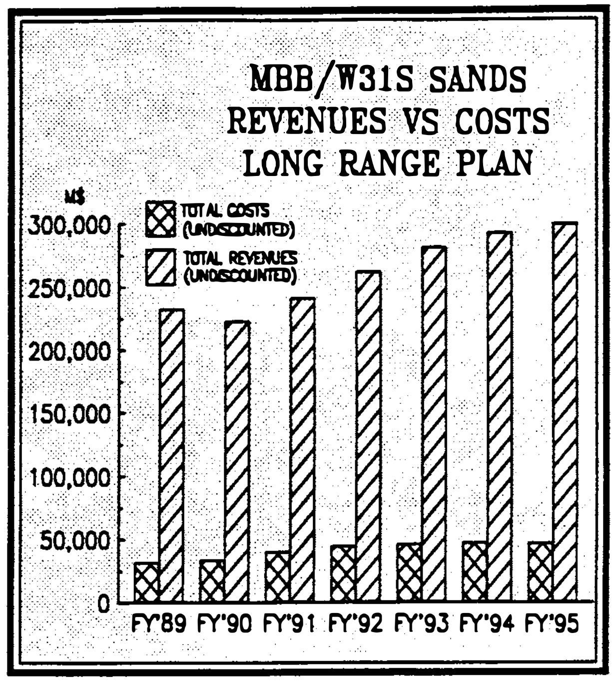


Figure 2

It is estimated that the Total Development Case would generate $1.8 billion in undiscounted revenues from FY'89 to FY'95, with associated direct expenditures of $287 million. Annual revenues and expenditures for the Total Development Case are as shown in Figure 2.

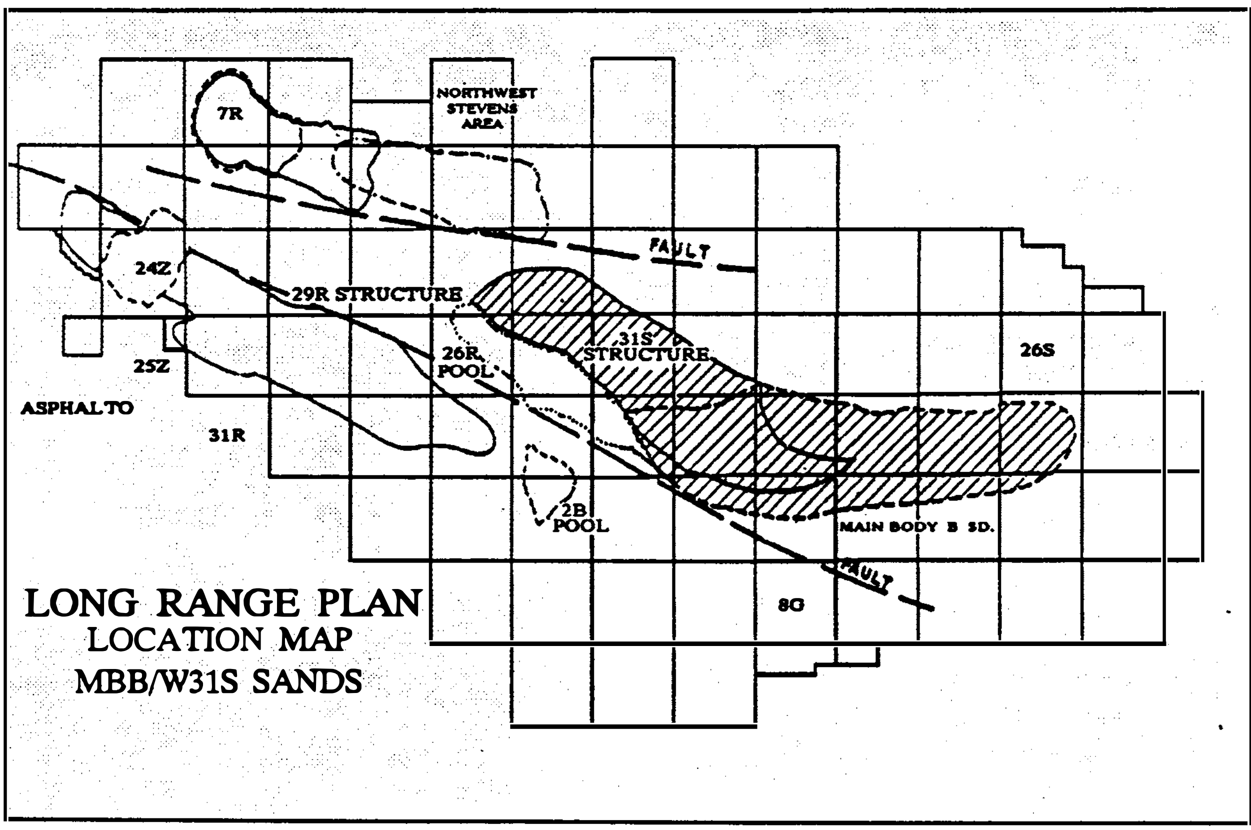


Figure 1

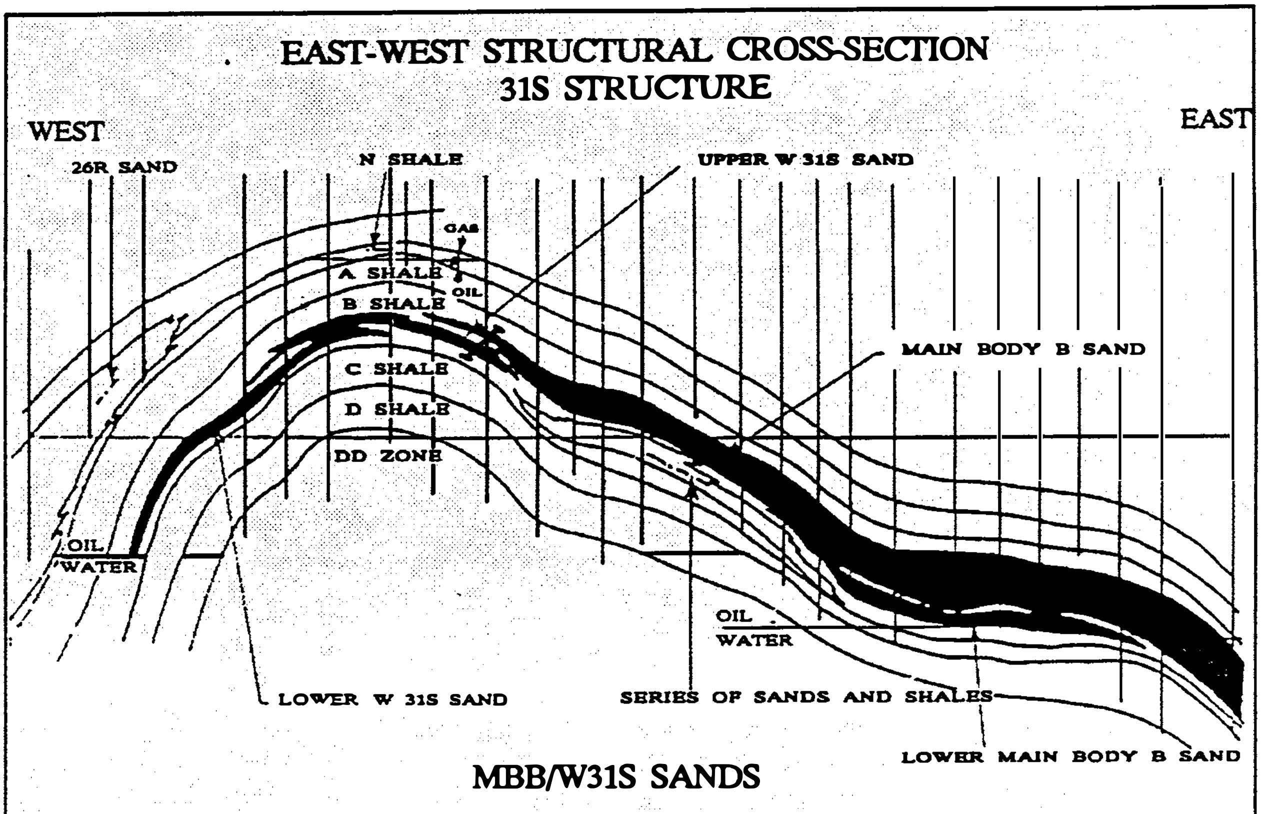


Figure 3

Additional statistics that demonstrate the economic feasibility of the Total Development Case are shown in Figure 4. The net present value for the Total Development Case at 10% discount rate is $1058.5 million from in FY'89 to FY'95 and $1,868.9 million from FY'89 to economic limit.

Total oil recovery for the Total Development Case is 68.8 million barrels from FY'89 to FY'95 and 125.3 million barrels from FY'89 to economic limit in FY'2017.

The reservoirs are estimated to contain 610 million barrels as original oil-in-place with ultimate recoverable reserves off 244 million barrels by the Elk Hills Engineering Committee.

Cumulative oil production through September 30, 1988, was 117 million barrels and the remaining reserves are estimated to be 125 million barrels. Total water and gas injection through October 31, 1988, are 144 million barrels and 116 BCF, respectively. The relative pro-

MBB/W31S SANDS
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$1,840.3 Million	$5,925.8 Million
Operating Cost:	$148.3 Million	$859.8 Million
Investment:	$139.4 Million	$216.3 Million
Total Costs:	$287.7 Million	$1,076.1 Million
Net Revenue:	$1,552.7 Million	$4,849.7 Million
Net Present Value(@ 10%)	$1,058.5 Million	$1,868.9 Million
Recovery:		
Oil (MMB)	68.8	125.3
Natural Gas (BCF)	167.4	438.7
Oil Equivalent (MMBOE)	102.4	213.5

Figure 4

portions of the oil reserves and residual oil indicate that considerable volumes of oil may be left in the reservoir at the end of the waterflood project. This suggests that the MBB/W31S reservoir could be a viable candidate for enhanced oil recovery projects. Since the reservoirs are extensive, different production practices have been in effect in different segments of the reservoirs. The southeastern flank has a well-developed waterflood. The middle section is basically under a depletion-type drive and was pressure-supported by gas injection through June 30, 1988. The northwestern areas are beginning to respond gradually to water injection. In Sections 33S and 34S, a second row of water injectors was drilled to increase water injection in these areas.

The Maintenance Case reflects continuation of routine remedial work such as stimulations, recompletions and artificial lift installations. From FY'89 to FY'95, total costs under the Maintenance Case are $163.2 million with total net revenues of $1,083.4 million. The Development Drilling/Deepening Project covers drilling of new wells or deepening of existing wells in other parts of the reservoirs except Sections 32S, 33S and 34S. This case will generate a total net revenue of $295.6 million at a total cost of $83.6 million from FY'89 to FY'95. The Waterflood Expansion projects in Sections 34S, 33S and 32S are non-exclusive projects planned for the sole purpose of augmenting the waterflooding process in these parts of the reservoir. The total cost of the 34S Waterflood Expansion Project is $10.2 million with total net revenues of $33.2 million. The total cost of the 33S Waterflood Expansion Project is $10.0 million with total net revenues of $14.4 million. And the total cost for the 32S Waterflood Expansion Project is $20.7 million with total net revenues of $126.1 million.

The current reservoir operating strategy for MBB/W31S Sands is to produce the reservoir with a voidage-balanced, peripheral waterflood. This strategy has been modified slightly to accommodate the impact on voidage balance of possible communication between the MBB/W31S Sands, the 31S N/A Shales and the 26R Sands. Beginning July 1, 1988, the three reservoirs were considered to be a single unit for voidage balance purposes. Total production from the three reservoirs is balanced by water injection in MBB/W31S Sands and gas injection in 26R Sands. This strategy will be in effect for a 12-month trial period, during which the pressures of the three reservoirs will be monitored.

Future reservoir operating strategy stresses expansion of the waterflood project by increasing water injection through conversion of watered out wells and drilling of new water injectors. In concert with increased water injection, the future operating strategy includes plans to drill infill wells ahead of the floodfront to exploit the oil bank created by the waterflood. This strategy is embodied in the Development Drilling/Deepening Project and the Waterflood Expansion Projects. Under the Total Development Case, production is expected to decline from 32,922 BOPD in FY'89 to 23,815 in FY'95. In comparison, the Maintenance Case will average 30,887 BOPD in FY'89 and 10,098 BOPD in FY'95.

The historical production for MBB/W31S from 1976 to 1988 and the projected production to economic limit in 2017 is depicted in Figure 5. The historical

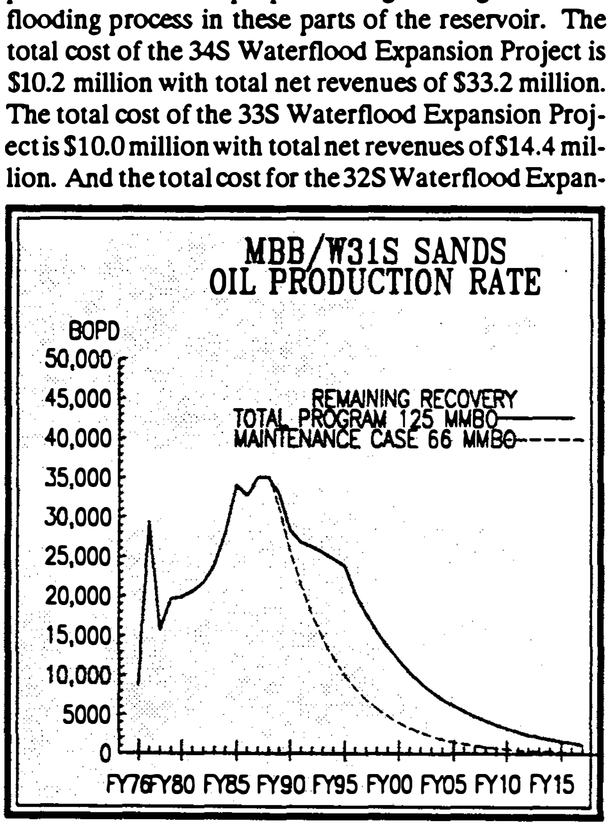


Figure 5

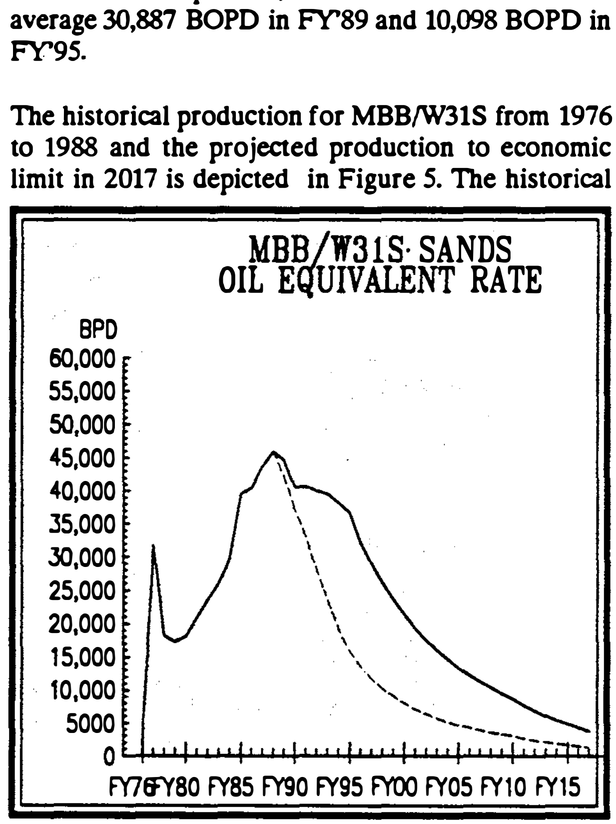


Figure 6

equivalent barrels of oil production from 1976 to 1988 and the projected production to economic limit in 2017 is as shown in Figure 6.

Several reservoir studies are in progress or planned for MBB/W31S Sands. These are:

1. Stevens Material Balance Study (in progress).
2. 31S Comprehensive Reservoir Geologic Description (in progress).
3. 31S Structure Study (in progress).
4. Eastern Upper Main Body "B" Reservoir Study (FY'90).
5. Western Upper Main Body "B" Reservoir Study (FY'91).
6. Lower Main Body "B" Reservoir Study (FY'91).
7. Western 31S Reservoir Study (FY'91).

The results of these studies will provide other strategies for the operation of the reservoirs.

RESERVOIR DESCRIPTION

The 31S Structure is the most extensive of all the petroleum bearing formations at the Elk Hills Naval Petroleum Reserve in California. It is an anticlinal structure about 7.5 miles long by 1.5 miles wide, trending west-northwest and east-southeast (Figures 1 & 3). The most prolific zone within the 31S structure is the Stevens Zone, which was discovered in 1941. The Stevens Zone is believed to have been deposited in deepwater turbidite environment, resulting in a complex interlayering of sands and shales.

The Main Body "B"/Western 31S (MBB/W31S) Sands are productive segments within the B Shale interval of the 31S Structure. This interval consists of four channel-like turbidite sands that together cover the entire 31S Anticline. The Upper Main Body "B" (UMBB) is the most extensive of the four, covering approximately two-thirds of the structure and becoming thinner westward to its effective pinch-out in Sections 36R and 31S. The productive area of the Lower Main Body "B" (LMBB) covers about one-third of the area of the UMBB and pinches out to the north in Sections 33S, 34S and 35S, and to the northwest in Sections 5G, 4G and 33S. The Upper and Lower Western 31S (UW31S and LW31S) are stratigraphically lower than the Main Body "B" Sands. These sands are thinner and appear more channelized than the MBB Sands. The productive Western 31S Sands cover approximately one-half of the 31S Anticline.

The Main Body "B" and Western 31S Sands are produced under a peripheral waterflood project. Crestal gas injection for pressure maintenance started in October 1976 and was terminated in June 1988. Water injection was initiated in the southeastern sections in June 1978. This has been expanded into a peripheral waterflood. There are approximately 350 wells completed in MBB/W31S Sands as of November 30, 1988, consisting of 242 producers, 102 water injectors and six idle gas injectors. Fifty-one wells are shut-in as high gas-oil ratio wells. Most of the reservoir has been developed on 20-acre well spacing. However, to improve recovery from the oil bank created by water injection, several sections (2G, 3G, 4G, 35S, etc.) have well spacing of 10 acres.

The estimated original oil-in-place and reservers shown in Figure 7 are from the "Stevens Zone Estimated Recoverable Oil and Third Revision of Percentage Participations as of November 20, 1942.

MBB/W31S SANDS
TOTAL DEVELOPMENT CASE

	EQUITY STUDIES	LONG RANGE PLAN MAINT.	LONG RANGE PLAN TOTAL
Original-Oil-In-Place (MMB):	610.0	---	---
Estimated Recoverable Oil (MMB):	244.0	182.9	242.2
Cumulative Production 9/30/88 (MMB):	116.9	116.9	116.9
Remaining Reserves:			
Oil (MMB)	127.1	66.0	125.3
Natural Gas (BCF)	---	238.3	438.7
Oil Equivalent (MMBOE)	---	113.9	213.5
Economic Limit (BOPD, YEAR):	---	167FY'2017	1133FY'2017

Figure 7

The reservoir data for MBB/W31S Sands are summarized below:

Porosity (%):	20	Producing Wells (#):	350
Water Sat. (%):	38-40	Injection Wells (#):	102
Air Perm. (md):	23	Top Pay (Ft-VSS):	4,500
Oil Gravity (API):	34-41	Max Pay (Ft-VSS):	450
Oil Form. Vol. Factor (RB/STB):	1.552	Pay Area (Ac):	7,024
Oil Viscosity (cp):	0.42	Pay Volume (AF):	406,433
Initial Press. (psi):	2,844	GOC (Ft-VSS):	5,000
Bub. Pt. Press. (psi):	2,830	WOC (Ft-VSS):	6,000-6,600
Current Press. (psi):	2,576	Press. Datum (Ft-VSS):	6,000

RESERVOIR STUDIES

Many reservoir studies are either in progress or planned for MBB/W31S. The Stevens Material Balance Study to be completed in FY'89 would investigate fluid migration and aquifer depletion in the Stevens reservoirs. The 31S Comprehensive Reservoir Geologic Description was started by Scientific Software-Intercomp (SSI) in FY'88 and completion is expected in FY'89. This work would provide a detailed geologic and petrophysical description of all the Stevens reservoirs in the 31S Structure. In FY'89, the 31S Structure Study was initiated by J. R. Bergeson and Associates and BPOI Task Force. The study is expected to result in the provision of a comprehensive depletion strategy for the 31S Structure with particular emphasis on MBB/W31S Sands. Specifically, it would review the performance of the waterflood project in MBB/W31S, and the state of depletion in the N/A Shales and C/D Shales. More studies are planned in future years in MBB/W31S by SSI. These are the Eastern Upper Main Body "B" Study (FY'90), the Western Upper Main Body "B" Study (FY'91), the Lower Main Body "B" Study (FY'91) and the Western 31S Study (FY'91).

RESERVOIR DEVELOPMENT STRATEGY

The MBB/W31S Sands are a complex system of reservoirs. Consequently, various operating policies have been in effect since production started in March 1976. Crestal gas injection for pressure maintenance started in October 1976. The reservoirs were produced by solution-gas drive mechanism until a peripheral water injection project was begun in the southeastern flank in June 1978. From 1978 to 1983, insignificant amounts of water were injected into the reservoirs. Most of the reservoirs could still be considered to be producing under depletion drive during this period. Because the water injection project was initiated in the southeastern flank, production response to the waterflood is most observable in this area. Most first line producers in this area are watered-out and have been converted to water injectors. The operating policy for well conversions is to review candidate wells for bypassed reserves prior to conversion. In some cases, conversion candidates are actually tested for productive potential in several zones using isolation packers. If a first-line producer has no productive potential, it is converted to a water injector.

The middle section of the MBB/W31S (Sections 25R, 31S, 32S) reservoir can be considered to be under depletion drive since 1976. This is evident in the pressure decline of wells in these sections. Crestal gas injection into Sections 25R and 31S was terminated in June 1988. Most of the wells which are shut-in due to high gas-oil ratios are located in these sections. The operating policy in MBB/W31S Sands on controlling excessive gas production is to review wells producing at or above 5,000 SCF/bbl for shut-in. Controlling production from high GOR wells is expected to assist in conserving reservoir energy.

In the northwestern areas of MBB/W31S reservoir, a gradual response to the water injection project is being observed. The peripheral water injectors are in place and the first line producers have demonstrated production response. In Sections 33S and 34S, a second row of water injectors was introduced to increase water injection since the injectivity in the peripheral wells was very low due to low rock permeabilities. The general operating policy is to maximize water injection while optimizing the sweep efficiencies attainable through the waterflood process.

Production data, material balance studies and reservoir simulation work suggest that MBB/W31S Sands, 26R Sands and 31S N/A Shales are in communication. This means that gas could percolate into the 31S N/A Shales from MBB/W31S and 26R Sands. Oil may be migrating into these reservoirs from the N/A Shales in a counter current flow. If fluid communication exists between these reservoirs, it is obvious that they should not be operated in isolation from each other. Especially for pressure supported reservoirs such as the 26R Sands, operating practices in the 31S N/A Shales could impact 26R Sands pressure. As a result of this observation, the current operating policy treats the three reservoirs as a unit with respect to the balance of reservoir voidage. Total production from these reservoirs is balanced by water injection into MBB/W31S and gas injection into 26R Sands. If reservoir voidage cannot be balanced with available injection capacities, production from the reservoirs is curtailed by shutting-in high gas-oil ratio and/or high water-cut wells. The above operating policy was implemented on July 1,1988 for a 12-month trial period during which the performance of the three reservoirs will be monitored.

Recent work completed by BPOI Reservoir Review Task Force indicates that no communication pathways nor evidence of communication from production data exist between MBB/W31S Sands and 31S N/A Shales. If this view is adopted or supported by the results of ongoing work, the reservoir management strategy will be modified accordingly. Specifically, it will result in the decoupling of MBB/W31S Sands from the 31S N/A Shales and 26R Sands for voidage balance purposes.

The Reservoir Management Strategy planned for MBB/W31S Sands falls under the following categories:

1. Maintenance Case.
2. Development Drilling/Deepening Project.
3. 34S Waterflood Expansion Project.
4. 33S Waterflood Expansion Project.
5. 32S Waterflood Expansion Project.

The reservoir strategies under Development Drilling and the waterflood expansion projects include the drilling of infill wells ahead of the floodfront to properly exploit the oil bank created by the flood. These strategies also include the conversion of watered-out wells to water injectors if such wells could not recover additional reserves economically. However, there are other views that suggest that booked reserves could be recovered through existing wells and the entire reservoir would be swept through existing configuration of injectors. Such conflicting viewpoints would be addressed by the studies described earlier and the operating strategies would be modified as deemed necessary at that time.

The Total Development Case is the sum of all the cases enumerated above. The evaluation of the Total Case is shown in Table 1. The key economic indicators on the feasibility of the plan are summarized in Figure 4.

All the cases, projects and the Total Case were evaluated with the cost and production data as shown in Figure 8.

Maintenance Case: The Maintenance Case assumes that all remedial activities should be limited to supporting existing wells, facilities and other routine well work necessary to continue the operation of the reservoirs. Production from the reservoirs would not be supported by drilling new wells or deepening existing wells.

MBB/W31S SANDS
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job($)	InitialRate (BOPD)	Decline (%/Yr)
Stimulation (Acidizing)	66,000	50	10
Recompletion	160,000	228	10
Conversions	150,000	-	-
Artificial Lift	140,000	108	10
Deepenings	450,000	315	10
New Wells:			
Development Case	820,000	405	10
34S Project	820,000	450	15
33S Project	820,000	195	10
32S Project	820,000	-	-
Facilities:			
Gas Lift Comp.	425,000	-	-
18G Booster Pump	300,000	-	-
4G Closed Loop Gas Lift	1,673,000	-	-
Conversion to Produced Water Injection	9,996,000	-	-
Stevens Waterflood Expansion	400,000	-	-

Figure 8

It is expected that the level of remedial activities in the MBB/W31S Sands would be high due to the maturity of the waterflood project. These activities include acid stimulations, recompletions, installation of artificial lift systems, profile control on water injectors and water isolations.

The sharp decline in oil-producing rate from 1991 is caused by the watering-out of existing wells coupled with the absence of infill wells to produce the oil bank created by the flood. Under this plan, oil production is projected to drop from 30,887 BOPD in FY'89 to 10,098 BOPD in FY'95.

The evaluation of the Maintenance Case is shown in attached Economics Table 2. The relevant economic parameters are summarized in Figure 9.

Development Drilling/Deepening Project: Opportunities still exist in MBB/W31S Sands for development drilling and location of infill wells. Part of the drilling program would seek to develop W31S Sands in the northern portion of the structure and extending eastward into Sections 30S, 31S and 32S. Similar development is planned for MBB Sands in the same sections but extending westward.

MBB/W31S SANDS
MAINTENANCE CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$1,246.6 Million	$2,735.3 Million
Operating Cost:	$109.3 Million	$524.4 Million
Investment:	$53.9 Million	$84.2 Million
Total Costs:	$163.2 Million	$608.6 Million
Net Revenue:	$1,083.4 Million	$2,126.7 Million
Net Present Value (@ 10%)	$778.3 Million	$1,057.9 Million
Recovery:		
Oil (MMB)	48.3	66.0
Natural Gas (BCF)	120.6	238.3
Oil Equivalent (MMBOE)	72.6	113.9

Figure 9

Infill drilling is planned to continue at several locations such as in Sections 4G, 5G, 33S, 23R, 26R and 36R. These sites would become suitable as take-points in the oil bank with the propagation of the floodfront. The deepening candidates would be several 31S N/A Shales wells which are ideally located in the path of the floodfront. Also, there are several MBB/W31S wells that were not drilled deep enough to expose all the MBB/W31S Sands. Such wells qualify as deepening candidates.

The B Shale is considered part of MBB/W31S Sands. Several wells have produced, or are producing from the B Shales. The pressure of the B Shale has continued to decline because the reservoir is not supported with injection. The B Shale appears to contain considerable oil reserves. To support current production and improve recovery, evaluation of the potential of waterflooding this reservoir is desirable. The results of the evaluation of the Development Drilling/Deepening Case are shown in Table 3. The key economic factors are summarized in Figure 10.

34S Waterflood Expansion Project: In FY'89, the waterflood project in Section 34S is recommended to be expanded by the drilling of three new wells as pro-

MBB/W31S SANDS
DEVELOPMENT/DEEPENING PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$379.2 Million	$2,556.0 Million
Operating Cost:	$25.3 Million	$258.1 Million
Investment:	$58.3 Million	$ 90.6 Million
Total Costs:	$83.6 Million	$348.7 Million
Net Revenue:	$295.6 Million	$2,207.3 Million
Net Present Value (@ 10%)	$174.5 Million	$609.3 Million
Recovery:		
Oil (MMB)	11.9	40.6
Natural Gas (BCF)	34.6	177.3
Oil Equivalent (MMBOE)	18.9	76.2

Figure 10

ducers and the conversion of three producers to water injectors. The new producers are Wells 327-34S, 347-34S and 367-34S. The conversions to injectors are Wells 326-34S, 346-34S and 366- 34S.

The new wells are justified by the state of the waterflood project in Section 34S. The leading edge of the oil bank from Section 3G is moving into Section 34S. This is demonstrated by the recent performance of Well 368-34S. This well was a gas injector located between Sections 34S and 3G. It now produces over 600 barrels of oil per day with little or no water production. Other similarly located wells such as 348- 34S and 378-34S are showing comparable production. Also, the oil bank from Section 35S is advancing into Section 34S. This view is supported by the performance of Wells 316-35S, 317- 35S, 318-35S and 388-34S. The current density of wells in Section 34S may be insufficient to exploit this oil bank.

The proposed conversions to water injectors are necessary to support production from this Section. At the current average water injection rate of 8,200 B/D, it will take about 19 years to flood 0.40 pore volumes of the Section. The proposed injectors will provide additional injection volume of 4,500 B/D. The locations of the injectors have been selected to minimize the possibility of pushing the oil bank into the low permeability sands in the northern regions of the Section.

Table 4 shows the results of the evaluation of the 34S Waterflood Expansion Project. Figure 11 contains the key economic parameters.

33S Waterflood Expansion Project: The reservoir management justification for this project is similar to the justification for the 34S Waterflood Expansion Project. As in Section 34S, the plan is to expand the water injection volumes by converting three wells to water injectors. The conversion candidates are Wells 346-33S, 366-33S and 386-33S, which are planned for FY'91. Six new producers would be drilled in FY'92. These are Wells 345-33S, 336-33S, 356-33S, 376-33S, 367-33S and 387-33S. These wells are positioned to exploit the oil bank that would be created by the new injectors.

The results of the evaluation of the 33S Waterflood Expansion project are shown in Table 5. The key economic yardsticks are summarized in Figure 12.

32S Waterflood Expansion Project: The waterflooding process has barely started in Section 32S where the average water injection in September 1988 was only 106 BWIPD. In October 1988, daily production averaged 564 BOPD, 33 BWPD and 1700 MCFPD. There are 20 producers in the Section. Half of these wells are shut-in due to high gas-oil ratio. Production has been mainly by depletion drive and only 22% of the proven reserves have been recovered. Considerable reserves still appear to exist in this Section and these could be recovered by waterflooding.

The plan to expand the waterflood project in this Section was analyzed with the Craig-Geffen-Morse Model, which indicated additional recovery of up to 19.8 million barrels. Production will peak at 4,168 BOPD at a water injection rate of 7,500 B/D.

MBB/W31S SANDS
34S WATERFLOOD EXPANSION PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$43.5 Million	$67.0 Million
Operating Cost:	$3.6 Million	$10.2 Million
Investment:	$6.6 Million	$7.4 Million
Total Costs:	$10.2 Million	$17.6 Million
Net Revenue:	$33.2 Million	$49.5 Million
Net Present Value (@ 10%)	$23.6 Million	$29.3 Million
Recovery:		
Oil (MMB)	2.1	2.7
Natural Gas (BCF)	1.8	2.8
Oil Equivalent (MMBOE)	2.5	3.3

Figure 11

MBB/31S SANDS
33S WATERFLOOD EXPANSION PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$24.4 Million	$47.2 Million
Operating Cost:	$2.4 Million	$11.9 Million
Investment:	$7.6 Million	$8.9 Million
Total Costs:	$10.0 Million	$20.8 Million
Net Revenue:	$14.4 Million	$26.4 Million
Net Present Value (@ 10%)	$8.6 Million	$12.7 Million
Recovery:	1.0	1.5
Natural Gas (BCF)	1.0	2.1
Oil Equivalent (MMBOE)	1.2	2.0

Figure 12

This project has been proposed in two phases. In FY'90, Phase I is expected to require drilling four new wells (311-32S, 323- 32S, 343-32S, 363-32S), deepening of three wells (312-32S, 332- 32S, 353-32S (completed FY'89) and remedial work on four wells (353-32S, 384-32S, 373A-31SA, 373-32S). For Phase II in FY'91, five new wells (334-32S, 344X-32S, 354-32S, 374-32S, 385-32S) will be drilled and remedial work is planned for four wells (333-32S, 355-32S, 364-32S, 386-32S).

This project and the earlier ones presented for Sections 33S and 34S are designed to reduce gradually the secondary gas cap in these sections and eventually force the gas into the gas cap in Section 31S.

The results from the evaluation of the32S Waterflood Expansion Project are shown in Table 6. The key economic indicators are summarized in Figure 13.

Several facilities modifications are planned between FY'89 and FY'95 which would benefit all the cases discussed above. The closed loop gas lift compressor would require additional costs of $425,000 in FY'89. An 18G booster pump spare would be installed to provide additional capacity in FY'89 at a cost of $300,000.

MBB/W31S SANDS
32S WATERFLOOD EXPANSION PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$146.7 Million	$520.3 Million
Operating Cost:	$7.6 Million	$55.3 Million
Investment:	$13.1 Million	$25.1 Million
Total Costs:	$20.7 Million	$80.4 Million
Net Revenue:	$126.1 Million	$439.9 Million
Net Present Value (@ 10%)	$73.5 Million	$159.8 Million
Recovery:		
Oil (MMB)	5.4	14.4
Natural Gas (BCF)	9.4	18.1
Oil Equivalent (MMBOE)	7.3	18.1

Figure 13

Due to increased water production in response to the waterflood projects, it is environmentally preferable to re-inject the produced water in place of Tulare water. The project to inject produced water would start in FY'89 and will be completed in FY'94 at a total allocated cost of $10.0 million for MBB/W31S Sands. This includes the costs to convert to the injection of produced water, the improvement of the 18G waste water tank and development of an alternate waste water disposal system. And in FY'89, a new pump train is expected to be installed at the 33S Injection Plant at cost of $400,000 to meet current water injection needs. In FY'90 the installation of the 4G closed loop gas lift compressors will begin at a total cost of $1,673,000.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The annual reservoir development activities planned for MBB/W31S Sands would achieve maximum efficient rate of production by optimizing the peripheral waterflood project. The activities would include drilling new wells to take advantage of the mobile oil bank and converting watered-out wells to injectors. The waterflood expansion projects in Sections 32S, 33S and 34S are designed to enhance the waterflood process in these sections in view of the low permeability of their sands. The attached Table 7 shows the number of remedials and development projects per year.

FY'89

Reservoir development activities in this year would concentrate on drilling wells in the oil bank in Section 34S. In this year, SSI is expected to complete their work on the comprehensive geologic description of the 31S Stevens reservoir. This work should provide more insight into these reservoirs and result in changes in their management.

FY'90

Expansion of the 32S waterflood project is planned to begin. The results from the 31S Structure Study are expected to influence the management strategies for these reservoirs.

FY'91

Several studies are expected to be initiated by SSI on MBB/W31S which could provide detailed plans on how to operate the waterflood project in the late stages. Especially, the reservoirs would be studied in greater detail with respect to the subject of bypassed oil. Expected recommendations are expected to include areas to drill for recovery of such reserves.

FY'92 - FY'95

During these years, the waterflood project would be in its late stages. Reservoir development activities will concentrate on location of bypassed oil especially in low permeability sands. Special efforts would be made to produce these reserves by performing water isolations on several producers or performing other types of recompletions as needed. It is expected that production costs would escalate due to high water-cuts and the difficulty of producing additional oil from the reservoirs.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
MBB/W318 SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	32922	21923	58961	118008	0	0	16166	5290	980	2467	980	8233
1990	28317	23232	61201	127700	0	0	17227	5274	1087	3490	1087	4938
1991	26791	26447	69159	142000	0	0	19407	5072	1348	2461	1339	9736
1992	26260	29046	68270	166500	0	0	22199	4240	1926	2075	1924	9585
1993	25533	31317	69703	176500	0	0	23817	4342	2125	1557	2136	11918
1994	24738	33760	67067	176500	0	0	24436	4233	2163	1587	2155	12190
1995	23815	36458	64321	176500	0	0	25090	4499	2284	0	2283	12352
SUBTOTAL *	68757	73797	167419	395553	0	0	148342	32950	11913	13637	11904	68952
1996-2017 *	56537	520549	271305	1378423	0	0	711427	40913	4647	0	4647	26777
TOTAL *	125294	594346	438724	1773976	0	0	859769	73863	16560	13637	16551	95729

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	182291	36272	14154	232717	34116	31015	198601	180546	16344
1990	166095	41788	15414	223296	33103	27358	190193	157184	14828
1991	169074	52832	19294	241200	39363	29574	201837	151643	14855
1992	179238	57922	25030	262190	41949	28652	220241	150428	14596
1993	188441	65028	27894	281363	45895	28497	235468	146207	14435
1994	197201	67329	28635	293166	46764	26397	246402	139087	13952
1995	200796	73921	31781	306498	46508	23866	259990	133416	13413
SUBTOTAL	1283136	395092	162202	1840430	287698	195359	1552732	1058511	102423
1996-2017	1982921	1471000	631469	4085391	788411	157953	3296980	810394	111092
TOTAL	3266057	1866092	793671	5925821	1076109	353312	4849712	1868905	213515

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
MBB/W31S SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	30887	21515	56500	113208	0	0	15500	5290	630	2067	630	0
1990	25636	21883	57000	120000	0	0	16082	4643	1015	3490	1015	0
1991	21278	22466	58206	120000	0	0	16266	4328	974	2461	965	0
1992	17661	21771	50634	120000	0	0	16020	3071	1078	2075	1077	0
1993	14658	20022	43836	120000	0	0	15609	2712	1259	1557	1270	0
1994	12167	18393	35518	120000	0	0	15127	2573	1282	1587	1274	0
1995	10098	16887	28629	120000	0	0	14733	2809	1387	0	1386	0
SUBTOTAL *	48321	52172	120568	304121	0	0	109337	25426	7625	13237	7617	0
1996-2017 *	17697	230395	117779	963600	0	0	415028	24973	2671	0	2671	0
TOTAL *	66018	282567	238347	1267721	0	0	524365	50399	10296	13237	10288	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	171023	34758	13563	219344	24117	21925	195227	177479	15421
1990	150369	38919	14356	203644	26245	21690	177399	146611	13541
1991	134282	44465	16239	194986	24994	18779	169992	127717	12039
1992	120545	42959	18564	182068	23321	15928	158747	108427	10163
1993	108180	40896	17543	166619	22407	13913	144212	89544	8568
1994	96990	35657	15165	147812	21843	12330	125969	71106	7048
1995	85141	32902	14145	132189	20315	10425	111874	57409	5787
SUBTOTAL	866530	270556	109575	1246662	163242	114990	1083420	778293	72567
1996-2017	572762	640767	275070	1488599	445343	85305	1043256	279584	41381
TOTAL	1439292	911323	384645	2735261	608585	200295	2126676	1057877	113948

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
DEVELOPMENT/DEEPENING PROJECT
MBB/W31S SANDS
(NOMINAL DOLLARS)

FY		OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989		596	313	1097	0	0	0	127	0	0	400	0	3295
1990		832	537	1719	0	0	0	201	0	0	0	0	826
1991		3167	2508	7342	10000	0	0	1657	0	299	0	299	5422
1992		4548	4420	11829	30000	0	0	3852	248	310	0	308	4249
1993		6643	7531	19389	40000	0	0	5658	434	787	0	787	11918
1994		8007	10590	24669	40000	0	0	6515	442	801	0	801	12190
1995		8812	13598	28659	40000	0	0	7292	450	816	0	816	12352
SUBTOTAL	*	11901	14416	34567	58400	0	0	25302	1574	3013	400	3011	50252
1996-2017	*	28686	222587	142756	321200	0	0	232781	2169	1721	0	1721	26777
TOTAL	*	40587	237003	177323	379600	0	0	258083	3743	4734	400	4732	77029

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	3300	675	263	4238	3822	3474	416	378	298
1990	4880	1174	433	6487	1027	849	5460	4512	430
1991	19986	5609	2048	27643	7677	5768	19966	15001	1695
1992	31042	10036	4337	45415	8967	6125	36448	24894	2528
1993	49027	18089	7759	74875	19584	12160	55291	34331	3848
1994	63829	24765	10533	99127	20749	11712	78378	44242	4733
1995	74298	32937	14160	121395	21726	11149	99669	51146	5320
UBTOTAL	246362	93285	39533	379180	83552	51237	295628	174504	18852
96-2017	1059813	781535	335505	2176854	265169	54843	1911685	434775	57392
TOTAL	1306175	874820	375038	2556034	348721	106080	2207313	609279	76244

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4
LONG RANGE PLAN
348 WATERFLOOD EXPANSION PROJECT
MBB/W31S SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	1366	94	1182	4500	0	0	505	0	350	0	350	4115
1990	1145	188	1064	4500	0	0	510	0	0	0	0	0
1991	939	226	851	4500	0	0	504	242	0	0	0	0
1992	770	271	681	4500	0	0	502	497	0	0	0	0
1993	631	406	545	4500	0	0	513	508	0	0	0	0
1994	518	609	436	4500	0	0	536	259	0	0	0	0
1995	424	914	349	4500	0	0	578	263	0	0	0	0
SUBTOTAL *	2114	988	1864	11498	0	0	3648	1769	350	0	350	4115
1996-2005 *	608	4406	972	16425	0	0	6519	819	0	0	0	0
TOTAL *	2722	5394	2836	27923	0	0	10167	2588	350	0	350	4115

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	7564	727	284	8575	5320	4837	3255	2959	585
1990	6716	726	268	7711	510	421	7201	5951	496
1991	5926	650	237	6813	746	561	6067	4558	405
1992	5256	578	250	6083	999	682	5084	3473	331
1993	4657	508	218	5384	1021	634	4363	2709	270
1994	4129	438	186	4753	795	449	3958	2234	221
1995	3575	401	172	4148	841	432	3307	1697	180
SUBTOTAL	37823	4028	1615	43467	10232	8016	33235	23581	2488
1996-2005	17706	4097	1759	23562	7338	2363	16224	5674	804
TOTAL	55529	8125	3374	67029	17570	10379	49459	29255	3292

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 5
LONG RANGE PLAN
338 WATERFLOOD EXPANSION PROJECT
MBB/W31S SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0	0	0	0
1992	1170	714	1092	4500	0	0	619	0	462	0	462	5336
1993	786	864	702	4500	0	0	601	254	0	0	0	0
1994	528	1050	558	4500	0	0	605	517	0	0	0	0
1995	312	1278	408	4500	0	0	621	527	0	0	0	0
SUBTOTAL *	1021	1426	1007	6570	0	0	2446	1298	462	0	462	5336
1996-2007 *	527	8575	1087	19710	0	0	9422	1390	0	0	0	0
TOTAL *	1548	10001	2094	26280	0	0	11868	2688	462	0	462	5336

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0
1992	7986	926	400	9313	6879	4698	2434	1663	507
1993	5801	655	281	6737	855	531	5882	3652	338
1994	4209	560	238	5007	1122	634	3885	2193	234
1995	2631	469	202	3301	1148	589	2153	1105	144
SUBTOTAL	20627	2610	1121	24358	10004	6452	14354	8613	1223
1996-2007	15934	4818	2069	22821	10812	3181	12009	4073	746
TOTAL	36561	7428	3190	47179	20816	9633	26363	12686	1969

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 6
LONG RANGE PLAN
328 WATERFLOOD EXPANSION PROJECT
MBB/W31S SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	73	1	182	300	0	0	34	0	0	0	0	823
1990	704	624	1418	3200	0	0	434	631	72	0	72	4112
1991	1407	1247	2761	7500	0	0	979	503	75	0	75	4314
1992	2111	1871	4035	7500	0	0	1206	424	77	0	77	0
1993	2814	2494	5231	7500	0	0	1436	434	79	0	79	0
1994	3518	3117	5886	7500	0	0	1651	442	80	0	80	0
1995	4168	3781	6276	7500	0	0	1866	450	82	0	82	0
SUBTOTAL *	5400	4794	9413	14965	0	0	7606	2884	465	0	465	9249
1996-2016 *	9017	54588	8712	57488	0	0	47677	11560	254	0	254	0
TOTAL *	14417	59382	18125	72453	0	0	55283	14444	719	0	719	9249

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	404	112	44	560	857	779	-297	-270	40
1990	4129	968	357	5455	5321	4397	134	111	361
1991	8879	2109	770	11759	5946	4468	5813	4367	716
1992	14409	3423	1479	19311	1784	1219	17527	11971	1067
1993	20768	4880	2093	27742	2028	1259	25714	15966	1411
1994	28044	5909	2513	36466	2253	1272	34213	19312	1716
1995	35142	7213	3101	45456	2480	1273	42976	22053	1982
SUBTOTAL	111775	24614	10357	146749	20669	14667	126080	73510	7293
1996-2016	316684	39785	17067	373532	59745	12261	313787	86284	10769
TOTAL	428459	64399	27424	520281	80414	26928	439867	159794	18062

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 7

MBB/W31S SANDS
(NUMBER OF REMEDIAL/DEVELOPMENT PROJECTS PER YEAR)

FISCAL YEAR

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-2023	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	5	5	8	6	5	5	5	168	207
b. RECOMPLETIONS	31	26	22	15	13	12	13	59	191
c. ARTIFICIAL LIFT	9	14	13	14	16	16	17	31	130
d. DEEPENINGS	0	0	0	0	0	0	0	0	0
e. NEW WELLS	0	0	0	0	0	0	0	0	0
SUB-TOTAL	45	45	43	35	34	33	35	258	528
2. DEVELOPMENT DRILLING/DEEPENING:									
a. STIMULATIONS	0	0	0	1	1	1	1	5	9
b. RECOMPLETIONS	0	0	0	1	2	2	2	9	16
c. ARTIFICIAL LIFT	0	0	4	4	10	10	10	20	58
d. DEEPENINGS	0	0	8	7	5	5	5	12	42
e. NEW WELLS	4	1	2	1	10	10	10	20	58
SUB-TOTAL	4	1	14	14	28	28	28	66	183
3. 34S WATERFLOOD EXPANSION PROJECT:									
a. STIMULATIONS	0	0	1	2	2	1	1	3	10
b. RECOMPLETIONS	0	0	1	2	2	1	1	3	10
c. ARTIFICIAL LIFT	5	0	0	0	0	0	0	0	5
d. CONVERSIONS	3	0	0	0	0	0	0	0	3
e. NEW WELLS	5	0	0	0	0	0	0	0	5
SUBTOTAL	13	0	2	4	4	2	2	6	33
4. 33S WATERFLOOD EXPANSION PROJECT:									
a. STIMULATIONS	0	0	0	0	1	2	2	5	10
b. RECOMPLETIONS	0	0	0	0	1	2	2	5	10
c. ARTIFICIAL LIFT	0	0	0	6	0	0	0	0	6
d. CONVERSIONS	0	0	3	0	0	0	0	0	3
e. NEW WELLS	0	0	0	6	0	0	0	0	6
SUBTOTAL	0	0	3	12	2	4	4	10	35
5. 32S WATERFLOOD EXPANSION PROJECT:									
a. STIMULATIONS	0	0	0	1	1	1	1	21	25
b. RECOMPLETIONS	0	1	2	2	2	2	2	42	53
c. ARTIFICIAL LIFT	0	1	1	1	1	1	1	3	9
d. DEEPENINGS	1	2	0	0	0	0	0	0	3
e. CONVERSIONS	0	3	1	0	0	0	0	0	4
f. NEW WELLS	0	4	5	0	0	0	0	0	9
SUBTOTAL	1	11	9	4	4	4	4	66	103
TOTAL:	63	57	71	69	72	71	73	406	882

24Z SANDS

The 24Z Sands Reservoir is one of many Stevens Zone Reservoirs producing at NPR-1 (See Location Map, Figure 1 and Cross Section, Figure 3).The reservoir covers a productive area of approximately 603 acres and was estimated to originally contain 65.4 million barrels of recoverable oil and 36.4 billion cubic feet of gas cap gas. Both water and gas injection have historically been used to support reservoir pressure. In FY'87, a full-scale peripheral waterflood was initiated to improve recovery and increase production rates. As water injection rates increased, gas injection was curtailed and eventually ceased in May 1988. Cumulative production through September 1988 was 32.0 million barrels with remaining reserves of 33.4 million barrels based on the Stevens Equity Study. This compares with remaining recovery of 26.1 million barrels of oil generated by this plan.

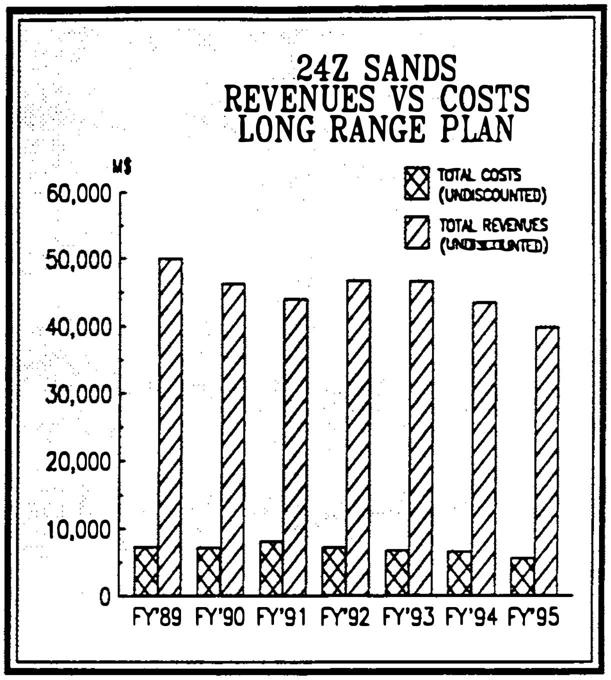


Figure 2

The Total Development Case for the 24Z Sands Reservoir consists of a Maintenance Case and a Development Drilling Project. The Total Development Case is projected to provide $317 million in undiscounted revenues between FY'89 and FY'95, with associated total costs of $48 million. Annual revenue and cost values are displayed in Figure 2.

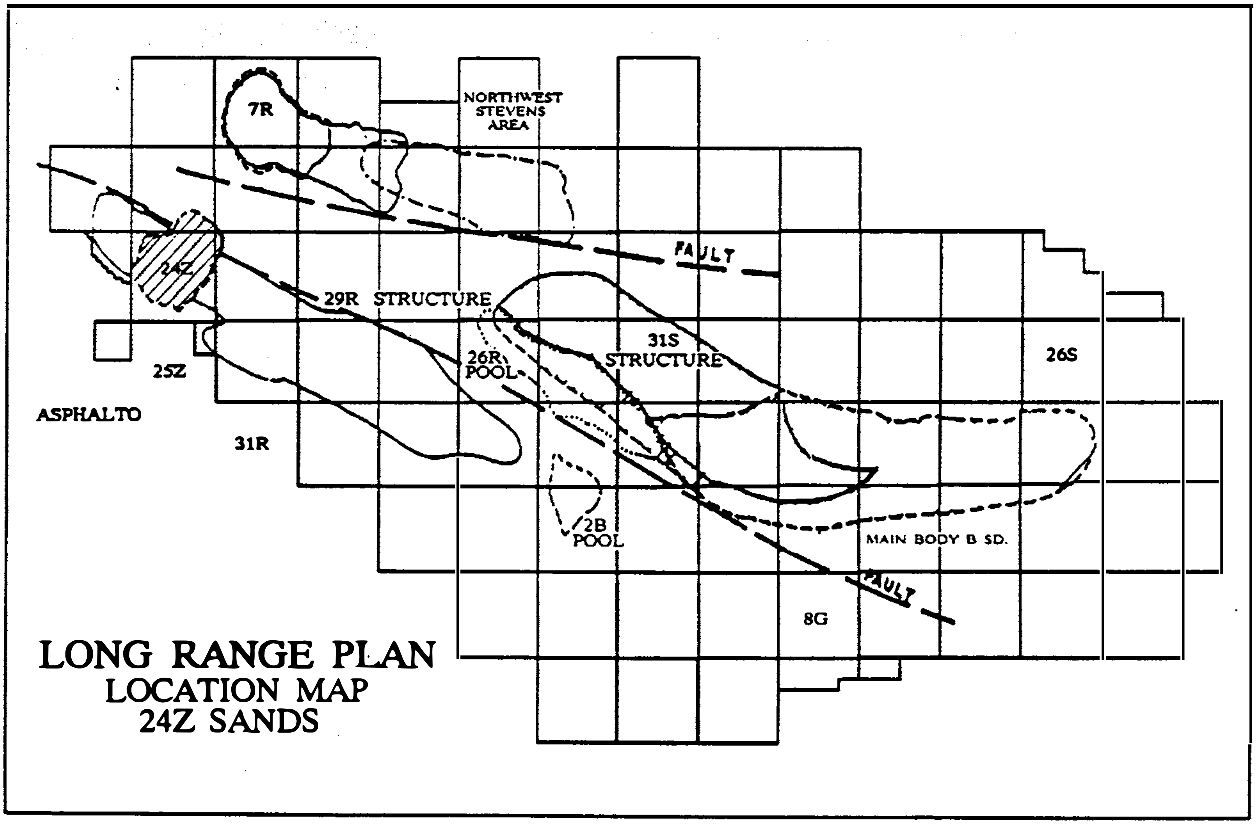


Figure 1

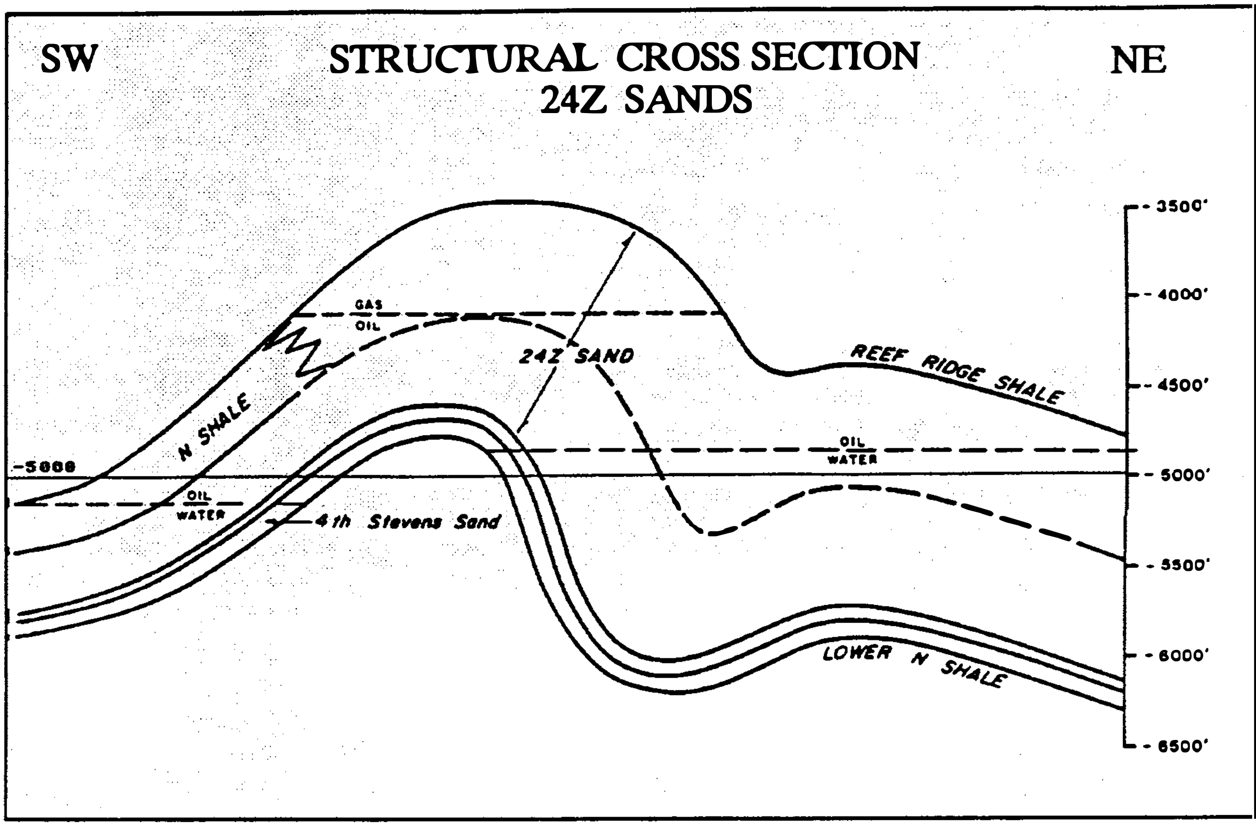


Figure 3

Shown in Figure 4 is an economic summary of the Total Development Case for both the seven year plan period and FY'89 to the economic limit.

Estimated oil, gas and oil equivalent recovery from the Total Development Case is also presented.

The estimated oil reserves for the 24Z Sands shown in Figure 5 are from the "Stevens Zone Estimated Recoverable Oil and Third Revision of Percentage Participations as of November 20, 1942." This estimate is compared with the Long Range Plan Maintenance and Total Development Cases. It should also be noted that the 24Z Structure had an original gas cap containing an estimated 36.4 BCF of gas.

The Maintenance Case consists of remedial and facility activity in support of continued waterflooding opera-

24Z SANDS
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$317.4 Million	$1,364.1 Million
Operating Cost:	$37.0 Million	$144.8 Million
Investment:	$11.2 Million	$15.8 Million
Total Costs:	$48.2 Million	$160.6 Million
Net Revenue:	$269.2 Million	$1,203.5 Million
Net Present Value (@ 10%)	$188.9 Million	$314.3 Million
Recovery:		
Oil (MMB)	13.7	26.1
Natural Gas (BCF)*	19.4	56.2
Oil Equivalent (MMBOE)	17.8	37.6

* Total Production Minus Injection

Figure 4

24Z SANDS
TOTAL DEVELOPMENT CASE

	EQUITY STUDIES	LONG RANGE PLAN MAINT.	LONG RANGE PLAN TOTAL
Original-Oil-In-Place (MMB):	145.4	----	----
Estimated Recoverable Oil (MMB):	65.4	56.4	58.1
Cumulative Production 9/30/88 (MMB):	32.0	32.0	32.0
Remaining Reserves:			
Oil (MMB)	33.4	24.4	26.1
Natural Gas (BCF)	----	53.7	56.2
Oil Equivalent (MMBOE)	----	35.5	37.6
Economic Limit (BOPD, YEAR):	----	52/2025	52/2025

Figure 5

tions. Total expenditures of $45.4 million are anticipated between FY'89-'95 with resulting net revenues of $253.2 million. The Development Drilling Project consists of a single redrill (Well 352-24Z) in FY'89 and one new well in FY'91. Associated costs for this project are expected to be $2.8 million with net revenues totalling $16.0 million over the next seven year period.

The current reservoir operating strategy is continued peripheral water injection at rates sufficient to maintain reservoir pressure. It is proposed that crestal gas injection be reinitiated as wells completed near the original gas-oil contact are observed to resaturate with oil. This measure should be taken to prevent reserve losses associated with displacement of oil into the primary gas cap. Historical production from the 24Z Reservoir and projected performance to the economic limit is shown in Figures 6 and 7.

RESERVOIR DESCRIPTION

The 24Z Sand is a channel sand approximately one mile wide which crosses the 29R Structure in Sections 24Z and 13Z (see Location Map, Figure 1). These sands trend in a SW-NE direction and grade laterally into the N Shale along the channel edges (see Cross-

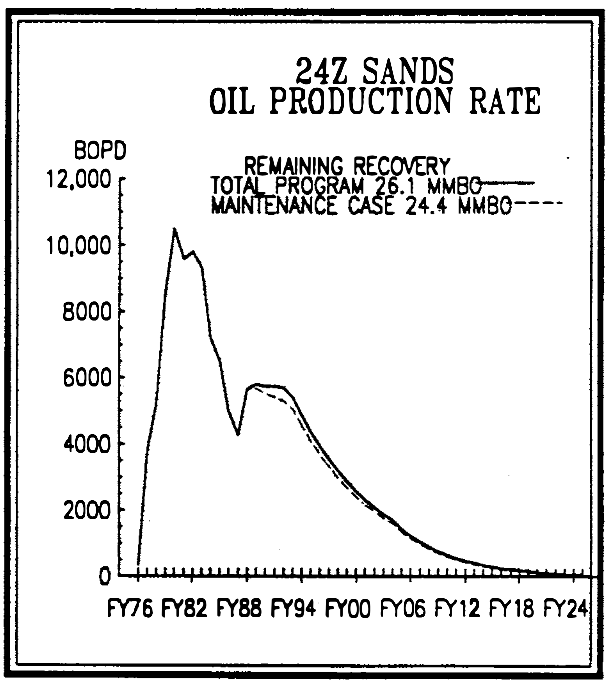


Figure 6

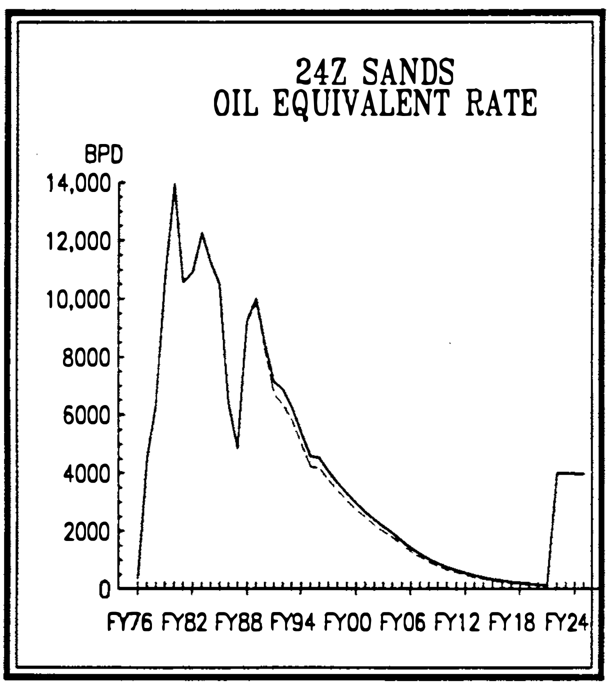


Figure 7

24Z SANDS
RESERVOIR CHARACTERISTICS

Porosity (%):	22.7	Production Wells (#):	29 (Active)
Water Sat. (%):	12.3	Injection Wells (#):	2 gas
Air Perm. (md):	73		13 water
Oil Gravity (API):	36	Top Pay (Ft-VSS):	3571
Oil Form. Vol. Fact.(RB/STB):	1.43	Max Pay (Ft.):	900
Oil Viscosity (cp):	0.502	Pay Area (AC):	603
Initial Press. (psi):	2661	Pay Volume (AF):	161,877
Bubble Point Press.(psi):	2345	GOC (Ft-VSS):	4050 (Original)
Current Press. (psi):	2104	WOC (Ft-VSS):	
Press. Datum (Ft-VSS):	5000	North Flank	4850 (Original)
		South Flank	5120-5200 (Original)

Figure 8

Section, Figure 3). Subsequent folding of the western Elk Hills anticline developed two anticlinal structures within the 24Z Sand. These are referred to as the 13Z and 24Z Structures. Oil-water contacts vary across the reservoir but are generally lower along the South Flank of the 24Z Structure. As is characteristic of a turbidite deposit, the 24Z Sand consists of a series of smaller sand units with interbedded shales and siltstones.

Recent mapping has divided the massive 24Z Sand into four major intervals (1st, 2nd, 3rd, and 4th Stevens Sands). Combined, these sands are more than 1000 feet thick along the steeply dipping flanks of the 24Z and 13Z Structures. Reservoir characteristics are displayed in Figure 8.

Although discovered in 1946, very little oil was produced from the 24Z Reservoir until open-up in 1976. Upon continued development, production rates steadily increased to a peak level of approximately 12,000 BOPD in 1979. In 1983, oil production rates began a more rapid decline as producing gas-oil ratios sharply increased. Both gas and water injection have been used as a means to support reservoir pressure and augment solution gas drive and gravity drainage mechanisms. In 1987, conversion to a full-scale peripheral waterflood was initiated based on a Waterflood Feasibility Model developed by SSI. When water injection rates increased as a result of the expansion, gas injection was curtailed to approximately 4000 MCFD and eventually ceased in May 1988. Since discovery, a total of 57 wells have been drilled into the 24Z Reservoir. Currently there are 29 active producers (including commingled 24Z Sand/24Z Shale producers), in addition to 13 water injectors and two idle gas injectors.

The 24Z Sand production facilities include the 1-24Z, 4-24Z and 4- 19R tank settings. In addition to serving 24Z, these settings also accommodate production from the 29R/24Z Shale Reservoir. Water injection facilities consist of two separate pump stations, one in Section 17R and the other in Section 24Z. Three pump trains at the 17R Pump Station supply approximately 35,000 BWPD of Tulare Source water to the 24Z Waterflood and 19,000 BWPD to the Northwest Stevens Reservoir at a pressure of 3000 psi. These pumps are currently operating very near their design capacity of 60,000 BWPD. Injection facilities in Section 24Z consist of two centrifugal pumps with a capacity of 9000 BWPD @ 2150 psi. This facility currently supplies approximately 6000 BWPD of Stevens Zone produced water to three injectors along the South Flank of the 24Z Structure.

RESERVOIR STUDIES

During FY'89, Scientific Software-Intercomp (SSI) will initiate a geological and petrophysical study of the 24Z Reservoir. The study will couple the existing geologic description developed by BPOI with petrophysical properties for each of the geologic layers to provide a more complete reservoir description. Though currently not scheduled, it is anticipated that this reservoir description will be utilized in a FY'90 design level simulation of the 24Z Reservoir. This simulation would be useful in determining the best operating strategy for the reservoir. An earlier model developed by SSI as a waterflood feasibility model did not contain the reservoir description necessary to adequately predict reservoir performance.

RESERVOIR DEVELOPMENT STRATEGY

During the seven year period covered by this plan, the strategy for the 24Z Reservoir will be to:

1. Maintain production by continued peripheral water injection. This is anticipated to require remedial, drilling, and facility support through FY'95. Emphasis will be placed on meeting or exceeding water injection requirements to balance reservoir withdrawals, maintain reservoir pressure, and offset the potential migration of injected water off-structure. Pressure maintenance is critical in order to prevent reserve losses associated with oil shrinkage in addition to the formation of higher free gas saturations in the oil band.

2. Guard against and prevent the potential loss of reserves associated with displacement of oil into the primary gas cap.

3. Monitor possible off-structure effects of the 24Z Waterflood in the adjacent 24Z Shale and Asphalto Reservoirs.

The above stated objectives have been considered in two scenarios within the Total Development Case. These scenarios include the Maintenance Case and a Development Drilling Project.

Figure 9 shows the assumptions used for the preparation of the Total Development Case. A more detailed breakdown of production, cost and revenue is provided in attached Economics Table 1.

24Z SANDS
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/Yr)
Stimulations (Acidizing producers and injectors)	90,000	150	15
Recompletions (Water isolation, perf. additions)	100,000	50	10
Artificial Lift	150,000	--	--
Conversions	200,000	--	--
Redrill	550,000	250	10
New Well	875,000	250	10
Facilities			
- 17R Additional Pump Capacity	402,200	--	--
- Conversion to Produced Water Injection	3,484,000	--	--

Figure 9

The Maintenance Case represents projections based on continued peripheral water injection including remedial and facility activity to support existing operations. Although water injection rates were forecasted to meet or slightly exceed voidage replacement requirements, declining oil production, coupled with decreasing gas-oil ratios are anticipated to reduce water injection requirements during this plan period. Based on volumetric calculations and projected free gas production levels, reinitiation of crestal gas injection at a rate of 7000 MCF/D was assumed by FY'90 to prevent displacement of oil into the primary gas cap.

Maintenance Case remedial efforts consist of numerous artificial lift installations, acid stimulations, recompletions, and conversions. Artificial lift is expected to be employed as watercuts steadily increase and wells become incapable of sustained flow. When possible, the installation of equipment would be completed prior to the wells equalizing in an effort to minimize both downtime and the resultant impact on production. Stimulations will be performed on both producers and injectors to remove scale build-up and/or formation damage associated with drilling and workover operations. Recompletions would involve perforation additions to recover potential reserves behind pipe in addition to the isolation of water in wells where breakthrough has been observed. Isolations of this type would be required to prevent unnecessary cycling of injected water. Conversion of producers to injectors is also anticipated as wells updip of the current injectors water out. Conversion of selected wells is expected to result in improved areal sweep efficiencies and hence greater recovery from waterflooding operations.

Maintenance Case projections also include surface facility expenditures through FY'94. Expenditures are anticipated for the purchase and installation of additional pump capacity at the 17R Injection Plant (FY'91) and conversion to Stevens produced water injection (FY'89-'94). Purchase and installation of an additional pump train at the 17R Injection Plant is recommended as back-up capacity for the three pump trains currently in operation. As previously discussed, the 17R Injection Plant currently operates near its design capacity with no stand-by capacity available. Conversion of the 24Z Waterflood to Stevens produced water is a result of plans to phase-out Tulare Zone disposal. Injection of produced water into the 24Z Reservoir not only serves as an environmentally acceptable system with which to dispose of water, but also has an eco-

24Z SANDS MAINTENANCE CASE	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$298.6 Million	$1,300.0 Million
Operating Cost:	$ 35.9 Million	$136.4 Million
Investment:	$ 9.5 Million	$14.0 Million
Total Costs:	$ 45.4 Million	$150.4 Million
Net Revenue:	$253.2 Million	$1,149.6 Million
Net Present Value (@ 10%)	$178.8 Million	$294.8 Million
Recovery:		
Oil (MMB)	13.0	24.4
Natural Gas (BCF)*	18.2	53.7
Oil Equivalent (MMBOE)	16.8	35.5

* Total Production Minus Injection

Figure 10

nomic benefit associated with utilization of produced water for replacement of Tulare water injection.

Figure 10 is a summary of economic and recovery data for the Maintenance Case. Further details are supplied in attached Economics Table 2.

The Development Drilling Project includes incremental production and injection requirements associated with the redrill of Well 352-24Z in FY'89 in addition to one new producer in FY'91. These wells should be drilled to improve recovery from the 24Z Reservoir. More specifically, Well 352RD-24Z would further develop the second and third Stevens Sand Intervals along the North Flank of the 24Z Structure. These sand intervals have proven highly productive in other areas of the reservoir but are undeveloped along portions of the North Flank. Additional funding for the purchase and installation of artificial lift equipment is also included. A summary of economic and recovery data for the Development Drilling Project is provided in Figure 11, while additional details are included in attached Economics Table 3.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

Reservoir Development Activities are expected to be focused primarily on water flood surveillance and optimization. Activities are expected to include remedial operations, drilling, and facility support in addition to reservoir studies and ongoing performance monitor-

24Z SANDS DEVELOPMENT DRILLING PROJECT	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$18.8 Million	$64.1 Million
Operating Cost:	$1.0 Million	$8.3 Million
Investment:	$1.8 Million	$1.8 Million
Total Costs:	$2.8 Million	$10.1 Million
Net Revenue:	$16.0 Million	$54.0 Million
Net Present Value (@ 10%)	$10.2 Million	$19.5 Million
Recovery:		
Oil (MMB)	0.8	1.7
Natural Gas (BCF)	1.2	2.5
Oil Equivalent (MMBOE)	1.0	2.2

Figure 11

ing. Annual management activities are summarized below while details of drilling and remedial support are provided in attached Table 4 and Table 5.

FY'89

During FY'89, a detailed geological and petrophysical study will be initiated by SSI. The study is expected to extend the existing reservoir description to include petrophysical properties for each of the geologic layers. Results of the study are anticipated to include layer maps of average effective porosity, net pay, average water saturation, permeability, and hydrocarbon pore volume. The resultant product should be a complete reservoir description with a geological and petrophysical database of sufficient detail to be used for design level reservoir simulation. Data obtained from this study can also be used to determine better estimates of remaining reserve potential.

As the floodfront continues to advance through the reservoir, free gas saturation should be reduced and uphole sands should resaturate with oil. In order to evaluate the extent of resaturation, FY'89 activity includes continued periodic production testing of shut-in high GOR wells and isolated high GOR intervals. This activity was initiated in FY'88 upon cessation of gas injection. When resaturation is observed to be occurring in regions near the original gas-oil contact, it is proposed that gas injection be reinitiated to prevent reserve losses associated with displacement of oil into the primary gas cap. Reservoir management activities should also include pressure monitoring of selected wells in the adjacent Asphalto and 24Z Shale Reservoirs. This monitoring would be performed in an effort to help determine whether or not off- structure migration of injected fluid is occurring. Knowledge of migration is critical in assessing the effectiveness of the water injection program and in maintaining the appropriate voidage balance. Waterflood surveillance activity initiated with flood start-up in FY'87 will continue through FY'95. Surveillance tools utilized in this effort include production logs, injection surveys, pressure surveys, and geochemical analyses. This information, together with results obtained from the SSI study, are expected to be utilized to help track floodfront movement, identify high permeability "thief" zones between producers and injectors, evaluate displacement efficiencies, and determine the effectiveness of water injection in supporting reservoir pressure. Recommendations to alter injection profiles and/or rates in addition to recommendations for remedial and drilling activity would be based on analysis of these data.

Remedial activity in support of Maintenance Case operations includes artificial lift installations, stimulations, and recompletions. In addition, one redrill, Well 352RD-24Z, will be performed in FY'89 as part of the Development Drilling Project. As previously discussed, this well would further exploit the second and third Stevens Sand Intervals along the North Flank of the 24Z Structure. Facility activity in FY'89 includes initiation of the project to convert the 24Z Waterflood (in addition to a portion of the 31S and Northwest Stevens Waterflood projects), from Tulare Source injection to Stevens produced water injection. A study is also anticipated to determine the feasibility of installing a closed- loop gas lift system for the 24Z and 29R Reservoirs. As this project is currently in the evaluation stage, no funding is provided in this plan.

FY'90

Having completed their geological and petrophysical description in FY'89, SSI is anticipated to initiate a full-field design level simulation of the 24Z Reservoir in FY'90. The simulation would be used to determine the most economically attractive operating strategy for the reservoir. Simulation cases would likely include predictions assuming a continuation of the current operating method, various injection rates and operating limits of gas-oil and water-oil ratio, reinitiation of crestal gas injection, and partial pressure maintenance. An earlier Waterflood Feasibility Model developed by SSI was designed not to contain the geological and petrophysical description necessary to adequately model reservoir performance but was used to evaluate the feasibility of waterflooding this reservoir.

FY'90 activity also includes remedial support of both the Maintenance Case and Development Drilling Project, in addition to continued conversion to Stevens produced water injection. Although no new wells are currently planned in FY'90, favorable results obtained from the redrill of Well 352-24Z in FY'89 may support an additional second and third Stevens Sand producer along the North Flank of the 24Z Structure.

FY'91

In addition to Maintenance Case remedials, FY'91 activity includes one new development well, continued conversion to Stevens produced water injection and the purchase and installation of an additional pump train at the 17R Injection Plant for standby capacity.

FY'92-'95

Between FY'92 and FY'95, only Maintenance Case remedial activity and continued conversion to Stevens produced water injection is planned at this time.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
24Z SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	5809	7005	21021	40114	0	0	5079	570	200	467	400	550
1990	5730	8541	15790	34524	2333	0	4912	590	207	920	414	0
1991	5738	10365	13641	32630	7000	0	5204	620	160	971	321	936
1992	5691	12030	12441	32255	7000	0	5513	637	110	720	220	0
1993	5410	12921	10944	31068	7000	0	5591	202	56	543	112	0
1994	4878	13178	9118	28653	7000	0	5404	320	57	554	114	0
1995	4390	13513	7586	26642	7000	0	5270	105	58	0	117	0
SUBTOTAL *	13741	28307	33015	82448	13627	0	36973	3044	848	4175	1698	1486
1996-2025 *	12319	108861	44871	134912	8092	0	107798	3840	243	0	488	0
TOTAL *	26060	137168	77886	217360	21719	0	144771	6884	1091	4175	2186	1486

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	32165	12932	5046	50143	7266	6606	42877	38979	3663
1990	33610	8811	3954	46374	7043	5821	39331	32505	3084
1991	36212	4011	3806	44028	8212	6169	35816	26909	2615
1992	38844	3437	4561	46842	7200	4917	39642	27076	2510
1993	39927	2382	4380	46690	6504	4038	40186	24952	2298
1994	38885	731	3893	43509	6449	3640	37060	20919	1970
1995	37014	-924	3748	39838	5550	2848	34288	17595	1679
SUBTOTAL	256657	31380	29388	317424	48224	34039	269200	188935	17819
1996-2025	449165	405061	192471	1046696	112369	21201	934327	125338	19822
TOTAL	705822	436441	221859	1364120	160593	55240	1203527	314273	37641

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
24Z SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	5667	6958	20808	39702	0	0	5022	570	200	467	400	0
1990	5506	8457	15364	33865	2333	0	4817	590	155	920	311	0
1991	5394	10214	13125	31596	7000	0	5048	620	107	971	214	0
1992	5285	11825	11832	31009	7000	0	5318	637	110	720	220	0
1993	5045	12706	10396	29916	7000	0	5405	202	56	543	112	0
1994	4549	12952	8625	27584	7000	0	5226	320	57	554	114	0
1995	4094	13276	7142	25646	7000	0	5098	105	58	0	117	0
SUBTOTAL *	12972	27882	31862	80051	13627	0	35934	3044	743	4175	1488	0
1996-2025 *	11410	101974	43507	125689	8092	0	100500	3840	243	0	488	0
TOTAL *	24382	129856	75369	205740	21719	0	136434	6884	986	4175	1976	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	31378	12801	4995	49174	6659	6054	42515	38650	3596
1990	32296	8581	3870	44746	6793	5614	37953	31366	2977
1991	34041	3617	3662	41319	6960	5229	34359	25815	2452
1992	36073	2920	4338	43331	7005	4784	36326	24811	2317
1993	37234	1871	4160	43265	6318	3923	36947	22941	2124
1994	36263	236	3683	40181	6271	3540	33910	19142	1813
1995	34519	-1435	3529	36613	5378	2760	31235	16028	1538
SUBTOTAL	241804	28591	28237	298629	45384	31904	253245	178753	16817
1996-2025	414081	397885	189391	1001356	105071	20206	896285	116019	18638
TOTAL	655885	426476	217628	1299985	150455	52110	1149530	294772	35455

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
DEVELOPMENT DRILLING PROJECT
242 SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	142	47	213	412	0	0	57	0	0	0	0	550
1990	224	84	336	659	0	0	95	0	52	0	103	0
1991	344	151	516	1034	0	0	156	0	53	0	107	936
1992	406	205	609	1246	0	0	195	0	0	0	0	0
1993	365	215	548	1152	0	0	186	0	0	0	0	0
1994	329	226	493	1069	0	0	178	0	0	0	0	0
1995	296	237	444	996	0	0	171	0	0	0	0	0
SUBTOTAL *	769	425	1153	2397	0	0	1038	0	105	0	210	1486
1996-2021 *	909	6888	1364	9222	0	0	7299	0	0	0	0	0
TOTAL *	1678	7313	2517	11619	0	0	8337	0	105	0	210	1486

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	786	131	51	968	607	552	361	328	67
1990	1314	229	85	1628	250	207	1378	1139	106
1991	2171	394	144	2709	1252	940	1457	1095	163
1992	2771	517	223	3511	195	133	3316	2265	193
1993	2694	511	219	3424	186	116	3238	2010	173
1994	2623	495	210	3328	178	101	3150	1778	156
1995	2496	510	219	3225	171	88	3054	1567	141
SUBTOTAL	14855	2787	1151	18793	2839	2137	15954	10182	999
1996-2021	35066	7176	3080	45323	7299	995	38024	9313	1184
TOTAL	49921	9963	4231	64116	10138	3132	53978	19495	2183

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4

DRILLING ACTIVITY

24Z SANDS

(NUMBER OF DRILLING WELLS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-25	TOTAL
1. DEVELOPMENT DRILLING PROJECT :									
a. NEW WELLS	0	0	1	0	0	0	0	0	1
b. REDRILLS	1	0	0	0	0	0	0	0	1
TOTAL:	1	0	1	0	0	0	0	0	2

TABLE 5

REMEDIAL ACTIVITY

24Z SANDS

(NUMBER OF REMEDIAL WELLS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-25	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	3	3	2	2	2	2	1	15	30
b. RECOMPLETIONS	3	3	2	2	0	1	0	15	26
c. ARTIFICIAL LIFT	4	3	2	2	1	1	1	4	18
d. CONVERSIONS	0	0	1	1	0	0	0	0	2
SUBTOTAL:	10	9	7	7	3	4	2	34	76
2. DEVELOPMENT DRILLING PROJECT:									
a. ARTIFICIAL LIFT	0	1	1	0	0	0	0	0	2
SUBTOTAL:	0	1	1	0	0	0	0	0	2
TOTAL:	10	10	8	7	3	4	2	34	78

The 2B Sands Reservoir is one of the smallest at Elk Hills and is being produced under a combination of natural water drive and solution gas drive. (See Location Map, Figure 1 and Cross Section, Figure 3). This reservoir has never been subjected to pressure maintenance and on the basis of a recent simulation study is not recommended for pressure maintenance.

The Total Development Case for the 2B Sands Reservoir is the Maintenance Case. It requires total costs of $6 million over FY'89 - FY'95 to continue the current production strategy and generate undiscounted revenues of $22 million. Annual revenue and cost values are displayed in Figure 2.

The economic parameters as shown in Figure 4 are a summary of the Total Development Case for the plan period and to the economic limit.

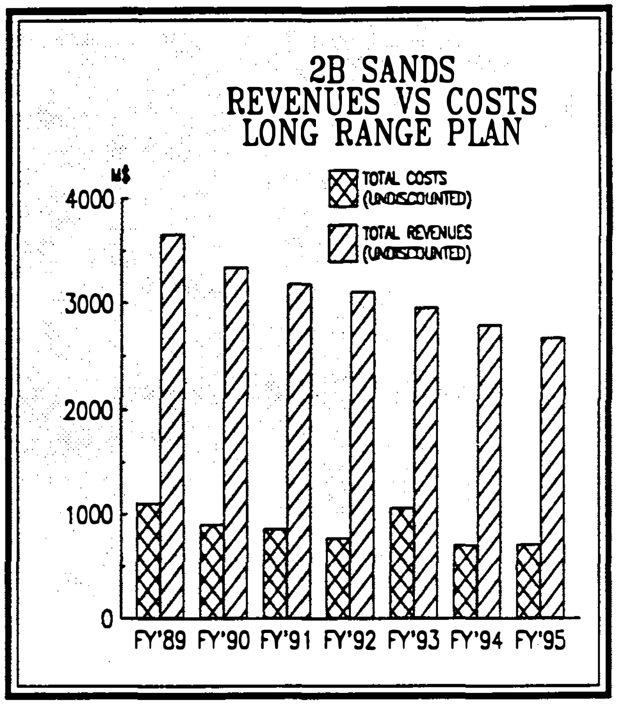


Figure 2

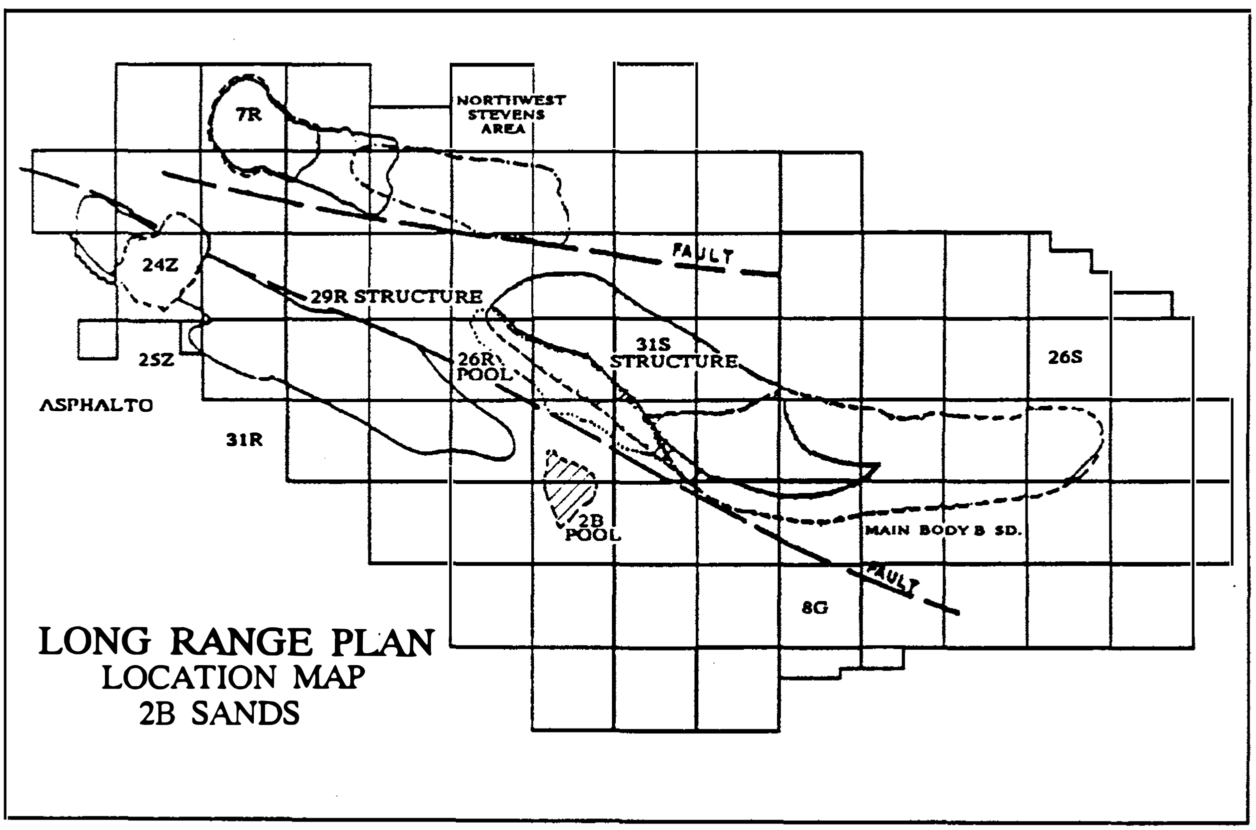


Figure 1

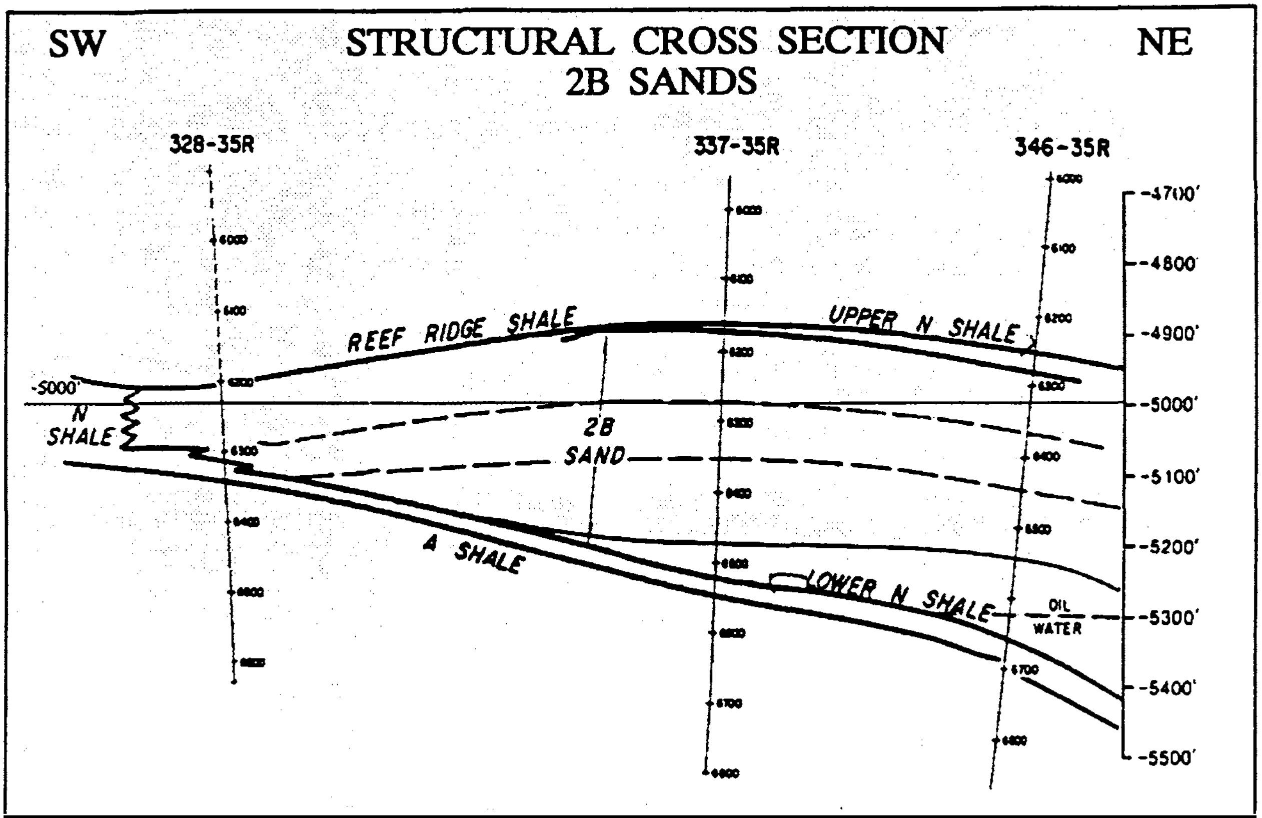


Figure 3

The recovery for the Total Development Case in terms of oil production, gas production and total oil equivalent barrels is shown in Figure 4.

The estimated oil reserves for the 2B Sands Reservoir shown in Figure 5 are from the "Stevens Zone Estimated 4.7 million barrels. Reservoir performance and Scientific Software-Intercomp (SSI) do not agree with these recoverable reserves. The SSI simulation for the Depletion Case shows 1.5 million barrels of remaining reserves and 14.8 million barrels in-place based on a geological study completed by BPOI in January 1987.

2B SANDS
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$21.7 Million	$59.5 Million
Operating Cost:	$ 4.4 Million	$24.8 Million
Investment	$ 1.6 Million	$ 3.9 Million
Total Cost	$ 6.0 Million	$28.7 Million
Net Revenue:	$15.7 Million	$30.7 Million
Net Present Value (@ 10%)	$11.3 Million	$14.8 Million
Recovery:		
Oil (MMB)	0.8	1.4
Natural Gas (BCF)	2.6	3.8
Oil Equivalent (MMBOE)	1.3	2.2

Figure 4

2B SANDS TOTAL DEVELOPMENT CASE	EQUITY STUDIES	LONG RANGE PLAN MAINT.	TOTAL
Original-Oil-In-Place (MMB):	21.5	-	-
Estimated Recoverable Gas (MMB):	8.6	5.3	5.3
Cumulative Production 9/30/88 (MMB):	3.9	3.9	3.9
Remaining Reserves:			
Oil (MMB)	4.7	1.4	1.4
Natural Gas (BCF)	---	3.8	3.8
Oil Equivalent (MMBOE)	---	2.2	2.2
Economic Limit (BOPD, YEAR):	---	43/2021	43/2021

Figure 5

Historical production from the 2B Sands Reservoir and projected performance to the economic limit is shown in Figure 6 and Figure 7.

The field activities planned over the seven year plan period are to install artificial lift systems on wells as needed and perform water and gas isolations to maximize production efficiency. During the plan period a total of 15 remedials are scheduled for a total cost of $1.0 million. Artificial lift accounts for $281 thousand of this total. There are no current drilling objectives in this reservoir since it is drilled on 20-acre spacing and production rates do not justify the cost of additional wells. Simulation of additional drilling for the waterflood did not help the present value.

RESERVOIR DESCRIPTION

The 2B Sands Reservoir is a southern extension of the 26R Sand and is found on the southeastern nose of the 29R Structure (see Location Map, Figure 1). The sands are equivalent in age to the N and A Shales. Figure 3 is a southwest-northeast structural cross section showing how the sands pinch out to the southwest and become thicker to the northeast. The productive area of the reservoir covers approximately 208 acres and has a net producing thickness of up to 335 feet. The original oil/water contact was about 5,300 feet subsea. Petrophysical analysis shows a higher clay (shale) content in the 2B and hence a higher average water saturation (35.6%) than 26R. In modeling the history match for the 2B Sands, SSI found that the gas produced by the

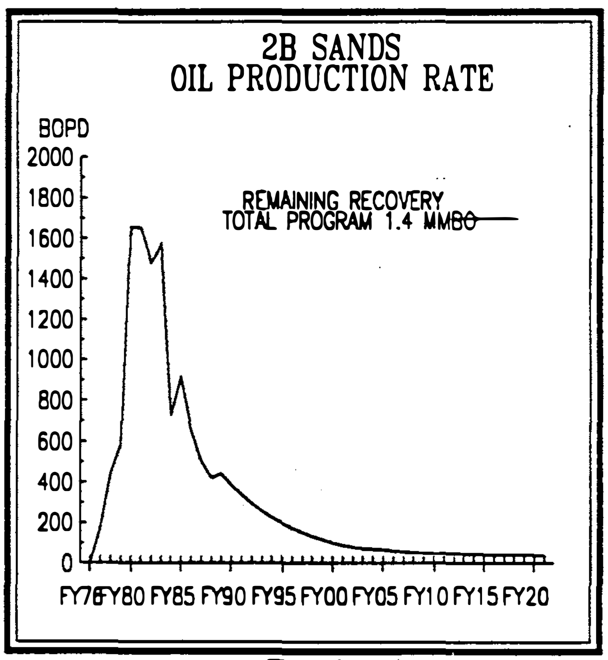


Figure 6

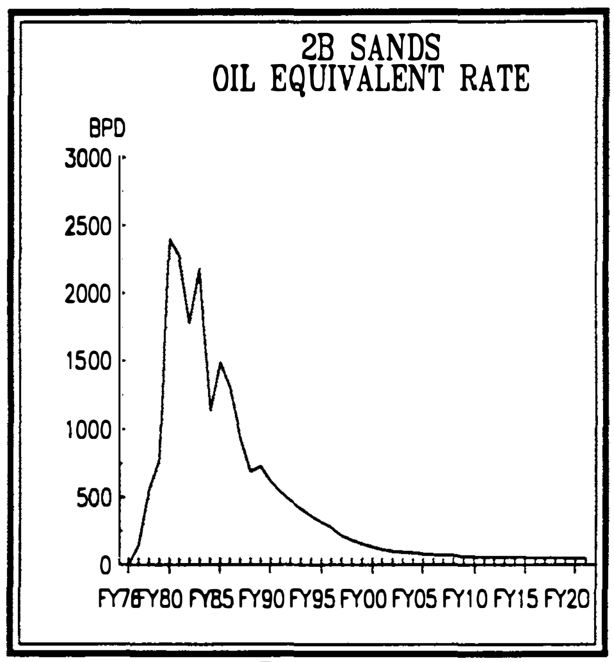


Figure 7

pool is in excess of the solution gas in the oil. To provide the proper amount of produced gas, the initial gas cap was moved from -5000 feet to -5047 feet subsea. The 2B Stevens Sands were put on production in 1977 with no pressure maintenance to date. As of October 1988, 55% of the estimated reserves remained to be produced.

Currently there are 11 production wells with eight wells on rod pump, one well on electrical submersible pump, one well flowing and one well idle. Well 331-2B has the submersible pump and accounts for almost 40% of the oil and up to 60% of the water produced from the reservoir. In the past this well has experienced significant downtime due to mechanical problems and has caused substantial fluctuation in production rates. In the reservoir simulation, Well 331-2B was given a higher pumped off Bottom Hole Pressure (BHP) limit of 1200 psi than the other wells that had pumped off BHP limits of 500 psi and 850 psi for 326-35R and 346-35R, respectfully. Simulated gross production was limited to 900 STB/D for all wells except for Well 331-2B which was given a limit of 3500 STB/D. In the field, 331-2B is watched closely for mechanical problems and excessive production rates that tend to increase water production and decrease oil production. Thus, the model limits were set to represent actual field conditions.

The 2B Sands surface facilities are located at tank setting 4-35R. A larger test separator is needed at this location so that more accurate gauges can be obtained from Well 331-2B and other 2B Sands wells to maintain optimum pumping conditions.

RESERVOIR STUDIES

A simulation study by SSI was completed in August 1988 which showed that an additional 1.1 million barrels of oil would be recovered with a waterflood, but gas production would be 1.2 billion cubic feet less. Economic analysis showed that a water injection project would lose $5.7 million. A gas injection project resulted in almost the same increase in oil production as that realized from water injection; however, gas injection lost $2.0 million.

The four cases that were run by SSI are as follows:

- Continuation of the current strategy of production by natural water drive and solution gas drive
- Waterflooding by conversion of three existing production wells to injectors
- Waterflooding as above plus one new infill producer
- Pressure maintenance by gas injection

2B SANDS
RESERVOIR CHARACTERISTICS

Porosity (%):	20.0	Production Wells (#)	11
Water Sat. (%):	35.6	Injection Wells (#):	0
Air Perm. (md):	111	Top Pay (Ft-VSS):	4,900
Oil Gravity (API):	32	Max Pay (Ft):	335
Oil Form. Vol. Fact. (RB/STB):	1.48	Pay Area (AC):	208
Oil Viscosity (cp):	0.576	Pay Volume (AF)	31,792
Initial Press. (psi):	2,765	GOC (Ft-VSS):	5,000
BubblePtPress.(psi):	2,522	WOC (Ft-VSS):	5,300
Current Press (psi):	1,550	Press.Datum (Ft-VSS)	5,000

Figure 8

The reservoir data for 2B Sands are summarized in Figure 8.

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy in the 2B Sands is production through solution gas drive augmented by an active water drive. Remedials to the wells and water and gas isolations to efficiently produce the reservoir are scheduled for future years. The Total Development Case includes this plan to optimize production and is based upon the August 1988 SSI waterflood evaluation.

In the future other simulation sensitivities can be determined as follows:

- The effect of gas injection with an early blowdown.
- The effect of pressure depleting the 2B Reservoir upon the 26R reservoir. Are they in communication?

The production cost and revenue streams for the Total Development Case are shown in Economics Table 1. Key economic parameters are summarized in Figure 4. The cost and production assumptions are shown in Figure 9.

2B SANDS
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Stimulations (acidizing)	59,000	20	12
Recompletions (plugbacks)	80,000	40	12
Artificial Lift (submersible pump)	150,000	20	12

Figure 9

The Total Development Case represents continuation of the present production strategy. Stimulations, recompletions and artificial lift expenditures are necessary to maintain the production.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The annual reservoir development activities are described below for the ensuing seven-year plan period. Details of the remedial activities are shown in Table 2.

FY'89
Two recompletions are required to continue production as planned.

FY'90
In order to maintain the production level, plans are to perform one acid stimulation, one plug back to control water and replace one submersible pump.

FY'91-95
During the outyears, only maintenance remedial activityis planned. This activity will remain constant for the period.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
2B SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	423	3261	1543	0	0	0	619	160	0	0	0	0
1990	369	3155	1255	0	0	0	608	144	52	0	103	0
1991	323	3157	1098	0	0	0	617	86	0	0	0	0
1992	283	3159	962	0	0	0	625	153	0	0	0	0
1993	248	3162	843	0	0	0	632	90	112	0	225	0
1994	217	3164	738	0	0	0	636	68	0	0	0	0
1995	190	3166	647	0	0	0	641	69	117	0	233	0
SUBTOTAL *	749	8112	2586	0	0	0	4378	770	281	0	561	0
1996-2021 *	634	30351	1262	0	0	0	20434	2294	0	0	0	0
TOTAL *	1383	38463	3848	0	0	0	24812	3064	281	0	561	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	2342	949	370	3662	779	708	2883	2621	268
1990	2164	857	316	3337	907	749	2430	2008	227
1991	2038	839	306	3184	703	529	2481	1864	198
1992	1932	816	353	3101	778	532	2323	1586	174
1993	1830	786	337	2954	1059	657	1895	1177	152
1994	1730	741	315	2786	704	397	2082	1175	133
1995	1602	744	320	2665	1060	544	1605	824	117
SUBTOTAL	13638	5732	2317	21689	5990	4116	15699	11255	1269
1996-2021	27774	6990	3000	37765	22728	3777	15037	3560	888
TOTAL	41412	12722	5317	59454	28718	7893	30736	14815	2157

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2

REMEDIAL ACTIVITY

2B SANDS

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-21	TOTAL
	FISCAL YEAR								
1. MAINTENANCE CASE:									
a. STIMULATIONS	0	1	0	1	0	1	1	25	29
b. RECOMPLETIONS	2	1	1	1	1	0	0	0	6
c. ARTIFICIAL LIFT	0	1	0	0	2	0	2	0	5
TOTAL:	2	3	1	2	3	1	3	25	40

29R/24Z SHALES

The 29R/24Z Shales consists of two main structures, the 29R Shales and the 24Z Shales. (See Location Map, Figure 1 and Cross Section, Figure 3). A channel sand extending from 26R into Section 34R of the 29R structure has been the major productive zone for the past year. The reservoir is being produced under primary depletion since the open-up in 1976.

The Total Development Case for the 29R/24Z Shales consists of a Maintenance Case and a Development Drilling Project. Total estimated costs of $61 million over FY'89 - FY'95 are required to generate undiscounted total revenues of $426 million. Revenue and cost values of the Total Development Case are shown in Figure 2.

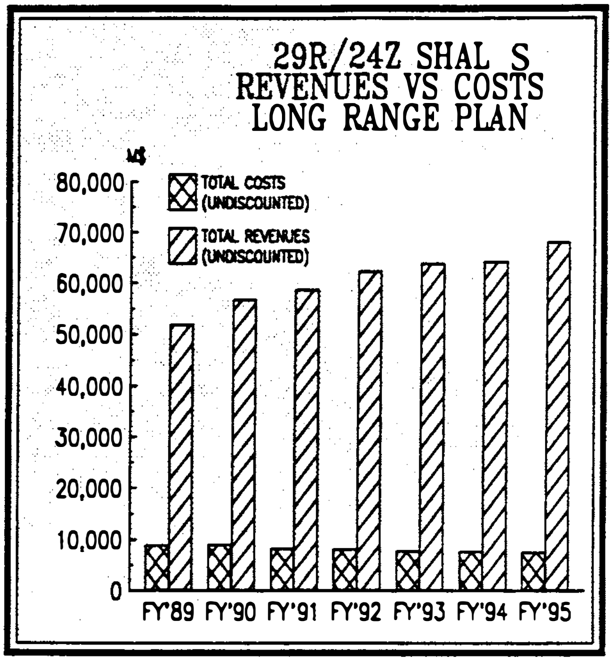


Figure 2

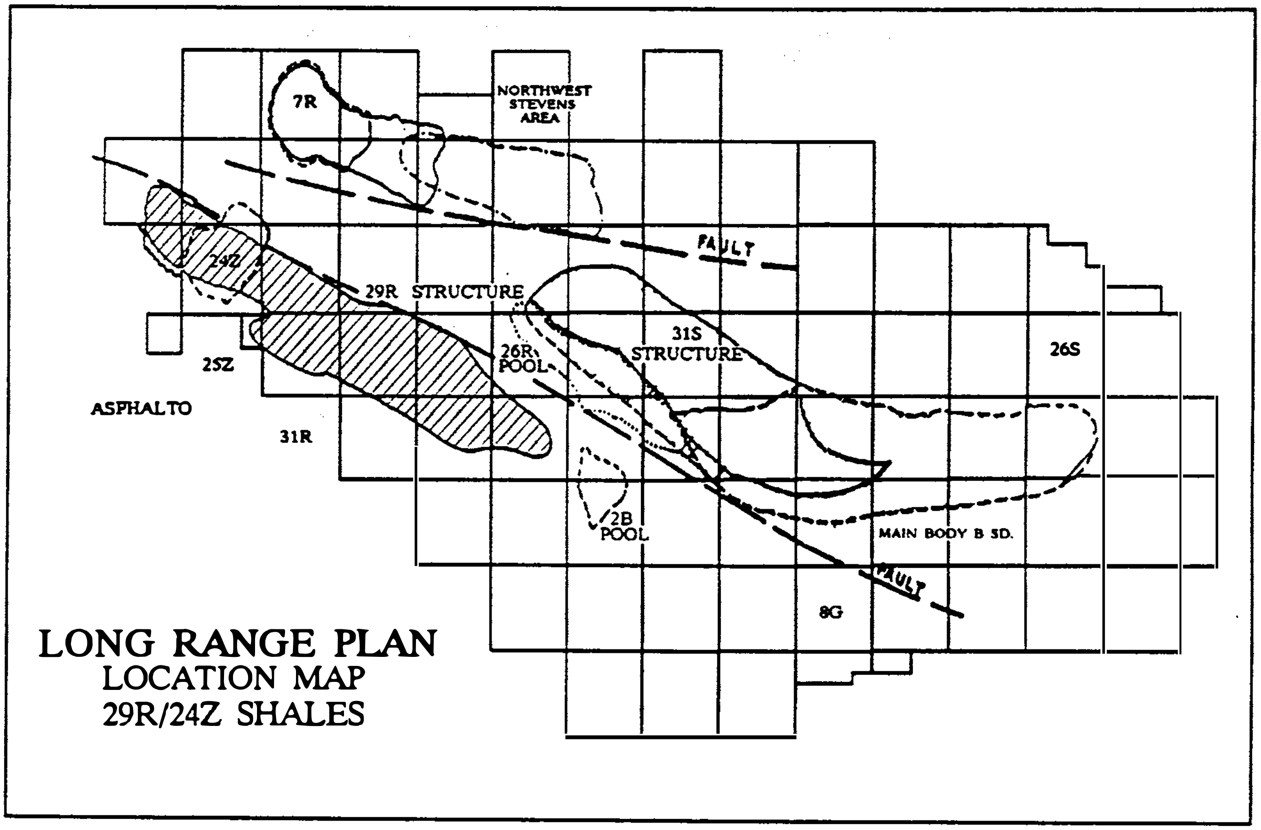


Figure 1

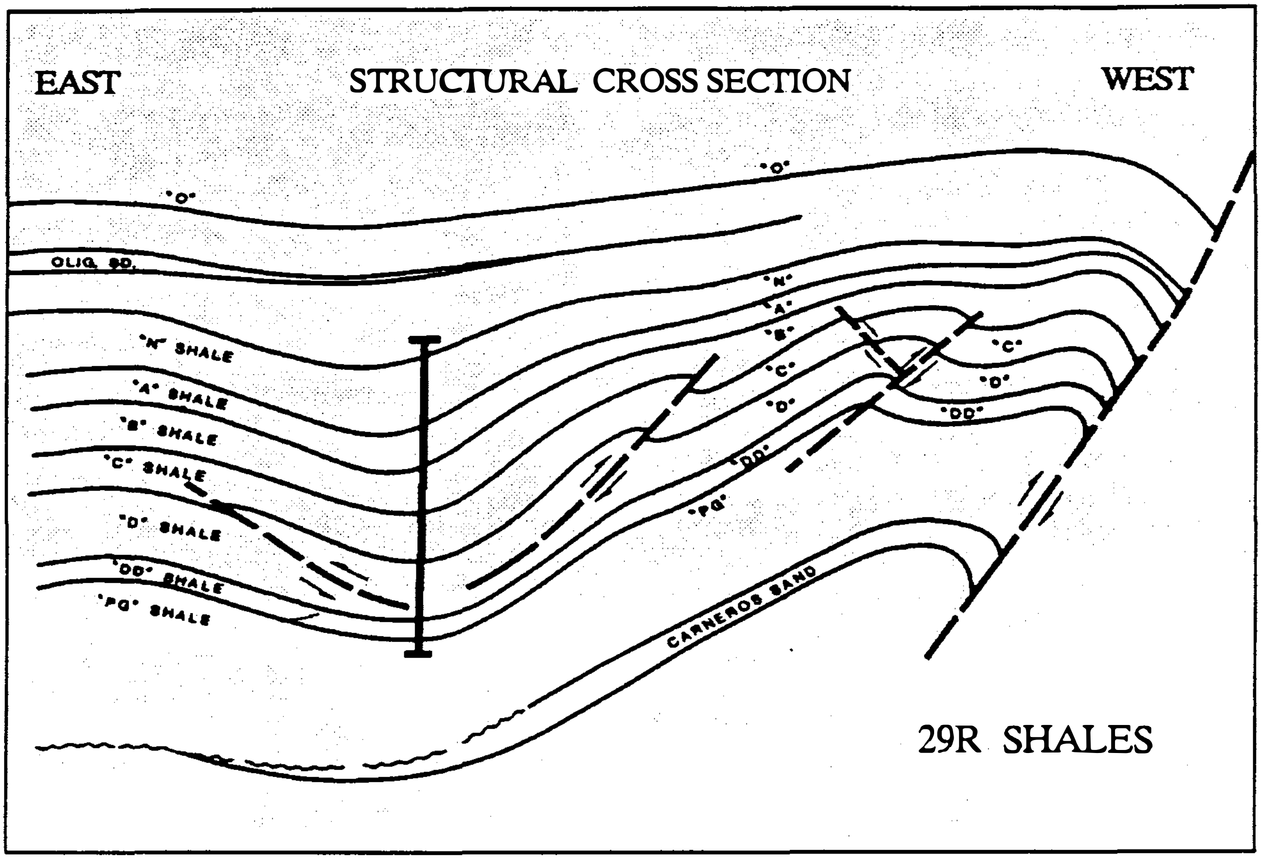


Figure 3

The economics and estimated recovery from the Total Development Case is summarized in Figure 4.

The estimated reserves of the 29R/24Z Shales shown in Figure 5 are from the "Third Revision, dated November 20, 1980, of Estimated Recoverable Oil and Percentage Participations as of November 20, 1942". As of October 1988, 52% of the estimated recoverable reserves remain to be produced.

The Maintenance Case, including well remedials and facilities to continue the current production strategy, requires total costs of $58.6 million over FY'89 - FY'95 and yields a net revenue of $351.5 million. The Devel-

29R/24Z SHALES
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$426.1 Million	$2,159.6 Million
Operating Cost:	$41.9 Million	$146.8 Million
Capital Cost:	$18.8 Million	$23.4 Million
Total Costs:	$60.8 Million	$170.3 Million
Net Revenue:	$365.4 Million	$1,989.3 Million
Net Present Value (@10%)	$248.9 Million	$536.9 Million
Recovery:		
Oil (MMB)	6.8	10.4
Natural Gas (BCF)	92.5	273.3
Oil Equivalent (MMBOE)	25.4	65.3

Figure 4

29R/24Z SHALES
TOTAL DEVELOPMENT CASE

	EQUITY STUDIES	LONG RANGE PLAN MAINT.	TOTAL
Original-Oil-In-Place (MMB):	581.0	-----	-----
Estimated Recoverable Oil (MMB):	75.5	45.6	46.2
Cumulative Production 9/30/88 (MMB):	35.9	35.9	35.9
Remaining Reserves:			
Oil (MMB)	39.6	9.7	10.4
Natural Gas (BCF)	-----	263.5	273.3
Oil Equivalent	-----	62.7	65.3
Economic Limit (BOPD, YEAR):	-----	27,FY'2022	27,FY'2022

Figure 5

opment Drilling Project, including a new well in FY'89 and an additional well in FY'90 to evaluate the potential in some undrained areas, will cost a total of $2.2 million and yield $13.9 million in net revenue.

The current reservoir operating strategy is to maintain the primary depletion process of gravity drainage assisted by solution gas drive, gas cap expansion and aquifer influx. Due to the belief of fracture dominated production in the past, high Gas-Oil Ratio (GOR) and high Water Cut (WC), no attempt has been made to inject any fluids for either pressure maintenance or displacement. A total of 61 producing wells will produce an average rate of 3,546 BOPD in FY'89. Remaining oil reserves are estimated from the Stevens Equity Reserves Study to be 39.6 million barrels.

The two graphs show the oil production rate (Figure 6) and oil equivalent rate (Figure 7) for the Total Development Case and the Maintenance Case from the open-up in FY'1976 to the economic limit in FY'2022.

RESERVOIR DESCRIPTION

The 29R/24Z Shale reservoir consists of two structures, 29R and 24Z. The 29R Shales occur along the northwest-trending 29R structure, with commercial oil production over an area about six miles long and

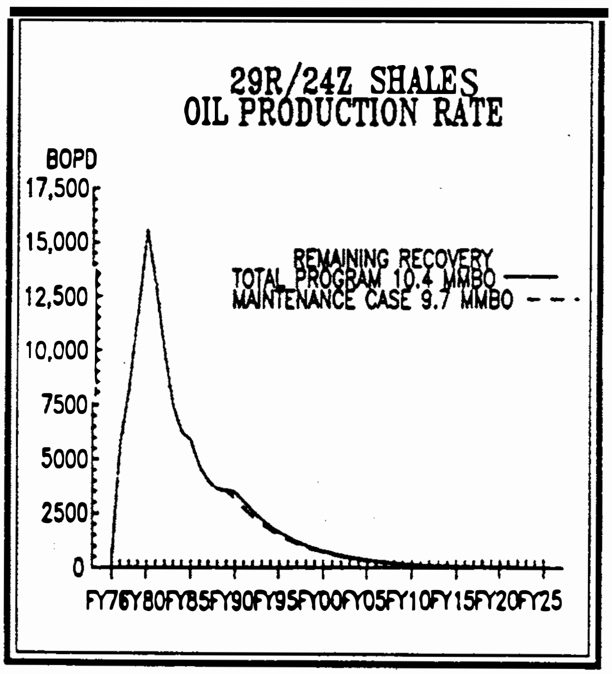


Figure 6

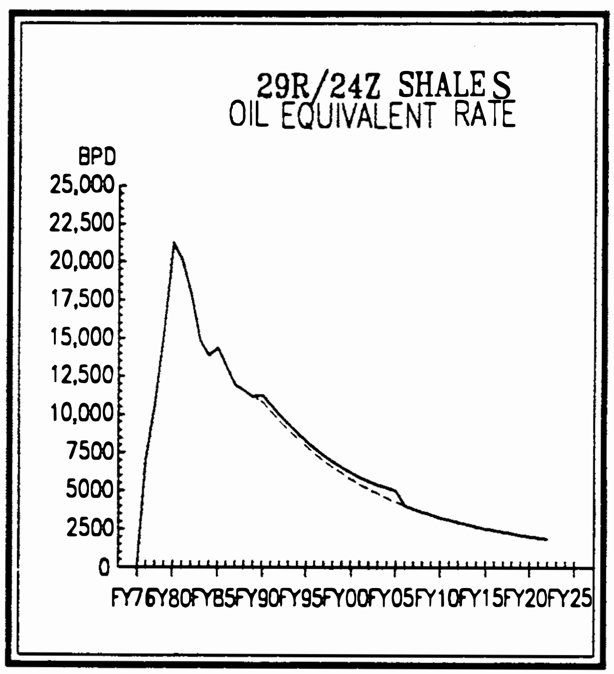


Figure 7

29R/24Z SHALES RESERVOIR CHARACTERISTICS			
Porosity (%):	26	Producing Wells (#):	61
Water Sat. (%):	55	Injection Wells (#):	0
Air Perm. (md):	1.5	Top Pay (Ft-VSS):	3,550
Oil Gravity (API):	35	Max Pay (Ft):	1,000
Oil Form. Vol. Fact. (RB/STB):	1.38	Pay Area (AC):	1,325
Oil Viscosity (cp):	0.44	Pay Volume (AF):	1,842,239
Initial Res. Pressure (psi):	2,690	GOC (Ft-VSS):	4,600
Bubble Point Press. (psi):	2,490	WOC (Ft-VSS):	4,950

Figure 8

one mile wide (see Location Map, Figure 1). The productive zone averages 1,100 feet (see Cross Section, Figure 3) in thickness and contains interbedded fine grain rock types formed in a deep marine environment, representing distal submarine fan and slope deposits. Five productive zones are identified in the reservoir; N, A, B, C and D. The reservoir is further divided into two producing horizons: the NAB Shales and the CD Shales. These two horizons are believed to be in pressure communication.

The 24Z Shales are located west of the 29R Structure and are commingled with 24Z Sands. Since a majority of the 24Z Shales production is collected from the wells commingled with 24Z Sands intervals, it has been prorated from the total production through allocation factors.

A summary of the 29R/24Z Shales reservoir characterstics is shown in Figure 8.

A channel sand crosses the 29R structure in section 34R and is producing nearly one-fourth of the total oil rate from three wells. This channel sand is postulated to be an extension from the lower 26R sands.
It was commonly believed in the past that the fractures observed in the core samples played an important role in the communication between the matrix and the wellbores. However, after analyzing 55 pressure surveys conducted in the 29R Shales, a recent study by Scientific Software-Intercomp concluded that no significant evidence of dual porosity behavior was found. It is indicated that the matrix in the 29R Shales is able to produce oil to the wellbores on its own. These different geological and engineering interpretations may lead to alternative depletion strategies, such as changing GOR guidelines or to gas or water injection.

The reservoir pressure has declined steadily since open-up in 1976, falling from 2,690 psi to approximately 1,930 psi at datum depth of 4,900' VSS. With this declining reservoir pressure, the average water cut has increased to 90% and the gas-oil ratio now averages over 10,000 SCF/STB. Consequently, there are 33 wells out of a total of 94 wells currently shut in to mitigate this problem. Of the producing wells, about half are on artificial lift which includes conventional rod pump, electrical submersible pump and gas lift.

The 29R/24Z surface facilities include 13 tank settings located in Sections 19R, 28R, 29R, 30R, 33R, 34R and 24Z. Some of these tank settings also serve the 24Z Sands as a result of the commingled production.

RESERVOIR STUDIES

A 29R simulation study funded by Department of Energy (DOE) is being conducted by Scientific Software-Intercomp (SSI) and is scheduled to be completed in FY'89. The history match of this simulation was achieved in November 1988 and the following prediction cases are being investigated for future operating strategy in 29R/24Z Shales:

- Infill drilling
- Aggressive remedials
- Optimum time for blowdown
- Crestal gas injection
- Continuation of the current operation
- Peripheral waterflood

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy for 29R/24Z Shales is to continue current operations through gravity drainage process assisted by solution gas drive, gas cap expansion and aquifer influx. A GOR limit of 15,000 SCF/STB has been implemented as a guideline for screening workover candidates. In the past, several studies were conducted in attempts to develop alternatives and enhanced recovery schemes to improve the ultimate oil recovery, however, without success.

The recent SSI simulation study scheduled to be completed in FY'89 will review the following alternative projects for this reservoir:

Continuation of current operations-This case would be a continuation of the current operating strategy. Flowing wells would be put on artificial lift as needs arise.

Infill Drilling-In this project, a total of 17 infill wells are proposed to be added to the model in order to recover a "high mobile oil volume" observed during the history match.

Remedials to all wells-An aggressive remedial program, including 52 workovers, would be conducted. The wells are proposed to be perforated in the zone having the most potential to increase the oil production. Gas and water isolations are also proposed to shut off excessive gas and water production.

Blowdown-In this project, 11 wells could be selected for blowdown service. These wells are chosen based on their crestal locations, low current contribution to field production and their penetration of the primary gas cap area. A reasonable bottom hole flowing pressure would be selected for controlling the production rates.

Gas injection-In this project, 10 crestal wells used in the Blowdown project would be converted to gas injectors and total field injection should be sufficient to replace voidage.

Water injection-In this project, the strategy is to peripherally waterflood to maintain reservoir pressure by converting existing wells to water injectors. Water injection would be controlled to below the fracture pressure and will be limited to the N, A and B shales.

29R/24Z SHALES
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Stimulations (acidizing)	90,000	50	20
Recompletions (Reperforations, Gas and Water isolations)	130,000	200	20
Artificial Lift (Installation)	80,000	--	--
Artificial Lift (Repairing)	70,000	--	--
Drilling	850,000	200	20
Facility (FY90 Closed -Loop Gas Lift system)	2,802,000	--	--
Facility (FY91 Closed-Loop Gas Lift System)	1,600,000	--	--

Figure 9

29R/24Z SHALES MAINTENANCE CASE	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$410.1 Million	$2,086.8 Million
Operating Cost:	$41.5 Million	$144.5 Million
Capital Cost	$17.1 Million	$21,7 Million
Total Costs:	$58.6 Million	$166.2 Million
Net Revenue:	$351.5 Million	$1,920.6 Million
Net Present Value (@10%)	$240.2 Million	$512.7 Million
Recovery:		
Oil (MMB)	6.3	9.7
Natural Gas (BCF)	90.7	263.5
Oil Equivalent (MMBOE)	24.5	62.7

Figure 10

A preliminary evaluation indicated that due to its significant increase of oil production the Remedials Project should be the most profitable case. After finalizing all prediction projects and their economics, a recommendation for the reservoir management plan is expected to be submitted.

The production, cost and revenue streams for the Total Development Case are shown in Table 1. Figure 9 shows the cost and assumptions used.

The Maintenance Case represents continuation of the current operating strategy with emphasis on remedial activity including stimulations, gas and/or water isolations, and artificial lift installation to maintain production and to conserve reservoir energy. A closed-loop gas lift system is scheduled for FY'90 and FY'91 to reduce demand on the high pressure gas injection system. Details of the Maintenance Case can be found in attached Economics Table 2. The values of revenue, cost and recovery are summarized in Figure 10.

The Development Drilling Project in FY'89 will investigate the productive potential from the areas which have unusually favorable production or wide well spacing. The production for the northeast corner of Sec-

29R/24Z SHALES DEVELOPMENT DRILLING PROJECT	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$16.1 Million	$72.8 Million
Operating Cost:	$0.5 Million	$2.3 Million
Capital Cost:	$1.7 Million	$1.7 Million
Total Costs:	$2.2 Million	$4.1 Million
Net Revenue:	$13.9 Million	$68.7 Million
Net Present Value (@10%)	$8.7 Million	$24.3 Million
Recovery:		
Oil (MMB)	0.5	0.7
Natural Gas (BCF)	1.9	9.8
Oil Equivalent (MMBOE)	0.9	2.7

Figure 11

tion 32R showed an unusual low water cut (< 10%) and GOR (< 4,000 SCF/STB). It was suspected that a channel sand might be deposited in this area. A well location, 323-33R has been selected to confirm its geological variation and improve the recovery from this area. An additional new well is scheduled in FY'90 to continue the investigation of production potential in Section 13Z. This well will be a follow-up well for the newly completed Well 317X-13Z. The initial production from these two wells was estimated to be 200 BOPD per well and then decline at 20% annually. The production forecast and economics of this project is fully described in Table 3. The resulting key economic parameters are shown in Figure 11.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The annual reservoir development activities for the period from FY'89 to FY'95 are described below. Drilling and remedial activities presented in separate form for the Maintenance Case and the Development Drilling Project are included in attached Table 4 and Table 5 respectively.

FY'89

Reservoir development activities include maintenance remedials and the drilling of a new well to meet the FY'89 objectives.

FY'90 - FY'95

During the period from FY'90 to FY'95 most of the activity planned is for remedials necessary to maintain the production decline and a new well to investigate production potential of the cherty reservoir in Section 13Z. The number of artificial lift installations decrease yearly. However, the cost of repairing the artificial lift equipment increases in order to properly maintain the existing units. Funding is provided for installing a Closed-Loop Gas Lift System for the 24z and 29R reservoirs in FY'90 and FY'91.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
29R/24Z SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	3546	25991	37806	0	0	0	5421	570	820	0	500	850
1990	3496	27950	38810	0	0	0	5938	314	942	2900	725	880
1991	3079	28664	37683	0	0	0	6159	374	644	1710	428	0
1992	2631	28501	36594	0	0	0	6211	385	813	0	443	0
1993	2251	28012	35429	0	0	0	6181	247	967	0	225	0
1994	1927	27283	34209	0	0	0	6082	401	1260	0	575	0
1995	1650	26390	32963	0	0	0	5955	408	1099	0	351	0
SUBTOTAL *	6782	70369	92525	0	0	0	41947	2699	6545	4610	3247	1730
1996-2022 *	3574	140930	180810	0	0	0	104899	2037	2571	0	0	0
TOTAL *	10356	211299	273335	0	0	0	146846	4736	9116	4610	3247	1730

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	19634	23258	9076	51968	8161	7419	43807	39825	4069
1990	20506	26499	9775	56780	11699	9668	45081	37257	4125
1991	19431	28787	10513	58731	9315	6999	49416	37127	3890
1992	17958	31047	13417	62422	7852	5363	54570	37272	3646
1993	16613	33053	14178	63844	7620	4732	56224	34910	3422
1994	15361	34343	14606	64310	8318	4695	55992	31606	3214
1995	13912	37883	16287	68082	7813	4009	60269	30928	3022
SUBTOTAL	123415	214870	87852	426137	60778	42885	365359	248925	253[illegible]
1996-2022	124818	1125527	483103	1733444	109507	23655	1623937	287996	399[illegible]
TOTAL	248233	1340397	570955	2159581	170285	66540	1989296	536921	65320

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
29R/24Z SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	3546	25991	37806	0	0	0	5421	570	820	0	500	0
1990	3196	27850	38060	0	0	0	5862	314	942	2900	725	0
1991	2759	28549	37008	0	0	0	6078	374	644	1710	428	0
1992	2375	28369	35835	0	0	0	6131	385	813	0	443	0
1993	2046	27860	34575	0	0	0	6100	247	967	0	225	0
1994	1763	27108	33248	0	0	0	5998	401	1260	0	575	0
1995	1519	26189	31882	0	0	0	5865	408	1099	0	351	0
SUBTOTAL *	6279	70049	90671	0	0	0	41455	2699	6545	4610	3247	0
1996-2022 *	3403	139215	172828	0	0	0	103070	2037	2571	0	0	0
TOTAL *	9682	209264	263499	0	0	0	144525	4736	9116	4610	3247	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	19634	23258	9076	51968	7311	6646	44657	40598	4069
1990	18746	25987	9586	54319	10743	8879	43576	36013	3960
1991	17412	28271	10325	56007	9234	6938	46773	35141	3723
1992	16211	30403	13138	59752	7772	5308	51980	35503	3497
1993	15100	32256	13837	61193	7539	4681	53654	33315	3284
1994	14054	33378	14196	61628	8234	4648	53394	30140	3084
1995	12807	36641	15753	65201	7723	3963	57478	29495	2894
SUBTOTAL	113964	210194	85911	410068	58556	41063	351512	240205	24511
1996-2022	119894	1089306	467547	1676745	107678	23135	1569067	272464	38156
TOTAL	233858	1299500	553458	2086813	166234	64198	1920579	512669	62667

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
DEVELOPMENT DRILLING PROJECT
29R/24Z SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	850
1990	300	100	750	0	0	0	76	0	0	0	0	880
1991	320	115	675	0	0	0	81	0	0	0	0	0
1992	256	132	759	0	0	0	80	0	0	0	0	0
1993	205	152	854	0	0	0	81	0	0	0	0	0
1994	164	175	961	0	0	0	85	0	0	0	0	0
1995	131	201	1081	0	0	0	90	0	0	0	0	0
SUBTOTAL *	502	319	1854	0	0	0	493	0	0	0	0	1730
1996-2022 *	171	1714	7981	0	0	0	1829	0	0	0	0	0
TOTAL *	673	2033	9835	0	0	0	2322	0	0	0	0	1730

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	850	773	-850	-773	0
1990	1760	512	189	2461	956	790	1505	1244	165
1991	2019	516	188	2723	81	61	2642	1985	166
1992	1747	644	278	2670	80	55	2590	1769	149
1993	1513	797	342	2651	81	51	2570	1596	138
1994	1307	965	410	2682	85	48	2597	1466	130
1995	1105	1242	534	2881	90	46	2791	1432	127
SUBTOTAL	9451	4676	1941	16068	2223	1824	13845	8719	875
1996-2022	4923	36221	15555	56701	1829	520	54872	15533	177[illegible]
TOTAL	14374	40897	17496	72769	4052	2344	68717	24252	265[illegible]

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4

DRILLING ACTIVITY

29R/24Z SHALES

(NUMBER OF DRILLING WELLS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-2022	TOTAL
	FISCAL YEAR								
1. DEVELOPMENT DRILLING PROJECT:									
a. NEW WELLS	1	1	0	0	0	0	0	0	2
TOTAL:	1	1	0	0	0	0	0	0	2

TABLE 5
REMEDIAL ACTIVITY

29R/24Z SHALES

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-2022	TOTAL
	FISCAL YEAR								
1. MAINTENANCE CASE:									
a. STIMULATION	2	1	1	1	1	1	1	4	12
b. RECOMPLETIONS	3	2	2	2	1	2	2	10	24
c. ARTIFICIAL LIFT (INSTALLATION)	5	7	4	4	2	5	3	0	30
d. ARTIFICIAL LIFT (REPAIRING)	6	5	4	6	10	10	10	30	81
TOTAL:	16	15	11	13	14	18	16	44	147

26R SANDS

The 26R Sands is one of the significant oil producing reservoirs at Elk Hills. (See Location Map, Figure 1 and Cross Section, Figure 3). Its current oil production is about one fourth of the total production from NPR-1. The reservoir has been pressure maintained by crestal gas injection since the open-up in 1976.

The Total Development Case for the 26R Sand reservoir consists of a Maintenance Case and a Horizontal Drilling Project. For the period from FY'89, the Total Development Case should yield $644 million in undiscounted revenues for a total expenditure outlay of $83 million. Figure 2 shows the revenue and cost values of the Total Development Case.

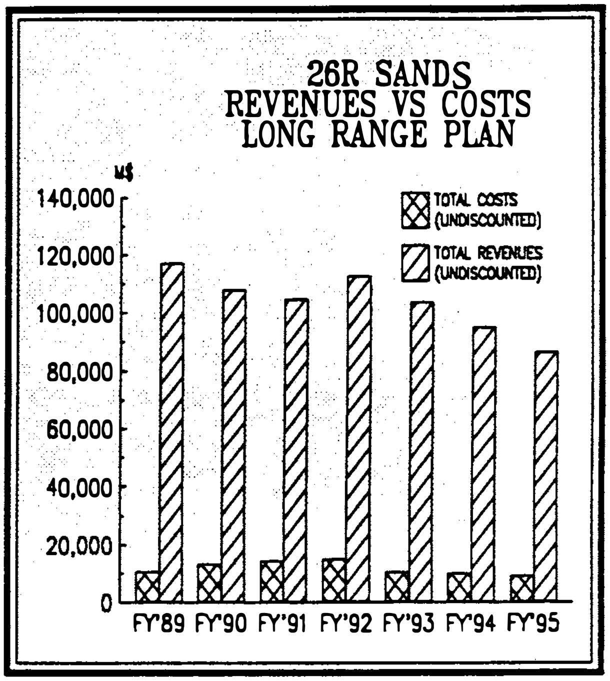


Figure 2

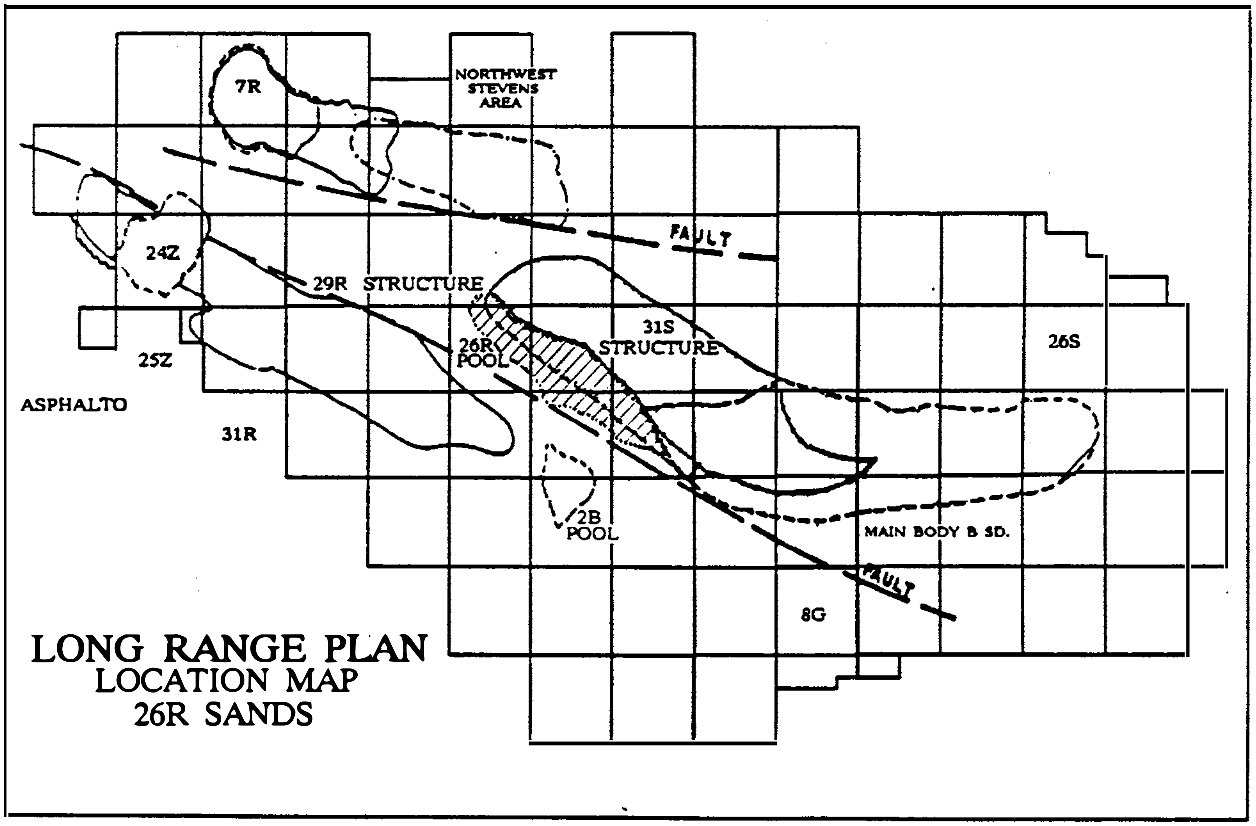


Figure 1

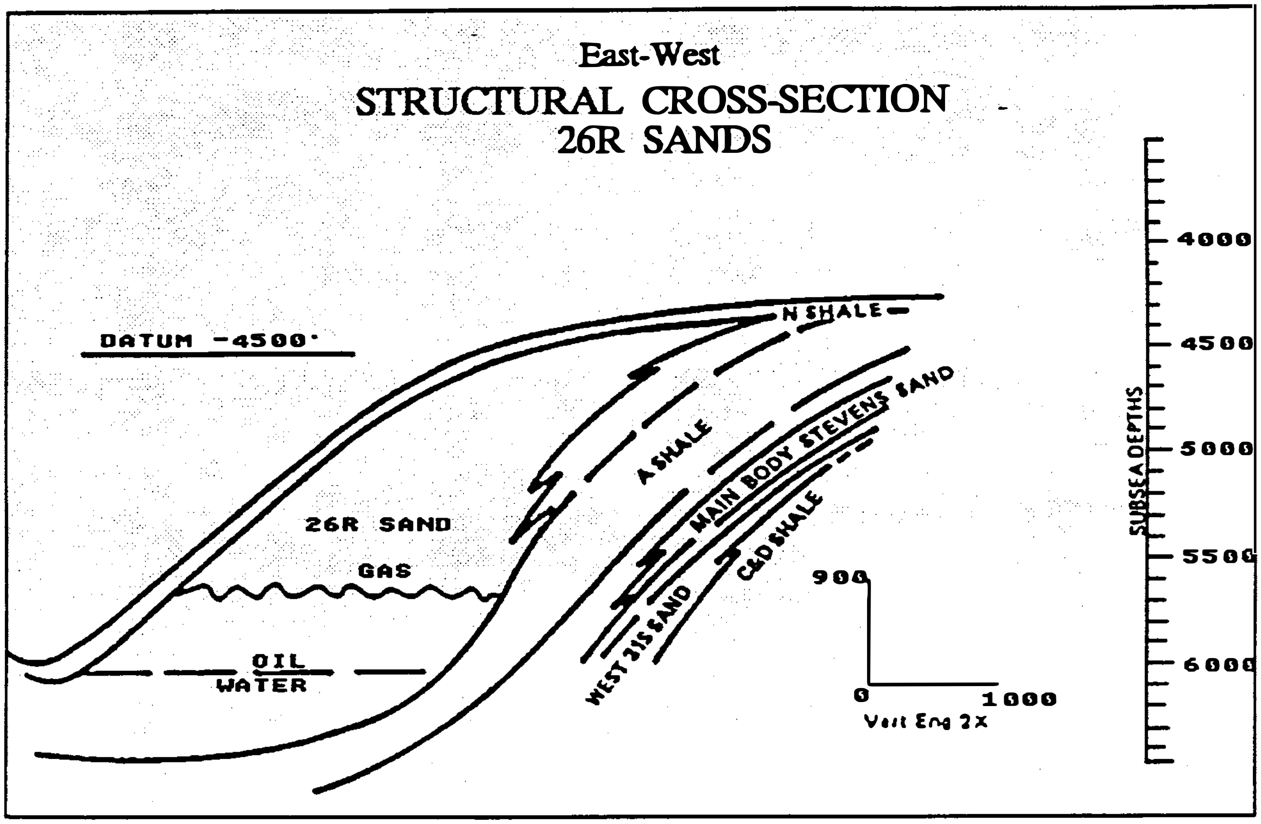


Figure 3

The economics and estimated recovery from the Total Development Case is summarized in Figure 4.

The estimated oil reserves for the 26R Sands shown in Figure 5 are from the "Third Revision, Dated November 20, 1980, of Estimated Recoverable Oil and Percentage Participations as of November 20, 1942". As of October 1988, 26.7% of the estimated reserves remained to be produced.

The Maintenance Case, including well remedials and facility activities to continue the current operating strategy, requires total costs of $65.5 million over FY'89 - FY'95 and generates a net revenue of $603.7 million. The Horizontal Drilling Project, including 7 horizontal wells to accelerate oil recovery and possibly improve the recovery efficiency, will cost a total of $17.3 million and yield $40.5 million in net revenue from FY89-FY95.

26R SANDS
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$727.0 Million	$5,779.8 Million
Operating Cost:	$58.4 Million	$149.5 Million
Investment:	$24.4 Million	$28.0 Million
Total Costs:	$82.8 Million	$177.5 Million
Net Revenue:	$644.2 Million	$5,602.3 Million
Net Present Value (@ 10%)	$454.8 Million	$1,359.9 Million
Recovery:		
Oil (MMB)	40.6	61.3
Natural Gas (BCF)*	-71.9	392.9
Oil Equivalent (MMBOE)	32.1	148.1

* Total Production Minus Injection

Figure 4

26R SANDS			
TOTAL DEVELOPMENT CASE			
	EQUITY STUDIES	LONG RANGE PLAN MAINT.	TOTAL
Original-Oil-In-Place (MMB):	423.7	-----	-----
Estimated Recoverable Oil (MMB):	211.9	213.8	216.7
Cumulative Production 9/30/88 (MMB):	155.4	155.4	155.4
Remaining Reserves:			
Oil (MMB)	56.5	58.4	61.3
Natural Gas (BCF)*	-----	393.1	392.9
Oil Equivalent (MMBOE)	-----	145.0	148.1
Economic Limit (BOPD, YEAR):	-----	125,FY'2025	125,FY'2025

* Total Production minus Injection

Figure 5

The current reservoir operating strategy is to continue gas injection assisted by gravity drainage with solution gas drive and gas cap expansion. A total of 9 gas injectors located at the crest of the structure provide an injection capacity of 185,000 MCFPD. In FY'89, 51 active wells will provide an average rate of 22,076 BOPD. Figure 6 shows the oil production rate and Figure 7 shows the oil equivalent rate for the Total Development Case and the Maintenance Case from the open-up in FY'1976 to the economic limit in FY'2025.

RESERVOIR DESCRIPTION

The 26R Sand reservoir is a submarine fan channel sand approximately one mile wide and three miles long, which is located on the southwestern limb of the 31S Structure (see Location Map, Figure 1). The channel has a vertical thickness of up to 2,500 feet with up to 1,200 feet in the oil column (see Cross Section, Figure 3). This massive sand can be divided into four megaunits, A-C, C-F, F-K and K-P. The Oil-Water

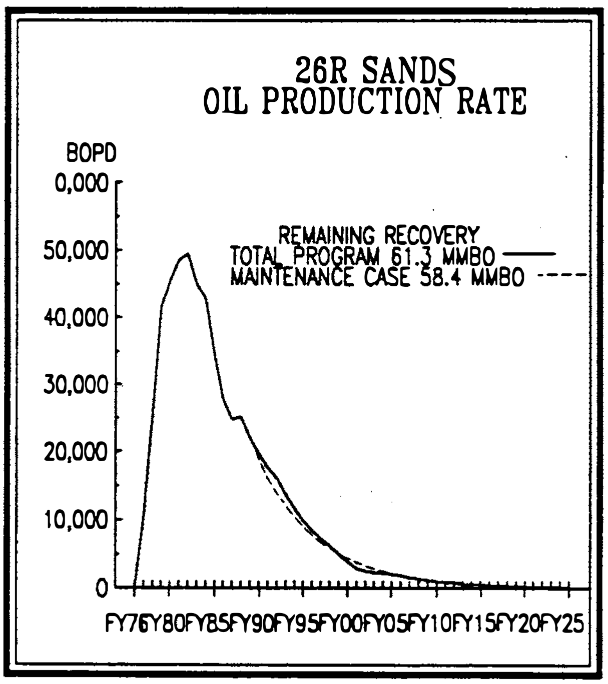


Figure 6

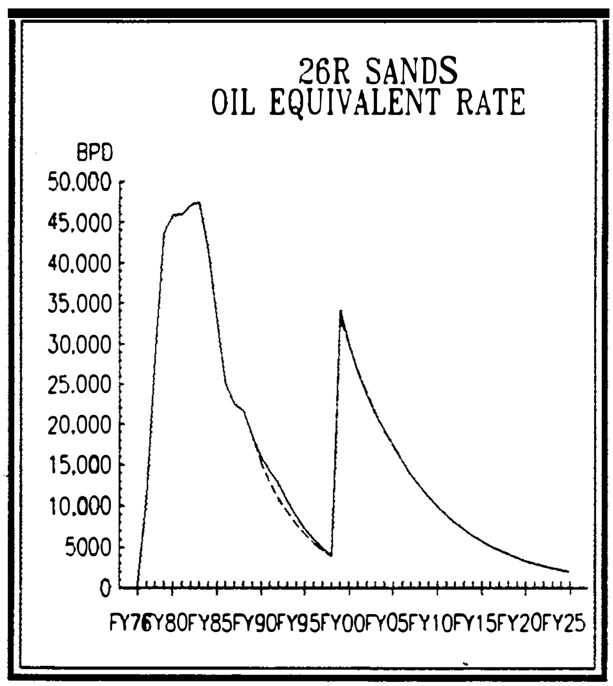


Figure 7

26R SANDS RESERVOIR CHARACTERISTICS			
Porosity (%):	23	Producing Wells (#):	51
Water Sat. (%):	16	Injection Wells (#):	9
Air Perm. (md):	400	Top Pay (Ft-VSS):	4,200
Oil Gravity (API):	36	Max Pay (Ft):	1,200
Oil Form. Vol. Fact. (RB/STB):	1.38	Pay Area (AC):	1,038
Oil Viscosity (cp):	0.42	Pay Volume (AF):	455,600
Initial Res. Pressure (psi):	3,030	GOC (Ft-VSS):	5,600
Bubble Point Press. (psi):	2,950	WOC (Ft-VSS):	6,010
Current Press. (psi):	2,600	Press. Datum (Ft-VSS):	6,000

Figure 8

Contact (OWC) is about 6,010 feet subsea and has remained constant since 1978. Although this reservoir did not have an original gas cap, an irregular secondary gas cap several hundred feet thick was formed, with the Gas-Oil Contact (GOC) varying from 5,800 feet subsea in 26R and 27R to 5,400 feet subsea in 36R. Gas injection was started in 1976 shortly after the open-up of NPR-1 to balance the voidage and to maintain the reservoir pressure. A summary table of the reservoir characteristics is shown in Figure 8.

The reservoir pressure has declined from the original 3,030 psi in 1976 to the present 2,600 psi. A material balance study conducted recently by the BPOI Task Force group indicated that during the period from open-up to mid-1984, the reservoir received a net influx migration from the 31S NA Reservoir. However, from mid-1984 to present, a significant efflux may have occurred from the 26R Sands into the 31S NA Reservoir. The study further concluded that the primary area of efflux is believed to be in the eastern portion of the reservoir. Because pressure in the 26R reservoir could not be maintained with the 100% voidage replacement strategy, gas injection was increased to 110% voidage in April 1987. In July 1988, a one year test was initiated to determine if voidage could be controlled by combining the 26R, Main Body B, and N/A Reservoirs. After injecting at this high rate for about a year the gas cap pressure apparently stabilized at 2,400 psi. The current injection capacity is estimated at 185,000 MCFPD through 9 crestal wells.

The 26R Sands surface facilities include 8 tank settings located in Sections 26R, 27R, 35R and 36R, and a gas compression station located in Section 35R.

RESERVOIR STUDIES

A detailed 26R reservoir simulation study is being conducted by Scientific Software-Intercomp (SSI). This fine-grid model is presently in the stage of history matching and is scheduled to be completed in FY'89. It will be utilized to determine the best operating strategy for this reservoir. Meanwhile, a coarse grid simulation model completed in FY'88 by SSI is also being used to investigate the possibility of altering the gas injection strategy to improve profitability (NPV). SSI is also conducting a field-wide Material Balance Study to investigate the fluid migration between the Stevens reservoirs.

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy for the 26R Sands is to continue current operations and produce the reservoir by gas injection assisted by gravity drainage with solution gas drive and gas cap expansion. The 110% voidage replacement rate will also be continued to maintain the reservoir pressure.

Presently, a simulation study is being conducted by SSI using the coarse grid model completed in FY'88 to investigate the potential of altering the current gas injection strategy in the 26R Sands. A preliminary economic evaluation indicates that two favorable scenarios are gas cycling and/or partial pressure maintenance. However, it was found that since revenues generated from the sales of the natural gas liquids (NGL) and the gas production provide a large portion of the current income for the reservoir, the gas cycling scheme may generate more profit compared with the partial pressure maintenance. Further investigation is required. Gas injection may be continued until 1999, depending upon the production results in the early years.

The SSI Material Balance Study scheduled to be completed in FY'89 should provide a better understanding of the behavior of fluid communication between Stevens reservoirs, especially between 26R Sands and the 31S Structure. An operating strategy for the entire Stevens is expected to be developed from this study.

The simulation study, including various injection and production strategies, the timing of each scheme, and its economic evaluation are expected to be completed in FY'89. A recommendation for the reservoir management plan should be submitted at that time.

The production, cost and revenue streams for the Total Development Case are shown in attached Economics Table 1. Figure 9 shows the cost and production assumptions used.

The Maintenance Case represents continuation of the current operating strategy with emphasis on remedial activity including well stimulation, gas and/or water isolation, and recompletion work. A recent review on gas isolation work revealed that this aggressive remedial program should be able to maintain low production GOR (<6,000 SCF/STB) for a period of time. However, as a result of rising gas production, an increase in injection capacity to 200,000 MCFPD is anticipated to overcome extra voidage and energy losses.

26R SANDS
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Stimulations (acidizing)	60,000	200	20
Recompletions (Reperforations, Gas and Water isolations)	105,000	100	10
Conversion (Increase Inj. Capacity)	175,000	---	--
Drilling (Horizontal wells)	1,935,000	500	20

Figure 9

It is estimated that, in FY'91, an existing producer should be converted to a gas injector to boost the injection capacity to the total required volume of approximately 200,000 MCFPD.

Details of the Maintenance Case can be found in the attached Economics Table 2. A summary of the key economic indicators and recovery is in Figure 10.

The Horizontal Drilling Project is designed to investigate and to expand the use of horizontal well technology in the 26R Sands. Early results of the horizontal well #372-35R, partially completed in November 1988, indicated that, by extending the wellbore into the

26R SANDS
MAINTENANCE CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$669.2 Million	$5,708.0 Million
Operating Cost:	$55.4 Million	$145.7 Million
Investment:	$10.1 Million	$13.7 Million
Total Costs:	$65.5 Million	$159.4 Million
Net Revenue:	$603.7 Million	$5,548.6 Million
Net Present Value (@ 10%)	$429.8 Million	$1,329.2 Million
Recovery:		
Oil (MMB)	37.3	58.4
Natural Gas (BCF)*	-67.2	393.1
Oil Equivalent (MMBOE)	29.4	145.0

* Total Production Minus Injection

Figure 10

26R SANDS HORIZONTAL DRILLING PROJECT	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$57.8 Million	$71.8 Million
Operating Cost:	$3.0 Million	$3.8 Million
Investment:	$14.3 Million	$14.3 Million
Total Costs:	$17.3 Million	$18.1 Million
Net Revenue:	$40.5 Million	$53.7 Million
Net Present Value (@ 10%)	$25.0 Million	$30.8Million
Recovery:		
Oil (MMB)	3.3	2.8
Natural Gas (BCF)*	-4.7	-0.2
Oil Equivalent (MMBOE)	2.6	3.1

Figure 11

undrained area of existing vertical wells, the horizontal wells may be capable of sustaining water-free and low GOR oil production for a long time. They will, therefore, improve ultimate recovery efficiency of the 26R Sands. During the four- year period from FY'89 to FY'92, this plan reflects that one horizontal well will be drilled in FY89, and two wells per remaining year. The initial production from each well is estimated at 500 BOPD declining at 20% annually.

The Horizontal Drilling Project is described in attached Economics Table 3 and the results are summarized in Figure 11.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The annual reservoir development activities for the period from FY'89 to FY'95 are described below. Details of the drilling and remedial activities are included in attached Table 4 and Table 5.

FY'89

Reservoir development activities include maintenance remedials and the drilling of one horizontal well. Gas injection is currently planed to continue at the 110% voidage rate to maintain the reservoir pressure.

FY'90

During the period of FY'90 the activities include remedials to reduce the gas production, and two more horizontal wells.

FY'91

Activities include the drilling of two more horizontal wells and an increased number of remedials to maintain production from aging wells. Additionally, an existing producer will be converted to gas injection to replace extra voidage generated by gas production.

FY'92 to FY'95

Similar remedial activity as for the previous year will be completed to maintain the field production decline. The horizontal well program will end in FY'92 with 2 additional wells.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
26R SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	22076	2051	139238	0	168279	0	7413	1380	0	0	0	1935
1990	19781	3648	148468	0	179526	0	8106	1118	0	0	0	4005
1991	17714	4795	154860	0	184297	0	8601	1663	0	0	0	4138
1992	16153	5243	165481	0	195528	0	9275	1237	0	0	0	4253
1993	13734	5436	154186	0	181953	0	8810	1619	0	0	0	0
1994	11705	5639	143327	0	169080	0	8328	1648	0	0	0	0
1995	9996	5854	131877	0	155743	0	7820	1433	0	0	0	0
SUBTOTAL *	40573	11923	378665	0	450558	0	58353	10098	0	0	0	14331
1996-2025 *	20689	77934	610983	0	146208	0	91086	3606	0	0	0	0
TOTAL *	61262	89857	989648	0	596766	0	149439	13704	0	0	0	14331

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	122236	-38427	33425	117235	10728	9753	106507	96824	6735
1990	116026	-45552	37393	107867	13229	10933	94638	78214	5804
1991	111790	-50449	43204	104545	14402	10821	90143	67725	5191
1992	110252	-58440	60671	112484	14765	10085	97719	66743	4631
1993	101361	-59618	61704	103446	10429	6476	93017	57756	3850
1994	93308	-59566	61195	94937	9976	5631	84961	47958	3195
1995	84281	-62977	65160	86464	9253	4748	77211	39621	2646
SUBTOTAL	739254	-375029	362752	726978	82782	58447	644196	454841	32052
1996-2025	743328	2830661	1478818	5052804	94692	21692	4958112	905073	116074
TOTAL	1482582	2455632	1841570	5779782	177474	80139	5602308	1359914	148126

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
26R SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	22076	2051	139238	0	168279	0	7413	1380	0	0	0	0
1990	18781	3463	145000	0	175000	0	7873	1118	0	0	0	0
1991	15964	4321	148000	0	175373	0	8130	1663	0	0	0	0
1992	13840	4429	155000	0	182009	0	8550	1237	0	0	0	0
1993	12000	4540	146000	0	171202	0	8207	1619	0	0	0	0
1994	10404	4654	136960	0	160488	0	7822	1648	0	0	0	0
1995	9020	4770	126982	0	148860	0	7389	1433	0	0	0	0
SUBTOTAL *	37261	10303	363971	0	431142	0	55384	10098	0	0	0	0
1996-2025 *	21166	78347	601328	0	141022	0	90293	3606	0	0	0	0
TOTAL *	58427	88650	965299	0	572164	0	145677	13704	0	0	0	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	122236	-38427	33425	117235	8793	7994	108442	98583	6735
1990	110161	-44215	36519	102465	8991	7431	93474	77251	5495
1991	100746	-47519	41290	94518	9793	7358	84725	63655	4661
1992	94465	-53584	56829	97709	9787	6685	87922	60052	3944
1993	88564	-55233	58428	91758	9826	6101	81932	50873	3353
1994	82937	-55619	58477	85794	9470	5346	76324	43083	2842
1995	76052	-59121	62741	79672	8822	4527	70850	36357	2402
SUBTOTAL	675161	-353718	347709	669151	65482	45442	603669	429854	29432
1996-2025	764478	2812608	1461744	5038827	93899	21301	4944928	899297	115584
TOTAL	1439639	2458890	1809453	5707978	159381	66743	5548597	1329151	145016

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
HORIZONTAL DRILLING PROJECT
26R SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	1935
1990	1000	184	3468	0	4526	0	232	0	0	0	0	4005
1991	1750	474	6860	0	8925	0	471	0	0	0	0	4138
1992	2313	814	10481	0	13518	0	725	0	0	0	0	4253
1993	1734	895	8186	0	10750	0	603	0	0	0	0	0
1994	1301	985	6367	0	8593	0	506	0	0	0	0	0
1995	976	1084	4895	0	6883	0	431	0	0	0	0	0
SUBTOTAL *	3312	1619	14694	0	19416	0	2968	0	0	0	0	14331
1996-2025 *	-477	-414	9656	0	5186	0	793	0	0	0	0	0
TOTAL *	2835	1205	24350	0	24602	0	3761	0	0	0	0	14331

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	1935	1759	-1935	-1759	0
1990	5866	-1336	873	5403	4237	3502	1166	963	309
1991	11044	-2932	1914	10026	4609	3463	5417	4070	530
1992	15787	-4855	3843	14776	4978	3400	9798	6692	686
1993	12797	-4384	3276	11690	603	374	11087	6884	496
1994	10371	-3948	2718	9141	506	285	8635	4874	353
1995	8229	-3856	2419	6792	431	221	6361	3264	243
SUBTOTAL	64094	-21311	15043	57828	17299	13004	40529	24988	2617
1996-2025	-21150	18052	17074	13976	793	391	13183	5775	490
TOTAL	42944	-3259	32117	71804	18092	13395	53712	30763	3107

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4
DRILLING ACTIVITY

26R SANDS

(NUMBER OF DRILLING WELLS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-2025	TOTAL
1. MAINTENANCE CASE: NONE									
2. HORIZONTAL DRILLING PROJECT:									
a. NEW WELLS	1	2	2	2	0	0	0	0	7
SUB-TOTAL:	1	2	2	2	0	0	0	0	7
TOTAL:	1	2	2	2	0	0	0	0	7

TABLE 5
REMEDIAL ACTIVITY

26R SANDS

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-2025	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	2	2	9	10	10	10	10	25	78
b. ISOLATIONS	12	10	8	5	8	8	6	14	71
c. INCREASE INJ. CAPACITY	0	0	1	0	0	0	0	0	1
SUB-TOTAL:	14	12	18	15	18	18	16	39	150
2. HORIZONTAL DRILLING PROJECT: NONE									
TOTAL:	14	12	18	15	18	18	16	39	150

31S C/D SHALES

The 31S C/D Shales are reservoirs within the Stevens Zone of the 31S Structure. They are stratigraphically underneath the Main Body "B" Sands. (See Location Map, Figure 1 and Cross Section, Figure 3). The reservoirs are produced by depletion drive with well spacing at 40 acres. Production and other reservoir performance data indicate that the 31S C/D Shales are separate and not in communication with other Stevens reservoirs in the 31S Structure.

The Total Development Case for 31S C/D Shales consists of the Maintenance Case and the following two projects:

1. Development Drilling/Deepening Project
2. Pilot Waterflood Project

The Total Development Case is expected to provide $343 million in undiscounted revenues from FY'89 to FY'95, and the total costs are estimated to be $54 million. Annual total revenues and expenditures for the Total Plan are as shown in Figure 2.

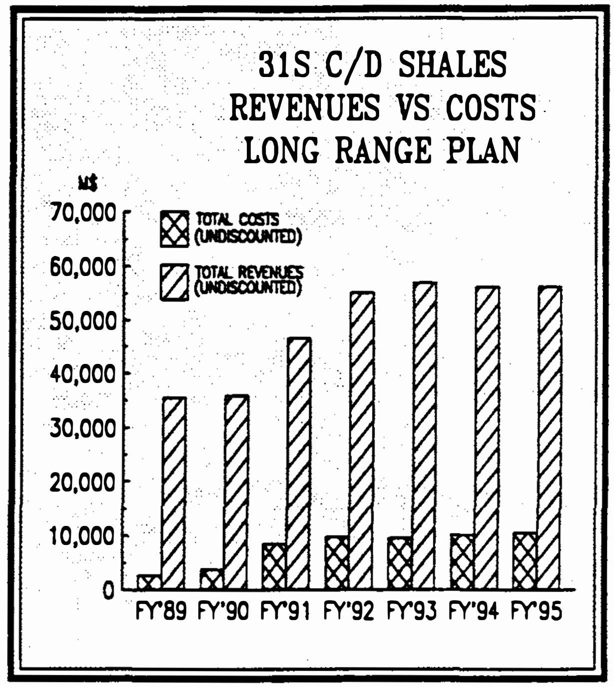


Figure 2

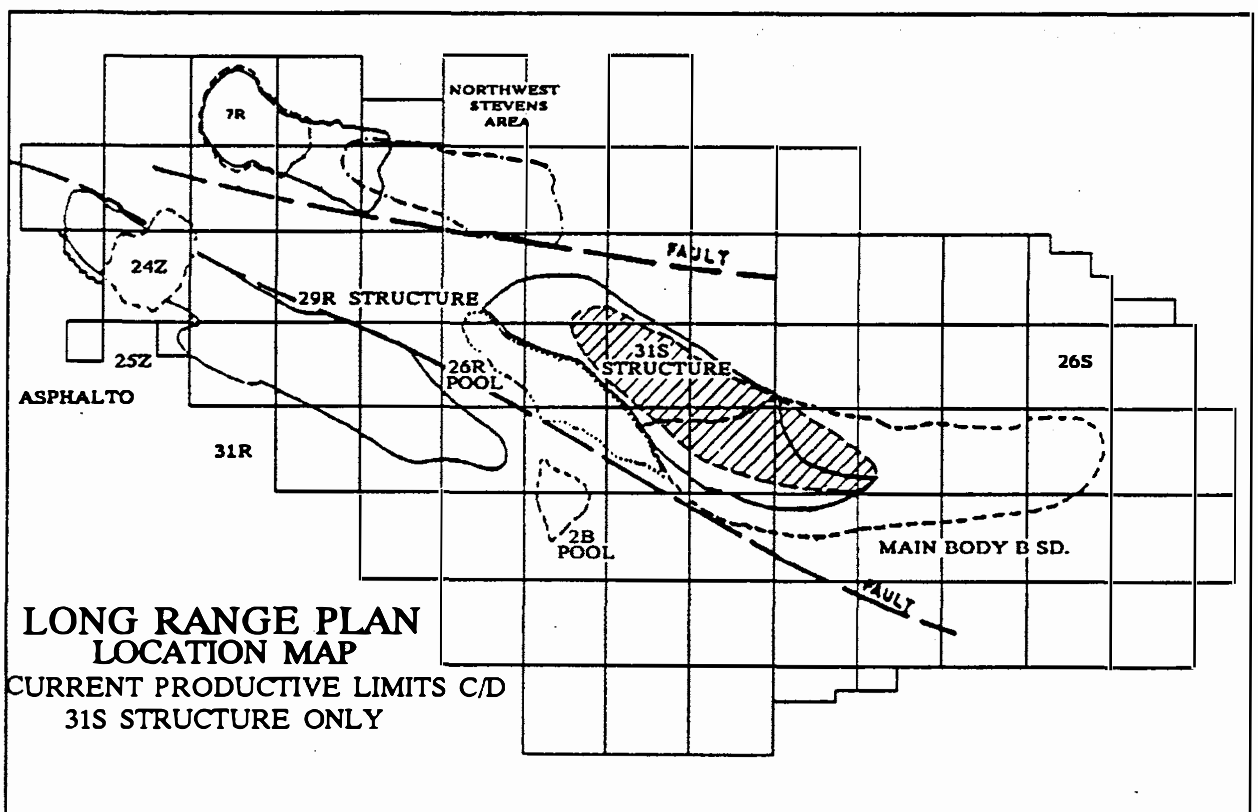


Figure 1

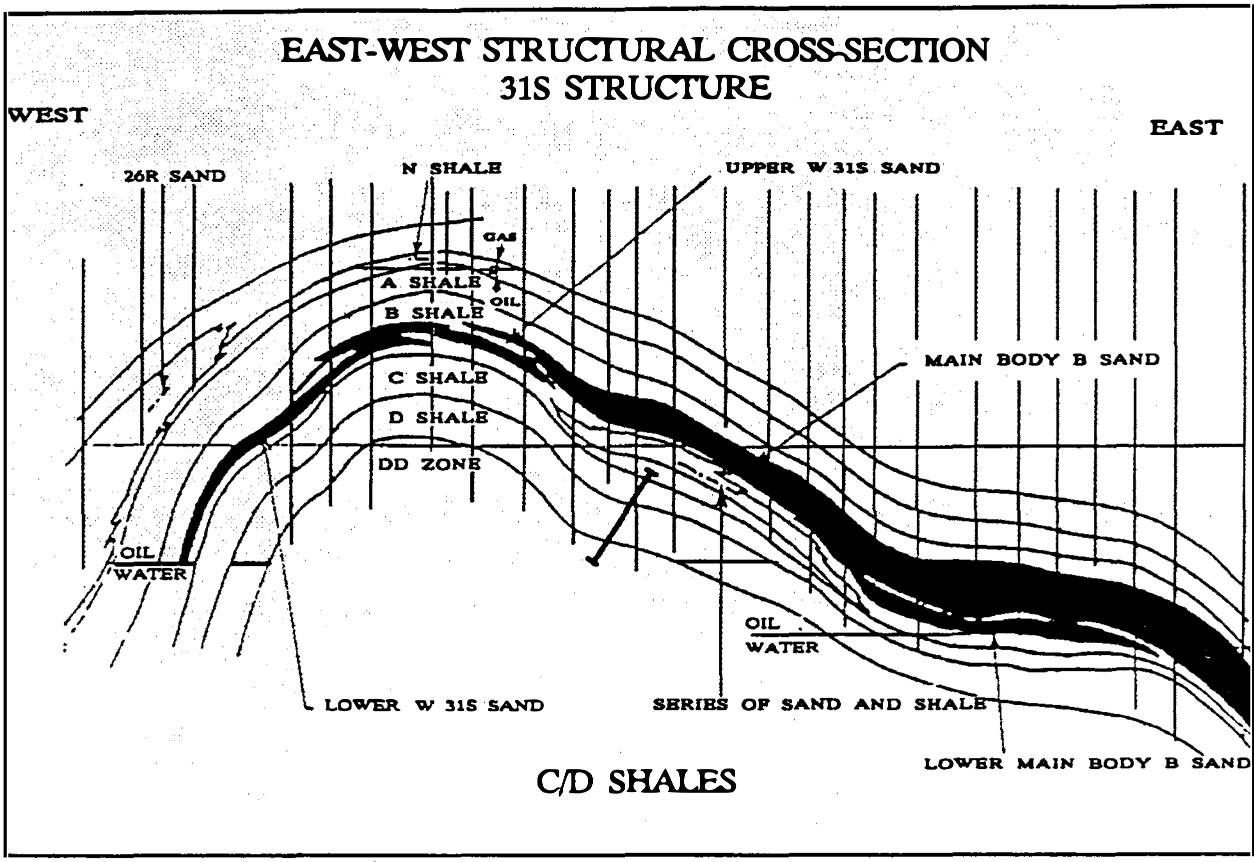


Figure 3

As shown in Figure 4, several economic yardsticks exemplify the economic viability of the Total Development Case. The net present value at 10% discount rate is $196 million from FY'89 to FY'95 and $459.0 million from FY'89 to economic limit in FY'2022.

Under the Total Development Case, 7.2 million barrels of oil would be recovered from FY'89 to FY'95 and 13.9 million barrels of oil from FY'89 to FY'2022. Other recoveries are included in Figure 4.

31S C/D SHALES
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$342.9 Million	$3,994.2 Million
Operating Cost:	$18.7 Million	$143.6 Million
Investment:	$35.0 Million	$70.1 Million
Total Costs:	$53.7 Million	$213.7 Million
Net Revenue:	$289.3 Million	$3,780.6 Million
Net Present Value (@ 10%)	$196.0 Million	$459.0 Million
Recovery:		
Oil (MMB)	7.2	13.9
Natural Gas (BCF)	62.6	289.7
Oil Equivalent (MMBOE)	19.8	72.1

Figure 4

31S C/D SHALES TOTAL DEVELOPMENT CASE	EQUITY STUDIES	LONG RANGE PLAN MAINT.	TOTAL
Original-Oil-In-Place (MMB):	-	257.0	257.0
Estimated Recoverable Oil (MMB):	33.4	36.3	43.4
Cumulative Production 9/30/88 (MMB):	29.5	29.5	29.5
Remaining Reserves:			
Oil (MMB)	3.9	6.8	13.9
Natural Gas (BCF)	-	244.6	289.7
Oil Equivalent (MMBOE)	-	56.0	72.1
Economic Limit (BOPD, YEAR):	-	10 FY'2022	10 FY'2022

Figure 5

The Elk Hills Engineering Committee estimated recoverable oil reserves in 31S C/D Shales at 33.4 million barrels. By analogy to other California Shale reservoirs, the original oil-in-place was estimated to be 257 million barrels using a 13 percent recovery factor. However, it is clearly evident that probable reserves in the 31S C/D Shales are substantial and that the reservoirs are prime candidates for secondary and/or enhanced oil recovery projects. The proven reserves are almost depleted and substantial residual oil should exist in the reservoir under the current operating strategy. The high recovery rate(89%) indicate that oil reserves may have been underestimated. A summary of the reserve estimate is shown in Figure 5.

The 31S C/D Reservoir Management Strategy is based on three exclusive but complementing activities. These activities are described as the Maintenance Case, Development Drilling/ Deepening Project and the Pilot Waterflood Project. Reservoir operations at the maintenance level are expected to require remedial work such as stimulations, recompletions and installation of artificial lift systems. These activities should maintain the production rate at the current annual decline rate of 15.5 percent. From FY'89 to FY'95, the total projected cost under the Maintenance Case is $24.3 million with net revenues of $196.0 million. The Development Drilling/Deepening Project is planned to test for production from undepleted portions of the reservoirs. Total costs from FY'89 to FY'95 is $22.0 million with net revenues of $74.7 million. The 31S C/D Shales Pilot Waterflood Project would improve recovery from the reservoirs after primary production. Total costs from FY'89 to FY'95 are $7.4 million and the net revenues generated are $18.5 million. If performance results from the pilot flood are favorable, it is expected that a field-wide peripheral waterflood project would be installed. Production forecast under the Total Development Case would vary from 2,886 BOPD in 1989 to 31 BOPD in 2022 with peak production of 3,001 BOPD in 1994. The Maintenance Case production is expected to decline from 2,886 BOPD in 1989 to 10 BOPD in 2022. These production rates and remaining recovery are shown in Figure 6.

The historic equivalent barrels of oil production rate from 1976 to 1988 and the projections from 1989 to economic limit in 2022 are shown in Figure 7. The increased production rates from 2018 to 2022 are due to gas blow-down of the reservoir.

Several reservoir studies are underway or planned for the 31S C/D Shales. These are the Stevens Material Balance Study, the 31S Comprehensive Reservoir Geologic Description and the 31S C/D Shale Reservoir Study. These studies should improve knowledge of the original-oil-in-place, reserves and alternative management strategies for the 31S C/D Shale Reservoirs.

RESERVOIR DESCRIPTION

The Stevens Zone is believed to have been deposited in deepwater turbidite environment, resulting in a complex interlayering of sands and shales. It is the most productive zone in the 31S Structure. The 31S C/D Shales are located in Sections 25R, 26R, 36R, 30S, 31S, and 32S (see Location Map, Figure 1 and Cross-Section, Figure 2). A subsidiary structure exists and extends eastward into Section 34S. The anticlinal structure of 31S C/D Shales resembles those of other 31S Stevens structures. The crest of the structure is at 4160 ft. subsea in the southeast quarter of Section 25R and northwest quarter of Section 31S.

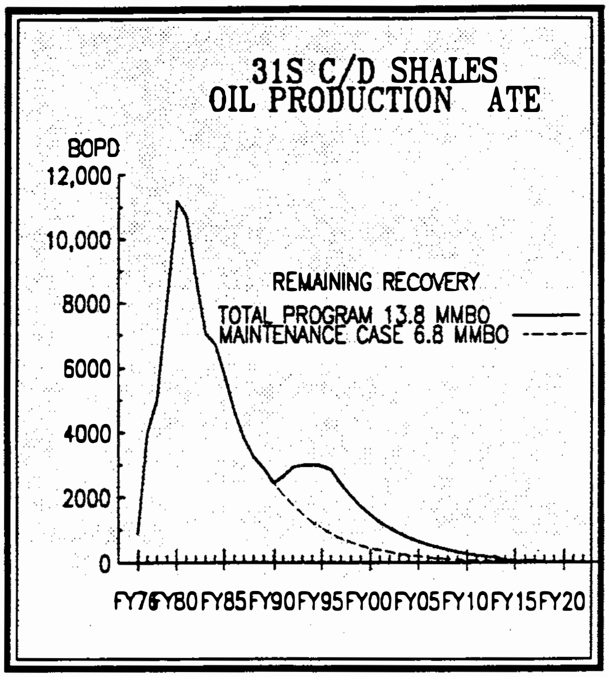


Figure 6

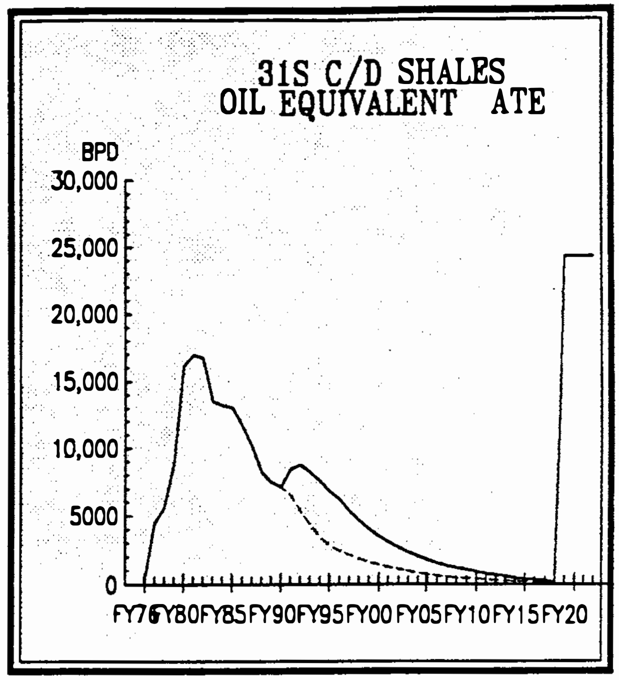


Figure 7

The 31S C and D Shales are different geologic units. The C Shales are made up of shale and siltstone beds which exhibit a typically low SP-low resistivity shale response on E-logs. This indicates that the unit may be slightly siliceous and dolomitic in comparison to other shales. The D Shale, in contrast, exhibits high SP-high resistivity response consistently and is very siliceous and dolomitic.

In the 31S Structure, the 31S C/D Shales underlie the Main Body "B" Sands/Western 31S Sands stratigraphically. Primary production has been at 40-acres well spacing. As of November 1988, fifty- nine wells were completed in the reservoir. Forty-seven (80%) wells were completed only in 31S C/D Shales. Twelve (20%) wells have commingled production with other reservoirs--mainly with MBB/W31S Sands. Twenty-seven (45%) wells completed in the reservoir areshut-in due to high producing gas-oil ratios.

The mechanism of depletion for the 31S C/D Shales is solution-gas drive. There has been no attempt at pressure maintenance or improved recovery by fluid injection. Production peaked at slightly more than 12,000 BOPD in April 1980. Production has declined steadily to 3,115 BOPD in October 1988. The current operating strategy is to conserve reservoir energy by shutting-in wells producing at high gas-oil ratios. The criterion is to review wells producing at or above the gas-oil ratio limit of 12,000 SCF/BBL for shut-in. Conservation of reservoir energy by shutting-in high gas-oil ratio wells has not been entirely successful in controlling decline of reservoir pressure. Average reservoir pressure has declined from initial pressure of 3160 psi to 2341 psi (1988) at 6000 ft. SS. It is generally believed that further substantial decline in reservoir pressure could have adverse impact on ultimate recovery. The reservoir data for the 31S C/D Shales is shown in Figure 8.

31S C/D SHALES
RESERVOIR CHARACTERISTICS

Porosity (%):	14-22	Production Wells (#):	59
Water Sat. (%):	50	Injection Wells (#):	0
Air Perm. (md):	4.23	Top Pay (Ft-VSS):	5,000
Oil Gravity (API):	35-41	Max Pay (Ft):	300
Oil Form. Vol. Fact. (RB/STB):	1.58	Pay Area (AC):	2,763
Oil Viscosity (cp):	0.45	Pay Volume (AF)	903,000
Initial Press. (psi):	3,087	GOC (Ft-VSS):	5,500
Bubble Point Press. (psi):	2,934	WOC (Ft-VSS):	5,900
Current Press (psi):	2,341	Press. Datum (Ft-VSS):	6,000

Figure 8

RESERVOIR STUDIES

Several reservoir studies are underway or planned for 31S C/D Shales. These are the Stevens Material Balance Study, the 31S Comprehensive Reservoir Geologic Description, 31S Structure Study, and the 31S C/D Shale Reservoir Study. The Stevens Material Balance Study is expected to evaluate fluid migration and aquifer depletion in the Stevens reservoirs. This study started in FY'88 and will be completed in FY'89. The 31S Geologic Description is a comprehensive geological and petrophysical description of the Stevens Zone in the 31S Structure. It should be completed in FY'89. In FY'89, J. R. Bergeson and Associates started the 31S Structure Study which would evaluate the reservoir performance of 31S C/D Shales, 31S N/A Shales and MBB/W31S Sands in particular. The 31S C/D Shale Reservoir Study should be started in FY'89 and is expected to be completed in FY'90. It will evaluate different operating strategies for the reservoirs and provide recommendations for optimal production. These studies should improve knowledge of the original-oil-in-place, reserves and alternative management strategies of the 31S C/D Shale reservoirs.

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy for the 31S C/D Shales encompasses operation of the reservoirs under three complementary strategies:

1. Maintenance Case
2. Development Drilling/Deepening Project
3. Pilot Waterflood Project

These constitute the Total Development Case. The economic evaluation of this plan is shown in Table 1 and key economic parameters are summarized in Figure 4.

Historically, the 31S C/D Shales have been considered to be fractured. Preliminary results from the 31S Comprehensive Reservoir Geologic Description suggest that the shales may not be fractured but consists of a complex interlayering of sands and shales. It is fully expected that better reservoir description from the above work or other planned studies may change the strategies offered here.

Maintenance Case: The current annual production decline rate for 31S C/D Shales is 15.5 percent. At maintenance level, oil production rate is projected to decline from 2,886 BOPD in FY'89 to 1,051 in FY'95. To maintain production at these projected levels would require performance of remedial work such as stimulations, recompletions and installation of artificial lift systems. The ultimate oil recovery at the maintenance level is estimated to be 36.3 million barrels which is 2.9 million barrels higher than the booked reserves of 33.4 million barrels. The economic evaluation of the Maintenance Case is shown in Table 2. Key economic feasibility factors are summarized in Figure 9.

Development Drilling/Deepening Project: It was stated earlier that considerable undeveloped reserves may be present in 31S C/D Shale reservoirs The reserves are believed to be present in several unexploited portions of the reservoir. To explore the productive potential of such areas, it is planned that some new MBB/W31S

31S C/D SHALES
MAINTENANCE CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$220.2 Million	$3,538.5 Million
Operating Cost:	$10.9 Million	$76.9 Million
Investment:	$13.4 Million	$30.6 Million
Total Costs:	$24.3 Million	$107.4 Million
Net Revenue:	$196.0 Million	$3,431.0 Million
Net Present Value (@ 10%)	$140.7 Million	$329.2 Million
Recovery:		
Oil (MMB)	4.7	6.8
Natural Gas (BCF)	44.0	244.6
Oil Equivalent (MMBOE)	13.5	56.0

Figure 9

31S C/D SHALES
DEVELOPMENT DRILLING/DEEPENING PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$96.7 Million	$337.5 Million
Operating Cost:	$5.2 Million	$45.8 Million
Investment:	$16.8 Million	$34.1 Million
Total Costs:	$22.0 Million	$79.9 Million
Net Revenue:	$74.7 Million	$257.5 Million
Net Present Value (@ 10%)	$45.3 Million	$96.4 Million
Recovery:		
Oil (MMB)	1.7	3.8
Natural Gas (BCF)	16.5	40.8
Oil Equivalent (MMBOE)	5.1	12.0

Figure 10

wells would be drilled to 31S C/D Shales and tested for production. This strategy offers a very economic utilization of drilling funds since the additional cost to drill into the 31S C/D Shales is minimal. Furthermore, ideally located MBB/W31S wells would be deepened to the 31S C/D Shales at the earliest opportunity. These activities are expected to improve the proven reserves in the reservoirs. Oil production from development drilling/deepening is expected to peak at 1105 BOPD in 1994. Expected production may be higher especially if some of the wells are hydraulically fractured. The potential of hydraulic fracture stimulation in 31S C/D Shales in unknown at this time. Well 344A- 32S has been approved for hydraulic fracturing. The potential of this stimulation technique for the 31S C/D Shales is expected to be evaluated at the completion of the approved work. The economic viability of this project was evaluated as shown in attached Table 3. The key economic parameters are summarized in Figure 10.

Pilot Waterflood Project: Preliminary findings from the 31S Comprehensive Reservoir Geologic Description indicate the 31S C/D Shales may not be fractured. In essence, the geology of the reservoirs is now considered to be a complex interlayering of sands and shales. To evaluate the waterflood process in the 31S C/D Shales, a pilot waterflood is planned to begin in FY'90. The pilot will be a peripheral waterflood and would utilize existing MBB/W31S injectors where possible. Plans are to deepen MBB/W31S water injectors to the 31S C/D Shales and recomplete with dual strings where necessary. The pilot project would require six wells in Section 25R, 26R and 36R. Total water injection rate of 5,300 BWPD will be reached in FY'93. The water injection facility has the capacity to satisfy this requirement. Peak oil production of 1,060 BOPD should be reached in 1996. The strategy is to evaluate the 31S C/D Shales as a waterflood prospect with the aid of the pilot. If the pilot flood performance is favorable, plans are to subject the entire reservoir to a full scale peripheral waterflood. The economic evaluation of this pilot project is shown in Table 4 and the key economic factors are summarized in Figure 11.

All the projects, Maintenance Case and the Total Plan were evaluated with the cost and production data as shown in Figure 12.

31S C/D SHALES
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Stimulations	180,000	75	18
Recompletions	130,000	100	18
Artificial Lift	150,000	80	18
Deepenings	400,000	75	18
Test New Wells (MBB/W31S New Wells)	230,000	75	18
New Wells	1,000,000	--	--

Figure 12

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

Annual activities for reservoir development are planned for the Maintenance Case, Development Drilling/ Deepening Case and the Pilot Waterflood Project. The Maintenance Case activities are projected to sup-

31S C/D SHALES PILOT WATERFLOOD PROJECT	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$25.9 Million	$118.3 Million
Operating Cost:	$2.6 Million	$20.9 Million
Investment:	$4.8 Million	$5.3 Million
Total Costs:	$7.4 Million	$26.2 Million
Net Revenue:	$18.6 Million	$92.1 Million
Net Present Value (@ 10%)	$10.0 Million	$33.4 Million
Recovery:		
Oil (MMB)	0.8	3.2
Natural Gas (BCF)	2.2	4.3
Oil Equivalent (MMBOE)	1.2	4.1

Figure 11

port production at the current annual production decline rate of 15.5 percent. The Development Drilling/Deepening Project should explore the productive potential of the unexploited portions of the reservoir. In the Pilot Waterflood Project, the reservoir activities would explore the feasibility of waterflooding the entire reservoir. The schedule of remedial and drilling activities is shown in attached Table 5.

FY'89

Reservoir deveolpment activities at the maintenance level would revolve around conservation of reservoir energy by recompletion of high gas-oil ratio wells. The most important activity that will be monitored closely is the stimulation of Well 344A-32S by hydraulic fracturing. If hydraulic fracturing of 31S C/D wells prove successful, it would dramatically improve the productivity of these reservoirs and more wells can be fractured in future years.

FY'90

The Pilot Waterflood Project is planned to be initiated with the deepening of two existing MBB/W31S water injectors to the C/D Shales. As in FY'89, reservoir performance at the maintenance level would be sustained by recompletion of wells and the installation of artificial lift systems.

FY'91

The Development Drilling/Deepening Project is expected to proceed with the deepening of three existing MBB/W31S wells and testing of five new wells drilled through 31S C/D Shales. Development drilling/deepening would be enhanced if the hydraulic fracturing project proves successful. For the Pilot Waterflood Project, three wells would be deepened and the project will be about 80% completed by the end of the fiscal year.

FY'92 - FY'95

From FY'92 - FY'95, the 31S C/D Shale reservoirs are expected to be managed at the maintenance levels by conserving reservoir energy through recompletions and prolonging well productivity through stimulations and utilization of artificial lift systems. During the same period, development drilling/deepening would be pursued to produce from the undepleted portions of the reservoir. Reservoir performance data of the Pilot Waterflood Project would be evaluated in terms of water breakthrough times, channeling of injected water through potential fractures, sweep efficiencies, oil recoveries, etc. The performance of the pilot waterflood should determine the future course of action on whether the entire reservoir should be waterflooded.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
31S C/D SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	2886	5212	22955	0	0	0	1596	1062	150	0	300	0
1990	2433	5452	23232	0	0	0	1643	641	103	0	207	828
1991	2657	7352	28721	1760	0	0	2291	1465	160	0	320	3796
1992	2916	9442	29070	4400	0	0	2928	2044	330	0	659	3682
1993	2993	11058	26144	5300	0	0	3243	1686	507	0	1012	2642
1994	3001	12546	22565	5300	0	0	3428	2015	630	0	1259	2690
1995	2976	13915	18953	5300	0	0	3594	2110	639	0	1282	2738
SUBTOTAL *	7250	23717	62649	8052	0	0	18723	11023	2519	0	5039	16376
1996-2022 *	6608	156274	227056	34821	0	0	124827	26028	3022	0	6043	0
TOTAL *	13858	179991	289705	42873	0	0	143550	37051	5541	0	11082	16376

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	15980	14122	5511	35612	3108	2825	32504	29549	2738
1990	14271	15863	5851	35985	3422	2828	32563	26912	2593
1991	16768	21940	8013	46721	8032	6035	38689	29068	3078
1992	19903	24664	10658	55225	9643	6586	45582	31133	3198
1993	22089	24390	10463	56942	9090	5644	47852	29712	3011
1994	23923	22653	9634	56210	10022	5657	46188	26072	2752
1995	25092	21782	9365	56239	10363	5318	45876	23541	2477
SUBTOTAL	138026	145414	59495	342934	53680	34893	289254	195987	19847
1996-2022	219170	2402795	1029277	3651245	159920	27992	3491325	263022	52266
TOTAL	357196	2548209	1088772	3994179	213600	62885	3780579	459009	72113

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
318 C/D SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	2886	5212	22955	0	0	0	1596	1062	150	0	300	0
1990	2433	5452	23232	0	0	0	1643	641	103	0	207	0
1991	2057	5692	22236	0	0	0	1662	1465	160	0	320	0
1992	1739	5932	18032	0	0	0	1589	1505	165	0	329	0
1993	1470	6172	14150	0	0	0	1519	1135	338	0	675	0
1994	1243	6412	11104	0	0	0	1466	1157	401	0	801	0
1995	1051	6652	8713	0	0	0	1436	1236	406	0	816	0
SUBTOTAL *	4701	15156	43954	0	0	0	10911	8201	1723	0	3448	0
1996-2022 *	2074	73565	200628	0	0	0	65984	14149	1011	0	2022	0
TOTAL *	6775	88721	244582	0	0	0	76895	22350	2734	0	5470	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	15980	14122	5511	35612	3108	2825	32504	29549	2738
1990	14271	15863	5851	35985	2594	2144	33391	27596	2593
1991	12981	16986	6204	36171	3607	2710	32564	24466	2383
1992	11870	15299	6611	33779	3588	2451	30191	20621	1958
1993	10849	13201	5663	29713	3667	2277	26046	16173	1575
1994	9909	11147	4741	25797	3825	2159	21972	12402	1269
1995	8862	10013	4305	23180	3894	1998	19286	9897	1023
SUBTOTAL	84722	96631	38886	220237	24283	16564	195954	140704	13539
1996-2022	70387	2273882	973949	3318217	83166	12403	3235051	188512	42418
TOTAL	155109	2370513	1012835	3538454	107449	28967	3431005	329216	55957

(1) OPERATING COST OR OPERATING AND MAINTENABCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
DEVELOPMENT DRILLING/DEEPENING PROJECT
31S C/D SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0	0	0	0
1991	600	1660	6485	0	0	0	485	0	0	0	0	2513
1992	924	3152	9581	0	0	0	844	396	110	0	220	2583
1993	1070	4492	10299	0	0	0	1105	405	112	0	225	2642
1994	1105	5701	9872	0	0	0	1304	710	114	0	229	2690
1995	1072	6787	8890	0	0	0	1465	722	117	0	233	2738
SUBTOTAL *	1741	7954	16471	0	0	0	5203	2233	453	0	907	13166
1996-2017 *	2094	69777	24341	0	0	0	40580	11725	1891	0	3783	0
TOTAL *	3835	77731	40812	0	0	0	45783	13958	2344	0	4690	13166

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	3787	4954	1809	10550	2998	2252	7552	5674	695
1992	6307	8129	3513	17948	4153	2837	13795	9422	1040
1993	7897	9608	4122	21627	4489	2788	17138	10641	1146
1994	8809	9911	4215	22934	5047	2849	17887	10097	1128
1995	9039	10217	4392	23648	5275	2707	18373	9428	1044
SUBTOTAL	35839	42819	18051	96707	21962	13433	74745	45262	5053
1996-2017	69572	119767	51404	240744	57979	11598	182765	51187	6989
TOTAL	105411	162586	69455	337451	79941	25031	257510	96449	12042

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4
LONG RANGE PLAN
PILOT WATERFLOOD PROJECT
318 C/D SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0	0	0	828
1991	0	0	0	1760	0	0	144	0	0	0	0	1283
1992	253	358	1457	4400	0	0	494	143	55	0	110	1099
1993	453	394	1696	5300	0	0	619	146	56	0	112	0
1994	653	433	1589	5300	0	0	658	149	114	0	229	0
1995	853	476	1349	5300	0	0	694	151	117	0	233	0
SUBTOTAL *	807	606	2223	8052	0	0	2609	589	342	0	684	3210
1996-2013 *	2441	12933	2087	34821	0	0	18264	154	119	0	237	0
TOTAL *	3248	13539	4310	42873	0	0	20873	743	461	0	921	3210

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	828	684	-828	-684	0
1991	0	0	0	0	1427	1072	-1427	-1072	0
1992	1727	1236	534	3497	1901	1299	1596	1090	199
1993	3343	1582	679	5604	933	579	4671	2900	290
1994	5205	1595	678	7479	1150	649	6329	3573	355
1995	7192	1550	667	9409	1195	613	8214	4215	410
SUBTOTAL	17467	5963	2558	25989	7434	4896	18555	10022	1254
1996-2013	79291	9149	3924	92362	18774	3991	73588	23338	2861
TOTAL	96758	15112	6482	118351	26208	8887	92143	33360	4115

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 5

318 C&D SHALES
(NUMBER OF REMEDIAL/DEVELOPMENT PROJECTS PER YEAR)

TYPE OF PROJECT	FISCAL YEAR 1989	1990	1991	1992	1993	1994	1995	1996-2022	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	3	2	4	4	2	2	3	30	50
b. RECOMPLETIONS	4	2	5	5	5	5	4	30	60
c. ARTIFICIAL LIFT	3	2	3	3	6	7	7	16	47
SUB-TOTAL	10	6	12	12	13	14	14	76	157
2. DEVELOPMENT DRILLING:									
a. STIMULATIONS	0	0	0	2	2	2	2	27	35
b. RECOMPLETIONS	0	0	0	0	0	2	2	27	31
c. ARTIFICIAL LIFT	0	0	0	2	2	2	2	27	35
d. DEEPENINGS	0	0	3	3	3	3	3	0	15
e. NEW WELLS	0	0	5	5	5	5	5	0	25
SUB-TOTAL	0	0	8	12	12	14	14	81	141
3. PILOT WATERFLOOD PROJECT:									
a. STIMULATIONS	0	0	0	0	0	0	0	0	0
b. RECOMPLETIONS	0	0	0	1	1	1	1	1	5
c. ARTIFICIAL LIFT	0	0	0	1	1	2	2	2	8
d. DEEPENINGS	0	2	3	0	0	0	0	0	5
e. NEW WELLS	0	0	0	1	0	0	0	0	1
SUB-TOTAL	0	2	3	3	2	3	3	3	19
TOTAL	10	8	23	27	27	31	31	160	317

31S N/A SHALES

The 31S N/A Shales are reservoirs within the Stevens Zone of the 31S Structure. They overlie the Main Body "B"/Western 31S Sands stratigraphically on the 31S Structure (See Location Map, Figure 1 and Cross Section, Figure 3). The reservoirs are produced by depletion drive mechanism with well spacing of 40 acres. There are indications from production performance that the reservoir is in communication with MBB/W31S Sands and 26R Sands. Consequently, the current reservoir operating strategy requires balancing volumetric voidage from the three reservoirs by gas injection into 26R Sands and water injection into MBB/W31S Sands. This strategy was implemented on July 1, 1988 and is expected to be in effect for a twelve-month trial period, during which the reservoir pressures of the three reservoirs will be monitored.

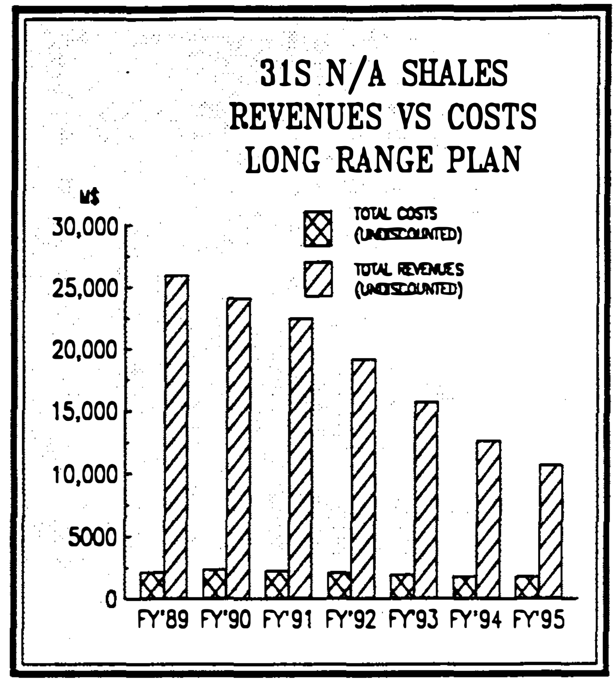


Figure 2

The total Development Case for the 31S N/A Shales represents the Maintenance Case wherein routine remedial activities such as stimulations, recompletions and artificial lift installations are planned. The main objective of these activities is to conserve reservoir energy and hence maintain production at projected levels. Figure 2 is a comparison of total revenues and total costs from FY'89-FY'95. For this period, the total cost of operating this reservoir is $14 million with a total undiscounted revenue yield of $131 million.

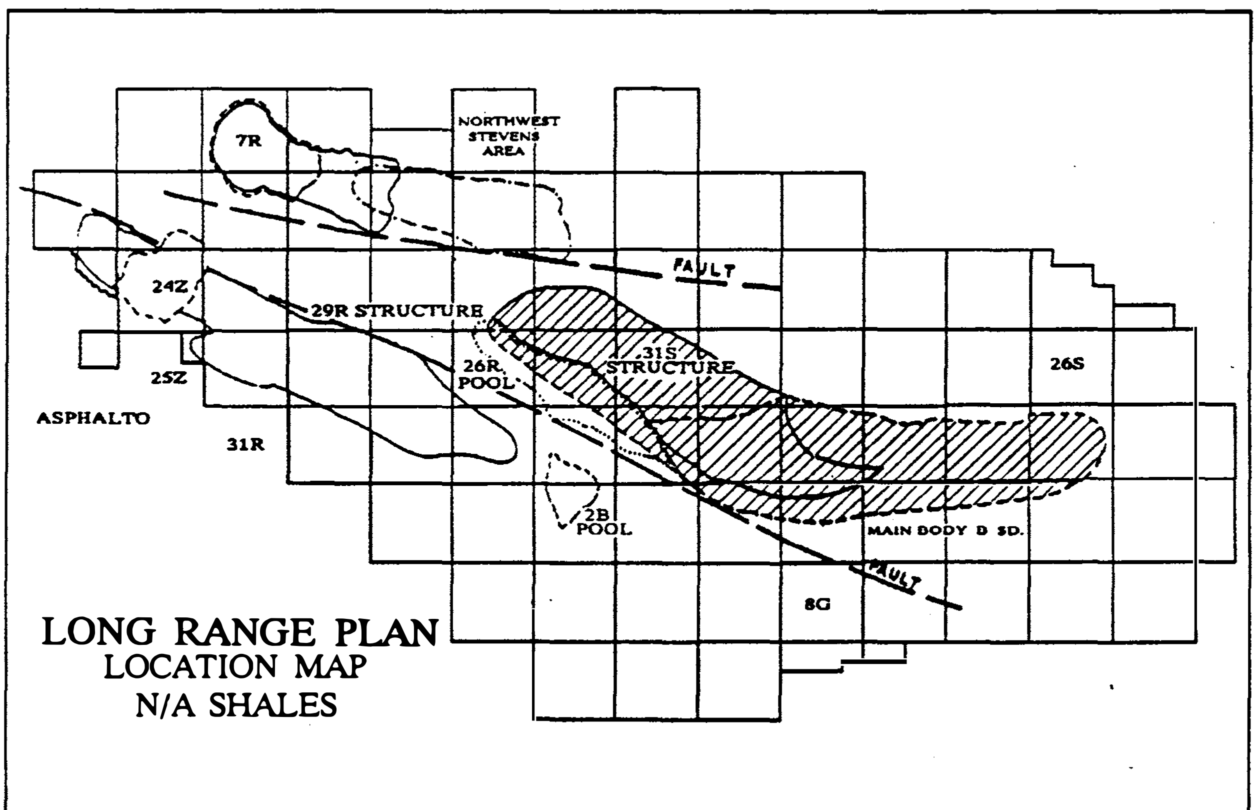


Figure 1

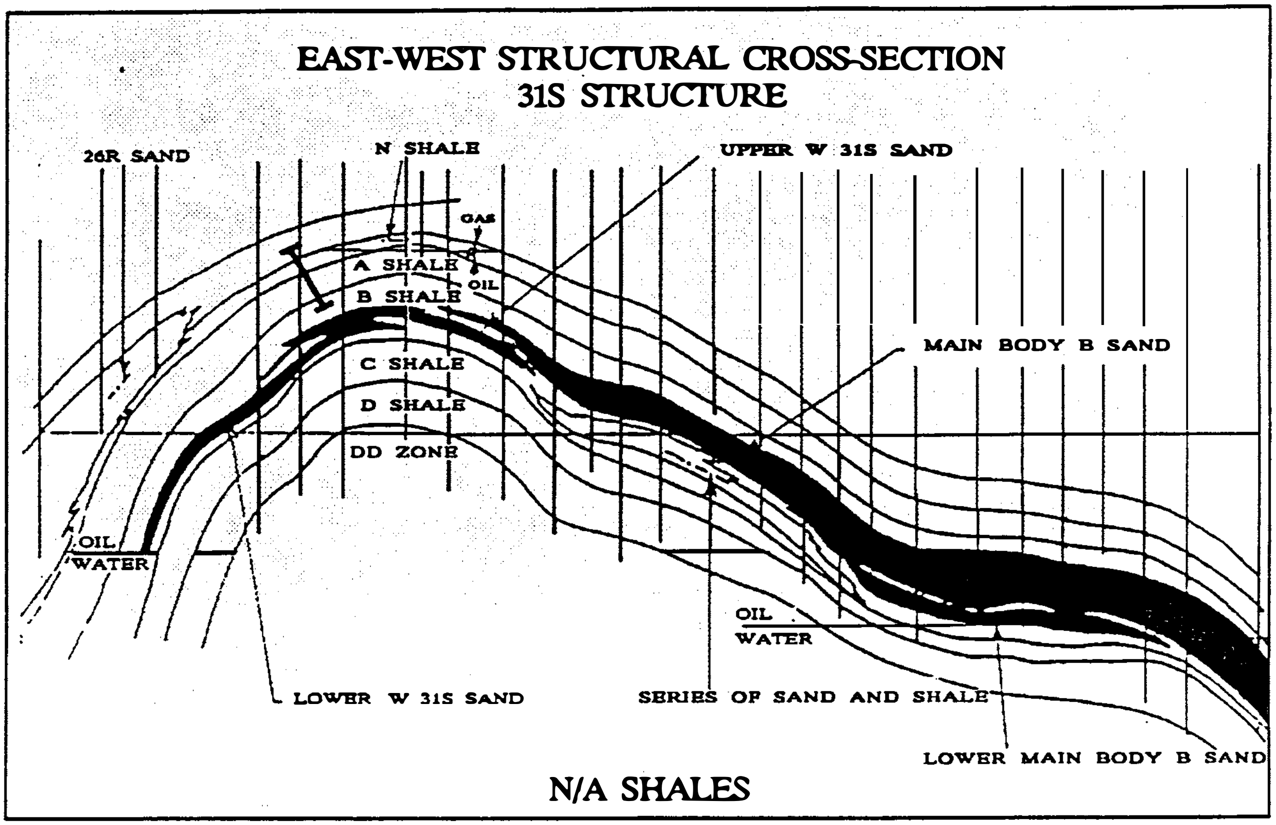


Figure 3

Various economic statistics on the Total Development Case are shown in Figure 4. The net present value for the Total Development Case at 10% discount rate is $86.1 million from FY'89 to FY'95 and $443.6 million from FY'89 to economic limit in FY'2022.

Total oil recovery is 2.3 million barrels from FY'89 to FY'95 and 3.3 million barrels from FY'89 to economic limit.

The estimated original oil-in-place and reserves shown in Figure 5 for the 31S N/A Shales are from the "Stevens Zone Estimated Recoverable Oil and Third Revision of Percentage Participations as of November

31S N/A SHALES
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$130.7 Million	$6,289.9 Million
Operating Cost:	$7.9 Million	$68.9 Million
Investment:	$5.7 Million	$20.1 Million
Total Costs:	$13.6 Million	$89.0 Million
Net Revenue:	$117.1 Million	$6,200.9 Million
Net Present Value (@ 10%)	$86.1 Million	$443.6 Million
Recovery:		
Oil (MMB)	2.3	3.3
Natural Gas (BCF)	29.8	423.6
Oil Equivalent (MMBOE)	8.3	88.5

Figure 4

31S N/A SHALES TOTAL DEVELOPMENT CASE	EQUITY STUDIES	LONG RANGE PLAN MAINT.	TOTAL
Original-Oil-In-Place (MMB):	---	750.0	750.0
Estimated Recoverable Oil (MMB):	97.5	31.8	31.8
Cumulative Production 9/30/88 (MMB):	28.5	28.5	28.5
Remaining Reserves:			
Oil (MMB)	69.0	3.3	3.3
Natural Gas (BCF)	---	423.6	423.6
Oil Equivalent (MMBOE)	---	88.5	88.5
Economic Limit (BOPD, YEAR):	---	39/FY'2022	39/FY'2022

Figure 5

20, 1942" along with a comparison to the Total and Maintenance Cases of the Long Range Plan. There are indications that substantial residual oil may exist in the reservoir at economic limit.

The historical production from 1976 to 1988 and the projected production to the economic limit in FY'2022 is shown in Figure 6. Figure 7 shows historic production and projected production in barrels of oil equivalent. The increase in barrels of oil equivalent produced from FY'2014 to FY'2022 represents blow-down of the reservoir.

RESERVOIR DESCRIPTION

The 31S N/A Shales are reservoirs within the Stevens Zone of the 31S Structure. The Stevens Zone is believed to have been deposited in deepwater turbidite environment, resulting in a complex interlayering of sands and shales. It is the most prolific zone in the 31S Structure. The structure of the 31S N/A Shales is that of a 7.5 mile long anticline with an overall WNW- ESE trend (Figure 1). The crest of the structure lies in the northwest quarter of Section 31S where the top N Shale reaches 3,470 feet subsea and the top A Shales is

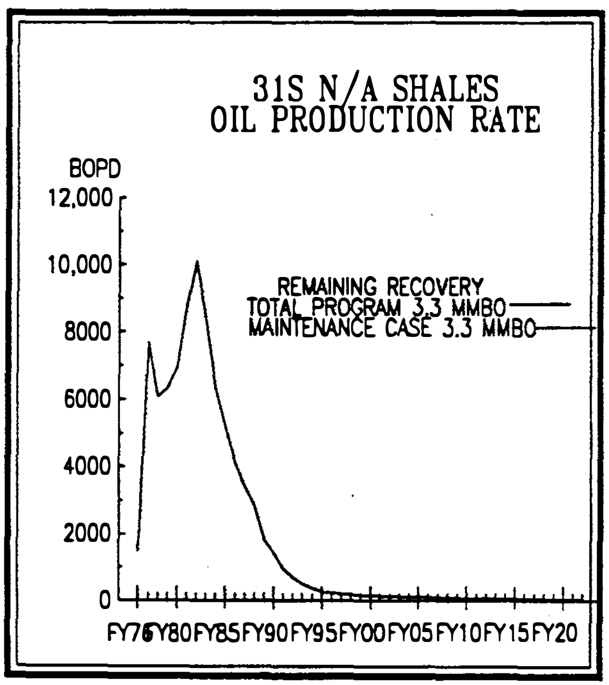


Figure 6

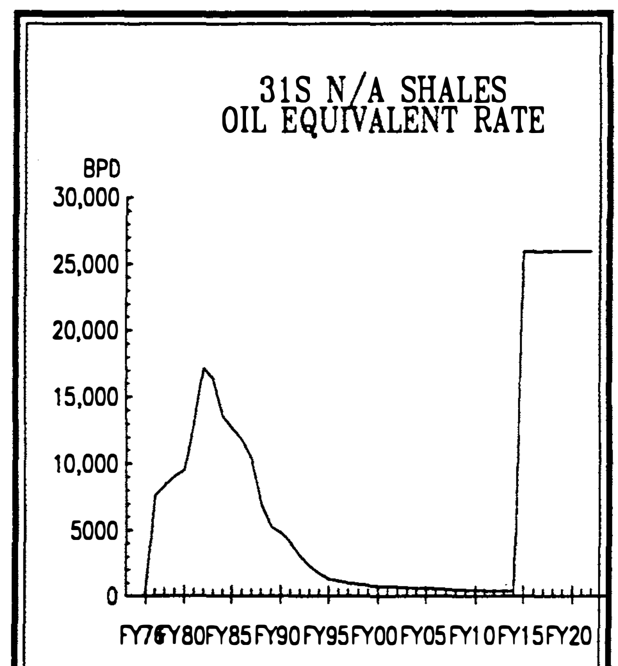


Figure 7

at 3,570 feet subsea. The 31S N/A Shales are all upper Miocene. They consist of shale, siltstone and sandstone beds which may be described as diatomaceous, siliceous, calcareous or dolomitic. Geologically, the shales are equivalent to the 26R Sands.

The 31S N/A Shales overlie the Main Body "B" Sands stratigraphically on the 31S Structure (Figure 3). It has been under primary development at a well spacing of 40 acres. As of November 15, 1988, about 95 wells were completed in the reservoir. Forty-five of these wells are dedicated solely to this reservoir. Fifty wells have commingled production with other reservoirs-- mainly MBB/W31S Sands and 26R Sands. Forty-six of the 95 wells completed in the reservoir are shut-in due to high producing gas-oil ratios.

Figure 8 is a summary of the reservoir characteristics for the 31S N/A Shale.

RESERVOIR STUDIES

Several studies are planned for the 31S N/A Shales in FY '89 and FY '90. The 31S Comprehensive Geologic Description by Scientific Software-Intercomp (SSI) is expected to be completed in FY '89. This study will provide detailed geologic analyses of the 31S Structure and examine evidence of geologic links between 31S N/A Shales, the MBB/W31S Sands and 26R Sands. Another 31S Structure Study by J. R. Bergeson and Associates was initiated in FY '89 which is expected to review the performance of reservoirs in the 31S Structure and make recommendations for the optimization of recoveries from the reservoirs. In FY '90, SSI is planning to start an in-depth reservoir simulation of the 31S N/A Shales. At the completion of this work, a history-matched model will be available for the evaluation of other operating strategies.

RESERVOIR DEVELOPMENT STRATEGY

The 31S N/A Shales reservoir production mechanism is solution gas drive. Except for a brief period of gas injection from 1976 to 1979, the reservoir pressure has not been supported nor maintained. Consequently, the pressure of the reservoir has declined steadily. The reservoir is believed to be in communication with 26R Sands and MBB/W31S Sands. Fluid communication between 31S N/A Shales, 26R Sands and MBB/W31S Sands most likely caused the creation of a huge gas cap in the 31S N/A Shales. It is believed that the gravitational migration of gas into the 31S N/A Shales must have been accompanied by counterflow of oil from this reservoir to the 26R Sands and probably MBB/W31S Sands. The current operating strategy for the 31S N/A Shales is based on the three reservoirs in the 31S Structure being in communication as described earlier. However, recent work completed by the BPOI Reservoir Review Task Force indicates that no communication links nor evidence of communication appear to exist between the MBB/W31S Sands and 31S N/A Shales. Their work suggests the existence of communication pathways between the 26R Sands and 31S N/A Shales. If these findings are confirmed, the management strategy for the 31S N/A Shales will be modified accordingly.

The current reservoir development strategy for 31S N/A Shales considers the impact of communication between the three reservoirs on ultimate recovery. Total fluid production from the reservoirs are considered as produced from one reservoir and balanced in volumetric terms by water injection into MBB/W31S Sands and gas injection into 26R Sands. If injection capacities are insufficient for voidage balance, production from three reservoirs will be curtailed as necessary. In addition,

31S N/A SHALES
RESERVOIR CHARACTERICTICS

Porosity (%):	18.9	Production Wells (#):	95
Water Sat. (%):	45	Injection Wells (#):	0
Air Perm. (md):	29	Top Pay (Ft-VSS):	3,400
Oil Gravity (API):	34-41	Max Pay (Ft-VSS):	400
Oil Form. Vol. Fact.(RB/STB):	1.552	Pay Area (AC):	10,870
Oil Viscosity (cp):	0.42	Pay Volume (MAF):	2,788
Initial Press.(psi) @ -5500:	2,844	GOC (Ft-VSS):	3,600
Bub. Pt. Press.(psi) @ -5500:	2,830	WOC (Ft-VSS):	5,800
Current Press (psi):	2,522	Press. Datum (Ft-VSS):	6,000

Figure 8

wells completed in 31S N/A Shales will be evaluated at a gas-oil ratio of 10,000 SCF/BBL. Wells producing above this level will be reviewed for a remedial job, shut-in or continued operation. This reservoir management strategy took effect on July 1, 1988 for a 12-month trial period.

The 31S N/A Shales oil production rates are projected to decline from 2,097 BOPD in 1989 to 275 BOPD in 1995. These rates are based on the presumption that some form of gas-oil ratio controls will be maintained on the reservoir. Such controls are necessary to minimize any adverse effects that may result because of communication with 26R Sands and probably with MBB/W31S Sands. If gas-oil ratio controls are discontinued, the reservoir will produce at higher oil and gas production rates, which could cause accelerated decline of reservoir pressure and rapid depletion of reservoir energy. This may preclude the implementation of other strategies that may be recommended at the completion of the proposed studies discussed earlier. Several wells completed in 31S N/A Shales reservoirs in Sections 36R and 6G, have been affected by channelling of water from the MBB/W31S waterflood. Geochemical analyses of produced water from the affected wells indicate the presence of Tulare water. Sound management of the 31S N/A Shales reservoirs requires that channelling of injected water from MBB/W31S waterflood must be minimized or eliminated where possible. The reservoir management strategies devised for this problem are well recompletions, routine survey of the mechanical integrity of MBB/W31S water injectors and continuation of production from flank wells to minimize channelling of water towards the crest of the structure.

To optimize production from the 31S N/A Shale reservoirs, two reservoir studies are planned in FY '89 and one study in FY '90. A comprehensive geological description of the 31S Structure was started in FY '88 by Scientific Software-Intercomp (SSI) and is scheduled for completion in FY '89. The study will examine evidence of geologic links between 31S N/A Shales, MBB/W31S Sands and 26R Sands. In FY'89, the 31S Structure Study was initiated by J. R. Bergeson and Associates. In FY '90, SSI is scheduled to start an in-depth 31S N/A Shale Reservoir Study. This simulation study will provide a history-matched model of 31S N/A Shales and facilitate the evaluation of other management strategies for the reservoir.

In the interim, it is generally expected that the findings of the BPOI Reservoir Review Task Force, the yet-to-be published results of the 31S Comprehensive Reservoir Description Study and the on- going work on 31S Structure Study will definitely have impact on future management strategies for the 31S N/A Shales. Depending on the conclusions reached by these studies, possible future management strategies may include the resumption of gas injection into 31S N/A shales or the decoupling of the 26R Sands and 31S N/A Shales reservoirs from the MBB/W31S as separate reservoirs.

The annual production, costs and revenue streams for the Total Development Case are shown in attached Table 1. Key economic parameters are summarized in Figure 4. Cost and production assumptions are shown in Figure 9.

The Recommended Program represents continuation of the current practice of performing routine remedial wellwork such as stimulations, recompletions and installation of artificial lift systems.

The annual remedial and facilities projects planned for 31S N/A Shales are expected to maintain production at

31S N/A SHALES
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Stimulations (acidizing)	80,000	90	15
Recompletions	190,000	100	15
Artificial Lift Installation	170,000	280	15

Figure 9

an average annual decline rate of 25%. Two stimulations per year are planned from FY '89 - FY '95. Two recompletions are scheduled in FY '89. As the reservoir pressure declines, more wells will equalize. To restore these wells to production, two artificial lift installation per year are planned from FY '89 - FY '95. No new wells dedicated solely to 31S N/A Shales are planned for FY'89-FY'95. However, some new wells planned for MBB/W31S Sands will be evaluated for 31S N/A Shales productive potential. A summary of the remedial activity levels is presented as Table 2.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The 31S N/A Shale reservoir is produced by depletion-type mechanism. Consequently, a major part of the annual reservoir development activities is devoted to programs to conserve reservoir energy. From FY '89 - FY '95, several activities are planned to maintain average annual reservoir decline rate at 25%. Oil production is expected to decline from 2,097 BOPD in 1989 to 275 BOPD in 1995. During the same period, gas production will decline from 16,811 MCFPD to 5082 MCFPD. Current practice of conserving reservoir energy by shutting-in high gas-oil ratio wells appears to be stabilizing reservoir pressure. The reservoir pressure averaged 2,522 psi at -6,000' datum in January 1988. Recent data collected in May 1988 indicated there had been no change in reservoir pressure.

FY '89

During this year, the major activity should be the review of the current strategy of balancing voidage from MBB/W31S Sands, 26R Sands and 31S N/A Shales by water injection into MBB/W31S Sands and gas injection into 26R Sands. The above practice was started on July 1, 1988 for a 12-month trial period and is expected to end on June 30, 1989. Future management strategy for 31S N/A Shales would be decided on the basis of the findings of BPOI Reservoir Review Task Force, the expected report of the 31S Comprehensive Geologic Description and the 31S Structure Study.

FY '90 - FY '95

A detailed simulation study of the 31S N/A Shales is scheduled to start in FY '90 which should provide a history-matched model of the reservoir and facilitate evaluation of other management strategies. During the period FY '90 - FY '95, only, maintenance remedial activities are planned at this time. The level of remedial activities should be moderate as shown in attached Table 2.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
31S N/A SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	2097	5717	16811	0	0	0	1424	540	120	0	220	0
1990	1457	6321	16671	0	0	0	1484	363	124	0	228	0
1991	969	5622	15643	0	0	0	1349	578	128	0	236	0
1992	707	4942	11810	0	0	0	1147	385	132	0	241	0
1993	516	4345	8916	0	0	0	977	393	135	0	247	0
1994	377	3820	6731	0	0	0	833	401	137	0	252	0
1995	275	3781	5082	0	0	0	780	408	140	0	256	0
SUBTOTAL *	2335	12610	29807	0	0	0	7994	3068	916	0	1680	0
1996-2022 *	1011	22833	393750	0	0	0	60880	11012	1215	0	2224	0
TOTAL *	3346	35443	423557	0	0	0	68874	14080	2131	0	3904	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	11611	10342	4036	25989	2304	2094	23685	21532	1999
1990	8546	11383	4199	24128	2199	1817	21929	18123	1755
1991	6115	11950	4364	22429	2291	1721	20138	15130	1502
1992	4826	10020	4330	19175	1905	1301	17270	11795	1125
1993	3808	8318	3568	15694	1752	1088	13942	8657	843
1994	3005	6757	2874	12636	1623	916	11013	6217	632
1995	2319	5841	2511	10670	1584	813	9086	4662	473
SUBTOTAL	40230	64611	25882	130721	13658	9750	117063	86116	8329
1996-2022	44023	4277904	1837248	6159174	75331	8506	6083843	357496	80189
TOTAL	84253	4342515	1863130	6289895	88989	18256	6200906	443612	88518

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2

31S N&A SHALES
(NUMBER OF REMEDIAL/DEVELOPMENT PROJECTS PER YEAR)

F I S C A L   Y E A R

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-2022	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	2	2	2	2	2	2	2	26	40
b. RECOMPLETIONS	2	1	2	1	1	1	1	26	35
c. ARTIFICIAL LIFT	2	2	2	2	2	2	2	16	30
TOTAL	6	5	6	5	5	5	5	68	105

NORTHWEST STEVENS (A1-A3) SANDS

The Northwest Stevens structure consists of three major reservoirs: the upper (A1-A3) Sands, the lower (A4-A6) Sands and the T Sands and N Shales. (See Location Map, Figure 1 and Cross Section, Figure 3. The (A1-A3) Sands are pressure maintained by crestal gas injection, the (A4-A6) Sands are peripherally waterflooded and the T Sands and N Shales are being produced under primary depletion with no pressure maintenance.

The Total Development Case for the Northwest Stevens (A1-A3) Reservoir, consists of a Maintenance Case and a Horizontal Drilling Project. An estimated $190 million of undiscounted revenues should be realized over the plan period from FY'89 to FY'95, with associated total costs of $17 million. Annual revenue and cost values are displayed in Figure 2.

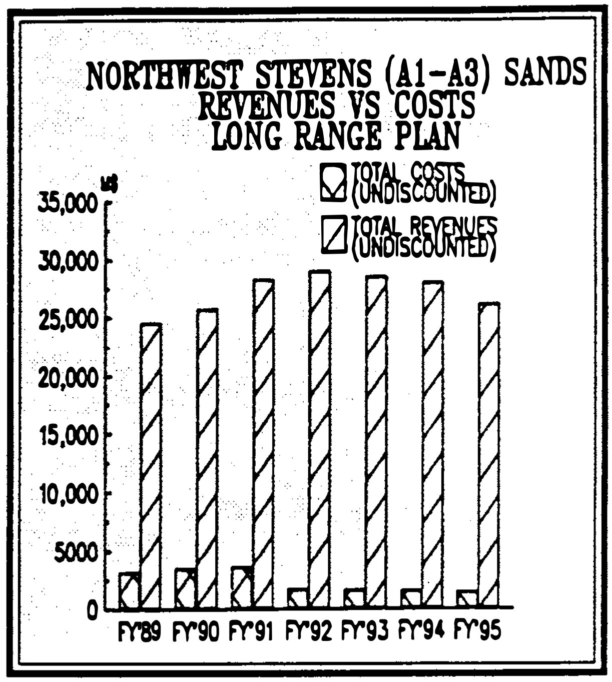


Figure 2

The economic parameters as shown in Figure 4, are a summary of the Total Development Case for the Plan Period and to the Economic Limit.

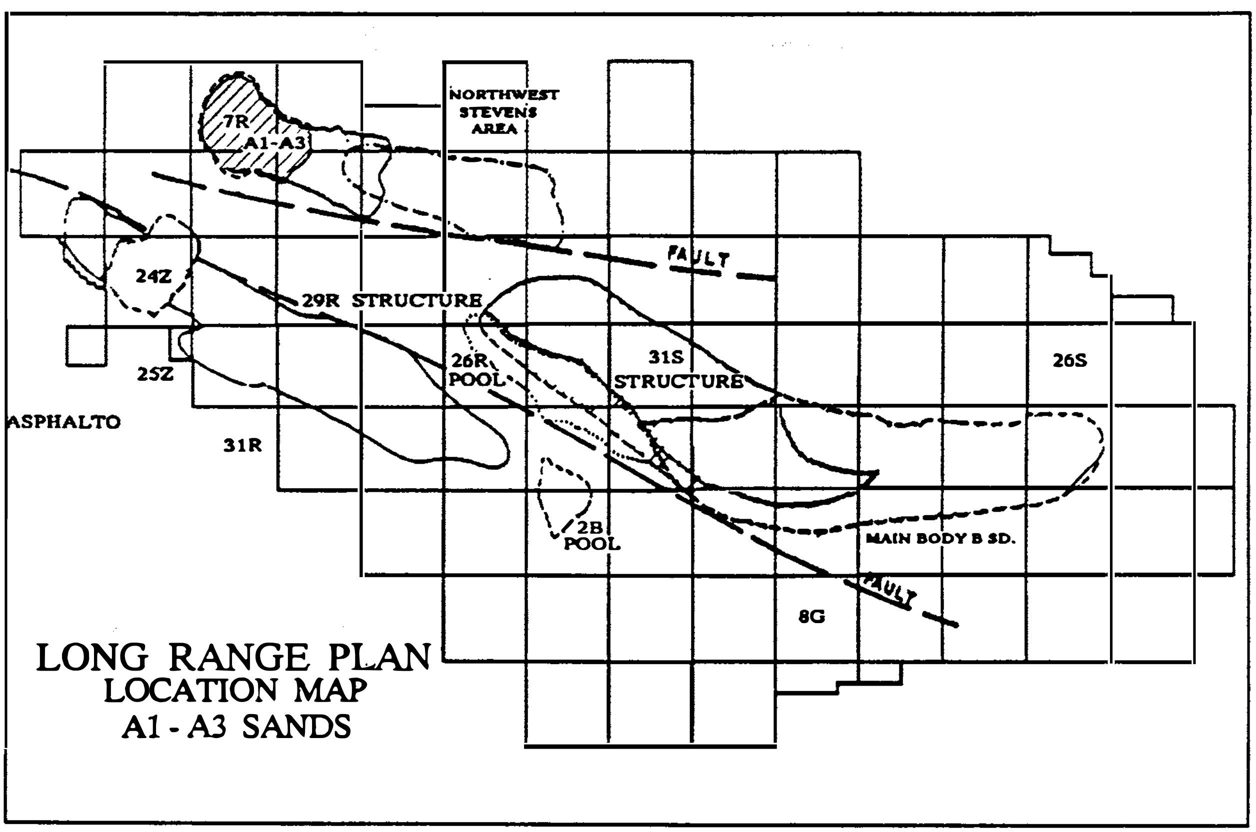
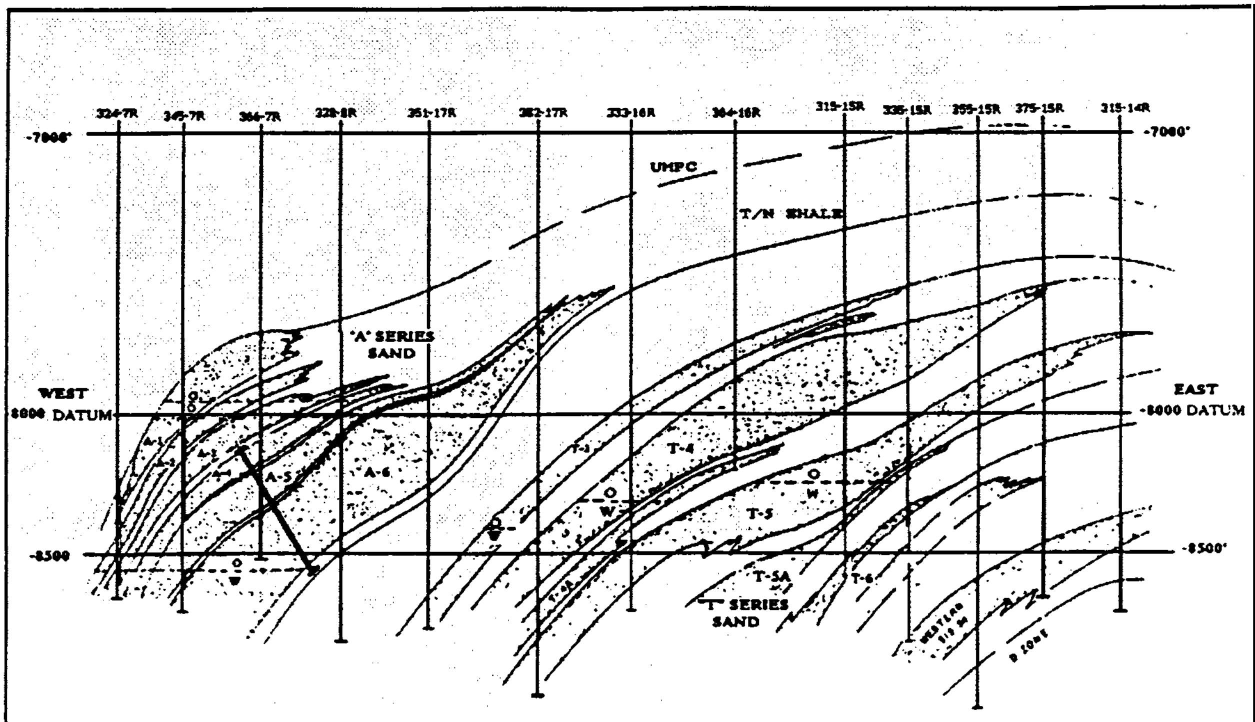


Figure 1



EAST-WEST STRUCTURAL CROSS SECTION
NORTHWEST STEVENS
A 1-3 SANDS

Figure 3

The recovery for the Total Development Case in terms of oil production, gas production and total oil equivalent barrels is also shown in Figure 4.

The estimated oil reserves for the Northwest Stevens (A1-A3) Sands shown in Figure 5 are from the "Stevens Zone Estimated Recoverable Oil and Third Revision of Percentage Participations as of November 20, 1942." These reserves are compared with the Long Range Plan Maintenance Case and Total Development Case.

The Maintenance Case, which includes well remedials and facilities to maintain the current production strat-

NORTHWEST STEVENS (A1-A3) SANDS
TOTAL DEVELOPMENT CASE

	FY'89- FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$190.0 Million	$1,596.3 Million
Operating Cost:	$10.6 Million	$31.9 Million
Investment:	$6.3 Million	$9.2 Million
Total Costs:	$16.9 Million	$41.1 Million
Net Revenue:	$173.1 Million	$1,555.2 Million
Net Present Value (@ 10%)	$119.0 Million	$254.5 Million
Recovery:		
Oil (MMB)	10.5	18.4
Natural Gas (BCF)*	-10.1	57.9
Oil Equivalent (MMBOE)	9.2	31.4

*Total Production Minus Injection

Figure 4

NORTHWEST STEVENS (A1-A3) SANDS TOTAL DEVELOPMENT CASE	EQUITY STUDIES	LONG RANGE PLAN MAINT.	TOTAL
Original-Oil-In-Place (MMB):	77.1	----	----
Estimated Recoverable Oil (MMB):	34.7	34.8	35.4
Cumulative Production 9/30/88 (BCF):	16.9	16.9	16.9
Remaining Reserves:			
Oil (MBB)	17.8	17.8	18.4
Natural Gas (BCF)*	----	58.0	57.9
Oil Equivalent (MMBOE)	----	30.7	31.4
Economic Limit (BOPD, YEAR):	----	26/2021	26/2021
*Total Production Minus Injection			

Figure 5

egy, requires total costs of $12.1 million over FY'89 - FY'95 and yields a net revenue of $150.2 million. The two-well Horizontal Drilling Project is expected to cost a total of $4.9 million over FY'89 FY'95 to yield $22.8 million in net revenue.

Historical production from the Northwest Stevens (A1-A3) Sands Reservoir and projected performance to the economic limit is shown in Figures 6 and 7.

The current reservoir operating strategy is pressure maintenance by crestal gas injection. A total of 25 producing wells are forecast to produce an average rate of 4515 BOPD in FY'89. One gas injection well is expected to provide the required gas injection of approximately 20,000 MCF per day to balance voidage. Remaining oil reserves are estimated from the Stevens Equity Study Reserves to be 17.8 million barrels as of October 1, 1988.

The major field activities planned over the seven-year plan period are the drilling of two horizontal wells, gas isolation work and a new high pressure gas collecting system. The Horizontal Drilling Project provides for one well to be drilled in FY'90 and a follow-up contingent well in FY'91 at a total investment of $3.4 million. These wells should minimize the effect of gas cycling and improve oil recovery by exposing more sand interval to production. A total of 27 gas isolation and remedial jobs are planned to be performed on a routine

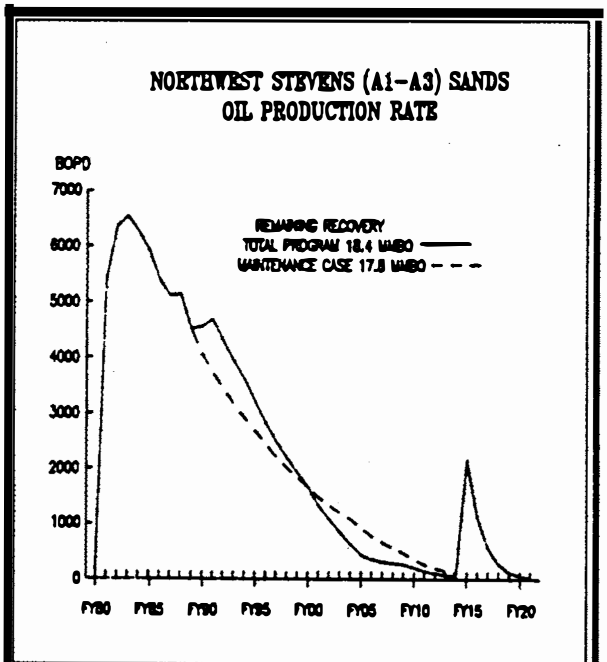


Figure 6

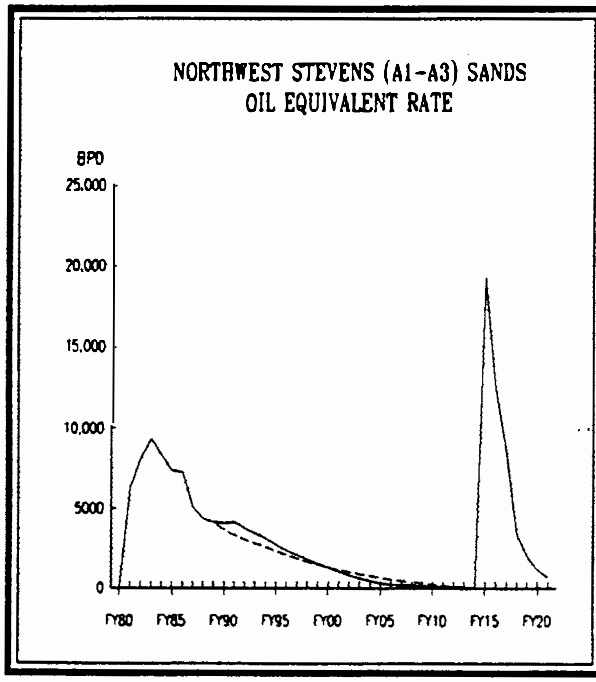


Figure 7

basis to minimize gas cycling and to conserve reservoir energy at a total investment of $1.7 million. Facility investments of $1.4 million are planned for FY'89. A high pressure 14" gas collecting system is recommended to replace the existing pipelines that have reached the end of their useful life due to metal loss from corrosion.

RESERVOIR DESCRIPTION

The Northwest Stevens Structure, located in the northwest area of NPR-1 (see Location Map, Figure 1), is approximately four miles long and one mile wide. The trapping mechanism consists of a series of discrete sand bodies that trend nearly north-south across the west-northwesterly plunge of the asymmetrical Northwest Stevens Anticline (see Cross Section, Figure 3. The A Sands are composed of poorly sorted, moderately uniform, porous and permeable, arkosic sandstones interbedded with thin to thick shale units and other fine grained rocks. Limited petrophysical analysis from cores and logs indicates an average porosity of 17- 20% with permeabilities averaging 50-100 md. Average water saturations are reported to be approximately 24% (See Figure 8 for reservoir data).

The Northwest Stevens (A1-A3) Sands were put on production in 1980 and have been under gas injection since 1983 to support reservoir pressure. As of October 1988, 51% of the estimated reserves remained to be produced.

Currently there are 31 production wells and one injection well which balances voidage by injecting approximately 20,000 MCF/Day into the (A1-A2) Sands. It was initially thought that this injection was also supporting the A3; however, pressure surveys have indicated that the A3 Sand is not being supported. Results of a Pressure Monitoring Program completed in May 1988 show the (A1-A2) Sand pressure to be stabilized at 2878 psi due to gas injection, while the pressure of the A3 Sand is 2514 psi because it is not apparently in communication with the (A1-A2) Sands.

The Northwest Stevens surface facilities include six tank settings located in Sections 7R, 8R, 15R, 16R and 17R. Facilities used for (A1-A3) Sands production are the 1-7R, 3-8R and 1-17R tank settings, the gas compression station in 35R which accommodates gas injection and a gas lift compressor system in 8R.

RESERVOIR STUDIES

Scientific Software-Intercomp (SSI) and Evans, Carey and Crozier (EC&C) have completed studies on this reservoir. A simulation study by SSI should be completed in FY'89. An "Evaluation and MER Determination" by EC&C was completed in 1986 and concluded that the gas injection program into the (A1-A2) Sands, has been effective. The study also recommended pressure support by water injection into the A3 Sand. Based on preliminary data, a simulation study which was completed by SSI in January 1989, recommended that the A3 Sand be included with the (A4-A6) Waterflood. The history matched model will be used to investigate the economics of producing the (A1-A3) Sands under various alternative operating strategies to determine the most economically attractive operational strategy for this reservoir:

- Continuation of the current full pressure maintenance program
- Pressure depletion
- Various gas-oil ratio production programs
- Waterflood of the A3 Sand
- Partial pressure maintenance
- Optimum time for gas blowdown

NORTHWEST STEVENS (A1-A3) SANDS
RESERVOIR CHARACTERISTICS

Porosity (%):	18.9	Production Wells (#):	31
Water Sat. (%):	23.4	Injection Wells (#):	1
Air Perm. (md):	35-190	Top Pay (Ft-VSS):	7,660
Oil Gravity (API):	34-41	Max Pay (Ft):	484
Oil Form. Vol. Fact. (RB/STB):	1.45	Pay Area (AC):	615
Oil Viscosity (cp):	2.0	Pay Volume (AF)	59,632
Initial Press. (psi):	4,152	GOC (Ft-VSS):	8,260
Bubble Point Press. (psi):	2,760	WOC (Ft-VSS):	8,550
Current Press. A1-A2 (psi):	2,878	Press. Datum (Ft-VSS):	8,300
Current Press. A3 (psi):	2,514		

Figure 8

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy for the Northwest Stevens (A1- A3) Sands is primarily concerned with maintaining the reservoir at constant pressure by gas injection to balance reservoir voidage. Recent pressure and production data exhibit strong evidence that the A3 Sand is not in communication with the A1 and A2 Sands and needs additional pressure support. Results of a Pressure Monitoring Program completed in May 1988 showed a difference in pressures between the (A1-A2) and A3 to be 364 psi. A plan is being formulated to include the A3 Sand with the (A4-A6) Waterflood and to continue gas injection into the (A1-A2) Sands to increase recovery. Production allocation factors will be changed to reflect this new plan. It is anticipated that the A3 Sand will be under waterflood by opening the A3 Sand in some of the current peripheral injectors. This anticipated waterflood plan is being simulated on a history matched model. Also, alternate production strategies are expected to be studied using the model. These model studies should result in an economic analysis of the various strategies so that the most economic method of production can be employed. An expanded discussion of the A3 Sand strategy is presented in the A4-A6 Reservoir Operating Plan.

The production, cost and revenue streams for the Total Development Case are shown in the Economics Table 1. Key economic parameters are summarized in Figure 4. Cost and production assumptions are shown in Figure 9.

The Maintenance Case represents continuation of the present production strategy of supporting the (A1-A3) Sands with gas injection. Gas isolation remedials are required to maintain production as upper perforations produce excessive gas due to the lowering of the gas-oil contact. Facility expenditures are provided for the replacement of the Northwest Stevens High Pressure Gas Collecting System which runs from Stevens Tank Setting 1-7R to the 35R Gas Processing Facilities. The proposed replacement pipeline will be 14" nominal diameter, a length of approximately 32,000' and would roughly parallel the existing system. This pipeline system is now experiencing a very high rate of corrosion. Repairs and replacement of short sections of the piping have been made to extend the service life approximately another 12 months. The existing pipeline must be replaced because of its design and condition which prevents adequate corrosion protection to prevent failures. Gas injection is assumed to continue throughout the life of this case and the high related costs result in the economic limit being reached at a relatively high oil rate.

Details of the Maintenance Case are shown in the Economics Table 2. A summary of the key economic parameters and the remaining recoveries are shown in Figure 10.

NORTHWEST STEVENS (A1-A3) SANDS
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Stimulations (acidizing)	60,000	50	10
Recompletions (Reperforations, Gas isolations)	130,000	50	10
Miscellaneous Wireline Stimulations	20,000	50	10
Horizontal Well	1,600,000	527	10
Facilities (Replacement Pipeline 14", 32,000')	1,354,000	--	--

Figure 9

NORTHWEST STEVENS (A1-A3) SANDS MAINTENANCE CASE	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$162.3 Million	$1,601.9 Million
Operating Cost:	$9.1 Million	$31.8 Million
Investment:	$3.0 Million	$5.8 Million
Total Costs:	$12.1 Million	$37.6 Million
Net Revenue:	$150.2 Million	$1,564.3 Million
Net Present Value (@ 10%)	$104.4 Million	$244.6 Million
Recovery:		
Oil (MMB)	8.9	17.8
Natural Gas (BCF)*	-8.2	58.0
Oil Equivalent (MMBOE)	8.0	30.7

*Total Production Minus Injection

Figure 10

The Horizontal Drilling Project is expected to be initiated with the drilling of one well in FY'90, with the horizontal portion of the hole extending approximately 1000' in length at the base of the A1 and A2 Sands. The purpose of this well is to minimize the effect of gas cycling through the upper portion of the sands and improve oil production. A second well will be drilled in FY'91 if the first well is successful. This project is fully described in Economics Table 3 and the results are summarized in Figure 11.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The annual reservoir development activities are described on the following page for the ensuing seven-year plan period. Details of the drilling and remedial activities are shown in Table 4 and Table 5.

FY'89

Gas injection is currently planned to continue balancing

NORTHWEST STEVENS (A1-A3) SANDS HORIZONTAL DRILLING PROJECT	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$27.7 Million	$-5.6 Million
Operating Cost:	$1.5 Million	$0.1 Million
Investment:	$3.4 Million	$3.4 Million
Total Costs:	$4.9 Million	$3.5 Million
Net Revenue:	$22.8 Million	$-9.1 Million
Net Present Value (@ 10%)	$14.4 Million	$10.0 Million
Recovery:		
Oil (MMB)	1.6	0.7
Natural Gas (BCF)*	-1.9	-0.1
Oil Equivalent (MMBOE)	1.3	0.7

*Total Production Minus Injection

Figure 11

production voidage to maintain reservoir pressure. Maintenance remedials necessary to continue production operations consist of acid stimulation, recompletions to eliminate excessive gas entry problems and miscellaneous wireline stimulation. Pressure maintenance of the A3 Sand will be addressed during the year and it is expected that the A3 Sand should become part of the (A4-A6) Sand waterflood.

FY'90

Reservoir development activities include maintenance remedials and the drilling of one horizontal well completed at the base of the sand. This well is expected to provide an opportunity to determine the feasibility of eliminating excessive gas entry problems. Other opportunities that should be investigated to decrease gas entry are reducing gas injection to move toward partial pressure maintenance in the (A1-A3) Sands, or producing at higher GOR limits.

FY'91

In addition to maintenance remedials, a second horizontal well is planned to be drilled in FY'91, if the horizontal well is successful in FY'90.

FY'92-95

During the outyears, only maintenance remedial activity is planned at this time. This activity will remain constant for the period.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
NORTHWEST STEVENS (A1-A3) SANDS
(NOMINAL DOLLARS)

FY		OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989		4515	668	15906	0	19039	0	1246	730	0	1354	0	0
1990		4560	912	20410	0	24566	0	1548	300	0	0	0	1656
1991		4688	1184	21854	0	26355	0	1721	171	0	0	0	1711
1992		4300	1284	20068	0	24380	0	1654	110	0	0	0	0
1993		3944	1344	18423	0	22532	0	1578	112	0	0	0	0
1994		3616	1407	16912	0	20841	0	1502	114	0	0	0	0
1995		3212	1396	15174	0	18799	0	1389	117	0	0	0	0
SUBTOTAL	*	10525	2991	46993	0	57127	0	10638	1654	0	1354	0	3367
1996-2021	*	7914	6715	113173	0	45140	0	21225	2826	0	0	0	0
TOTAL	*	18439	9706	160166	0	102267	0	31863	4480	0	1354	0	3367

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	25000	-4254	3818	24565	3330	3028	21235	19304	1510
1990	26747	-6169	5140	25718	3504	2896	22214	18359	1477
1991	29585	-7437	6097	28245	3603	2707	24642	18514	1507
1992	29350	-7767	7358	28941	1764	1205	27177	18562	1370
1993	29108	-8008	7373	28472	1690	1050	26782	16629	1246
1994	28825	-8100	7221	27946	1616	912	26330	14863	1132
1995	27082	-8457	7497	26122	1506	773	24616	12632	997
SUBTOTAL	195697	-50192	44504	190009	17013	12571	172996	118863	9239
1996-2021	312747	690011	403524	1406285	24051	4505	1382234	135674	22189
TOTAL	508444	639819	448028	1596294	41064	17076	1555230	254537	31428

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
NORTHWEST STEVENS (A1-A3) SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	4515	668	15906	0	19039	0	1246	730	0	1354	0	0
1990	4060	743	18716	0	22353	0	1393	300	0	0	0	0
1991	3736	790	18680	0	22125	0	1408	171	0	0	0	0
1992	3438	839	17189	0	20464	0	1349	110	0	0	0	0
1993	3164	892	15818	0	18941	0	1289	112	0	0	0	0
1994	2911	948	14555	0	17548	0	1227	114	0	0	0	0
1995	2679	1008	13394	0	16273	0	1171	117	0	0	0	0
SUBTOTAL *	8944	2149	41704	0	49911	0	9083	1654	0	1354	0	0
1996-2021 *	8813	7543	116642	0	50438	0	22722	2826	0	0	0	0
TOTAL *	17757	9692	158346	0	100349	0	31805	4480	0	1354	0	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	25000	-4254	3818	24565	3330	3028	21235	19304	1510
1990	23814	-5515	4714	23013	1693	1399	21320	17620	1322
1991	23577	-5989	5211	22800	1579	1186	21221	15943	1217
1992	23466	-6227	6302	23541	1459	997	22082	15082	1113
1993	23351	-6423	6330	23258	1401	870	21857	13572	1017
1994	23205	-6504	6214	22916	1341	757	21575	12179	927
1995	22588	-7023	6618	22183	1288	661	20895	10722	845
SUBTOTAL	165001	-41935	39207	162276	12091	8898	150185	104422	7951
1996-2021	357073	669749	412829	1439654	25548	4683	1414106	140134	22790
TOTAL	522074	627814	452036	1601930	37639	13581	1564291	244556	30741

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
HORIZONTAL DRILLING PROJECT
NORTHWEST STEVENS (A1-A3) SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	500	169	1694	0	2214	0	155	0	0	0	0	1656
1991	952	394	3174	0	4231	0	313	0	0	0	0	1711
1992	862	444	2879	0	3916	0	305	0	0	0	0	0
1993	780	452	2606	0	3591	0	290	0	0	0	0	0
1994	705	458	2356	0	3293	0	274	0	0	0	0	0
1995	533	388	1780	0	2526	0	218	0	0	0	0	0
SUBTOTAL *	1581	841	5288	0	7216	0	1555	0	0	0	0	3367
1996-2015 *	-899	-828	-3470	0	-5299	0	-1497	0	0	0	0	0
TOTAL *	682	13	1818	0	1917	0	58	0	0	0	0	3367

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	2933	-655	427	2704	1811	1497	893	738	155
1991	6008	-1449	886	5444	2024	1521	3420	2570	290
1992	5884	-1540	1056	5399	305	208	5094	3480	257
1993	5757	-1584	1043	5215	290	180	4925	3058	230
1994	5620	-1597	1006	5029	274	155	4755	2684	204
1995	4494	-1434	879	3940	218	112	3722	1910	152
SUBTOTAL	30696	-8259	5297	27731	4922	3673	22809	14440	1288
1996-2015	-44328	20261	-9305	-33373	-1497	-178	-31876	-4459	-60[illegible]
TOTAL	-13632	12002	-4008	-5642	3425	3495	-9067	9981	687

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4

DRILLING ACTIVITY

NWS(A1-A3) SANDS

(NUMBER OF DRILLING WELLS PER YEAR)

TYPE OF PROJECT	FISCAL YEAR 1989	1990	1991	1992	1993	1994	1995	1996-14	TOTAL
1. MAINTENANCE CASE:									
a. NEW WELLS	0	0	0	0	0	0	0	0	0
SUB-TOTAL:	0	0	0	0	0	0	0	0	0
2. HORIZONTAL DRILLING PROJECT:									
a. NEW WELLS	0	1	1	0	0	0	0	0	2
SUB-TOTAL:	0	1	1	0	0	0	0	0	2
TOTAL:	0	1	1	0	0	0	0	0	2

TABLE 5

REMEDIAL ACTIVITY

NWS(A1-A3) SANDS-

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	FISCAL YEAR 1989	1990	1991	1992	1993	1994	1995	1996-14	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	1	2	2	1	1	1	1	27	36
b. RECOMPLETIONS	5	1	0	0	0	0	0	0	6
c. ARTIFICIAL LIFT	0	0	0	0	0	0	0	0	0
d. STIM/WIRELINE	1	2	2	2	2	2	2	54	67
SUB-TOTAL:	7	5	4	3	3	3	3	81	109
2. HORIZONTAL DRILLING PROJECT: NONE									
TOTAL:	7	5	4	3	3	3	3	81	109

NORTHWEST STEVENS (A4-A6) SANDS

The Northwest Stevens structure consists of three major reservoirs: the upper (A1-A3) Sands, the lower (A4-A6) Sands, and the T Sands and N Shales (See Location Map, Figure 1 and Cross Section, Figure 3). The (A1-A3) Sands are pressure maintained by crestal gas injection, the (A4-A6) Sands are peripherally waterflooded and the T Sands and N Shales are being produced under primary depletion with no pressure maintenance.

The Total Development Case for the Northwest Stevens (A4-A6) Reservoir, consists of a Maintenance Case and a Development Drilling Project. This Total Plan is estimated to yield $254 million in undiscounted revenues over the next seven-year period, for a total expenditure of $46 million. Annual revenue and cost values are displayed in Figure 2.

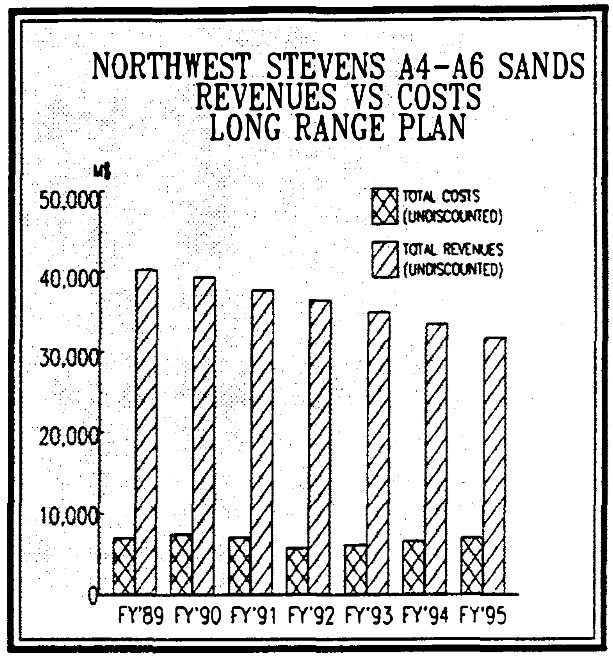


Figure 2

The economic parameters shown in Figure 4 are a summary of the Total Development Case for the plan period and to the economic limit.

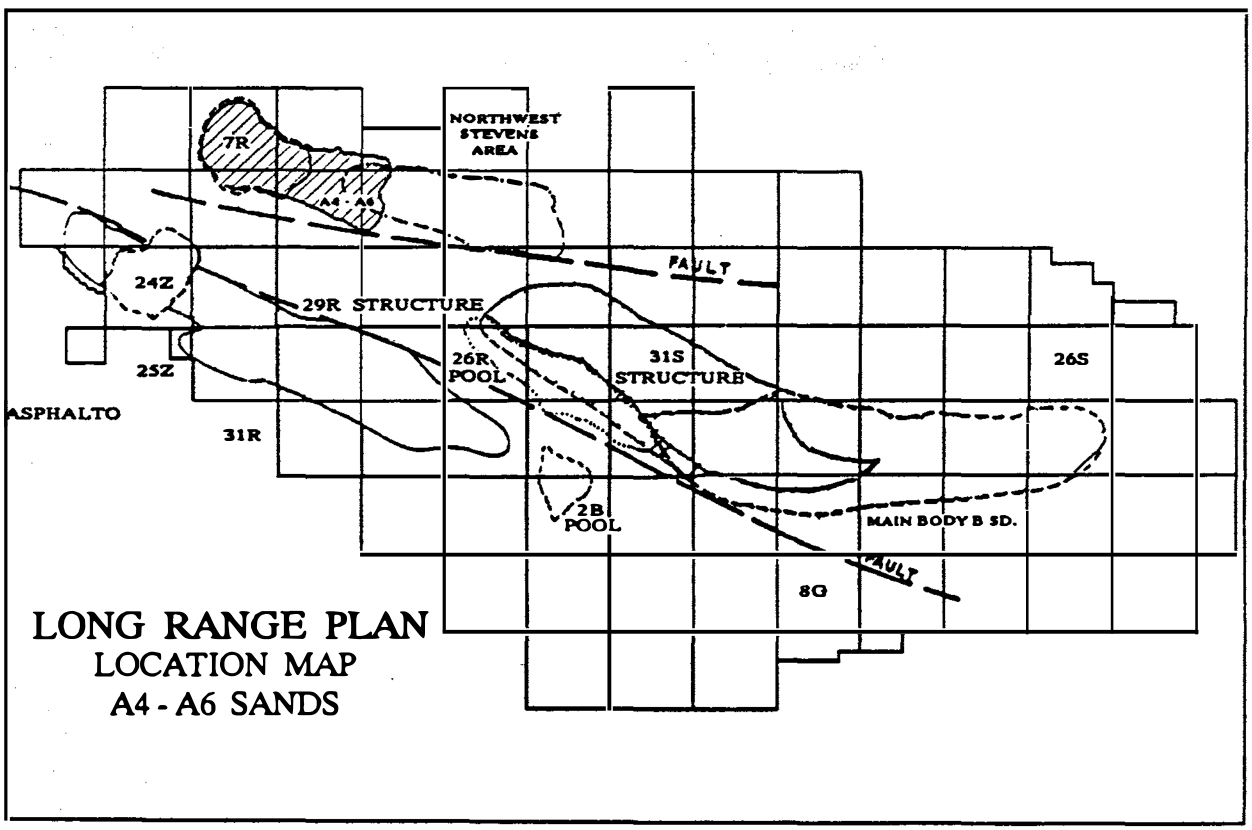
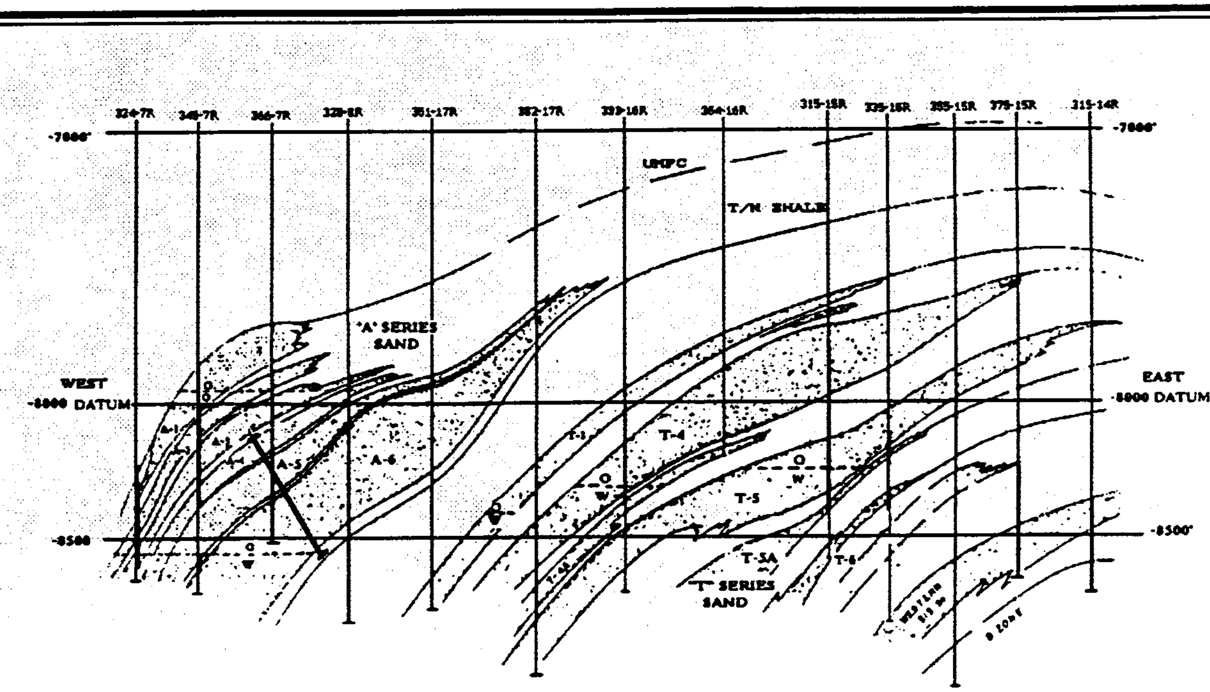


Figure 1



EAST-WEST STRUCTURAL CROSS SECTION
NORTHWEST STEVENS
A 4-6 SANDS

Figure 3

The recovery for the Total Development Case in terms of oil production, gas production and total oil equivalent barrels is also shown in Figure 4.

The estimated oil reserves for the Northwest Stevens (A4-A6) Sands shown in Figure 5 are from the "Stevens Zone Estimated Recoverable Oil and Third

NORTHWEST STEVENS (A4-A6) SANDS
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$254.0 Million	$426.8 Million
Operating Cost:	$32.4 Million	$105.1 Million
Investment:	$13.2 Million	$21.1 Million
Total Costs:	$45.6 Million	$126.2 Million
Net Revenue:	$208.4 Million	$300.6 Million
Net Present Value (@ 10%)	$147.3 Million	$183.0 Million
Recovery:		
Oil (MMB)	12.5	18.0
Natural Gas (BCF)	7.8	11.3
Oil Equivalent (MMBOE)	14.1	20.3

Figure 4

NORTHWEST STEVENS (A4-A6) SANDS TOTAL DEVELOPMENT CASE	EQUITY STUDIES	LONG RANGE PLAN MAINT.	TOTAL
Original-Oil-In-Place (MMB):	138.9	--	--
Estimated Recoverable Oil (MMB):	55.6	44.5	45.8
Cumulative Production 9/30/88 (MMB):	27.8	27.8	27.8
Remaining Reserves:			
Oil (MMB)	27.7	16.7	18.0
Natural Gas (BCF)	--	10.6	11.3
Oil Equivalent	--	18.8	20.3
Economic Limit (BOPD, YEAR):	--	1311/2002	1438/2002

Figure 5

Revision of Percentage Participations as of November 20, 1942." They are compared with the Long Range Plan Maintenance and Total Development Cases.

The Maintenance Case, which includes well remedials and facilities to maintain the current production strategy, requires total costs of $41.2 million over FY'89 - FY'95 and yields a net revenue of $196.1 million. The two-well Development Drilling Project will cost a total of $4.4 million over FY'89 - FY'95 to yield $12.3 million in net revenue.

The current Reservoir Operating Strategy is to inject water into peripheral wells to support reservoir pressure and improve recovery over primary depletion methods. A total of 44 active wells are estimated to produce an average rate of 6,616 BOPD in FY'89. Historical production from the Northwest Stevens (A4-A6) reservoir and projected performance to the economic limit is shown in Figures 6 and 7. The oil production and total hydrocarbon production in those graphs is expressed as barrels of oil equivalent.

Eighteen water injection wells should provide the required water injection of approximately 19,000 BWPD to balance voidage. Remaining oil reserves from the Stevens Equity Study Reserves are 27.7 million barrels as of October 1, 1988.

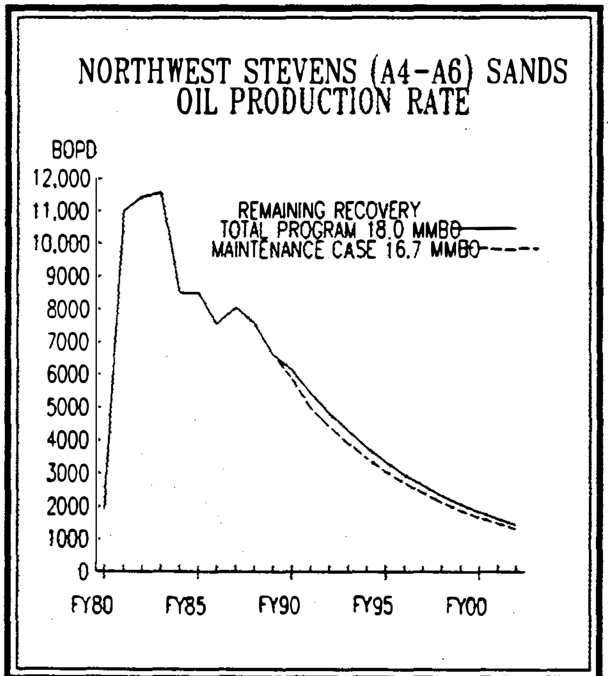


Figure 6

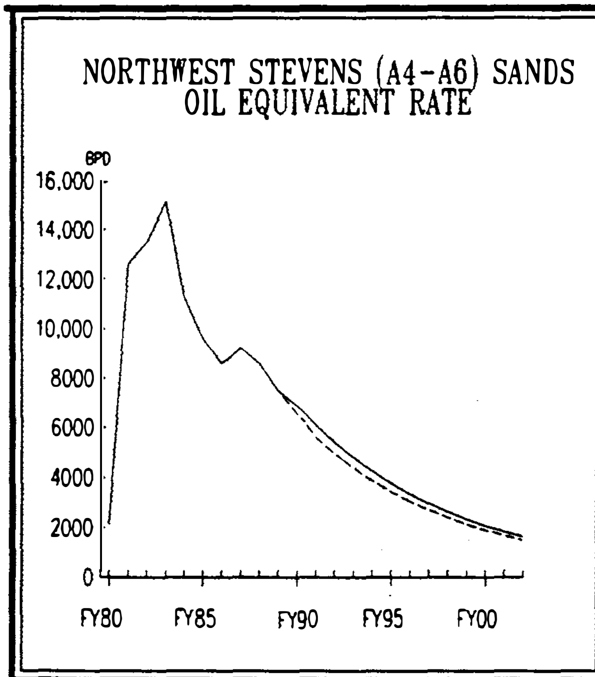


Figure 7

A general field operating strategy for this reservoir will be to continue water injection, control water floodfronts at the injection wells and to perform water isolations on producers as necessary. Controlling floodfronts from the injectors with sands of varying permeability should be an easier and more cost effective strategy than allowing more permeable zones in producers to "water-out" before isolation. Packer/mandrels are currently used in injectors to control profiles. Cement squeezes and limited entry perforating are proposed to control profiles while minimizing crossflow behind cement in blank sections of casing. The current strategy is to produce the wells to their economic limit regardless of water cut. This involves some water cycling, but will allow high cumulative oil rates before shut-in. Stimulations to remove skin damage due to scale and asphaltenes are required to maximize fluid withdrawals from each well and maintain high reservoir productivity.

RESERVOIR DESCRIPTION

The Northwest Stevens Structure, located in the northwest area of NPR-1 (see Location Map, Figure 1), is approximately four miles long and one mile wide. The trapping mechanism consists of a series of discrete sand bodies that trend nearly north-south across the west-northwesterly plunge of the asymmetrical Northwest Stevens Anticline (see Cross Section, Figure 3). The A4-A6 Sands are composed of poorly sorted, moderately uniform, porous and permeable, arkosic sandstones interbedded with thin to thick shale units and other fine grained rocks. Genesis of a significant portion of these sands are similar to other Elk Hills channel-fill Stevens turbidite deposits. Limited petrophysical analysis from cores and logs indicates an average porosity of 17-20% with permeabilities averaging 50-100 md. Average water saturations are reported to be approximately 31%. Reservoir characteristics are displayed in Figure 8.

The Northwest Stevens (A4-A6) Sands were put on open-up production in 1980 and water injection was initiated in 1983 to support pressure from the periphery. As of October 1988, 50% of the estimated reserves remained to be recovered.

Currently there are 44 active producing wells and 18 injection wells which balance voidage by injecting approximately 19,000 BWPD into the (A4-A6) Sands. New injection wells are expected to be necessary to provide additional pressure support in the future for the A-3 and A-6 Sands.

The Northwest Stevens surface facilities include six tank settings located in Sections 7R, 8R, 15R, 16R, and 17R. Facilities used for (A4-A6) Sands production are the 1-7R, 3-8R, 1-17R, and 2-17R Tank Settings, the 8R Gas Lift Compression Station, the 17R Field Gas Compression Station, the 17R Waterflood Plant, and the 35R HPI Gas Injection Plant. Gas gathering has been a facilities problem in the Northwest Stevens particularly at the prolific 1-7R Tank Setting where problems can occur with the compressors on site. If high pressures from the gas plant occur, difficulty is encountered in distributing Northwest Stevens gas. To correct this problem, an old 10" high pressure line is to be replaced by a new 14" piggable line for relief. Other facility projects include the buyout of the leased closed-loop gas lift compressors at 8R, installing a spare pump for the waterflood plant, making waste water tank improvements and installing facilities for injection of produced water into the Stevens Sand.

NORTHWEST STEVENS (A4-A6) SANDS
RESERVOIR CHARACTERISTICS

Porosity (%):	18.2	Production Wells (#):	54
Water Sat. (%):	31.4	Injection Wells (#):	18
Air Perm. (md):	35-190	Top Pay (Ft-VSS):	7,944
Oil Gravity (API):	30	Max Pay (Ft):	556
Oil Form. Vol. Fact. (RB/STB):	1.49	Pay Area (AC):	886
Oil Viscosity (cp):	1.2	Pay Volume (AF)	92,615
Initial Press. (psi):	4,150	GOC (Ft-VSS):	N/A
Bubble Point Press. (psi):	2,490	WOC (Ft-VSS):	8,550
Current Press (psi):	2,500	Press. Datum (Ft-VSS):	8,300

Figure 8

RESERVOIR STUDIES

Scientific Software-Intercomp (SSI) and Evans, Carey and Crozier (EC&C) have completed studies on this reservoir. A 1986 study by EC&C recommended that additional drilling is necessary in unswept areas to recover reserves and that additional water injection is necessary in the A6 Sand. This conclusion was investigated by a SSI reservoir simulation completed in January 1989. Inclusion of the A3 Sand into the waterflood project and increasing A6 sand injectivity are currently being studied by predictive runs in the model.

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy for the Northwest Stevens (A4- A6) Sands is to continue to support the reservoir pressure through water injection into peripheral wells. A detailed reservoir simulation study of the Northwest Stevens A Sands has been performed by Scientific Software-Intercomp (SSI) and the history matched model was completed with a report in January 1989. This history matched model is now being utilized to perform various predictive runs that are investigating strategies for optimizing pressure maintenance by water injection and maximizing economic recovery. The model predictive runs to date include:

- Current strategy
- Water injection into the A-3 Sand
- Line drive waterflood in the A-6 with no new producers
- A line drive waterflood in the A-6 with 15 new producers

Future predictive runs could be as follows:

- Sensitivity to Gas Liquid Ratio (GLR) and Water Cut (WC)
- A-6 flood with peripheral injectors
- A-3 case with new take-points
- Production with partial voidage

For each of these cases, economic analysis and total recovery will be the deciding factors on which case or cases will be used as the chosen operating strategy. Initiating injection into the A-3 Sand and increasing injection into the A-6 Sand is expected to be of primary importance. The SSI simulation has shown that water injection is primarily entering the A4 and A5 Sands in some injectors, resulting in the floodfront advancing rapidly through those sands. The A3 Sand is not now being pressure supported directly by injection; however, some migration of fluids from the A4 Sand to the A3 Sand is occurring. The rapid advance of water in the A4 and A5 Sands and the uncontrolled influx of water into the A3 Sand raises the possibility of by-passing oil reserves. In the A-6 reservoir, the scenario of a line drive waterflood with 15 new producers is anticipated to optimize oil production, however, the scenario where no producers are to be drilled may be the most economic. Further evaluation of the Scientific Software-Intercomp (SSI) study is expected to optimize the most specific approach.

The production, cost and revenue streams for the Total Development Case are shown in Economics Table 1. Key economic parameters are summarized in Figure 4. Cost and assumptions are shown in Figure 9.

The Maintenance Case represents continuation of the present production strategy of supporting the (A4-A6) Sands with water injection. Recompletion remedials are required to isolate water from "watered-out" intervals in producing wells. Stimulations are required to remove scale and asphaltene deposits in the wellbores. Rod pump artificial lift installations are necessary for wells converted to the (A4-A6) Sands. Profile control is necessary to maintain uniform layer injectivities in each water injection well to improve waterflood sweep efficiencies.

Several surface facilities modifications are necessary in the Maintenance Case. A spare pump and motor are necessary at the 17R Waterflood Plant to provide for the expanding demands of the total Stevens waterfloods and provide backup capacity in the event of a pump or motor failure. The 18G waste water tank improvements are necessary to improve the clean-up efficiency of the disposal system since Stevens waste water is planned to replace Tulare injection water. Gas blankets for both water tanks and a separate slop oil system will be included. The present operation allows excessive amounts of oil to be commingled with the waste water where oxygen entry into the system is causing increased corrosion. A new 14" high-pressure pipeline is scheduled to relieve high pressure gas distribution difficulties and to replace the old 10" pipeline which is experiencing a high rate of corrosion. Repairs and replacement of short sections of the old pipe have increased its life approximately 12 months but will not provide long term service and prevent large monetary losses and environmental damage. The construction program to convert the Stevens waterfloods to produced water and eliminate Tulare Zone disposal are included in this plan. The construction program is expected to include: (FY'89) conversion of 24Z Sand and Northwest Stevens waterfloods, (FY'90) conversion of SE leg of 33S Plant to produced water and repair 18G/24Z waste water pipeline, (FY'91) hookup

NORTHWEST STEVENS (A4-A6) SANDS
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Stimulations (acidizing)	70,000	100	10
Recompletions (Water isolation)	90,000	100	10
Artificial lift (Pumping unit installation)	186,000	250	10
Profile control	200,000	---	--
Waterflood pump	150,000	---	--
Produced water injection	1,665,000	---	--
Replacement 14" pipeline	1,354,000	---	--
Buy Closed Loop Compressors	225,000	---	--
Drilling (New Well)	1,500,000	500	10

Figure 9

alternate disposal wells and clean up SOZ water, and (FY'92-94) waste water gathering system and water knockout at 30 tank settings.

Details of the Maintenance Case are shown in the Economics Table 2. A summary of key economic parameters and recoveries are shown in Figure 10.

The Development Drilling Project provides for drilling one well in FY'90 and one well in FY'91. These wells will be used for infill injection and production in the A-6 Sand, based on a study to commence during FY'89 utilizing the SSI "A" Sand reservoir simulation runs. Economics of this project are fully described in Economics Table 3 and the results are summarized in Figure 11.

NORTHWEST STEVENS (A4-A6) SANDS
MAINTENANCE CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$237.4 Million	$395.1 Million
Operating Cost:	$31.2 Million	$103.0 Million
Investment:	$9.9 Million	$17.8 Million
Total Costs:	$41.1 Million	$120.8 Million
Net Revenue:	$196.3 Million	$274.3 Million
Net Present Value (@ 10%)	$139.9 Million	$170.5 Million
Recovery:		
Oil (MMB)	11.8	16.7
Natural Gas (BCF)	7.4	10.6
Oil Equivalent (MMBOE)	13.2	18.8

Figure 10

NORTHWEST STEVENS (A4-A6) SANDS
DEVELOPMENT DRILLING PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$16.6 Million	$31.7 Million
Operating Cost:	$1.2 Million	$2.0 Million
Investment:	$3.2 Million	$3.2 Million
Total Costs:	$4.4 Million	$5.2 Million
Net Revenue:	$12.2 Million	$26.5 Million
Net Present Value (@ 10%)	$7.5 Million	$12.8 Million
Recovery:		
Oil (MMB)	0.8	1.3
Natural Gas (BCF)	0.5	0.8
Oil Equivalent (MMBOE)	0.9	1.4

Figure 11

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The anuual reservoir management activities are described below for the ensuing seven-year period. Details of the drilling and remedial activities are shown in Table 4 and Table 5.

FY'89

Projected production for this year is 6616 BOPD by waterflood pressure maintenance. Remedials necessary to maintain the production are three stimulations, five recompletions and four profile control jobs (Table 5 shows the level of remedial activity). The effectiveness of cement squeezes should be examined along with limited entry perforations as a cost efficient way for profile control in water injectors. This is an alternative to installation of downhole flow regulators which have had limited success.

Facilities work includes a replacement of the 10" High Pressure Gas Gathering System with a piggable 14" pipeline, a spare pump for the Waterflood, Waste Water Tank Improvements and Facilities for Injection of Produced Water into the Stevens Sand. The NWS A1- A3 Sands, 24Z Sand and MBB/W31S projects should share in the cost of some of these facilities.

FY'90

Reservoir Development activities include a continuation of the Maintenance Case with an addition of one artificial lift and two stimulations. The plan for water injection into the A3 Sand and the increased injection into the A6 Sand should be implemented. Facility costs are expected to be required to continue injection of produced water into the Stevens Sands. One new well is planned to be drilled in the Development Drilling Project.

FY'91

Reservoir Development activities include a continuation of the Maintenance Case with one less recompletion and two less profile controls. Facility Costs should continue for the injection of produced water into the Stevens Sands. One new well is planned to be drilled in the Development Drilling Project.

FY'92 - FY'95

Reservoir Development activities are expected to continue without additional artificial lift installation since all wells should be equipped by this time. Facility costs for the injection of produced water should continue through FY'94.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
NORTHWEST STEVENS (A4-A6) SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	6616	9921	4276	19658	0	0	3672	1660	0	2116	0	0
1990	6120	10741	3743	19109	0	0	3801	1025	78	440	115	1552
1991	5424	12259	3338	19700	0	0	4103	864	0	258	0	1604
1992	4807	13991	2977	20608	0	0	4468	451	0	345	0	0
1993	4261	15968	2655	21853	0	0	4902	562	0	260	0	0
1994	3776	18224	2367	23458	0	0	5412	801	0	264	0	0
1995	3347	20799	2111	25454	0	0	6031	816	0	0	0	0
SUBTOTAL *	12538	37195	7835	54692	0	0	32389	6179	78	3683	115	3156
1996-2002 *	5431	93347	3502	100993	0	0	72724	7889	0	0	0	0
TOTAL *	17969	130542	11337	155685	0	0	105113	14068	78	3683	115	3156

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	36633	2631	1026	40290	7448	6771	32842	29857	2729
1990	35897	2556	943	39396	7011	5794	32385	26765	2509
1991	34230	2550	931	37711	6829	5130	30882	23202	2225
1992	32810	2526	1091	36427	5264	3595	31163	21285	1973
1993	31447	2477	1063	34987	5724	3554	29263	18170	1750
1994	30101	2376	1011	33488	6477	3656	27011	15247	1552
1995	28220	2426	1043	31689	6847	3514	24842	12748	1377
SUBTOTAL	229338	17542	7108	253988	45600	32014	208388	147274	14115
1996-2002	153567	13506	5790	172863	80613	27463	92250	35743	6135
TOTAL	382905	31048	12898	426851	126213	59477	300638	183017	20250

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
NORTHWEST STEVENS (A4-A6) SANDS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	6616	9921	4276	19658	0	0	3672	1660	0	2116	0	0
1990	5836	10354	3570	18334	0	0	3649	1025	78	440	115	0
1991	4976	11648	3066	18479	0	0	3855	864	0	258	0	0
1992	4404	13441	2732	19510	0	0	4239	451	0	345	0	0
1993	3898	15473	2434	20863	0	0	4691	562	0	260	0	0
1994	3449	17778	2169	22567	0	0	5218	801	0	264	0	0
1995	3053	20398	1933	24652	0	0	5854	816	0	0	0	0
SUBTOTAL *	11765	36140	7366	52583	0	0	31178	6179	78	3683	115	0
1996-2002 *	4954	92695	3212	99692	0	0	71885	7889	0	0	0	0
TOTAL *	16719	128835	10578	152275	0	0	103063	14068	78	3683	115	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	36633	2631	1026	40290	7448	6771	32842	29857	2729
1990	34231	2438	899	37568	5307	4386	32261	26662	2392
1991	31403	2342	855	34600	4977	3739	29623	22256	2041
1992	30060	2318	1002	33379	5035	3439	28344	19360	1808
1993	28768	2271	974	32013	5513	3423	26500	16454	1601
1994	27494	2177	926	30598	6283	3547	24315	13725	1418
1995	25741	2222	955	28918	6670	3423	22248	11417	1256
BTOTAL	214330	16399	6637	237366	41233	28728	196133	139731	13245
96-2002	140077	12389	5311	157776	79774	27152	78002	30537	5600
TOTAL	354407	28788	11948	395142	121007	55880	274135	170268	18845

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
DEVELOPMENT DRILLING PROJECT
NORTHWEST STEVENS (A4-A6) SANDS
(NOMINAL DOLLARS)

FY		OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989		0	0	0	0	0	0	0	0	0	0	0	0
1990		284	387	173	774	0	0	152	0	0	0	0	1552
1991		448	611	272	1222	0	0	248	0	0	0	0	1604
1992		403	550	245	1099	0	0	229	0	0	0	0	0
1993		363	495	221	990	0	0	211	0	0	0	0	0
1994		327	446	199	891	0	0	193	0	0	0	0	0
1995		294	401	179	802	0	0	177	0	0	0	0	0
SUBTOTAL	*	773	1055	470	2109	0	0	1210	0	0	0	0	3156
1996-2002	*	477	650	290	1301	0	0	839	0	0	0	0	0
TOTAL	*	1250	1705	760	3410	0	0	2049	0	0	0	0	3156

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	1666	118	44	1828	1704	1408	124	103	116
1991	2827	208	76	3111	1852	1391	1259	946	183
1992	2751	208	90	3048	229	156	2819	1925	165
1993	2679	206	88	2974	211	131	2763	1716	149
1994	2607	200	85	2891	193	109	2698	1523	134
1995	2479	206	88	2773	177	91	2596	1332	120
SUBTOTAL	15009	1146	471	16625	4366	3286	12259	7545	867
1996-2002	13498	1117	479	15094	839	311	14255	5210	536
TOTAL	28507	2263	950	31719	5205	3597	26514	12755	1403

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4

DRILLING ACTIVITY

NWS(A4-A6) SANDS

(NUMBER OF DRILLING WELLS PER YEAR)

TYPE OF PROJECT	FISCAL YEAR 1989	1990	1991	1992	1993	1994	1995	1996-02	TOTAL
1. DEVELOPMENT DRILLING PROJECT:									
a. NEW WELLS	0	1	1	0	0	0	0	0	2
TOTAL:	0	1	1	0	0	0	0	0	2

TABLE 5

REMEDIAL ACTIVITY

NWS(A4-A6) SANDS

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	FISCAL YEAR 1989	1990	1991	1992	1993	1994	1995	1996-02	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	3	2	2	2	2	2	2	26	41
b. RECOMPLETIONS	5	5	3	3	4	4	4	52	80
c. ARTIFICIAL LIFT	0	1	0	0	0	0	0	0	1
d. PROFILE CONTROL	5	2	2	0	0	1	1	18	29
TOTAL:	13	10	7	5	6	7	7	96	151

NORTHWEST STEVENS T SANDS AND N SHALES

The Northwest Stevens Structure consists of three major reservoirs: The upper (A1-A3) Sands, the lower (A4-A6) Sands and the T Sands and N Shales. (See Location Map, Figure 1 and Cross Section, Figure 3). The (A1-A3) Sands are pressure maintained by crestal gas injection, the (A4-A6) Sands are peripherally waterflooded and the T Sands and N Shale are being produced under primary depletion.

The Total Development Case for the Northwest Stevens T Sands and N Shale Reservoir, consists of the Maintenance Case and a Hydraulic Fracture Project. During the plan period from FY'89 to FY'95, the Total Development Case is expected to provide $45 million in undiscounted revenues, and require total costs of $9 million. Annual revenue and cost values are displayed in the Figure 2.

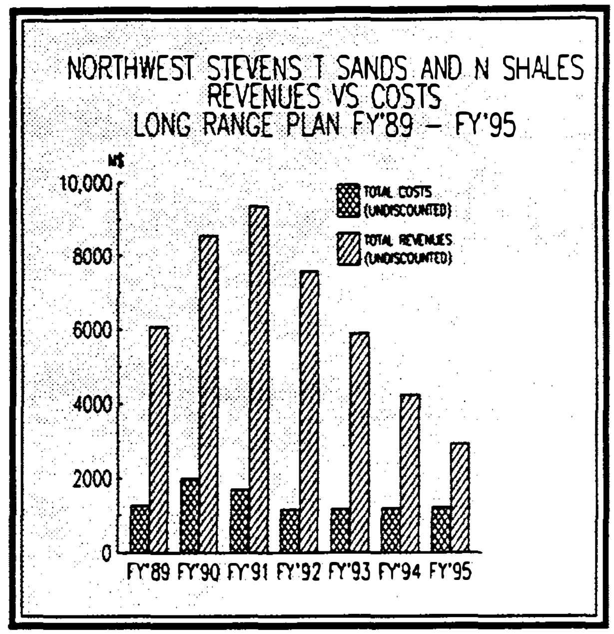


Figure 2

The economic parameters in Figure 4 summarize the Total Development Case for the plan period and to the economic limit.

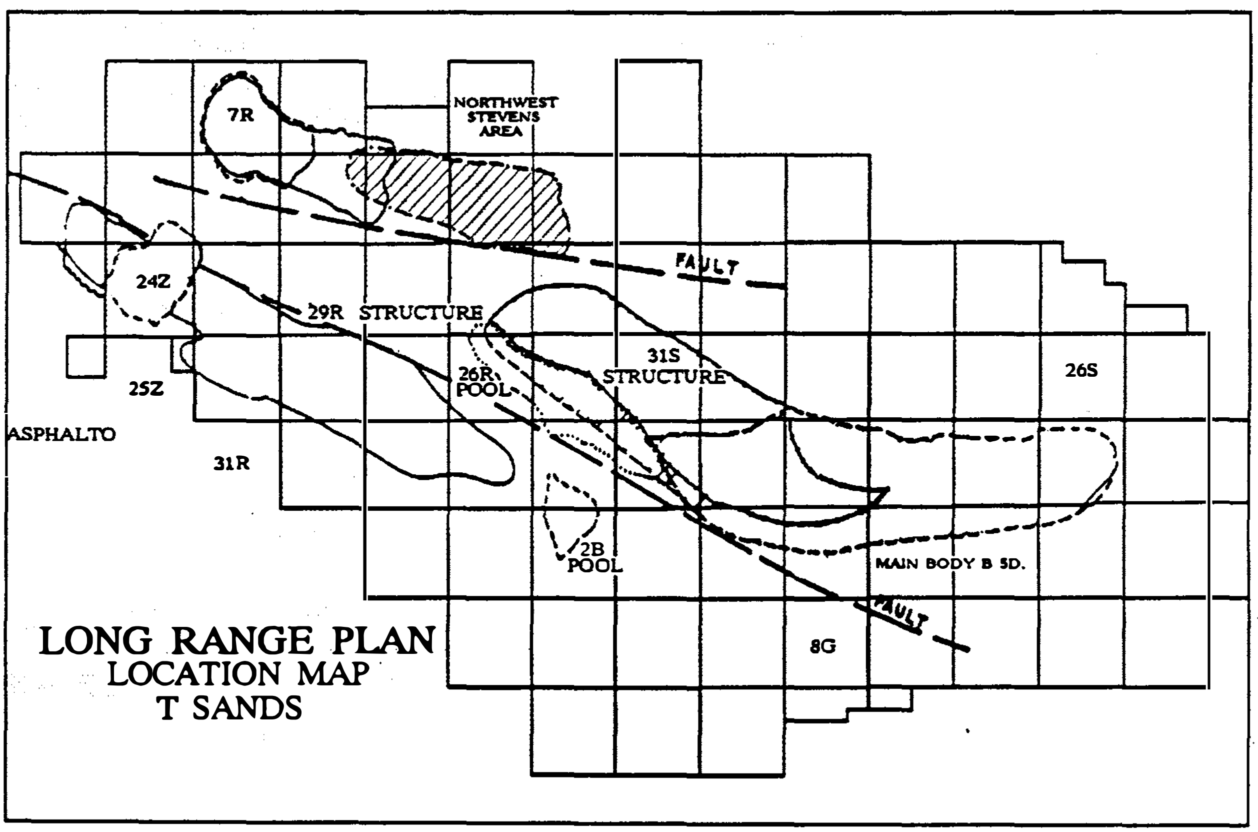
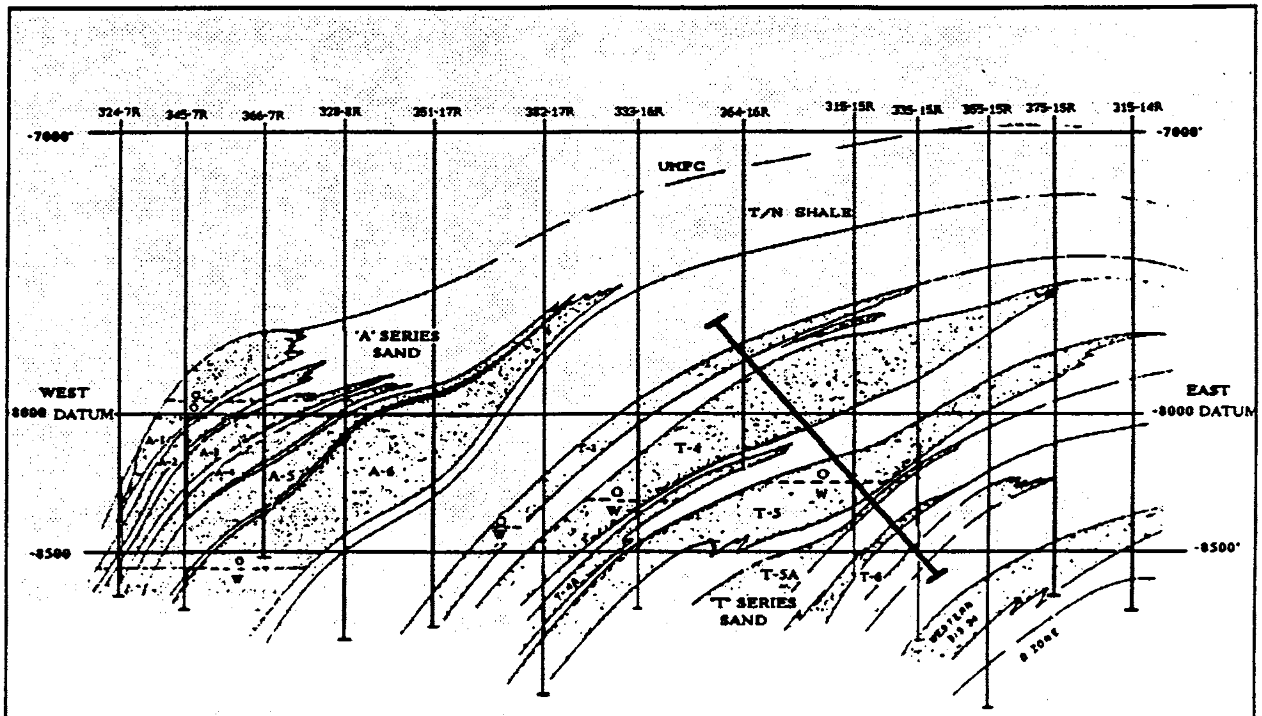


Figure 1



EAST-WEST STRUCTURAL CROSS SECTION
NORTHWEST STEVENS
T SANDS

Figure 3

The recovery for the Total Development Case in terms of oil production, gas production and total equivalent barrels is also shown in Figure 4.

The estimated oil reserves for the Northwest Stevens T Sands and N Shales as shown in Figure 5 from the "Stevens Zone Estimated Recoverable Oil and Third Revision of Percentage Participations as of November 20, 1942." These reserves are compared with The Long Range Plan Maintenance and Total Development Cases.

The Maintenance Case, which includes well remedials and facilities modifications, also includes a Hydraulic Fracture Test. The total cost for this case is $4.4 million over FY'89-FY'95 and yields a net revenue of $27.8 million. The Hydraulic Fracture Project will cost

NORTHWEST STEVENS T SANDS AND N SHALES
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$44.7 Million	$50.2 Million
Operating Cost:	$2.3 Million	$3.7 Million
Investment:	$6.8 Million	$7.7 Million
Total Costs:	$9.1 Million	$11.4 Million
Net Revenue:	$35.6 Million	$38.8 Million
Net Present Value (@ 10%)	$26.0 Million	$27.4 Million
Recovery:		
Oil (MMB)	2.1	2.3
Natural Gas (BCF)	2.2	2.5
Oil Equivalent (MMBOE)	2.6	2.8

Figure 4

NORTHWEST STEVENS T SANDS AND N SHALES TOTAL DEVELOPMENT CASE	EQUITY STUDIES	LONG RANGE PLAN MAINT.	LONG RANGE PLAN TOTAL
Original-Oil-In-Place (MMB):	48.3	----	----
Estimated Recoverable Oil (MBB):	21.7	8.6	8.9
Cumulative Production 9/30/88 (MMB):	6.6	6.6	6.6
Remaining Reserves:			
Oil (MMB)	15.1	2.0	2.3
Natural GAS (BCF)	----	2.5	2.5
Oil Equivalent (MMBOE)	----	2.5	2.8
Economic Limit (BOPD, YEAR):	----	32/2008	45/2008

Figure 5

a total of $4.6 million over FY'89-FY'95 to yield $7.9 million in net revenue.

Historical production from the Northwest Stevens T Sands and N Shales Reservoir and projected performance to the economic limit is shown in the Figures 6 and 7.

The current reservoir operating strategy is to maintain the current primary production by the mechanism of solution gas drive combined with an active natural aquifer. A total of 25 active wells should produce an average rate of 921 BOPD in FY'89. Pressure maintenance has not been a problem in this pool since the reservoir has maintained pressure through a natural aquifer. The remaining oil reserves are estimated from the Stevens Equity Study Reserves to be 15.1 million barrels as of October 1, 1988. If fracturing techniques are found to be successful, then it is feasible that the recoverable oil should increase.

The major field activities planned over the seven year plan period are the Hydraulic Fracture Project, along with routine well remedials such as stimulations, re-

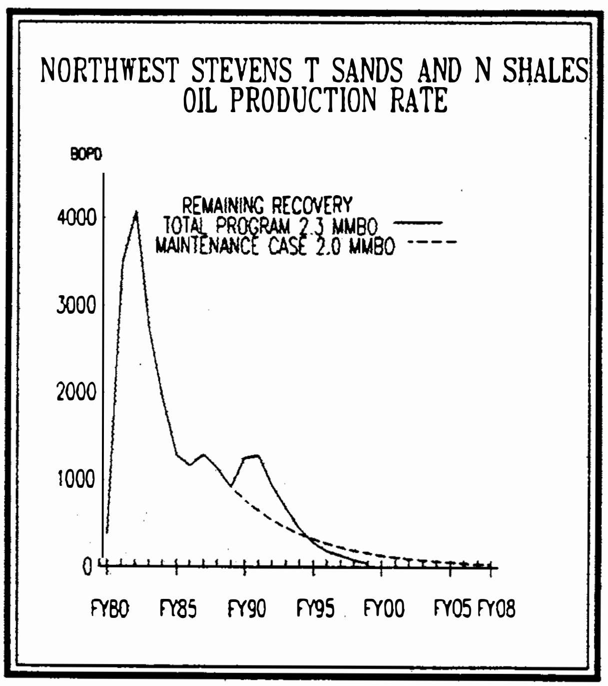


Figure 6

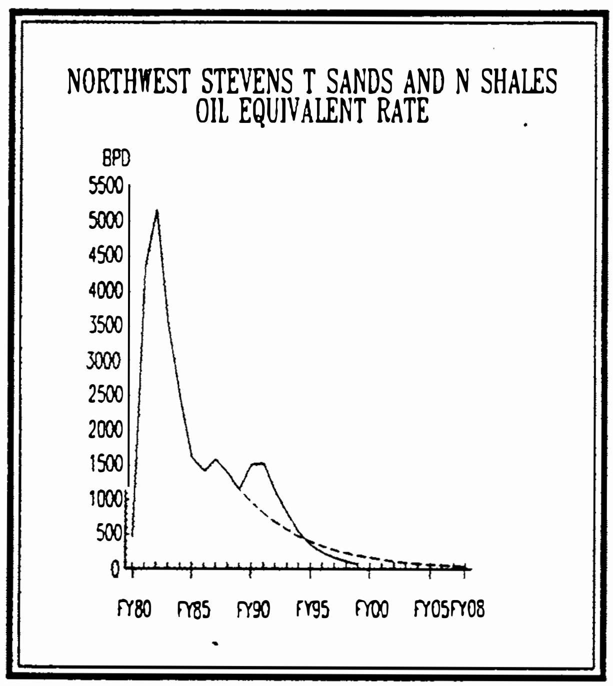


Figure 7

completions, low volume acid jobs and artificial lift installations. The recompletions mostly involve plugging back watered-out zones. During the plan period, a total of 33 remedials are scheduled for a total cost of $2.2 million. No drilling activity is scheduled in this plan, but may be required. The facilities costs are those associated with artificial lift for a total of $421,000 for new equipment costs for four installations. The Hydraulic Fracture Project is anticipated to improve oil recovery from the T Sands and is contingent upon the test fracturing of a well for $511,000 in the fourth quarter of FY'89. Initial production of 250 BOPD is expected, declining at 15% per year. A total of seven wells at a cost of $3.9 million during this planning period may be fractured, if this well is economically successful.

RESERVOIR DESCRIPTION

The Northwest Stevens Structure, located in the northwest area of NPR-1 (see Location Map, Figure 1), is approximately four miles long and one mile wide. The trapping mechanism consists of a series of discrete sand bodies that trend nearly north-south across the west-northwesterly plunge of the asymmetrical Northwest Stevens Anticline (see Cross Section, Figure 3).

The Northwest Stevens Sandstones are divided into the "A" and "T" Sands. The "T" Sands (T2-T6), along with the "N" Shale, occur stratigraphically below the "A" Sands and are older. The deposition pattern of these sands are of deep marine channel-fill turbidites. The "T" Sands are generally less uniform in appearance on SP logs, are finer grained, less porous, dirtier, often thinner and separated from each other by thicker shale breaks than the "A" Sands. Limited petrophysical analysis from logs and cores suggest a porosity average of 17-18% with permeabilities of 1-14 md. Average water saturation is reportedto be approximately 30%. Reservoir characteristics are displayed in Figure 8.

The Northwest Stevens "T" Sands and "N" Shale were first placed on production in 1976. The cumulative oil production through September 30, 1988, is 6.6 MMB.

The Total Development Case and other estimates indicate that remaining reserves are less than 15.1 million barrels.

Currently there are 30 production wells with no injection wells. The Average Reservoir Pressure is estimated to be 3100 psi @ 8300' SS. Static Pressure data is limited due to the high number of rod pump wells. Despite the absence of pressure maintenance, the reservoir pressure decline has been negligible while on continuous production due to a natural aquifer and tight sands.

The Northwest Stevens surface facilities include six tank settings located in Sections 7R, 8R, 15R, 16R and 17R. Facilities used for the T&N production are the 3-15R, 4-16R and 2-17R Tank Settings with all production routed through the low pressure system.

RESERVOIR STUDIES

Study of this reservoir has been limited to: 1) Analogy study by Scientific Software-Intercomp, and 2) Part of reserve study by Bergeson and Associates. This reservoir has not been studied in significant detail. Additional studies are expected to be done on a level-of-effort basis. A new geological study will be completed in the Second Quarter of FY'89. SSI is planning a Material Balance Study on this reservoir in FY'89.

NORTHWEST STEVENS T SANDS AND N SHALES
RESERVOIR CHARACTERISTICS

Porosity (%):	16.8	Production Wells (#):	30
Water Sat. (%):	29.5	Injections Wells (#):	0
Air Perm. (md):	1-14	Top Pay (Ft-VSS):	7,200
Oil Gravity (API):	35	Max Pay (Ft):	367
Oil Form. Vol.FACT. (RB/STB):	1.51	Pay Area (Ac):	1,240
Oil Viscosity (cp):	1.0	Pay Volume (AF):	36,192
Initial Press. (psi):	4,152	GOC (Ft-VSS):	NA
Bubble Point Press. (psi):	2,240	WOC (Ft-VSS):	8,250
Current Press. (psi):	3,100	Press. Datum (Ft-VSS):	8,300

Figure 8

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy for the Northwest Stevens T Sands and N Shale is continued production by primary recovery under the mechanism of solution gas drive with natural water influx. Other methods to accelerate production and recover a higher percentage of oil-in-place will also be investigated. Emphasis should be placed on maintaining wells on continuous production and preventing wellbore saturation changes from shut- ins due to equalization or down-hole failures. This, along with stimulations to remove scale and asphaltine deposits, should help the reservoir maintain production. Water entry identification has been a major problem with this reservoir, particularly with wells producing from rod pump. Remedial zone isolations and testing should be done in order to curtail excessive water production. The Hydraulic Fracture Project, if deemed feasible by core studies and other petrophysical information, should help to improve production from zones which would otherwise have little potential. Scientific Software-Intercomp (SSI) is scheduled to complete a Material Balance Study on this reservoir in the fourth quarter of FY'89.

The production, cost and revenue streams for the Total Development Case are shown in Table 1. Key economic parameters are summarized in Figure 4. Cost and productions assumptions are shown in Figure 9. The Maintenance Case represents continuation of the present production strategy of primary production through the mechanism of solution gas drive with natural water influx. Stimulations and miscellaneous low volume acidizing should help to remove skin damage due to calcium carbonate scale and asphaltines. The recompletions will be required to open new zones and shut off excessive water producing intervals. Rod pump artificial lift should maintain production in the flowing wells that equalize. The Hydraulic Fracture should be a pilot remedial to determine the potential of opening low permeability intervals to production.

Details of the Maintenance Case are shown in the Economics Table 2. A summary of the key economic parameters and the recoveries are shown in Figure 10.

The Hydraulic Fracture Project is expected to be initiated following a successful pilot Hydraulic Fracture listed in the Maintenance Case. The purpose will be the development of the fracturing potential of the T&N Reservoir. Two wells are expected to be treated in FY'90and two in FY'91, and one well will be treated each year from FY'92 through FY'95. Details of the Hydraulic Fracture Project are shown in Economics Table 3, with a summary of the key economic parameters listed in Figure 11.

NORTHWEST STEVENS T SANDS AND N SHALES
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BCPD)	Decline (%/Yr.)
Stimulations (Acidizing)	70,000	50	15
Recompletions (Perforation, Water Isolation)	85,000	75	15
Artificial Lift (Pumping Unit Installation)	180,000	150	15
Hydraulic Fracturing	511,000	250	15
Miscellaneous (Low Volume Acidizing)	9,000	75	15

Figure 9

NORTHWEST STEVENS T SANDS AND N SHALES MAINTENANCE CASE	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$32.1 Million	$52.6 Million
Operating Cost:	$1.5 Million	$4.3 Million
Investment:	$2.9 Million	$6.9 Million
Total Costs:	$4.4 Million	$11.2 Million
Net Revenue:	$27.8 Million	$41.4 Million
Net Present Value (@ 10%)	$19.9 Million	$24.7 Million
Recovery:		
Oil (MMB)	1.5	2.0
Natural Gas (BCF)	1.8	2.5
Oil Equivalent (MMBOE)	1.8	2.5

Figure 10

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The Annual Reservoir Development Activities are described for each of the cases presented in this Operating Plan.(See attached Table 4) These cases are the Maintenance Case that projects current production and the Hydraulic Fracture Project that improves production and total economics.

FY'89

The Maintenance Case is projected to produce an average of 921 BOPD, largely from solution gas drive. Remedials that may be necessary to maintain the Maintenance Case are acid stimulations, recompletions to plug back watered out zones, and low volume acid jobs to maintain production by keeping the tubing and the perforations open to flow. One well is expected to be hydraulically fractured as a test to determine if this is a feasible economic method to increase revenue. Also, the feasibility of waterflooding the T Sands should be studied. The determination of the effective drainage radius of the T Sands and N Shales is anticipated to be started using pulse testing, pressure build-up surveys and flow testing of the perforated intervals.

NORTHWEST STEVENS T SANDS AND N SHALES HYDRAULIC FRACTURE PROJECT	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$12.5 Million	$-2.4 Million
Operating Cost:	$0.7 Million	$-0.6 Million
Investment:	$3.9 Million	$0.7 Million
Total Costs:	$4.6 Million	$0.1 Million
Net Revenue:	$7.9 Million	$-2.5 Million
Net Present Value (@ 10%)	$6.1 Million	$2.7 Million
Recovery:		
Oil (MMB)	0.6	0.5
Natural Gas (BCF)	0.4	0.3
Oil Equivalent (MMBOE)	0.7	0.6

Figure 11

FY'90

Reservoir Development Activities include a continuation of the Maintenance Case activities and the Hydraulic Fracturing Project if fracturing of the well is economic. A review of feasibility studies to waterflood the T Sands will be completed so that a waterflood pilot might be initiated in FY'91. The effective drainage radius of the T Sands and N Shales should be resolved in this year.

FY'91-'95

If the studies for waterflooding the T Sands are positive, a waterflood pilot might be started in FY'91. The level of remedials and hydraulic fracturing established in FY'92 should continue through FY'95, depending on results of fracturing project. No additional projects are currently anticipated after FY'91.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
NORTHWEST STEVENS T SANDS AND N SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	921	1228	1140	0	0	0	230	675	133	0	207	0
1990	1257	1647	1272	0	0	0	314	781	138	0	214	0
1991	1284	1798	1222	0	0	0	342	1353	0	0	0	0
1992	945	2000	927	0	0	0	338	819	0	0	0	0
1993	675	2180	690	0	0	0	337	838	0	0	0	0
1994	444	2342	488	0	0	0	337	773	0	0	0	0
1995	275	2492	370	0	0	0	343	868	0	0	0	0
SUBTOTAL *	2117	4996	2230	0	0	0	2241	6107	271	0	421	0
1996-2008 *	159	3882	281	0	0	0	1437	900	0	0	0	0
TOTAL *	2276	8878	2511	0	0	0	3678	7007	271	0	421	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	5100	701	274	6075	1245	1132	4830	4391	420
1990	7373	869	320	8562	1447	1196	7115	5880	552
1991	8103	934	341	9378	1695	1274	7683	5772	558
1992	6450	786	340	7576	1157	790	6419	4384	413
1993	4982	644	276	5902	1175	730	4727	2935	297
1994	3539	490	208	4238	1110	627	3128	1766	198
1995	2319	425	183	2927	1211	621	1716	881	128
SUBTOTAL	37866	4849	1942	44658	9040	6370	35618	26009	2566
1996-2008	4109	1001	429	5539	2337	999	3202	1346	216
TOTAL	41975	5850	2371	50197	11377	7369	38820	27355	2782

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
NORTHWEST STEVENS T SANDS AND N SHALES
(NOMINAL DOLLARS)

FY		OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	ART.LIFT	DRILLING INVESTMENTS (4) M$
1989		921	1228	1140	0	0	0	230	675	133	0	207	0
1990		773	1257	968	0	0	0	225	252	138	0	214	0
1991		647	1270	811	0	0	0	219	260	0	0	0	0
1992		542	1284	680	0	0	0	214	257	0	0	0	0
1993		454	1297	570	0	0	0	210	263	0	0	0	0
1994		380	1311	478	0	0	0	206	188	0	0	0	0
1995		318	1324	400	0	0	0	204	273	0	0	0	0
SUBTOTAL	*	1473	3274	1842	0	0	0	1508	2168	271	0	421	0
1996-2008	*	539	6766	680	0	0	0	2807	4041	0	0	0	0
TOTAL	*	2012	10040	2522	0	0	0	4315	6209	271	0	421	0

	REVENUES OIL M$	GAS M$	NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	DISC 10.0% M$	NET REVENUES UNDISC M$	DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	5100	701	274	6075	1245	1132	4830	4391	420
1990	4534	661	244	5439	829	685	4610	3810	353
1991	4083	620	226	4929	479	360	4450	3343	296
1992	3699	577	249	4526	471	322	4055	2770	248
1993	3351	532	228	4111	473	294	3638	2259	208
1994	3029	480	204	3713	394	222	3319	1873	174
1995	2681	460	198	3339	477	245	2862	1469	145
UBTOTAL	26477	4031	1623	32132	4368	3260	27764	19915	1844
6-2008	16469	2824	1212	20507	6848	1879	13659	4777	676
OTAL	42946	6855	2835	52639	11216	5139	41423	24692	2520

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
HYDRAULIC FRACTURE PROJECT
NORTHWEST STEVENS T SANDS AND N SHALES
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	484	390	304	0	0	0	89	529	0	0	0	0
1991	637	528	411	0	0	0	123	1093	0	0	0	0
1992	403	717	247	0	0	0	124	562	0	0	0	0
1993	221	883	120	0	0	0	128	575	0	0	0	0
1994	64	1031	10	0	0	0	131	585	0	0	0	0
1995	-43	1167	-30	0	0	0	139	595	0	0	0	0
SUBTOTAL *	645	1721	388	0	0	0	734	3939	0	0	0	0
1996-2008 *	-380	-2884	-398	0	0	0	-1371	-3208	0	0	0	0
TOTAL *	265	-1163	-10	0	0	0	-637	731	0	0	0	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	2839	208	77	3123	618	511	2505	2070	199
1991	4020	314	115	4449	1216	914	3233	2429	263
1992	2751	210	91	3051	686	469	2365	1615	165
1993	1631	112	48	1791	703	436	1088	676	89
1994	510	10	4	524	716	404	-192	-108	24
1995	-363	-34	-15	-412	734	377	-1146	-588	-18
SUBTOTAL	11388	820	320	12526	4673	3111	7853	6094	722
1996-2008	-12360	-1823	-783	-14967	-4579	-905	-10388	-3405	-460
TOTAL	-972	-1003	-463	-2441	94	2206	-2535	2689	262

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4

REMEDIAL ACTIVITY

NWS T SANDS & N SHALES

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-08	TOTAL
	FISCAL YEAR								
1. MAINTENANCE CASE:									
a. STIMULATIONS	1	2	2	2	2	1	2	26	38
b. RECOMPLETIONS	1	1	1	1	1	1	1	13	20
c. ARTIFICIAL LIFT	2	2	0	0	0	0	0	0	4
d. LOW VOL ACID	1	2	2	1	1	1	1	13	22
e. HYDRAULIC FRAC	1	0	0	0	0	0	0	0	1
SUB-TOTAL:	6	7	5	4	4	3	4	52	85
2. HYDRAULIC FRACTURE PROJECT:									
a. HYDRAULIC FRAC	0	1	2	1	1	1	1	1	8
SUB-TOTAL:	0	1	2	1	1	1	1	1	8
TOTAL:	6	8	7	5	5	4	5	53	93

SHALLOW OIL ZONE

The Shallow Oil Zone (SOZ) Reservoir produces from nine sands, covers 20,236 acres at Elk Hills, and is of significant economic importance to NPR-1 (See Location Map, Figure 1 and Cross Section, Figure 3). The production mechanism is primarily gravity drainage except for a steamflood pilot. The evaluation of this pilot is represented in the Maintenance Case. Incremental economic analyses were performed on five SOZ projects as follows:

1. Development Drilling Project
2. Hydraulic Fracturing Project
3. Steamflood Pilot Phase II Project
4. Steamflood Expansion Project
5. SS-2/Mulinia Waterflood Project

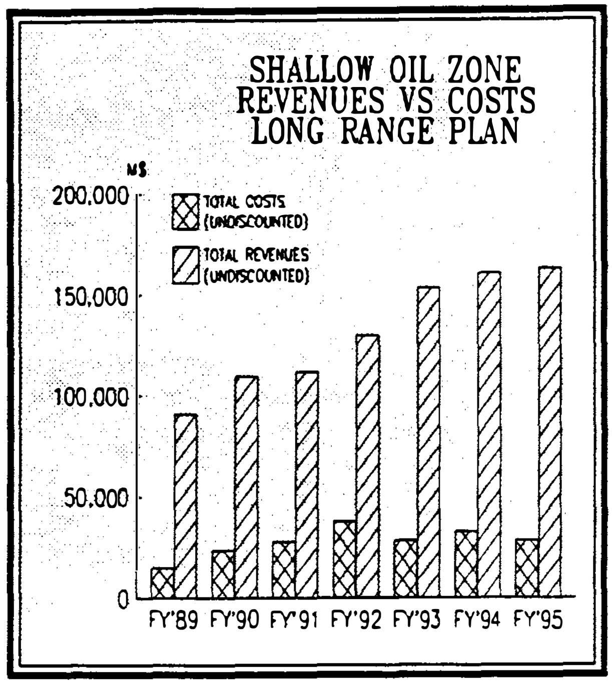


Figure 2

The Total Development Case for the SOZ Reservoir is a combination of the Maintenance Case plus the five projects. It is estimated that $921 million of undiscounted revenues will be generated from this Total Development Case over the next seven years. The total costs are projected to be $195 million($125 million operating and $70 million investments). Annual revenue and cost values are displayed in Figure 2.

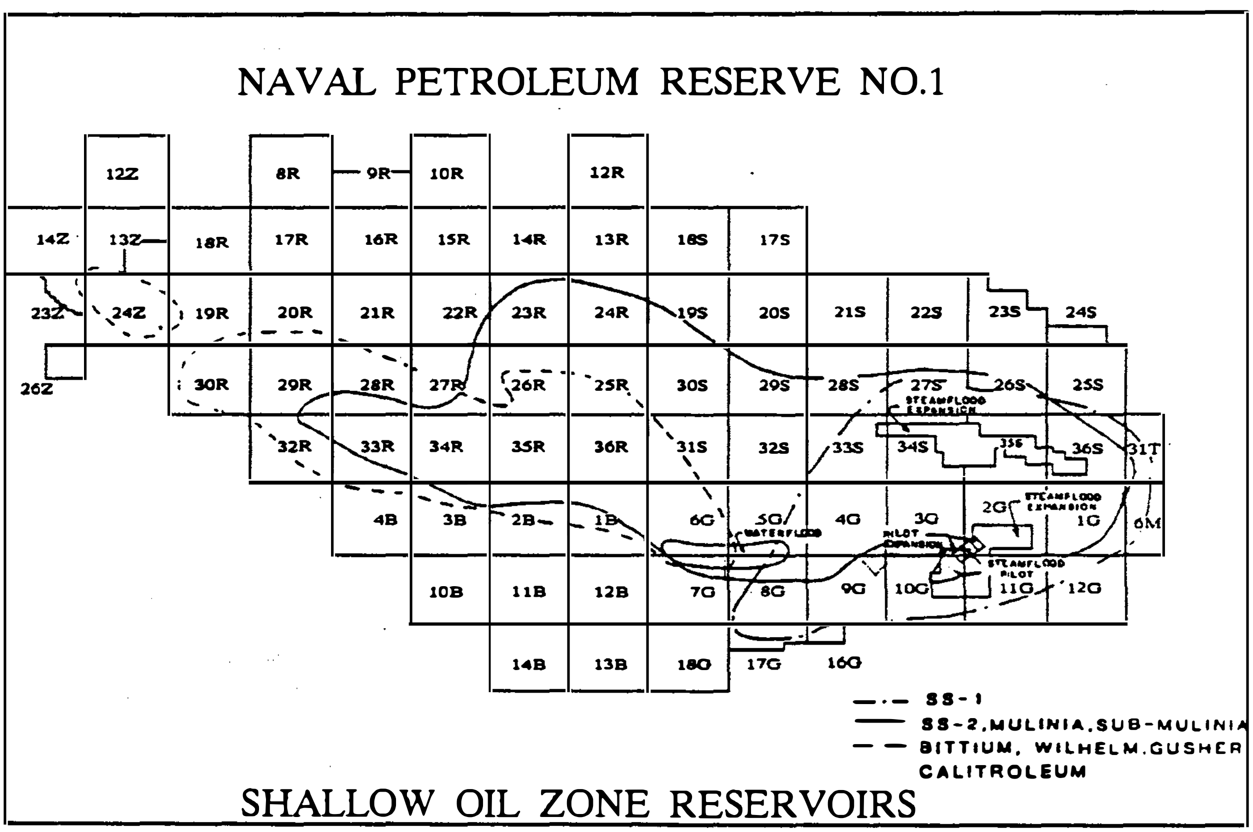


Figure 1

ELK HILLS
DIAGRAMMATIC STRUCTURAL CROSS-SECTION
SHALLOW OIL ZONE

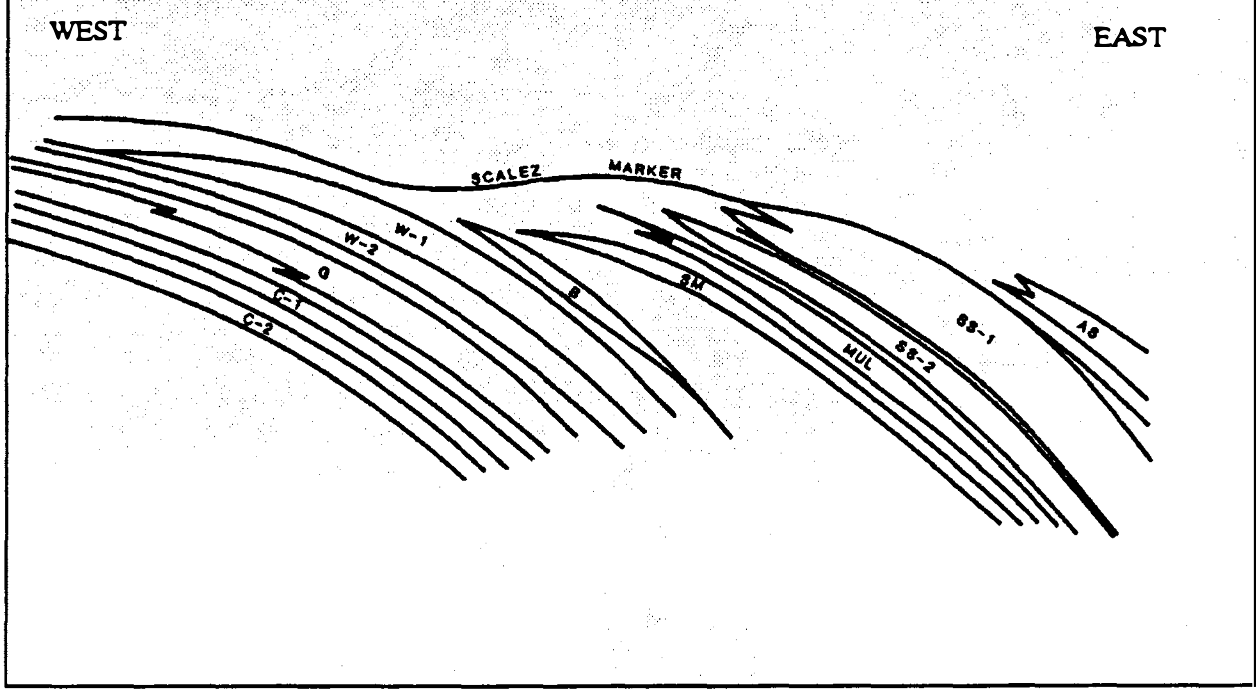


Figure 3

The Total Revenue, Operating Cost, Investment, Total Cost, Net Revenue, Net Present Value and Net Revenue/Investment Ratio for the Total Development Case are presented in Figure 4.

Recovery data for the total development case in terms of oil production, gas production and total equivalent barrels is also shown in Figure 4.

SHALLOW OIL ZONE
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$920.6 Million	$2,938.4 Million
Operating Cost:	$125.2 Million	$636.1 Million
Investment:	$69.9 Million	$143.5 Million
Total Costs:	$195.1 Million	$779.6 Million
Net Revenue:	$725.5 Million	$2,158.8 Million
Net Present Value (@ 10%)	$484.9 Million	$915.8 Million
Recovery:		
Oil (MMB)	45.6	103.0
Natural Gas (BCF)	24.6	58.5
Oil Equivalent (MMBOE)	50.6	114.8

Figure 4

SHALLOW OIL ZONE TOTAL DEVELOPMENT CASE	EQUITY STUDIES	LONG RANGE PLAN MAINT.	LONG RANGE PLAN TOTAL
Original-Oil-In-Place (MMB)	1251.4	-	-
Estimated Recoverable Oil (MMB):	598.7	476..5	521.9
Cumulative Production 9/30/88 (MMB):	418.9	418.9	418.9
Remaining Reserves:			
Oil (MMB)	179.8	57.6	103.0
Natural Gas (BCF)	-	34.5	58.5
Oil Equivalent (MMBOE)	-	64.8	116.1
Economic Limit (BOPD, YEAR):	-	546/2022	679/2022

Figure 5

The estimated oil reserves for the SOZ shown in Figure 5 are from the "Shallow Oil Zone Second Revision Dated May 1, 1957". They are compared with the long range plan maintenance and total development cases.

The Maintenance Case, which includes well remedials and facilities to maintain the current production strategy, requires total costs of $92.2 million ($79.0 million operating and $13.2 million capital) over FY'89 - FY'95 and yields net revenues of $512.4 million. The five projects and their associated costs and net revenues are as follows:

FY'89 - FY'95

Project Description		Total Costs $ Million	Net Revenue $ Million
Development Drilling Project	Drill six wells per year for a total of forty-two wells	2.0 (Oper.) 14.6 (Inv.) 16.6	32.3
Hydraulic Fracturing Project	Fracture one well in FY'89 & two wells each in FY'90 & FY '91	0.7 (Oper.) 1.4 (Inv.) 2.1	9.2
Steamflood Pilot Phase II Project	Expand steamflood pilot by four patterns in FY'90	4.0 (Oper.) 3.5 (Inv.) 7.5	8.4
Steamflood Expansion Project	Make major field expansions of steamflood in FY'92 and FY'94	22.5(Oper.) 34.8 (Inv.) 57.3	144.7
SS-2/Mulinia Waterflood Project	Begin produced water injection into down-dip South Flank Sands in FY'90	17.1 (Oper.) 2.4 (Inv.) 19.5	18.6

The current operating strategy is to produce the reservoir by gravity drainage in the Eastern SOZ and by gravity drainage and gas expansion in the Western SOZ. A total of 643 producing wells will produce an average rate of 15,184 BOPD in FY '89. Four steamflood injection wells will provide 2,200 barrels of steam per day (cold water equivalent) as required by the steamflood pilot. Remaining oil reserves are estimated from the 1957 Shallow Oil Zone Equity Study Reserves to be 179.8 million barrels, as of October 1, 1988. Historical production from the SOZ and projected performance to the economic limit is shown in two graphs (Figure 6 and Figure 7).

The major field activities planned over the seven-year plan period are the five projects previously mentioned. In addition to these projects are the following Maintenance Case requirements.

Item	Reason	Cost $ Thousand
Drill one	Monitor steamflood pilot observation well	315
Replace 16" Gravity Line	Line has reached end of its useful life	587
Perform 154 Remedials and four Logging jobs	Maintain production and monitor steamflood pilot	12,261
Steamflood	Pilot Facilities	26

RESERVOIR DESCRIPTION

The Shallow Oil Zone (SOZ) Reservoir has been one of the major units in the Elk Hills field for more than 60 years. The reservoir is divided into two sectors; the

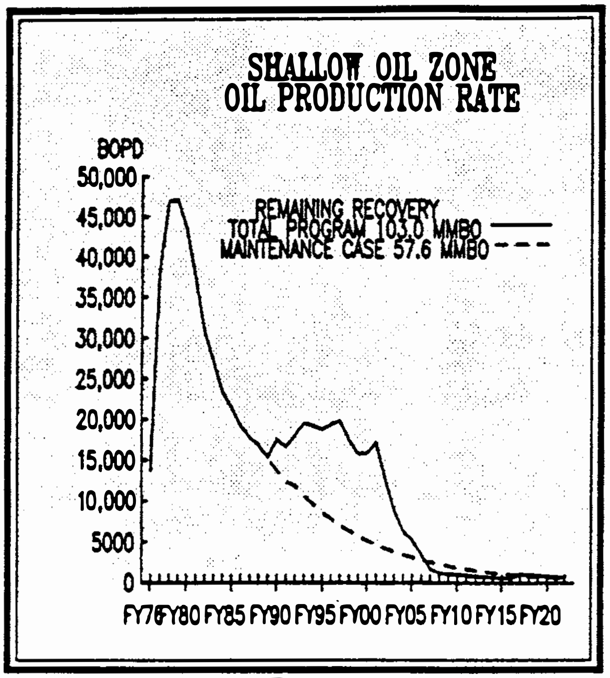


Figure 6

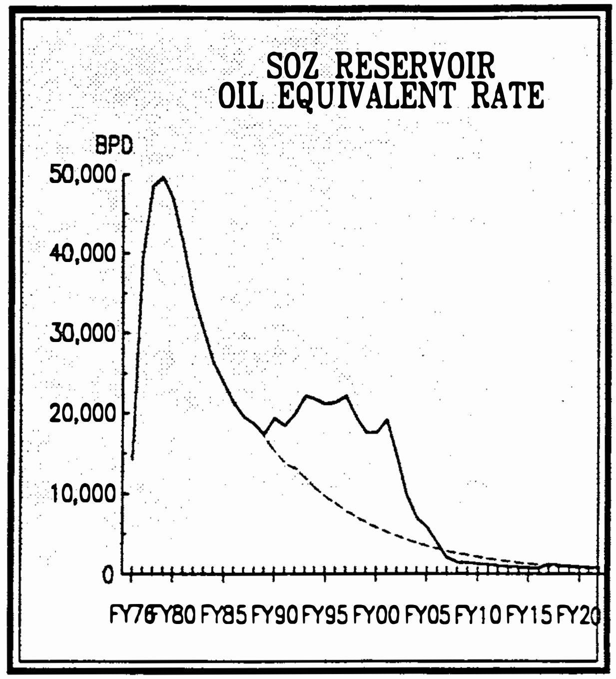


Figure 7

eastern SOZ located primarily in the Townships S and G, and the western SOZ located in S and R Townships (see Location Map, Figure 1). The reservoir consists of nine sands: Above Scalez (AS), Sub-Scalez 1 (SS-1), Sub-Scalez 2 (SS-2), Mulinia (M), Sub-Mulinia (SM), Bittium (B), Wilhelm (W), Gusher (G), and Calitroleum (C). Reservoir depth ranges from 2,700 feet to 3,200 feet. In general, the younger sands are productive in the eastern portion of the 31S Structure and the older sands of the B, W, G, and C (Etchegoin Formation) are productive to the West. The SOZ is a combination trap that is formed primarily by the Elk Hills anticline structure (see Cross Section, Figure 3). Petrophysical analysis from cores and logs indicates an average porosity of 30% with permeabilities averaging 500 md. Average water saturations are reported to be approximately 45%.

The SOZ was discovered with the completion of a commercial well in section 36R in 1919. As of October 1988, 30% of the estimated reserves remained to be produced. A table of reservoir characteristics is shown in Figure 8.

Currently there are 643 producing wells in the field. The SS-1 sand steamflood pilot has four steam injection wells that are injecting 2,200 barrels of steam per day (cold water equivalent). This pilot could lead to a major steamflood expansion if it is successful. One SOZ waste water disposal well is injecting 600 barrels

SHALLOW OIL ZONE
RESERVOIR CHARACTERISTICS

Porosity (%):	30	Production Wells (#):	643
Water Sat. (%):	45	Injection Wells (#):	5
Air Perm. (md):	500	Top Pay (Ft-VSS):	1,500
Oil Gravity (API):	25	Max Pay (Ft):	100
Oil Form. Vol. Fact. (RB/STB):	1.30	Pay Area (AC):	20,236
Oil Viscosity (cp):	17	Pay Volume (AF):	362,000
Initial Press. (psi)	NA	GOC (Ft-VSS):	1,900
Sat. Press. (psi)	NA	WOC (Ft-VSS):	3,100
Avg. Current Press (psi):	50	Press. Datum (FT-VSS):	1,950

Figure 8

per day on the South Flank below the oil-water contact into the SS-1 sand. This injection is being monitored for any effect upon oil production from updip production wells.

SOZ surface facilities include 79 tank settings and a low pressure gas system that recovers casing head gas and also improves oil production. A 50 million BTU per hour steam generator services the steamflood pilot.

RESERVOIR STUDIES

Bergeson and Associates and the BPOI Reservoir Review Task Force initiated a study of the SOZ in FY'89. The study is designed to assess the ultimate recovery efficiency under various depletion strategies in order to recommend a comprehensive depletion plan for the SOZ. Applicable primary and secondary strategies include continued operations (gravity drainage), waterflooding and gas injection. The SOZ is a structurally and stratigraphically complex reservoir. Due to the complex faulting, numerous fault blocks are present. As a result of differences in structural positions and proximity to the aquifer, individual fault blockshave different depletion histories (e.g., gravity drainage, water influx). Therefore, individual strategies will be developed for specific areas of the SOZ. The study is initially focusing on the southern and northeastern flank in the eastern portion of the SOZ and will be expanded to include the western SOZ in FY'90. The EOR potential for the western SOZ is alkaline-surfactant polymer flooding and polymer-augmented waterflooding.

Injection in the Light Oil Steamflood Pilot was started in July 1987 in an attempt to investigate the economic feasibility of this enhanced oil recovery process. Scientific Software-Intercomp and Chevron USA are simulating the four-pattern pilot in the SS-1 sand to better understand performance to date and help assess the economic potential of light oil steamflooding. Given success in this pilot, the Steamflood Pilot Phase II Project will expand the current five-acre steamflood by adding four patterns in FY'90. Continued success in the FY'90 pilot expansion should result in major field expansions in FY'92 and FY'94. In addition to steamflooding, the feasibility of several EOR processes are planned to be investigated as part of the Bergeson/BPOI task force study. Enhanced oil recovery processes that are also planned to be investigated include alkaline-surfactant- polymer flooding, polymer- augmented waterflooding, carbon-dioxide flooding and insitu combustion with air/oxygen and water. The EOR studies will initially focus on determining which process or combination of processes has the best economic potential in the SOZ.

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy for the SOZ is to continue producing the reservoir by its primary depletion mechanism of gravity drainage while actively depending on developing methods to increase production and recover a high percentage of oil-in-place. The SOZ Light Oil Steamflood Pilot was started in July 1987 in an attempt to enhance oil recovery. Other methods of proposed enhanced recovery include waterflooding in the Southeast and Northeast Flank areas and fracturing tight reservoirs in the western SOZ area. Besides the depletion plans being developed by the BPOI Task Force, Bergeson and Associates and SSI, alternate production strategies will be studied using history matched models. The model studies will be followed by economic analysis of the various strategies to determine the most profitable method of production.

The production, cost and revenue streams for the Total Development Case are shown in the attached Economics Table 1. Key economic parameters are summarized in Figure 4 The cost and production assumptions that were used throughout are shown in Figure 9-1 and Figure 9-2.

The Maintenance Case represents continuation of the present production strategy of gravity drainage. Remedials necessary to maintain the Maintenance Case are stimulations to reduce the effect of scale, recompletions to recover reserves behind pipe, sand control that is necessary in areas subject to fine sand migration and water isolation for wells that are exposed to water encroachment. Facility expenditures are provided for the replacement of the 16" North Flank Gravity Line which has reached the end of its useful life due to internal corrosion. Numerous leaks have occurred in this section of line and the leak frequency is increasing. Steam injection at the rate of 2,200 barrels per day (cold water equivalent) into four five-acre spacing five spot patterns will continue for three years. In FY '92 the steam injection will be replaced by water injection at 1600 barrels per day for one year to produce any oil bypassed by the steam. Table 8 shows the separate economics for the Steamflood Pilot Phase I, even though it is included in the Maintenance Case.

Details of the Maintenance Case are shown in Economics Table 2. A summary of the key economic parameters and recoveries are shown in Figures 10 and 11.

SHALLOW OIL ZONE COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Stimulations (Acidizing)	60,000	30	50
Sand Control (Run Inner Liners)	135,000	50	50
Recompletions (Reperforations)	55,000	47	50
Water Isolation (Plug Wet Sands)	80,000	50	50
Frac Jobs	275,000	75	14
Conversions (Steamflood Producer to Injector)	150,000	-	-
Profile Control (Foam)	30,000	-	-
Conversions (Waterflood Producer to Injector)	80,000	-	-
Sand Control (Waterflood Inner Liners)	55,000	30	10
Recompletion (Waterflood Reperforations)	20,000	20	10
Water Isolation (Waterflood Plugbacks)	30,000	25	10

Figure 9-1

SHALLOW OIL ZONE COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (BOPD)	Decline (%/yr)
Drilling (New Wells)	315,000	65	10
Drilling (Temp. Obs. Wells)	315,000	-	-
Drilling (Steam Injectors)	270,000	-	-
Drilling (Steamflood Redrills)	150,000	65	10
Replace 16" Gravity Line	587,000	-	-
Facilities (FY'91 - '93 Steamflood Expansions Per Year)	4,003,600	-	-
Facilities (FY'94 Steamflood Expansion)	2,008,700	-	-
Facilities (FY'95 Steamflood Expansion)	798,000	-	-
Facilities (FY'90 Waterflood)	676,000	-	-
Logging (Monitor Steamflood)	10,000	-	-
Facilities (FY'91 Waterflood)	281,000	-	-
Facilities (FY'89 Steamflood Pilot)	26,000	-	-

Figure 9-2

The Development Drilling Project should require drilling six wells per year to increase production under current operating conditions. Selective wells (42 total) shall be drilled each year from FY '89 through FY'95. This project is designed to improve recovery of reserves and obtain data through coring and logging to better determine remaining reserves, especially in light of potential EOR processes. New drilling and completion techniques should be employed to enhance production. These include better sand control methods and other completion techniques. This is an ongoing project that is projected through future years. This project is fully described in Economics Table 3 and the results are summarized in Figure 12.

The Hydraulic Fracturing Project starting with one well in FY'89 involves fracturing low permeability SOZ sands. A western SOZ well is planned to test the feasibility of fracturing the Gusher, Wilhelm or Calitroleum Sands. These are low permeability, high pressure sands that contain hydrocarbons that can only be recovered through fracturing. If this program is economically successful, additional wells are expected to be considered in future years. Previous fracture attempts were made, however, they did not employ a mini-frac, wide fractures supported by high sand concentrations, and nitrified carrying fluid. These new techniques will build on previous hydraulic fracturing experience. One well is scheduled for FY '89 and two wells per year are scheduled for FY '90 and FY '91. The economics are described in Table 4 and the results are summarized in Figure 13.

The Steamflood Pilot Phase II Project is planned to expand the current five-acre steamflood by four patterns in FY'90. It is contingent on the success of the

SHALLOW OIL ZONE
MAINTENANCE CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$604.5 Million	$1,824.4 Million
Operating Cost:	$ 78.9 Million	$ 459.8 Million
Investment:	$ 13.3 Million	$ 35.5 Million
Total Costs:	$ 92.1 Million	$ 495.4 Million
Net Revenue:	$512.4 Million	$1,329.1 Million
Net Present Value (@ 10%)	$358.2 Million	$ 560.7 Million
Recovery:		
Oil (MMB)	30.0	57.6
Natural Gas (BCF)	16.7	34.1
Oil Equivalent (MMBOE)	33.4	64.4

Figure 10

SHALLOW OIL ZONE
STEAMFLOOD PILOT PHASE I MAINTENANCE CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$2.4 Million	$2.4 Million
Operating Cost:	$1.4 Million	$1.4 Million
Investment:	$1.2 Million	$1.2 Million
Total Costs:	$2.6 Million	$2.6 Million
Net Revenue:	$-0.2 Million	$-0.2 Million
Net Present Value (@ 10%)	$-0.2 Million	$-0.2 Million
Recovery:		
Oil (MMB)	0.2	0.2
Natural Gas (BCF)	0.4	0.4
Oil Equivalent (MMBOE)	0.3	0.3

Figure 11

SHALLOW OIL ZONE
DEVELOPMENT DRILLING PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$48.9 Million	$294.5 Million
Operating Cost:	$2.0 Million	$ 8.5 Million
Investment:	$14.6 Million	$ 14.6 Million
Total Costs:	$16.6 Million	$ 23.1 Million
Net Revenue:	$32.3 Million	$271.5 Million
Net Present Value (@ 10%)	$18.3 Million	$ 71.1 Million
Recovery:		
Oil (MMB)	2.4	8.6
Natural Gas (BCF)	0.04	0.1
Oil Equivalent (MMBOE)	2.4	8.6

Figure 12

SHALLOW OIL ZONE
HYDRAULIC FRACTURING PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$11.3 Million	$26.6 Million
Operating Cost:	$0.7 Million	$ 3.1 Million
Investment:	$1.4 Million	$ 1.4 Million
Total Costs:	$2.1 Million	$ 4.5 Million
Net Revenue:	$9.2 Million	$22.2 Million
Net Present Value (@ 10%)	$5.8 Million	$ 9.5 Million
Recovery:		
Oil (MMB)	0.5	0.9
Natural Gas (BCF)	0.3	0.5
Oil Equivalent (MMBOE)	0.6	1.0

Figure 13

initial pilot and consists of four additional five-acre patterns adjacent to the existing pilot area. Four injectors and four observation wells would be required to accelerate production in this five-acre per pattern area. This expansion is expected to require a minimum of 1600 barrels of steam per day (fresh water equivalent). One year of water injection will follow four years of steam injection. No facilities are planned for the pilot expansions since existing steam facilities are planned to be used. There are several activities that need to be completed for this pilot expansion as follows:

a. The production reporting system is to be modified. Project wells are be isolated for production monitoring purposes.

b. Fault block performance and pressures should be monitored closely.

c. A database should be set up for the project.

d. The geologyshould be understood in detail by layer.

e. A pressure database should be set up using quartz gauges that can measure differences in the low pres sures encountered.

f. Special core analyses should be run for simulating well performance.

The purpose of the Light Oil Steamflood is to improve recovery by lowering residual oil saturations.

The economics are described in Table 5 and the results are summarized in Figure 14.

The Steamflood Expansion Project in FY '92 is on ten acre spacing and is contingent upon the success of the initial five-acre spacing pilot. Should the ten-acre spacing response be less than expected, spacing is planned to revert to five acres in subsequent years. Production projections are based on ten-acre expected response by modifying the simulated five-acre spacing performance. This involves expansion into six areas over a thirteen year period. Each expansion will accelerate the production in these areas so that remaining recoverable oil in each area will be produced within five years. A maximum of 34,500 BWPD (steam equivalent barrels) is expected to be required in FY '95. One year of water injection will follow four years of steam injection. The project includes the design, purchase and installation of surface facilities in phases. The installations will expand the SOZ Steamflood activity in the 3G, 4G, 9G and 10G areas, as well as introduce steamflood in the 34S, 35S and 36S areas. The project will consist of multiple 50 MMBTU/Hr steam generation facilities to a maximum of 11 units. Dehydrators are also considered to dry the casing gas and provide fuel gas for the steam generators. Also, consideration

SHALLOW OIL ZONE
STEAMFLOOD PILOT PHASE II PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$15.9 Million	$2.9 Million
Operating Cost:	$4.0 Million	$3.6 Million
Investment:	$3.5 Million	$3.5 Million
Total Costs:	$7.5 Million	$7.1 Million
Net Revenue:	$8.4 Million	$-4.2 Million
Net Present Value (@ 10%)	$6.3 Million	$2.8 Million
Recovery:		
Oil (MMB)	0.8	0.4
Natural Gas (BCF)	1.7	1.4
Oil Equivalent (MMBOE)	1.1	0.7

Figure 14

SHALLOW OIL ZONE
STEAMFLOOD EXPANSION PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$202.0 Million	$774.8 Million
Operating Cost:	$22.5 Million	$144.7 Million
Investment:	$34.8 Million	$ 86.1 Million
Total Costs:	$57.3 Million	$230.8 Million
Net Revenue:	$144.7 Million	$544.0 Million
Net Present Value (@ 10%)	$81.0 Million	$265.3 Million
Recovery:		
Oil (MMB)	9.7	34.0
Natural Gas (BCF)	5.9	22.3
Oil Equivalent (MMBOE)	10.9	38.5

Figure 15

SHALLOW OIL ZONE
SS-2/MULINIA WATERFLOOD PROJECT

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$38.1 Million	$15.1 Million
Operating Cost:	$17.1 Million	$16.3 Million
Investment:	$2.4 Million	$ 2.4 Million
Total Costs:	$19.5 Million	$18.7 Million
Net Revenue:	$18.6 Million	$-3.6 Million
Net Present Value (@ 10%)	$15.3 Million	$6.4 Million
Recovery:		
Oil (MMB)	2.2	1.4
Natural Gas (BCF)	0	0
Oil Equivalent (MMBOE)	2.2	1.4

Figure 16

has been given to increasing the capacity to the water knockout and shipping facilities at 10G and 25S. Details for the Steamflood Expansion Project are shown in Table 6 and the economic results are summarized in Figure 15.

The SS-2/Mulinia Waterflood Project in FY'90 will inject produced SOZ water into down-dip South Flank SOZ Sands. This will begin by converting 12 wells to injection at a rate of approximately 2,000 BWPD per well. This will be expanded by six patterns per year if successful. Expansion of facilities in FY'90 will extend lines and modify pumps. The economics are described in Table 7 and the results are summarized in Figure 16.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The annual reservoir development activities are described for each of the six cases presented in this Reservoir Operating Plan for the SOZ. Details of the annual drilling and remedial activities are shown in Table 9 and Table 10.

FY'89

In FY '89, the Maintenance Case is projected to produce 15,184 BOPD largely from gravity drainage. The ongoing Steamflood Pilot is projected to produce up to 800 BOPD in the Maintenance Case. One LOSF observation well will be drilled.

A Development Drilling Project will result in six production wells drilled in FY'89. Also, a hydraulic fracture well is submitted for FY'89.

A facility expenditure is required to replace a 16" Gravity Line on the North Flank.

Reservoir studies planned for this year are the ongoing SSI and CUSA simulation of the Steamflood Four-Pattern Pilot and the BPOI Task Force, Bergeson and Associates and SSI studies of the eastern SOZ area.

FY'90

During FY'90, reservoir development activities include a continuation of the Maintenance Case, the Development Drilling Project and the Hydraulic Fracturing Project, plus the expansion of the Steamflood Pilot Phase II Project and the start of the SS- 2/Mulinia Waterflood Project on the South Flank of SOZ. A total of six new production wells would be drilled under the Development Drilling Project.

If the current Steamflood Pilot proves to be successful, then the Steamflood Pilot Phase II Project would start in FY'90. This would require the drilling of four injection wells and four temperature observation wells.

The SS-2/Mulinia Waterflood Project is a down-dip peripheral flood that will convert 12 idle wells to water injection. Production response from gas injection has shown that the SS-2/Mulinia Sands are sensitive to pressure and thus should respond to water injection. Produced SOZ water will be used for injection. A possible waterflood and insitu combustion in the eastern SOZ along the northeast flank is planned to be proposed for FY'92. This will result from the BPOI Task Force and Bergeson Studies being made in FY'89. Reservoir studies for the western SOZ may be started.

FY'91

Plans for EOR projects may be proposed in future years based on Task Force and Bergeson studies. The other projects will continue during this year. Generators will need to be ordered for the 10- acre steamflood expansion. Possible projects resulting from FY'90 western SOZ studies will be proposed for FY'93.

FY'92

The 10-acre Steamflood Expansion Project is planned for this year and is contingent upon the Steamflood Pilot Phase II Project. The Hydraulic Fracture Project is not scheduled beyond FY '91, but will be extended if the FY '89 hydraulic fracture is successful.

The 10-acre Steamflood Expansion Project would require simulation on 10-acre spacing before it is started. Other activities required will be the same as those listed under the Phase II Expansion in FY '90. This is a major expansion that will require many technical problems to be solved by all disciplines before it can be started.

FY'93 - '95

This period is represented by the projection of the base production, the Development Drilling Project and the Steamflood Expansion Project. Other enhanced recovery could be included during this period if the waterflooding fracturing projects and possible future EOR projects are potentially economic.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
SHALLOW OIL ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	15298	20839	8057	0	0	2133	10770	1640	0	613	0	2461
1990	17569	28833	8167	12600	0	4400	14500	3954	0	700	0	4378
1991	16598	38600	7950	18900	0	4400	17821	3586	0	4580	0	2021
1992	18067	45413	8324	20500	0	11105	21291	2873	0	4400	0	9364
1993	19528	35902	12104	6700	0	19210	19586	2417	0	4500	0	2125
1994	19217	34137	11847	1100	0	25258	19426	3119	0	2300	0	8207
1995	18743	39829	10988	1500	0	31305	21779	3536	0	930	0	2202
SUBTOTAL *	45632	88897	24615	22375	0	35701	125173	21125	0	18023	0	30758
1996-2022 *	57372	368828	33874	34049	0	95618	510900	35922	0	9789	0	27845
TOTAL *	103004	457725	58489	56424	0	131319	636073	57047	0	27812	0	58603

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	84706	4485	1934	91125	15484	14076	75641	68765	6175
1990	103052	4496	2057	109605	23532	19448	86073	71135	7012
1991	104747	4865	2218	111830	28008	21043	83822	62977	6642
1992	123316	3674	3052	130043	37928	25906	92115	62916	7205
1993	144122	4848	4844	153814	28628	17776	125186	77730	8016
1994	153190	2775	5058	161024	33052	18657	127972	72237	7884
1995	158032	-309	5429	163152	28447	14598	134705	69125	7648
SUBTOTAL	871165	24834	24592	920593	195079	131504	725514	484885	50582
1996-2022	1925701	22183	69889	2017772	584456	128375	1433316	430951	64184
TOTAL	2796866	47017	94481	2938365	779535	259879	2158830	915836	114766

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
SHALLOW OIL ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	15184	20826	8046	0	0	2133	10735	1345	0	613	0	351
1990	13748	22827	7782	0	0	2200	11298	2153	0	0	0	0
1991	12408	23121	7110	0	0	2200	11328	2197	0	0	0	0
1992	11840	23418	6495	1600	0	400	11466	1643	0	0	0	0
1993	10686	23719	5934	400	0	0	11392	1591	0	0	0	0
1994	9644	24024	5421	0	0	0	11328	1711	0	0	0	0
1995	8704	24333	4953	0	0	0	11304	1649	0	0	0	0
SUBTOTAL *	30008	59228	16695	730	0	2531	78851	12309	0	613	0	351
1996-2022 *	27572	288200	17448	0	0	0	380977	22260	0	0	0	0
TOTAL *	57580	347428	34143	730	0	2531	459828	34569	0	613	0	351

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	84075	4478	1932	90484	13064	11876	77420	70382	6133
1990	80640	4773	1960	87373	13451	11117	73922	61092	5589
1991	78305	4827	1984	85116	13525	10161	71591	53788	5051
1992	80814	5388	2381	88584	13109	8954	75475	51550	4798
1993	78866	5536	2375	86777	12983	8061	73794	45821	4336
1994	76878	5442	2315	84635	13039	7360	71596	40414	3918
1995	73388	5692	2447	81527	12953	6647	68574	35189	3540
SUBTOTAL	552966	36136	15394	604496	92124	64176	512372	358236	33365
1996-2022	1082027	96487	41410	1219924	403237	66357	816687	202463	31080
TOTAL	1634993	132623	56804	1824420	495361	130533	1329059	560699	64445

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
DEVELOPMENT DRILLING PROJECT
SHALLOW OIL ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	95	7	1	0	0	0	27	0	0	0	0	2110
1990	320	25	5	0	0	0	95	0	0	0	0	1878
1991	660	25	10	0	0	0	194	0	0	0	0	2021
1992	967	25	14	0	0	0	288	0	0	0	0	2077
1993	1243	26	19	0	0	0	377	0	0	0	0	2125
1994	1493	26	22	0	0	0	460	0	0	0	0	2163
1995	1719	26	26	0	0	0	538	0	0	0	0	2202
SUBTOTAL *	2371	58	35	0	0	0	1979	0	0	0	0	14576
1996-2022 *	6242	311	95	0	0	0	6536	0	0	0	0	0
TOTAL *	8613	369	130	0	0	0	8515	0	0	0	0	14576

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	526	1	0	527	2137	1943	-1610	-1464	35
1990	1877	3	1	1882	1973	1631	-91	-75	117
1991	4165	8	3	4176	2215	1664	1961	1473	242
1992	6600	12	5	6617	2365	1616	4252	2904	354
1993	9174	18	8	9199	2502	1554	6697	4158	455
1994	11902	22	9	11933	2623	1480	9310	5255	547
1995	14494	30	13	14536	2740	1406	11796	6053	629
SUBTOTAL	48738	94	39	48870	16555	11294	32315	18304	2379
1996-2022	244955	506	217	245679	6536	1621	239143	52834	6261
TOTAL	293693	600	256	294549	23091	12915	271458	71138	8640

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4
LONG RANGE PLAN
HYDRAULIC FRACTURING PROJECT
SHALLOW OIL ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	19	6	9	0	0	0	7	275	0	0	0	0
1990	212	70	106	0	0	0	87	569	0	0	0	0
1991	330	109	165	0	0	0	140	588	0	0	0	0
1992	284	111	142	0	0	0	130	0	0	0	0	0
1993	244	114	122	0	0	0	120	0	0	0	0	0
1994	210	116	105	0	0	0	111	0	0	0	0	0
1995	181	118	90	0	0	0	103	0	0	0	0	0
SUBTOTAL *	540	235	270	0	0	0	698	1432	0	0	0	0
1996-2022 *	399	1576	199	0	0	0	2359	0	0	0	0	0
TOTAL *	939	1811	469	0	0	0	3057	1432	0	0	0	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	105	6	2	113	282	257	-169	-154	8
1990	1243	72	27	1343	656	542	687	567	85
1991	2083	126	46	2255	728	547	1527	1147	133
1992	1938	120	52	2111	130	89	1981	1353	114
1993	1801	114	49	1963	120	75	1843	1144	98
1994	1674	105	45	1824	111	63	1713	967	84
1995	1526	103	44	1674	103	53	1571	806	73
SUBTOTAL	10370	646	265	11283	2130	1626	9153	5830	595
1996-2022	14001	950	408	15361	2359	401	13002	3652	439
TOTAL	24371	1596	673	26644	4489	2027	22155	9482	1034

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 5
LONG RANGE PLAN
STEAMFLOOD PILOT PHASE II PROJECT
SHALLOW OIL ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	901	644	274	0	0	2200	560	404	0	0	0	2501
1991	805	1767	666	0	0	2200	931	417	0	0	0	0
1992	447	2238	1044	0	0	2200	1036	148	0	0	0	0
1993	162	2630	1279	0	0	2200	1124	0	0	0	0	0
1994	-93	597	1148	1100	0	1100	353	0	0	0	0	0
1995	-134	0	348	1500	0	0	23	0	0	0	0	0
SUBTOTAL *	762	2875	1737	949	0	3614	4027	969	0	0	0	2501
1996-2022 *	-317	0	-337	0	0	0	-394	0	0	0	0	0
TOTAL *	445	2875	1400	949	0	3614	3633	969	0	0	0	2501

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	5285	-353	69	5001	3465	2863	1536	1270	349
1991	5080	-96	186	5170	1348	1013	3822	2871	343
1992	3051	215	383	3648	1184	809	2464	1683	240
1993	1196	455	512	2163	1124	698	1039	645	153
1994	-741	755	490	504	353	199	151	85	50
1995	-1130	400	172	-558	23	12	-581	-298	-23
SUBTOTAL	12741	1376	1812	15928	7497	5594	8431	6256	1112
1996-2022	-11084	-1370	-589	-13041	-394	-121	-12647	-3480	-385
TOTAL	1657	6	1223	2887	7103	5473	-4216	2776	727

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 6
LONG RANGE PLAN
STEAMFLOOD EXPANSION PROJECT
SHALLOW OIL ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0	4280	0	0
1992	3138	0	628	0	0	8505	1371	907	0	4400	0	7287
1993	6797	2405	4750	0	0	17010	4055	826	0	4500	0	0
1994	8083	9374	5150	0	0	24158	7210	1408	0	2300	0	6044
1995	8574	15351	5571	0	0	31305	9902	1888	0	930	0	0
SUBTOTAL *	9706	9902	5876	0	0	29557	22538	5029	0	16410	0	13331
1996-2022 *	24333	78742	16472	34049	0	95618	122176	13661	0	9789	0	27845
TOTAL *	34039	88644	22348	34049	0	125175	144714	18690	0	26199	0	41176

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	4280	3216	-4280	-3216	0
1992	21418	-2062	230	19587	13965	9538	5622	3840	1191
1993	50164	-1275	1901	50790	9381	5825	41409	25712	2830
1994	64434	-3551	2199	63083	16962	9574	46121	26034	3328
1995	72292	-6534	2753	68510	12720	6527	55790	28629	3538
SUBTOTAL	208308	-13422	7083	201970	57308	34680	144662	80999	10887
1996-2022	618781	-74377	28448	572851	173471	60419	399380	184329	27645
TOTAL	827089	-87799	35531	774821	230779	95099	544042	265328	38532

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 7
LONG RANGE PLAN
88-2/MULINIA WATERFLOOD PROJECT
SHALLOW OIL ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	2388	5268	0	12600	0	0	2460	828	0	700	0	0
1991	2394	13578	0	18900	0	0	5227	384	0	300	0	0
1992	1392	19620	0	18900	0	0	6999	175	0	0	0	0
1993	396	7009	0	6300	0	0	2519	0	0	0	0	0
1994	-120	0	0	0	0	0	-36	0	0	0	0	0
1995	-300	0	0	0	0	0	-92	0	0	0	0	0
SUBTOTAL *	2245	16598	0	20696	0	0	17077	1387	0	1000	0	0
1996-2022 *	-854	0	0	0	0	0	-751	0	0	0	0	0
TOTAL *	1391	16598	0	20696	0	0	16326	1387	0	1000	0	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	14007	0	0	14007	3988	3296	10019	8280	872
1991	15108	0	0	15108	5911	4441	9197	6910	874
1992	9501	0	0	9501	7174	4900	2327	1589	508
1993	2923	0	0	2923	2519	1564	404	251	145
1994	-957	0	0	-957	-36	-20	-921	-520	-44
1995	-2529	0	0	-2529	-92	-47	-2437	-1251	-110
SUBTOTAL	38053	0	0	38053	19464	14134	18589	15259	2245
1996-2022	-22907	0	0	-22908	-751	-301	-22157	-8841	-854
TOTAL	15146	0	0	15145	18713	13833	-3568	6418	1391

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 8
LONG RANGE PLAN
STEAMFLOOD PILOT
SHALLOW OIL ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	279	317	168	0	0	2133	272	405	0	26	0	315
1990	151	678	245	0	0	2200	364	300	0	0	0	0
1991	48	752	349	0	0	2200	378	166	0	0	0	0
1992	56	828	204	1600	0	400	348	0	0	0	0	0
1993	5	146	2	400	0	0	57	0	0	0	0	0
1994	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0	0
SUBTOTAL *	197	993	353	730	0	2531	1419	871	0	26	0	315
1996-2022 *	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL *	197	993	353	730	0	2531	1419	871	0	26	0	315

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	1545	-368	40	1217	1018	925	199	181	114
1990	886	-373	62	575	664	548	-89	-73	73
1991	303	-338	97	63	544	409	-481	-362	43
1992	382	51	75	508	348	238	160	109	35
1993	37	2	1	40	57	36	-17	-11	2
1994	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0
SUBTOTAL	3153	-1026	275	2403	2631	2156	-228	-156	267
1996-2022	0	0	0	0	0	0	0	0	0
TOTAL	3153	-1026	275	2403	2631	2156	-228	-156	267

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 9

DRILLING ACTIVITY

SHALLOW OIL ZONE

(NUMBER OF DRILLING WELLS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-22	TOTAL
	FISCAL YEAR								
1. MAINTENANCE CASE:									
a. OBSERVATION WELLS	1	0	0	0	0	0	0	0	1
SUB-TOTAL:	1	0	0	0	0	0	0	0	1
2. DEVELOPMENT DRILLING PROJECT:									
a. NEW WELLS	6	6	6	6	6	6	6	0	42
SUB-TOTAL:	6	6	6	6	6	6	6	0	42
3. HYDRAULIC FRACTURING PROJECT:									
a. NEW WELLS	0	0	0	0	0	0	0	0	0
SUB-TOTAL:	0	0	0	0	0	0	0	0	0
4. STEAMFLOOD PILOT PHASE II PROJECT:									
a. NEW WELLS	0	4	0	0	0	0	0	0	4
b. OBSERVATION WELLS	0	4	0	0	0	0	0	0	4
SUB-TOTAL:	0	8	0	0	0	0	0	0	8
5. STEAMFLOOD EXPANSION PROJECT:									
a. REDRILLS	0	0	0	7	0	7	0	21	35
b. NEW WELLS	0	0	0	20	0	15	0	70	105
SUB-TOTAL:	0	0	0	27	0	22	0	91	140
6. SS-2/MULINIA WATERFLOOD PROJECT:									
a. NEW WELLS	0	0	0	0	0	0	0	0	0
SUB-TOTAL:	0	0	0	0	0	0	0	0	0
TOTAL:	7	14	6	33	6	28	6	91	191

TABLE 10

REMEDIAL ACTIVITY

SHALLOW OIL ZONE

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	FISCAL YEAR 1989	1990	1991	1992	1993	1994	1995	1996-22	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	6	10	10	10	10	10	10	120	186
b. RECOMPLETIONS	8	7	7	7	7	7	7	84	134
c. SAND CONTROL	3	5	6	2	2	2	2	28	50
d. WATER ISOLATION	2	5	3	3	2	3	2	32	52
e. LOGGING	0	2	2	0	0	0	0	0	4
SUB-TOTAL:	19	29	28	22	21	22	21	264	426
2. DEVELOPMENT DRILLING PROJECT:									
NONE									
3. HYDRAULIC FRACTURING PROJECT:									
a. FRAC JOBS	1	2	2	0	0	0	0	0	5
SUB-TOTAL:	1	2	2	0	0	0	0	0	5
4. STEAMFLOOD PILOT PHASE II PROJECT:									
a. STIMULATIONS	0	2	2	0	0	0	0	0	4
b. CONVERSIONS	0	0	0	0	0	0	0	0	0
c. PROFILE CONTROL	0	0	0	0	0	0	0	0	0
d. SAND CONTROL	0	2	2	1	0	0	0	0	5
SUB-TOTAL:	0	4	4	1	0	0	0	0	9
5. STEAMFLOOD EXPANSION PROJECT:									
a. STIMULATIONS	0	0	0	0	0	0	0	0	0
b. CONVERSIONS	0	0	0	1	0	0	3	22	26
c. PROFILE CONTROL	0	0	0	0	2	2	3	28	35
d. SAND CONTROL	0	0	0	5	5	5	8	48	71
e. RECOMPLETIONS	0	0	0	0	0	9	0	7	16
SUB-TOTAL:	0	0	0	6	7	16	14	105	148
6. SS-2/MULINIA WATERFLOOD PROJECT:									
a. SAND CONTROL	0	0	2	0	0	0	0	0	2
b. RECOMPLETIONS	0	6	2	0	0	0	0	0	8
c. WATER ISOLATION	0	0	1	2	0	0	0	0	3
d. CONVERSIONS	0	12	6	0	0	0	0	0	18
SUB-TOTAL:	0	18	11	2	0	0	0	0	31
TOTAL:	20	53	45	31	28	38	35	369	619

ASPHALTO

The Asphalto Reservoir is located at the southwest edge of NPR-1, outside the Unit (See Location Map, Figure 1). The reservoir is in an advanced stage of depletion having produced approximately 68% of the estimated original oil-in-place under primary depletion. Current oil production from the reservoir amounts to less than one-quarter of one percent of total Elk Hills oil production.

The Total Development Case for the Asphalto Reservoir consists of a single Maintenance Case generating total undiscounted revenues of $11 million and having total associated costs of $3 million over the next seven years. Annual revenue and cost values are displayed in Figure 2.

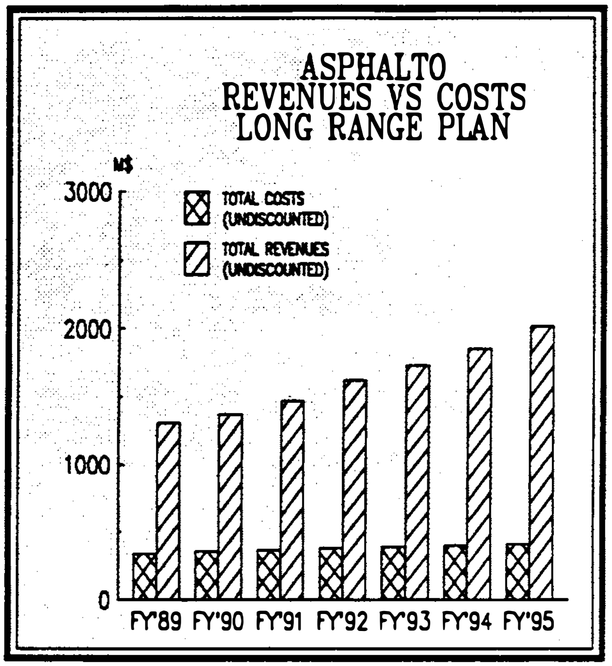


Figure 2

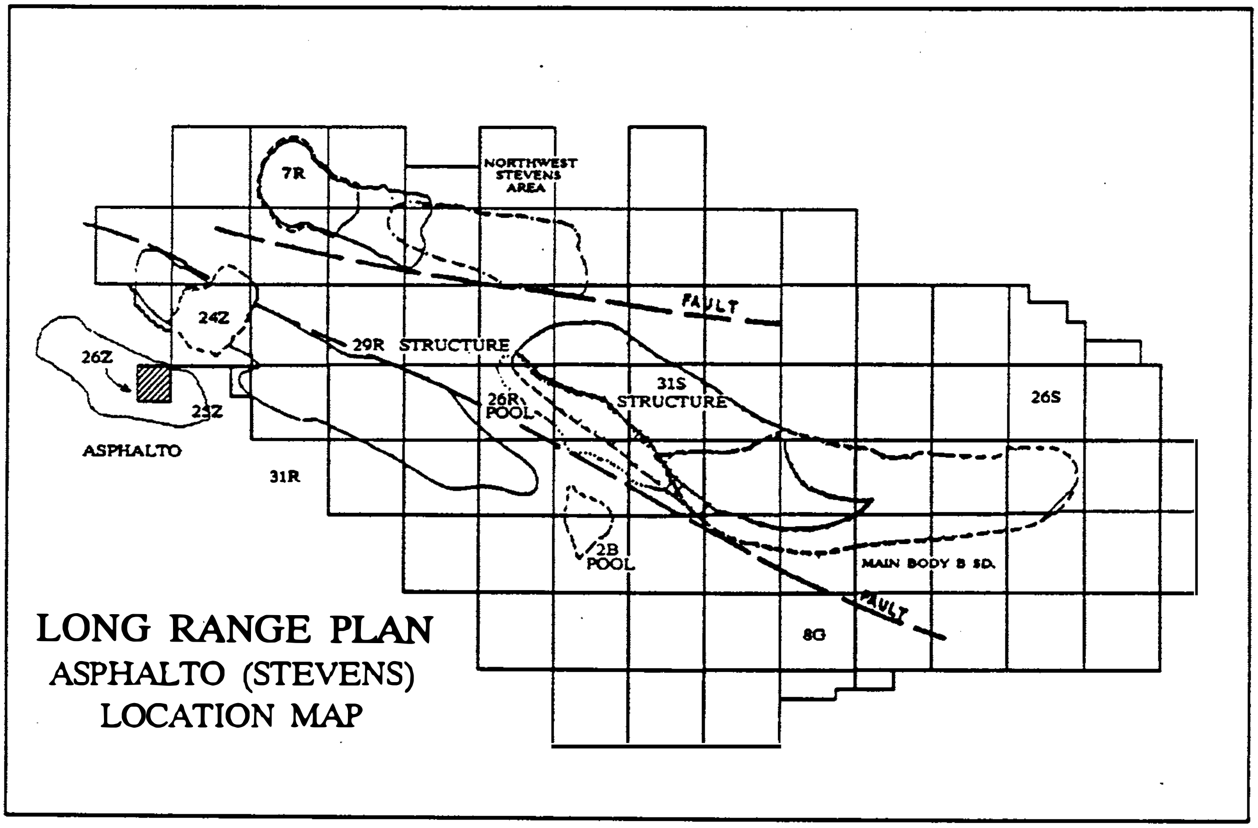


Figure 1

ASPHALTO
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$11.4 Million	$58.1 Million
Operating Cost:	$2.7 Million	$12.4 Million
Investment:	$ 0 Million	$0 Million
Total Costs:	$2.7 Million	$12.4 Million
Net Revenue:	$8.7 Million	$45.7 Million
Net Present Value (@ 10%)	$5.9 Million	$13.6 Million
Recovery:		
Oil (MMB)	0.3	0.9
Natural Gas (BCF)	1.5	4.9
Oil Equivalent (MMBOE)	0.6	1.8

Figure 3

Shown in Figure3 is an economic summary of the Total Development Case for both the seven year plan period and FY'89 to the economic limit.

Estimated oil, gas and oil equivalent recovery from the Total Development Case is also included in Figure 3.

The Total Development Case combines costs and production associated with "non-unit" operations in the Asphalto Stevens and Antelope Shale Reservoirs. The plan considers that only routine well work should be performed in an effort to maintain production.

Primary recovery from the Asphalto Stevens Reservoir has been exceptionally high (approximately 68%) as a result of possible migration of oil from the 24Z Structure and/or incorrect estimates of original oil-in-place. The reserve summary shown in Figure 4 compares commonly reported estimates contained in previous Long Range Plan documents with reserves contained in this plan. Equity study reserve estimates are not available for this reservoir.

The current reservoir operating strategy is continued primary depletion of both reservoirs to their economic

ASPHALTO
TOTAL DEVELOPMENT CASE

	EQUITY STUDIES*	LONG RANGE PLAN MAINT.	LONG RANGE PLAN TOTAL
Original-Oil-In-Place (MMB):	16.3	----	----
Estimated Recoverable Oil (MMB):	11.3	12.0	12.0
Cumulative Production 9/30/88 (MMB):	11.1	11.1	11.1
Remaining Reserves:			
Oil (MMB)	0.2	0.9	0.9
Natural Gas (BCF)	----	4.9	4.9
Oil Equivalent (MMBOE)	----	1.8	1.8
Economic Limit (BOPD, YEAR):	----	42/2015	42/2015

* Commonly reported estimate from prior Long Range Plan Documents.

Figure 4

limit. A total of 13 wells are expected to produce an average rate of 151 BOPD and 557 MCFD in FY'89. Given the outstanding recovery to-date, secondary or enhanced oil recovery methods would not be feasible. Historical production from the Asphalto Reservoir and projected performance is shown in Figures 5 and 6.

RESERVOIR DESCRIPTION

The Asphalto Reservoir is located at the southwest edge of NPR-1, outside the Unit (see Location Map, Figure 1). The Asphalto Sand is the southwestern extension of the 24Z Sand extending across Sections 22Z, 23Z, 25Z and 26Z. Deposited primarily by turbidity currents, these sands vary in thickness from 200 to 500 feet in the better developed part of the channel. Closure to the southwest and northeast is structural and defined by oil-water contacts, while closure to the northwest and southeast is stratigraphic with sand-to-shale facies changes.

Production from the Asphalto Stevens Reservoir is confined to the northeast quarter of Section 26Z, outside the Unit. Since initial development in 1963, the Asphalto Stevens Sands have been produced by solution gas drive and natural waterdrive. Concern over migration of oil from the 24Z Reservoir, suggested by declining pressure in the 24Z Reservoir while shut-in, led to the establishment of water injection between the 24Z and Asphalto Structures in 1966. This water injection program was used effectively to maintain pressure in the 24Z Reservoir prior to open-up in 1976. Currently there are 11 active Asphalto Stevens wells producing approximately 150-170 BOPD at a 96% watercut by means of artificial lift. Reservoir characteristics are shown in Figure 7.

In addition to Asphalto Stevens production, this plan includes other "non-unit" production associated with the Antelope Shale Reservoir. Antelope Shale production in Section 14Z comes from two areas, the easterly plunge of the Railroad Gap Field and the westerly extension of the 29R Structure. The Antelope Shale is equivalent to the NAB Shales within the Unit. Currently, there are only two active Antelope Shale producers which combined, account for approximately five to ten BOPD. Through September 1988, only 12.9 MBBLS had been produced from the Antelope Shale.

RESERVOIR STUDIES

There are no reservoir studies planned for this reservoir.

RESERVOIR DEVELOPMENT STRATEGY

The reservoir development strategy for Asphalto is continued primary production of both the Asphalto Stevens and Antelope Shale Reservoirs to their economic limit. Only routine remedial activity should be performed (e.g., pump replacements, rod part and tubing leak repairs, etc.), as necessary to maintain produc-

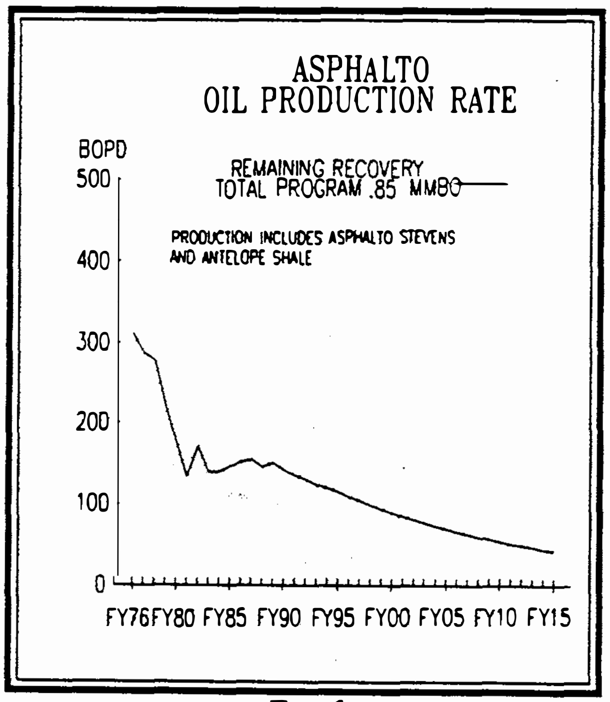


Figure 5

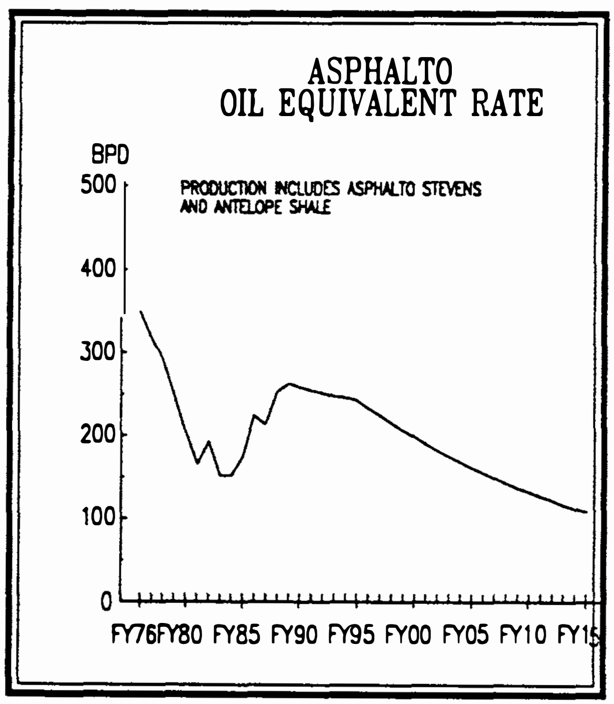


Figure 6

ASPHALTO STEVENS
RESERVOIR CHARACTERISTICS

Porosity (%):	23	Production Wells (#)*:	11
Water Sat. (%)	29	Injection Wells (#)*:	0
Air Perm. (md):	255	Top Pay (Ft VSS)*:	+4,600
Oil Gravity (API):	36	Max Net Pay (Ft)*:	290
Oil Form. Vol. Fact.(RB/STB):	1.42	Pay Area (AC)*:	160
Oil Viscosity (cp):	.59	Pay Volume (AF)*:	18,487
Initial Press. (psi):	2,403	GOC (Ft-VSS)*:	NA
Bubble Point Press. (psi):	NA	WOC (Ft-VSS)*:	4,800-5,050 (initial)
Current Press. (psi):	NA	Press. Datum (Ft-VSS):	4,774

* Values denoted with an "*" reference the DOE quarter section of 26Z specifically. All other values represent reasonable field averages as determined by the Pre-Unit Engineering Committee.

Figure 7

tion. When, and where possible, production would be maximized by increasing pump sizes, pumping unit speeds, and stroke lengths to lower existing fluid levels. As wells become uneconomic to produce on an individual well basis, they are expected to be converted to pressure observation wells to monitor the off-structure effects from the 24Z Waterflood. This strategy has been incorporated in the Total Development Case.

Figure 3 is a summary of economic and recovery data for the Total Development Case. A more detailed breakdown of production, cost and revenue streams is provided in Economics Table 1.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

In support of the Total Development Case, activity during FY'89-'95 is expected to include continued monitoring of both production rates and fluid levels to assure that wells are being produced at their maximum rates. Additional monitoring is also expected to assess the possible off-structure effects of water injection in the South Flank of the adjacent 24Z Reservoir. This includes periodic static pressure testing of Asphalto Stevens Zone producers that are either shut-in uneconomic, or temporarily down for routine well work.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
ASFALTO
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	151	4222	557	0	0	0	340	0	0	0	0	0
1990	142	4312	577	0	0	0	359	0	0	0	0	0
1991	136	4326	587	0	0	0	372	0	0	0	0	0
1992	131	4338	598	0	0	0	383	0	0	0	0	0
1993	124	4351	610	0	0	0	393	0	0	0	0	0
1994	120	4362	624	0	0	0	402	0	0	0	0	0
1995	115	4373	638	0	0	0	410	0	0	0	0	0
SUBTOTAL *	335	11054	1530	0	0	0	2659	0	0	0	0	0
1996-2015 *	516	32244	3336	0	0	0	9743	0	0	0	0	0
TOTAL *	851	43298	4866	0	0	0	12402	0	0	0	0	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	836	343	134	1312	340	309	972	884	96
1990	833	394	145	1372	359	297	1013	837	94
1991	858	448	164	1470	372	279	1098	825	93
1992	894	507	219	1621	383	262	1238	845	92
1993	915	569	244	1728	393	244	1335	829	90
1994	957	626	266	1849	402	227	1447	817	90
1995	970	733	315	2018	410	210	1608	825	89
TOTAL	6263	3620	1487	11370	2659	1828	8711	5862	644
6-2015	20315	18452	7916	46685	9743	2027	36942	7764	1187
OTAL	26578	22072	9403	58055	12402	3855	45653	13626	1831

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

CARNEROS

The Carneros Reservoir provides significant gas production at Elk Hills and includes production from three Carneros Sands and the Santos (See Location Map, Figure 1 and Cross Section, Figure 3). This plan includes Carneros production from the 29R Structure and Asphalto Well 584-26Z. Based upon reservoir studies and a Scientific Software-Intercomp (SSI) Simulation on the 29R Structure Carneros, a compressor was recently installed to lower the 500 psi line pressure.

The Total Development Case for the Carneros Reservoir including the 29R Structure and Asphalto is the Maintenance Case. During the period of FY'89 to FY'95, an estimated $101 million in undiscounted revenues will be generated. The total expenditure should amount to $10 million to continue the current production strategy. Annual revenue and cost values are shown in the Figure 2.

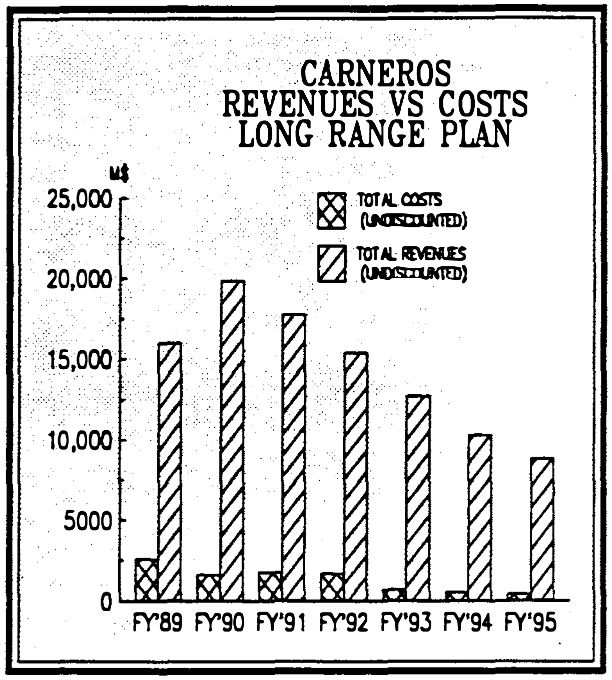


Figure 2

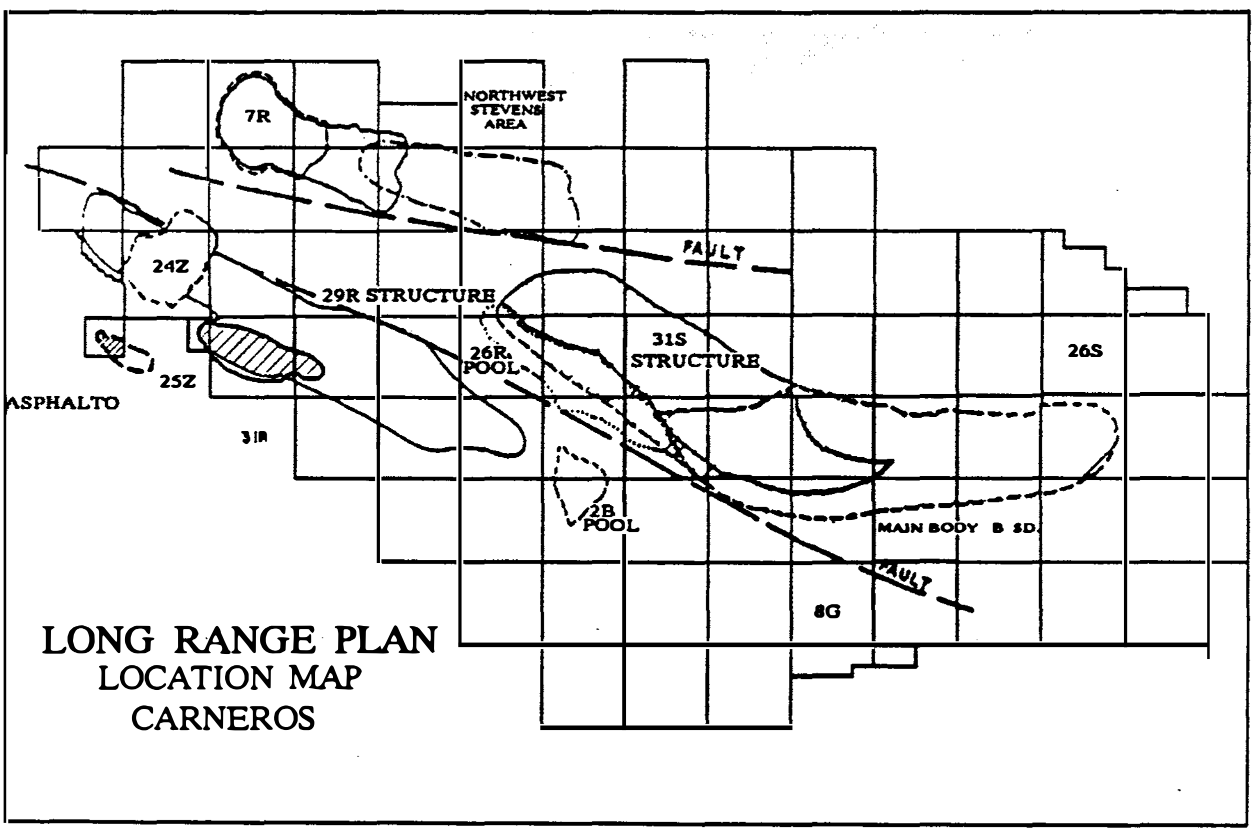


Figure 1

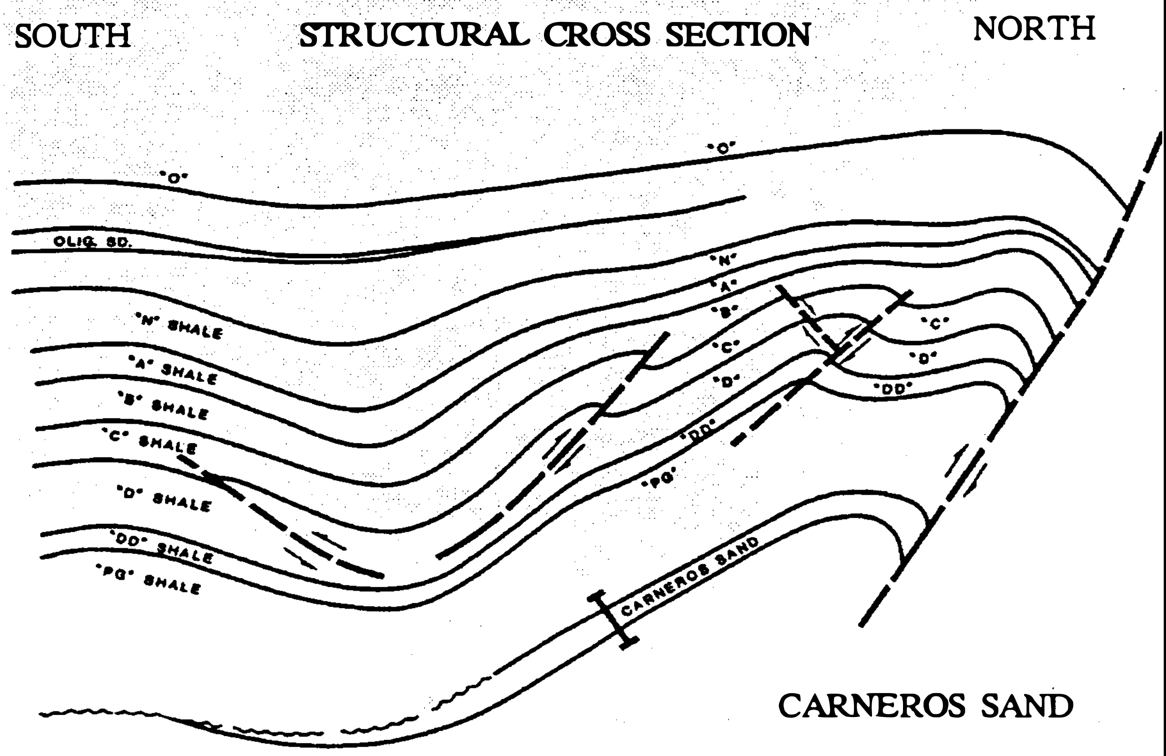


Figure 3

The economic parameters shown in Figure 4 are a summary of the Total Development Case for the plan period and to the economic limit.

The Recovery for the Total Development Case in terms of oil production, gas production and total oil equivalent barrels is also shown in Figure 4.

A total of eight active 29R Structure Carneros wells and Asphalto Well 584-26Z are projected to produce an average of 16,450 MCFPD in FY'89. Remaining gas reserves for the Carneros Sands are estimated to be 35.9 billion cubic feet. Movement of gas from the 29R Structure to Asphalto has caused Well 584-26Z to produce more than its estimated recoverable gas reserves.

CARNEROS
TOTAL DEVELOPMENT CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$100.9 Million	$140.9 Million
Operating Cost:	$ 6.6 Million	$ 8.3 Million
Investment:	$ 3.2 Million	$ 3.2 Million
Total Costs:	$ 9.9 Million	$ 11.5 Million
Net Revenue:	$ 91.0 Million	$129.4 Million
Net Present Value (@ 10%)	$ 65.6 Million	$ 78.0 Million
Recovery:		
Oil (MMB)	0.7	0.9
Natural Gas (BCF)	29.3	34.9
Oil Equivalent (MMBOE)	6.6	7.9

Figure 4

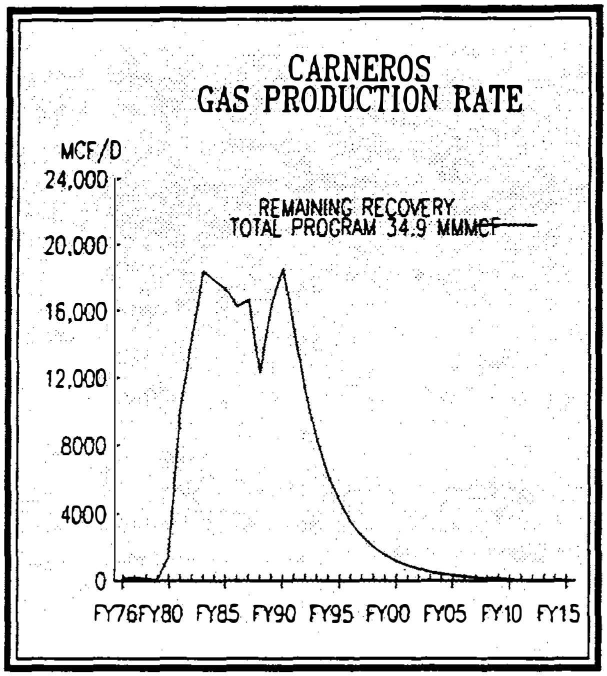


Figure 5

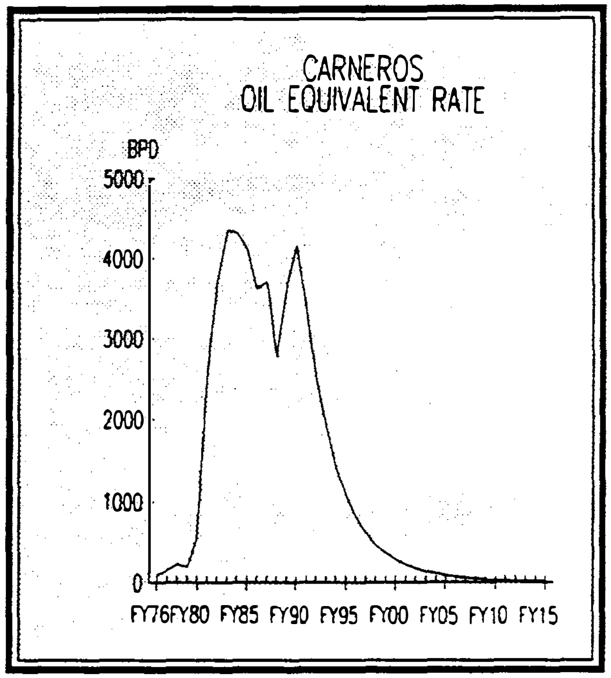


Figure 6

Historical production from the Carneros Reservoir and projected performance to the Economic Limit is shown in Figure 5 and Figure 6.

The estimated gas reserves for the Carneros Reservoir shown below are from a December 1987 SSI report entitled "Reservoir Engineering and Compositional Simulation Study" for the 1st and 2nd Carneros Sands. The less significant Santos and 3rd Carneros are estimated to have 5 billion cubic feet of gas in-place and 3.5 billion cubic feet estimated recoverable, with 1.0 billion cubic feet remaining. Carneros Well 584-26Z is estimated to have seven billion cubic feet of gas in-place and six billion cubic feet estimated recoverable reserves. The equity reserves were never determined.

Figure 7 represents gas reserves determined by SSI and estimated reserves for the Santos and third Carneros Sands, plus Asphalto Carneros Well 584-26Z. These reserves are compared with the Long Range Plan Maintenance and Total Development Cases.

CARNEROS
TOTAL DEVELOPMENT CASE

	EQUITY *STUDIES	LONG RANGE PLAN MAINT.	LONG RANGE PLAN TOTAL
Original-Gas-In-Place (BCF):	123.4	----	----
Estimated Recoverable Gas (BCF):	86.0	91.5	91.5
Cumulative Production 9/30/88 (BCF):	56.6	56.6	56.6
Remaining Reserves:			
Natural Gas (BCF)	35.9	34.9	34.9
Oil Equivalent (MMBOE)	----	7.9	7.9
Economic Limit (MCFD, YEAR):	----	41/2015	41/2015

*Reserves Determined by SSI Report

Figure 7

The field activities planned over the seven year plan period are as follows:

ITEM	REASON	COST $THOUSANDS
Deepen Well to Agua	If 514-30R finds additional productive sands.	900
Three Remedials	Maintain production.	485
New Compressor	Increased profitability and reserves.	310

RESERVOIR DESCRIPTION

The Carneros Reservoir consists of three sands containing oil, gas and gas condensate. The accumulation of gas and/or oil in the Carneros Zone is controlled primarily by the 29R structural closure and secondarily by the pinching out of sands to the East. (See Location Map, Figure 1, and Cross-Section, Figure 3). The productive area of the 29R Structure Carneros Reservoir covers approximately 602 acres and has a net producing thickness of up to 250 feet. Carneros Sands generally exhibit low porosity and permeability in many cases and are not fractured. The Carneros is a retrograde condensate reservoir with a thin black oil band associated with the gas in the 3rd Carneros Sand. As of October 1988, 43% of the estimated gas reserves in the 29R Structure Carneros Reservoir remained to be produced. A table of reservoir characteristics for the Carneros 29R Structure is shown as Figure 8.

Currently there are eight active wells producing from the Carneros 29R Reservoir and one well from Asphalto. Well 583-30R is a dual completion that has lower production from the Santos and upper production from the 1st and 2nd Carneros Sands. Well 578-24Z is the only well producing from the 3rd Carneros and Well 583-30R is the only well producing from the Santos. The compressor that is currently being installed is designed to provide 18,000 MCF per day at an intake pressure of 60 psi to a discharge pressure of 500 psig. Well 514-30R is currently being production tested in six intervals that may lead to an addition of productive sands to the Carneros Reservoir.

RESERVOIR STUDIES

Reservoir studies and an SSI simulation have been completed for the 29R Structure Carneros Reservoir. The simulation study entitled "Reservoir Engineering and Compositional Simulation Study" was completed by SSI in December 1987. Predictions were performed for continued straight depletion and for a case involving the installation of compressors. Both cases were compared on the basis of acceleration of hydrocarbon recovery and the effect on continued gas migration. The study showed that an additional 17.0 billion cubic feet of gas could be produced by installing a compressor to lower the 500 psi line pressure, allowing the reservoir to be depleted at a faster rate. The additional recoverable gas will vary, depending upon when the compressor is installed, due to migration of gas to the Asphalto Carneros Structure. Compressor installation was finished by the Second Quarter of FY'89. Bergeson and Associates reported that exploration for deeper producing Carneros horizons appears favorable.

CARNEROS
RESERVOIR CHARACTERISTICS

Porosity (%):	16	Production Wells(#):	8
Water Sat. (%):	21	Injection Wells (#):	0
Air Perm. (md):	6.0	Top Pay (Ft-VSS):	6,500
Oil Gravity (API):	50	Max Pay (Ft):	250
Gas Form. Vol.Fact. (RCF/SCF):	0.0045	Pay Area (Ac):	602
Gas Viscosity (cp):	0.016	Pay Volume (AF):	80,000
Initial Press. (psi):	4,160	GOC (Ft-VSS):	7,980
Sat. Press. (psi):	3,900	WOC (Ft-VSS):	8,140
Current Press. (psi):	1,500	Press. Datum (Ft-VSS):	7.900

Figure 8

RESERVOIR DEVELOPMENT STRATEGY

The Reservoir Development Strategy for the Carneros Reservoir is production through pressure depletion. The compressor installation should allow the reservoir to be depleted at a faster rate and permit less gas to escape to the Asphalto Carneros Reservoir. Exploration activities for deeper productive horizons are contingent upon Well 514-30R that is now being tested.

The production, cost and revenue streams for the Total Development Case are shown in the Economics Table 1. Key economic parameters and recoveries are summarized in Figure 4. Cost and production assumptions are shown in Figure 9.

CARNEROS
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (MCFPD)	Decline (%/Yr.)
Stimulations (Acidizing)	155,000	240	4
Deepening (Contingent on #514-30R)	900,000	-	-
Facilities (Supplemental Carneros Compressor)	310,000	-	-
Artificial Lift*	180,000	500	12

* Installation costs are $20,000 of total cost.

Figure 9

The Total Development Case represents a continuation of the present production strategy. Stimulations and facilities are necessary to maintain the production and the deepening will help to investigate the full potential of the Carneros Reservoir.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

The annual reservoir development activities are described below for the ensuing seven-year plan period. Details of the remedial and deepening activities are shown in Table 2 and Table 3.

FY'89

The Total Development Case is projected to produce at an average rate of 16,905 MCFD during the year. Well 566-29R, which has equalized due to high production line pressure and scale, will require remedial work when the compressor is installed. Pending the results of current testing of Well 514-30R, a well may be deepened to the Agua zone. The compressor installation should be completed in FY'89.

FY'90 - FY'95

One stimulation in FY'90 and one stimulation in FY'92 are expected to be required to maintain production. These acid-solvent stimulations will ensure that scale and asphaltines should not reduce production potential. Previous experience has shown that these jobs can be effective. Three artificial lifts should be installed in FY'91 and FY'92, while two are scheduled for FY'93. Reservoir pressures are estimated to be unable to lift the fluid during these years.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
CARNEROS
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	351	175	16450	0	0	0	1259	155	0	310	0	900
1990	430	199	18550	0	0	0	1473	160	0	0	0	0
1991	346	199	14922	0	0	0	1230	0	64	0	513	0
1992	271	165	11150	0	0	0	948	170	66	0	528	0
1993	213	142	8348	0	0	0	730	0	44	0	360	0
1994	167	123	6263	0	0	0	561	0	0	0	0	0
1995	131	110	4711	0	0	0	433	0	0	0	0	0
SUBTOTAL *	697	406	29344	0	0	0	6634	485	174	310	1401	900
1996-2015 *	227	299	5532	0	0	0	1617	0	0	0	0	0
TOTAL *	924	705	34876	0	0	0	8251	485	174	310	1401	900

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	1944	10120	3949	16012	2624	2386	13388	12171	1335
1990	2522	12666	4672	19860	1633	1350	18227	15063	1518
1991	2184	11399	4163	17746	1807	1357	15939	11975	1222
1992	1850	9460	4088	15398	1712	1169	13686	9348	917
1993	1572	7788	3341	12701	1134	704	11567	7182	690
1994	1331	6287	2674	10293	561	317	9732	5494	521
1995	1105	5414	2328	8846	433	222	8413	4317	394
SUBTOTAL	12508	63134	25215	100856	9904	7505	90952	65550	6597
1996-2015	7798	22597	9693	40090	1617	555	38473	12425	1340
TOTAL	20306	85731	34908	140946	11521	8060	129425	77975	7937

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2

DRILLING ACTIVITY

CARNEROS

(NUMBER OF DRILLING WELLS PER YEAR)

TYPE OF PROJECT	FISCAL YEAR 1989	1990	1991	1992	1993	1994	1995	1996-08	TOTAL
1. MAINTENANCE CASE:									
a. DEEPENINGS	1	0	0	0	0	0	0	0	1
b. NEW WELLS	0	0	0	0	0	0	0	0	0
TOTAL:	1	0	0	0	0	0	0	0	1

TABLE 3

REMEDIAL ACTIVITY

CARNEROS

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	FISCAL YEAR 1989	1990	1991	1992	1993	1994	1995	1996-08	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	1	1	0	1	0	0	0	0	3
b. RECOMPLETIONS	0	0	0	0	0	0	0	0	0
c. ARTIFICIAL LIFT	0	0	3	3	0	0	0	0	6
TOTAL:	1	1	3	4	0	0	0	0	9

DRY GAS ZONE

The Dry Gas Zone (DGZ) is the only dry gas producing reservoir at NPR-1.(See location map, Figure 1). Currently, the reservoir is being produced by means of surface compression and the gas utilized as a source for Stevens high pressure gas injection. Engineering calculations suggest that production levels from the reservoir will decline unless measures are taken to reduce the compressor intake pressure and/or develop additional reserves.

The Total Development Case for the Dry Gas Zone consists of a Maintenance Case, a Remedial Project and a Compressor Project. The Total Development Case is anticipated to generate $ 102 million in undiscounted revenues for a total projected expenditure of $12 million over the next seven years. Annual revenue and cost values are displayed in the Figure 2.

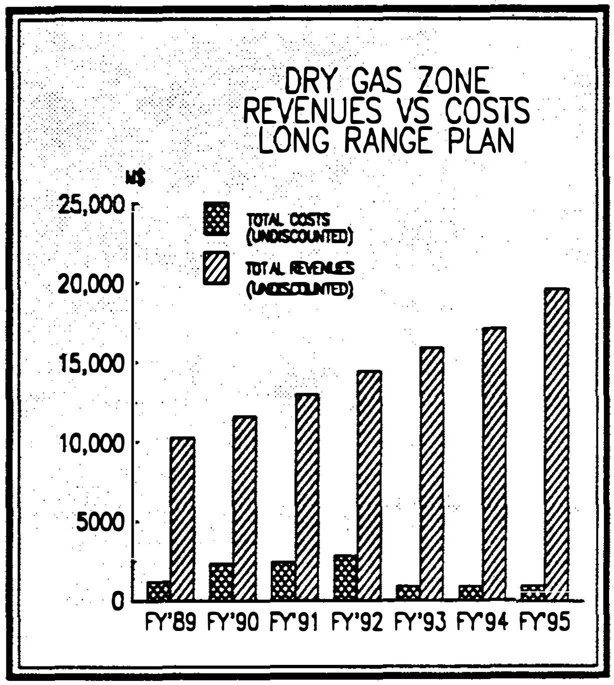


Figure 2

Shown in Figure 3 is an economic summary of the Total Development Case for both the seven year plan period and FY'89 to the economic limit.

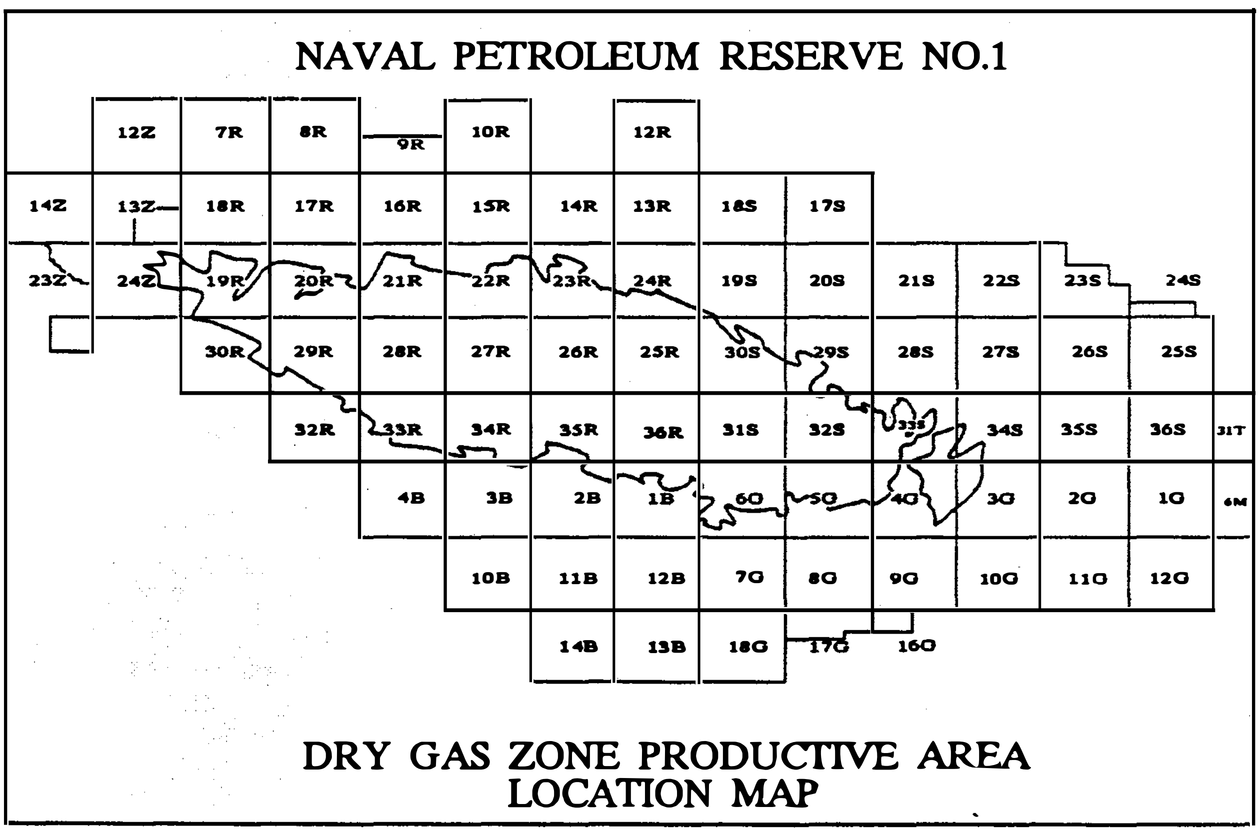


Figure 1

DRY GAS ZONE TOTAL DEVELOPMENT CASE	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$101.9 Million	$ 166.7 Million
Operating Cost:	$5.5 Million	$ 8.0 Million
Investment:	$6.1 Million	$ 6.1 Million
Total Costs:	$11.6 Million	$ 14.1 Million
Net Revenue:	$90.3 Million	$ 152.6 Million
Net Present Value (@ 10%)	$59.8 Million	$ 85.0 Million
Recovery:		
Oil (MMB)	----	----
Natural Gas (BCF)	45.9	64.8
Oil Equivalent (MMBOE)	6.8	9.6

Figure 3

Estimated gas and oil equivalent recovery from the Total Development Case is also included in Figure 3.

The estimated reserves for the Dry Gas Zone shown in Figure 4 are based on volumetric calculations contained in the 1988 Dry Gas Zone Reservoir Management Plan. This estimate is compared with the Long Range Plan Maintenance and Total Development Cases.

The Maintenance Case represents base production levels assuming no remedial, drilling, or facility expenditures (i.e., continued current operations). The Remedial Project includes both remedial and facility activity designed to exploit and develop Dry Gas Zone reserves. A total of 31 remedial jobs are currently planned over the next seven years including 22 recompletions of undepleted higher pressure zones and nine artificial lift installations to remove static water columns and reduce reservoir back-pressure. Surface facility expenditures totalling $1.7 million are also included in this project for well-site separation of water and possible modifications/upgrades to the process equipment.

The Compressor Project involves the installation of a booster compressor by FY'92 to reduce compressor intake pressure and improve recovery from the Dry Gas Zone. Actual timing of the compressor installation is highly dependent on the performance of remedial activity performed as part of the Remedial Project.

DRY GAS ZONE TOTAL DEVELOPMENT CASE	RESERVE *ESTIMATES	LONG RANGE PLAN MAINT.	LONG RANGE PLAN TOTAL
Original-Gas-In-Place (BCF):	212.2	----	----
Estimated Recoverable Gas (BCF):	192.0	172.7	226.0
Cumulative Production 9/30/88 (BCF):	161.2	161.2	161.2
Remaining Reserves:			
Oil (MMB)	----	----	----
Natural Gas (BCF)	30.8	11.5	64.8
Oil Equivalent (MMBOE)	----	1.7	9.6
Economic Limit (MCFD, YEAR):	----	11/2001	12/2009

* From 1988 Dry Gas Zone Reservoir Management Plan.

Figure 4

The current reservoir operating strategy is to continue pressure depletion of the reservoir at rates consistent with the capacity of the existing compressors (currently 18,000-18,500 MCFD at 95 psi intake). To offset declining production, recompletions and artificial lift-installations are planned. When remedial activity is no longer capable of supporting production rates, it is anticipated that booster compression will be added to further reduce compressor intake pressures. Historical production from the Dry Gas Zone Reservoir and projected performance to the economic limit is shown in Figures 5 and 6. It should be noted that steeply declining production depicted in these graphs reflects facility imposed limitations (i.e., compressor intake pressure) and is not indicative of true reservoir capability.

RESERVOIR DESCRIPTION

The Dry Gas Zone is the shallowest zone currently producing at Elk Hills. It is composed of relatively thin, unconsolidated, fine-grained channel sands collectively referred to as the Mya Sands. These sands extend in a NNE-SSW trend across a broad anticline overlaying the western two-thirds of the 31S Structure and the eastern half of the 29R Structure (see Location Map, Figure 1). Individual channels are typically less than one-half mile wide. Low displacement normal faults parallel to these channels provide varying degrees of trap modification. A total of 17 stratigraphic intervals and 57 tank-like gas reservoirs have been correlated and mapped. Although current average reservoir pressure is approximately 160 psi, Repeat Formation Test (RFT) measurements indicate the presence of zones with pressures in excess of 500 psi. These higher pressure zones suggest incomplete drainage of existing reserves and/or isolated "tanks" that are currently underdeveloped. (See Figure 7 for reservoir characteristics).

Remaining reserves of 64.8 BCF contained in the Total Development Case exceed Reservoir Management Plan estimates based on assumed incremental recovery associated with recompletion activity. The FY'89 study by Evans, Carey and Crozier is anticipated to provide additional insight regarding remaining reserve potential.

Continuous production from the Dry Gas Zone Reservoir was initiated in October 1980. Between 1980 and late 1987, well deliverability exceeded the throughput capacity of the existing compressors. As a result, production remained essentially constant at approximately 20,000 MCFD. As reservoir pressure continued to fall and approach the compressors' intake pressure (i.e., approximately 110 psi), a drop in total reservoir production was observed in late 1987. This drop was further magnified by the accumulation of liquids at low points in the gas gathering lines. In early 1988, modifications to the existing compressors were made to lower intake pressure requirements (i.e., to 95 psi) and enable continuous production at approximately 18,000-18,500 MCFD.

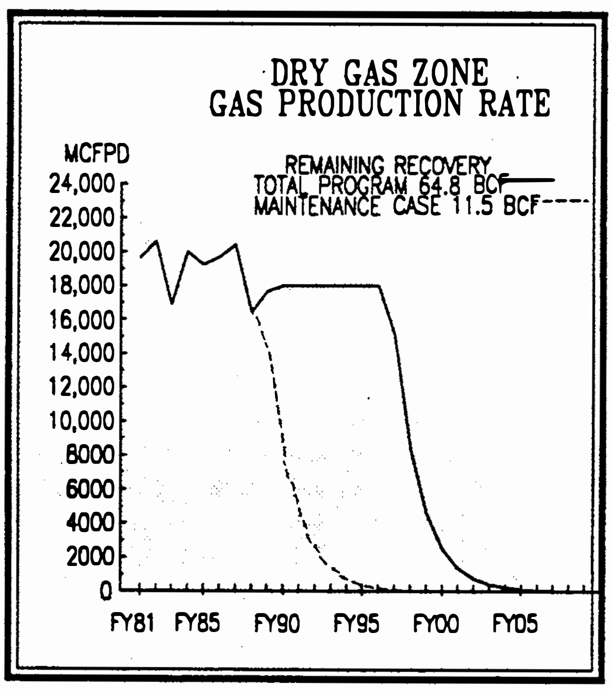


Figure 5

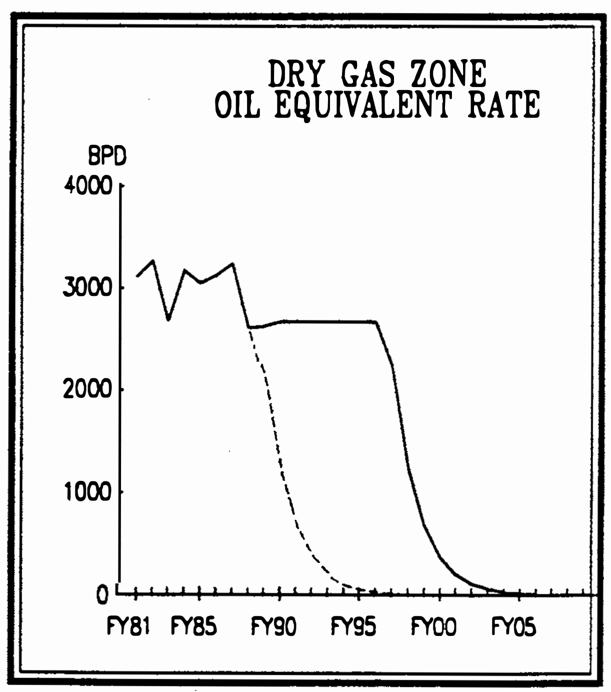


Figure 6

DRY GAS ZONE RESERVOIR CHARACTERISTICS			
Porosity (%):	36	Producing Wells (#):	30
Water Sat. (%):	50	Injection Wells (#):	0
Air Perm (md):	1,200	Top Pay (Ft-VSS):	+100
Gas Gravity:	.58	Max Pay (Ft.):	N/A
Gas Form. Vol. Fact.			
Gas Viscosity (cp):	.012	Pay Volume (AF):	978,619
Initial Press. (psi):	620	GOC (Ft-VSS):	N/A
Sat. Press. (psi):	NA	GWC (Ft-VSS):	Variable
Avg. Current Press. (psi):	157	Press. Datum (Ft-VSS):	684

Figure 7

Although more than 1000 wells have penetrated the Dry Gas Zone, a total of only 36 have been completed in the Mya Interval. Of these, 30 continue to produce under pressure depletion and surface compression. Cumulative production through September 1988 was 161.2 BCF, which represents a recovery-to-date of approximately 76% of the original-gas-in-place.

RESERVOIR STUDIES

During FY'89, the consulting firm of Evans, Carey and Crozier is expected to complete their 100% DOE funded evaluation of the Dry Gas Zone. This study should provide an in-depth geological and engineering analysis of the reservoir. It would be utilized to help identify additional development potential and refine long term exploitation strategies and objectives.

RESERVOIR DEVELOPMENT STRATEGY

During the seven year period covered by this plan, the strategy is to continue pressure depletion of the reservoir at rates consistent with the throughput capacity of the compressors. This rate is approximately 18,000-18,500 MCFD at a compressor intake pressure of 95 psi, given the current compressor configuration.

Accomplishment of this objective has been considered in three scenarios within this plan: the Maintenance Case, the Remedial Project, and the Compressor Project. Combined, they constitute the Total Development Case.

Shown in Figure 3 is an economic summary of the Total Development Case. Figure 8 shows the assumptions used in its preparation. A more detailed breakdown of production, cost and revenue streams is provided in Economics Table 1.

The Maintenance Case represents anticipated base production levels assuming that no remedial, drilling, or facility expenditures are made during the next seven year period. Production is anticipated to decrease from an average rate of 14,275 MCFD in FY'89 to 395 MCFD in FY'95 as a result of declining reservoir pressure coupled with the existing compressor intake pressure requirements. A summary of economic and recovery data for the Maintenance Case is provided in Figure 9, while additional details are included in Economics Table 2.

The Remedial Project is a production enhancement program designed to exploit and develop Dry Gas Zone reserves through recompletions and artificial lift installations. As average reservoir pressure continues to fall, decreased well deliverability coupled with compressor limitations is anticipated to result in sharply declining field production (as shown in the Maintenance Case). To offset this decline, an aggressive remedial program is proposed. Recompletions will target higher pressure undepleted zones identified by RFT measurements. Where possible, idle wellbores in the Stevens and Shallow Oil Zones will be utilized. Artificial lift equipment will be installed on wells with identifiable static water columns in an effort to reduce reservoir back-pressure and thus improve productivity.

Facility expenditures are also included within the Remedial Project to place well-site separators back into service and upgrade existing process equipment. Process equipment modifications may be required to enable Dry Gas Zone gas to meet sales specifications. Currently, Dry Gas Zone gas is being injected into the Stevens Zone for purposes of pressure maintenance. However, during times of processing plant upset, Dry Gas Zone production is mixed with residue gas for sales. At the present time the gas would not meet sales specifications and therefore, facilities at 36R may need

DRY GAS ZONE
COST AND PRODUCTION ASSUMPTIONS

Description	Cost/Job ($)	Initial Rate (MCFD)	Decline (%/Yr)
Recompletions (perforation additions)	96,000	1000	*
Artificial Lift	70,000	750	45
Facilities			
Process Equipment Upgrades/Modifications	1,284,500	---	--
Water Collection (Well-Site Separation)	450,000	---	--
Booster Compressor	1,201,000	---	--

* Single decline rate does not apply. Performance was based on assumed deliverability and a drainage volume containing 2 BCF of gas at a pressure of 250 psi.

Figure 8

to be upgraded. Well-site separators should be put back into service at selected locations in order to prevent produced water from accumulating in the main gas collecting pipeline. Accumulation of water at low points along the line results in added back-pressure at the wellhead and reduced well deliverability.

Activity within the Remedial Project is anticipated to support production rates at the 18,000 MCFD level through FY'92, at which time rates are once again forecast to decline. Figure 10 is a summary of economic and recovery data for the Remedial Project. Additional details are supplied in Economics Table 3.

DRY GAS ZONE
MAINTENANCE CASE

	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$20.5 Million	$21.0 Million
Operating Cost:	$1.3 Million	$ 1.3 Million
Investment:	$0 Million	$0 Million
Total Costs:	$1.3 Million	$ 1.3 Million
Net Revenue:	$19.2 Million	$19.7 Million
Net Present Value (@ 10%)	$15.5 Million	$15.7 Million
Recovery:		
Oil (MMB)	----	----
Natural Gas (BCF)	11.3	11.5
Oil Equivalent (MMBOE)	1.7	1.7

Figure 9

DRY GAS ZONE REMEDIAL PROJECT	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$50.6 Million	$54.2 Million
Operating Cost:	$2.8 Million	$2.9 Million
Investment:	$4.7 Million	$4.8 Million
Total Costs:	$7.5 Million	$7.7 Million
Net Revenue:	$43.1 Million	$46.5 Million
Net Present Value (@ 10%)	$29.2 Million	$30.6 Million
Recovery:		
Oil (MMB)	----	----
Natural Gas (BCF)	23.4	24.5
Oil Equivalent (MMBOE)	3.5	3.6

Figure 10

The Compressor Project involves the installation of a booster compressor to further reduce compressor intake pressure and improve recovery from the Dry Gas Zone. The project should be implemented to support production when rates decline following completion of activity in the Remedial Project. Assuming compressor intake pressures are reduced to approximately 35 psi, incremental production obtained in this project is projected to sustain total reservoir production at 18,000 MCFD beyond FY'95. Should activity identified in the Remedial Project fail to sustain production rates and support minimum compressor intake pressure requirements, acceleration of additional compression may be required. Compressor Project economic and recovery data shown in Table 4 are summarized in Figure 11.

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

On the following page the annual reservoir development activities are described for each of the scenarios presented in the Total Development Case. Once again, these scenarios consist of the Maintenance Case, the Remedial Project, and the Compressor Project.

DRY GAS ZONE COMPRESSOR PROJECT	FY'89-FY'95 PLAN	FY'89 TO ECONOMIC LIMIT
Total Revenue:	$30.8 Million	$91.4 Million
Operating Cost:	$1.4 Million	$3.8 Million
Investment:	$1.3 Million	$1.3 Million
Total Costs:	$2.7 Million	$5.1 Million
Net Revenue:	$28.1 Million	$86.3 Million
Net Present Value (@ 10%)	$15.1 Million	$38.7 Million
Recovery:		
Oil (MMB)	----	----
Natural Gas (BCF)	11.2	28.9
Oil Equivalent (MMBOE)	1.7	4.3

Figure 11

FY'89

As previously discussed, Maintenance Case production is anticipated to decline sharply during FY'89. To offset this decline, a remedial program constituting the Remedial Project should be initiated (see Table 5). Proposed recompletion candidates would be taken from a prioritized list of wells in an effort to exploit undepleted higher pressure zones identified by RFT measurements. Facility work should also be initiated to place well-site separators back into service in order to prevent the accumulation of produced water in the main gas collecting pipeline.

During FY'89, the consulting firm of Evans, Carey and Crozier should complete their geologic and engineering evaluation of the Dry Gas Zone. This study is expected to be utilized to identify and/or refine recompletion potential in addition to helping define remaining development opportunities. As wells are recompleted in FY'89, a substantial amount of engineering and geological support activity is anticipated by BPOI to assess the performance of these recompletions and repriortize future activity. This would include deliverability testing of new recompletions and periodic field-wide pressure monitoring for refinement of P/Z trends. RFT testing of new wells penetratingthe Dry Gas Zone should also be continued in FY'89 to identify additional high pressure reserves.

FY'90-'91

During FY'90-'91, continuation of both the Maintenance Case and Remedial Project is anticipated. Facilitywork should be initiated in FY'90 and completed in FY'91 to upgrade/modify the existing process equipment as necessary to assure sales quality gas. Artificial lift activityshould also be initiated in the Remedial Project to remove static water columns from existing wells and reduce reservoir backpressure.

FY'92

In addition to continued remedial activity associated with the Remedial Project, FY'92 activity includes the purchase and installation of a booster compressor. This compressor should be installed upstream of the existing compressor units and used to reduce intake pressures to approximately 35 psi.

FY'93-'95

This period is represented by the projection of base production and incremental response from both remedial activity and additional compression. Aside from continued installation of artificial lift, additional projects or activities are not anticipated during this period.

TABLE 1
LONG RANGE PLAN
TOTAL DEVELOPMENT CASE
DRY GAS ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	17687	0	0	0	710	480	0	50	0	0
1990	0	0	18000	0	0	0	748	497	83	814	207	0
1991	0	0	18000	0	0	0	773	616	21	960	53	0
1992	0	0	18000	0	0	0	794	633	22	1320	55	0
1993	0	0	18000	0	0	0	813	0	22	0	56	0
1994	0	0	18000	0	0	0	827	0	23	0	57	0
1995	0	0	18000	0	0	0	842	0	23	0	58	0
SUBTOTAL *	0	0	45876	0	0	0	5507	2236	194	3144	486	0
1996-2009 *	0	0	18925	0	0	0	2535	0	24	0	59	0
TOTAL *	0	0	64801	0	0	0	8042	2226	218	3144	545	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	10291	0	10291	1240	1127	9051	8228	957
1990	0	11625	0	11625	2349	1941	9276	7666	974
1991	0	13006	0	13006	2423	1820	10583	7951	974
1992	0	14444	0	14444	2824	1929	11620	7936	974
1993	0	15883	0	15883	891	553	14992	9309	974
1994	0	17092	0	17092	907	512	16185	9136	974
1995	0	19566	0	19566	923	474	18643	9567	974
SUBTOTAL	0	101907	0	101907	11557	8356	90350	59793	6801
1996-2009	0	64868	0	64868	2618	1076	62250	25207	280[illegible]
TOTAL	0	166775	0	166775	14175	9432	152600	85000	9607

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2
LONG RANGE PLAN
MAINTENANCE CASE
DRY GAS ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	13962	0	0	0	561	0	0	0	0	0
1990	0	0	7851	0	0	0	326	0	0	0	0	0
1991	0	0	4318	0	0	0	185	0	0	0	0	0
1992	0	0	2375	0	0	0	105	0	0	0	0	0
1993	0	0	1306	0	0	0	59	0	0	0	0	0
1994	0	0	718	0	0	0	33	0	0	0	0	0
1995	0	0	395	0	0	0	18	0	0	0	0	0
SUBTOTAL *	0	0	11288	0	0	0	1287	0	0	0	0	0
1996-2001 *	0	0	172	0	0	0	23	0	0	0	0	0
TOTAL *	0	0	11460	0	0	0	1310	0	0	0	0	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	8124	0	8124	561	510	7563	6876	756
1990	0	5070	0	5070	326	270	4744	3920	425
1991	0	3120	0	3120	185	139	2935	2205	234
1992	0	1906	0	1906	105	72	1801	1230	129
1993	0	1152	0	1152	59	37	1093	679	71
1994	0	682	0	682	33	19	649	366	39
1995	0	429	0	429	18	9	411	211	21
SUBTOTAL	0	20483	0	20483	1287	1056	19196	15487	1675
1996-2001	0	574	0	575	23	10	552	233	25
TOTAL	0	21057	0	21058	1310	1066	19748	15720	1700

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 3
LONG RANGE PLAN
REMEDIAL PROJECT
DRY GAS ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	3725	0	0	0	150	480	0	50	0	0
1990	0	0	10149	0	0	0	422	497	83	814	207	0
1991	0	0	13682	0	0	0	587	616	21	960	53	0
1992	0	0	15625	0	0	0	690	633	22	0	55	0
1993	0	0	11554	0	0	0	522	0	22	0	56	0
1994	0	0	6272	0	0	0	288	0	23	0	57	0
1995	0	0	3070	0	0	0	144	0	23	0	58	0
SUBTOTAL *	0	0	23388	0	0	0	2803	2226	194	1824	486	0
1996-2001 *	0	0	1101	0	0	0	146	0	24	0	59	0
TOTAL *	0	0	24489	0	0	0	2949	2226	218	1824	545	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	2167	0	2167	680	618	1487	1352	202
1990	0	6554	0	6554	2023	1672	4531	3745	549
1991	0	9886	0	9886	2237	1681	7649	5747	741
1992	0	12539	0	12539	1400	956	11139	7608	846
1993	0	10195	0	10195	600	372	9595	5958	625
1994	0	5955	0	5955	368	208	5587	3154	339
1995	0	3337	0	3337	225	115	3112	1597	166
SUBTOTAL	0	50633	0	50633	7533	5622	43100	29161	3468
1996-2001	0	3624	0	3623	229	102	3394	1466	163
TOTAL	0	54257	0	54256	7762	5724	46494	30627	3631

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 4
LONG RANGE PLAN
COMPRESSOR PROJECT
DRY GAS ZONE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	0	0	0	0	0	0	0	0	1320	0	0
1993	0	0	5140	0	0	0	232	0	0	0	0	0
1994	0	0	11010	0	0	0	506	0	0	0	0	0
1995	0	0	14535	0	0	0	680	0	0	0	0	0
SUBTOTAL *	0	0	11200	0	0	0	1418	0	0	1320	0	0
1996-2009 *	0	0	17650	0	0	0	2367	0	0	0	0	0
TOTAL *	0	0	28850	0	0	0	3785	0	0	1320	0	0

	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0
1992	0	0	0	0	1320	902	-1320	-902	0
1993	0	4525	0	4535	232	144	4303	2672	278
1994	0	10454	0	10454	506	286	9948	5615	596
1995	0	15800	0	15800	680	349	15120	7759	787
SUBTOTAL	0	30789	0	30789	2738	1681	28051	15144	1661
1996-2009	0	60659	0	60659	2367	965	58292	23507	2617
[illegible]	0	91448	0	91448	5105	2646	86343	38651	4278

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 5

REMEDIAL ACTIVITY

DRY GAS ZONE

(NUMBER OF REMEDIALS PER YEAR)

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-09	TOTAL
	F I S C A L	Y E A R							
1. REMEDIAL PROJECT									
a. RECOMPLETIONS	5	5	6	6	0	0	0	0	22
b. ARTIFICIAL LIFT	0	4	1	1	1	1	1	1	10
TOTAL:	5	9	7	7	1	1	1	1	32

TULARE ZONE

The Tulare Zone is important to operations at NPR-1, providing both a fresh water source for waterflood operations and a location for produced water disposal. A 40 acre region in Section 30R produced "heavy oil" from the Tulare Zone between 1975 and 1986. Attempts to enhance recovery by steam stimulation proved uneconomic and as a result, Tulare Zone production was discontinued in October 1986.

The Tulare Zone Total Development Case consists of a single Maintenance Case including remedial and facility activity for continued water source and water disposal operations. The total costs are estimated to be $1.8 million through FY'95. There are no revenues generated from the Tulare Zone during this plan period.

The Total Development Case consists of remedial funds through FY'95 to perform 17 pump and motor repairs for water source wells and to perform 31 low volume acid stimulations of disposal wells. A facility project involving conversion of existing waterfloods to produced water injection and the development of an alternate water disposal system is planned during years FY'89 through FY'94. This project will cost a total of $15.1 million and is allocated entirely to the Northwest Stevens, 24Z Sands and Main Body B Waterfloods. The project will phase-out Tulare Zone water disposal and the use of waste water sumps. This activity is planned in anticipation of future waste water disposal requirements of the Regional Water Quality Control Board and potential off-site contamination.

RESERVOIR DESCRIPTION

The Tulare Zone is the youngest and most shallow hydrocarbon bearing interval at NPR-1, ranging in depth from 700' to 1,300'. Areally, the Tulare Zone is very extensive, having been penetrated by every well at NPR-1. The Tulare Zone is composed of numerous thin sand intervals with interbedded siltstones and clays. Because of its shallow depth of burial, porosities and permeabilities are high, ranging from 30 to 40 percent and from 60 to 8,000 millidarcies, respectively. The Elk Hills anticlinal structure is the main trapping mechanism although stratigraphic controls are also present. Figure 1 shows the Tulare reservoir characteristics.

Between 1975 and 1984, seven Tulare Zone producers were drilled and completed in a 40 acre region in Section 30R. The oil bearing sand in this area is approximately 15 feet thick and contains a 12 degree API oil with a viscosity of 3,000 centipoise. In an effort to improve recovery, a cyclic steam project of three wells was conducted between 1983 and 1984. The economics of the steam project proved unfavorable and as a result Tulare Zone production was discontinued in October 1986, at which time the cumulative production amounted to 18.4 thousand barrels of oil.

In other areas of the field, the Tulare Zone is utilized for waste water disposal and as a source for waterflood injection water. Currently, there are four Tulare Source wells which produce approximately 160,000 BWPD. Fourteen Tulare Zone wells are designated for disposal of waste water at NPR-1. Thirteen of these wells

TULARE ZONE
RESERVOIR CHARACTERISTICS

Porosity (%):	38	Production Wells (#):	7 (idle)
Water Sat. (%):	(est) 35	Injection Wells (#):	0
Air Perm. (md):	430	Top of Pay (FT-VSS):	+300
Oil Gravity (API):	12	Avg. Thickness (Ft):	15
Oil Form. Vol. Fact. (RB/STB):	(est)1.02	Pay Area (Ac):	40
(Developed Acres)			
Oil Viscosity (cp):	3000	Pay Volume (AF):	NA
Initial Press. (psi):	(est) 506	GOC (FT-VSS):	NA
Bubble Point Press. (psi):	NA	WOC (FT-VSS)	NA
Current Press. (psi):	NA	Press. Datum (FT-VSS):	+156

Figure 1

are currently active and dispose of approximately 80,000 BWPD including Well 51WD-26Z, which disposes of Asphalto waste water from Sections 26Z and 14Z. The Regional Water Quality Control Board is anticipated to issue regulations that will prevent water disposal in the Tulare Zone.

RESERVOIR STUDIES

There are no reservoir studies planned for the Tulare Zone.

RESERVOIR DEVELOPMENT STRATEGY

Based on the results of both primary production and cyclic steam testing, the recommended strategy with respect to oil production is to maintain the reservoir in a shut-in status. Significant economic changes or identification of thicker pay intervals will require re-evaluation of this strategy.

In view of the possible restriction that may be imposed by the Regional Water Quality Control Board, the strategy with regard to water disposal and source water production is to phase-out Tulare Zone disposal and develop a new, environmentally acceptable, waste water disposal system. A facility project is currently planned to meet anticipated phase-out of Tulare Zone disposal. This project involves utilization of produced water for injection in 24Z, Northwest Stevens and Main Body B. It will be initiated in FY'89 and completed by FY'94. The costs have been allocated to each of the impacted reservoirs in proportion to their injection requirements. No costs are allocated to the Tulare Zone.

A portion of the facility cost will be used to develop an alternate water disposal system. During FY'89, a detailed study is anticipated to determine the best alternate system for NPR-1. Alternatives to be considered include:

1) Using produced water for possible waterflood projects such as the Shallow Oil Zone SS-2 Waterflood Project.

2) Deepening the current water disposal wells to an environmentally acceptable zone.

3) Drilling new disposal wells in acceptable areas or zones, such as the Dry Gas Zone.

4) Either treating the produced water at NPR-1 or subcontracting for the treatment and disposal of produced water.

Prior to phase-out, remedial activity will be conducted as necessary to meet water source and water disposal demands for continued operations at NPR-1. Expense streams for the Total Development Case are shown in Table 1 and based on the following assumptions.

TULARE ZONE COST ASSUMPTIONS

Description	Cost/Job ($)
Stimulations (Acidizing)	35,000
Pump/Motor Replacements	35,000

PLANNED RESERVOIR DEVELOPMENT ACTIVITIES

Annual reservoir development activities for the ensuing seven-year period includes periodic remedial activity to maintain injectivity in disposal wells and to maintain deliverability from source wells (see Table 2). Downhole pump and/or motor failure in water source wells is anticipated to require three jobs per year in FY'89, FY'90, and FY'91. By FY'92, this activity level is expected to decrease to two jobs per year as water source demands are reduced with the re-injection of produced water in Northwest Stevens, 24Z, and portions of the 31S Waterflood.

Numerous low volume acid stimulations will also be required to maintain water disposal capacity. This is needed as injected fines and scale build-up reduce injectivity and raise injection pressures beyond their maximum limits. Beyond FY'91, Tulare Zone disposal is assumed to be phased out and require no additional remedial activity.

Facility activity will be initiated in FY'89 and completed in FY'94 for the phase-out of Tulare Zone disposal. As previously discussed, this project involves the conversion of existing waterflood projects to produced water injection and the development of an alternate disposal system. These costs have been allocated to the 24Z, Northwest Stevens and Main Body B Waterfloods.

TABLE 1
LONG RANGE PLAN
MAINTENANCE CASE
TULARE
(NOMINAL DOLLARS)

FY	OIL PROD BD	WTR PROD BD	GAS PROD MCFD	WATER INJECTION BD	GAS INJECTION MCFD	STEAM INJECTION BD	COST OF OPERATIONS (1) M$	REMEDIAL COSTS (2) M$ RESERVOIR	REMEDIAL COSTS (2) M$ ART.LIFT	FACILITY INVESTMENTS (3) M$ SURFACE	FACILITY INVESTMENTS (3) M$ ART.LIFT	DRILLING INVESTMENTS (4) M$
1989	0	0	0	0	0	0	0	245	105	0	0	0
1990	0	0	0	0	0	0	0	435	109	0	0	0
1991	0	0	0	0	0	0	0	449	112	0	0	0
1992	0	0	0	0	0	0	0	0	77	0	0	0
1993	0	0	0	0	0	0	0	0	79	0	0	0
1994	0	0	0	0	0	0	0	0	80	0	0	0
1995	0	0	0	0	0	0	0	0	82	0	0	0
SUBTOTAL *	0	0	0	0	0	0	0	1129	644	0	0	0
1996-2021 *	0	0	0	0	0	0	0	0	2723	0	0	0
TOTAL *	0	0	0	0	0	0	0	1129	3367	0	0	0

FY	REVENUES OIL M$	REVENUES GAS M$	REVENUES NGL M$	TOTAL REVENUES M$	TOTAL COSTS UNDISC M$	TOTAL COSTS DISC 10.0% M$	NET REVENUES UNDISC M$	NET REVENUES DISC 10.0% M$	OIL EQUIVALENT (5) MBOE
1989	0	0	0	0	350	318	-350	-318	0
1990	0	0	0	0	544	450	-544	-450	0
1991	0	0	0	0	561	421	-561	-421	0
1992	0	0	0	0	77	53	-77	-53	0
1993	0	0	0	0	79	49	-79	-49	0
1994	0	0	0	0	80	45	-80	-45	0
1995	0	0	0	0	82	42	-82	-42	0
SUBTOTAL	0	0	0	0	1773	1378	-1773	-1378	0
1996-2021	0	0	0	0	2723	450	-2723	-450	0
TOTAL	0	0	0	0	4496	1828	-4496	-1828	0

(1) OPERATING COST OR OPERATING AND MAINTENANCE COST (O&M)
(2) REMEDIAL COSTS INCLUDE MAJOR REMEDIAL OR WORKOVER COSTS.
(3) FACILITY INVESTMENTS INCLUDE NEW SURFACE INSTALLATIONS AND MAJOR MODIFICATIONS TO EXISTING ONES.
(4) DRILLING INVESTMENTS INCLUDE THOSE FOR DEEPENINGS AND NEW WELLS.
(5) OIL EQUIVALENT = THOUSAND BARRELS OF OIL EQUIVALENT (MBOE) BASED ON BTU CONTENTS
* PRODUCTION VOLUMES REFLECT CUMULATIVE PRODUCTION FOR PERIOD SPECIFIED (UNITS = MBBLS OR MMSCF)

TABLE 2

REMEDIAL ACTIVITY

TULARE

(NUMBER OF REMEDIAL WELLS PER YEAR)

F I S C A L   Y E A R

TYPE OF PROJECT	1989	1990	1991	1992	1993	1994	1995	1996-21	TOTAL
1. MAINTENANCE CASE:									
a. STIMULATIONS	7	12	12	0	0	0	0	0	31
b. MISC. PUMP AND MOTOR REPAIRS	3	3	3	2	2	2	2	52	69
TOTAL:	10	15	15	2	2	2	2	52	100

CHAPTER 3:

FACILITIES DEVELOPMENT PLANS

INTRODUCTION

Facility operations involve all surface activities required to support production of reservoirs at MER in a safe, cost-effective, and environmentally sound manner. Surface facilities are the critical link between the reservoirs and sales points; they represent a substantial amount of activity, and afford numerous opportunities for increased profitability.

As described in the reservoir development plans, reservoir operations will be dynamic, requiring a significant amount of investment in facilities during the period FY 1989 to FY 1995. A significant amount of activity will be required in the future to accommodate production and development activities as NPR-1 reservoirs mature. A continuing challenge will be to accommodate and minimize the cost of projected growing total fluid production. As oil production naturally declines, water production will increase; increased pressure maintenance through water and gas injection will add to total fluid handling.

These facilities operations are described and evaluated within the following systems:

1. Crude Oil
2. Natural Gas
3. Natural Gas Liquids
4. Water
5. Electrical Transmission and Distribution

This chapter provides a detailed analysis of each of the above systems. It identifies opportunities for optimizing the efficiency of these systems as well as requirements for operations, maintenance, repair, and/or construction. Figure 3.1 on the following page schematically depicts these inter-related operations. Following are summary descriptions of these systems.

Crude Oil Systems

The crude oil systems at NPR-1 collect the oil, water and gas produced from each well and transport the fluid through pipelines (flow lines) to field production separation facilities (tank settings). After the gas is separated from the oil and water at the tank settings, the oil and water are collected and transported again through steel pipelines to dehydration and sales or disposal facilities.

Crude oil, water and gas are produced from four different zones at NPR-1: Stevens, Shallow, Carneros and Tulare (abandoned, uneconomical). Each zone has its own collection, separation, distribution, dehydration and sales facilities. The sales facilities, typically LACT (Lease Automatic Custody Transfer) units and dehydration/sales facilities are located in the following Sections on the Reserve:

1. Stevens: 18G and 24Z
2. Shallow (SOZ): 10G and 25S
3. Carneros: 35R and 26Z
4. Tulare: 30R (abandoned, uneconomical)

Natural Gas Systems

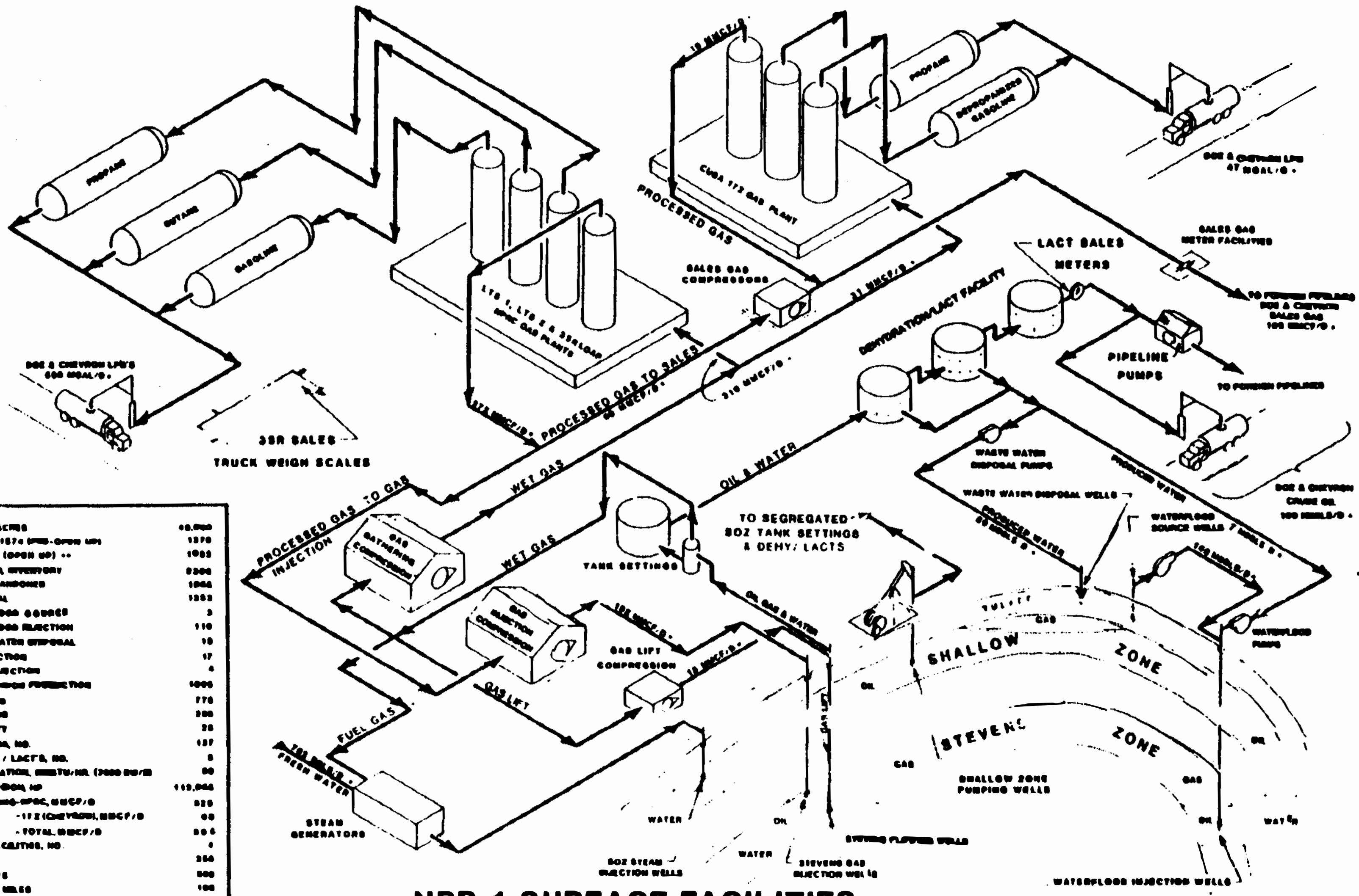
The purpose of the gas systems (collection, process, injection and sales distribution) is to collect approximately 380 million cubic feet per day of natural gas produced from oil and gas wells, process the gas to remove water and NGL, and to pressure and distribute the gas for injection into reservoirs or sales to customers.

At the tank settings, gas is separated from the production and transported by pipeline to the gas plant complexes in Sections 35R and CUSA 17Z for processing. Prior to processing, this gas is commonly referred to as wet gas. Some wet gas is consumed as fuel for field operations. Additional wet gas condenses into a liquid and is removed from the gas collection system and put into the condensate collection system. The remaining wet gas is processed at the 35R and CUSA 17Z Gas Plants, regardless of zone of origin. At each point of commingling, metering facilities are provided for ownership accounting purposes.

Natural Gas Liquids

The Natural Gas Liquids (NGL) System function is to extract, store, deliver and account for approximately 535,000 gallons per day of natural gas liquids produced at NPR-1. These products are Propane (C3), Mixed-Butane (C4 mix), Natural Gasoline (C5+) and heavy condensate (addressed in a separate section).

The products are recovered from gas (vapor) streams processed through the gasoline plants' "recovery" section, then distilled through the "fractionation" section transferred to storage tanks, and delivered to CUSA (as equity) and to DOE contractors through a tanker truck loading facility.



NPR-1 AREA, ACRES	[illegible]
WELLS AT CY 1974 (PRE-OPEN UP)	[illegible]
WELLS ADDED (OPEN UP) **	[illegible]
CURRENT WELL INVENTORY	[illegible]
SHUT-IN/ABANDONED	[illegible]
OPERATIONAL	[illegible]
WATERFLOOD SOURCE	3
WATERFLOOD INJECTION	110
WASTE WATER DISPOSAL	10
GAS INJECTION	17
STEAM INJECTION	4
HYDROCARBON PRODUCTION	[illegible]
PUMPING	[illegible]
FLOWING	[illegible]
GAS LIFT	25
TANK SETTINGS, NO.	137
DEHYDRATION / LACT'S, NO.	5
STEAM GENERATION, MMBTU/HR. (2000 BW/D)	[illegible]
GAS COMPRESSION, HP	[illegible]
GAS PROCESSING-NPRC, MMCF/D	[illegible]
-172 (CHEVRON), MMCF/D	[illegible]
-TOTAL, MMCF/D	[illegible]
GAS SALES FACILITIES, NO.	4
ROAD, MILES	[illegible]
PIPELINE, MILES	[illegible]
POWERLINES, MILES	100
LPG STORAGE, MGAL	[illegible]

** EXCLUDE 25 DEEPENING/ REDRILL

NPR-1 SURFACE FACILITIES
FLOW DIAGRAM

* ESTIMATED ACTUALS THRU JUNE FY 80

Figure 3.1

Condensate System

The condensate collection system collects all liquids (gas condensate, oil and water) which condense in the gas gathering lines. The purpose of the system is to remove the liquids from the gas collection systems and thus prevent interference with the transportation of the gas from the field to the gas plants. Separate systems exist for the Stevens and SOZ, the two major producing zones at Elk Hills.

Water Systems

There are three major water systems at Elk Hills, as follows:

1. **Tulare Water System**

   Low pressure source distribution
   High pressure waterflood distribution

2. **Produced Water Disposal System**

   SOZ (25S, 10G and 18G)
   Stevens (18G, 24Z and 26Z)
   Future alternates

3. **Fresh Water Systems**

   Light Oil Steamflood Pilot
   Fire water, including cooling water and other potable water

All three major systems are related to each other. The Tularewater systems furnish the bulk of water injected into several reservoirs for pressure maintenance and/or direct waterflood efforts. That water which is injected is eventually returned, in some proportion, as produced water from the target reservoir. To a minor extent, this is also true of the fresh water system since the early part of LOSF steam injection is utilizing fresh water sources, and will continue to do so as long as purchased water costs remain below the cost of lifting and treating Tulare water for steam generation.

All disposal water is currently injected into Tulare Zone wells. Due to environmental concerns, it may become necessary to eliminate this practice. To meet these requirements, an extensive program is currently being developed to convert portions of the Stevens Waterflood to produced water in lieu of Tulare source water. Any excess produced water will be disposed of utilizing alternatives currently being studied. These include deepening existing disposal wells into an acceptable zone and/or drilling new disposal wells.

Electrical Transmission and Distribution System

NPR-1 uses approximately 24 Meg. of electricity each day, provided by a Unit-owned electrical power transmission and distribution system, with power being purchased from Pacific Gas and Electric Company (PG&E). The main intake power supply is from a Unit-owned metering and service facility located at the 35R Substation, where PG&E delivers power at 115 kilovolts (KV). Electrical power is distributed at 115 KV to the other main area substations located at 18G, 3G, 33S and 8R.

FUNCTION AND DESCRIPTION OF SAFETY AND ENVIRONMENTAL FACILITIES PROJECTS

The goal of the Environmental Program is to ensure that facilities and operations at NPRC meet the requirements of federal, state, and local environmental laws, regulations and applicable DOE Orders. Facility development projects involve minimization of air emissions and water contaminants, handling of hazardous and nonhazardous wastes, prevention of oil and chemical spills, and prevention of surface and groundwater contamination.

The goals of the Safety/Health/Fire Program is to limit the risk of injury to personnel and damage to property. The risk is limited by adherance to applicable statutes, regulations, and DOE Orders. Projects have been identified to address compliance with applicable safety regulations, to protect personnel health, minimize risk of fire, and improve the overall safety of operations at NPRC.

STUDIES AND FUTURE OPPORTUNITIES

Operations at NPR-1 offer many opportunities to develop additional revenues or reduce operating costs. Such opportunities, when identified, warrant investigation. Present practice is to document the results of investigation by funding conceptual and feasibility studies. The following opportunity is presently being investigated.

COGENERATION FACILITIES

The SOZ Steamflood Expansion identified in the "Reservoir Operating Plan" section of this Long Range Plan calls for the generation of significant amounts of steam at NPR-1 for reservoir stimulation. It is feasible to install electrical power generation facilities (Cogeneration) and recoversteam as a byproduct. Current co-generation studies suggest that 250MM BTU/hr of heat would be available from a 40 megawatt (MW) turbine power generator.

The projected engineering and facilities cost ($000) for the project, including piping to wells, is:

	91	92	93	94	95	OUTYEARS
Conceptual Design	1000	--	--	--	--	--
Commercial Plant/Facilities	--	40,000	40,000	--	--	--

INDIVIDUAL FACILITIES DEVELOPMENT PLANS

CRUDE OIL SYSTEMS

As stated previously, crude oil (in conjunction with water and gas) is produced from four different zones. Each zone has its own collection, separation, distribution, and dehydration facilities. Historically, these systems have handled more oil than water. However, the extensive waterflood program has resulted in water production exceeding oil production in some areas. Therefore, it is not anticipated that major modifications to the crude oil collection, dehydration and/or sales facilities will be required for long range planning purposes.

Stevens Zone Facilities

System Description

The Stevens Crude Oil System at NPR-1 collects the oil, water and gas produced from approximately 400 Stevens zone wells and transports the fluids through some 800 miles of welded steel flow lines to 54 field production separation facilities (tank settings). Gas is separated from the oil and water at the tank settings, and the oil and water is transported further through welded steel pipelines to dehydration and sales or disposal facilities. The dehydration facilities and LACT (Lease Automatic Custody Transfer) Units for Stevens crude are located in Sections 18G and 24Z. A schematic of the Stevens Crude Oil System is shown as Figure 3.2.

Crude oil, gas and water are produced from the Stevens Zone by several methods of production. There are about 200 wells flowing under pressure from the reservoir. An additional 200 wells are produced by rod pump, electric submersible pump (ESP), hydraulic pump and gas lift, all considered methods of "artificial lift."
The flow lines which carry the oil, water and gas are typically constructed of 2" and 3" welded steel pipe. In 1976, the Unit standardized on 3", Schedule 40, Grade B, line pipe for flow line installations. As the reservoir declines in pressure, or the gas production increases as a result of gas lifting, larger size flow lines may be required.

Tank Settings and Collection Lines

The 54 Stevens Zone tank settings are typically equipped with two stages (high pressure and low pressure) of gas/liquid separation facilities (both production and test), surge tankage, shipping pumps and vapor recovery equipment. A typical Stevens Zone Tank Setting Piping and Instrument Diagram (P&ID) is shown as, Figure 3.3.

High pressure wells are those flowing wells where there is sufficient pressure from the reservoir for the wells to produce through the flow lines and into the high pressure separators with a minimum pressure of 480 to 500 psi. Artificially lifted and low pressure flowing wells produce through the flow lines and into the low pressure separators which typically operate at 80 to 100 psi. The actual pressure at the individual tank settings depends on several factors such as gas flow rate of the tank setting, gas gathering system pressure, nearness to the compressor plants, and available compressors throughout the system.

Most tank settings will need increased low pressure separation capacity as the pressure in high pressure wells declines and the wells have to be produced into the low pressure system. Other tank settings will need new low pressure test separation equipment as the water cut of the production increases or when total fluid increases due to waterflood response or installation of electrical submersible units.

The fluid from each well produced into Stevens tank settings is measured when it flows from the 3-phase (oil, water and gas) low pressure test separator into the surge tank. The fluid from the wells not being tested flows from the low pressure separator into the surge tank.

From the surge tank, all Stevens oil and water production is either pumped or gravitated into the Stevens Oil Gathering System. The gathering system is a network of some 2000 miles of welded steel pipelines ranging in

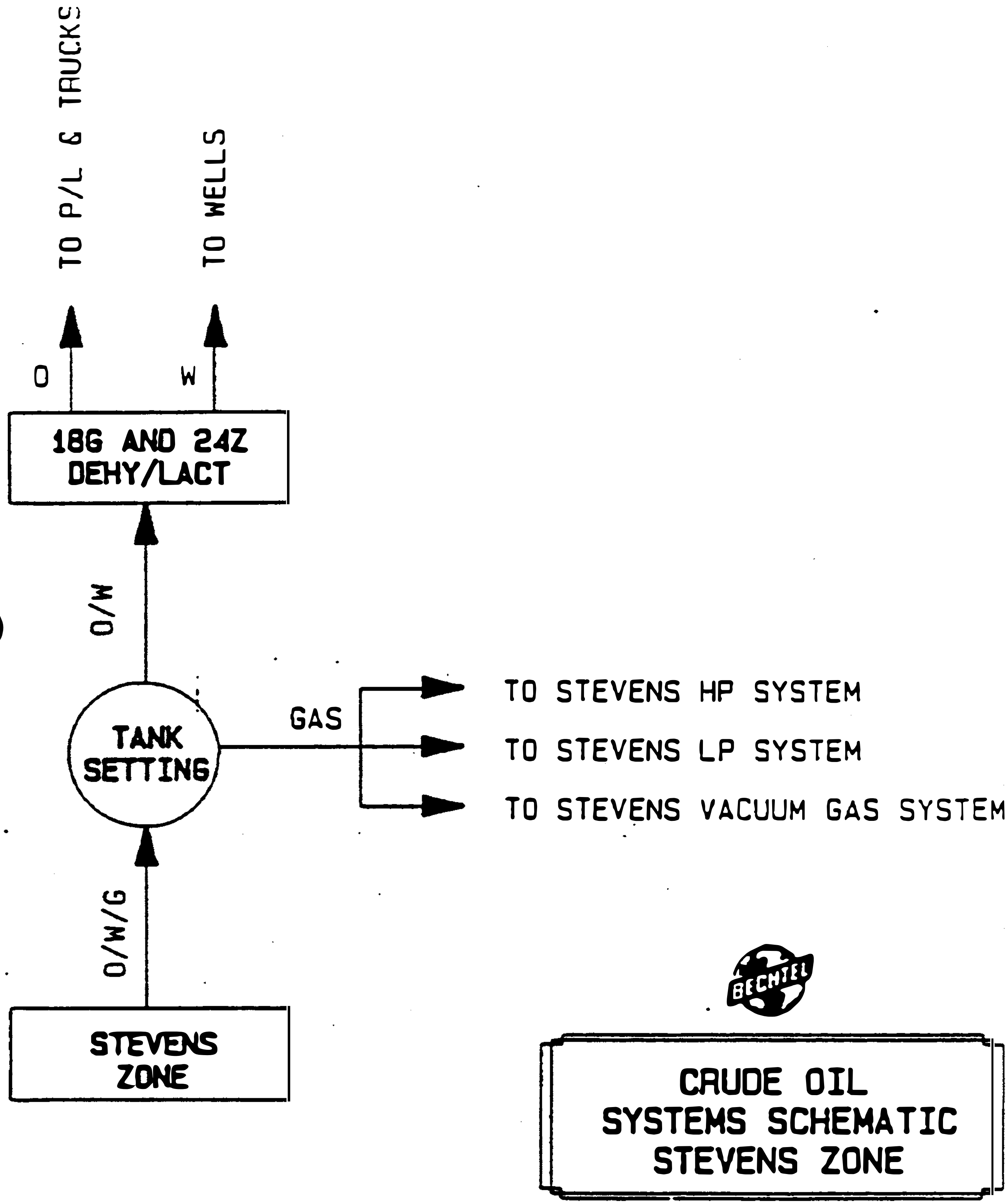

TO P/L & TRUCKS
TO WELLS
O
W
186 AND 24Z DEHY/LACT
O/W
TANK SETTING
GAS
TO STEVENS HP SYSTEM
TO STEVENS LP SYSTEM
TO STEVENS VACUUM GAS SYSTEM
O/W/G
STEVENS ZONE
CRUDE OIL
SYSTEMS SCHEMATIC
STEVENS ZONE

Figure 3.2

TYPICAL STEVENS TANK SETTING

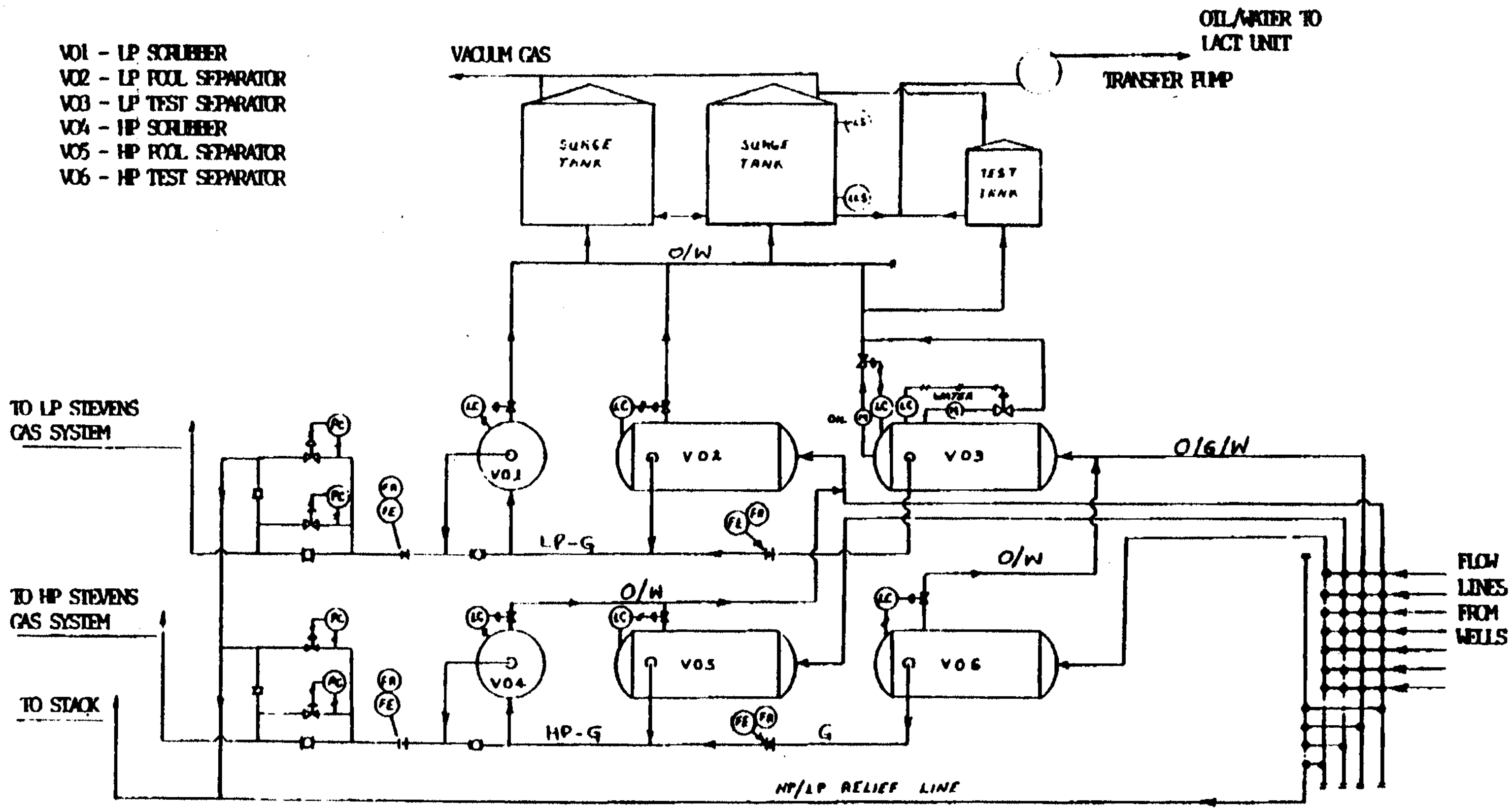


Figure 3.3

size from 4" to 12" that transports Stevens Zone oil and water from the tank settings to the dehydration and sales facilities located in Sections 18G and 24Z. As was stated earlier, it is not anticipated that the fluid production forecasted in the Long Range Plan will cause any constraints in the system which will require major projects to be funded for modifications to the Stevens Crude Oil Gathering System.

The major projects which allow for impact to the Stevens Crude Oil System in the Long Range Plan are for tank setting and flow line modifications and replacement.

18G LACT Facility

Approximately 85,000 BOPD and 100,000 BWPD are handled at the 18G LACT Facility. The facilities at 18G consist of a free water knockout/ flow splitter, six dehydration facilities and twelve LACT units. Each dehydration facilities consists of three 16,000 barrel welded steel tanks in series which separate all remaining water in the fluid from the oil. Each dehydration facility is connected in series by two LACT units in parallel. The nominal capacity of two LACT units is 25,000 BOPD. Sales contracts for oil allow no more than 1% and 3% by volume BS&W (basic sediment and water) content. Downstream of the LACT units, the purchased oil is pumped to FourCorners pipeline or CUSA.

Each dehydration facility has a 12 MMBTU/Hr waste water heating and circulating system to facilitate oil/ water separation during cold weather.

The produced water separated from the oil at 18G is collected in surge tanks and pumped into the waste water disposal system.

Gas vapors are recovered during dehydration by vapor recovery equipment.

The dehydration and sales facilities at 18G have sufficient capacity to handle the fluid production volumes forecasted in the Long Range Plan. No major projects are planned for these facilities.

DOE 18G Pipeline

DOE's pipeline transports oil to a pipeline owned by the Four Corners Pipeline Company. DOE's line is 12" diameter and about 4.5 miles in length. Oil pumping equipment at 18G is composed of two 750 HP and two 250 HP electric driven centrifugal pumps to the Four-Corners pipeline. These pumps are operated automatically in coordination with the LACT pumps. One 750 HP pump has a capacity of about 96,000 BOPD, depending on the amount of pressure in the Four-Corners pipeline.

CUSA 18G Pipeline

The 18G LACT units also pump directly into CUSA's pipeline. Movement of this oil requires no booster pumps at 18G because CUSA's line is provided with pumps located about a mile away from 18G. This pipeline has a nominal capacity of about 30,000 BOPD depending on the amount of oil being pumped through it from areas other than NPR-1.

24Z LACT Facility

Approximately 15,000 BOPD and 80,000 BWPD are handled at the 24Z LACT Facility. The facilities at 24Z consist of one dehydration facility, two 16,000 bbl wash tanks in parallel followed by two 16,000 bbl tanks in series, two pipeline LACT units and one truck loading LACT unit. The dehydration facility is made up of three 16,000 bbl welded steel tanks in series, which separate the water remaining in the fluid from the oil. The nominal capacity of the pipeline LACT units is approximately 25,000 BOPD, and the capacity of the truck loading LACT unit is approximately 11,000 BOPD. Sales contracts for oil specify 1% and 3% by volume BS&W content. Downstream of the LACT units, oil is either pumped into pipeline or is loaded onto trucks.

The dehydration facility has a 12 MMBTU/Hr waste water heating and circulating system to facilitate oil/ water separation during cold weather.

The produced water separated from the oil is stored in surge tanks and pumped into disposal and injection wells.

Gas vapors from the dehydration train tanks are recovered by vapor recovery equipment.

The dehydration and sales facilities at 24Z have sufficient capacity to handle the fluid production forecasted in the Long Range Plan.

Shallow Oil Zone Facilities

System Description

The SOZ Crude Oil System at NPR-1 collects the oil, water and gas produced from approximately 650 SOZ wells, and transports the fluid through some 600 miles of welded steel flow lines to field production separation facilities (tank settings). After the gas is separated from the oil and water at the tank settings, the oil and water is collected and transported again through some 200 miles of welded steel pipelines to dehydration and sales facilities. The dehydration and sales facilities for SOZ production are located in Sections 10G and 25S.

All oil from the SOZ is lifted by rod pump. The wells produce through flow lines which are typically 2" and 3" welded steel pipe to the SOZ tank settings. There are currently 67 SOZ tank settings in operation.

Tank Settings and Collection Lines

SOZ tank settings have only one stage of gas/fluid separation and operate at approximately 30 psig. Typically, there are no tankage or shipping pumps at the tank settings, and the separators (production and 3-phase test) dump the oil and water into either the north flank or south flank gravity oil collection systems. The gas which is separated at the tank settings is produced into the SOZ 0-PSIG Gas Gathering System and the Stevens Vacuum Gas Gathering System. A schematic of the SOZ System is shown in Figure 3.4.

Installed on the SOZ Crude Oil Gravity Collection Systems are 13 vapor tank settings. These facilities have surge tankage, shipping pumps and vapor recovery equipment. The purpose of the facilities is to remove the vapors from the crude oil and water which get into the gravity collection system due to pressure drop across the separator dump valves and other conditions which might cause the liquid pressure to drop below its vapor pressure. Prior to the installation of these facilities, there were common occurrences of vapor locking throughout the system and release of vapors into the atmosphere at vapor bleed traps. The welded steel piping network that makes up the gravity collection systems ranges in size from 4" to 12" in diameter.

The North Flank SOZ Gravity Gathering System flows into the dehydration/sales facilities at Section 25S. The South Flank SOZ Gravity Gathering System flows into the dehydration/sales facilities at Section 10G. There is a transfer pump at the 10G facilities in order to transfer oil to 25S as needed to meet oil sales contractual obligations.

10G LACT Station

Oil and water are produced into a production tank, the first of three 16,000 bbl tanks in series at this oil cleaning/LACT station. After the separation of oil and water by gravity separation, the oil is skimmed off the top into the settling tank, the second tank in the series. The water is bled from the bottom of the production tank and gravitated to adjacent waste water disposal facilities.

The same process takes place again in the settling tank with the oil being skimmed into the shipping tank, the third tank in the series. The water is drained from the settling tank to waste water facilities. Vacuum compressors recover gas vapors from each of the three tanks and discharge these vapors into the Shallow Oil Zone low pressure gas collection system.

From the shipping tank, clean oil is pumped into two LACT pump/sampler/meter units with a total capacity of 25,000 BOPD. Oil containing basic sediment and water (BS&W) greater than 1% is sensed by a probe and the oil is returned to the production tank to be cleaned again. Any oil with a BS&W content less than 1% is considered pipeline quality oil and is shipped through the LACT meter.

Any excess pipeline quality oil which is not committed to sales from the 10G LACT unit to the Four Corners Pipeline may be transported to the 25S LACT Station. This oil is transported from 10G to the North Flank gathering line at 23S, and through this line to the 25S LACT Station.

DOE 10G Pipeline

Sales quality oil (less than 1% BS&W) is transported to the Four Corners Pipeline 6" and 8" shipping lines via DOE's 10" diameter one mile long pipeline. Oil is pumped by one main, electrically-driven, 350 HP centrifugal shipping pump. A similar 150 HP pump provides back-up shipping capability. These same pumps also transport dehydrated oil to 23S as mentioned above.

25S LACT Facility

At the 25S LACT Facility, produced oil and water enter a 20,000 bbl production tank, the first of three tanks in series at this oil cleaning/LACT station, where the oil and water separate by gravity separation. The water is bled off the bottom of the production tank into a 30,000 bbl settling tank, the second tank in the series. The oil is then skimmed off the top of the production tank and gravitated to a 30,000 bbl shipping tank, the third tank of the LACT. From there the waste water is pumped to adjacent waste water disposal facilities.

Vacuum compressors recover gas vapors from each of the three tanks and discharge these vapors into the Shallow Oil Zone low pressure gas collection system.

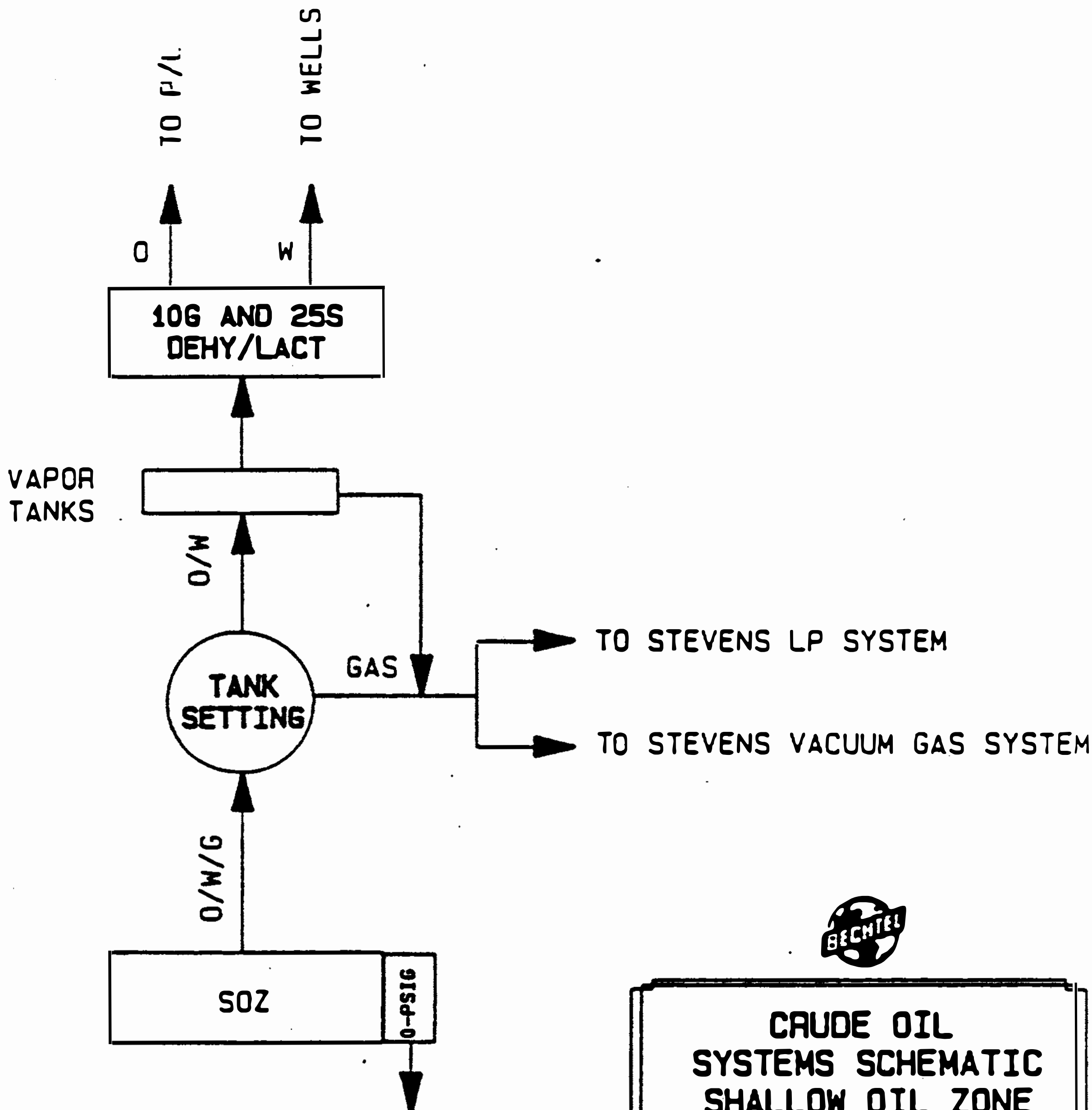

TO F/L
TO WELLS
O
W
10G AND 25S
DEHY/LACT
VAPOR
TANKS
O/W
GAS
TO STEVENS LP SYSTEM
TANK
SETTING
TO STEVENS VACUUM GAS SYSTEM
O/W/G
SOZ
0-PSIG
CRUDE OIL
SYSTEMS SCHEMATIC
SHALLOW OIL ZONE

Figure 3.4

From the above mentioned shipping tank, the clean oil containing less than 1% BS&W is transferred through two LACT pump/ sampler/meter units, each with a capacity of 20,000 BOPD. Once metered, the oil is delivered to Chevron USA's pipeline shipping pumps, approximately 100 feet away.

It should be noted that the 30,000 bbl production tank (#373) is presently isolated for cleaning, inspection and possible replacement/abandonment. The settling tank mentioned above has been temporarily converted to a shipping tank.

DOE 25S Pipeline

Pipeline quality oil is transported from the 25S LACT Station through DOE's 6" pipeline to Section 6M, where it is connected to a pipeline owned by Four-Corners Pipeline Company.

Carneros Zone Facilities

System Description

The Carneros Zone is a gas and light condensate producing reservoir on the west end of NPR-1. The function of the Carneros Zone Condensate System is to transport approximately 2000 barrels per day of the well production fluid to the tank settings and on to the point of dehydration and sales. A schematic of the Carneros System is shown in Figure 3.5.

There are currently nine Carneros Zone wells on production and two wells on evaluation at NPR-1. These wells are produced through 2" and 3" steel flow lines to a tank setting in Section 30R.

Tank Settings, Collection Lines and LACT Facility

The production and test separators at Section 30R operate at approximately 480 psig and the gas that is separated from the condensate and water is produced into the Stevens High Pressure Gas Gathering System. There is low pressure test separation, tankage and vapor recovery equipment at 30R.

The condensate from the high pressure production and test separators at Section 30R flows through a 4" welded steel pipeline to the low pressure 3-phase separator and tankage at a tank setting in Section 35R. The water separated at the 35R facility goes to the disposal system, and the condensate goes through LACT facilities and into the Stevens Crude Oil Gathering System. The capacity of the existing system is more than adequate to handle the relatively small amount of Carneros condensate that is produced.

However, to eliminate freezing problems in the 4" line from Section 30R to Section 35R, and to accommodate future low pressure production from the Carneros wells, Project 48304 will relocate the dehydration and LACT facilities from 35R to 30R, and build a new low pressure tank setting and install low pressure compression facilities at 30R. The work is scheduled for completion in FY 1989.

26Z Asphalto Zone (100% DOE)

System Description

The function of the Asphalto Crude Oil System is to transport approximately 100 barrels per day of well production fluid to the tank setting and the point of dehydration and sales. A schematic of the Asphalto system is shown in Figure 3.6.

There are presently 12 rod pumped Asphalto wells which produce oil, water and gas through welded steel flow lines to a single tank setting designation in Section 26Z.

Tank Setting and LACT Facility

The tank setting contains production and test separators which operate at approximately 100 psig. The gas separated from the oil and water at the tank setting is piped to the Stevens Low Pressure Gathering System in Section 24Z.

The dehydration and LACT sales facilities are at the same location as the tank setting in Section 26Z. Water is disposed of in a disposal well. The current facilities are more than adequate to handle the declining production from the Asphalto Zone.

There are no major modifications or additions to the Asphalto Crude Oil System in the Long Range Plan.

Critical Parameters/Resolutions

Additional Net Fluids Handling Capacity

As fluid production increases, some tank settings which gravitate fluid from the surge tanks to the oil collection lines have experienced surge tank overflowing. This is caused by higher line back pressure when tank settings with transfer pumps discharge fluid into the oil collection lines, thus preventing tank settings with no transfer pumps from gravitating fluid into the oil collection lines.

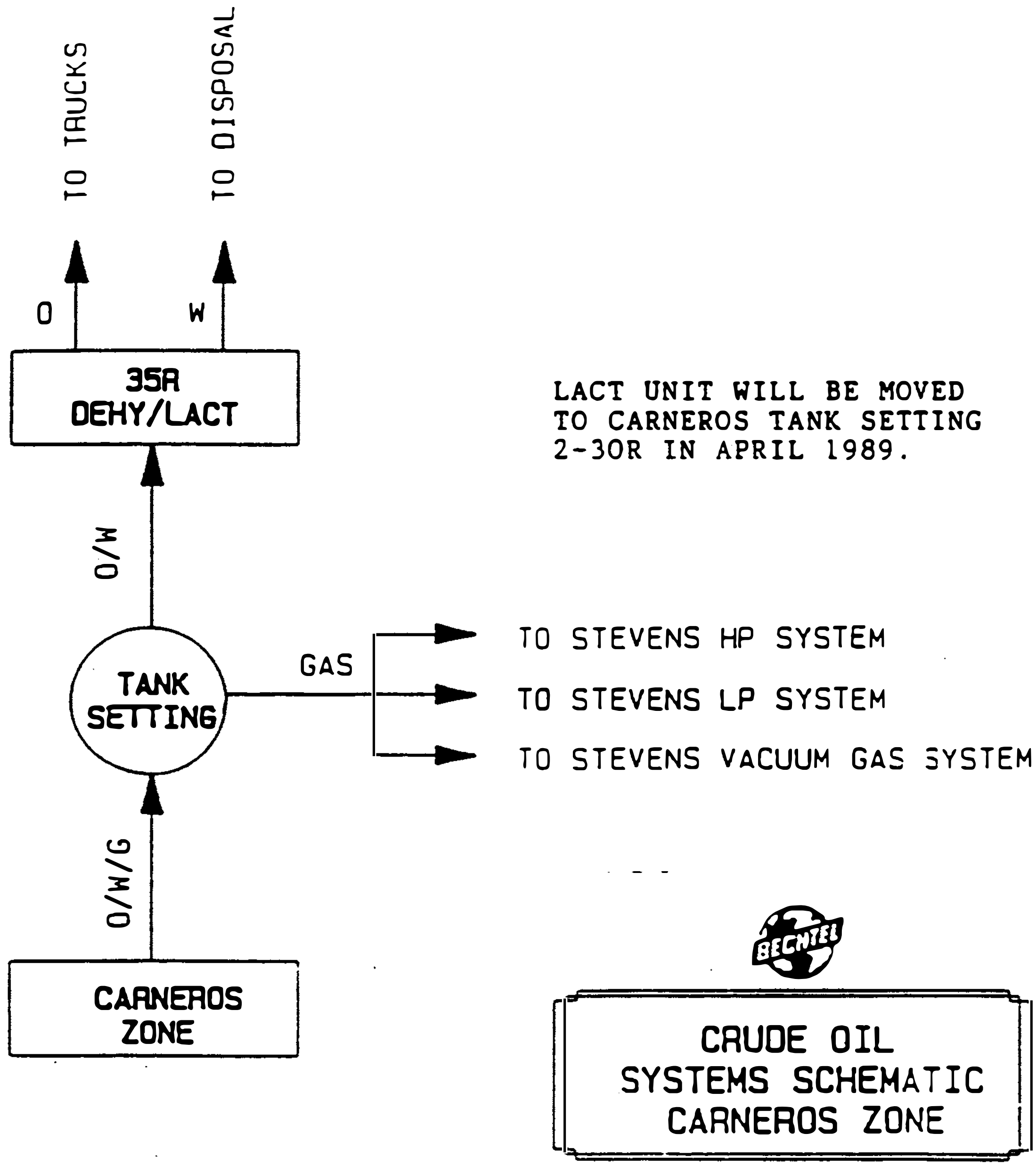

TO TRUCKS
TO DISPOSAL
O
W
35A
DEHY/LACT
LACT UNIT WILL BE MOVED
TO CARNEROS TANK SETTING
2-30R IN APRIL 1989.
O/W
TANK
SETTING
GAS
TO STEVENS HP SYSTEM
TO STEVENS LP SYSTEM
TO STEVENS VACUUM GAS SYSTEM
O/W/G
CARNEROS
ZONE
CRUDE OIL
SYSTEMS SCHEMATIC
CARNEROS ZONE

Figure 3.5

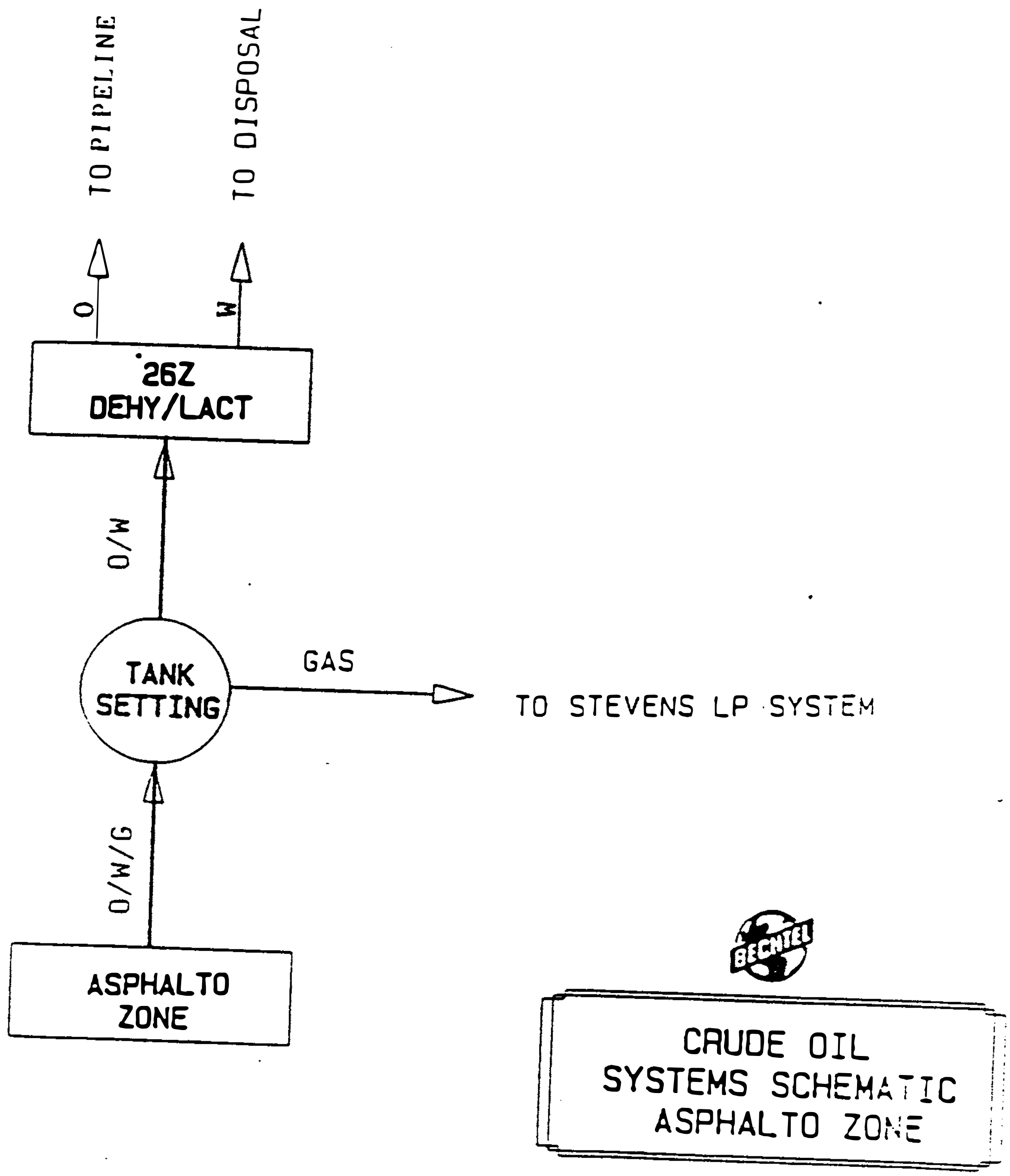

TO PIPELINE
TO DISPOSAL
O
W
26Z
DEHY/LACT
O/W
TANK
SETTING
GAS
TO STEVENS LP SYSTEM
O/W/G
ASPHALTO
ZONE
CRUDE OIL
SYSTEMS SCHEMATIC
ASPHALTO ZONE

Figure 3.6

To overcome this problem, booster pumps have been added to a few tank settings which have experienced surge tank overflowing. This effort will continue, along with other tank setting modifications.

ENVIRONMENTAL CONSTRAINTS

Environmental and Safety/Health Concerns

Environmental considerations for the crude oil system include air pollution and oil spill prevention as well as groundwater protection. Projects addressing these concerns include "1-7R Tank Setting Vapor Recovery Unit Installation", sump elimination ("35R Sump Replacement") and secondary containment ("Tank Setting Liquid Containment").

To sufficiently limit the risk of property damage and/or injury to personnel, safety/health/fire projects have been scheduled to deal with fire protection systems, both new and modifications to existing systems, H2S program, asbestos abatement and other safety/health/fire projects related to the crude oil system.

For further detail see individual project description sheets.

PROJECT DESCRIPTIONS

The following facilities project descriptions are associated with the Crude Oil System.

	Project Number	Title
1.	P49313	Stevens Tank Setting Mods.
2.	P49203	Repair/Replace Surge Tanks at 2-25S Stevens Tank Setting
3.	P55008B	Replace 16" NF SOZ Gravity Line
4.	P40301A	Pipeline Repair/Replacement - Oil & Water
5.	P49309	Artificial Lift
6.	P40302	Repair/Replace Tanks or Abandon Facilities at the 25S Dehydration Facility
7.	P49202	Tank Setting Liquid Containment
8.	P49313G	3-31S STV. Sys. Mod. *
9.	P49345	342-6G & 318-31S Flowline

* These projects are complete, no project sheet attached.

STEVENS TANK SETTING MODIFICATIONS

PROJECT P49313

This project provides for the modification of the existing Stevens tank settings to increase water handling capacity and safely process present and future production based on the February 1989 Production Forecast.

Background

Gas and water production continues to increase at several tank settings. This could cause oil production to be deferred if the tank setting capacity becomes inadequate. Modifications to the high pressure and the low pressure systems will be required to maintain MER production. The tank settings scheduled for modification in FY 89 are 1-4G, 4-29R, 3-31S, 4-35R and 1-24Z. The tank settings in FY 90 are 1-26R and 4-34S.

The following type of modifications are expected:

- Increase the size of flow lines due to the increase in gas/oil ratio.
- Add low pressure separation separators, control and piping.
- Add shipping pumps.
- Add test separators.
- Add low pressure and high pressure scrubbers

Economic Analysis

Each individual tank setting project will be economically justified at the time of the AFE submittal. If modifications are not implemented, then production will be evaluated against the value of the shut-in production for each tank setting project.

Plan

Make the necessary modifications to the tank setting to provide capacity to meet production requirements.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	460	1000	1070	1100	1125	1145	1165
Schedule							
Start	1Q	1Q	1Q	1Q	1Q	1Q	1Q
Complete	4Q	4Q	4Q	4Q	4Q	4Q	4Q

REPAIR/REPLACE TANKS OR ABANDON THE FACILITIES AT THE 25S DEHYDRATION FACILITY — PROJECT P40302

This project provides for the repair/replacement of the wash, settling and run tanks or diverting the oil to other treating facilities and abandoning the facilities, at the 25S Dehydration Facility.

Background

Tankage has deteriorated through the years of operation by corrosion and by weathering of bolted seams. The result of this deterioration is that leaks have developed mainly in tank bottoms, tops and sidewalls, or in tank seams. The degree of damage varies due to age and operating conditions. Tanks will have to be cleaned and inspected to determine if the tanks require minor repairs or if major repairs or replacement is necessary. A review of the other dehydration facilities will be made to determine if the oil going to 25S Dehydration Facilities can be diverted and the 25S Facility abandoned.

Applicable Statutes/Regulations/DOE Orders

Proposition 65 (Safe Drinking and Toxic Enforcement Act); California Code of Regulations (CCR), Title 14, Part 1773, and Title 22; Waste Discharge Requirements for NPR-1 58-491; DOE Order 5400.1.

Plan

Clean and inspect the tanks then make necessary repairs, or replace tank as required after reviewing other alternatives.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	664	259	0	0	0	0	0

Schedule
Start 1Q
Complete 4Q

REPLACE 16" NF SOZ GRAVITY LINE — PROJECT P55008B

This project entails the replacement of 7400' of 16" NF Gravity Line with approximately 6000' of 10" and 1400' of 12" diameter Class 150 reinforced fiberglass piping. The replacement is in Sections 28S, 27S and 23S of the Reserve. The existing piping will be flushed to displace hydrocarbons, recovered, and taken to the 2B Yard.

Background

This section of the line is experiencing a very high rate of internal corrosion. Numerous leaks have occurred in this section of line and the leak frequency is increasing.

Economic Analysis

This project provides for the installation of fiberglass replacement piping to prevent a major failure of the SOZ System for a period of 14 days. The economic analysis is based upon the potential major failure occurring in one year.

Total Investment	$587,000
Incremental Oil Prod. (BOPD)	5,500
Net Revenue (M$)	1168.1
NPV @ 10% (M$)	545.7
NPV @ 15% (M$)	543.7
Payout (Years)	.09
Rate of Return	>1000%
Project Life (Years)	20

Plan

The repair of this piping system is of high priority to the field operation personnel.

Cost /schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	587	0	0	0	0	0	0

Schedule
Start 1Q
Complete 4Q

PIPELINE REPAIR/REPLACEMENT OIL & WATER — PROJECT P40301A

This project is to provide funds for the repair and replacement of sections of pipe in the various oil and water gathering and distribution systems on the Reserve.

Background

Repair and replacement of sections of the various oil and water gathering and distribution systems are required each year to (1) ensure safety, (2) protect the environment and wildlife and (3) to maintain or increase production. Much of the piping has been installed over 30 years ago. Over the years, corrosion has occurred at various rates and, in a number of cases, has required pipeline repairs and replacements to be made.

Economic Analysis

This project will be composed of multiple AFE submittals as individual problems are identified. An economic analysis will be made to justify each pipeline repair/replacement as the projects develop. Projects of this type usually provide short payout periods with high rates of return since only two alternatives are usually available. The alternatives are either (1) repair or replace the defective section of pipeline or (2) shut in production. Shut in of production usually has a very high monetary impact.

Plan

While the exact requirements for unplanned repair and replacement of pipelines cannot be defined at this time, NPR-1 should expect to expend funds for this work at the level indicated below.

Cost/Schedule ($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	2000	2460	2640	2700	2750	2800
Schedule							
Start		1Q					
Complete							Ongoing

ARTIFICIAL LIFT

PROJECT P49309

Several Stevens Zone Reservoirs (MBB/W31S, 24Z, NWS (A4-A6), are currently under waterflood. Other waterflood projects are planned for pools such as the 2B Sands. As these reservoirs respond to the waterflood projects, the affected wells will equalize and will need artificial lift systems to continue production. In addition, several reservoirs (31S C/D Shales, 29R Shales, etc.) are experiencing declining pressures and will need artificial lift systems to sustain productions.

The primary artificial lift systems planned for installation are rod pumping units with their related equipment. Typical rod pumping equipment includes the rod pump, rods, beam pumping unit, gas or electric prime mover, concrete pad, etc.

For several high volume wells, installation of electric submersible pumps are planned. Electrical submersible pump installation and/or replacement is planned for the Tulare source wells.

Closed loop gas lift systems are planned for several pools, e.g., MBB/W31S, NWS (A4-A6). The closed loop gas lift systems have an additional advantage of providing relief on the quantity of gas to be processed at the 35R Gas Plants. Gas lift facilities include lift gas supply lines, metering and control equipment, and downhole mandrels and valves.

More detailed information regarding implementing artificial lift is provided in the individual Pool Outlook Plans.

Cost/Schedule ($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	2607	3300	3210	4070	4373	4412	4580
Schedule							
Start	1Q	1Q	1Q	1Q	1Q	1Q	1Q
Complete	4Q	4Q	4Q	4Q	4Q	4Q	4Q

REPAIR/REPLACE SURGE TANKS AT 2-25S STEVENS TANK SETTING

PROJECT P49203

This project provides for the repair or replacement of the surge tanks at the 2-25S Stevens Tank Setting.

Background

The tankage has deteriorated over time by corrosion and by weathering of bolted seams, so that the tanks are no longer secure from leakage. These tanks are on the alluvium and any discharge of waste water or oil from this facility to the ground other than an emergency type spill does not meet the requirements of Proposition 65 or Waste Discharge Order 58-491 for NPR-1 issued by the California Regional Water Quality Control Board (CRWQCB). This project would clean and inspect the tanks and make necessary repairs or replace tanks.

Applicable Statutes/Regulations/DOE Orders

DOE Order 5400.1, Proposition 65, Waste Discharge Order 58-491.

Plan

Clean and inspect the tanks and make necessary repairs or replace tanks.

Cost/Schedule ($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	150	0	0	0	0	0	0
Schedule							
Start	3Q						
Complete		1Q					

TANK SETTING LIQUID CONTAINMENT

PROJECT P49202

This project is to provide secondary containment for selected storage tanks at NPR-1

Background

A survey of NPR-1 indicates selected storage tanks may need provisions for secondary containment to assure leaks or spills from such tanks do not leave NPR-1 or cause adverse environmental impact on NPR-1. This project involves prioritizing and developing a cost estimate for secondary containment on tanks, presenting a clear and present danger to off-Reserve property, potable ground water or surface water, and construct secondary containment as required.

Applicable Statutes/Regulations/DOE Orders

CCR Title 14 and 23, EPA oil spill regulations, Endangered Species Act, Clean Water Act, Category II finding by the DOE- Washington Environmental Survey Team.

Plan

Prioritize and develop a cost estimate for secondary containment on tanks, presenting a clear and present danger to off-Reserve property, potable ground water or surface water, and construct secondary containments as required.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	20	100	110	0	0	0	0
Schedule							
Start	2Q						
Complete			4Q				

NATURAL GAS SYSTEMS

The Natural Gas Systems at NPR-1 transports approximately 380 million cubic feet per day of gas produced with the oil from the tank settings to three processing plants located in Section 35R and a CUSA-owned facility off the Reserve. At the processing plants, propane, butane, and natural gasoline are extracted and sold. The resulting residue gas is either sold or reinjected into the Stevens Zone for pressure maintenance.

When gas production exceeds the capacity of the gas processing plants in Section 35R, the excess gas is processed at the CUSA 17Z Gas Plant. CUSA is paid a fee to process the gas and operate the recovered propane and gasoline for sale at their loading rack at the 17Z Plant. The 17Z residue gas is returned to the Unit at the 17Z gas sales point. A portion of CUSA's equity gas is retained by CUSA at 17Z under the current processing agreement between DOE and CUSA.

The Condensate Systems at NPR-1 remove liquids from the gas gathering lines to reduce pressure drop in the gas gathering system. The liquids are eventually transported to LACT sales points and sold with the crude oil.

GAS COLLECTION

Stevens Zone Gas Collection

Stevens Zone gas is collected in three separate collection systems (High Pressure, Low Pressure, and Vacuum) from the 54 Stevens Tank Settings to the three gas processing plants in Section 35R. There are approximately 170 miles of welded steel pipelines ranging in size from 2" to 26" in diameter. The function of the Stevens Zone Gas Collection System is to transport natural gas from tank settings to the gas processing plants.

A simplified flow schematic of the NPR-1 natural gas systems is shown in Figure 3.7. As shown in Figure 3.3 with the exception of the Dry Gas Zone (DGZ), the Stevens Zone Gas Collection System is used by all other gas systems at NPR-1 for transporting gas to the gas processing plants. The production from each zone is measured by inter-zonal accounting meters at the point(s) where each zone enters the Stevens Gas Collection System.

The three separate Stevens Gas Collection Systems operate at different pressures because the gas is separated from the oil and water produced from the wells in three stages at the Stevens Tank Settings.

The High Pressure (HP) Gas Collection System operates between approximately 420 and 500 psig. The Low Pressure (LP) Gas Collection System operates between approximately 60 and 100 psi. The Vacuum Gas Collection System operates between approximately atmospheric pressure at the tank settings to 10" of mercury vacuum at the gas processing plants or field compressor stations. Pressures will vary throughout the systems depending on the volume of gas in the systems and distance away from the gas plants or field gas gathering compressors.

The gas gathering pipelines are installed above the ground surface on wooden or steel supports with facilities for expansion, corrosion prevention at buried portions, and condensate collection. The pipelines were installed aboveground for economy, ease of identification, ease of maintenance, and to minimize corrosion.

Shallow Oil Zone Gas Collection

The function of the Shallow Oil Zone (SOZ) Gas Collection System is to transport SOZ tank setting gas and wellhead casing gas to the Stevens Zone Gas Collection System, and ultimately the gas processing plants in Section 35R. The gas is transported through approximately 100 miles of steel pipelines ranging in size from 2" to 15" in diameter.

There are presently 643 SOZ wells authorized for production at NPR-1. There are 61 SOZ Tank Settings and 13 SOZ Vapor Tank Settings. The operation of SOZ Tank Settings and Vapor Tank Settings is detailed in other sections of the Systems Analysis.

SOZ gas is gathered from the wellhead casings and transported to the Stevens Vacuum Gathering System. This is done to reduce the casing pressure on the SOZ wells and allow more oil to flow into the well bore, thus maximizing production.

SOZ gas is also separated from the oil and water at SOZ Tank Settings. This gas flows into the same collection system as the wellhead casing gas.

SOZ vacuum gas is compressed at the 13 SOZ Vapor Tank Settings and transported to the Stevens Vacuum System along with the casing gas.

SOZ casing gas is compressed at 4-3G in the Zero PSIG Compressors and commingled with the Stevens LP gas in Section 3G.

Field wide, SOZ gas enters the Stevens Vacuum System at 22 locations, and the Stevens Low Pressure System at one location.

Carneros Zone Gas Collection

Carneros wells produce into the Carneros Tank Setting in Section 30R. At the tank setting, Carneros gas is separated from the condensate and water.

Carneros vacuum gas which flashes in the condensate storage tank is commingled with the Stevens Vacuum Gas System in Section 30R.

Carneros LP gas from the LP separators at the tank setting is compressed in Section 30R to HP and commingled with the Stevens HP Gas Collection System.

The Carneros gas is metered prior to comingling with the Stevens HP and Vacuum Gas Collection Systems.

26Z Asphalto Gas Collection

The NE quarter of Section 26Z is owned 100% by DOE and is non-Unit. Stevens and Carneros wells on this property and in Section 14Z (100% DOE) produce into one tank setting in Section 26Z.

Gas from the LP separators at the tank setting is collected in a 4" diameter steel pipeline and transported approximately one mile to the Unit Stevens LP Gas Gathering System in Section 24Z.

Vacuum gas which flashes in the storage tanks at 26Z is compressed at the tank setting into the 4" LP line.

The Asphalto gas is measured prior to combining with the Stevens LP production in Section 24Z.

Dry Gas Zone Gas Collection

There are 32 Dry Gas Zone (DGZ) wells presently authorized for production. Gas produced from the DGZ does not contain sufficient marketable liquids for the gas to be processed through the gas plants.

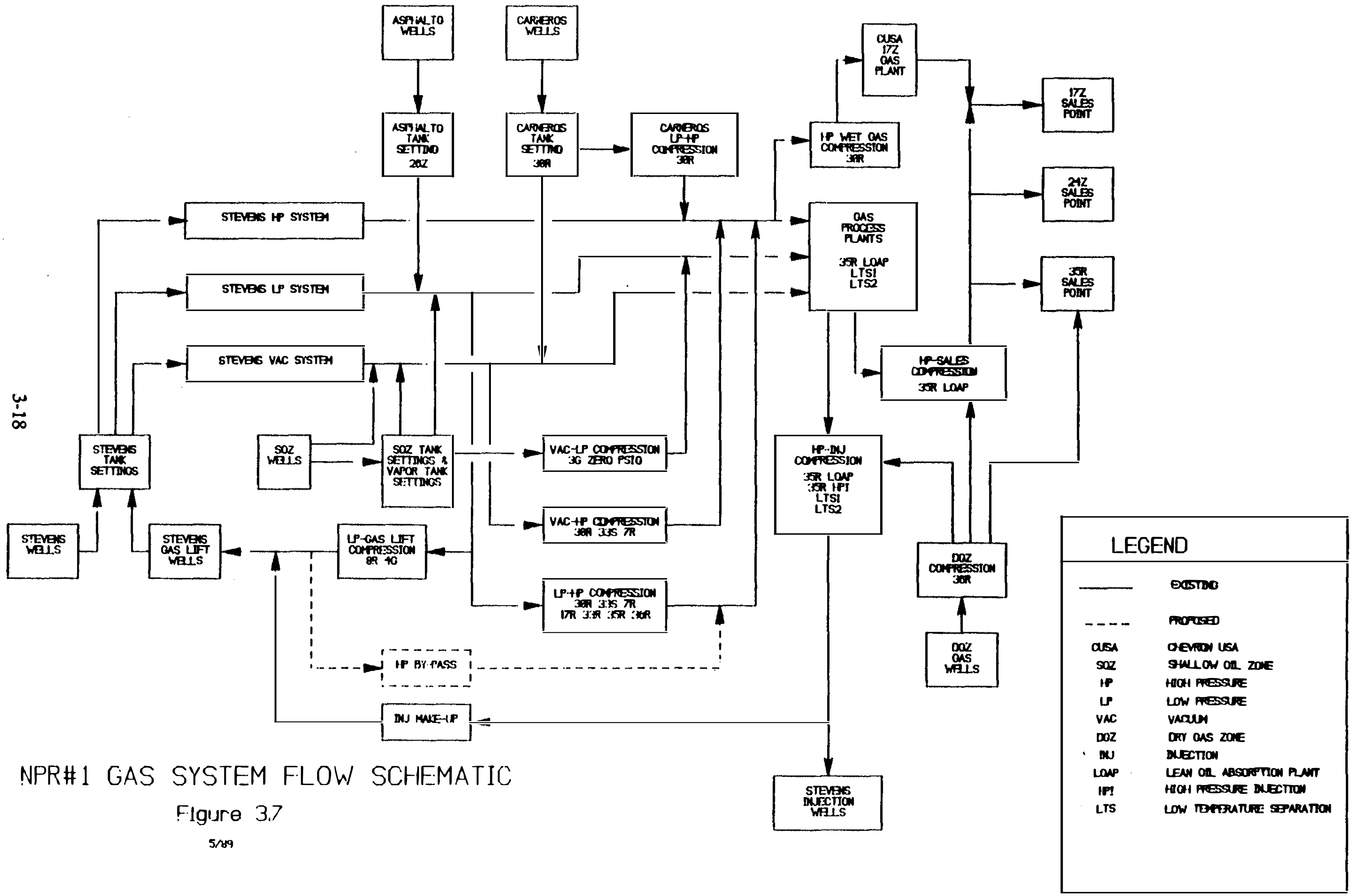
The DGZ gas is collected from the wells and transported through approximately 11 miles of steel pipelines ranging in size from 2" to 12" in diameter to the DGZ Compressor Station in Section 36R. There, the gas is dehydrated, compressed and piped to facilities in Section 35R for comingling with either the gas sales or gas injection systems. The gas flow is illustrated in Figure 3.7. DGZ gas is metered prior to combining with other Unit gas streams.

CONDENSATE SYSTEM

Stevens Condensate System

The Stevens Condensate Collection System is a series of traps and pipelines which collect liquids that condense in the Stevens gas gathering lines (HP, LP, and Vacuum) throughout NPR-1. A flow schematic of the Stevens Condensate System is shown in Figure 3.8.

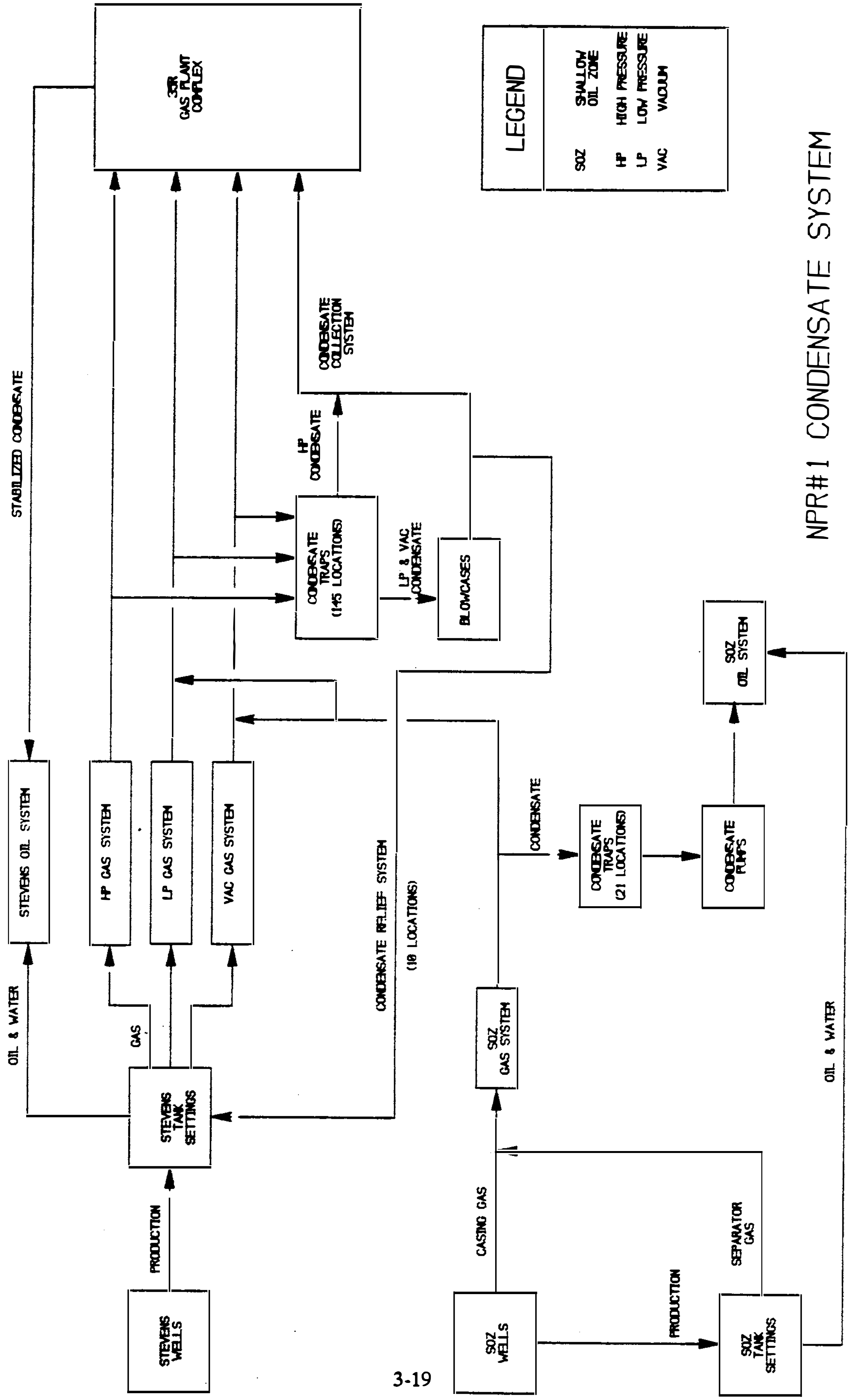
There are 145 traps in the Stevens Gas Gathering System. Condensate traps and blow cases are installed at low points in the piping systems. The blow cases



NPR#1 GAS SYSTEM FLOW SCHEMATIC

Figure 3.7

5/89



NPR#1 CONDENSATE SYSTEM

Figure 3.8

receive the condensate from the traps and dump it into welded steel pipelines which transport the condensate to the 35R Process Plants for stabilization. There are approximately 36 miles of pipelines in the Stevens Condensate Collection System which range in size from 2" to 6" in diameter.

The condensate is stabilized mainly at the 35R Lean Oil Absorption Plant (LOAP). Stabilization is achieved by heating the condensate to approximately 180°F and flashing the evolved gas in two stages. The stabilized condensate is then discharged into the Stevens Crude Gathering System and sold with the oil at the 18G LACT.

SOZ Condensate System

The Shallow Oil Zone (SOZ) Condensate Collection System consists of traps and pumps at 21 locations in the SOZ Gas Collection System. The system is shown on Figure II-1.

The SOZ condensate traps are vessels 5' in diameter and 10' in length. The vessels are equipped with level controls which operate electric motor driven pumps that pump the condensate through 2" diameter welded steel pipelines to the nearest point in the SOZ Crude Oil Gathering System. The condensate mixes with the oil and is sold eventually at the 25S LACT.

GAS COLLECTION COMPRESSORS

30R Stevens Compression Plant

This plant consists of eight 1,000 HP gas engine driven compressors.

Two of the compressors are in vacuum to low pressure service. The combined design capacity of these units is approximately 8 MMSCFD.

Four of the compressors are in low pressure to high pressure service. The combined design capacity of these units is approximately 26 MMSCFD.

The remaining two units can be used in low pressure to high pressure service or as HP wet gas boost compressors to compress Stevens HP gas for transportation to Chevron's 17Z Processing Plant through a 12" diameter, 6 mile steel pipeline. The combined design capacity of the units in low pressure to high pressure service is approximately 12 MMSCFD. The combined design capacity of the units in high pressure wet gas boost service is approximately 100 MMSCFD.

30R Carneros Compression Plant

This plant consists of two 1,000 HP gas engine driven compressors. The units are located on the same site as the above described Stevens compressors. The units compress Carneros gas from low pressure to high pressure for combining with the HP Stevens Gas Gathering System. The combined design capacity of the units is approximately 18 MMSCFD. The plant is currently under construction.

3G Compression Plant (Station 2-3G)

This inactive plant consists of nine gas engine driven compressors which total 3260 HP. The plant is not in service because of numerous costly repairs/modifications necessary to bring the plant into compliance with minimum safety standards. When in operation, the plant compressed vacuum and LP SOZ gas into the Stevens HP Gas Collection System. Current plans are to remove this plant in FY 90.

17R Compression Plant

This plant consists of three 650 HP gas engine driven compressors and one 1,000 HP gas engine driven compressor. The units are in Stevens LP to Stevens HP service and have a combined design capacity of approximately 18 MMSCFD.

33S Major Gas Gathering Compression Plant

The plant consists of four 2,000 HP gas engine driven compressors. The compressors are in Stevens Vacuum and Stevens LP to Stevens HP service. The combined design capacity of the units is approximately 4 MMSCFD Vacuum to HP gas and 58 MMSCFD LP to HP gas.

33S Vacuum Compression Plant

The plant consists of one 1,000 HP gas engine driven compressor in Stevens Vacuum to Stevens HP service. The design capacity of the unit is approximately 3 MMSCFD.

33R Compression Plant

The plant consists of one 650 HP gas engine driven compressor in Stevens LP to Stevens HP service. The design capacity of the unit is approximately 3 MMSCFD.

7R Compressor Plant

This plant is located at Stevens Tank Setting 1-7R. It consists of two 1,000 HP compressors compressing Vacuum and LP gas to Stevens HP. The combined design capacity of the units is approximately 2 MMSCFD Vacuum gas and 11 MMSCFD LP gas.

3G "Zero PSIG" Compression Plant (Station 4-3G)

This plant consists of two 250 HP electric motor driven compressors in SOZ Vacuum (wellhead casing gas) to Stevens LP service. The combined design capacity of the two units is approximately 5 MMSCFD.

36R Compressor Plant

This plant consists of three 1,000 HP gas engine driven compressors in Stevens LP to Stevens HP service. One of the units (approximately 5 MMSCFD capacity) is piped to take suction from the SOZ LP and DGZ as well as Stevens LP. The combined design capacity of the three units is approximately 21 MMSCFD.

35R LP-HP Compressor Plant

This plant consists of four 500 HP gas engine driven compressors in Stevens LP to Stevens HP service. The plant is physically located north of LTS-2 Gas Plant. The units were previously leased from Dresser-Rand, but were purchased by the Unit in FY 1988 when it was determined there was a long term need for the units. The combined design capacity of the units is approximately 15 MMSCFD.

35R LP-HP Rental Compressor Plant

This plant consists of two 1,000 HP gas engine driven compressors in Stevens LP to Stevens HP service. The plant is physically located northeast of the 35R LOAP (Lean Oil Absorption Plant). These compressors are presently leased from Production Operations, Inc. (POI) who operates and maintains the units. The combined design capacity of the units is approximately 14 MMSCFD.

Low Temperature Separation (LTS-1 and LTS-2) and Gas Collection Compressors

Each of these gas processing plants has one 2,000 HP gas engine driven compressor in Vacuum to LP and LP to HP service. The design compressor capacity at each plant is approximately 4 MMSCFD of Vacuum to LP gas and 12 MMSCFD of LP to HP gas.

35R LOAP Gas Collection Compressors

This plant has two 880 HP gas engine driven compressors in dual service (Vacuum to LP and LP to HP) with a combined design capacity of approximately 2 MMSCFD Vacuum to LP and 10 MMSCFD LP to HP.

There are two 880 HP gas engine driven compressors in LP to HP service with a combined design capacity of 18 MMSCFD.

There are three 1,000 HP gas engine driven compressors in LP to HP service with a combined design capacity of approximately 19 MMSCFD.

CLOSED LOOP GAS LIFT (CLGL) SYSTEMS

4G MBB CLGL Station

The function of this station is to compress Stevens LP gas to pressures sufficient to provide lift gas for Stevens wells in the Main Body B Reservior that use gas lift as a means of artificial lift.

This station consists of three 1,750 HP electric motor driven compressors in Stevens LP to Gas Lift service. The suction pressure is approximately 50 psig and the discharge is approximately 1,700 psig. The combined design capacity of the units is approximately 22.5 MMSCFD. The plant also contains gas dehydration facilities. Provisions have been made in the design for a fourth gas lift compressor to be installed in FY 89.

8R NWS CLGL Station

The function of this station is to compress Stevens LP gas to pressures sufficient to provide lift gas for Stevens wells in the Northwest Stevens Reservior that use gas lift as a means of artificial lift.

The station consists of two 1,750 HP electric motor driven compressors in Stevens LP to Gas Lift service. The suction pressure is approximately 50 psi and the discharge is approximately 1,700 psi. The combined design capacity of the units is approximately 15 MMSCFD. The plant also contains gas dehydration facilities.

GAS PLANT PROCESSING

LTS-1

This plant is designed to extract propane, mixed butanes and natural gasoline at a nominal throughput rate of 100 MMCFD. The plant is designed with refrigeration capacity to chill the inlet gas stream to about -30°F to liquify propane, butane and gasoline. Normal design process pressure is 415 psi. This plant has effectively processed gas at a rate of 120 MMCFD. LTS-1 usually is operated at a throughput rate of 116

MMCFD. At this rate, the plant produces about 95,000 gals/day of propane, 80,000 gals/day of butane, and 60,000 MMCFD of gasoline.

LTS-2

This plant is designed identically to LTS-1 with the exception of a few pieces of equipment from different manufacturers.

35R Absorption Plant

This plant is designed to process gas at a nominal rate of 94 MMCFD. It extracts propane, mixed butanes and natural gasoline by absorbing these products in lean oil as opposed to extractions of these products by refrigeration as is done by LTS-1 and LTS-2. This plant is usually operated at a throughput rate of 70 MMCFD. At this rate, the plant extracts about 48,000 gals/day of propane, 50,000 gals/day of butane, and 38,000 gals/day of gasoline.

17Z McKittrick Gas Plant

This plant is owned and operated by Chevron, USA, Inc. It is located about 2-1/2 miles west of the western boundary of NPR-1 and about 10 miles west of the 35R Gas Plants. This plant is contracted to process up to 60 MMCFD of Unit- owned gas. The plant is provided with storage and truck loading facilities and is designed to extract propane and a mixture of butanes and natural gasoline. In FY 88, an average daily rate of approximately 23 MMSCFD of wet gas was processed at 17Z yielding 24,526 gal/day of propane and 26,494 gal/day of butane/gasoline mix.

Gas Plants Product Storage and Shipping Facilities

Gas plant product storage and shipping facilities are described in the Natural Gas Liquids (NGL) System section of the report.

GAS PROCESSING SYSTEM

A flow diagram of the Gas Processing System is shown on Figure 3.9.

GAS INJECTION FOR PRESSURE MAINTENANCE

Residue gas from the gas plants is injected into two Stevens Zone structures to maintain reservoir pressure. These structures are the 26R, and NW Stevens. There are approximately 17 miles of steel pipe comprising the gas injection distribution system to the Stevens gas injection wells. The operating pressure of the system ranges between 2,800 psig and 3,200 psig depending on location and gas volumes. The pipelines range in size from 3" to 8" in diameter. The pipelines are installed aboveground on wooden and steel pipe supports.

The gas injection system also provides make-up gas for the two gas lift systems in 8R and 4G.

The flow schematic in Figure 3.7 includes the gas injection system.

Gas Injection Compressors LTS-1 and LTS-2

Each of these process plants has three 5,500 HP gas engine driven compressors which compress residue gas for injection. Each compressor has a design capacity of approximately 30 MMSCFD. The combined capacity of both plants is 33,000 HP and 180 MMSCFD. Each compressor is also equipped with cylinders to compress propane used as refrigerant in the gas plants.

35R Lean Oil Absorption Plant (LOAP)

This plant has three 880 HP gas engine driven compressors in residue gas to injection service. Each compressor has a design capacity of approximately 7 MMSCFD. The combined plant capacity is 2,460 HP and 21 MMSCFD. The compressors can also be used in residue gas to sales service (approximately 700 psig discharge pressure) if necessary.

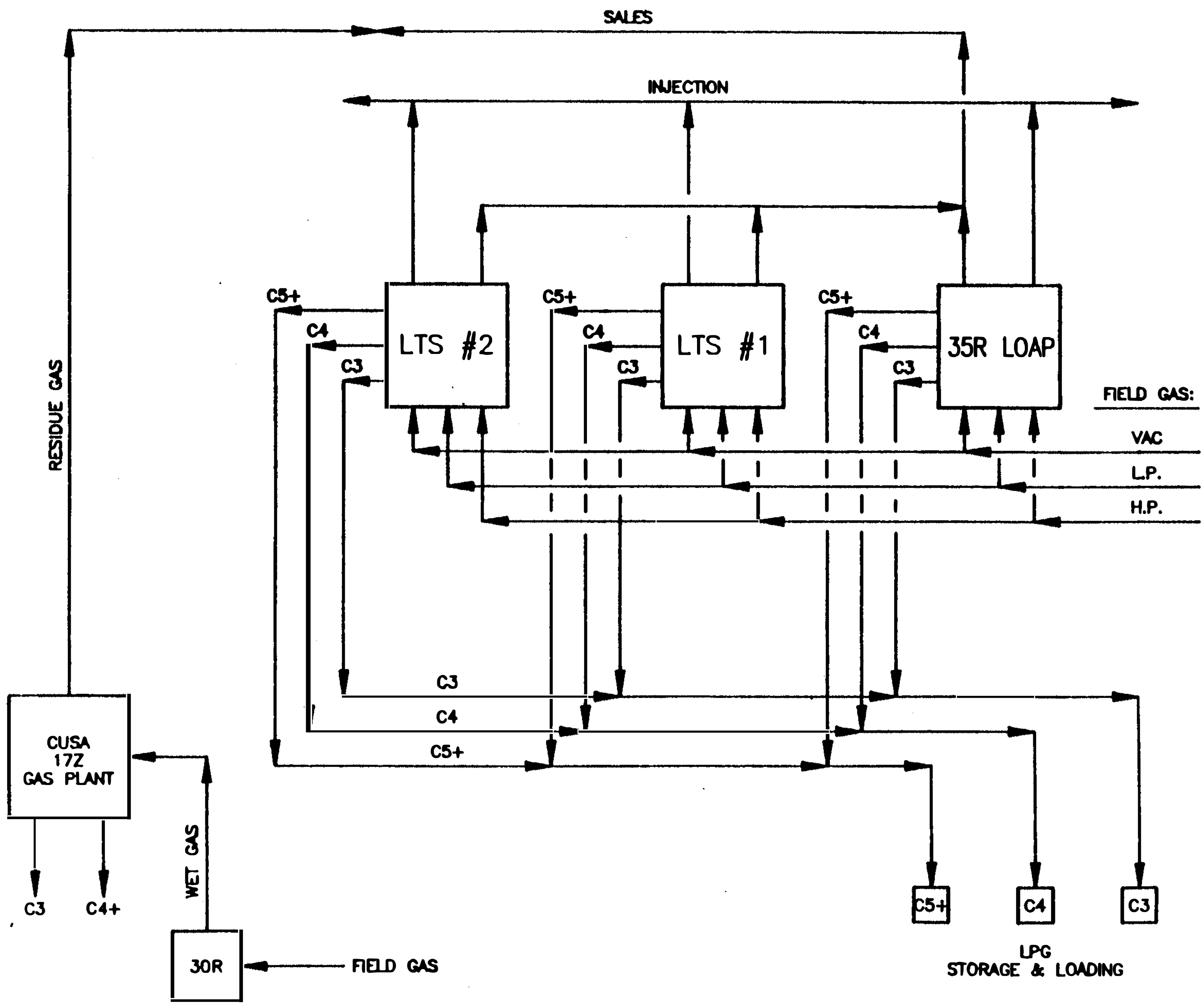
35R High Pressure Injection Facility (HPI)

This plant consists of three 4000 HP gas engine driven compressors in residue gas to injection service. The design capacity of each compressor is approximately 30 MMSCFD. The combined plant capacity is 12,000 HP and 90 MMSCFD.

1-7R Gas Injection Compressors

This plant consists of two 1,000 HP gas engine driven compressors installed near Stevens Injection Well 366-7R. The compressors were designed to compress injection gas at 2,800 psi to 5,500 psi for injection into the NW Stevens structure. The combined plant design capacity was approximately 34 MMSCFD.

The compressors are presently idle and the engines have been removed to replace other compressor engines in the field. The plant is no longer needed for its designed application.



GAS PROCESSING

Figure 3.9

GAS SALES

Residue gas is compressed by compressors in the 35R Gas Plant Complex and is transmitted by a 14" diameter welded steel pipeline to gas sales metering stations in Sections 35R, 24Z, and 17Z. The pipeline system is approximately 11 miles in length with an operating pressure between 450 and 700 psi depending on location and gas volumes. Customer sales gas pressure varies between 380 psi and 400 psi..

Metering Stations

Each of the three metering stations are equipped with coolers, scrubbers, flow controllers, samplers, orifice meter(s), and state of the art electronic flow computers. The 24Z metering facility also includes a coalescing filter and an odorizer.

The35R Metering Station has a nominal design capacity of 27 MMSCFD. The facility is connected to Chevron's gas line to their 1C Plant in Taft, California.

The 24Z Metering Station has a nominal design capacity of 60 MMSCFD, but will be upgraded to 105MMSCFD in FY89. The facility is connected to Southern California Gas Company's gas transmission line.

The 17Z Metering Station has a nominal design capacity of 135 MMSCFD. The facility is connected to lines owned by Chevron, Shell, Texaco, and Mobil. This facility also receives the Governments share of NPR - 1 residue gas that has been processed by Chevron's 17Z Plant.

GAS SALES COMPRESSORS

Residue Gas Sales Compressors

The 35R LOAP includes two 4,000 HP gas engine driven compressors in residue gas to sales service. The combined designed capacity of both units is approximately 144 MMSCFD.

As mentioned earlier, an additional 21 MMSCFD capacity is available, if necessary, from three injection compressors.

DGZ Gas Sales Compressors

This compression facility is located in Section 36R and consists of two 1,000 HP gas engine driven compressors with a combined design capacity of approximately 20 MMSCFD. The units are designed for a suction pressure of 100 psi and a discharge pressure of approximately 475 psi.

The discharge of the compressors is piped to both the injection and residue sales gas systems. The flow schematic of the system is included in Figure 3.7.

NATURAL GAS SYSTEM

The flow diagram of the Natural Gas System is shown on Figure 3.3.

CRITICAL PARAMETERS/RESOLUTIONS

Additional Gas Handling Capacity

The Compressor Optimization Study project (55202) was completed in FY 1988. This project analyzed the various gas systems at NPR-1 and presented recommendations for system modifications required to maintain forecasted production rates. The modifications consist of additional gas gathering pipelines and placing abandoned HP pipelines in LP service. The various projects are contained in Project 49312.

The high pressure gathering systems have experienced accelerated internal corrosion caused by the action of carbonic acid on the pipeline metal. The acid is formed by the interaction of carbon dioxide and water in the high pressure gas. To mitigate this problem, the following three projects are proposed:

Project 58767A involves replacing the NW Stevens high pressure gathering line with a piggable 14" diameter welded steel pipeline and the installation of dehydration facilities.

Project 48814A is proposed to provide dehydration facilities at the 33S Compressor Station.

Project 48814B and 40310 are proposed to provide dehydration facilities on the high pressure gas gathering system at selected locations throughout the field.

The Dry Gas Zone (DGZ) reservoir pressure is declining. Soon the DGZ Gathering System pressure will drop below the minimum suction pressure required by the DGZ compressors. Project 49324 is proposed to install booster compression to maintain MER production rates.

Project 48878A is proposed to increase the capacity of the 24Z gas sales point from 60 MMSCFD to 160 MMSCFD to allow the Unit to benefit from increased revenue when gas contract rates at this location are higher than other sales locations.

Condensate System

During the winter months, some of the condensate traps in the Stevens System are not effective at removing the condensate in the gathering lines. This is due primarily to control valve freezing and inadequate trap capacity/design in the above ground pipeline. When condensate accumulates in the pipeline, gas flow is restricted which causes higher operating pressures at the tank settings. Higher operating pressures at the tank settings can curtail production and cause venting of gas to the atmosphere. Projects to alleviate condensate system problems include the following:

Project 48762 has been funded to modify the control systems at 19 Stevens trap locations and 3 Stevens Tank Settings.

Project 49304 is proposed to study the Stevens and SOZ Condensate Systems and provide recommendations which will generate AFE's for system modifications.

POTENTIAL PROJECTS

The potential need for a fourth gas plant is discussed in the Studies and Future Opportunities Section.

ENVIRONMENTAL CONSIDERATIONS

The major environmental considerations for the natural gas system include the minimization of air pollution by control of gas stacking from tank settings. The tank settings throughout the field are equipped with facilities to vent gas to the atmosphere when gas gathering system pressures rise above the normal operating pressures at the tank settings. Gas is also vented during production upsets. A number of projects are planned to address this concern, including: "Minimize Gas Stacking", "LTS Vent Modifications" and "LTS-1 and LTS-2 Flare Bypass", as well as projects to reduce air emissions (the "Environmental Trigger") and those involved with additional NOx controls.

Another high priority project of environmental concern is Project 48796, which is proposed to install existing surplus electric motor driven vapor recovery compressors at Stevens Tank Setting 1-7R to maintain production and eliminate venting of tank vapors when the LP-HP compressors at the tank setting are down.

For further detail, individual project description sheets are included at the conclusion of the Natural Gas Systems section.

SAFETY CONSIDERATIONS

Safety/health/fire projects have been scheduled to deal with findings identified in three formal Safety Analysis Reviews involving the 35R Gas Plant, LTS 1 & 2, HPI, and 33S and 30R compressor stations. Fire protection systems, both new and modifications to existing systems, asbestos abatement in the 35R Gas Plant, and other safety/health/fire projects related to the natural gas system.

The Safety Analysis Reviews (SAR) completed during FY 86 and FY 87 identified safety related deficiencies in the 35R Gas Plant (SAR I), the LTS-1, LTS-2, HPI and associated Truck Loading Rack (SAR II), and the 3G Gas Plant, 30R, 33S Compressor Stations and related field facilities (SAR III).

Project 46256 is to continue correction of the safety related items identified in SAR I.

Project 48111X is to continue correction of the safety related items identified in SAR II.

Project 48101 is to correct various safety related items identified in SAR III.

PROJECT DESCRIPTIONS

The following facilities project descriptions are associated with the Natural Gas Systems.

1.	P40301B	Pipeline Repair/Replacement - Gas
2.	P49312	Compressor Optimization Implementation
3.	P48767A	New NWS HP Pipeline
4.	P48850	Minimize Gas Stacking
5.	P48814A	Install Gas Dehydration 33S
6.	P48814B	Install/Repair HP Gas Dehydrators
7.	P40310	Field HP Gas Dehydration
8.	P49304	Condensate Collection System Imp.
9.	P55127	30R LP Gas Separation
10.	P48304	Carneros Compressors
11.	P49102	Abandon/Demolitionof 3G Gas Plant
12.	P49349	Recylinder K-57/K-58
13.	P47615	LTS Vent Mods
14.	P48792	LTS Gas/Gas Exchanger
15.	P49208	LTS Flare Bypass
16.	P48815	35R Gas Plant Upgrade
17.	P49107	35R Lighting Mods
18.	P47536A	35R Asbestos Program
19.	P48796	1-7R TS Vapor Recovery Unit Install
20.	P47751C	Gas Lift Compressors - MBB
21.	P47751D	Gas Lift Compressors - NWS
22.	P49343	4G Closed Loop Gas Lift Comp. Install
23.	P49335	24Z/29R Closed Loop Gas Lift Comp.
24.	P48878A	24Z Gas Sales Point
25.	P49324	DGZ Program
26.	P46121	DGZ H20 Collection
27.	P48762	Debottleneck HP Gas Line
28.	P49703	Pipeline Corrosion Inspection
29.	P49314	Cathodic Protection Replacements
30.	P49210	H2S Program
31.	P46256	SAR I - 35R (Development Facilities)
32.	P48111X	SAR II - (Development Facilities)
33.	P49110	SAR III - 30R/33S (Dev. Facilities)
34.	P49003	Asbestos Abatement (Ex. 35R Gas Plant)(O & M Fund 111)
35.	P40201	Environmental Trigger
36.	P49109	NPR-1 Access Gates 2, 3 and 4
37.	P41102	Radio Communication Upgrade
38.	P48724	CP Anode Bed Replacement
39.	P49346	Gas Operations Expansion Project
40.		Miscellaneous Unscheduled Environ mental Projects (Operations & Maintenance Fund 111 and Development Facilities Fund 114)
41.		Miscellaneous Safety Projects (Opera tions & Maintenance Fund 111 and De velopment Facilities Fund 114)
42.		Facilities Engineering Miscellaneous Unscheduled Projects

PROJECT DESCRIPTIONS

The following facilities project descriptions are associated with the Natural Gas Systems.

43. P69001	*UT Insulated Vessels
44. P49302B	*Clean/Insp Tk 372
45. P49001	*TS/Pipeline Repair
46. P48794	*17Z/24Z SLS Gas CLR
47. P49332	*35R HP Gas Ln Rpr
48. P49704	*Add Unl K34, K35
49. Misc.	*Misc Prodn Projects
50. CC91040	**Sales Tax
51. P48740A	***HP Gas Inj P/L Rpr
52. P47751A	***CLGL @ NWS

*These projects are on-going and no project sheets are attached as they are less than $100,000.

** Cost Center for sales taxes, no project sheet attached.

***These projects are complete, no project sheets attached.

Following are descriptions for each of the projects listed previously.

PIPELINE REPAIR/REPLACEMENT GAS PROJECT P40301-B

This project is to provide funds for the repair and replacement of sections of the hundreds of miles of high volume pipe used for the various gas gathering and distribution systems on the Reserve.

Background

Repair and replacement of sections of the various gas gathering and distribution systems are required each year to (1) ensure safety, (2) protect the environment and wildlife and (3) to maintain or increase production. Much of the piping has been installed over 30 years ago. Over the years, corrosion has occurred at various rates and, in a number of cases, has required pipeline repairs and replacements to be made.

Economic Analysis

This project will be composed of multiple AFE submittals as individual problems are identified. An economic analysis will be made to justify each pipeline repair/replacement as the projects develop. Projects of this type usually provide short payout periods with high rates of return since only two alternatives are usually available. The alternatives are either (1) repair or replace the defective section of pipeline or (2) shut in production. Shut in of production usually has a very high monetary impact.

Plan

While the exact requirements for unplanned repair and replacement of pipelines cannot be defined at this time, NPR-1 can expect to expend funds for this work at the level indicated below.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	201	2840	3640	5060	4050	4120	4200

Schedule
Start 1Q
Complete Ongoing

COMPRESSOR OPTIMIZATION IMPLEMENTATION PROJECT P49312

This project consists of several sub-projects, each to be funded on separate AFE's whose respective scopes of work were identified in the Compressor Optimization Study, which was completed in FY 1988. The projects all involve piping additions or modifications to either the Stevens HP, the LP or the Vacuum Gas Gathering Systems.

Background

In order to continue to produce NPR-1 at the MER level, it will be necessary to modify the Stevens Gas Collection Systems for changes in gas production resulting from such things as increases in GOR, gas lift, artificial lift, or any of a variety of changes in production strategy for the various pools.

Using a computer model developed at Elk Hills, the existing systems were modeled with the most recent gas production forecast data, and system performance was simulated to identify areas where production would be constrained. The basis of the study was a tank setting production forecast prepared by BPOI Production Engineering in October 1987, which was later revised to correlate with the production forecast in the 1990 budget request.

Economic Analysis

The Compressor Optimization Study recommended modifications to the Stevens gas collection system which would avoid potential deferral of approximately 65 MMSCFD of gas and 13,000 BPD oil based on the forecast used in the study.

Plan

Implement the recommendations of the Compressor Optimization Study to insure NPR-1 MER production rates.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	723	2000	2140	2200	2250	2290	2330

Schedule
Start 1Q
Complete 4Q

NEW NWS HP PIPELINE

PROJECT P48767-A

This project provides for the replacement of the NW Stevens HP Gas Collecting System which runs from Stevens Tank Setting 1-7R to the 35R Gas Processing Facilities. The proposed replacement pipeline will be 14" nominal diameter, a length of approximately 32,000' and will roughly parallel the existing system.

Background

This pipeline system has and is now experiencing a very high rate of corrosion. Repairs and replacement of short sections of the piping have been made to extend the service life about another 12 months.

Economic Analysis

The existing NWS HP Gas Collecting System has an anticipated remaining life of about one year. After that time, unless the new pipeline system is in place, either (1) the pipeline must be shut in or (2) extensive and frequent repair/replacement of sections of the line would be required. In either case, production would be seriously impacted. The alternative of attempting to maintain production through frequent repair of the line would be unacceptable because (1) the rapidly corroding pipeline would present a constant safety hazard and (2) the cost of frequent nondestructive examination and repair/replacement, coupled with the value of deferred production, would soon exceed the cost of the proposed pipeline. The economic evaluation is, therefore, based on two alternatives, i.e., install the new line or shut in the NWS production.

Net Revenue (M$)	1,572,335
NPV @ 10% (M$)	753,108
NPV @ 15% (M$)	558,686
Payout (Years)	0.52
Project Life (Years)	15

Plan

Install a new pipeline system complete with fin fan coolers and separators in Sections 7R and 17R, and an automated pigging system to aid in the removal of liquids from the line.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	2707	0	0	0	0	0	0
Schedule							
Start							
Complete	3Q						

MINIMIZE GAS STACKING

PROJECT P48850

This project is to determine causes of gas stacking at various facilities at NPR-1 and then to implement remedial measures to reduce or eliminate unnecessary gas stacking.

Background

Over the past several years of operations, low pressure gas production has been increasing. This has required facilities to operate at their peak operating range, leaving little, if any, spare capacity. During upset conditions, pressures increase up to a level where gas is vented through a relief valve to the atmosphere.

Applicable Statutes/Regulations/DOE Orders

DOE Order 5400.1; DOG regulations (Title 14, CCR Sections 3300-3314 and 3500-3503); Rule 111, Kern County Air Pollution Control District regulations; Federal and State Clean Air Act.

Plan

This project will correct 7 tank settings in FY 89 and 8 tank settings in FY 90. Continue study to determine causes of gas stacking to minimize gas stacking to the atmosphere

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	500	207	0	0	0	0	0
Schedule							
Start	2Q						
Complete		4Q					

INSTALL GAS DEHYDRATION 33S

PROJECT P48814A

Provide new glycol dehydrator and piping to process 33S compressor discharge gas and main system high pressure gas from system east of the 33S Compressor Plant.

Background

Currently Stevens Zone low pressure and vacuum gas and Shallow Oil Zone low pressure gas is collected and boosted to high pressure at the 33S Compressor Station. High pressure gas is sent to the 35R Plant through approximately 5 miles of 12" and 16" diameter lines. Water in the gas is causing internal pipe corrosion and hydrate plugging in the high pressure lines to 35R. The catastrophic pipeline failure and fire at the 33S manifold in June 1985 was caused by this corrosion. In addition, hydrate formation in the high pressure line due to the high water content occurs every winter, resulting in plugging of the lines and associated higher compressor horsepower requirements to send gas to 35R.

Future failure of the high pressure pipeline, due to corrosion caused by free water, can be avoided by installing a glycol dehydration unit which will remove water from the discharge gas.

The following benefits would also be recognized by addition of a glycol dehydrator: high pressure gas lines would not be obstructed by hydrate formation on cold days, compressor horsepower would be reduced, pipeline maintenance and repair would be reduced, the load on the glycol dehydrators at the 35R Plant complex would be reduced and the high pressure gas lines will operate more safely with less chance of fire or release of hydrocarbons to the environment.

Economic Analysis

In the past 3 years, a number of repairs and replacements have been made to HP pipelines. The failure occurring at the 33S manifold in 1985 is considered a typical model and is used to estimate potential losses in oil and gas income and repair costs associated with possible future failures. The 33S failure resulted in a deferral of 500,000 bbls of oil, 1,000,000 MCF gas, and $1,500,000 in repair expenses.

It is possible that a failure of this magnitude could occur at present corrosion rates within 3 years (with a $11,611,000 loss in the year of failure) unless significant reductions in the corrosive environment are accomplished through gas stream water removal as proposed.

Project Requirements:
Facilities Investment (FY 89) $1,100,000

Incremental	Oil Production (BOPD)	Gas Production (MCFD)
1990	0	0
1991	0	0
1992	1370	2740
1993	0	0
1994 on	0	0

Net Revenue	$10,850,900
NPV @ 10%	7,467,400
NPV @ 15%	6,576,400
Payout (Years)	1.44
Project Life (Years)	15

Plan

Purchase and install a glycol dehydration system and piping at the 33S Compressor Station. Estimated cost is as follows:

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	1100	0	0	0	0	0	0
Schedule							
Start	1Q						
Complete	4Q						

INSTALL/REPAIR HP GAS DEHYDRATORS PROJECT P48814-B

Perform study and install supplemental equipment and/or repair equipment on existing high pressure system gas dehydrators.

Background

Currently Stevens Zone low pressure and vacuum gas, and Shallow Zone low pressure gas are collected throughout the field and boosted into the high pressure system. Additionally,, Stevens and Carneros Zone high pressure gas flows directly into the system without boosting. Condensed water in the system is causing internal pipe corrosion and hydrate pipe plugging. The existing dehydrators now in operation require enhancement and/or repairs to perform adequately to reduce the corrosion/hydrate problems.

Economic Analysis

In the past 3 years, a number of repairs and replacements have been made to HP pipelines. The failure occurring at the 33S manifold in 1985 is considered a typical model and is used to estimate potential losses in oil and gas income and repair costs associated with possible future failures. The 33S failure resulted in a deferral of 500,000 bbls of oil, 1,000,000 MCF gas, and $1,500,000 in repair expenses.

It is possible that a failure of this magnitude could occur at present corrosion rates within 3 years (with a $11,611,000 loss in the year of failure) unless significant reductions in the corrosive environment are accomplished through gas stream water removal as proposed.

Plan
As determined from study, enhance/modify existing gas dehydrators.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	523	0	0	0	0	0	0
Schedule							
Start	2Q						
Complete		1Q					

FIELD HP GAS DEHYDRATION
PROJECT P40310

Provide glycol dehydrators at selected locations at NPR-1 to mitigate corrosion.

Background
The most common undesirable impurity encountered in gas streams at NPR-1 is water vapor. It is not the water vapor itself that is objectionable, but the liquid or solid phase which precipitates when cooled during gas transmission. Liquid water in the presence of the encountered levels of CO_2 and H_2S has resulted in accelerated corrosion in gas pipelines. In addition, the formation of ice or solid hydrates has plugged valves, fittings, and in some cases, the gas transmission lines themselves. To mitigate such difficulties, selected gas streams must be dehydrated.

Economic Analysis
In the past 3 years, a number of repairs and replacements have been made to HP pipelines. The failure occurring at the 33S manifold in 1985 is considered a typical model and is used to estimate potential losses in oil and gas income and repair costs associated with possible future failures. The 33S failure resulted in a deferral of 500,000 bbls of oil, 1,000,000 MCF gas, and $1,500,000 in repair expenses.

It is possible that a failure of this magnitude could occur at present corrosion rates within 3 years (with a $10,850,900 loss in the year of failure) unless significant reductions in the corrosive environment are accomplished through gas stream water removal as proposed.

Project Requirements:
Facilities Investment (FY 90) $1,035,000

	Incremental Oil Prod. (BOPD)	Gas Prod.(MCFD)
1990	0	0
1991	0	0
1992	1370	2740
1993	0	0
1994 on	0	0

Net Revenue	$10,850,900
NPV @ 10%	7,566,100
NPV @ 15%	6,674,100
Payout (Years)	1.42
Project Life (Years)	15

Plan
Install glycol dehydration at selected locations on the high pressure gas system at NPR-1.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	1035	0	0	0	0	0
Schedule							
Start		1Q					
Complete		4Q					

CONDENSATE COLLECTION SYSTEM IMPROVEMENTS
PROJECT P49304

This project provides for improvements to the Stevens and SOZ condensate collecting systems and traps, including:

1. Study and identify the existing high risk problem areas, particularly the East End Stevens HP System, and recommend improvements.

2. Increase the capacities of various line segments and or provide gas removal facilities to enhance the transfer of condensate from the gas pipelines to points of disposal.

3. Modify condensate trap configuration and controls to increase effectiveness and reliability of the units.

Background
Capacity restrictions in the condensate collection systems cause back-up of condensate in the gas collecting systems. This problem is further increased by frequent malfunctions of the condensate trap controls. Without

an adequate condensate collecting system, condensate induced high gas collecting system pressures occur which increase operating costs and reduce both oil and gas production and discharge of hydrocarbons to the atmosphere sporadically occur.

Economic Analysis

The following economic indicators were developed for the Condensate Collection System Improvements project. Incremental investment requirements and operating savings have been identified. Economic benefit is realized when operating costs to operate condensate removal equipment and pipelines is reduced and production shut-in is eliminated. The economics presented are based on an annual operating saving of $100,000 per year and elimination of one three-day shut-in due to a line failure in over 3 successive years for each of 3 operating areas; NWR, West and East respectively. The net value of this production and operations savings is $3.9 million. In addition to the above tangible benefits, there is a major environmental benefit. This project results in an acceptable method of collecting and transporting condensate and complies with state and federal rules governing air quality and protection of the environment.

Incremental Production	BBL	MMCF	SAVINGS $/YR.
1989	6,000	48	$100,000
1990	12,000	90	100,000
1991	30,000	180	100,000
1992	-	-	100,000
1993	-	-	100,000
Net Revenue ($1000)			$3,911
NPV @ 10% ($1000)			2,216
NPV @ 15% ($1000)			1,891
Payout (Years)			1.34
Project Life (Years)			15

Plan

Implementation of this project will minimize deferment of production and reduce discharge of hydrocarbons to the atmosphere.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	600	0	0	0	0	0	0

Schedule
Start 2Q
Complete 4Q

30R LP GAS SEPARATOR

PROJECT P55127

This project includes the design, fabrication and installation of an additional LP gas separator/scrubber to reduce liquid entrainment in the gas and thereby decrease compressor downtime. Present plant capacity has nearly doubled due to a compressor relocation and recylindering of Units K-34 and K-35.

Background

Gas Operations has reported a high incidence of compressor downtime and excessive maintenance costs due to liquid carry over into the compressor cylinders. The addition of a properly sized separator/scrubber should minimize such liquid carry over.

Plan

Install the necessary equipment to provide adequate LP gas liquid separation and thereby improve operations at the 30R Compressor Station.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	155	0	0	0	0	0

Schedule
Start 2Q
Complete 4Q

CARNEROS COMPRESSORS

PROJECT P48304

Install additional compression, low pressure tank setting, gathering lines at the 30R Facility to compress 18 MMSCFD from 60 psi to 500 psi.

Background

The Carneros Zone presently produces directly into the high pressure system via its own high pressure tank setting at 2-30R. As wellhead pressures are declining, it is necessary to provide compression to boost this lower pressure back into the Stevens high pressure collection system for continued processing at 35R. The objective of this installation is to maintain gas and oil production at maximum efficiency rate (MER) while the Carneros field wellhead pressure decline below that of the existing high pressure collection system.

Plan

An AFE was submitted and approved in FY 88 ($3240K) for the design, construction and installation of low pressure gas compression at 30R, which is required to maintain Carneros gas production at MER, currently 18 MMSCFD. In addition, the Carneros gas gathering system will be upgraded to reduce pressure drop from thewellheads. An AFE supplement was submitted and approved in FY 89 for additional funding is required to cover scope changes and design development incurred since the original issue of the AFE as follows:

- Purchase new compressors rather than re cylinder existing ones.
- Additional tank setting area site preparation and a new access road.
- Increased scope for mechanical subcontractors.
- Addition of condensate stabilization system and flowline requirements.
- Deletion of dehydration unit relocation.
- Increased engineering manhours due to the above design development/scope changes.

Cost/Schedule
($000)

Cost Estimate	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
	310	0	0	0	0	0	0
Schedule							
Start	1Q						
Complete	4Q						

ABANDONMENT/DEMOLITION OF 3G GAS PLANT PROJECT P49102

This project includes the engineering, abandonment and demolition of the 3G Gas Plant.

Background

The 3G Gas Plant is currently not operating and is an aged facility. A recent Safety Analysis Review report identified numerous deficiencies with an estimated cost of $564,000 to correct if full operation were to be resumed. The facility is not required as part of the gas collection and processing system.

The level of copper contained in the cooling tower is above the maximum allowable limit and is therefore considered a hazardous waste.

Applicable Statutes/Regulations/DOE Orders

MPFL (Maximum Possible Fire Loss) Report; Title 22 and 23 CCR; Title 14 CCR Division of Oil and Gas regulations.

Plan

Remove cooling tower and abandon balance of plant in place at an estimated cost of $267,000.

Cost/Schedule
($000)

Cost Estimate	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
	0	0	267	0	0	0	0
Schedule							
Start			2Q				
Complete			4Q				

RECYLINDER K-57/K-58 PROJECT P49349

Sequentially recylinder Compressor Units K-57 and K-58 for 2stage, low pressure service.

Background

Currently Stevens Zone vacuum and low pressure gas is compressed by Units K-57and K-58at the 1-7R Tank Setting. A significant portion of each units' capacity is dedicated to the compression of vacuum gas. Actual vacuum gas handled is approximately 30% of each compressors' vacuum gas capacity.

A separate project is planned whereby the vacuum gas will be more efficiently handled by small electric motor driven vacuum units. After installation of the small vacuum units, it will become possible to recylinder K-57 and K-58 from 3-stage to 2-stage service to more fully utilize the horsepower for the low pressure compression service. It is estimated each units' capacity will be increased from 4500 MCFD to 7000 MCFD. To maximize operating capacity during the construction phase, it is planned to modify the units sequentially.

Economic Analysis

The additional 5 MMSCFD gas compression capacity will allow one of the 17R LP-HP compressors to be relocated to the 35R area where additional LP-HP compression is needed to handle the forecasted LP gas production. Based on a GOR of 5000:1, oil production of 1000 BOPD would not have to be deferred.

Total Investment	$550,000
Incremental Oil Production	1,000 BOPD
Incremental Gas Production	5 MMSCFD
Net Revenue	$46,015,200
NPV @ 10%	$31,616,500
NPV @ 15%	$26,993,700
Payout	3.65 Days
Rate of Return	> 1,000%
Project Life	7 Years

Plan

Recylinder Units K-57 and K-58 at the 1-7R Tank Setting from 3-stage to 2-stage service to increase the low pressure gas handling capacity from 4500 MCFD to 7000 MCFD per unit. Funding for this project is being evaluated; thus, no funding is shown in the tables.

Cost/Schedule
($000)

	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Cost Estimate	0	0	0	0	0	0	0
Schedule							
Start							
Complete							

LTS VENT MODS — PROJECT P47615

Reroute the atmospheric vents from injection gas compressor relief valves into the closed relief header.

Background

The LTS-1 and LTS-2 flare and relief systems may be considered identical for the purpose of discussion.

The current configuration of the LTS relief system allows the atmospheric venting of hydrocarbons from a total of 17 PSV's per gas plant. For environmental and safety reasons, the current practice is not desireable. The recommended safety practice is not to discharge any flammable vapors within 100' from an ignition source. If such discharge is inevitable, the discharge point must be 25' away from the major equipment. However, the environmental regulations are more stringent. Such venting to the atmosphere is prohibited unless these hydrocarbon emissions have been permitted by the District or an emergency condition exists. Hydrocarbon emissions are a precursor for ozone formation. Western Kern County is currently nonattianment for ozone (i.e., the ambient air quality ozone standard for 0.12 ppm has been exceeded). Numerous control strategies have been implemented by regulatory agencies to address this problem and continued venting of hydrocarbons to the atmosphere is not in keeping with the spirit and intent of these regulations.

Applicable Statutes/Regulations/DOE Orders

DOE Order 5400.1, Federal and State Clean Air Act, Kern County Air Pollution Control District Regulations, various safety guidelines

Plan

All PSV discharges should be rereouted to the closed relief header in order to address safety and environmental concerns.

Cost/Schedule
($000)

	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Cost Estimate	0	217	0	0	0	0	0
Schedule							
Start		1Q					
Complete		4Q					

LTS GAS/GAS EXCHANGER — PROJECT P48792

Purchase a new gas/gas exchanger for the replacement of one of the existing exchangers currently in service in the Low Temperature Separation (LTS) Plants.

Background

Since the LTS plants were started up in 1979-1981, there have been numerous failures experienced in the gas/gas exchangers. All tube failures were attributed to tube vibrations. The new exchanger has the same thermal performance but with different baffle spacing to eliminate the tube vibration problem. The last tube failure occurred at LTS-2 in August 1988, requiring an eight hour shutdown to plug the leaking tubes.

Plan

Implementation of this project will reduce maintenance and downtime of LTS Plants.

Cost/Schedule
($000)

	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Cost Estimate	100	0	0	0	0	0	0
Schedule							
Start	1Q						
Complete	3Q						

LTS FLARE BYPASS

PROJECT P49208

Install two pressure control valves, one on the HP and the other on the LP gas line, for each plant.

Background

This project is intended to minimize the need for relieving or venting gas at the tank settings due to the unexpected shutdown of LTS-1 or LTS-2 or both plants at the same time.

For each plant, two pressure relief valves will be installed upstream of the gas plants. The pressure control valves will release the gas to the respective flare when they pop open.

Plan

To minimize venting of unburned hydrocarbons in the field, install a total of four pressure control valves, two for each LTS plant so that the gas may be bypassed around each plant to the flare.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	350	0	0	0	0	0	0
Schedule							
Start	3Q						
Complete		4Q					

35R GAS PLANT UPGRADE

PROJECT P48815

Install facilities to lower the hydrocarbon and water dew points of the 35R Lean Oil Absorption Plant processed gas to provide gas of sales quality. Major units required would include a skid mounted refrigeration system, a gas to gas heat exchanger, a gas chiller, separator and a gas glycol dehydrator.

Background

Currently the 35R Plant residue gas must be injected because the hydrocarbon dew point of the gas does not meet sales gas specifications. Additionally, the water dew point may exceed sales gas specifications when plant throughput exceeds 70 MMSCFD. These limitations pose severe restrictions on the capability and flexibility of the entire 35R Complex to operate during emergency or planned maintenance in any of the gas processing/compression plants causing shut-in oil and gas production.

Economic Analysis

At present, the 35R Lean Oil Absorption Plant (LOAP) residue gas is required for injection. The demand for injection is decreasing on the Reserve. It is projected that a minimum of 15 MMSCFD of LOAP residue gas will be available for sales by FY 1992 and thereafter. Benefits realized due to the enhancement of the flexibility of the 35R Gas Plant Complex during emergencies and planned maintenance are not included in the economic analysis.

Project Requirements	
Facilities Investment	$6,090,000
FY91	$2,140,000
Incremental Gas Sales (MMSCFD)	

1991	0
1992	15
1993	15
1994 on	15

Net Revenue ($)	604,000,000
NPV @ 10% ($)	211,000,000
NPV @ 15% ($)	142,000,000
Payout (Years)	0.33
Project Life (Years)	20

Plan

Purchase and install the proposed gas processing system rated for the 35R Gas Plant capacity of 94 MMSCFD. Estimated cost is as follows:

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	50	1000	2140	2950	0	0	0
Schedule							
Start	4Q						
Complete					3Q		

35R LIGHTING MODIFICATIONS (DEVELOPMENT FACILITIES)

PROJECT P49107

Modify and install additional lighting in the following areas of the 35R Gas Plant:

- Feedwater chemical injection & storage
- Boilers at steam drum level
- V115 pump
- Cooling tower at fan level
- Cooling tower pumps
- Condensate spheres and transfer pumps
- South end of propane bullet tanks
- Between compressors K-11, 12 & 13 and south of K-13
- Fan drivers for compressor engine coolers
- Fan drivers for stripper condenser
- Compressor building - north side (inside)
- Sulfuric acid area

Background
This project was identified in a lighting survey during the 35R Gas Plant SAR. The survey indicated that the existing plant lighting did not meet minimum levels for illumination in the above areas.

The 35R Gas Plant was originally built to 1952 illumination standards. During expansions to the facility, adequate lighting was not installed. Pre-AFE engineering is complete. An AFE has been prepared and was submitted for approval on January 20, 1989.

Applicable Statutes/Regulations/DOE Orders
Title 8 CCR Subchapter 7, Article 7, Section 3317; and CCR Title 8, Subchapter 14, Article 48, Section 6657

Plan
The objective of this project is to upgrade the 35R Gas Plant Lighting System to meet current minimum illumination standards. This work is a part of the 35R Gas Plant SAR follow-up.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	81	0	0	0	0	0	0

Schedule
Start 1Q
Complete 4Q

35R ASBESTOS PROGRAM

PROJECT P47536A

The project is to remove all asbestos-containing insulation from piping and vessels in the 35R Gas Plant, then reinsulate as necessary with appropriate materials.

Background
Most insulation in the 35R Gas Plant was installed prior to 1970; based upon laboratory results, an estimated 50-75% of all insulation in this plant contains asbestos. The asbestos- containing insulation exists on most large vessels and piping systems. This insulation is in poor condition. In some instances, small bits of asbestos-related debris could fall to the ground or otherwise become friable.

New and more stringent regulations regarding asbestos have significantly escalated the costs of related work in recent years. Specifically, simple maintenance/ repair activities involving the disturbance of asbestos materials will require considerable time and material. Encapsulation methods may be of temporary benefit, but are not permanent solutions.

Economic Analysis
This project is a safety-related project. Cal-OSHA's Consultation Division (Occupational Cancer Control Unit) indicated that loose and crumbly asbestos shall be considered as asbestos spill and any such condition must be corrected. In addition, California Assembly Bill 2040 imposes stricter requirements. The current presence of loose, exposed, crumbly asbestos provokes an unsafe working condition. Unit Operator, therefore, proposes a remedial work program which is encapsulation and/or replacement of all asbestos-containing insulation materials at the 35R Gas Plant.

Applicable Statutes/Regulations/DOE Orders
Asbestos Regulations, OSHA 1910.1001, National Emission Standards for Hazardous Air Pollutants (NESHAP)

Plan
The most cost effective long term solution to the asbestos-containing insulation problem in the 35R Gas Plant is complete removal and reinsulation. All other control measures are only temporary measures.

The FY 89 schedule and budget is for remedial action only. The FY 90 schedule and budget is for complete removal and reinsulation. Total project cost is $1,106,000. scheduled for FY 89 - 90.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	100	518	541	0	0	0	0
Schedule							
Start	1Q						
Complete			4Q				

1-7R TS VAPOR RECOVERY UNIT INSTALLATION PROJECT P48796

This project will permit the more economical recovery of tank vapors at the 1-7R tank setting of approximately 400 MSCFD. Presently, the vapors are compressed by the two 23" first stage cylinders on each of the two 7R compressors. When both units are down, vapors must be stacked until production can be shut in. Available skid mounted vapor recovery units will be installed then the first stage horsepower on the K57-58 Ingersoll Rand units will become available for low to high pressure compression but cylinder resizing would be required.

Background

The California Division of Oil and Gas has inspected tank settings on NPR-1 and found that tank setting stacking is occurring too frequently. Revisions need to be made to meet Kern County Air Pollution Control District (KCAPCD) regulations and DOG regulations.

Tank setting 1-7R was originally considered a remote area. The recovery of vapors from the tanks using the gas engine driven compressors was a good application. Presently, the venting of tank vapors are insufficient to load the first stage cylinders. Nearly 50% of the cylinder capacity must be loaded with low- pressure gas bypassing from the second stage of compression. Consequently, high temperatures cause significant maintenance due to high by-passed gas temperatures and insufficient first stage cooler capacity.

Applicable Statutes/Regulations/DOE Orders

Title 14 CCR (Division of Oil and Gas Regulations), KCAPCD Rules and Regulations

Plan

Proceed with the project in order to reduce fuel and maintenance costs at 1-7R and eliminate frequent stacking of gas.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	200	0	0	0	0	0	0
Schedule							
Start	3Q						
Complete	4Q						

GAS LIFT COMPRESSORS - MBB PROJECT P47751C

Provide 20 MMSCFD of compression for the Closed Loop Gas Lift System at Section 7R by leasing with option to buy the electric driven compressors over a 12-month period. As part of the implementation of the NOx Emissions Reduction Program, compression of low pressure gas for gas lift to the Main Body B area was completed in FY88. The Closed Loop Gas Lift is now in operation.

Background

EPA's State Implementation Plan (SIP) for California ozone and carbon monoxide indicated that Kern County was a "non-attainment" area for ozone. Kern County drafted control measures to comply with the requirements for ozone precursors (NOx and HC) which were adopted by the California Air Resources Board (CARB), including the internal combustion (I.C.) engine rule to limit NOx and CO emissions. Due to the "borderline" status of Western Kern County, a trigger rule required that the I.C. engine rule be automatically implemented if four or more ozone exceedances are recorded between 1988 and 1990. The NOx offsets are required to comply with the I.C. engine rule (Rule 427). Also, the NOx increase for gas-fired closed loop compressors could not be demonstrated by modeling. Approval of a PSD application by EPA (Region IX) takes up to 12 months. The approval process was not consistent with our scheduled production requirements.

Due to permitting constraints, leasing (with option to buy) electric motor driven compressors is the prudent method to minimize deferral of production revenue due to temporary NOx compression outages. Leasing also provides enough time to pursue permits for gas engine driven compressors which could, in the future, replace the leased compressors. Moreover, leasing provides time to evaluate whether replacing the leased machines with permitted gas driven compressors is more economical given the trends in fuel costs (i.e. possible rate reductions) and the option of cogeneration.

Plan
The lease-option opted in FY88 is in progress. The FY89 funds complete our commitment for buyout of the compressors for a period of 12 months.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY93	FY 94	FY 95
Estimate	425						
Schedule							
Start							
Complete	2Q						

GAS LIFT COMPRESSORS - NWS
PROJECT P47751D

Provide 15 MMSCFD of compression for the Closed Loop Gas Lift System at Section 4G by leasing with option to buy the electric driven compressors over a 12-month period. As part of the implementation of the NOx Emissions Reduction Program, compression of low pressure gas for gas lift to the Northwest Stevens area was completed in FY88. The Closed Loop Gas Lift is now in operation.

Background
EPA's State Implementation Plan (SIP) for California ozone and carbon monoxide indicated that Kern County was a "non-attainment" area for ozone. Kern County drafted control measures to comply with the requirements for ozone precursors (NOxand HC) which were adopted by the California Air Resources Board (CARB), including the internal combustion (I.C.) engine rule to limit NOx and CO emissions. Due to the "borderline" status of Western Kern County, a trigger rule required that the I.C. engine rule be automatically implemented if four or more ozone exceedances are recorded between 1988 and 1990. The NOx offsets are required to comply with the I.C. engine rule (Rule 427). Also, the NOx increase for gas-fired closed loop compressors could not be demonstrated by modeling. Approval of a PSD application by EPA (Region IX) takes up to 12 months. The approval process was not consistent with our scheduled production requirements.

Due to permitting constraints, leasing (with option to buy) electric motor driven compressors is the prudent method to minimize deferral of production revenue due to temporary NOx compression outages. Leasing also provides enough time to pursue permits for gas engine driven compressors which could, in the future, replace the leased compressors. Moreover, leasing provides time to evaluate whether replacing the leased machines with permitted gas driven compressors is more economical given the trends in fuel costs (i.e. possible rate reductions) and the option of cogeneration.

Plan
The lease-option opted in FY88 is in progress. The FY89 funds complete our commitment for buyout of the compressors for a period of 12 months.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	225						
Schedule							
Start							
Complete	2Q						

4G CLOSED LOOP GAS LIFT COMPRESSOR INSTALLATION
PROJECT P49343

To provide for the 4G Closed Loop Gas Lift facility forecasted requirement of 32 MMSCFD through the year 1995 and other LP system requirements, it is proposed to install a fourth compressor. The current nominal capacity at the 4G facility is 22 MMSCFD.

Background
Gas is compressed and distributed as gas lift energy to certain targeted wells. Current gas levels are forecasted to increase because of an increase in gas lifted wells within the MBB Reservoir. AFE 68000 provided for the installation in FY 88 of up to 22 MMSCFD of gas lift capacity. Our forecasted demand has been increased to 32 MMSCFD and expected to remain level until 1995.

4G Gas Lift Requirements

		At Optimum GLR (MMSCFD)
Current Requirements	21 Wells	19.404
Work in Progress	9 Wells	8.316
7 Addt. Wells Approved	7 Wells	4.349
	TOTAL	32.069

The results from the planned remedial work in the 31S Structure is expected to overload the current low pressure compressor capabilities. With the installation of a fourth Closed Loop Gas Lift compressor at 4G, this overload can be alleviated.

Economic Justification
The fourth Closed Loop Gas Lift compressor and associated substation work is expected to cost $1,700,000.

At this time, 11 additional gas lift installations are pending in the Closed Loop region. The total remedial costs of the 11 wells are approximately $1.7MM and is expected to support 6410 BOPD. Therefore, total project costs (remedial costs and new compressor) are expected to be $3.4MM. Payout is expected in one month.

Plan
The new compressor will have long term benefits of reducing low pressure gas system constraints. Without the additional 4G compression, HPI make-up gas would be needed and this would overload the low pressure collection system. The expected production impact is 2500-5000 BOPD if the new unit is not provided.

Cost/Schedule *
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	850	910	0	0	0	0
Schedule							
Start		1Q					
Complete			4Q				

* Project schedule and Funding being evaluated.

24Z/29R CLOSED LOOP GAS LIFT COMPRESSORS PROJECT 49335

To provide for the 24Z/29R Closed Loop Gas Lift (CLGL) facility forecasted requirement of 26 MMSCFD through the year 1995 and other LP system requirements, it is proposed to install four 1750 HP compressors and associated equipment.

Background
This project provides for a CLGL system to serve the 24Z/29R Pool. There are presently 14 gas lift wells utilizing lift gas from the 3000 psig HPI distribution system; an additional 19 installations are planned. The total supply gas requirement is estimated to be 26 MMSCFD. This volume will impose additional burdens on the existing field gas handling and compression capacity. These wells should be included in a CLGL system designed to operate at 1500 psi thus reducing field operating expense and the transportation cost associated with the high pressure (450 psi) gas collection system connected to the 35R Complex. It is not necessary to utilize 3000 psi gas for lifting when only 1500 psi is required. The work will include four 1750 HP electric motor driven compressors, an electric power substation, a glycol dehydration system, and associated facilities.

Economic Justification
The 24Z/29R CLGL facility, including the electrical substation is expected to cost $4,500,000. Recent simulation studies (29R and 26R reservoirs) have shown that gas injection and gas cycling are methods that can increase oil reserves, natural gas liquids recovered, and increased net present value through additional daily production. An incremental cash flow of more than $14,000,000 per year has been estimated. The investment would therefore payout in less than 4 months.

Recommendation
The new compressor installation will have long term benefits of reducing low pressure gas system constraints and eliminating, except for emergencies, the use of HPI gas.

Cost/Schedule *
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	*0	2900	1710	0	0	0	0
Schedule							
Start		1Q					
Complete			4Q				

* Project schedule and Funding being evaluated.

24Z GAS SALES POINT PROJECT P48878-A

This project will increase the capacity of the 24Z Gas Sales Point facilities from 60 MMCFD to 105 MMCFD.

Background
The current 24Z Gas Sales Point capacity is 60 MMSCFD and can be increased to 105 MMSCFD with the addition of a coalescing filter and a separator. This pre-

vents the sale of all the Government's gas at this facility when contract sales rates are higher at this sales point compared to others. This limitation could also prevent production of larger volumes of gas or adoption of a partial pressure strategy for the 26R Reservoir. The capacity of the piping system to the facility is 120 MMCFD.

Plan
Increase the capacity of the 24Z Gas Sales Point from 60 MMCFD to 105 MMCFD.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	466	0	0	0	0	0
Schedule							
Start		3Q					
Complete		4Q					

Economic Analysis
Based on a production increase of 445,000 MSCF during summer months, a payout of 1.5 years is expected.

Plan
Upgrade DGZ processing facilities as necessary to assure sales quality gas and install a booster compressor.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	400	960	1320	0	0	0
Schedule							
Start		1Q					
Complete				4Q			

DGZ PROGRAM

PROJECT P49324

This project is to supply gas to the existing DGZ compressors at the current design level of 18 MMSCFD and 100 psi inlet pressure. The existing processing equipment will be evaluated to determine if upgrading is necessary. A booster compressor will be installed to compensate for reservoir pressure decline so that the existing compressors (K50 and K51) will operate at a constant volume and constant pressure. In addition, a study of the existing equipment will include evaluation of an evaporative cooling system for the compressor discharge gas, scrubber/ coalescers upstream and downstream of the glycol contactor and the existing glycol dehydration system.

Background
Dry Gas Zone (DGZ) production is gathered at the 36R Compressor Station for compression and dehydration. The compressors, K50 and K51, are designed for a 100 psi suction pressure and 400 psi discharge pressure. The design volume of gas is 18 MMSCFD. As the reservoir pressure has declined, it has become necessary to reduce the compressor suction/discharge pressure. Additionally, the reservoir is producing more water which requires larger separation facilities at the wells and improved dehydration facilities at the compressors. Currently, DGZ gas is being injected via HPI. During plant upsets, DGZ is mixed with residue gas for sales. However, the gas does not always meet sales specifications, and facilities at 36R may need to be upgraded.

DGZ H_2O COLLECTION

PROJECT P46121

This project will put back in service separators at well sites and install pumping units at high water level wells.

Background
This project will remove water at the wellhead of the DGZ Wells and help reduce the pressure drop through the DGZ Gas Collection System

Applicable Statutes/Regulations/DOE Orders
DOE Order 5400.1, Title 23 CCR, Proposition 65

Plan
Put back in service separators at well sites and install pumping units at high water level wells. Funding to install the pumping units is not included in this project.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	50	414	0	0	0	0	0
Schedule							
Start	2Q	1Q					
Complete	4Q	4Q					

DEBOTTLENECK HP GAS TRANSMISSION LINE

Project P48762

This project provides for modifying the control systems at 19 trap locations and 3 tank settings where ineffective liquid removal causes frequent flow restrictions in the Stevens interdependent HP, LP and vacuum gas collection systems.

Background

The liquid removal system is ineffective during the winter months and the control instruments will not reliably control the evacuation of the increased volumes of liquids from the HP, LP and vacuum gas pipelines which build up in the deep valleys. Production Operations has identified the trap locations which receive heavy fluid build-up, develop frequent freeze-ups in the level control valves, and require the most significanattention.

Recommendation

Implementation of this project will minimize deferment of production and reduce discharge of hydrocarbons to the atmosphere.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	221	0	0	0	0	0	0
Schedule							
Start	1Q						
Complete	2Q						

PIPELINE CORROSION INSPECTION

Project P49703

Background

One of the objectives of the Corrosion Control Program is to identify corrosion problems and to formulate solutions to those problems in gas systems. A plan to systematically identify corrosion problems is prioritized. The most critical gas systems receive the highest priority for inspection. All main trunk lines were inspected during FY 88.

This project for inspection of lateral lines and yearly NDE of main trunk lines for the following systems are prioritized in the order listed.

- HPI
- West-North-East HPGG
- NWS - Closed Loop Gas Lift
- Dry Gas Zone
- SOZ VRU

Plan

Continue systematic inspection of gas systems to identify conditions detrimental to good corrosion control.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	145	0	0	0	0	0
Schedule							
Start		2Q					
Complete			1Q				

CATHODIC PROTECTION REPLACEMENTS

Project P49314

Replace in kind 105 dead or weak groundbeds to restore cathodic protection for 429 wells. A subcontract to replace 45 of the 105 groundbeds has been awarded.

Background

Cathodic protection was initiated due to excessive corrosion failures of well casings and pipelines. Maintaining the integrity of well casings is economically justified. The Unit plan calls for securing the "maximum ultimate recovery" of hydrocarbons in future years. The Unit's reserve status, coupled with future anticipated advances in oil recovery techniques, dictates preservation of expensive capital plant investments such as well casings. The cathodic protection program is considered a good investment in the future. This project replaces 105 groundbeds that have deteriorated because they have exceeded their design life.

Economic Justification

Economic analysis consists of comparing two options:

Option 1 - Do nothing.
Option 2 - Restore cathodic protection to 429 well casings.

Option 1 does not require any capital investment. Instead, a number of casing failures is projected. Cost Center costs are assumed for a 10 year period since increased casing failures caused by corrosion, produce major disruptive effects on production, engineering and drilling, and corrosion.

Option 2 requires a capital investment of $2 million dollars. Annual operating costs include those of Cathodic Protection Cost Center, electricity and equipment maintenance. Costs are inflated at 2% and discounted at 12%. The cash flow results in a payout of 5 years. A basis of 10 years is used because it is the minimum design life of new groundbeds.

Plan

Restore cathodic protection to 429 wells.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	1000	0	0	0	0	0	0
Schedule							
Start	1Q						
Complete		4Q					

H_2S PROGRAM PROJECT

PROJECT P49210A

This project includes the following:

1. Installation of temporary H2S monitoring facilities on selected field gas streams (FY 89).
2. Analysis of data collected to identify upstream source of any high H2S concentrations (FY 90).
3. Prepare plans for both short and long range solutions to problem (FY 90).

Background

The Hydrogen Sulfide (H2S) concentration in the sales contract has a limit of .25 grains/100 SCF.

Plan

Proceed with above actions to prevent loss of revenue should the H2S concentration at sales points cause purchasers to refuse delivery of contracted gas sales volumes.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	60	0	0	0	0	0	0
Schedule							
Start	1Q						
Complete	4Q						

SAR I - 35R (DEVELOPMENT FACILITIES) RELOCATE 35R BLDGS

PROJECT P46256
PROJECT 46256P

The correction of safety related discrepancies identified in the 35R Gas Plant SAR (completed FY 86) is to be accomplished from FY 89 through FY 90.

Background

The FY 86 35R Gas Plant SAR generated 281 safety related line items that required corrective action. One hundred and sixty-two (162) items have been corrected and/or resolved. Fire protection items are covered under Fire Protection Modification Project.

These discrepancies are identified in the 35R Gas Plant SAR report and relate to ASME, OSHA, API, NFPA, California Code of Regulations, good safety engineering practice, etc. The two year period was viewed as the maximum time period under which correction of safety related items could be completed without imposing undue risk.

Applicable Statutes/Regulations/DOE Orders

API, NFPA, CCR, OSHA, etc.; DOE Orders 5480.4, 5480.7, 5480.10, 5481.1B, and 6430.1; 1949 UBC/1988 UBC.

Recommendation

This project will have a number of AFE's submitted to correct these deficiences.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	348	500	540	0	0	0	0
	0	191	0	0	0	0	0
Schedule							
Start	2Q						
Complete			4Q				

SAR II (DEVELOPMENT FACILITIES)

PROJECT P48111X

The correction of safety related discrepancies identified in the SAR of LTS-1, LTS-2, HPI and associated Truck Loading Rack is to be accomplished from FY 89 through FY 90.

Background

The FY 87 SAR of LTS-1, LTS-2, HPI identified 256 safety related line items that required corrective action. One hundred and twenty- four (124) items have been corrected and/or resolved. Fire protection items are covered under the Fire Protection Modification Project.

These discrepancies are identified in the formal SAR Report and relate to violations/inconsistencies with API recommendations, NFPA, California Code of Regulations, etc. The three year period is viewed as the maximum time period under which correction of safety related items could be completed in a cost effective manner without imposing undue risk.

Applicable Statutes/Regulations/DOE Orders
CCR, API, NFPA, OSHA; DOE Orders 5480.4, 5480.7, 5480.10, 5481.1B, and 6430.1

Plan
Implement recommended corrective action as described in SAR. This project will have a number of AFE's submitted to identify actions necessary to meet requirements.

Cost/Schedule ($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	330	0	0	0	0	0	0
Schedule							
Start							
Complete		4Q					

SAR III - 30R/33S (DEVELOPMENT FACILITIES) PROJECT P49110

This project will provide funding for follow-up activities for SAR III adjusted to exclude the 3G Gas Plant, where the follow-up activities were completed in March 1987.

Background
SAR III was completed in March 1987. It consisted of a safety analysis and review of the 3G Gas Plant, 33S Compressor Stations, 30R Compressor Station and related field facilities. Since completion of SAR III, a decision has been made to demolish the 3G Gas Plant. Funding for 3G is provided by separate project.

It has been determined that the findings generated from SAR III will require approximately $384,000. The cost will be split according to Development Facilities and Operations and Maintenance.

Applicable Statutes/Regulations/DOE Orders
API, NFPA, CCR, OSHA, etc.; DOE Orders 5480.4, 5480.7, 5480.10, 5481.1B and 6430.1, etc.

Plan
Implement all recommendations and corrective action from SAR III.

Cost/Schedule ($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	192	0	0	0	0	0	0
Schedule							
Start	1Q						
Complete	4Q						

ASBESTOS ABATEMENT (EXCLUDING 35R GAS PLANT) (OPERATIONS & MAINTENANCE FUND 111) PROJECT P49003

The project is to remove and replace asbestos-containing materials as appropriate, exclusive of the 35R Gas Plant. Due to the amount of asbestos-containing insulation in the 35R Gas Plant, a separate additional project has been proposed.

Background
Much construction occurred at NPR-1 prior to 1970, and asbestos- containing materials were used in buildings, on piping and vessels, and in other applications. Surveys are underway to identify areas with friable exposed asbestos as well as operations where asbestos-containing materials are likely to be disturbed. In FY 87 asbestos-containing materials were found during the 36S Administration Building demolition, at a well site south of the 3G Gas Plant, on a pipeline from 23S to 25S, and during several pipe gasket removal operations. In FY 88, asbestos-containing wrapping materials have been found at many locations on NPR-1. We expect to encounter similar circumstances in the future. Any necessary cleanup, maintenance or demolition activity will require costly special procedures.

The removal and replacement of certain asbestos-containing materials may result in major expenditures during the period through FY 92, resulting in elimination of the problem. Interim controls such as special work procedures, special equipment, and engineering controls including encapsulation would require substantial expenditures, but would not permanently eliminate the problem. We believe that essentially all asbestos on NPR-1 will be identified by FY 90.

Economic Analysis
This project is a safety related project. Cal-OSHA's Consultation Division (Occupational Cancer Control

Unit) indicated that loose and crumbly asbestos shall be considered as asbestos spill and any such condition must be corrected. In addition, California Assembly Bill 2040 imposes stricter requirements. The current presence of loose, exposed, crumbly asbestos provides an unsafe working condition. Unit Operator, therefore, proposes a remedial work program of encapsulation.

Applicable Statutes/Regulations/DOE Orders
Asbestos Regulations, OSHA 1910.1001, National Emission Standard for Hazardous Air Pollutants (NESHAP).

Plan
The most cost-effective long term solution regarding friable and exposed asbestos-containing materials as well as intact asbestos materials which may be disturbed is the removal and replacement of such materials. To limit costs, these activities would be coordinated as possible, with other maintenance, building renovation activities. Estimated cost is $920,000. Schedule - begin removal in FY 90 and complete in FY 92.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	103	353	0	0	0	0
Schedule							
Start	1Q						
Complete				4Q			

ENVIRONMENTAL TRIGGER

PROJECT P40201

Background
On June 1, 1987, the Kern County Air Pollution Control Board (KCAPCB) adopted Rule 427 - "Emissions from Stationary Internal Combustion Engines" which includes a "trigger" mechanism for the implementation of I.C. engine NOx controls in Western Kern County. This rule shall become effective in Western Kern County only upon a finding by the KCAPCB that four or more separate validated exceedances of the ozone National Ambient Air Quality Standards (NAAQS) of 0.12 ppm have occurred between January 1, 1988 and December 31, 1990. The following engines would be required to be modified within 15 months of this finding:

(1) rich-burn engines greater than 200 hp would be required to achieve an 80% NOx reduction or 90 ppm by volume on a dry basis corrected to 15% exhaust oxygen;

(2) lean-burn engines greater than 500 hp would be required to achieve a 70% NOx reduction or 150 ppm by volume on a dry basis corrected to 15% exhaust oxygen or 2 gm/bph-hr for existing engines controlled exclusively by combustion modi fications.

The remaining rich-burn and lean-burn engines greater than 50 hp would be required to achieve compliance with the above standard by December 31, 1995.

Five validated ozone exceedances have occurred in 1988. Based on this information, we anticipate the implementation of Kern County Rule 427 on 4/18/89.

Applicable Statutes/Regulations/DOE Orders
KCAPCD Rule 427, DOE Order 5400.1

Plan
If trigger is implemented, an attempt will be made to use available offsets in lieu of installation of NOx control technologies. Recent Clean Air Act legislation may not allow the utilization of this approach. Should this approach be unworkable, modification of internal combustion engines may require future funding as indicated on Table 1. (A conservative estimate of $3.2 million would be required within 15 months of the trigger with an additional $6 million needed by 1995.)

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	3200	1070	2200	1125	1150	1165
Schedule							
Start		1Q					
Complete							4Q

NPR-1 ACCESS - GATES 2, 3 AND 4

PROJECT P49109
PROJECT P48882

This project is for improving vehicle access to NPR-1 at Gates 2, 3, and 4.

Background
This project is to provide improved and safer NPR-1 access at Gates 2, 3, and 4. Both intersections are situated on two-lane highways traveled at high speed which makes ingress and egress hazardous. Gate 4 is also the primary arrival and departure point of about

80 LPG tanker trucks per day as well as all trucks required to be weighed at the scalehouse. In addition, both intersections are subject to Tule fog which severely limits visibility.

The project provides for:

Gate 2 Access (Highway 119) Improvements:

- Widening the existing highway.
- Replace the existing shoulders with traffic lanes.
- Add new shoulders.
- Repaint road surface to provide left turn channelization for eastbound (op tional for westbound) traffic and right turn channelization for westbound traffic.

Gate 3 and 4 Access (Elk Hills at Skyline Rd) Improvements:

- Widen the existing shoulders
- Add acceleration lanes for both north and south bound access to Elk Hills Road
- Add deceleration lanes for both north and south bound access to Skyline Road
- Repaint road surface to provide proper channelization of traffic
- Provide traffic control lights

All tasks are to be accomplished in accordance with the Caltrans Highway Design Manual.

Plan

Proceed with this project so as to enhance turn movements into NPR-1 and reduce the potential for traffic accidents at these intersections.

Cost/Schedule
($000)

Cost Est.	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Gate 2	500	0	0	0	0	0	0
Gate 3 & 4	600	0	0	0	0	0	0
Schedule							
Start	2Q						
Complete		1Q					

RADIO COMMUNICATION UPGRADE

PROJECT P41102

Background

The NPR-1 communication system needs to be studied to determine if it meets the needs of NPR-1, and to develop alternate solutions to any deficiencies. Due to the terrain there are numerous "dead spots" where radio reception between some locations is virtually impossible.

Also, the Communications Center may need improvements in equipment to help the single operator respond to the response team's needs in an efficient manner.

Applicable Statutes/Regulations/DOE Orders

"Radio communications systems are not adequate to support emergency response at NPR-1" per DOE Multidiscipline Technical Safety Assurance Appraisal - NPRC September - October 1988.

Plan

Study the need modify to the communication system to eliminate "dead-spots" caused by the terrain. Multiple on-site antennas or the use of off-site antennas are two options of several to be explored.

Study the need to modify the Communication Center ("Juliette") to facilitate ease of operation during all activities, and especially during an emergency. Such modifications might include a multi-channel recording system to enable the operator to record communications for future reference.

These situations and alternative solutions will be studied and evaluated in FY 89.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	0	0	0	0	0	0	0
Schedule							
Start	1Q	4Q	1Q	1Q	1Q	1Q	1Q
Complete	4Q	4Q	4Q	4Q	4Q	4Q	4Q

CP ANODE BED REPLACEMENT

PROJECT P48724

This project provides for the replacement of 105 dead or weak groundbeds. Work to replace 45 of the groundbeds is in progress.

Background

Cathodic Protection was initiated due to excessive corrosion failures of well casings and pipelines. Maintaining the integrity of well casings is economically justified. The Unit plan calls for securing the "maximum ultimate recovery" of hydrocarbons in future years. The Unit's reserve status, coupled with future anticipated advances in oil recovery techniques, dictates preservation of expensive capital plant investment such as well casings. The cathodic protection program is considered good investment in the future by the Unit Operator. This project restores cathodic protection for 400 wells. The casings are presently subjected to stray current electrolysis. Mathematical modeling of field wide cathodic protection is in progress and may reduce FY 90 requirements.

Economic Justification

Economic analysis consists of comparing two options:

Option 1 - Do nothing.

Option 2 - Extend cathodic protection to unprotected casings.

Option 1 does not require any capital investment. Instead, a number of casing failures is projected. Cost Center costs are assumed for a 10 year period since increased casing failures caused by corrosion produce major disruptive effects on production, engineering and drilling.

Option 2 requires a capital investment of $1.967 million dollars. Annual operating costs include those of Cathodic Protection Cost Center, electricity and equipment maintenance. Costs are inflated at 2% and discounted at 12%. The cash flow results in a payout of 5 years. A basis of 10 years is used because it is the minimum design life of new groundbeds.

Plan

Expand cathodic protection to include 400 wells not presently under protection.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	867	569	588	0	0	0	0
Schedule							
Start	1Q	1Q	1Q				
Complete	4Q	4Q	4Q				

GAS OPERATIONS EXPANSION PROJECT

Project 49346

This project is to sustain continued production of hydrocarbons from NPR-1 by the construction of an additional gas processing plant. The project will increase gas processing capacity by 100 million standard cubic feet per day (MMSCFD).

Background

Since 1976, natural gas production has steadily increased to the point that current NPR-1 processing facilities do not have the capacity to process all the natural gas produced while achieving MER. Current production strategies have achieved MER in the larger reservoirs at NPR-1 primarily through gas injection for pressure maintenance. Other reservoirs have been produced with extensive controls on the amount of gas produced. The remaining gas in some of these reservoirs, therefore, is quite large. Combined natural gas reserves in three of these reservoirs - the "29R", "31S C/D Shales", and "31S N/A Shales" - approach one trillion cubic feet. These reservoirs are at a stage of depletion in which it will be necessary to produce and process increasingly larger amounts of natural gas to achieve MER. Estimated remaining gas reserves at NPR-1 are over 1.5 trillion cubic feet. These large reserves have a tremendous market potential in the vicinity of NPR-1, as do natural gas liquids.

Existing gas processing facilities at NPR-1 have a combined design throughput of 294 MMSCFD, and are capable of handling up to 320 MMSCFD. Production of gas in the Summer of 1988 frequently required that some wells be shut in, with the resulting loss of crude oil, natural gas, and natural gas liquids. This project will provide facilities to handle current gas processing needs, and provide for additional gas handling, including compression and injection. The plant is designed to utilize refrigeration to condense natural gas liquids from the inlet stream. These liquids will be separated into propane, butanes, and natural gasoline prior to sales; residual gas will be injected for pressure maintenance and additional hydrocarbon recovery. Maximum recovery can be attained by cycling the gas to strip liquids from the reservoirs.

Economic Analysis

Strategies for production at MER will require gas production for processing and injection. Therefore, the estimated economic benefit of this project is based solely on producing an additional 100 MMSCFD for injection. The revenues generated as a result of this will be from sales of additional crude oil produced with this gas and the propane, butanes and natural gasoline processed from it. The inherent assumptions in this analysis are as follows:

1. Incremental oil production would be 4,000 BOPD, decreasing at a rate of 20% per year for a period of 15 years.

2. OMB-provided prices for oil and natural gas liquids, adjusted for the local market.

3. Capital costs of $80 Million.

4. Operating costs based on current costs for an identical plant, escalating at 5.5% per year.

NPV at 10%	$503,000,000
Payout	1.33 years

The design uses a financial scenario that assumes all residue gas will be injected for pressure maintenance and recovery of natural gas liquids. Should reservoir engineering studies determine that optimum MER strategies dictate the relaxation of reservoir pressure requirements, substantial additional quantities of gas could be sold. Under that situation, Government revenues would climb significantly and the NPV of the project could be well in excess of $1 billion.

For 100% residue sales, the NPV of this project may reach $1.663 billion, with a discounted payout period of 6 months and an internal rate of return of 209%.

Plan

A conceptual design report for this project has been submitted to the Office of Project and Facilities Management of DOE for evaluation prior to budget submittal. If the project is approved for FY 91 budget submittal, preliminary engineering should start in FY 90. A proposed plant site and plant layout are shown in Figure 3.10 and 3.11.

Cost/Schedule
($1000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93
Estimate	*80	*1,700	7,260	71,740	1,000
Schedule					
Start	1Q	1Q	1Q		
Complet	1Q	4Q			2Q

*Design in FY 89 and FY 90 will be funded out of Unit operating funds, Cost Center 90520.

MISCELLANEOUS UNSCHEDULED ENVIRONMENTAL PROJECTS (OPERATIONS & MAINTENANCE FUND 111 AND DEVELOPMENT FACILITIES FUND 114)

Project involves the NPR-1 actions necessary to meet new requirements of environmental legislation and/or rules or regulations for waste, water, air or other environmental areas.

Background

New environmental legislation is frequently passed by Congress the State of California or local government which requires additional expenditures of funds to bring NPR-1 into compliance or to address new requirements. Additional environmental rules and regulations are passed by various agencies and local governments on the federal, state and local level which also causes additional expenditures of funds. We expect this will continue in the future.

Applicable Statutes/Regulations/DOE Orders

Clean Air Act and implementing regulations; Clean Water Act and implementing regulations; Resource Conservation and Recovery Act (RCRA), CERCLA, Titles 14, 22 & 23 CCR, California Water Code, California Health and Safety Code, California Natural Resource Code, Safe Drinking Water Act and implementing regulations, new state and federal laws

Plan

While the costs are unknown for future environmental legislation, rules and regulations, past experience shows that expected costs could be as much as the following.

Cost/Schedule
($000)

	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Fund 111	654	207	537	1325	1244	1265	1588
Fund 114	0	200	210	220	230	230	230
Total	654	407	747	1545	1474	1495	1518
Schedule							
Start	1Q	1Q	1Q	1Q	1Q	1Q	1Q
Complete	4Q	4Q	4Q	4Q	4Q	4Q	4Q

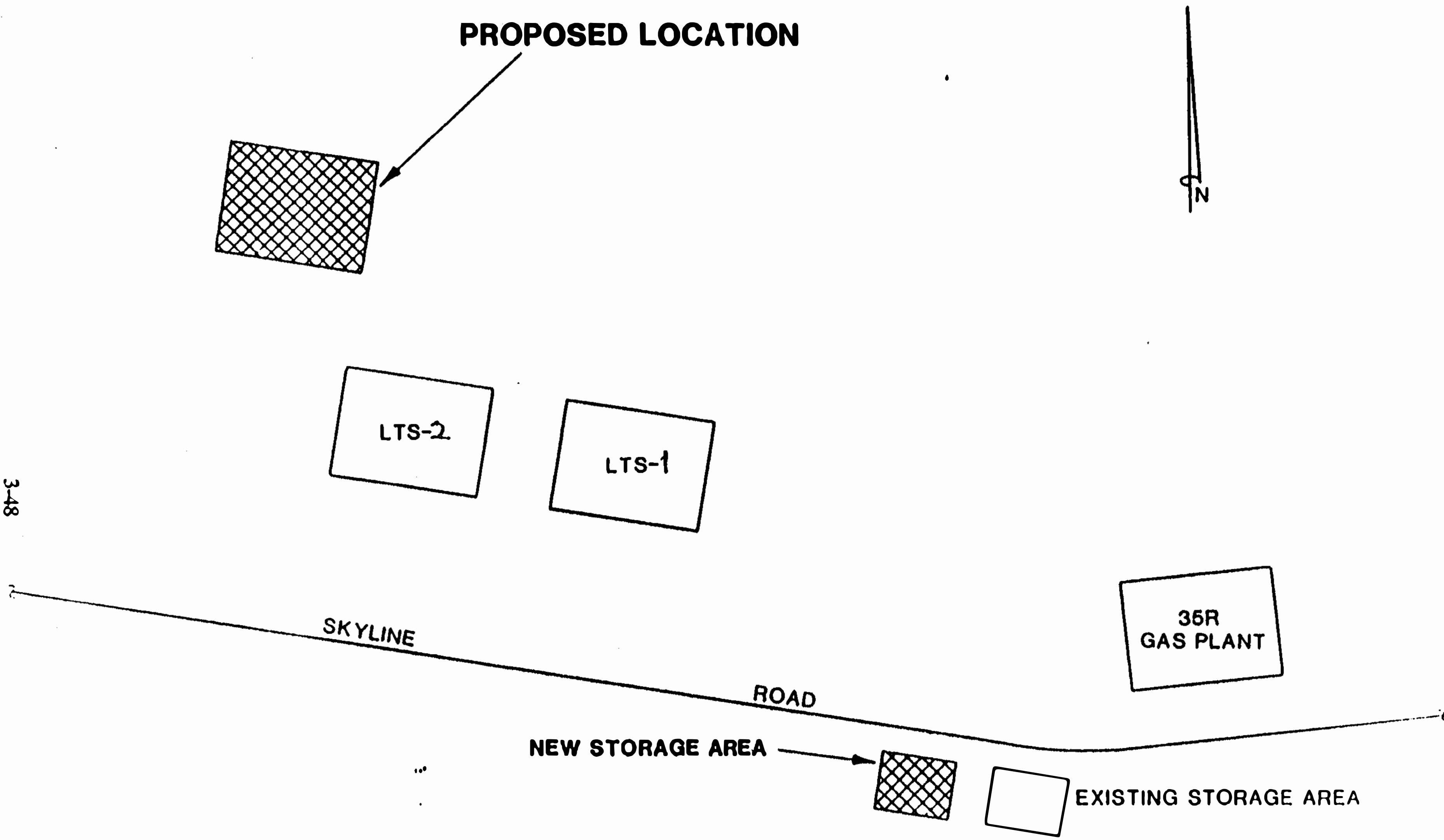


Figure 3.10

GAS OPERATIONS EXPANSION PROJECT

PROPOSED GAS PLANT LOCATION IN 35R COMPLEX

GAS OPERATIONS EXPANSION PROJECT

CONCEPTUAL SITE PLAN FOR NEW GAS PLANT

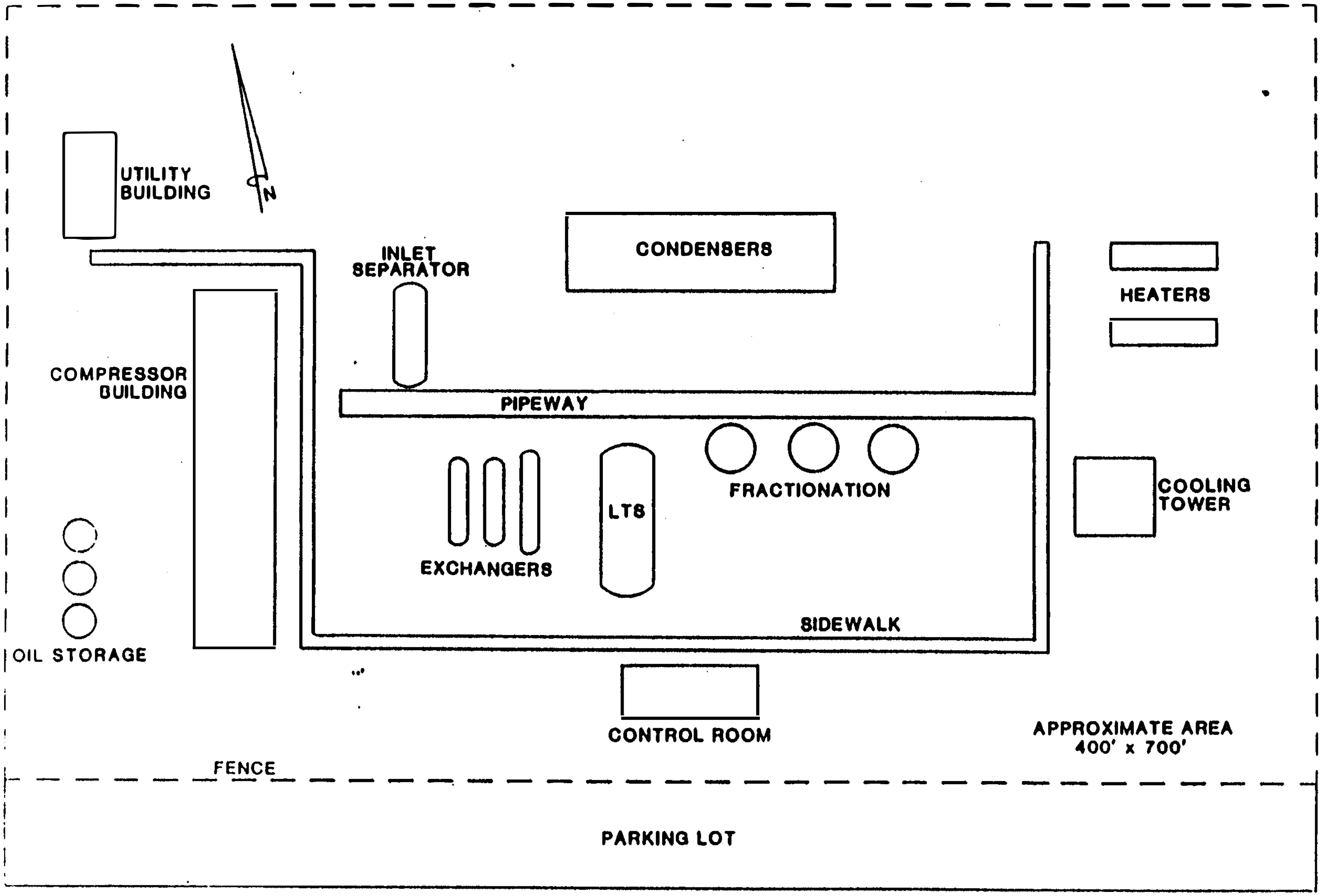


Figure 3.11

MISCELLANEOUS SAFETY PROJECTS (OPERATIONS & MAINTENANCE FUND 111 AND FACILITIES DEVELOPMENT FUND 114)

Background
Certain safety deficiencies and problems which are identified during inspections, audits and appraisals must be expeditiously corrected through operational, maintenance or engineering methods. In addition, future legislation and regulations will probably establish additional requirements for the NPR-1 safety program. Funding is required to address anticipated safety related projects for years FY 89* through FY 95.

Applicable Statutes/Regulations/DOE Orders
Compliance with API, NFPA, CCR, OSHA; DOE Orders 5480.4, 5480.7, 5480.10; etc.

Plan
Provide funds for miscellaneous safety projects that may be required due to new legislation; for correction of OSHA type deficiencies.

The objective is to correct safety problems and deficiencies discovered either by safety inspections, unusual occurrences or accidents/injuries in order to provide a safe working environment at NPR-1.

Cost/Schedule
($000)

Cost Est.	FY 89*	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Fund 111		0	110	110	110	110	120
Fund 114		200	210	220	230	230	230
Total		200	320	320	340	340	350
Schedule							
Start		1Q	1Q	1Q	1Q	1Q	1Q
Complete		4Q	4Q	4Q	4Q	4Q	4Q

* ALL PROJECTS IDENTIFIED IN FY 89 ARE TO BE FUNDED THROUGH MUPS.

FACILITIES ENGINEERING MISCELLANEOUS UNSCHEDULED PROJECTS

Additions, modifications and repairs to facilities are required each year due to unscheduled occurrences to maintain or increase production, and/or lower operating costs. Because these projects result from unscheduled occurrences, they cannot be defined but they can be anticipated.

Background
Deficiencies and problems are identified by operating personnel and others during inspections or by changes in production or injection rates which require modifications or additions to facilities to maintain or increase production or lower operating costs.

Plan
While the exact requirements for unplanned occurrences cannot be defined at this time, NPR-1 should expect to expend funds at the level indicated below.

Cost/Schedule
($000)

Cost	FY 89	FY 90	FY 91	FY 92	FY 93	FY 94	FY 95
Estimate	1564	2868	2780	3300	3370	3430	3500

NATURAL GAS LIQUIDS (NGL) SYSTEM

The Natural Gas Liquids (NGL) System is intended to transfer, store, deliver and account for the 560,000 gallons per day of natural gas liquids (NGL) products produced at NPR-1. The products are propane (C3), mixed-butane (C4 mix), natural gasoline (C5+) and heavy condensate (addressed elsewhere). (Refer to Figure 3.12.)

The products are recovered from gas (vapor) streams processed through the processing plants' "recovery" section; then distilled through the "fractionation" section; transferred to storage tanks, and delivered to CUSA (as equity) and DOE contractors through a tanker truck loading facility.

Product fractions are pumped (C3 and C4 mix) or transferred by pressure difference (C5+) from accumulation vessels within the boundary of the processing plants through dedicated 3" and 4" steel pipelines to horizontal "bullet-type" vessels located outside the plant boundaries. These vessels are filled and emptied individually to allow for periodic quality checks.

Product delivery is accomplished at truck loading stations (islands) in the 35R Gas Complex by pumping the product at 600 gallons per minute from the storage vessel to the loading islands into customer's bottom-loading pressure tankers. Vapors, resulting from "phase" changes (liquid-to-vapor) are transported by pressure differential from the tanker trucks back to the vacuum vapor system. (See Figure 3.16.) Vapors from all storage tanks are then commingled and returned to the vacuum gas inlet system at the gas plants to be recycled. This return is accomplished by pressure differential as opposed to pumping or compression. Approximately 80 tanker trucks are loaded each day.

A liquid product re-run or recycle system is in place in the event it becomes necessary to return product to the plant from the storage vessels for reprocessing. The re-run system pumps liquid product at 20 gallons per minute from its storage vessel to the fractionating tower inlet specific to that product. (See Figures 3.13, 3.14 and 3.15.)

A product odorizing system adds a mercaptan odorant to the product at the time of delivery. The odorant is transferred from its storage vessel to the desired loading island by pressure differential where it is commingled with the product as tanker loading takes place. The addition of odorant is dependent upon the ultimate destination of the product and is designated by the customer at the time of delivery. (See Figure 3.17).

A transfer system is in-place to move product from one storage facility (old 35R) to the primary storage facility. This is a one-way system, in that product can be pumped only from the old facility to the new.

All NGL product is delivered by weight at NPR-1. This weigh/scale operation is accomplished by the scale-house facility located adjacent to the loading facility. Customer tanker trucks are weighed in empty and weighed out full.

Product accounting is accomplished by reconciling storage vessel gauge readings, recorded by an Operator (Loader), in-line flow meter readings and delivered quantities. A calculation is performed, taking into account the product's specific gravity and temperature relative to the tanker's weight differential per ASME standards and actual gallonage.

Storage facilities, both old and new, are capable of approximately 3 days holding of all plant production ("make"), assuming no deliveries. The loading facility ("rack") has serviced as many as 100 tanker trucks in a single 24-hour period.

Based on the loading rack's configuration, it is anticipated that 200 tankers per day could be serviced. If each tanker held 8,500 gallons, then 1.7 million gallons per day could be delivered. A review of the forecasted NGL production through 1995 indicates a peak of 865,500 gallons per day. Even if significantly larger volumes of natural gas are produced and processed, therefore, it is not anticipated that the NGL system will be impacted and current facilities will be more than adequate through 1995.

PROPANE (C3) See Figure 3.13

Propane vapors pass from the depropanizer column overheads through a condenser. Liquid propane from the condenser then flows into the propane reflux accumulator. The liquid at this point is considered to be a saleable product.

The propane product then flows to the suction of one of two centrifugal pumps at a nominal pressure of 290 psi. The pump discharges the product propane at a nominal pressure of 330 psi at a rate of 560 gallons per minute.

The product stream splits at the pump discharge. The greatest portion of the stream feeds to the top of the depropanizer tower through a temperature control valve and acts as reflux for distillation within the tower. The balance flows through 4" piping to and from a single pass shell-and-tube cooler. From the product cooler the propane flows through 4" piping out of the plant, commingles with propane from both other plants and flows into one of ten propane storage vessels.

MIXED BUTANE (C4 Mix) See Figure 3.14

Mixed butane vapors pass from the debutanizer column overheads through a condenser. Liquid butane from the condenser then flows into the butane reflux accumulator. The liquid at this point is considered to be a saleable product.

The mixed butane product then flows to the suction of one of two centrifugal pumps at a nominal pressure of 85 psi. The pump discharges the product propane at a nominal pressure of 125 psi at a rate of 240 gallons per minute.

The product stream splits at the pump discharge. The greatest portion of the stream feeds to the top of the debutanizer tower through a temperature control valve and acts as reflux for distillation within the tower. The balance flows through 4" piping to and from a single pass shell-and-tube cooler. From the product cooler the butane flows through 3" piping out of the plant, commingles with butane from both other plants and flows into one of six butane storage vessels.

NATURAL GASOLINE (C5+) See Figure 3.15

The final fraction of distillation is natural gasoline (C5+). This product originates from the debutanizer column. Prior to being transferred to storage, it is utilized as a heat exchange medium in the glycol system within the LTS Plants. It goes directly to storage from the debutanizer column reboiler at the 35R LOAP. In both cases its transfer is accomplished by pressure differential.

Natural gasoline feeds from the debutanizercolumn to the column's reboiler. From the reboiler, the product is transferred through 3" pipelines at a nominal 100 psig through a single pass shell-and-tube cooler, commingles C5+ product from both other plants, and into one of four storage vessels.

Initial design criteria for the LTS Plants sized in-plant transfer systems to accommodate a maximum output of 460,000 gallons per day each, of total product during maximum production periods. Each plant was expected to produce nominal volumes of 230,000 GPD of propane, 141,000 GPD of mixed butane and 88,000 GPD of natural gasoline. The expectations were based on ± 5 gallons per thousand cubic feet of liquid in the process gas at -30°F recovery temperature.

The total production of 35R LOAP has historically been approximately 175,000 GPD. This is based on 92 MMSCFD throughput of process gas. Recovery has peaked at a nominal 1.9 GPM. This represents an average of 75,000 GPD of propane, 60,000 GPD of mixed butanes and 40,000 GPD of natural gasoline. Product transfer lines are all 2" and are adequate for these volumes.

No additions or modifications to this subsystem are anticipated through 1995.

PRODUCT STORAGE

All product is stored in pressure vessels located in two separate areas of Section 35R. The primary storage facility is located south of Skyline Road and was commissionedin 1979. A secondary facility is located north of Skyline Road, behind the 35R LOAP and was constructed in 1952. It was mothballed until 1976. Both facilities are capable of receiving product from all process plants. Operationally, however, the oldest storage area is used as spare capacity.

A system for transferring product from the old storage area to the new is in place. Each product is pumped from the old storage vessels into the product stream flowing to the new storage vessels. This system is one-way only, from old to new.

Total storage capacity is equivalent to approximately 75 hours of product from all process plants at peak production. Table 3.1 tabulates the capacities by product and location.

TABLE 3.1

NGL PRODUCT STORAGE CAPACITY

PRODUCT	NUMBER OF VESSELS	NAMEPLATE CAPACITY (GALLONS)	ALLOWABLE FOR VAPOR SPACE (%)	OPERATIONAL CAPACITY (GALLONS)	TOTAL OPERATIONAL CAPACITY (GAL)
LTS STORAGE					
PROPANE	10	90,000 EA	13.5	77,850	778,500
MIXED BUTANE	6	90,000 EA	13.5	77,850	467,100
NAT GASOLINE	4	90,000 EA	13.5	77,850	311,400
SUBTOTAL	20				1,557,000
35R STORAGE					
PROPANE	5	30,000 EA	13.5	25,950	129,750
MIXED BUTANE	6	30,000 EA	13.5	25,950	155,700
NAT GASOLINE	2	60,000 EA	13.5	51.900	103.800
SUBTOTAL	13				389,250
EMERGENCY STORAGE					
MIXED BUTANE	1	120,000EA	13.5	103800	103,800
MIXED BUTANE OR NATURAL GASOLINE	2	90,000 EA	13.5	77,850	155.700
SUBTOTAL					259.500
GRAND TOTAL	36				2,205,750

SCHEMATIC NGL 1

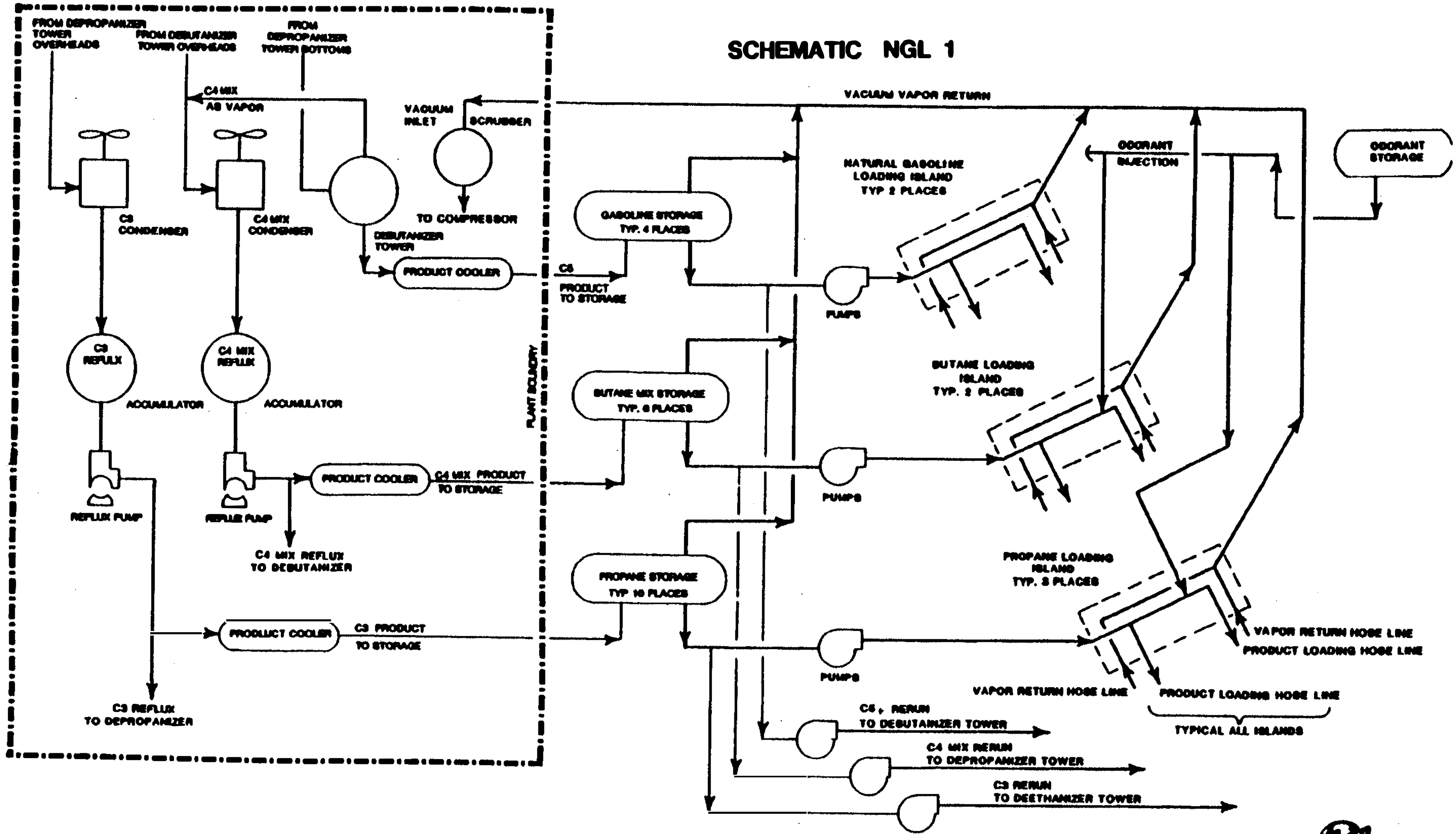
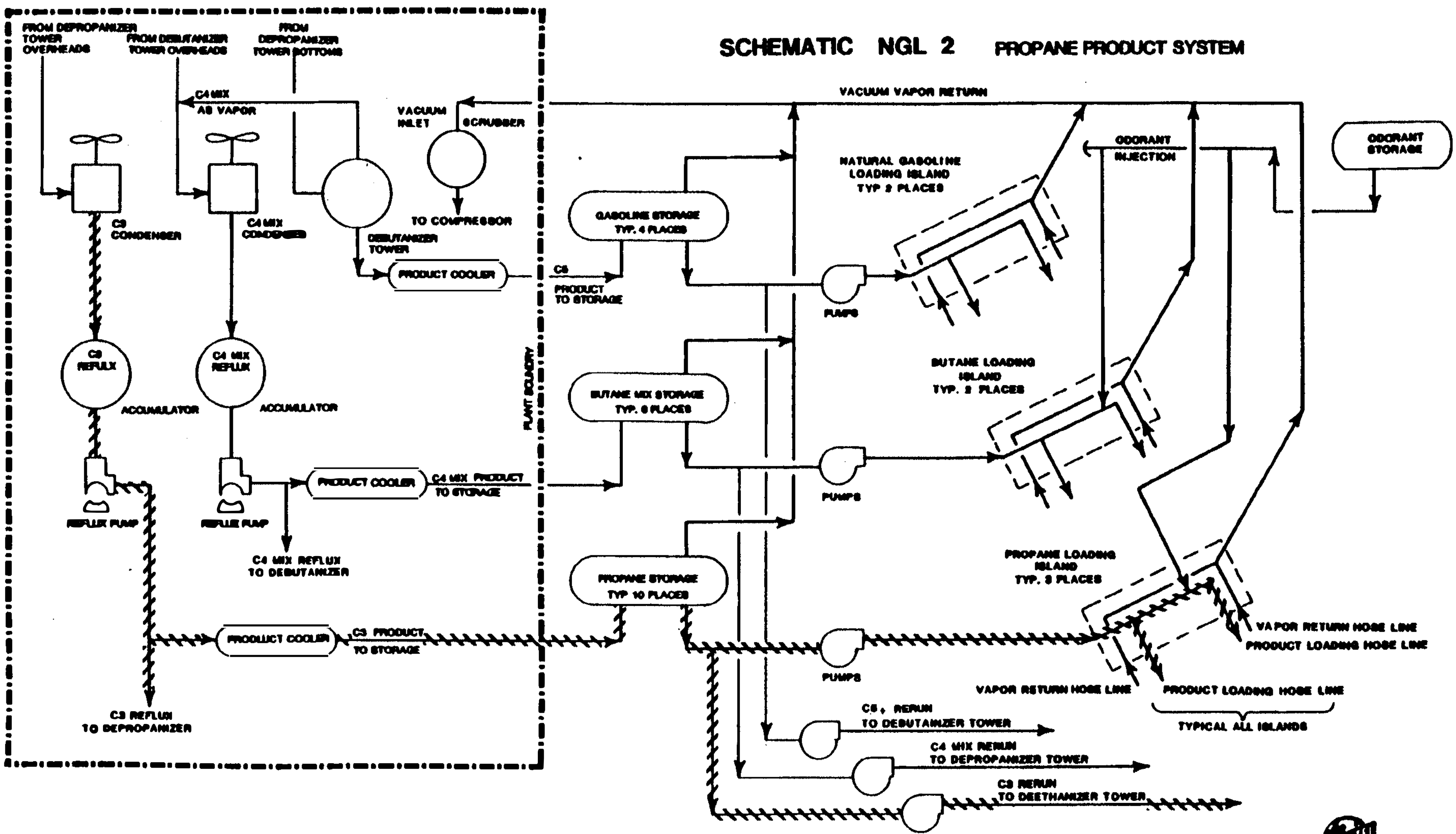


Figure 3.12


SCHEMATIC NGL 2 PROPANE PRODUCT SYSTEM
FROM DEPROPANIZER TOWER OVERHEADS
FROM DEBUTANIZER TOWER OVERHEADS
FROM DEPROPANIZER TOWER BOTTOMS
C4 MIX AS VAPOR
VACUUM INLET
SCRUBBER
TO COMPRESSOR
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PRODUCT COOLER
C3 PRODUCT TO STORAGE
C3 REFLUX TO DEPROPANIZER
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VACUUM VAPOR RETURN
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BUTANE MIX STORAGE TYP. 6 PLACES
PROPANE STORAGE TYP 10 PLACES
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NATURAL GASOLINE LOADING ISLAND TYP 2 PLACES
BUTANE LOADING ISLAND TYP. 2 PLACES
PROPANE LOADING ISLAND TYP. 3 PLACES
ODORANT INJECTION
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VAPOR RETURN HOSE LINE
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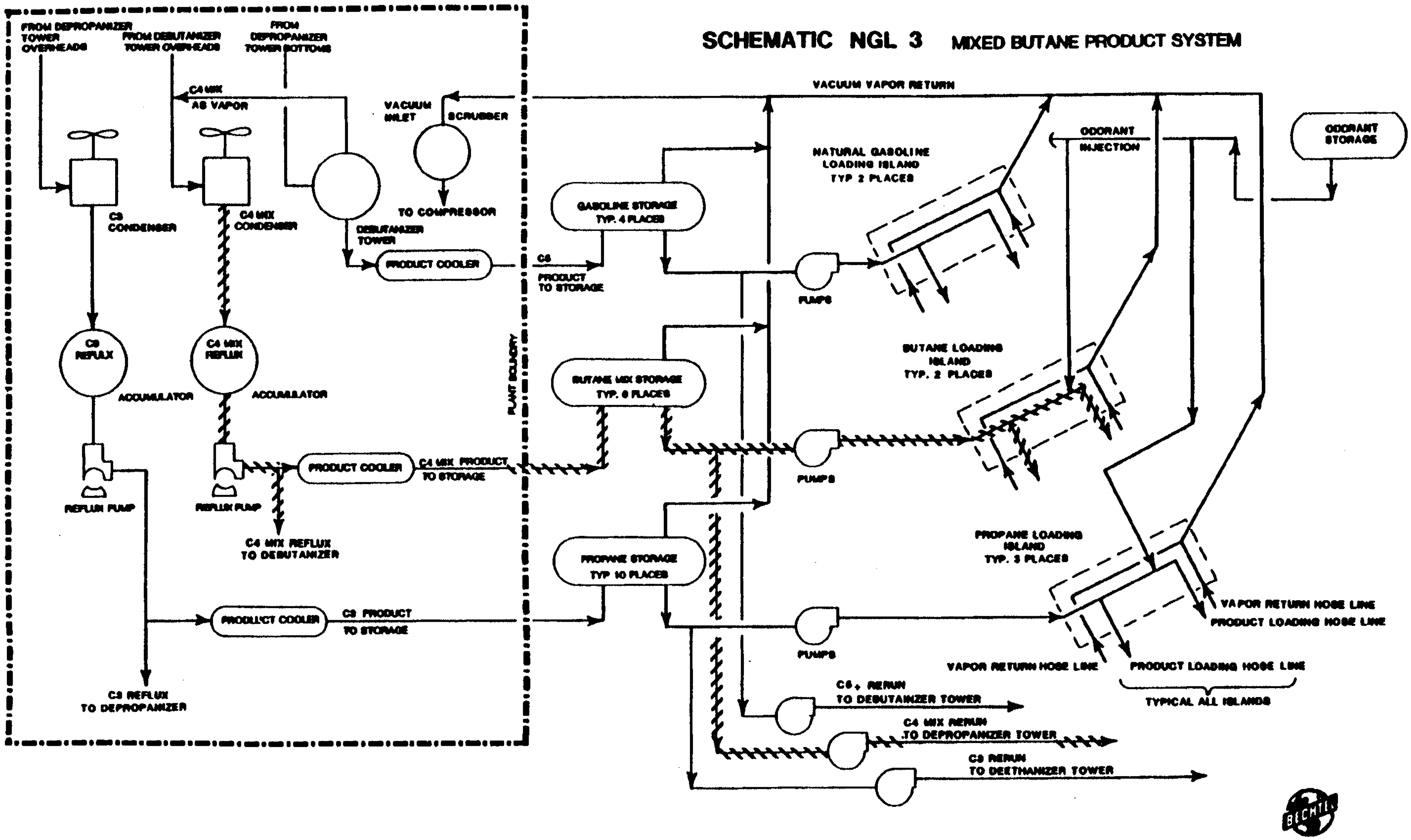
TYPICAL ALL ISLANDS
C5+ RERUN TO DEBUTANIZER TOWER
C4 MIX RERUN TO DEPROPANIZER TOWER
C3 RERUN TO DEETHANIZER TOWER

Figure 3.13


SCHEMATIC NGL 3 MIXED BUTANE PRODUCT SYSTEM
FROM DEPROPANIZER TOWER OVERHEADS
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C4 MIX AS VAPOR
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C5+ RERUN TO DEBUTANIZER TOWER
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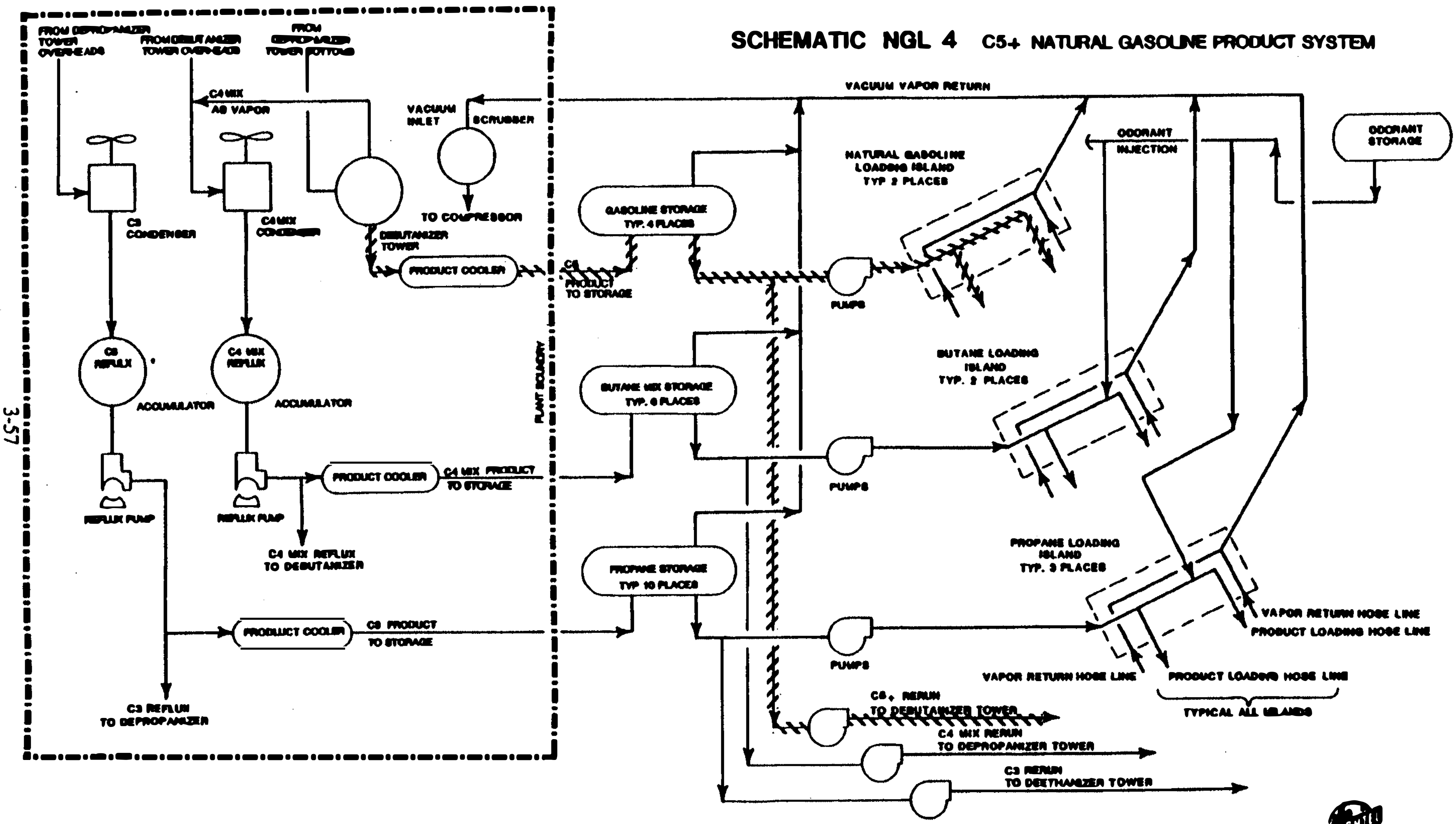

SCHEMATIC NGL 4 C5+ NATURAL GASOLINE PRODUCT SYSTEM
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VAPOR RETURN HOSE LINE
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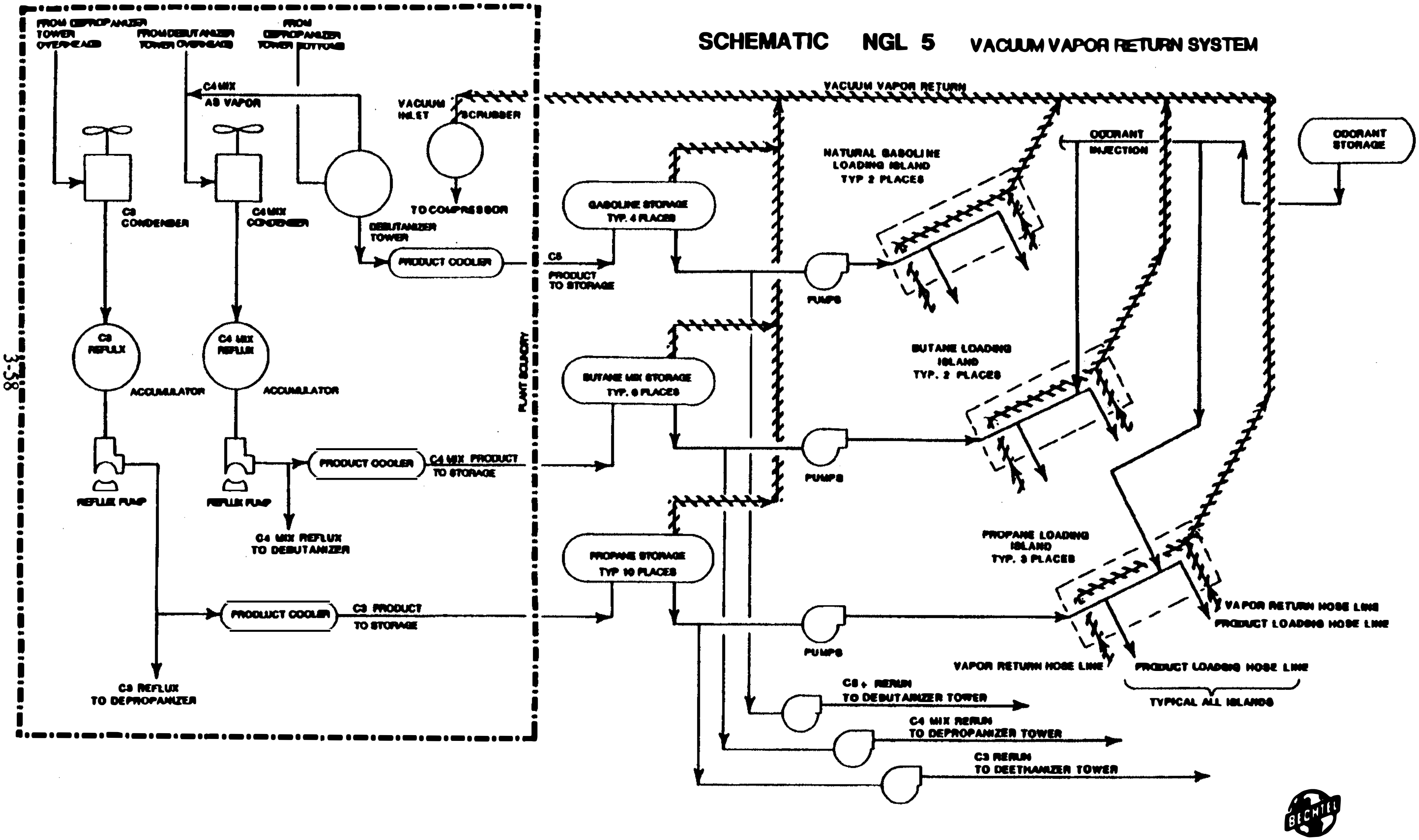
TYPICAL ALL ISLANDS
C5+ RERUN TO DEBUTANIZER TOWER
C4 MIX RERUN TO DEPROPANIZER TOWER
C3 RERUN TO DEETHANIZER TOWER

Figure 3.15

3-38


SCHEMATIC NGL 5 VACUUM VAPOR RETURN SYSTEM
FROM DEPROPANIZER TOWER OVERHEAD
FROM DEBUTANIZER TOWER OVERHEAD
FROM DEPROPANIZER TOWER BOTTOMS
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PLANT BOUNDARY
VACUUM VAPOR RETURN
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BUTANE MIX STORAGE TYP. 6 PLACES
PROPANE STORAGE TYP 10 PLACES
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VAPOR RETURN HOSE LINE
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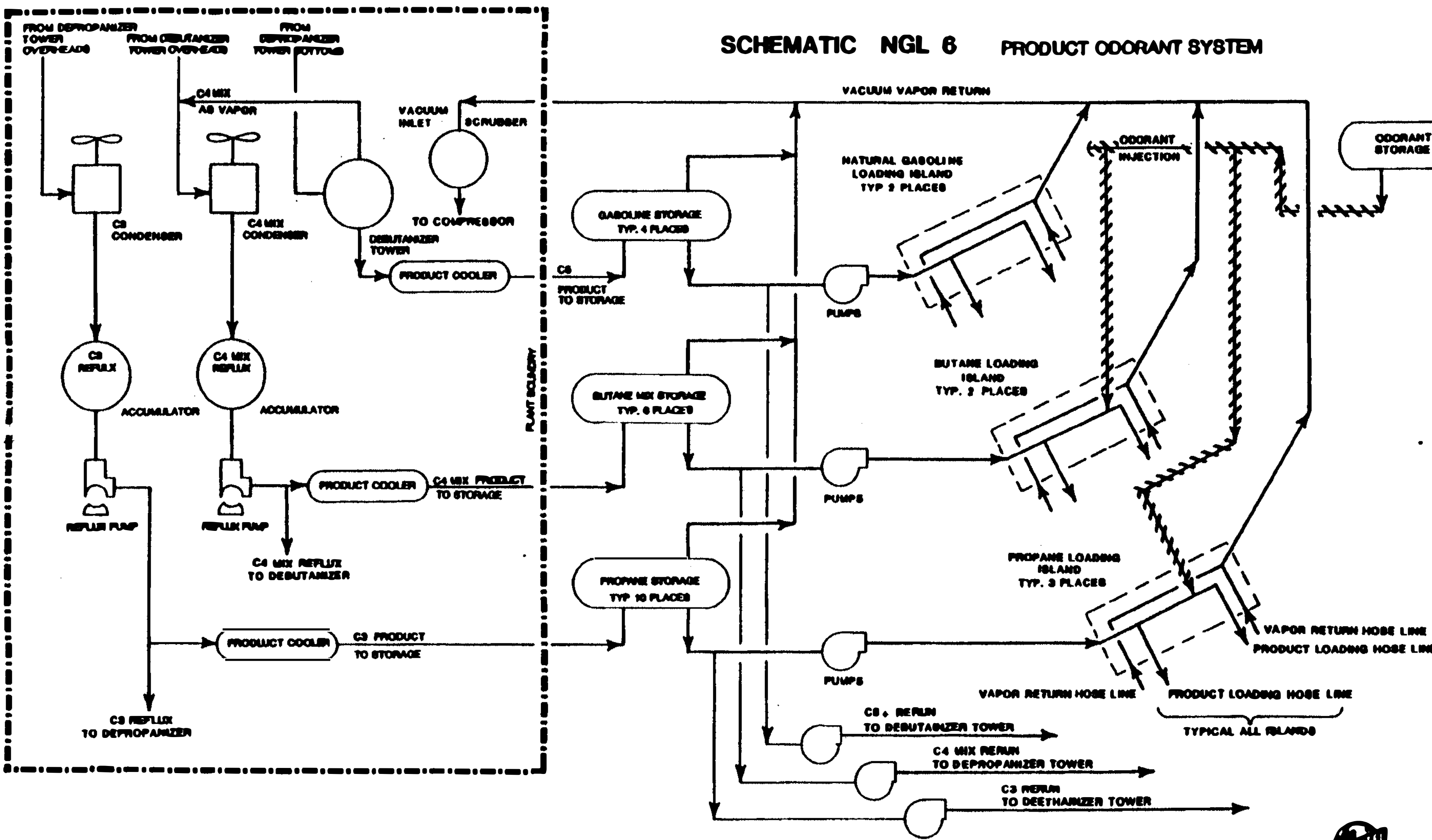
VAPOR RETURN HOSE LINE
PRODUCT LOADING HOSE LINE
TYPICAL ALL ISLANDS
C5+ RERUN TO DEBUTANIZER TOWER
C4 MIX RERUN TO DEPROPANIZER TOWER
C3 RERUN TO DEETHANIZER TOWER
BECHTEL

FIGURE 3. ..


SCHEMATIC NGL 6 PRODUCT ODORANT SYSTEM
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FROM DEPROPANIZER TOWER BOTTOMS
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VAPOR RETURN HOSE LINE
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PRODUCT LOADING HOSE LINE
TYPICAL ALL ISLANDS
C5+ RERUN TO DEBUTANIZER TOWER
C4 MIX RERUN TO DEPROPANIZER TOWER
C3 RERUN TO DEETHANIZER TOWER

Figure 17

No additions or modifications to this subsystem are anticipated through 1995.

PRODUCT LOADING - See Figures 3.13, 3.14 and 3.15

NGL products are delivered/loaded at the loading rack in Section 35R, commissioned in 1979. Additionally, the loading rack behind the 35R LOAP commissioned in 1952, although not utilized at present, can be placed in service should the need arise.

The facilities include, for both racks, four propane, three mixed butane and three natural gasoline loading islands. Product delivery pumps direct liquids from the storage vessels to the islands at a rate of 600 GPM at the new facility, and 250 GPM at the old facility. Each island is equipped with hardware to enable the loading of the truck tanker and trailer tanker simultaneously.

The potential loading capacity of the seven islands at the newest facility is 5.1 MM gallons total product per day. This assumes pumps operating 51 minutes per hour at rated output to all seven islands. The potential loading capacity of the three islands at the old facility is 918,000 gallons total product per day.

On a product-by-product basis, the potential loading capacity is listed in Table 3.2.

TABLE 3.2
NGL LOADING CAPACITY

	New Rack	Old Rack	Total
Propane	2,203,200 GPD	306,000 GPD	2,509,200 GPD
Mixed Butane	1,468,800 GPD	306,000 GPD	1,774,800 GPD
Natural Gasoline	1,468,800 GPD	306,000 GPD	1,774,800 GPD
Total	5,140,800 GPD	918,000 GPD	6,058,800 GPD

No additions or modifications to this subsystem are anticipated through 1995.

PRODUCT ACCOUNTING

Product accounting takes place in the scalehouse facility south of Skyline Road in Section 35R. The facility consists of truck scale, microprocessor, ticket (Bill of Lading/Highway/Transfer) BOL/HTR imprinter, and scale balance.

Tankers are weighed in empty and this "tare" weight is automatically imprinted on the inserted BOL/HTR. Following loading, the tanker is weighed out. This weight is again automatically imprinted on the BOL/HTR, as well as the arithmetic difference between the full and tare weights. The Weighmaster then calculates the actual gallonage delivered, based upon the specific gravity and delivery temperature relative to the scaled weight difference. The result is then written on the BOL/HTR.

A reconciliation between gallons produced and gallons delivered is accomplished daily. The source of gallons produced is the storage vessel gaugings; and DOE copies of BOL/HTRs are the source of delivered gallons. The basic calculation is "Ending Inventory + Deliverables Beginning Inventory = Production". The target is: Production = Deliverables, $\pm 1\%$.

The Scalehouse is a 24-hour per day operation. Therefore, this operation can handle all scheduled NGL tankers. The number of tankers per day is determined by the amount of production available for delivery. The schedule is forecasted approximately one month in advance and adjustments are made when necessary.

No additions or modifications to this subsystem are anticipated through 1995.

CRITICAL PARAMETERS/RESOLUTIONS

Inplant Systems

Actual recoverable liquid content of the process gas is anticipated to remain at its historical level of approximately 1.9 gallons per thousand cubic feet. This situation results in lower than design volumes being handled by this system through 1995. Further, anticipated work field-wide through 1995 is not expected to result in volumes which would approach the design limits. Therefore, the in-plant NGL product transfer systems will be adequate in their present configuration through 1995.

Product Storage

Maximum anticipated NGL production is 707,000 gallons daily. This equates to 2.1 million gallons over a 3-day production period. Present storage is 2.2 million gallons. This assumes no deliveries will be made during the 3-day period. However, it is not anticipated that this extreme situation will occur.

Product Loading

The maximum forecasted daily sales are 707,000 GPD. As shown in Table 3.2, NGL Loading Capacity, the NGL delivery facilities have a potential capacity to deliver 6+ MMGPD. Therefore, this subsystem will be adequate through 1995.

Product Accounting

The product accounting facilities are considered adequate for the period through 1995.

Environmental and Safety/Health Concerns

Environmental - N/A

Safety/fire projects have been scheduled to deal with fire protection systems, both new and modifications to existing systems.

PROJECT DESCRIPTIONS

The following facilities project description is associated with the Natural Gas Liquids (NGL) Systems.

Project Number	Title
P41104	Butane Isomerization

BUTANE ISOMERIZATION

PROJECT P41104

This project includes the design, purchase and installation of butane isomerization facilities. The installation will include the following facilities:

- Butane isomerization unit and fractionation facilities for separation of isobutane and normal butane.
- Mixed butane feed storage.
- Electrical distribution, relief and blowdown, fuel, air supply, process water supply and other utilities.

It is anticipated that a single fractionation column will be used to recover isobutane contained in the mixed butane feed, as well as the reaction section isobutane product. The proposed mixed butanes feed rate is 4,000 BPD (168,000 GPD) based on current butane LPG sales.

Background

Currently, mixed butanes recovered in the NPR-1 gas processing facilities are marketed as LPG. The butane LPG market is depressed at this time and it is anticipated that the market for mixed butanes will continue to deteriorate due to restrictions proposed by EPA to limit butane content of gasoline. These restrictions will primarily affect normal butane demand since isobutane will continue to be in demand as a feed for production of high octane stocks needed for gasoline production.

Alternative marketing strategies for mixed butanes were investigated in a recent study. The results of this study indicated that the sales value of mixed butanes would be enhanced by marketing isobutane. Three alternatives are possible:

- Use the existing 35R Gas Plant deisobutan izer to recover about 31,000 GPD of isobutane.
- Debottleneck the existing deisobutanizer to permit recovery of about 49,000 GPD of isobutane.
- Install a butane isomerization unit to convert all the normal butane to isobutane.

The economics favor butane isomerization due to the low market value of normal butane.

Economic Justification

The cost estimate for a new butane isomerization unit is estimated to be $7 million (based on preliminary estimates from a qualified process equipment supplier). The $2 million cost estimate for offsite facilities includes provision for 1) modifying existing storage and loading facilities to accommodate the separate handling of isobutane and mixed butanes and 2) installing new facilities for electrical distribution, feed and product storage, and auxiliary process systems. Engineering and construction supervision costs are estimated at $1 million.

The payout for the project is 1.0 years, with a rate of return in excess of 1000% over a 10 year life. Net revenue is estimated at $26,110 per day.

Plan

It is recommended that funding in the amount of $10 million be budgeted for this project.

Cost/Schedule ($000)							
Cost	FY89	FY90	FY91	FY92	FY93	FY94	FY95
Estimate	0	0	2140	7490	1070	0	0
Schedule							
Start			1Q				
Complete					4Q		

WATER SYSTEMS

Discussion of the Water Systems at NPR-1 is divided into three sections, covering Produced Water, Tulare Water, and FreshWater/Fire water systems.

PRODUCED WATER SYSTEMS

In conjunction with the production of oil, large quantities of water are produced. Estimated water production during FY 89 will be in excess of 110,000 BPD. This number will continue to increase as the extensive waterflood system matures: each barrel of oil produced will be associated with a greater amount of water each year. Therefore, even if oil production remains constant, produced water will continue to increase.

The original system of produced water handling relied first on sumps, then injection into the Tulare reservoirs. A significant proportion of SOZ water production was injected into the original Stevens pilot flood area, now identified as the southeast leg of the 33S Waterflood System. This was accomplished by sending SOZ produced water to the 3G Pilot Waterflood Injection Plant. There oil and solids were removed prior to injection. The 3G Plant was retired from service with the final conversion of the last of the original pilot wells from SOZ to Tulare source water.

In all but one area, sumps are no longer utilized on a regular basis to dispose of produced water. Furthermore, the Regional Water Quality Control Board (RWQCB) may eliminate all water disposal into the Tulare Zones and surface sumps.

An extensive program is currently being developed to treat the produced water and utilize it for waterflooding, with a secondary benefit of reducing the need for sumping/injection.

STEVENS ZONE FACILITIES

Collection Lines

Approximately 80,000 BWPD produced from the Stevens water is routed through the same collection system as the Stevens oil production. It ultimately is routed to either the 18G or 24Z Dehydration Facilities discussed in detail below.

18G Water Facility/Disposal Wells

The water disposal facilities receive water from the 18G flowsplitter and dehydration facilities. Disposal facilities consist of two 10,000 barrel waste water tanks and five 300 HP electrically driven/automatically operated pumps with a combined capacity of 175,000 BWPD.

Stevens water is pumped into six disposal wells completed in the Tulare Zone. These wells are located near the 18G Facility and are as follows:

18WD-8G
71WD-18G
78WD-7G
61WD-18G
68WD-7G
48WD-7G

Water disposal into each of these wells is at, or near, capacity, and totals 54,000 BWPD.

24Z Water Facility/Disposal Wells

Water from the 24Z LACT Station is received by two 5,000 barrel tanks. A 2,000 barrel skim tank has been provided to collect minor amounts of crude oil that is skimmed from the receiving tanks.

Water is pumped from the receiving tanks by three 50 HP electrically driven/automatically operated pumps for a combined capacity of 18,000 BWPD into four disposal wells. These wells, which are completed in the Tulare Zone, are as follows:

13WD-24Z
22WD-24Z
23WD-24Z
24WD-24Z

Water disposal into each of these wells is at capacity, and totals 18,000 BWPD.

Stevens water generated at the 24Z LACT Facility is also transported to the 24Z Waterflood Facility and

APPENDIX H

PUBLIC COMMENTS

DRAFT SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT

H.1 INTRODUCTION

This section describes the efforts of the Department of Energy, Naval Petroleum Reserves in California to involve and consult individuals, agencies, and organizations during the review of the Draft Supplemental Environmental Impact Statement (DSEIS).

It briefly discusses the public involvement process, lists those who commented on the DSEIS, identifies each comment and provides responses to each comment.

H.2 PUBLIC INVOLVEMENT PROCESS ON THE DSEIS

On June 5, 1992, Notice of Availability of the DSEIS was published in the Federal Register, establishing a public comment period ending July 31, 1992.

An initial distribution of 201 copies was made to individuals, agencies, organizations, elected officials, and others known to be interested. Approximately five additional copies were subsequently distributed. Copies were also available at the Naval Petroleum Reserves in California office in Tupman, California and at Kern County Library branches in Bakersfield and Taft.

During the public review period, one public hearing was held in Bakersfield, California on June 24, 1992. A copy of the public hearing transcript is provided in <u>Section H.3</u>.

H.3 PUBLIC HEARING ON THE DRAFT SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT

PUBLIC HEARING

on the

DRAFT SUPPLEMENTAL

ENVIRONMENTAL

IMPACT STATEMENT

for

PETROLEUM

PRODUCTION AT

MAXIMUM EFFICIENT

RATE (MER), NAVAL

PETROLEUM RESERVE

NO. 1 AT ELK HILLS

DOE/EIS-0158

Wednesday, June 24, 1992

7:00 p.m.

Hearing Officer: Jim Killen

Reported by: Sylvia Mendez, Court Reporter
CSR No. 7636

215 Oregon Street
Bakersfield, California 93305
(805) 631-2904

ORIGINAL

Bakersfield, California;

Wednesday, June 24, 1992; 7:00 p.m.;

Red Lion, Buena Vista Room

MR. JIM KILLEN: Let's go ahead and get started.

For those of you who don't know me, I'd like to introduce myself. I'm Jim Killen, the Technical Assurance Manager of the Department of Energy's Office of the Naval Petroleum Reserves in California, commonly referred to as Elk Hills. I'm also the Project Manager for the Elk Hills Supplemental Environmental Impact Statement Project, commonly referred to as the SEIS Project.

Among other Elk Hills participants, I'm joined here tonight by Mr. David Vroom. David. David is representing Chevron. Chevron is a member of the operating committee, DOE's equity partner in Elk Hills operations.

I have about a five- to ten-minute prepared statement I'd like to make, which is actually more like an explanation proceedings tonight than a true statement. Please bear with me while we go through this.

I'd like to welcome our guests to this proceeding, which is the Public Hearing for the

Draft SEIS document, otherwise known as the DSEIS document. The document was released by DOE last month pursuant to The National Environmental Policy Act, NEPA, which requires federal agencies to disclose the environmental impacts of major federal actions. In this case, the major federal action began in 1976 with the passage of the Naval Petroleum Reserves Production Act (Public Law 94-258). This Act requires the production of Elk Hills at the maximum efficient rate in a manner that is both economic and does not cause detriment to the ultimate recovery from the reservoirs.

Prior to 1976, Elk Hills essentially was shut in as a petroleum reserve for defense and other national security purposes. As a result of the Act, DOE released an Environmental Impact Statement in 1979 which identified environmental impacts associated with the production strategies that were in place at that time. As with any oil field, as time passed and information and technology improved, production strategies changed correspondingly. Eventually it became significant that future plans included projects that were not specifically addressed in the 1979 document. Most importantly, the 1979 document did not address current plans to conduct enhanced oil recovery operations in the Shallow Oil Zone; it did not address current plans to construct and operate a cogeneration facility; it did not address current butane isomerization plans; it did not sufficiently address well drilling and abandonment plans; it did not sufficiently address gas processing and compression plans; and it did not sufficiently address current environmental protections plans which have become necessary in response to growing environmental laws, regulations and requirements.

As the result of the production strategies -- changes in production strategies, in 1988 DOE made a decision to supplement the 1979 document to access associated changes in environmental effect and, thus, the genesis of this SEIS project that's the subject of tonight's hearing. In addition to the major projects involving the Shallow Oil Zone, cogeneration, butane isomerization, wells, gas and environmental protection, the proposed action addresses many other lesser projects, as well as the continued operation of existing facilities, all of which are described in Elk Hills planning documents.

One of several steps in the NEPA process is the public release of a draft of the document that ultimately will be issued in final form. The purpose of the draft release is to give the public an opportunity to comment so that concerns and questions can be addressed in the final document. Today's Public

Hearing is a part of the public comment process. The comment period began on June 5, and it's scheduled to complete on July 31.

In accordance with NEPA procedures, DOE will respond in writing to all comments and questions that are placed on the record during this Public Hearing and/or that DOE receives in writing during the comment period. Momentarily, I'll give all of you an opportunity to comment, if you'd like to, and put your comments on the record. And this record is being kept by a certified recorder this evening, and it's being backed up by tape recording.

You also may submit your written comments as explained in the instructions on the forms that were passed out to you at the sign-in table. Your written comments can be submitted tonight by turning them in at the sign-in table or by mailing them to me at the address indicated on the form. If you need additional forms, just request them. We should have plenty for everyone. Your written comments do not have to be submitted on the forms that are provided. Comments will be accepted in any manner they are submitted. We would request, however, that you include with your comments the information about yourself requested on the forms; for example, your name, address, phone number, affiliation, et cetera, might be needed if it's necessary to contact you later to clarify some aspect of your comment.

Following the public comment period, which, again, concludes on July 31, DOE will prepare written responses to all comments, and these responses will be incorporated into a section of the final SEIS document, along with the record of these proceedings this evening. In addition, the draft document will reflect appropriate changes to the draft -- excuse me. In addition, the final document will reflect appropriate changes to the draft document. This does not mean that all comments will result in changes, but in many cases, depending on the comment, it will. It is anticipated that the final document will be released to the public in approximately March, 1993, following Elk Hills preparation of the document and DOE Washington D.C. headquarters' review, approval and final release.

The draft document that is the subject of this Hearing tonight was prepared by DOE's Elk Hills staff based on a July, 1990, Preliminary Draft of the document prepared by Argonne National Laboratory under contract to DOE, and, also, based on review comments of the Argonne document provided by the staffs of the various Elk Hills organizations, including Chevron; Bechtel Petroleum Operations, Inc., DOE's management and operating contractor; EG&G Energy Measurements, Inc., DOE's endangered species contractor; Resource Management Consultants, Inc., DOE's current support services contractor; and Systematic Management Services, Inc., DOE's former support services contractor. Comments also were provided by the DOE Headquarters staff.

From this long list of contributors, I think you can understand that the preparation of the draft document has been a major undertaking involving a large number of technical experts, only a few of which it is possible to make available here tonight. For this reason, we will not be able to respond formally on the record to comments that are received here tonight. Formal responses will be developed later between the appropriate technical experts and will be included in the final document. However, to assist anyone who would like to better understand the DSEIS document and to help you frame the questions and comments you might wish to put on the record, an informal breakout room has been provided across the hall in the Nevada Room, where, if you wish, you can go to informally discuss areas of interest off the record with some of our more knowledgeable contributors.

The Nevada Room consists of eight tables for addressing eight different areas of interest. These include a general information table; a proposed action table; an air quality table; a waste table; a table for geology and hydrology; one for biology, including endangered species; a safety table; and a table for cultural resource, land use and socioeconomic issues. If you would like to discuss a particular issue, I encourage you to interact with the staffs that are manning these tables. All you have to do is go across the room, across the hall to the Nevada Room and walk up to the appropriate table and initiate discussions. The staffs manning the tables will be happy to respond to your inquiries to the best of their ability. I need to say again, however, that discussions in the Nevada Room are informal and off the record. Nothing said in the Nevada Room by you or the Elk Hills staff will be recorded, nor will any formal written DOE responses be provided later. To obtain a formal DOE response, you either must submit your comments in writing, or put them on the record here in the Buena Vista Room, as previously explained.

That concludes my prepared statement. The rest of the evening will be devoted to taking your comments on the record here in the Buena Vista Room and/or discussing areas of interest informally off the record in the Nevada Room across the hall. Except for a 15-minute break from 8:00 to 8:15, we will be here in the Buena Vista Room to take your comments until approximately 9:00 p.m. We plan to stay until 9:00, even if commenting stops before then, on the chance that some members of the public might arrive late. At approximately 8:55 to 9:00 p.m., I will make a very brief closing statement which will conclude the proceedings. Activities in the Nevada Room will be conducted concurrently with activities here in the Buena Vista Room. You may go between the Buena Vista and Nevada Rooms as you wish until 9:00 p.m., when the proceedings are scheduled to conclude.

Before inviting anyone forward first, I'd like to ask if there are any administrative questions as to how we're conducting these proceedings this evening. Do you understand the difference between what's taking place here in the Buena Vista Room and what we have planned for the Nevada Room? Or do you have any other administrative questions?

(No response.)

Okay. If there are no questions, I would like to start receiving formal comments on the record.

As explained earlier, you may stay here and provide or listen to formal comments, or you can go to the Nevada Room and return here later. We'll be here until 9:00.

Chris, did you -- did anyone make a request to make comments?

MR. CHRIS VALENTINO: Mr. Rector mentioned he --

THE COURT REPORTER: I can't hear you, sir.

MR. CHRIS VALENTINO: Mr. Rector said he may or may not make a comment. That's all that we have right now.

MR. JIM KILLEN: Mike, did you want to step forward and make your comment?

If you would, if you'd state your full name and spell your last name for the recorder, please.

MR. MICHAEL RECTOR: Is that on?

I'm Michael R. Rector of Bakersfield. I'm a groundwater resources -- groundwater resources consultant. As a hydrogeologist, I reviewed the report to see if the requirements relative to the protection of groundwater were carried out. I have just two or three comments.

It is my opinion that the maps or graphics in the report are lacking; in other words, I would like to see groundwater structure, groundwater quality, water well locations, and monitoring well locations at least on one map. I saw no reference to a specific groundwater monitoring plan. I feel that possibly the initial monitoring program should include wells to detect whether there is any off-site flow of product from the reservation. Also, to verify on-site groundwater quality conditions near the noted problem areas, I think it's very important to work with the down-slope people to determine what is natural and what is artificial water quality.

I did take a look at Appendix G, which I feel sets forth an in-house adjusted policy for your activities several years ago. And I think that this one quotation, "Groundwater protection is a primary concern"; yet, I -- as I pointed out, I found that this concern was not exhibited.

I would like to know what the status is at this time of a monitoring that was proposed six or seven years ago.

MR. JIM KILLEN: Okay. Thank you, Mike.

Do any of our other guests care or plan to make a comment? If you do, you may step forward now and identify yourself. If you don't, I'm going to retire from the podium for now. We'll wait for other people to possibly come, and we'll continue to receive comments here, as I indicated, through nine o'clock. While we wait, you're invited to, as I indicated before, step across to the Nevada Room.

Mike, in particular, yourself, may want to visit with some of our groundwater people to discuss a little bit some of the issues you just put on the record. Thank you.

(Whereupon, a recess was taken.)

MR. JIM KILLEN: Okay. It's nine o'clock, and all of our guests have left. There were no further comments, and so that will conclude the proceedings tonight.

I'd like to express my appreciation to all the Elk Hills people who came out and supported this effort. Thank you very much.

(Whereupon, the proceedings were adjourned at 9:04 p.m.)

STATE OF CALIFORNIA)
) ss.
COUNTY OF KERN)

I, Sylvia Mendez, a Certified Shorthand Reporter for the State of California, hereby certify that I was present and reported in stenotypy all the proceedings in the foregoing-entitled matter; and I further certify that the foregoing is a full, true, and correct statement of such proceedings and a full, true, and correct transcript of my stenotype notes thereof.

Dated at Bakersfield, California, on July 9, 1992.

Sylvia T Mendez

Sylvia Mendez, CSR No. 7636

H.4 LIST OF COMMENTORS/RESPONDENTS

This section provides a list of all DSEIS commentors.

Argonne National Laboratory
California Department of Food and Agriculture,
  Control and Eradication
California Department of Water Resources
California Energy Commission
The Resources Agency of California
California State Water Resources Control Board,
  Division of Clean Water Programs
Kern County Fire Department
Kern County Resource Management Agency,
  Environmental Health Services Department
Kern County Water Agency
Richard D. Olsen, Ph.D.
Michael R. Rector, Inc., Water Resources Consultant
United States Department of the Interior
United States Environmental Protection Agency, Region IX

H.5 PUBLIC HEARING COMMENTS AND DEPARTMENT OF ENERGY RESPONSES

Only one individual, Michael R. Rector, provided verbal comments at the June 24, 1992 public hearing. Following are Mr. Rector's three comments. The Department of Energy responses are shown in italics after each comment.

1. "It is my opinion that the maps or graphics in the report are lacking; in other words, I would like to see groundwater structure, groundwater quality, water well locations, and monitoring well locations at least on one map."

   Please refer to the responses to comments 6.a, 6.b, 6.c, 6.i, 6.k, 6.l, and 11.0 in Section H.6.

2. "I saw no reference to a specific groundwater monitoring plan. I feel that possibly the initial monitoring program should include wells to detect whether there is any off-site flow of product from the reservation. Also, to verify on-site groundwater quality conditions near the noted problem areas, I think it's very important to work with the down-slope people to determine what is natural and what is artificial water quality."

   Please refer to the responses to comments 6.b, 6.c, 9.a, 9.d, and 11.a in Section H.6.

3. "I would like to know what the status is at this time of a monitoring that was proposed 6 or 7 years ago."

   Please refer to the responses to comments 11.a and 11.b in Section H.6.

H.6 LETTERS FROM PUBLIC AGENCIES, INTERESTED INDIVIDUALS, AND DEPARTMENT OF ENERGY RESPONSES

Following are copies of all comment letters received from public agencies and interested individuals. Each comment letter has been assigned an individual number as follows:

1. Argonne National Laboratory
2. California Department of Food and Agriculture, Control and Eradication
3. California Department of Water Resources
4. California Energy Commission
5. The Resources Agency of California
6. California State Water Resources Control Board, Division of Clean Water Programs
7. Kern County Fire Department
8. Kern County Resource Management Agency, Environmental Health Services Department
9. Kern County Water Agency
10. Richard D. Olsen, Ph.D.
11. Michael R. Rector, Inc., Water Resources Consultant
12. United States Department of the Interior
13. United States Environmental Protection Agency, Region IX

Within each comment letter, each comment was bracketed and identified with the comment letter number and sequential lower case letter. For example, Argonne National Laboratory's letter (1) had one comment, which has been identified as 1a.

For EPA's comment letter (13), the comments were grouped according to major impact area with the following upper case letter designation:

G -- General
N -- NEPA
B -- Biodiversity/Threatened and Endangered Species
H -- Hazardous Materials/Waste
W -- Water Resources
A -- Air Quality
O -- Operations

Each EPA comment was bracketed and identified with the comment letter number 13 and applicable upper case letter and sequential number. For example, the first EPA NEPA comment is 13N-1.

Immediately following each complete letter is a reduced version of the letter and the Department of Energy responses, numbered and lettered correspondingly and presented in a side-by-side format. All responses are maintained in the administrative records for the NPR-1 FSEIS in the Technical Assurance Library, Naval Petroleum Reserves in California, 28590 Highway 119, Tupman, California.

ARGONNE NATIONAL LABORATORY
9700 South Cass Avenue, Argonne, Illinois 60439
Telephone: 708/252-3804
Fax: 708/252-3847

July 20, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

This letter is submitted by Argonne National Laboratory (ANL) as a comment to the Draft Supplement to the 1979 Final Environmental Impact Statement, Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California, DOE/EIS-0158, dated May 1992. Specifically, ANL and ANL staff should not be listed as preparers/contributors of this draft supplemental environmental impact statement (DSEIS).

Section 8.0 states that this DSEIS was prepared by the U.S. Department of Energy, Naval Petroleum Reserves in California, based on a preliminary draft of the document (PDSEIS) prepared by the Environmental Assessment and Information Sciences Division of Argonne National Laboratory (ANL 1990), and review comments provided by the staffs of DOE-NPRC, Chevron U.S.A. Inc. (CUSA), Bechtel Petroleum Operations, Inc. (BPOI), EG&G Energy Measurements, Inc. (EG&G/EM), and Research Management Consultants, Inc. (RMCI). The project was managed by DOE-NPRC with coordination and technical assistance provided by RMCI. However, the preparers/contributors table lists ANL staff as the specific authors of the technical and written material contained in the DSEIS. Other than DOE-NPRC management and support staff listed in the table, the current DSEIS explicitly shows ANL authors to be individually responsible for the material contained in the DSEIS.

Section 1502.17, entitled List of Preparers, of the Council of Environmental Quality Regulations for Implementing the National Environmental Policy Act 40, CFR Parts 1500-1508, states:

> "The environmental impact statement shall list the names, together with their qualifications (expertise, experience, professional disciplines), of the persons who were primarily responsible for preparing the environmental impact statement or significant background papers, including basic components of the statement (§§ 1502.6 and 1502.8). Where possible the persons who are responsible for a particular analysis, including analyses in background papers, shall be identified. Normally the list will not exceed two pages."

Implicit in this statement is that the persons listed were primarily ~~responsible for~~ preparing the text and technical material contained in the document, as issued. This is a disclosure standard and allows the public and interested parties to identify the authors and sources of the basic components and technical background materials included in the document. This is especially critical for an environmental impact statement which serves a regulatory purpose and whose authors can be called to provide expert testimony to defend the statement.

Upon submittal of the ANL 1990 PDSEIS, the DOE Naval Petroleum Reserve informed ANL that they will assume the responsibility for the preparation of the DSEIS and would consult with ANL. At that time, ANL informed the DOE Naval Petroleum Reserve of its position with regard to the List of Preparers. If ANL were to be listed as preparers, we must have the opportunity to review and concur on the analyses DOE presented in the DSEIS. This was especially true given the General Accounting Report (GAO/RCED-91-129) that showed a disagreement between ANL and the DOE Naval Petroleum Reserve over certain technical findings contained in the 1990 PDSEIS. After ANL submitted the 1990 PDSEIS, ANL staff and management were not consulted on the revisions nor provided the opportunity to review and concur before DOE issued the DSEIS to the public. The CEQ recognizes that individuals preparing materials that become a part of an EIS should be identified even if the agency modifies their contributions (Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations). However, due to the material revisions made to the text, technical analyses, and conclusions in ANL's PDSEIS when compared to the final DSEIS issued by DOE, ANL feels listing ANL or ANL technical staff as preparers of the final document is not appropriate under the CEQ regulations. ANL personnel were not primarily responsible for the text and analyses contained in the final document. Consequently, ANL is asking all reference to ANL authorship be removed from the Draft and Final SEIS. Instead, the ANL prepared 1990 PDSEIS should be listed as a reference, as has been done for all other references, and cited, where appropriate, to support DOE's analyses. 1a

For Argonne National Laboratory,

H. Drucker
Associate Laboratory Director
Energy, Environmental and
Biological Research

STATE OF CALIFORNIA PETE WILSON, Governor

DEPARTMENT OF FOOD AND AGRICULTURE

Control and Eradication
2895 N. Larkin, Suite A
Fresno, CA 93727

June 3, 1992

James C. Killen
Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, California 93276

Dear Mr. Killen:

I received a copy of the Department of Energy Draft Supplement to the 1979 Final Environmental Impact Statement (EIS) for Naval Petroleum Reserve No. 1 (Elk Hills). I appreciate the opportunity to review and comment on the draft supplement EIS for NPR-1.

Although the document is extensive in its content, I feel the draft would be more complete if a brief description of the Curly Top Virus Control Program (CTVCP) was included. Because the CTVCP is not considered part of the Proposed Action, I am not certain as to the placement of such a description within the body of the draft. Future Non-Federal Actions (1.2.2.21), Miscellaneous (1.2.2.22) or the Cumulative Impact Section (4.1.5.5), are areas where the CTVCP could be described. The exact placement can be best determined by DOE staff who are close to the document. 2a

If the CTVCP is included in the supplement EIS, delays and confusion may be avoided if future amendments are necessary.

I can certainly appreciate the time and effort necessary to produce a document of this size and complexity. If a decision is made to include a brief description of the CTVCP in the supplement EIS, I will be available to provide you and your staff any additional information you may need.

Sincerely,

Rodney A. Clark

Rodney A. Clark
Associate Economic Entomologist
Curly Top Virus Control Program
(209) 445-5472

cc Foote
Gotan
Peterson

STATE OF CALIFORNIA—THE RESOURCES AGENCY PETE WILSON, Governor

DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET, P.O. BOX 942836
CRAMENTO, CA 94236-0001
6) 653-5791

July 7, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
Post Office Box 11
Tupman, California 93276

Dear Mr. Killen:

As you are aware, the Department of Water Resources has purchased a tract of land adjacent to the Naval Petroleum Reserve No. 1 (Elk Hills). This land is being developed as a ground water banking facility of the State Water Project and is referred to as the Kern Fan Element of the Kern Water Bank. We are very concerned about potential threats to ground water quality of the KFE. Therefore, we were pleased to note in our review of the Draft Supplemental EIS for Petroleum Production at the Maximum Efficient Rate at Elk Hills that the potential for ground water degradation and off site migration of poor quality ground water was recognized and that efforts to reduce this risk and to develop a ground water monitoring program are under way.

As a result of our mutual concerns over potential ground water quality problems that could result from operations at Elk Hills, I propose that we cooperate in the review of the proposed ground water monitoring program to be developed and in evaluating proposed risk reduction measures. In turn, the Department will share the information from the KFE ground water monitoring program and from our studies that is pertinent to your efforts. To initiate this process, we would like to receive copies of the attached list of materials referenced in the draft EIS. 3a

Mr. James C. Killen
July 7, 1992
Page Two

If you have any questions or wish to discus this issue, please call me at (916) 653-9633 or John Fielden at (916) 653-9495.

Sincerely,

Jack Erickson, Chief
Kern Water Bank Section
Division of Planning

Attachment

cc: Mr. John Fielden
Post Office Box 942836
Sacramento, California 94236-0001

Fishburn, M. D., 1990, Department of Energy, Memorandum to File, Naval Petroleum Reserves in California, February 14.

Golder Associates Inc., 1990, NPR-1 Groundwater Monitoring Plan, prepared for Bechtel Petroleum Operations, Inc., Tupman, California, May 15

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Nicholson, G. E., 1985, Probable Communication between Wastewater Disposal Wells and Tulare Source Wells, interoffice memorandum to A. Palmer, Bechtel Petroleum Operations, Inc., Naval Petroleum Reserve No. 1, Tupman, California.

Nicholson, G. E., 1989, Source of Surface Seeps in Sections 3G, 4G, and 35S, Draft Report, Bechtel Petroleum Operations, Inc., Tupman, California

Remsen, W. E., 1990, Clarification of Upper and Lower Tulare Contact, NPR-1, Elk Hills, California, Bechtel Petroleum Operations, Inc., Memorandum to File, Tupman, California 93276

Stuart, J., 1987, A Review of Waste Water Disposal Operations at Elk Hills, Bechtel Petroleum Operations, Inc., Naval Petroleum Reserve No. 1 (Elk Hills). Kern County, California, August.

Waldron, J., 1989, Chevron. U. S. A., Inc., Bakersfield, California, letter to T. H. Filley, Argonne National Laboratory, Argonne, Illinois., Jan. 10.

STATE OF CALIFORNIA—THE RESOURCES AGENCY PETE WILSON Governor

CALIFORNIA ENERGY COMMISSION
516 NINTH STREET
SACRAMENTO, CA 95814-5512

July 30, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
P.O. Box 11
Tupman, CA 93276

Re: Comments on the Department of Energy's DSEIS for the Naval Petroleum Reserve No. 1 (Elk Hills) in Kern County (Sch. 92064002)

Dear Mr. Killen:

Staff of the California Energy Commission (Commission) have reviewed the Draft Supplement to the 1979 Final Environmental Impact Statement (DSEIS), "Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California". Staff believes that the DSEIS does not provide essential information needed to assess all potentially significant environmental impacts, and does not provide adequate mitigation. Our comments address the areas of biological, cultural, and paleontological resources; and socioeconomics.

Summary of Recommendations

1. The DSEIS should provide estimates of indirect impacts to plant and animal habitats due to construction and operation of oil development-related activities at NPR-1 for the entire site over a 30-year project life. 4a

2. Biological mitigation measures should address all species potentially impacted by development-related activities at NPR-1, as well as provide for revegetation and kit fox monitoring. 4b

3. DOE should provide additional information on revegetation efforts to permit a realistic evaluation of the effectiveness of this mitigation measure, and develop criteria for evaluating the successes or failures of future revegetation programs. 4c

4. To determine the relationship between oil development and kit fox population dynamics, DOE must use a reliable method to distinguish oil-developed from non-developed lands. 4d

5. DOE should provide a comprehensive evaluation of mortality to giant kangaroo rats, blunt-nosed leopard lizards, and other listed species as a result of construction and operation activities at NPR-1. 4e

6. DOE should compensate for loss of plant and animal habitat by purchase or protection of endangered species habitat, and set 4f land aside in perpetuity to ensure the long-term preservation of those species impacted.

7. DOE should include a contingency plan in the cultural resource management plan, in the event of discovery of subsurface 4g cultural resources.

8. DOE should also develop a contingency plan in the event of 4h discovery of paleontological resources.

9. The socioeconomic section should be updated to reflect current conditions (beyond 1988). The discussion of potential impacts resulting from out-of-county workers should be clarified; and 4i a discussion of potential impacts to local school enrollments should be added.

Biological Resources-Background Information

The Naval Petroleum Reserve 1 (NPR-1) supports four federally endangered animals, one federally threatened plant, and one state threatened animal. All but one of these species are endemic to the Southern San Joaquin Valley and, for each of these, the major reason for population decline is habitat loss. Cumulative habitat disturbance due to past development at NPR-1 is reported as approximately 6,546 acres. There has also been development-related habitat disturbance at NPR-2, which is adjacent to, and supports the same listed species as NPR-1; however, figures for acreage disturbed on NPR-2 are not provided in this document. The proposed action to expand operations at NPR-1 would result in an estimated loss of an additional 1,569 acres of known threatened and endangered species habitat over the next 30 years. The DSEIS does not provide estimates of indirect impacts due to construction and 4a operation of oil development-related activities at NPR-1 other than an estimate of 6,780 acres that would be disturbed by seismic surveys over a 30-year project life.

Past mitigation measures for all impacts from development-related activities at NPR-1 have mainly consisted of revegetation and kit fox population monitoring programs. Although valuable, these types 4b of measures are not acceptable as mitigation for the type and degree of impacts experienced by the development activities at NPR-1.

Biological Resources-Revegetation

The document reports that to date 1,689 acres of the 6,546 acres disturbed have been revegetated. However, more than half of the revegetation claimed (920 acres) occurred naturally and was not a result of active mitigation. The percent of ground and shrub cover (per acre covered) and species diversity achieved from the revegetation effort is not reported. Therefore, it is not possible to evaluate the effectiveness of this mitigation measure from the information given. DOE considers areas revegetated (1,689 acres) as a credit to total areas disturbed by past activities (6,546 acres). In the proposed action to expand development, DOE figures that of the 1,569 acres of habitat that will be directly disturbed by development-related activities, impacts to 1,045 acres will be off-set by revegetation. If DOE has not done so already, further revegetation programs should establish criteria for revegetation success and provide for monitoring the successes and failures. 4c 4c

Biological Resources-Kit Fox Monitoring

The DOE kit fox monitoring program has been in place on NPR-1 since 1981 to determine the relationship between oil development and kit fox population dynamics. This effort has documented drastic declines in the kit fox population on NPR-1 over the duration of the study (from 165 foxes in 1981 to 19 foxes in 1991). The majority of the decline occurred in the foothills where development has been most intense. Although several factors may have contributed to this 81-88% decline, the effect of development is still uncertain and lack of equivalent declines (43-58%) in flatter undeveloped areas and on NPR-2 where there is less development suggests that development is somewhat responsible. Furthermore, reproductive success was lower in the developed areas than in undeveloped areas from 1982 to 1985. 4d

Several studies have been conducted on NPR-1 and NPR-2 in an attempt to determine differences in kit fox population dynamics in developed and undeveloped lands. However, the method used to distinguish oil-developed from undeveloped lands is not reported. Following a review of the literature we have determined that the criteria used (0-15% surface disturbance/sq. mile as undeveloped areas and 16-100% surface disturbance/sq. mile as developed areas) do not clearly distinguish between these land uses. Therefore, any results from these studies cannot be used in the context intended. The percent intervals are not equal and the potential impacts between the 16 percent end of the interval are significantly different from those at the 100 percent end of the interval. Statistical evaluation would be greatly improved if actual areas of disturbance were reported rather than using ratio or percent values. If intervals, either actual areas or percent, are used they should be of equal length and small enough intervals to characterize expected impacts. Consideration should also be given to describing disturbance in terms of animal use areas, such as the amount of an animal's home range. 4d

Mitigation for the proposed project provides for continued monitoring of kit fox population dynamics and conduction of pre-activity surveys to minimize impacts. Any further attempts to study kit fox population dynamics in relation to oil-developed vs. non-developed lands must clearly identify the level of development in the study areas and eliminate the effects of other land uses such as agriculture and urban developments. We further recommend that past studies be re-analyzed using the new criteria, since a major objective of these studies was to test the effects of oil development on various aspects of kit fox ecology. 4d

Biological Resources-Other Affected Species

In regard to the other listed species on-site, mortality as a result of operation activities has been documented for giant kangaroo rats and blunt-nosed leopard lizards. However, a comprehensive evaluation of the effects of construction and operation activities at NPR-1 on these and other listed animal and plant species is not provided in the DSEIS. 4e

Biological Resources-Concluding Comments

Although the kit fox and revegetation programs that have occurred on NPR-1 are notable, they are not in line with current mitigation practices common for all other development activities occurring in the Southern San Joaquin Valley. Federal and state requirements have established that the loss of habitat must be compensated by the purchase or protection of endangered species habitat. Compensation ratios used in the Southern San Joaquin Valley have ranged from 3-to-1 to 5-to-1 for direct loss of habitat known to support listed species. Indirect or temporary disturbances to listed species habitat have been compensated at ratios ranging from 1.1-to-1 to 3-to-1. Compensation can be accomplished by dedicating surface lands not under development on NPR-1 or NPR-2 or by purchasing nearby lands known to support the same listed species being impacted by activities on NPR-1. Such lands have already been identified through threatened and endangered species planning efforts in the Southern San Joaquin Valley and include the Buena Vista Valley and the Lokern Natural Area, both adjacent to NPR-1. Chevron owns most lands in the Lokern Natural Area and is the primary producer at NPR-1. 4f

Land must be set aside in perpetuity to ensure the long term preservation of those species impacted. Further, an endowment fund must be established for the purpose of long term land management. Endowments should be managed by a land management agency such as The Nature Conservancy.

Revegetation efforts should continue but be applied as mitigation to lands temporarily disturbed by development activities and not considered as a measure to off-set loss of habitat. The kit fox program could be used to monitor the population, but again, should not be done in lieu of habitat compensation. Additionally, these studies must utilize a more realistic definition of oil-developed and undeveloped lands to make an effective comparison of these land uses. 4f

Cultural Resources

The Draft Supplement identifies that significant finds of cultural resources are unlikely, and that a cultural resource management plan is under development in cooperation with the California State Historic Preservation Office. However, the description of that plan in the DSEIS does not identify whether a contingency plan is being developed as part of the management plan in the event of the discovery of subsurface resources. Such a contingency plan acts to minimize delays in the event of such finds, and it is recommended that one be included in the management plan. 4g

Paleontological Resources

While surveys have not indicated the presence of significant paleontological resources, the DSEIS does note that significant resources have been identified in nearby areas. It is recommended that a contingency plan, similar to that recommended above for cultural resources, be developed for previously undiscovered subsurface paleontological resources. 4h

Socioeconomics

Most of the data developed for the socioeconomic section covers only the period ending in 1986-88. Because socioeconomic data is often highly dependent upon the general state of the economy, and because conditions have changed in the four to seven years since this data was developed, it is recommended that the socioeconomic section be updated to reflect current conditions. In addition, it is recommended that the discussion of potential impacts resulting from in-migration of out-of-county workers be clarified. On p. 4.1.8-1, section 4.1.8, second paragraph it is stated that "Fourth, most temporary construction workers on the site would likely come from outside Kern County...". In section 4.1.8.2, same page, it is stated that "Although potential increases up to 30% of the temporary work force might be realized, most workers would come from local communities...". Are the same workers being discussed in both sections? 4i

The socioeconomic impact section does not discuss the potential impacts to schools which might result from the proposed project. Such a discussion, based on updated capacity and enrollment figures should include the potential effects resulting from out-of-county workers bringing their families with them. Commission staff has observed that significant impacts can result to local school districts and schools from even small increases in school enrollment. Agreements with individual districts covering non-reimbursable expenses resulting from enrollment of children associated with out-of-county workers are a recommended form of mitigation for such impacts. 4i

In conclusion, Commission staff believes that the DSEIS does not adequately address several potentially significant environmental and socioeconomic issues, and does not provide adequate mitigation measures to reduce or eliminate the expected impacts. We recommend that the Final SEIS incorporate these comments to adequately analyze all project impacts and consider all feasible mitigation measures.

We appreciate the opportunity to comment on this project. If you have any questions regarding any of our comments or would like assistance addressing our concerns, please contact Lorri Gervais at (916) 654-3944.

Sincerely,

Robert L. Therkelsen, Deputy Director for
Energy Facilities Siting and
Environmental Protection

cc: Christine Kinne
State Clearinghouse

The Resources Agency of California

Pete Wilson
Governor

Douglas P. Wheeler
Secretary

July 17, 1992

U. S. Department of Energy
Naval Petroleum Reserves in California
ATTN: James C. Killen
Technical Assurance Manager
P. O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

The State has reviewed the Draft Supplement to the 1979 Environmental Impact Statement (DOE/EIS-0158), Petroleum Production at Maximum Efficient Rate Naval Petroleum Reserve No. 1 (Elk Hills) Kern County, submitted through the Office of Planning and Research.

We coordinated review of this document with the Central Valley Regional Water Quality Control Board; Public Utilities, and State Lands Commissions; and the Departments of Conservation, Fish and Game, Health Services, Transportation, and Water Resources.

The State Water Resources Control Board stated that they are currently working with you on this project. We have no further comments at this time.

Thank you for providing an opportunity to review this project.

Sincerely,

for Carol Whiteside
Assistant Secretary,
Intergovernmental Relations

cc: Office of Planning and Research
1400 Tenth Street
Sacramento, CA 95814
(SCH 92064002)

The Resources Building Sacramento, CA 95814 (916) 653-5656 FAX (916) 653-8102

STATE OF CALIFORNIA PETE WILSON, Governor

STATE WATER RESOURCES CONTROL BOARD
DIVISION OF CLEAN WATER PROGRAMS
2014 T STREET, SUITE 130
P O BOX 944212
SACRAMENTO, CA 94244-2120

(916) 739-2728
FAX: (916) 739-2300

JUL 27 1992

Mr. James Killen
Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

I am providing review comments by State Water Resources Control Board staff on the "Draft Supplement to the 1979 Final Environmental Impact Statement, Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California" dated May 1992. These comments were coordinated with John Noonan, Central Valley Region, and are submitted as part of the State of California's (State) participation in the Agreement in Principle between the Department of Energy and the State.

If you have questions regarding the enclosed comments or wish to discuss them in more detail, please telephone me at (916) 739-2728 or Leslie Laudon at (916) 739-3313.

Sincerely,

John J. Adams, Jr., Chief
Site Remediation Unit
Land Disposal Section

Enclosure

cc: Ed Ballard
DOE/SAN
1333 Broadway
Oakland, CA 94612

John Noonan
California Regional Water Quality Control Board
Fresno Branch Office
3614 East Ashlan Avenue
Fresno, CA 93726

Gary Butner
Environmental Management Branch
Department of Health Services
601 North 7th Street
Sacramento, CA 94234-7320

Linda Fuller
Resources Agency
1416 9th Street
Sacramento, CA 95814

State of California

MEMORANDUM

To: John Adams
DOE Program Manager

Date: JUL [illegible]

Leslie Laudon
Associate Engineering Geologist

From: **STATE WATER RESOURCES CONTROL BOARD**
DIVISION OF CLEAN WATER PROGRAMS

Subject: REVIEW COMMENTS, DRAFT SUPPLEMENT TO THE 1979 FINAL ENVIRONMENTAL IMPACT STATEMENT, PETROLEUM PRODUCTION AT MAXIMUM EFFICIENT RATE, NAVAL PETROLEUM RESERVE NO.1 (ELK HILLS), KERN COUNTY, CALIFORNIA, MAY 1992

In accordance with the Agreement in Principle (AIP) between the Department of Energy (DOE) and the State of California (State), I reviewed the abovementioned EIS to assist in the evaluation of additional DOE sites for potential inclusion in the AIP program. This memo presents my comments on the EIS.

GENERAL COMMENTS

The EIS does not provide any water quality data to support the generalizations that the ground water beneath the site is of poor quality, and is not likely being impacted by site activities. There does not appear to be any data available from onsite monitoring wells to establish the ground water flow regime and quality beneath the site. Maps provided in the EIS depicting the ground water surface elevation do not show any information for the Navy site. **6a**

The disposal practices for produced water which is of poor quality show a lack of concern for potential degradation of ground water quality. This could be a major concern for the Kern Water Bank (KWB) due to the proximity of the water bank to the Naval Petroleum Reserve's (NPR) disposal ponds. There is not sufficient information regarding the geohydrology of the NPR area to determine whether the produced water disposal practices are impacting the KWB water. **6b**

It is my understanding that the Regional Water Quality Control Board (Regional Water Board) is working with the Navy to evaluate the ground water quality and flow conditions at the site. The **6c**

Regional Water Board is not convinced that historic and current operating procedures and wastewater disposal practices are not impacting usable ground water. The ground water evaluation will involve generating data from onsite wells to determine whether water quality has been adversely impacted by activities at the site. Apparently, the evaluation was initially proposed by the Navy, but they have been slow in initiating the study. 6c

SPECIFIC COMMENTS

p. xxvii - regarding the Tulare Formation "This water is of poor quality with no known beneficial uses except as waterflood source water. The NPR-1 Tulare Formation has been designated as an EPA Class 2 exempt aquifer..."

The Department of Conservation, Division of Oil and Gas (CDOG) has the authority and responsibility to regulate Class II wells used for injection of fluids generated from oil and gas production. The CDOG and State Water Resources Control Board (State Water Board) established a Memorandum of Agreement (MOA) for protection of the beneficial uses of the waters of the State. The State Water Board does not designate waterflood source water as a beneficial use. Use of this terminology throughout the EIS implies that waterflood source water is a designated beneficial use in the Water Quality Control Basin Plan (Basin Plan) prepared by the Regional Water Board. 6d

p. 3.2-7 "...acidic conditions within the borehole would be expected to reduce virtually all of the Cr^{+6} to Cr^{+3} which is the less hazardous state."

Acidic conditions will not necessarily assure the reduction of chromium. A reducing agent must be present and acids are not necessarily reducing agents. 6e

p. 3.2-8 "The State of California requires remedial action to remove hexavalent chromium from the soil whenever the concentration exceeds the State of California soluble threshold limit concentration (STLC) of 5 milligrams/liter."

Concentrations of metals in soil in excess of the STLC does not automatically trigger the need for remedial action. The STLC defines a waste as hazardous and requires that it be managed as such if the concentration of a metal in soil exceeds its STLC. There are many other factors which influence the decision to implement a remedial action. 6f

p. 3.2-8 "Chromium tests in the hazardous waste trench area of the 27R waste management facility indicated that chromium levels in this area ranged from 19 to 210 milligrams/kilogram which is below the STLC of 560 milligrams/kilogram."

The STLC is measured in milligrams/liter (mg/L). This point may need some clarification. There are two STLCs for chromium, the 5 mg/L STLC discussed above is for Cr^{+6}, the 560 mg/L STLC is for total Cr and/or Cr^{+3} compounds. It must be assumed that the chromium discussed in the hazardous waste trench area is not Cr^{+6}. 6g

p. 5-1 UNAVOIDABLE ADVERSE IMPACTS

- Inadvertent release of oil-field chemicals that are not entirely recovered on a timely basis could, over a period of time, migrate into and degrade groundwater aquifers. 6h

This impact could be avoided by good chemical management practices and timely remediation of inadvertent releases.

p. 5-1 UNAVOIDABLE ADVERSE IMPACTS

- If the program to recycle produced water for use as waterflood water does not eliminate the need to dispose of produced water into the Tulare Formation, then there is a possibility that such wastewater could degrade usable offsite groundwater. The proposed action includes the implementation of a Groundwater Protection Management Program that will address the potential risks to off-site groundwater 6i resources that may result from all NPR-1 operations.

If the program to recycle produced water does not eliminate the need for disposal of produced water, other options including treatment prior to disposal should be examined. It should not be assumed that continued degradation of water quality is the only other option, particularly if the water being degraded is usable offsite water.

p. D-4, 5 Section D.3.3.1 Zones of Saturated Groundwater

Groundwater is typically referred to as the saturated zone. 6j Saturated groundwater would seem to be a redundant term except that the next section is titled "Zones of Unsaturated Groundwater". This is a confusing use of terms. Different titles for the sections might provide better descriptions of the section's contents. Numerous references are cited as providing groundwater surface elevation data for the area. 6k Apparently these sources do not have any data regarding the groundwater surface elevation beneath the NPR site because this information is not provided on Figure D.4-3. The discussion in this section does not provide enough information to interpret the geohydrology. 6k

p. D-7 Section D.3.3.3 Water Chemistry

This section provides general descriptions of the groundwater chemistry but does not present any data. Reference is made to various water quality studies and maps; it might be helpful to provide a map of the TDS distribution throughout the system. It is stated on p. D-9 that a relationship may exist between oil-field wastewater disposal practices and groundwater quality. Without data, it is difficult to evaluate whether such a relationship exists. 6l

p. D-14 ..."These MCLs are enforceable Federal Standards that are also applicable to remedial action alternatives at hazardous and toxic waste sites."

MCLs are enforceable standards for treated drinking water; they may also be enforceable standards for remedial actions. Other regulations and policies of federal, state, and local agencies must also be considered to determine appropriate standards for remedial actions. 6m

KERN COUNTY FIRE DEPARTMENT

5643 Victor St. • Bakersfield, CA 93308 • Telephone (805) 861-2577 • FAX (805) 399-2915

FIRE CHIEF
THOMAS P. McCARTHY

ADMINISTRATIVE DEPUTY CHIEF
SCHUYLER T. WALLACE

OPERATIONS DEPUTY CHIEFS
DANIEL G. CLARK
CHARLES E. DOWDY
CHARLES A. VALENZUELA

ADMINISTRATIVE
SERVICES OFFICER
MICHAEL R. PARKER

May 27, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

In regards to the Department of Energy draft supplement to the 1979 Final Enviroment Impact Statement, "Petroleum Production at maximum efficient rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, CA" (DOE / EIS - 0158, May 1992) there is a correction that needs to be made under Fire Protection. The document states "The Taft Substation of the Kern County Fire Department has four trucks capable of fighting oil fires,..." this is not correct. Our Taft Substation (Station 21) only has one engine for fighting oil fires. We also have a patrol for fighting grass fires. It should also be noted that we have an engine available at our Fellows Substation (Station 23) capable of fighting oil fires within your 25 minute response times. 7a

Thank-you for allowing us to review your update. If you have any questions or I can be of assistance please contact me.

Sincerely,

THOMAS P. MCCARTHY

Steve Gage
Fire Marshal

TPM/SG/cb

cc: William Larsen, PADS

Protecting The Golden Empire

RESOURCE MANAGEMENT AGENCY

RANDALL L. ABBOTT
DIRECTOR

DAVID PRICE III
ASSISTANT DIRECTOR

Environmental Health Services Department
STEVE McCALLEY. REHS. DIRECTOR

Air Pollution Control District
WILLIAM J. RODDY. APCO

Planning & Development Services Department
TED JAMES. AICP. DIRECTOR

ENVIRONMENTAL HEALTH SERVICES DEPARTMENT

June 19, 1992

James C. Killen, Technical Assurance Manager
U. S. Department of Energy
P. O. Box 11
Tupman. CA 93276

SUBJECT: Draft Supplement to the 1979 Final Environmental Impact Statement. Naval Petroleum Reserve No. 1

Dear Mr. Killen:

This Department welcomes the opportunity to review this document as the Local Enforcement Agency (LEA) for the California Integrated Waste Management Board. We have the following comments.

1. Submit a list of all sanitary (nonhazardous) landfills on the Naval Petroleum Reserve. This list should include site legal description. type of waste received, and approximate date of inactivation. **8a**

2. Submit closure plans for all inactive and abandoned sanitary landfills on site according the procedure required in Title 14 of the California Code of Regulations. **8b**

If you have any questions. please contact Smith Efada at (805) 861-3636. Extension 522.

Sincerely.

William O'Rullian

William O'Rullian. R.E.H.S.
Environmental Health Specialist IV
Solid Waste Program

SE:jrw

·swletadavnori

2700 "M" STREET. SUITE 300 BAKERSFIELD. CALIFORNIA 93301 (805) 861-3636
FAX: (805) 861-3429

KERN COUNTY
WATER AGENCY

Mailing Address:
P.O. Box 58
Bakersfield, CA 93302-0058
Phone: 805/393-6200
Fax: 805/393-1713

August 4, 1992

James C. Killen
Technical Assurance Manager
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

RE: DRAFT ENVIRONMENTAL IMPACT NAVAL PETROLEUM RESERVE NO. 1 ELK HILLS

Dear Mr. Killen:

The Agency has reviewed the "Draft Supplemental EIS for Petroleum Production at Maximum Efficient Rate Naval Petroleum Reserve No. 1 (Elk Hills) Kern County, California". The Agency appreciates the opportunity to respond to this document. Due to the proximity of large scale, beneficial, ground water recharge and extraction projects to the east of historic and proposed produced water injection sites (Tulare Formation), it is crucial to better characterize the hydrogeology of the interface between the northeast flank of Elk Hills and the younger alluvial sediments to the east.

The Kern County Water Agency concurs with the Environmental Impact Statement (EIS) mitigation factor recognizing the eminent need for a ground water monitoring project in the northeast portion of the Naval Petroleum Reserve (NPR). Given the Department of Water Resources (DWR) development of a ground water monitoring network within and peripheral to the Kern Fan Element (KFE) of the Kern Water Bank (KWB), it would be beneficial to all concerned parties to coordinate the development of NPR ground water monitoring projects with the efforts of the DWR. 9a

Existing water chemistry data and water level measurements in conjunction with ground water modeling, being conducted by the DWR and KCWA, in the northeast portion of the NPR suggests the potential for recent faulting along the northeast flank of Elk Hills. While a fault at these shallow depths might beneficially impede movement of poor quality water from Elk Hills toward the east it could also generate earthquakes. These earthquakes could result from natural stresses of the continued deformation of Elk Hills or induced stress due to extraction and water flooding within the NPR. A relatively large magnitude earthquake along the northeast flank of Elk Hills could be detrimental to DWR 9b and KCWA well fields in the western portion of the KFE. the West Kern Water District well field and the California Aqueduct. It is important that the KCWA. as well as the DWR. better understand the potential for earthquakes associated with the Elk Hills structure. Section 3.1.2.5. on seismicity. notes that no active faults have been identified within the boundary of the site. However. the search method used for active fault identification and the criteria for constituting an active fault was not presented. Figure 3.1-4. Generalized Geologic Map of the NPR-1 Area. suggests Faults 1 to 4 extend to ground surface. Fault 4 is close to the area where large contrasts in water quality and depths occur over a very short distance suggesting these faults may represent ground water flow barriers. 9b

In Appendix D, page D-4. D.3.2. it is noted that the KCWA identifies two principal water bearing units in the San Joaquin Valley, the unconfined and confined aquifers. These units are also identified by the U.S. Geologic Survey (USGS) and the DWR. However, the Agency's interpretation is only based to a certain degree on these previous studies. The Agency suggests a more complicated system of an unconfined aquifer and potentially more than one semi-confined aquifer. based upon ongoing modeling, geological and geochemistry studies in conjunction with the DWR. In this same section the base of a confined aquifer is premised on the 2000 ppm TDS water quality. Confined aquifers are based on hydraulic constraints (top and bottom) not water quality demarcations. except in fresh water lenses where the base is constrained by a large contrasts in density between the fresh water and lower sea water. 9c

In conclusion. the Agency recommends a joint review between concerned Agencies of existing geophysical and geological data for the northeast flank of Elk Hills. Such a review may resolve shallow faulting in this area and various hydrogeological parameters of the aquifer system. Additionally, this review would assist DOE. Betchel. CUSA. DWR and KCWA geologists involved with the characterization of the structural and stratigraphic relationships adjacent to Elk Hills. The KCWA and DWR Geologists are especially interested in the area adjacent to Elk Hills from South Coles Levee to the Tule Elk Reserve. This review should be a prerequisite to development of a ground water monitoring network in this area. 9d

Should you have any questions with respect to the Agency's comments. please contact Kenneth Turner. Tom Haslebacher or Rick Iger of the Agency staff.

Sincerely,

m Burk for

Darrell K. Sorenson
Special Projects & Data Manager

July 25, 1992

Mr. James C. Killen, Technical Assurance Manager
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, Ca 93276

Dear Mr. Killen:

The following comments are offered for the Draft Supplement to the Final Environmental Impact Statement (DOE/EIS-0158) which was released for public comment by the U.S. Department of Energy in May 1992. I respectively request that these comments be included in the public and agency comment section of the Final Supplemental Environmental Impact Statement.

While an employee of Argonne National Laboratory, I was the Project Leader for preparation by Argonne staff of a preliminary draft Supplement to the 1979 Environmental Impact Statement covering operation of the Naval Petroleum Reserve. That preliminary draft document was presented to the U.S. Department of Energy in June 1990. I had no involvement with revision and modification of that preliminary draft document and preparation of the Draft Supplement to the 1979 Environmental Impact Statement by the U.S. Department of Energy and the Department's contractors at the Naval Petroleum Reserve. Substantial editorial and technical changes were made to the preliminary draft document during its conversion to the Draft Supplement to the 1979 Environmental Impact Statement. It is therefore inappropriate and incorrect to show or imply my involvement as Project Leader for the current document as is done in Section 8.1 of that document.

I therefore demand that my name not be listed in the Final Environmental Impact Statement as Project Leader, nor that it be implied or inferred in the Final Environmental Impact Statement that I had involvement in preparation of the document in any other capacity than as Project Leader for preparation of the preliminary draft provided to the U.S. Department of Energy in June 1990. Because of the substantial editorial and technical revisions and modifications to the June 1990 preliminary draft by the U.S. Department of Energy, the actual Project Leader and technical staff who prepared the Draft Supplement to the 1979 Environmental Impact Statement (i.e., staff of the U.S. Department of Energy and the Department's contractors at the Naval Petroleum Reserve) should be listed rather than my name and those of Agronne National Laboratory staff. 10a

Thank you for the opportunity to comment on the Draft Supplement to the 1979 Environmental Impact Statement.

Sincerely,

Richard D. Olsen

Richard D. Olsen, Ph.D.

13010 SW Hanson Road
Beaverton, Oregon 97005

MICHAEL R. RECTOR, INC.
Water Resources Consultant

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July 8, 1992

Mr. James C. Killen
U.S. Department of Energy
Technical Assurance Manager
P.O. Box 11
Tupman, California 93276

Dear Mr. Killen:

As a follow-up to the comments I entered into the record at the Public Hearing on the NPR-1 Draft Supplemental Environmental Impact Statement (DSEIS) on June 24, 1992, I would like to submit these additional comments on the DSEIS. I have one general comment and several suggestions relating to the document text.

On page 5-2 of Appendix G (NPRC FY 1989-1995 Long Range Plan) it is stated that, "Groundwater protection is a primary concern in water quality management." On page 5-6 of Appendix G a groundwater monitoring project is referenced. "DOE Order 5400.1 (11/4/88) calls for a groundwater monitoring program for groundwater that is or could be affected by DOE activities." "A plan must be completed by 5/9/90." What is the current status of this plan?

In reviewing the DSEIS I noted a shortage of maps detailing NPR-1 groundwater structure, groundwater quality, water well locations, and locations of existing groundwater monitoring wells. Although a draft monitoring plan has addressed the need to investigate several suspected problem areas, details of the proposed evaluation project were not mentioned in this document. **11a**

It is my feeling that the "big picture" has not yet been painted. Are Elk Hills activities affecting groundwater quality of down-slope water used by others?

In order to determine if groundwater has been contaminated, the characteristics of native water must be defined and direction of groundwater movement must be established. Specifics on proposed actions to accumulate these data were not mentioned in the DSEIS.

My comments on the DSEIS text are as follows:

1. Page 3.1-4. I suggest that you delete the last line of the last paragraph. The California Aqueduct is not a part of geology. 11b

2. Page 3.4-6. I suggest that you delete the word "potable" from the second line of the last paragraph. Aquifers are not identified by water quality that is drinkable. 11c

3. Page 3.4-8. The first paragraph states that, "The thickness of the confined aquifer is variable and has been defined as extending from the base of the E-Clay to the base of fresh water...". The base of fresh water should not limit the lower limit of the confined aquifer, a stratigraphic unit. 11d

4. Page 3.4-8. In the last line of the fourth paragraph, you refer to the San Joaquin Water District. I have never heard of a district with that title. 11e

5. Page 3.4-11. A statement should be included in the second paragraph that composite well structures also provide inflow from the unconfined aquifer into the confined aquifer. 11f

6. Page 3.4-11. In the fifth paragraph it is stated that water quality of the confined aquifer is normally better than that of the unconfined. This is not always true on the west side of the San Joaquin Valley. 11g

7. Page 3.4-11. In the last sentence of the last paragraph native salinity should be noted as a possible source of eastward migrating groundwater. 11h

8. Page 3.4-12. In the fifth sentence of the third paragraph I suggest you delete the parenthetical "(high quality water)". Confined water is not always high quality. 11i

9. Page 3.4-12. In the first sentence of the last paragraph, I suggest you delete the word "saturated". Groundwater is saturated. 11j

<u>APPENDIX D</u>

10. Page D-3. In the second paragraph I have the same comment as given for comment 4. 11k

11. Page D-3. In the third paragraph I would like to point out that crop irrigation recharge exceeds natural infiltration from the Kern River by a 5:1 ratio. 11l

12. Page D-4. My definition of the confined aquifer in the southern San Joaquin Valley is that portion of the Tulare Formation that underlies the Corcoran Clay. 11m

13. Page D-4. I suggest you delete the word "Saturated" from the subtitle for D.3.3.1. (See comment #9). 11n

14. Page D-5. Can you provide a map for the location of water supply well 61WS-8R? 11o

15. Page D-5. In the third sentence of the fourth paragraph, delete the word "saturated" (see comment #9). 11p

16. Page D-5. Can you provide a map of the 20 data points used by Rector to construct elevation surfaces of undifferentiated Tulare Zone groundwater? 11q

17. Page D-5. I suggest you delete the word saturated from the third sentence of the second full paragraph. 11r

18. Page D-5. In the sixth paragraph, Kern River is not the greatest source of groundwater recharge in the valley (See comment #11). 11s

19. Page D-7. In the D.3.3.2 Subtitle and following text I suggest you delete the words "saturated" and "unsaturated" when referring to groundwater. 11t

20. Page D-16. With reference to paragraph 2, groundwater underlying alluvial soils at NPR-1 is not usually considered to be "high quality". 11u

APPENDIX G

21. Page 5-7. The recommendations in the second paragraph are too limited. A definite time schedule and budget should be established for work to be performed by designated qualified people; the highest priority should be to identify native groundwater conditions. Initial monitoring should include down-slope NPR-1 property boundaries and might include cooperative activities with adjacent land owners. 11v

I thank you for the opportunity to comment on your Draft Supplemental EIS. If you would like to discuss any of my comments further I can be reached at (805)322-8206.

Sincerely,

Michael R. Rector

Michael R. Rector
Registered Geologist #78
REA #646

UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SECRETARY
Office of Environmental Affairs
600 Harrison Street, Suite 515
San Francisco, California 94107-1376

ER92/443

July 16, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

The Department of the Interior has reviewed the Draft Supplemental Environmental Impact Statement for the Petroleum Production at Maximum Efficient Rate Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California and has no comments.

Thank you for the opportunity to review this document.

Sincerely,

Patricia Sanderson Port
Regional Environmental Office

cc: Director, OEA (w/orig. incoming)
State Director, BLM, Sacramento

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105

July 30, 1992

James C. Killen, Technical Assurance Manager,
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

The Environmental Protection Agency (EPA) has reviewed the Supplemental Draft Environmental Impact Statement (SDEIS) for the proposed operations entitled **Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California.** Our review is provided pursuant to the National Environmental Policy Act (NEPA), Council on Environmental Quality (CEQ) regulations (40 CFR Parts 1500-1508), and Section 309 of the Clean Air Act.

The Department of Energy (DOE) has been directed by Public Law 94-258 (Naval Petroleum Reserves Production Act of 1976) to continue operating Naval Petroleum Reserve No. 1 at the Maximum Efficiency Rate (MER), which is defined as "the maximum rate that optimizes ultimate hydrocarbon recovery and economic return...consistent with...all...laws and regulations, including federal, state, and local laws pertaining to the environment." Within that context, and because of declining production rates, the DOE is proposing to enhance the recovery of hydrocarbon reserves by expanding operations within NPR-1. This expansion would involve drilling additional wells for production as well as for injection; constructing and operating compression and processing facilities; expanding waterflood operations; construction and operation of a 42 megawatt cogeneration facility; construction and operation of a butane isomerization facility; construction and operation of a 148 well, 500 acre, 625 million BTU/hour steamflood project; construction and operation of facilities to increase gas compression capabilities by approximately 46,250 horsepower; and would include "activities to permit third parties to construct, operate and maintain pipeline projects, geophysical surveys, and other projects/activities on NPR-1 lands."

In addition to the Proposed Action (identified as the preferred alternative), the DSEIS discusses two alternatives: "No Action" (Alternative 1) and a "Modified Proposed Action" (Alternative 2). No Action would essentially preclude further development at NPR-1, but would continue production of oil and gas at a naturally declining rate. The Modified Proposed Action eliminates the gas processing, steam injection, and cogeneration project aspects of the proposed action. It is uncertain whether Alternative 2 would meet "legislated MER requirements." DOE is undertaking studies to determine the feasibility of carrying this alternative forward. 13G-1

From a NEPA perspective, there are several instances in the DSEIS in which outdated information is referred to, especially in the Air Quality Section. In addition, in discussing the Proposed Action, the document often implies that certain environmental protection programs are linked only to that alternative. For example, on page 4.1.5-3, the document speaks of the Wildlife Management Plan as providing benefits to the proposed action whereas the Plan is not mentioned by name in the discussions of the other alternatives. While this may simply be a product of the organization of the document, it is misleading to suggest that such plans are connected to the proposed action. Further, it is not clear in the DSEIS that there is an actual need for the project. Given that the "legal" requirement to produce NPR-1 at the MER was based on "cold war" perspectives that may no longer be applicable and that military programs are actively and substantially being reduced, the purpose and need for the project should be re-evaluated and presented clearly in the FSEIS. 13G-2

From the environmental and related technical information provided in the DSEIS, it appears that in some instances there may be actual conflicts between operating at the MER (implementing the preferred alternative) and adherence to environmental laws such as compliance with the conformity provisions of the Clean Air Act (CAA) and in terms of complying with the provisions of the Endangered Species Act. In addition, EPA is very concerned with the large amount of fresh water that would be required to support enhanced recovery of hydrocarbon resources; with the potential for additional groundwater contamination; with the major increase in surface disturbance that would take place; with the increase in the generation of hazardous wastes; and with the rapidly declining biodiversity and carrying capacity of the Reserve. Our specific concerns are discussed further in the attached comments. 13G-3

As a result of our review, we have assigned the Proposed Action (Preferred Alternative) a rating of **EO-2, Environmental**

Objections - Insufficient Information. While the No Action Alternative appears to be the environmentally preferable alternative at this point, we do have several concerns with that alternative as detailed in the attached comments. Because of those concerns, we have rated No Action (Alternative 1) as **EC-2, Environmental Concerns - Insufficient Information.** These ratings are further defined in the attached "Summary of the EPA Rating System," also attached. The limited information available and uncertainties surrounding the specific scope of the Modified Proposed Action (Alternative 2) does not provide a appropriate basis for rating that alternative at this time. 13G-4

Given that the DSEIS has not, in our opinion, clearly defined the true need for increased production specifically from Elk Hills, we suggest that DOE consider a fourth course of action. We recommend that a subsequent alternative (Alternative 3) be developed to include provisions of the No Action alternative for the near term and provisions of the Preferred Alternative for the future. The alternative should/would:

* Place production in correlation with need;

* Immediately allow for enhanced and accelerated restoration of the existing Reserve (such as fully implementing the drainage reclamation program referred to on page 4.1.4-1 and providing additional resources into site and roadway reclamation);

* Allow for less near-term expansion and the activities related to such expansion, thereby providing undisturbed habitat for enhanced species recovery; 13G-5

* Minimize water usage during the current extended drought;

* Minimize aquifer drawdown and provide a respite from wastewater injection;

* Ensure that the activities which would be undertaken on the facility will be in compliance with the conformity provision of the new CAA, and;

* Provide time to undertake needed maintenance of aging equipment and replace marginal machinery with state of art equipment.

We appreciate the opportunity to review your DSEIS. Please send three copies of the Final SEIS to this office at the same time it is officially filed with our Washington, D.C. office. Meanwhile, should you have questions or wish to arrange a meeting to discuss any of the issues raised in our review, please contact Dr. Jacqueline Wyland, Chief, Office of Federal Activities at (415) 744-1584 or have your staff contact David Farrel at (415) 744-1574.

Sincerely,

Jacqueline Wyland

for ~~Deanna~~ Deanna Wieman, Director
Office of External Affairs

001626CL.DF

Enclosures (2)

SUMMARY OF RATING DEFINITIONS AND FOLLOW-UP ACTION

Environmental Impact of the Action

LO-Lack of Objections

The EPA review has not identified any potential environmental impacts requiring substantive changes to the proposal. The review may have disclosed opportunities for application of mitigation measures that could be accomplished with no more than minor changes to the proposal.

EC-Environmental Concerns

The EPA review has identified environmental impacts that should be avoided in order to fully protect the environment. Corrective measures may require changes to the preferred alternative or application of mitigation measures that can reduce the environmental impact. EPA would like to work with the lead agency to reduce these impacts.

EO-Environmental Objections

The EPA review has identified significant environmental impacts that must be avoided in order to provide adequate protection for the environment. Corrective measures may require substantial changes to the preferred alternative or consideration of some other project alternative (including the no action alternative or a new alternative). EPA intends to work with the lead agency to reduce these impacts.

EU-Environmentally Unsatisfactory

The EPA review has identified adverse environmental impacts that are of sufficient magnitude that they are unsatisfactory from the standpoint of environmental quality, public health or welfare. EPA intends to work with the lead agency to reduce these impacts. If the potential unsatisfactory impacts are not corrected at the final EIS stage, this proposal will be recommend for referral to the Council on Environmental Quality (CEQ).

Adequacy of the Impact Statement

Category 1-Adequate

EPA believes the draft EIS adequately sets forth the environmental impact(s) of the preferred alternative and those of the alternatives reasonably available to the project or action. No further analysis or data collection is necessary, but the reviewer may suggest the addition of clarifying language or information.

Category 2-Insufficient Information

The draft EIS does not contain sufficient information for EPA to fully assess environmental impacts that should be avoided in order to fully protect the environment, or the EPA reviewer has identified new reasonably available alternatives that are within the spectrum of alternatives analyzed in the draft EIS, which could reduce the environmental impacts of the action. The identified additional information, data, analyses, or discussion should be included in the final EIS.

Category 3-Inadequate

EPA does not believe that the draft EIS adequately assesses potentially significant environmental impacts of the action, or the EPA reviewer has identified new, reasonably available alternatives that are outside of the spectrum of alternatives analyzed in the draft EIS, which should be analyzed in order to reduce the potentially significant environmental impacts. EPA believes that the identified additional information, data, analyses, or discussions are of such a magnitude that they should have full public review at a draft stage. EPA does not believe that the draft EIS is adequate for the purposes of the NEPA and/or Section 309 review, and thus should be formally revised and made available for public comment in a supplemental or revised draft EIS. On the basis of the potential significant impacts involved, this proposal could be a candidate for referral to the CEQ.

*From: EPA Manual 1640, "Policy and Procedures for the Review of Federal Actions Impacting the Environment."

EPA COMMENTS ON THE DRAFT SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT FOR PETROLEUM PRODUCTION AT MAXIMUM EFFICIENT RATE, NAVAL PETROLEUM RESERVE NO. 1 (ELK HILLS), KERN COUNTY, CALIFORNIA 001625SD.DF

NEPA

XX The first sentence in the Summary of the DSEIS states that "(t)his document provides an analysis of the potential environmental impacts associated with **continued operation** (highlight added) of NPR-1 as authorized by Public Law 94-258, the Naval Petroleum Reserves Production Act of 1976 (Act)." While this may be an accurate statement from the perspective of persons familiar with operations at NPR-1, the proposed action (preferred alternative) actually includes several new and rather extensive undertakings such as drilling numerous new wells, construction of a co-generation plant, and implementation of enhanced recovery techniques, to mention a few. We recommend that for purposes of clarity the initial text be modified to reflect that the document actually provides an analysis of **continuing production** of oil and gas reserves at the maximum efficient rate (MER) in accord with Public Law 94-258 (the proposed action), **and** an analysis of alternatives to the proposed action, which also involve **continued operations** at NPR-1 but **at varying rates of production**. The theme of this introduction should then be reflected throughout the document to avoid confusion as to what constitutes operations in terms of the proposed action (preferred alternative) and operations in terms of no action and alternative 2.

This confusion is also evident on page 4.1.4-2 wherein the DSEIS titles section 4.1.4.2.1 "Impacts from Continuation of Current Oil and Gas Activities" and states that "this section addresses the impacts of the proposed action..." It is our understanding that **continuation** of current oil and gas activities is more in line with the description of the no action alternative since the no action alternative would, by definition, continue production **without additional development** and **without major modifications** to **current operations**. 13N-1

XXX For purposes of clarity, we recommend that the statement which attempts to compare areas of habitat disturbance between alternatives be re-worded as follows:

> "Implementation of Alternative 1, no action, would disturb approximately 741 acres of habitat on and off NPR-1 over the next 30 years. In comparison to no action, the preferred alternative would **increase** habitat disturbance by 828 acres, Alternative 2 would **increase** habitat disturbance by 378 acres, and both the proposed action and Alternative 2 would **increase** 'other areas of significant impacts' accordingly."

13N-2

Table S-1, "Summary of Impacts and Mitigation for Each Major Impact Area of the Proposed Action," presents a very good overview of the proposed action, however, the column entitled "Favorable Impacts/Mitigation Programs" is misleading. The presentation implies that the "Favorable Impacts/Mitigation Programs" are actually linked to implementation of the proposed action (preferred alternative). We assume, however, that many of the programs are ongoing or have no relation to implementation of any specific alternative. This should be made clear in the FSEIS. 13N-3

The DSEIS often compares the proposed action with an action that has taken place in the past or uses the proposed action as a basis for comparing other alternatives. For example, under Impact Area 2 (Waste), the document compares the proposed drilling program with the past program, stating that the proposed program would be significantly smaller. This is also in evidence on page 4.1.2-1 wherein the DSEIS states that "the proposed action would sharply reduce well-drilling activity...and the volume of spent drilling fluids requiring disposal." This infers that implementing the proposed action is the key in reducing the level of activity in the field...which is not true in comparison with the no action alternative. Such comparisons are also presented on pages 4.1.4-2 and 4.1.4-11. Discussions should not compare past activities with the proposed action, but should consistently compare the relative impacts and merits of the alternatives with no action as the base for comparison. This would give the reader a clearer picture of the extent of activities being proposed under each alternative. 13N-4

Also in Table S-1, in the impacts discussion of Item 9, the text compares the drilling program of the proposed action with that which took place in the past rather than comparing proposed activities with the no action alternative. This could give the false impression that the proposed action is favorable because it reduces hazardous operations on NPR-1. In actuality, implementing the proposed action would not reduce hazardous operations on NPR-1 and would, in fact, increase such operations in comparison to the appropriate baseline. 13N-5

P 1-3 The three year extension of Public Law 94-258 granted in April of 1991 was based on "economic and military preparedness criteria." In clarifying the rationale for the true need for the resources **at this time** we recommend that the FEIS discuss whether or not the latest developments in world-wide politics and military strategies have been considered and whether the significant reductions in our military forces have been factored into the decision to extend extraction of petroleum resources at MER. This discussion should be included in the purpose and need section of the FSEIS. 13N-6

P 1-12 Under the heading "Summary of Proposed Action" the DSEIS discusses two "scenarios": the "maintenance case" - which assumes that production would continue on NPR-1 without additional development; and the "full development case" - which assumes additional development and application of recovery techniques. Inasmuch as the DSEIS defines the No Action Alternative (1) as that alternative which "provides for the continued production of NPR-1 by operating and maintaining existing wells and facilities, but without...further development..." (page 2-1), and on page 2-13 defines the Proposed Action as the Preferred Alternative, it is unclear how the proposed action's "maintenance case" differs from the no action alternative, and whether the Preferred Alternative is actually the "full development case" scenario discussed as being but one "scenario" of the proposed action. 40 CFR 1502.14 specifies that an EIS present the alternatives "in a comparative form, thus sharply defining the issues and providing a clear basis for choice among options by the decisionmaker and the public." The manner in which the preferred alternative, no action alternative, and the proposed action are presented in this document does not provide sufficient clarity to accommodate the requirements of 40 CFR 1502.14. We recommend that the document be reformatted as previously suggested to more clearly identify the proposed action (and preferred alternative) as "full development" and the no action alternative (to be used as the basis for comparing all alternatives) as the "maintenance case." If our understanding of the maintenance case" is correct, it should not be linked to discussion of the proposed action/preferred alternative. **13N-7**

P 4.1.2-7 The DSEIS lists a number of "mitigation activities" which "focus on remediating impacts associated with past and current operations." Its stated that the activities are included in the Long Range Plan and the proposed action. The FSEIS should clarify whether these mitigations would be implemented if the proposed action was not the selected action. In addition, referring to the statement on page 4.1.2-6, wherein it is indicated that "proposed facility developments would undergo future project-specific environmental analyses which would address additional mitigation measures..." it is unclear whether each "mitigation activity" listed on page 4.1.2-7 would be prefaced by a NEPA document inasmuch as an appropriate level of detail is not provided in the DSEIS to assess the effects of each of the actions listed. The FSEIS should provide additional information to help clarify the specific NEPA process to be used for individual activities being proposed on NPR-1. **13N-8**

P 4.1.3-1 We assume the dates signifying onset of construction activities presented on this page (1989) and on page 4.1.3-3 (1990) have been inadvertently included in this document and that the activities noted have not been initiated. The FSEIS should include an updated version of this section. **13N-9**

P 4.2-1 The DSEIS suggests that "up to 500 million barrels of oil and 250 billion cubic feet of gas would not be recovered" if the no action alternative was implemented. While this is accurate in the short-term, we wonder if there would be any effort to recover these resources in the more distant future when demand is greater. We recommend that the FSEIS discuss such a scenario. 13N-10

P 5-2 The DSEIS states that 1.2 billion dollars in federal revenues would be lost if the no action alternative rather than the preferred alternative was implemented. We question the actual loss of such revenue given that:

1) the resource remains ultimately recoverable; and
2) the position elucidated in the document assumes that the resource would never be recovered and correlates that non-recovery to a market value. A similar position could be taken which assumes that the resource could be recovered during a period when the demand and related value were higher, thereby suggesting that the federal government might not lose revenue dollars by adopting the no action alternative. 13N-11

We recommend that the FSEIS address these issues to the extent practicable.

BIODIVERSITY/THREATENED & ENDANGERED SPECIES

XXX The DSEIS indicates that implementing the preferred alternative would more than double the current amount of disturbed habitat and that alternative 2 would increase habitat disturbance by 51%. Given that populations of threatened & endangered species are rapidly declining on the Reserve, the FSEIS should discuss the implications involved with expanding the amount of habitat disturbance in terms of the Endangered Species Act and the provisions of the MER which state that development must be "consistent with...all...laws and regulations, including federal, state, and local laws pertaining to the environment." 13B-1

P 1-39 The FSEIS should explain what constitutes "successful revegetation" and should describe the process that would be used to ensure that vegetation is successfully reestablished. 13B-2

P 1-40 The FSEIS should describe the effects geophysical sound waves have on animals residing on the reserve, particularly those species designated as threatened or endangered. 13B-3

4

Table 2.0-1 The discussion in Element 20, Endangered Species Program, indicates that the program under alternatives 1 and 2 would be "**approximately** (highlight added) the same as proposed action." The FSEIS should briefly identify the major differences. 13B-4

P 3.5-1 The discussion on terrestrial biota on this page and on page 3.5-13 indicates that one of the possible factors in the reduction of kit fox populations is an increase in coyote abundance. This statement appears to be in conflict with the statement on page 3.5-6 (which reflects the information presented in figure 3.5-1), namely that coyote populations have decreased since 1984. The FSEIS should clarify these important statements. 13B-5

P 3.5-13 The DSEIS indicates that the "FWS concluded in their 1987 Opinion that, although 'there are no assurances' that development activities will not 'eventually contribute to the extirpation' of the kit from the site, development activities are 'not likely to jeopardize the continued existence' of the species." It is unclear, however, whether the Opinion considered the proposed actions presented in this EIS. The FSEIS should provide an updated FWS Opinion (results of the consultation process required to undertake this project, as suggested on pages 3.5-14 and E-5), given that kit fox populations have declined approximately 85% in the last ten years and have continued to decline since the 1987 Opinion. 13B-6

Although the Summary of the DSEIS suggests that "NPR-1 supports a diverse variety of flora and fauna" the fact that four federally endangered species, one state threatened animal, one federally threatened plant and 27 other plant and animal species "that have been categorized at various levels of concern" are known to be present suggests that NPR-1 may not continue to support such a diversity unless actions, such as conducting operations at a rate that would encourage optimal species and habitat recovery, are implemented. Expanding oil and gas recovery operations, as described in the DSEIS, would not appear to encourage biodiversity. 13B-7

P 3.5-34 The DSEIS suggests that oil and oil-field chemicals that have been spilled or otherwise released could have been "inhaled or ingested by kit foxes through contaminated drinking water or prey," and that "oil-field wastewater often contains high concentrations of dissolved solids, salt, and various other minerals and can cause death, nervous disorders, tissue damage, and decreased reproduction in...wildlife if ingested." The FSEIS should expand upon these statements and detail the specific measures that would be (or are being) taken to prevent ingestion of such chemicals by threatened and endangered and other species. 13B-8

P 4.1.5-3 Given that past activities have had a variety of negative impacts on animal communities, including questionable 13B-9 impacts on threatened and endangered species, the statement that the proposed action would continue to have similar impacts suggests that an alternative action may be preferable. For example, the DSEIS states that with the implementation of the proposed action, "animals within construction areas would be killed during construction or would disperse to other areas; dispersing individuals tend to have a lower survivorship," and that "they could ingest oil-field chemicals present in sumps or assimilated by forage which might cause or contribute to death, disease or diminished ability to avoid predation." Death, reduced survivorship, and diminished avoidance of predation all equate to reduced populations. Inasmuch as the four animal species that are currently listed as threatened/endangered" are likely to be affected by the proposed action," (p 4.1.5-4) the FSEIS should detail the consultation process undertaken with the U.S. Fish and Wildlife Service, should provide a list of their recommended and required actions, should identify and quantify the impacts expected from other activities which would be undertaken in the region, and should discuss in detail the plans which would be undertaken at NPR-1 to ensure to the maximum extent possible the survivorship of the species in question. This is especially important because "the FWS believes that (other nearby) projects will result in significant cumulative effects to the kit fox, blunt-nosed leopard lizard, and giant kangaroo rat." 13B-9

In addition, given that "programs to mitigate the effects of NPR-1 activities on terrestrial biota have been in effect for a number of years..." and that species populations have continued to decline throughout that period of time, the FSEIS should discuss the potential for enhanced and accelerated mitigation programs to assist in reestablishing the carrying capacity of the immediate area. For example, on page 4.1.5-10, the DSEIS suggests that reclamation efforts between 1985 and 1988 resulted in a low of 115 acres being reclaimed in 1985 and a maximum of 200 acres being reclaimed in 1988. Based on figures presented in the DSEIS that each wellsite and access road encompasses approximately 2.2 acres, reclamation of 200 acres accounts for only nine wellsites. It was also noted that the average plant cover was only 6% in 1990. We encourage continued monitoring of reclaimed sites and recommend that the FSEIS provide more details on strategies to ensure enhanced and accelerated revegetation of disturbed sites. The discussion should also detail the strategies used at NPR-1 to re-plant sites containing minimal vegetation, should identify the levels at which replanting is undertaken, and should discuss the role erosion plays over time in terms of successful (or unsuccessful) revegetation. 13B-10

We share your concern that NPR-1 is regionally significant because "based on the 1979 estimate, it contains 8% of the remaining undeveloped habitat in the southern San Joaquin Valley." In the thirteen years since that estimate, it would seem plausible that the extent of undeveloped habitat within the southern San Joaquin Valley has continued to decline. This would seem to add impetus to undertaking accelerated and enhanced restoration efforts on the Reserve.

In terms of providing data which projects future restoration efforts (should the proposed action be implemented), we do question whether one can assume that continuing to implement the current habitat reclamation program would be successful (as suggested on page 4.1.5-13) given that the most recent plant cover on average was estimated at only 6% . The FSEIS should either provide information on an enhanced strategy for restoration or provide figures which relate more appropriately to the level of successful reclamation realized in the near past. 13B-10

P 4.2.1.5 The FSEIS should include the results of the toxicology study which is being undertaken to determine the extent to which oil-field chemicals may be entering the tissue of NPR-1 kit fox prey. The results should be discussed in terms of the extent to which oil-field activities indirectly impact the kit fox and should provide strategies to eliminate the intrusion of such chemicals into the food chain of the kit fox, if the study indicates their presence. 13B-11

P 5-2 The DSEIS suggests that impacts from implementing the no action alternative would include disturbance to various habitats from new construction. Our understanding of the no action alternative is that no new construction would occur. Please clarify this in the FSEIS. 13B-12

P E-5 The DSEIS states that "the kit fox population in the NPR-1 study area began stabilizing at or about the same time the (coyote) control program was put in place..." While this may be so, figure E.3-1 shows a long term continual increase in kit fox mortality from predation. This seems to suggest that even though fewer coyotes are using the kit fox as food source (since there are fewer coyotes on the reserve) they have, in fact, focused on the kit fox as a major food source, since kit fox mortality rates have continued to increase. The FSEIS should discuss this implication and its relationship to the possible declination of other food sources for the coyote as well as to the possibility that over time, disruption to kit fox habitat has placed them in a more precarious relationship with the coyote. 13B-13

HAZARDOUS MATERIALS/WASTE

13H-1

XXVII The FSEIS should clarify what is meant by the statement that many of the 106 "older inactive waste sites" have been addressed.

Table 2.0-2 The discussion in Element 2d, Hazardous Waste, states that hazardous waste from construction and operations would increase above the current level of approximately 19,800 lbs/yr to as much as approximately 500,000 lbs/yr. The constituents of this increase, approximately 26 times that which is currently generated, should be detailed and discussed in terms of applying waste minimization (source reduction) techniques. 13H-2

P 3.1-15 The FSEIS should reference descriptions of the "other additives" present within the oil waste fluid mixtures. 13H-3

P 3.2-17 The FSEIS should identify the materials currently being used as corrosion inhibitors since (we assume) arsenic is no longer being used. 13H-4

P 3.4-6 The FSEIS should describe the areal extent of the hydrocarbon stains referenced in the DSEIS, identify the specific source of contamination, and discuss what is being done to eliminate the contamination and control the source. 13H-5

P 4.1.2-2 The discussion and figures which supposedly reflect "the site's annual hazardous waste stream" should be clarified in the FSEIS. Table 2.0-2 suggests that the proposed action would increase this waste stream to as much as 500,000 pounds annually yet the discussion on this page refers to 19,800 pounds, that which is currently being generated. 13H-6

WATER RESOURCES

XXVII Wetland resources have not been identified as being present on NPR-1. The FSEIS should either discuss wetland resources or confirm that none exist on the Reserve. 13W-1

Table 8-1 The FSEIS should discuss the extent to which groundwater mining would occur, especially with the proposed increase in use of groundwater resources, and should describe how this would affect other aquifers, if at all. 13W-2

The discussion included as Item 4b, Groundwater, suggests that an analysis to assess the risks associated with hydrologic flow uncertainties is underway and, "based on preliminary results it appears that groundwater monitoring wells could be needed on the northeast portion of the site." We recommend that this analysis and any necessary mitigation measures be developed and presented in the FSEIS, and that decisionmaking on this EIS be delayed until the results of the analysis are available. 13W-3

P 1-34 The nature of the "water-treatment chemicals" and the environmental impacts (including byproducts) of using "selective catalytic reduction with ammonia injection" should be provided in the FSEIS. 13W-4

P 1-37 Implementing the preferred alternative would increase water requirements by 74,800 barrels per day by April 1995 (also note that the April 1990 figure presented is outdated). This water would come from WKWD. The FSEIS should outline the impacts which would be realized by other WKWD water users should supplies be increased to NPR-1. Is the "reduction in water deliveries to other westside oil companies" (the source of additional supplies from WKWD) permanent, or would these other oil companies also be preparing to enhance recovery operations thereby requiring additional water sources in the near future? The FSEIS should also discuss the implications involved in terms of impacts and alternative sources should WKWD not be able to supply needed water. 13W-5

P 3.4-12 The magnitude of the effect of disposing 2348 million barrels of oil field waste water in percolation sumps, stream channels, and ditches is unclear. The FEIS should succinctly describe the effects such disposal practices would have had on soil and groundwater resources in the vicinity of NPR-1, especially in light of the fact that "Rector (1983) has interpreted the direction of groundwater flow to be from the Elk Hills into the adjacent valleys." 13W-6

P 3.4-14 The discussion on this page suggests that "sometimes well operations result in the accumulation of oil in well cellars which, if not removed could eventually degrade groundwater." The FSEIS should evaluate operational modifications which could be accomplished to eliminate such accumulations and should discuss the reasons such accumulations would not be removed (promptly). 13W-7

P 3.4-19 Note that the UIC program does not allow the use of unlined sumps for disposal of oil and gas related wastes. All sumps receiving wastes should be closed or lined. The FEIS should address and resolve this issue. Refer also to the parallel discussion on page 4.1.4-5. 13W-8

P 4.1.4-6 The discussion concerning consumption of freshwater at NPR-1 suggests that "existing systems should be capable of providing requirements associated with the continuation of current operations." The information provided in this section should be more definitive, i.e., is the existing system capable, or will modifications be required? In addition, the DSEIS states that 29,000 barrels per day were required in 1988, and that the requirements "have been increasing" but does not provide current requirement figures. The FSEIS should include current data wherever possible. 13W-9

P 4.1.4-8 The DSEIS discusses a project to recycle approximately 50,000 barrels/day of wastewater and suggests that additional similar projects are planned to reduce disposal and possibly groundwater withdrawals, "pending the results of the first project" (this project is also discussed on pages XXVIII, 3.4-22 and 5-1). Given that the success of the first project has not been verified to date, the FSEIS should also discuss water needs and disposal impacts without the recycle project(s) and, depending upon the impacts, the success of the first project should be verified before a record of decision (ROD) is prepared for the alternatives evaluated in this EIS. 13W-10

P 4.1.4-12 The FSEIS should define what is meant by using "generally acceptable methods that pose minimal threats to underlying and peripheral groundwaters" to dispose of fluids that are "confirmed to be nonhazardous." Also, the FSEIS should define what is meant by "rare instances" when drilling fluids could test hazardous. 13W-11

P 6-1 The FSEIS should discuss the short-term requirements for water and use of the aquifers for disposal versus the long-term productivity of the region's water resources. 13W-12

P 7-1 The FSEIS should consider inclusion of freshwater resources in the discussion of irreversible and irretrievable commitments of resources. 13W-13

P D-3 Figures included in the DSEIS indicate that approximately 357 million gallons of wastewater were disposed of in sumps during 1979. The text indicates that wastewater production is increasing but does not supply current figures. These figures should be included in the FSEIS. 13W-14

On other pages in this appendix, the DSEIS indicates that there may be a link between sumps on the Reserve with brine-contaminated wells in the San Joaquin Valley. DOE should commit to making every effort to ensure that use of sumps is minimized and that those used are lined to prevent intrusion of low quality water into nearby waterwells. 13W-15

AIR QUALITY

Table S-1 The document should discuss each of the anticipated emissions increases in relation to the conformity provisions [§176(c)] of the new Clean Air Act (CAA). Please note that the CAA mandates that proposed activities will not 1) cause or contribute to any new violation of any standard in any area; 2) increase the frequency or severity of any existing violation of any standard in any area; or 3) delay timely attainment of any 13A-1 standard or any required interim emission reductions or other milestones in any area. The DSEIS does not acknowledge the new

CAA and therefore it is unclear whether or not the acknowledged increases in emissions would conform as required. For example, on page 4.1.3-3 the DSEIS states that there would be net increases in TSP and PM10 emissions from increased truck traffic delivering liquid products associated with increased production at the new fourth gas plant. The FSEIS should discuss these increases (and other sources of increased PM10 emissions as suggested in the document) in relation to the conformity provisions of the new CAA. It is unclear from the information presented in the DSEIS whether the existing SIP takes into account the new emissions which would result from the proposed action (refer also to page 4.1.3-19). 13A-1

P 3.9-5 The DSEIS states that NPR-1 reported that 3,748,000 miles of vehicle travel is completed per year on the Reserve. The FSEIS should include details on existing and/or proposed programs which NPR has established or will establish to reduce the vehicle miles travelled (VMT) and reduce air emissions from these mobil sources. 13A-2

P 4.1.3-10 It appears that the Caline 3 model was used to model transportation emissions. This model is outdated and modeling should be accomplished using the dated Caline 4 model. The data and resulting discussions should be included in the FSEIS. Refer also to page B-85. 13A-3

P 4.1.3-13 The FSEIS should explain how and when NPR-1 intends to "reduce emissions from the tank settings with high release records..." In addition, the document suggests a high level of uncertainty associated with emissions from anode bed wells. Methane, one of the primary pollutants emitted from anode bed wells, is considered a greenhouse gas which could contribute to global warming. Reductions of methane emissions is advisable to the extent possible. The FSEIS should discuss this situation in greater detail. 13A-4

P B-28 The DSEIS indicates that a revised "attainment plan with provisions for attainment of PM10 standards is due in mid-1990." The FSEIS should reflect the current status of the "attainment plan." 13A-5

Table B.7, Hazardous Air Pollutants, does not reflect information contained in the Clean Air Act of 1990, as amended. The table and associated text should be revised to reflect information contained in §112 of the Act. 13A-6

OPERATIONS

Table S-1 It should be made clear in the FSEIS (within the "Favorable Impacts/Mitigation Programs" section of Item 8, "Socioeconomics") that the preferred action would alleviate the "steep production decline" only for a finite period of time and that production would soon decline at the same rate currently being experienced, if not more rapidly. 130-1

Table S-1 In discussing risks, Item 9 includes a statement that suggests that the number of blowouts would decline due to a reduction of reservoir pressures. The discussion, however, does not acknowledge the difference in reservoir pressures that would be experienced from steam and waterflood injection. The FSEIS should provide a brief discussion of the relationship between anticipated blowout rates and injection. 130-2

The California Division of Oil and Gas (CDOG) has the primary responsibility for Class II (Oil and Gas) injection wells in California, and it issues permits for all injection wells related to oil and gas activities. DOE should work closely with CDOG on all aspects of its injection program and make sure it acquires the appropriate CDOG permits. 130-3

The FEIS should also provide updated information concerning the Tulare Formation being "an EPA Class II exempt aquifer since the 1950s." Since EPA did not exist in the 1950s, the Tulare may have been exempted by the State at that time.

P 1-5 The FSEIS should provide figures which discriminate between abandoned wells and shut-in wells on NPR-1. In addition, the FSEIS should discuss the feasibility of re-entering shut-in wells as an option to drilling new wells to increase production. 130-4

Figure 1.2-1 It is unclear whether this figure depicts projected oil production at NPR-1 with or without implementation of the preferred action. We suggest that the figure be redrawn as a comparison of production for all of the alternatives. 130-5

Page 1-32 The power source for the 10 proposed 1000 horsepower compressors and three 1500 horsepower compressors should be identified in the FSEIS. 130-6

P 1-39 The FSEIS should describe the Reserve's monitoring program in terms of ensuring that third party developers conduct activities in an environmentally responsible manner and should describe the enforcement mechanism used to ensure that developers are held responsible for impacts to the environment. 130-7

Page 2-10 The FSEIS should explain what is meant by the statement that "MER strategy is also consistent with that which is **generally pursued** (highlight added) within the private sector of 130-8 the oil-field industry." The explanation should describe the differences and provide the rationale for the differences. 130-8

P 3.2-16 The DSEIS mentions the presence of "pinholes" in the sides of a drilling fluid tank but does not indicate what is being done to curtail these leaks and to prevent other tanks from experiencing similar problems in the future. The FSEIS should expand the discussion to address these issues. 130-9

P 3.9-1 In discussing historical risks, the DSEIS states that the number of incidents (spills) "has increased steadily since 1983" and that "this increase may be attributed, in part, to increasing corrosion associated with aging equipment..." The FSEIS should provide information on any programs in place to repair and or replace aging equipment **before** accidents occur. 130-10

We also question the rationale for the contention that "the increasing age of equipment is not expected to be a serious problem." This statement appears to contradict the statement above. The FSEIS should clarify this contradiction and provide information on the schedule for replacing older equipment which **could** fail and result in pollution episodes. The FSEIS should also discuss the Reserve's plan for minimizing and/or eliminating waste streams, i.e., identify source reduction efforts. 130-11

P 4.1.3-20 The DSEIS suggests that worker exposure to benzene during spills and associated clean-up efforts could be higher than the OSHA's permissible exposure limits (PEL's), and indicates that procedures "**would be** (highlight added) incorporated into the SPCC plan so that the oil-spill cleanup crew arriving at the spill site would begin cleanup operations from the upwind side of the spill." The FSEIS should indicate why safety procedures are not already incorporated in the SPCC plan, and should discuss the precautions that would be taken if cleanup must be conducted downwind of the emission source. 130-12

P 4.1.4-2 While we agree that when production declines and wells are plugged and abandoned there will be less equipment in use, we do not necessarily agree that maintenance of the equipment would diminish. In fact we support your earlier statement that corroding equipment in a mature field needs enhanced maintenance to minimize spill occurrences. 130-13

P 4.1.4-11 The FSEIS should define how "spills would be minimized," and should define "regularly" as in "producing well cellars would be monitored regularly." 130-14

COMMENT LETTER 1

DOE RESPONSES

ARGONNE NATIONAL LABORATORY
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July 20, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

This letter is submitted by Argonne National Laboratory (ANL) as a comment to the Draft Supplement to the 1979 Final Environmental Impact Statement, Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California, DOE/EIS-0158, dated May 1992. Specifically, ANL and ANL staff should not be listed as preparers/contributors of this draft supplemental environmental impact statement (DSEIS).

Section 8.0 states that this DSEIS was prepared by the U.S. Department of Energy, Naval Petroleum Reserves in California, based on a preliminary draft of the document (PDSEIS) prepared by the Environmental Assessment and Information Sciences Division of Argonne National Laboratory (ANL 1990), and review comments provided by the staffs of DOE-NPRC, Chevron U.S.A. Inc. (CUSA), Bechtel Petroleum Operations, Inc. (BPOI), EG&G Energy Measurements, Inc. (EG&G/EM), and Research Management Consultants, Inc. (RMCI). The project was managed by DOE-NPRC with coordination and technical assistance provided by RMCI. However, the preparers/contributors table lists ANL staff as the specific authors of the technical and written material contained in the DSEIS. Other than DOE-NPRC management and support staff listed in the table, the current DSEIS explicitly shows ANL authors to be individually responsible for the material contained in the DSEIS.

Section 1502.17, entitled List of Preparers, of the Council of Environmental Quality Regulations for Implementing the National Environmental Policy Act 40, CFR Parts 1500-1508, states:

> "The environmental impact statement shall list the names, together with their qualifications (expertise, experience, professional disciplines), of the persons who were primarily responsible for preparing the environmental impact statement or significant background papers, including basic components of the statement (§§ 1502.6 and 1502.8). Where possible the persons who are responsible for a particular analysis, including analyses in background papers, shall be identified. Normally the list will not exceed two pages."

Implicit in this statement is that the persons listed were primarily responsible for preparing the text and technical material contained in the document, as issued. This is a disclosure standard and allows the public and interested parties to identify the authors and sources of the basic components

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Mr. J. Killen
July 20, 1992
Page 2

and technical background materials included in the document. This is especially critical for an environmental impact statement which serves a regulatory purpose and whose authors can be called to provide expert testimony to defend the statement.

Upon submittal of the ANL 1990 PDSEIS, the DOE Naval Petroleum Reserve informed ANL that they will assume the responsibility for the preparation of the DSEIS and would consult with ANL. At that time, ANL informed the DOE Naval Petroleum Reserve of its position with regard to the List of Preparers. If ANL were to be listed as preparers, we must have the opportunity to review and concur on the analyses DOE presented in the DSEIS. This was especially true given the General Accounting Report (GAO/RCED-91-129) that showed a disagreement between ANL and the DOE Naval Petroleum Reserve over certain technical findings contained in the 1990 PDSEIS. After ANL submitted the 1990 PDSEIS, ANL staff and management were not consulted on the revisions nor provided the opportunity to review and concur before DOE issued the DSEIS to the public. The CEQ recognizes that individuals preparing materials that become a part of an EIS should be identified even if the agency modifies their contributions (Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations). However, due to the material revisions made to the text, technical analyses, and conclusions in ANL's PDSEIS when compared to the final DSEIS issued by DOE, ANL feels listing ANL or ANL technical staff as preparers of the final document is not appropriate under the CEQ regulations. ANL personnel were not primarily responsible for the text and analyses contained in the final document. Consequently, ANL is asking all reference to ANL authorship be removed from the Draft and Final SEIS. Instead, the ANL prepared 1990 PDSEIS should be listed as a reference, as has been done for all other references, and cited, where appropriate, to support DOE's analyses. 1a

For Argonne National Laboratory,

H. Drucker
H. Drucker
Associate Laboratory Director
Energy, Environmental and
Biological Research

DOE RESPONSES

1.a Section 8.1 of the DSEIS has been revised by removing the names of all Argonne National Laboratory contributors from this document and by referencing Argonne National Laboratory's 1990 Preliminary Draft Supplemental Environmental Impact Statement.

COMMENT LETTER 2

DOE RESPONSES

STATE OF CALIFORNIA | PETE WILSON, Governor

DEPARTMENT OF FOOD AND AGRICULTURE

Control and Eradication
2895 N. Larkin, Suite A
Fresno, CA 93727

June 3, 1992

James C. Killen
Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, California 93276

Dear Mr. Killen:

I received a copy of the Department of Energy Draft Supplement to the 1979 Final Environmental Impact Statement (EIS) for Naval Petroleum Reserve No. 1 (Elk Hills). I appreciate the opportunity to review and comment on the draft supplement EIS for NPR-1.

Although the document is extensive in its content, I feel the draft would be more complete if a brief description of the Curly Top Virus Control Program (CTVCP) was included. 2a Because the CTVCP is not considered part of the Proposed Action, I am not certain as to the placement of such a description within the body of the draft. Future Non-Federal Actions (1.2.2.21), Miscellaneous (1.2.2.22) or the Cumulative Impact Section (4.1.5.5), are areas where the CTVCP could be described. The exact placement can be best determined by DOE staff who are close to the document.

If the CTVCP is included in the supplement EIS, delays and confusion may be avoided if future amendments are necessary.

I can certainly appreciate the time and effort necessary to produce a document of this size and complexity. If a decision is made to include a brief description of the CTVCP in the supplement EIS, I will be available to provide you and your staff any additional information you may need.

Sincerely,

Rodney A. Clark

Rodney A. Clark
Associate Economic Entomologist
Curly Top Virus Control Program
(209) 445-5472

cc Foote
Gotan
Peterson

2.a Section 1.2.2.21 of the DSEIS has been revised to include a description of the Curly Top Virus Control Program.

COMMENT LETTER 3

STATE OF CALIFORNIA—THE RESOURCES AGENCY

PETE WILSON, Governor

DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET PO BOX 942836
SACRAMENTO CA 94236-0001
(916) 653-5791

July 7, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
Post Office Box 11
Tupman, California 93276

Dear Mr. Killen:

As you are aware, the Department of Water Resources has purchased a tract of land adjacent to the Naval Petroleum Reserve No. 1 (Elk Hills). This land is being developed as a ground water banking facility of the State Water Project and is referred to as the Kern Fan Element of the Kern Water Bank. We are very concerned about potential threats to ground water quality of the KFE. Therefore, we were pleased to note in our review of the Draft Supplemental EIS for Petroleum Production at the Maximum Efficient Rate at Elk Hills that the potential for ground water degradation and off site migration of poor quality ground water was recognized and that efforts to reduce this risk and to develop a ground water monitoring program are under way.

As a result of our mutual concerns over potential ground water quality problems that could result from operations at Elk Hills, I propose that we cooperate in the review of the proposed ground water monitoring program to be developed and in evaluating proposed risk reduction measures. In turn, the Department will share the information from the KFE ground water monitoring program and from our studies that is pertinent to your efforts. To initiate this process, we would like to receive copies of the attached list of materials referenced in the draft EIS. 3a

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DOE RESPONSES

3.a The materials requested have been provided, and a commitment to continue cooperative efforts with the Department of Water Resources to develop NPR-1 groundwater monitoring plans was made by letter dated November 12, 1992 (DOE 1992a). Plans for cooperating are being developed. See also response to comment 9.d.

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DOE RESPONSES

Mr. James J. Hallen
July 7, 1992
Page Two

If you have any questions or wish to discus this issue, please call me at (916) 653-9632 or John Fielden at (916) 653-9495.

Sincerely,

Jack Erickson, Chief
Kern Water Bank Section
Division of Planning

Attachment

cc: Mr. John Fielden
Post Office Box 942836
Sacramento, California 94236-0001

Fishburn, M. D., 1990, Department of Energy, Memorandum to File, Naval Petroleum Reserves in California, February 14.

Golder Associates Inc., 1990, NPR-1 Groundwater Monitoring Plan, prepared for Bechtel Petroleum Operations, Inc., Tupman, California, May 15

McLemore, L., 1990, Pumping Volumes at NPR-1, Memorandum to Manager, Technical Assurance, U. S. Department of Energy, California.

Nicholson, G. E., 1985, Probable Communication between Wastewater Disposal Wells and Tulare Source Wells, interoffice memorandum to A. Palmer, Bechtel Petroleum Operations, Inc., Naval Petroleum Reserve No. 1, Tupman, California.

Nicholson, G. E., 1989, Source of Surface Seeps in Sections 3G, 4G, and 35S, Draft Report, Bechtel Petroleum Operations, Inc., Tupman, California

Remsen, W. E., 1990, Clarification of Upper and Lower Tulare Contact, NPR-1, Elk Hills, California, Bechtel Petroleum Operations, Inc., Memorandum to File, Tupman, California 93276

Stuart, C., 1987, A Review of Waste Water Disposal Operations at Elk Hills, Bechtel Petroleum Operations, Inc., Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California, August.

Waldron, J., 1989, Chevron, U. S. A., Inc., Bakersfield, California, letter to T. H. Filley, Argonne National Laboratory, Argonne, Illinois., Jan. 10.

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COMMENT LETTER 4

STATE OF CALIFORNIA—THE RESOURCES AGENCY PETE WILSON, Governor

CALIFORNIA ENERGY COMMISSION
516 NINTH STREET
SACRAMENTO CA 95814-5512

July 20, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
P.O. Box 11
Tupman, CA 93276

Re: Comments on the Department of Energy's DSEIS for the Naval Petroleum Reserve No. 1 (Elk Hills) in Kern County (Sch. 92064002)

Dear Mr. Killen:

Staff of the California Energy Commission (Commission) have reviewed the Draft Supplement to the 1979 Final Environmental Impact Statement (DSEIS), "Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California". Staff believes that the DSEIS does not provide essential information needed to assess all potentially significant environmental impacts, and does not provide adequate mitigation. Our comments address the areas of biological, cultural, and paleontological resources; and socioeconomics.

Summary of Recommendations

1. The DSEIS should provide estimates of indirect impacts to plant and animal habitats due to construction and operation of oil development-related activities at NPR-1 for the entire site over a 30-year project life. 4a

2. Biological mitigation measures should address all species potentially impacted by development-related activities at NPR-1, as well as provide for revegetation and kit fox monitoring. 4b

3. DOE should provide additional information on revegetation efforts to permit a realistic evaluation of the effectiveness of this mitigation measure, and develop criteria for evaluating the successes or failures of future revegetation programs. 4c

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DOE RESPONSES

4.a The CEQ regulations for NEPA (40 CFR 1508.8) define impacts to include direct impacts and indirect impacts that are reasonably foreseeable. To the extent possible and reasonably foreseeable, indirect impacts such as habitat fragmentation, wildlife displacement, and sublethal effects of oil-field chemicals are addressed in Sections 3.5 and 4.1.5. Please refer to the response to comment 13.B-11 for additional discussion regarding indirect effects of oil-field chemicals.

4.b All species and impacts are addressed in the NPR-1 Wildlife Management Plan in accordance with the U.S. Fish and Wildlife Service (FWS) 1987 Biological Opinion. Additional mitigation for protected species is being discussed with FWS and implementation will conform to the new Biological Opinion.

4.c The text in Section 4.1.5 of the DSEIS has been revised to include a discussion of revegetation monitoring and evaluation.

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DOE RESPONSES

4. To determine the relationship between oil development and kit fox population dynamics, DOE must use a reliable method to distinguish oil-developed from non-developed lands. 4d

4.d An analysis of kit fox decline rates in developed versus undeveloped areas of NPR-1 has been conducted (O'Farrell et al 1986). This analysis concluded that there were no significant differences in the decline rates between the two areas. Developed and undeveloped areas were defined taking into account circumstances unique to NPR-1. The methodologies employed were appropriate for their intended purposes. This is discussed in more detail as follows:

In part, this comment addresses the classification of disturbance as greater than 15% surface disturbance (developed) versus less than 15% surface (undeveloped). One concern is that the greater than 15% classification covers a range of 85% (15-100%), while the less than 15% classification covers a range of only 15% (0-15%). Actual disturbance on NPR-1 is low compared to most nearby oil-fields and is mostly less than 30% per section. In practice, the criteria used to classify developed versus undeveloped areas divides disturbance into two roughly equal ranges of disturbance. Furthermore, the statement that NPR-2 is less developed than NPR-1 is incorrect. NPR-1 is a more active oil-field, but surface disturbance on the two oil fields is similar with NPR-2 having slightly more surface disturbance.

The comment states that statistical evaluation would be greatly improved if actual area of disturbance were reported rather than using ratio or percent values. The meaning of this comment is unclear. While the reviewer's concern about using ratio values is in general, well founded, it is not appropriate in this case. If actual areas of disturbance were used instead of percent disturbance, they would need to be calculated per section (or on some other spatial basis). Actual disturbance per section is a ratio and differs from the percentage only by a scaling factor. This would not affect the significance tests of any statistical analyses.

The suggestion that disturbance be evaluated based on animal use areas (e. g., an animal's home range) is a good suggestion in theory, but one that cannot be implemented in practice. The areas used by individual animals are too poorly known to be able to analyze impacts on that basis.

It is unclear what is intended by the suggestion that any further attempts to study kit fox population dynamics eliminate the effects of other land uses such as agriculture and urban developments. The studies of kit fox population dynamics on NPR-1 and nearby are observational and are not designed experiments. Thus, there are inherent limitations to the inferences that may be drawn from these observations. Nonetheless, where possible, data analyses control for factors other than oil-development.

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5. DOE should provide a comprehensive evaluation of mortality to giant kangaroo rats, blunt-nosed leopard lizards, and other listed species as a result of construction and operation activities at NPR-1. 4e

Mr. James C. Killen
July 30, 1992
Page 2

6. DOE should compensate for loss of plant and animal habitat by purchase or protection of endangered species habitat, and set land aside in perpetuity to ensure the long-term preservation of those species impacted. 4f

7. DOE should include a contingency plan in the cultural resource management plan, in the event of discovery of subsurface cultural resources. 4g

8. DOE should also develop a contingency plan in the event of discovery of paleontological resources. 4h

9. The socioeconomic section should be updated to reflect current conditions (beyond 1988). The discussion of potential impacts resulting from out-of-county workers should be clarified; and a discussion of potential impacts to local school enrollments should be added. 4i

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DOE RESPONSES

4.e The text on page 4.1.5-4 of the DSEIS has been revised to incorporate by reference, the Biological Assessment prepared by DOE in 1991 that evaluates the effects of continued petroleum production at NPR-1 (DOE 1991). This Biological Assessment and the discussions in Section 4.1.5-3 provide the requested information on the effects to listed species. The commentor may obtain a copy of the Biological Assessment upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, P.O. Box 11, Tupman, California, 93276. In addition, most of the development proposed for NPR-1 will take place in areas where few giant kangaroo rats or blunt-nosed leopard lizards occur. The mitigation measures taken to minimize impacts on these species will be minor as long as there is little development in the lowland areas where these species are more abundant. Mortality is discussed in Sections 3.5.3 and 3.5.4 of this document. Additional baseline analyses are available in Biological Assessments prepared for the giant kangaroo rat (O'Farrell and Kato 1987) and the blunt-nosed leopard lizard (Kato and O'Farrell 1986).

4.f DOE is complying with the habitat compensation ratio and mitigation requirements agreed upon with FWS pursuant to the 1987 Biological Opinion. Mitigation including habitat compensation is being addressed in the ongoing Section 7 consultation with FWS, which has resulted in a new draft nonjeopardy Biological Opinion (see Appendix I.2).

4.g Section 4.1.6.1 of the DSEIS states that a Cultural Resource Management Plan for NPR-1 will be formulated in consultation with the State Historic Preservation Office (SHPO). This plan will address the protection of subsurface cultural resources.

4.h The NPR-1 Cultural Resource Management Plan, currently being developed in consultation with the SHPO, will also address paleontological resources, consistent with existing site paleontological data.

4.i DOE believes the existing socioeconomic analysis accurately reflects the beneficial impact of NPR-1 to Kern County and the Treasury of the United States. DOE does not believe that updating the information, which would be a significant and time consuming task, would significantly change this conclusion.

Section 4.1.8.2 of the DSEIS has been revised to clarify the potential impacts that would result from increases in the NPR-1 temporary work force as a result of the proposed action.

Because the proposed action requires the hiring of only a few additional permanent employees, the impact to local school districts is anticipated to be negligible.

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DOE RESPONSES

Biological Resources-Background Information

The Naval Petroleum Reserve 1 (NPR-1) supports four federally endangered animals, one federally threatened plant, and one state threatened animal. All but one of these species are endemic to the Southern San Joaquin Valley and, for each of these, the major reason for population decline is habitat loss. Cumulative habitat disturbance due to past development at NPR-1 is reported as approximately 6,546 acres. There has also been development-related habitat disturbance at NPR-2, which is adjacent to, and supports the same listed species as NPR-1; however, figures for acreage disturbed on NPR-2 are not provided in this document. The proposed action to expand operations at NPR-1 would result in an estimated loss of an additional 1,569 acres of known threatened and endangered species habitat over the next 30 years. The DSEIS does not provide estimates of indirect impacts due to construction and operation of oil development-related activities at NPR-1 other than an estimate of 6,780 acres that would be disturbed by seismic surveys over a 30-year project life. 4a

Refer to Comment Letter 4 Summary of Recommendations 1.

Past mitigation measures for all impacts from development-related activities at NPR-1 have mainly consisted of revegetation and kit fox population monitoring programs. Although valuable, these types of measures are not acceptable as mitigation for the type and degree of impacts experienced by the development activities at NPR-1. 4b

Refer to Comment Letter 4 Summary of Recommendations 2.

Biological Resources-Revegetation

The document reports that to date 1,689 acres of the 6,546 acres disturbed have been revegetated. However, more than half of the revegetation claimed (920 acres) occurred naturally and was not a result of active mitigation. The percent of ground and shrub cover (per acre covered) and species diversity achieved from the revegetation effort is not reported. Therefore, it is not possible to evaluate the effectiveness of this mitigation measure from the information given. 4c DOE considers areas revegetated (1,689 acres) as a credit to total areas disturbed by past activities (6,546 acres). In the proposed action to expand development, DOE figures that of the 1,569 acres of habitat that will be directly disturbed by development-related activities, impacts to 1,045 acres will be off-set by revegetation. If DOE has not done so already, further revegetation programs should establish criteria for revegetation success and provide for monitoring the successes and failures. 4c

Refer to Comment Letter 4 Summary of Recommendations 3.

Refer to Comment Letter 4 Summary of Recommendations 3.

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Biological Resources-Kit Fox Monitoring

The DOE kit fox monitoring program has been in place on NPR-1 since 1981 to determine the relationship between oil development and kit fox population dynamics. This effort has documented drastic declines in the kit fox population on NPR-1 over the duration of the study (from 165 foxes in 1981 to 19 foxes in 1991). The majority of the decline occurred in the foothills where development has been most intense. Although several factors may have contributed to this 81-88% decline, the effect of development is still uncertain and lack of equivalent declines (43-58%) in flatter undeveloped areas and on NPR-2 where there is less development suggests that development is somewhat responsible. Furthermore, reproductive success was lower in the developed areas than in undeveloped areas from 1982 to 1985. 4d

Several studies have been conducted on NPR-1 and NPR-2 in an attempt to determine differences in kit fox population dynamics in developed and undeveloped lands. However, the method used to distinguish oil-developed from undeveloped lands is not reported. Following a review of the literature we have determined that the criteria used (0-15% surface disturbance/sq. mile as undeveloped areas and 16-100% surface disturbance/sq. mile as developed areas) do not clearly distinguish between these land uses. Therefore, any results from these studies cannot be used in the context intended. The percent intervals are not equal and the potential impacts between the 16 percent end of the interval are significantly different from those at the 100 percent end of the interval. Statistical evaluation would be greatly improved if actual areas of disturbance were reported rather than using ratio or percent values. If intervals, either actual areas or percent, are used they should be of equal length and small enough intervals to characterize expected impacts. Consideration should also be given to describing disturbance in terms of animal use areas, such as the amount of an animal's home range. 4d

Mitigation for the proposed project provides for continued monitoring of kit fox population dynamics and conduction of pre-activity surveys to minimize impacts. Any further attempts to study kit fox population dynamics in relation to oil-developed vs. non-developed lands must clearly identify the level of development in the study areas and eliminate the effects of other land uses such as agriculture and urban developments. We further recommend that past studies be re-analyzed using the new criteria, since a major objective of these studies was to test the effects of oil development on various aspects of kit fox ecology. 4d

Biological Resources-Other Affected Species

In regard to the other listed species on-site, mortality as a result of operation activities has been documented for giant kangaroo rats and blunt-nosed leopard lizards. However, a comprehensive evaluation of the effects of construction and operation activities at NPR-1 on these and other listed animal and plant species is not provided in the DSEIS. 4e

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DOE RESPONSES

Refer to Comment Letter 4 Summary of Recommendations 4.

Refer to Comment Letter 4 Summary of Recommendations 4.

Refer to Comment Letter 4 Summary of Recommendations 4.

Refer to Comment Letter 4 Summary of Recommendations 5.

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DOE RESPONSES

Biological Resources-Concluding Comments

Although the kit fox and revegetation programs that have occurred on NPR-1 are notable, they are not in line with current mitigation practices common for all other development activities occurring in the Southern San Joaquin Valley. Federal and state requirements have established that the loss of habitat must be compensated by the purchase or protection of endangered species habitat. Compensation ratios used in the Southern San Joaquin Valley have ranged from 3-to-1 to 5-to-1 for direct loss of habitat known to support listed species. Indirect or temporary disturbances to listed species habitat have been compensated at ratios ranging from 1.1-to-1 to 3-to-1. Compensation can be accomplished by dedicating surface lands not under development on NPR-1 or NPR-2 or by purchasing nearby lands known to support the same listed species being impacted by activities on NPR-1. Such lands have already been identified through threatened and endangered species planning efforts in the Southern San Joaquin Valley and include the Buena Vista Valley and the Lokern Natural Area, both adjacent to NPR-1. Chevron owns most lands in the Lokern Natural Area and is the primary producer at NPR-1. 4f

Land must be set aside in perpetuity to ensure the long term preservation of those species impacted. Further, an endowment fund must be established for the purpose of long term land management. Endowments should be managed by a land management agency such as The Nature Conservancy.

Refer to Comment Letter 4 Summary of Recommendations 6.

Revegetation efforts should continue but be applied as mitigation to lands temporarily disturbed by development activities and not considered as a measure to off-set loss of habitat. The kit fox program could be used to monitor the population, but again, should not be done in lieu of habitat compensation. Additionally, these studies must utilize a more realistic definition of oil-developed and undeveloped lands to make an effective comparison of these land uses. 4f

Refer to Comment Letter 4 Summary of Recommendations 6.

Cultural Resources

The Draft Supplement identifies that significant finds of cultural resources are unlikely, and that a cultural resource management plan is under development in cooperation with the California State Historic Preservation Office. However, the description of that plan in the DSEIS does not identify whether a contingency plan is being developed as part of the management plan in the event of the discovery of subsurface resources. Such a contingency plan acts to minimize delays in the event of such finds, and it is recommended that one be included in the management plan. 4g

Refer to Comment Letter 4 Summary of Recommendations 7.

Paleontological Resources

While surveys have not indicated the presence of significant paleontological resources, the DSEIS does note that significant resources have been identified in nearby areas. It is recommended that a contingency plan, similar to that recommended above for cultural resources, be developed for previously undiscovered subsurface paleontological resources. 4h

Refer to Comment Letter 4 Summary of Recommendations 8.

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Socioeconomics

Most of the data developed for the socioeconomic section covers only the period ending in 1986-88. Because socioeconomic data is often highly dependent upon the general state of the economy, and because conditions have changed in the four to seven years since this data was developed, it is recommended that the socioeconomic section be updated to reflect current conditions. In addition, it is recommended that the discussion of potential impacts resulting from in-migration of out-of-county workers be clarified. On p. 4.1.8-1, section 4.1.8, second paragraph it is stated that "Fourth, most temporary construction workers on the site would likely come from outside Kern County...". In section 4.1.8.2, same page, it is stated that "Although potential increases up to 30% of the temporary work force might be realized, most workers would come from local communities...". Are the same workers being discussed in both sections? 4i

The socioeconomic impact section does not discuss the potential impacts to schools which might result from the proposed project. Such a discussion, based on updated capacity and enrollment figures should include the potential effects resulting from out-of-county workers bringing their families with them. Commission staff has observed that significant impacts can result to local school districts and schools from even small increases in school enrollment. Agreements with individual districts covering non-reimbursable expenses resulting from enrollment of children associated with out-of-county workers are a recommended form of mitigation for such impacts. 4i

In conclusion, Commission staff believes that the DSEIS does not adequately address several potentially significant environmental and socioeconomic issues, and does not provide adequate mitigation measures to reduce or eliminate the expected impacts. We recommend that the Final SEIS incorporate these comments to adequately analyze all project impacts and consider all feasible mitigation measures.

We appreciate the opportunity to comment on this project. If you have any questions regarding any of our comments or would like assistance addressing our concerns, please contact Lorri Garvais at (916) 654-3944.

Sincerely,

Robert L. Therkelsen, Deputy Director for
Energy Facilities Siting and
Environmental Protection

cc: Christine Kinne
State Clearinghouse

CONTINUED ON NEXT PAGE

DOE RESPONSES

Refer to Comment Letter 4 Summary of Recommendations 9.

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COMMENT LETTER 5

The Resources Agency

Pete Wilson
Governor

Douglas P. Wheeler
Secretary

of California

July 17, 1992

U. S. Department of Energy
Naval Petroleum Reserves in California
ATTN: James C. Killen
Technical Assurance Manager
P. O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

The State has reviewed the Draft Supplement to the 1979 Environmental Impact Statement (DOE/EIS-0158), Petroleum Production at Maximum Efficient Rate Naval Petroleum Reserve No. 1 (Elk Hills) Kern County, submitted through the Office of Planning and Research.

We coordinated review of this document with the Central Valley Regional Water Quality Control Board; Public Utilities, and State Lands Commissions; and the Departments of Conservation, Fish and Game, Health Services, Transportation, and Water Resources.

The State Water Resources Control Board stated that they are currently working with you on this project. We have no further comments at this time.

Thank you for providing an opportunity to review this project.

Sincerely,

for Carol Whiteside
Assistant Secretary,
Intergovernmental Relations

cc: Office of Planning and Research
1400 Tenth Street
Sacramento, CA 95814
SCH 92064002)

The Resources Building Sacramento CA 95814 (916) 653-5656 FAX (916) 653-8102

DOE RESPONSES

5. No response is required.

COMMENT LETTER 6

STATE OF CALIFORNIA PETE WILSON Governor
STATE WATER RESOURCES CONTROL BOARD
DIVISION OF CLEAN WATER PROGRAMS
2014 T STREET SUITE 130
P.O. BOX 944212
SACRAMENTO CA 94244-2120

(916) 739-2728
FAX: (916) 739-2300

JUL 27 1992

Mr. James Killen
Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

I am providing review comments by State Water Resources Control Board staff on the "Draft Supplement to the 1979 Final Environmental Impact Statement, Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California" dated May 1992. These comments were coordinated with John Noonan, Central Valley Region, and are submitted as part of the State of California's (State) participation in the Agreement in Principle between the Department of Energy and the State.

If you have questions regarding the enclosed comments or wish to discuss them in more detail, please telephone me at (916) 739-2728 or Leslie Lauoon at (916) 739-3313.

Sincerely,

John J. Adams, Jr., Chief
Site Remediation Unit
Land Disposal Section

Enclosure

cc: Ed Ballard
DOE/SAN
1333 Broadway
Oakland, CA 94612

John Noonan
California Regional Water Quality Control Board
Fresno Branch Office
3614 East Ashlan Avenue
Fresno, CA 93726

Gary Butner
Environmental Management Branch
Department of Health Services
601 North 7th Street
Sacramento, CA 94234-7320

Linda Fuller
Resources Agency
1416 9th Street
Sacramento, CA 95814

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DOE RESPONSES

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State of California

MEMORANDUM

To: John Adams
DOE Program Manager

Date: JUL

Leslie Laudon
Associate Engineering Geologist

From: STATE WATER RESOURCES CONTROL BOARD
DIVISION OF CLEAN WATER PROGRAMS

Subject: REVIEW COMMENTS, DRAFT SUPPLEMENT TO THE 1979 FINAL ENVIRONMENTAL IMPACT STATEMENT, PETROLEUM PRODUCTION AT MAXIMUM EFFICIENT RATE, NAVAL PETROLEUM RESERVE NO.1 (ELK HILLS), KERN COUNTY, CALIFORNIA, MAY 1992

In accordance with the Agreement in Principle (AIP) between the Department of Energy (DOE) and the State of California (State), I reviewed the abovementioned EIS to assist in the evaluation of additional DOE sites for potential inclusion in the AIP program. This memo presents my comments on the EIS.

GENERAL COMMENTS

The EIS does not provide any water quality data to support the generalizations that the ground water beneath the site is of poor quality, and is not likely being impacted by site activities. There does not appear to be any data available from onsite monitoring wells to establish the ground water flow regime and quality beneath the site. Maps provided in the EIS depicting the ground water surface elevation do not show any information for the Navy site. 6a

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DOE RESPONSES

6.a An array of six on-site water source wells are located on the south flank of NPR-1 structurally down-dip from NPR-1's produced water disposal wells. Structural cross-sections between wells clearly show completion intervals of both source and disposal wells to be in equivalent stratigraphic zones of the Tulare Formation. Source well water is analyzed routinely to determine if produced water injected into the disposal wells is moving downdip toward the periphery of the site (BPOI 1992b). These analyses show that Tulare groundwater quality ranges from approximately 4,000-6,000 ppm TDS, and that overall water quality has not changed in the last 13 years (BPOI 1992a, Phillips 1992). A groundwater surface elevation map for NPR-1 is provided as Figures 3.4.4 of the FSEIS.

Additional structural and stratigraphic cross-sections that show the relationship between Elk Hills stratigraphy in the immediate vicinity of the south flank source water and disposal wells, and equivalent units in Buena Vista Valley have been completed (Milliken 1992). These cross-sections show that disposal of on-site produced waters is being confined within the Tulare Formation and is prevented from migration into alluvial aquifers in the Buena Vista Valley by various clay aquicludes that separate the Tulare Formation from the Alluvium.

The foregoing information is discussed in greater detail in Appendix D (see Section D.4.2.2).

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The disposal practices for produced water which is of poor quality show a lack of concern for potential degradation of ground water quality. This could be a major concern for the Kern Water Bank (KWB) due to the proximity of the water bank to the Naval Petroleum Reserve's (NPR) disposal ponds. There is not sufficient information regarding the geohydrology of the NPR area to determine whether the produced water disposal practices are impacting the KWB water. 6b

It is my understanding that the Regional Water Quality Control Board (Regional Water Board) is working with the Navy to evaluate the ground water quality and flow conditions at the site. The 6c

Regional Water Board is not convinced that historic and current operating procedures and wastewater disposal practices are not impacting usable ground water. The ground water evaluation will involve generating data from onsite wells to determine whether water quality has been adversely impacted by activities at the site. Apparently, the evaluation was initially proposed by the Navy, but they have been slow in initiating the study. 6c

SPECIFIC COMMENTS

p. xxvii - regarding the Tulare Formation "This water is of poor quality with no known beneficial uses except as waterflood source water. The NPR-1 Tulare Formation has been designated as an EPA Class 2 exempt aquifer..."

The Department of Conservation, Division of Oil and Gas (CDOG) has the authority and responsibility to regulate Class II wells used for injection of fluids generated from oil and gas production. The CDOG and State Water Resources Control Board (State Water Board) established a Memorandum of Agreement (MOA) for protection of the beneficial uses of the waters of the State. The State Water Board does not designate waterflood source water as a beneficial use. Use of this terminology throughout the EIS implies that waterflood source water is a designated beneficial use in the Water Quality Control Basin Plan (Basin Plan) prepared by the Regional Water Board. 6d

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DOE RESPONSES

6.b NPR-1 is very concerned about any site practice that has potential to negatively impact off-site interests. Of particular concern is any possibility of degrading off-site groundwater resources as a result of produced water disposal practices. As indicated in Section 3.4.2.4 of the DSEIS, reliance upon sumping has been eliminated except for emergency and off-normal situations and all sumps overlying or near alluvial soils have been lined or taken out of service. Current produced water disposal is by injection into the Tulare Formation via Class II injection wells located approximately 1 1/2 miles from the Buena Vista Valley and 7 miles from the west boundary of the Kern Water bank. Studies have shown that water disposed of into these wells is confined within the Tulare Formation and cannot migrate off-site into useful groundwater in the Buena Vista Valley (see the response to comment 6.a).

As discussed in Section 4.1.4.3 of the DSEIS, a draft groundwater monitoring plan for NPR-1 was developed by Golder & Associates in 1990 (Golder 1990). The plan included a risk analysis of NPR-1 sites and facilities that have potential for causing off-site groundwater degradation. Currently, this plan is being revised and local water interests, including the Department of Water Resources and Kern County Water Agency, will be afforded an opportunity to participate in its development (see the responses to comments 3.a and 9.d).

6.c NPR-1 is aware of the risks associated with the disposal of produced water, and for this reason NPR-1 has worked both independent of and closely with the Central Valley Regional Water Quality Board to minimize risks. Among many actions taken to reduce risks, sumps have been lined, sumps have been taken out of service, sumping volumes have been greatly reduced, and studies have been conducted to ensure risks are acceptable and that disposal activities are in full compliance with requirements. In addition, groundwater management protection and monitoring program plans are under development to provide additional protection (See the responses to comments 6.a and 6.b).

6.d The description in the DSEIS of NPR-1's use of Tulare groundwater in reservoir waterflood operations was not intended to imply that such use constitutes a "beneficial use" as defined by the Tulare Lake Basin Plan. It was simply being stated that withdrawal of NPR-1 Tulare groundwater for waterflooding is the only known use of this water.

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DOE RESPONSES

p. 3.2-7 "...acidic conditions within the borehole would be expected to reduce virtually all of the Cr^{+6} to Cr^{+3} which is the less hazardous state."

Acidic conditions will not necessarily assure the reduction of chromium. A reducing agent must be present and acids are not necessarily reducing agents.

6e

6.e **The text on p. 3.2-7 of the DSEIS has been revised to clarify acidic conditions and reactions within well boreholes.**

p. 3.2-8 "The State of California requires remedial action to remove hexavalent chromium from the soil whenever the concentration exceeds the State of California soluble threshold limit concentration (STLC) of 5 milligrams/liter."

Concentrations of metals in soil in excess of the STLC does not automatically trigger the need for remedial action. The STLC defines a waste as hazardous and requires that it be managed as such if the concentration of a metal in soil exceeds its STLC. There are many other factors which influence the decision to implement a remedial action.

6f

6.f **The text on p. 3.2-8 of the DSEIS has been revised to discuss the remedial action chromium cleanup level that was negotiated with the California Department of Health Services.**

p. 3.2-8 "Chromium tests in the hazardous waste trench area of the 27R waste management facility indicated that chromium levels in this area ranged from 19 to 210 milligrams/kilogram which is below the STLC of 560 milligrams/kilogram."

The STLC is measured in milligrams/liter (mg/L). This point may need some clarification. There are two STLCs for chromium, the 5 mg/L STLC discussed above is for Cr^{+6}, the 560 mg/L STLC is for total Cr and/or Cr^{+3} compounds. It must be assumed that the chromium discussed in the hazardous waste trench area is not Cr^{+6}.

6g

6.g **The text on p. 3.2-8 of the DSEIS has been revised to clarify the form and concentration of chromium present in the 27R hazardous waste trench area.**

p. 5-1 UNAVOIDABLE ADVERSE IMPACTS

- Inadvertent release of oil-field chemicals that are not entirely recovered on a timely basis could, over a period of time, migrate into and degrade groundwater aquifers.

This impact could be avoided by good chemical management practices and timely remediation of inadvertent releases.

6h

6.h **Good chemical management practices are in place at NPR-1. This includes secondary containment around drum racks and chemical tanks, policies and procedures regarding oil/chemical spills and notifications of unplanned/unpermitted releases, environmental awareness and 40-hour hazardous waste training, and an approved and fully implemented Spill Prevention Control and Countermeasure Plan (SPCC). Additional training in chemical spills is planned as part of the revised SPCC plan. Given that NPRC is a large industrial activity, it is possible that despite this comprehensiveplanning, there is still a very small risk that spills could occur.**

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p. 5-1 UNAVOIDABLE ADVERSE IMPACTS

• If the program to recycle produced water for use as waterflood water does not eliminate the need to dispose of produced water into the Tulare Formation, then there is a possibility that such wastewater could degrade usable offsite groundwater. The proposed action includes the implementation of a Groundwater Protection Management Program that will address the potential risks to off-site groundwater resources that may result from all NPR-1 operations.

If the program to recycle produced water does not eliminate the need for disposal of produced water, other options including treatment prior to disposal should be examined. It should not be assumed that continued degradation of water quality is the only other option, particularly if the water being degraded is usable offsite water. 6i

p. D-4, 5 Section D.3.3.1 Zones of Saturated Groundwater

Groundwater is typically referred to as the saturated zone. Saturated groundwater would seem to be a redundant term except that the next section is titled "Zones of Unsaturated Groundwater". This is a confusing use of terms. Different titles for the sections might provide better descriptions of the section's contents. 6j

Numerous references are cited as providing groundwater surface elevation data for the area. Apparently these sources do not have any data regarding the groundwater surface elevation beneath the NPR site because this information is not provided on Figure 3.4-3. The discussion in this section does not provide enough information to interpret the geohydrology. 6k

p. D-7 Section D.3.3.3 Water Chemistry

This section provides general descriptions of the groundwater chemistry but does not present any data. Reference is made to various water quality studies and maps; it might be helpful to provide a map of the TDS distribution throughout the system. It is stated on p. D-9 that a relationship may exist between oil-field wastewater disposal practices and groundwater quality. Without data, it is difficult to evaluate whether such a relationship exists. 6l

p. D-14 ..."These MCLs are enforceable Federal Standards that are also applicable to remedial action alternatives at hazardous and toxic waste sites."

MCLs are enforceable standards for treated drinking water; they may also be enforceable standards for remedial actions. Other regulations and policies of federal, state, and local agencies must also be considered to determine appropriate standards for remedial actions. 6m

DOE RESPONSES

6.i The assumption has never been that degradation of useable off-site groundwaters is an acceptable, or sole option for disposal of NPR-1 produced waters. To be certain that future produced wastewater disposed on-site does not migrate off-site into useable groundwater aquifers, it would be necessary to fully complete all produced water recycling projects. This is NPR-1's objective. This notwithstanding, it is recognized that the recycling projects are very ambitious and may not be fully feasible from a technical and/or an economic standpoint. To the extent recycling projects are not completed, it will be necessary to continue Tulare disposal in accordance with permitted conditions. Studies clearly show that disposal of produced wastewater into the NPR-1 Tulare Formation is not impacting nor expected to impact useable off-site groundwaters (Milliken 1992, Phillips 1992, <u>Section D.4.2.2</u>). Plans also are in place to implement groundwater management protection and monitoring plans to afford even more protection. (See also the responses to comments 6.a, 6.b, and 6.c).

6.j The titles of <u>Sections D.3.3.1 and D.3.3.2</u> in the DSEIS have been revised as suggested.

6.k <u>Figure 3.4-3</u> is provided to give information concerning regional groundwater evaluations. A map approximating groundwater surface elevations at NPR-1 has been completed (Phillips 1992) and is provided as <u>Figure 3.4-4</u> of the SEIS. A more complete groundwater elevation map is being prepared and it will be included in future NPR-1 groundwater protection plans.

6.l Significant amounts of data exist and have been analyzed to determine the relationship between NPR-1 wastewater disposal practices and groundwater quality. To date, these analyses have clearly shown that at Elk Hills no adverse relationship exists (see the responses to comments 6.a and 6.b). Additional management protection and monitoring activities are being developed (see the responses to comment 6.c and 6.i). These measures will provide data for NPR-1 groundwater quality maps.

6.m The text on p. D-14 of the DSEIS has been revised to account for other factors in determining appropriate cleanup levels.

COMMENT LETTER 7

KERN COUNTY FIRE DEPARTMENT

FIRE CHIEF
THOMAS P. McCARTHY

ADMINISTRATIVE DEPUTY CHIEF
SCHUYLER T. WALLACE

OPERATIONS DEPUTY CHIEFS
DANIEL G. CLARK
CHARLES E. DOWDY
CHARLES A. VALENZUELA

ADMINISTRATIVE
SERVICES OFFICER
MICHAEL R. PARKER

May 27, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

In regards to the Department of Energy draft supplement to the 1979 Final Environment Impact Statement, "Petroleum Production at maximum efficient rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, CA" (DOE / EIS - 0158, May 1992) there is a correction that needs to be made under Fire Protection. The document states "The Taft Substation of the Kern County Fire Department has four trucks capable of fighting oil fires,..." this is not correct. Our Taft Substation (Station 21) only has one engine for fighting oil fires. We also have a patrol for fighting grass fires. It should also be noted that we have an engine available at our Fellows Substation (Station 23) capable of fighting oil fires within your 25 minute response times. 7a

Thank-you for allowing us to review your update. If you have any questions or I can be of assistance please contact me.

Sincerely,

THOMAS P. MCCARTHY

Steve Gage
Fire Marshal

TPM/SG/cb

cc: William Larsen, PADS

Protecting The Golden Empire

DOE RESPONSES

7.a The text in Section A.8.6 of the DSEIS has been revised to reflect the information provided in this comment.

COMMENT LETTER 8

DOE RESPONSES

RESOURCE MANAGEMENT AGENCY

RANDALL L. ABBOTT
DIRECTOR

DAVID PRICE III
ASSISTANT DIRECTOR

Environmental Health Services Department
STEVE McCALLEY, REHS, DIRECTOR

Air Pollution Control District
WILLIAM J. RODDY, APCO

Planning & Development Services Department
TED JAMES, AICP, DIRECTOR

ENVIRONMENTAL HEALTH SERVICES DEPARTMENT

June 19, 1992

James C. Killen, Technical Assurance Manager
U. S. Department of Energy
P. O. Box 11
Tupman, CA 93276

SUBJECT: Draft Supplement to the 1979 Final Environmental Impact Statement, Naval Petroleum Reserve No. 1

Dear Mr. Killen:

This Department welcomes the opportunity to review this document as the Local Enforcement Agency (LEA) for the California Integrated Waste Management Board. We have the following comments.

1. Submit a list of all sanitary (nonhazardous) landfills on the Naval Petroleum Reserve. This list should include site legal description, type of waste received, and approximate date of inactivation. 8a

2. Submit closure plans for all inactive and abandoned sanitary landfills on site according the procedure required in Title 14 of the California Code of Regulations. 8b

If you have any questions, please contact Smith Efada at (805) 861-3636, Extension 522.

Sincerely,

William O'Rullian, R.E.H.S.
Environmental Health Specialist IV
Solid Waste Program

SE:irw

2700 "M" STREET, SUITE 300 BAKERSFIELD, CALIFORNIA 93301 (805) 861-3636 FAX: (805) 861-3429

8.a **The information requested in this comment was provided to the Kern County Environmental Health Services Department in April 1992 (Solid Waste Assessment Test for the 25R, 36R, 26S West and 26S East Sites). There currently are no active landfills on NPR-1.**

8.b **Solid Waste Assessment Tests (SWATS) for the four inactive NPR-1 landfills were submitted to the Kern County Environmental Health Services Department in April 1992. SWAT analyses are the first step in the development of sanitary landfill closure plans. Title 14 closure plans for the four landfills are currently being developed and will be submitted to the Kern County Environmental Health Services Department in 1993. All four landfills are currently covered by two-foot soil foundation layers to prevent exposure to wind and water.**

COMMENT LETTER 9

KERN COUNTY
WATER AGENCY

August 4, 1992

James C. Killen
Technical Assurance Manager
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

RE: DRAFT ENVIRONMENTAL IMPACT NAVAL PETROLEUM RESERVE NO. 1 ELK HILLS

Dear Mr. Killen:

The Agency has reviewed the "Draft Supplemental EIS for Petroleum Production at Maximum Efficient Rate Naval Petroleum Reserve No. 1 (Elk Hills) Kern County, California". The Agency appreciates the opportunity to respond to this document. Due to the proximity of large scale, beneficial, ground water recharge and extraction projects to the east of historic and proposed produced water injection sites (Tulare Formation), it is crucial to better characterize the hydrogeology of the interface between the northeast flank of Elk Hills and the younger alluvial sediments to the east.

The Kern County Water Agency concurs with the Environmental Impact Statement (EIS) mitigation factor recognizing the eminent need for a ground water monitoring project in the northeast portion of the Naval Petroleum Reserve (NPR). Given the Department of Water Resources (DWR) development of a ground water monitoring network within and peripheral to the Kern Fan Element (KFE) of the Kern Water Bank (KWB), it would be beneficial to all concerned parties to coordinate the development of NPR ground water monitoring projects with the efforts of the DWR. 9a

Existing water chemistry data and water level measurements in conjunction with ground water modeling, being conducted by the DWR and KCWA, in the northeast portion of the NPR suggests the potential for recent faulting along the northeast flank of Elk Hills. While a fault at these shallow depths might beneficially impede movement of poor quality water from Elk Hills toward the east it could also generate earthquakes. These earthquakes could result from natural stresses of the continued deformation of Elk Hills or induced stress due to extraction and water flooding within the NPR. A relatively large magnitude earthquake along the northeast flank of Elk Hills could be detrimental to DWR 9b

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Bakersfield, CA 93302-0058
Phone: 805/393-6200
Fax: 805/393-6713

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DOE RESPONSES

9.a Coordination activities with the Department of Water Resources and Kern County Water Agency were initiated by letters dated November 12, 1992 (DOE 1992a, 1992b).

9.b Section 3.1.2.5 of the DSEIS has been revised to include the source for the statement that no active faults have been identified within the boundaries of NPR-1.

The four faults shown in Figure 3.1-4 of the DSEIS initially were mapped by Woodring et al (1932). Maher et al, subsequently included Woodring's surface geologic map in U.S. Geological Survey Professional Paper 912 (USGS 1976).

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DOE RESPONSES

James C. Killen
Page 2
August 4, 1992

and KCWA well fields in the western portion of the KFE, the West Kern Water District well field and the California Aqueduct. It is important that the KCWA, as well as the DWR, better understand the potential for earthquakes associated with the Elk Hills structure. Section 3.1.2.5, on seismicity, notes that no active faults have been identified within the boundary of the site. However, the search method used for active fault identification and the criteria for constituting an active fault was not presented. Figure 3.1-4, Generalized Geologic Map of the NPR-1 Area, suggests Faults 1 to 4 extend to ground surface. Fault 4 is close to the area where large contrasts in water quality and depths occur over a very short distance suggesting these faults may represent ground water flow barriers. 9b

In Appendix D, page D-4, D.3.2, it is noted that the KCWA identifies two principal water bearing units in the San Joaquin Valley, the unconfined and confined aquifers. These units are also identified by the U.S. Geologic Survey (USGS) and the DWR. However, the Agency's interpretation is only based to a certain degree on these previous studies. The Agency suggests a more complicated system of an unconfined aquifer and potentially more than one semi-confined aquifer, based upon ongoing modeling, geological and geochemistry studies in conjunction with the DWR. In this same section the base of a confined aquifer is premised on the 2000 ppm TDS water quality. Confined aquifers are based on hydraulic constraints (top and bottom) not water quality demarcations, except in fresh water lenses where the base is constrained by a large contrasts in density between the fresh water and lower sea water. 9c

9.c The text in <u>Section D.3.2</u> of the DSEIS has been revised to more accurately reflect historical and contemporary descriptions of the San Joaquin Valley aquifers.

In conclusion, the Agency recommends a joint review between concerned Agencies of existing geophysical and geological data for the northeast flank of Elk Hills. Such a review may resolve shallow faulting in this area and various hydrogeological parameters of the aquifer system. Additionally, this review would assist DOE, Betchel, CUSA, DWR and KCWA geologists involved with the characterization of the structural and stratigraphic relationships adjacent to Elk Hills. The KCWA and DWR Geologists are especially interested in the area adjacent to Elk Hills from South Coles Levee to the Tule Elk Reserve. This review should be a prerequisite to development of a ground water monitoring network in this area. 9d

9.d A commitment to continue cooperative efforts with the Kern County Water Agency to develop NPR-1 groundwater monitoring plans was made by letter dated November 12, 1992. Plans for cooperating are being developed. (See the response to comment 3.a).

Should you have any questions with respect to the Agency's comments, please contact Kenneth Turner, Tom Haslebacher or Rick Iger of the Agency staff.

Sincerely,

[signature] for

Darrell K. Sorenson
Special Projects & Data Manager

COMMENT LETTER 10

July 25, 1992

Mr. James C. Killen, Technical Assurance Manager
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, Ca 93276

Dear Mr. Killen:

The following comments are offered for the Draft Supplement to the Final Environmental Impact Statement (DOE/EIS-0158) which was released for public comment by the U.S. Department of Energy in May 1992. I respectively request that these comments be included in the public and agency comment section of the Final Supplemental Environmental Impact Statement.

While an employee of Argonne National Laboratory, I was the Project Leader for preparation by Argonne staff of a preliminary draft Supplement to the 1979 Environmental Impact Statement covering operation of the Naval Petroleum Reserve. That preliminary draft document was presented to the U.S. Department of Energy in June 1990. I had no involvement with revision and modification of that preliminary draft document and preparation of the Draft Supplement to the 1979 Environmental Impact Statement by the U.S. Department of Energy and the Department's contractors at the Naval Petroleum Reserve. Substantial editorial and technical changes were made to the preliminary draft document during its conversion to the Draft Supplement to the 1979 Environmental Impact Statement. It is therefore inappropriate and incorrect to show or imply my involvement as Project Leader for the current document as is done in Section 8.1 of that document.

I therefore demand that my name not be listed in the Final Environmental Impact Statement as Project Leader, nor that it be implied or inferred in the Final Environmental Impact Statement that I had involvement in preparation of the document in any other capacity than as Project Leader for preparation of the preliminary draft provided to the U.S. Department of Energy in June 1990. Because of the substantial editorial and technical revisions and modifications to the June 1990 preliminary draft by the U.S. Department of Energy, the actual Project Leader and technical staff who prepared the Draft Supplement to the 1979 Environmental Impact Statement (i.e., staff of the U.S. Department of Energy and the Department's contractors at the Naval Petroleum Reserve) should be listed rather than my name and those of Agronne National Laboratory staff. 10a

Thank you for the opportunity to comment on the Draft Supplement to the 1979 Environmental Impact Statement.

Sincerely,

Richard D. Olsen, Ph.D.

13010 SW Hanson Road
Beaverton, Oregon 97005

DOE RESPONSES

10.a See the response to comment 1.a.

COMMENT LETTER 11

DOE RESPONSES

MICHAEL R. RECTOR, INC.
Water Resources Consultant
Toxic Chemical Monitoring
Geology and Hydrology
Agricultural Drainage
Water Use Evaluation
Groundwater Quality
Water Supply

1415 18th Street, Suite 708
Bakersfield, CA 93301
805/322-8206

July 8, 1992

Mr. James C. Killen
U.S. Department of Energy
Technical Assurance Manager
P.O. Box 11
Tupman, California 93276

Dear Mr. Killen:

As a follow-up to the comments I entered into the record at the Public Hearing on the NPR-1 Draft Supplemental Environmental Impact Statement (DSEIS) on June 24, 1992, I would like to submit these additional comments on the DSEIS. I have one general comment and several suggestions relating to the document text.

On page 5-2 of Appendix G (NPRC FY 1989-1995 Long Range Plan) it is stated that, "Groundwater protection is a primary concern in water quality management." On page 5-6 of Appendix G a groundwater monitoring project is referenced. "DOE Order 5400.1 (11/4/88) calls for a groundwater monitoring program for groundwater that is or could be affected by DOE activities." "A plan must be completed by 5/9/90." What is the current status of this plan?

In reviewing the DSEIS I noted a shortage of maps detailing NPR-1 groundwater structure, groundwater quality, water well locations, and locations of existing groundwater monitoring wells. Although a draft monitoring plan has addressed the need to investigate several suspected problem areas, details of the proposed evaluation project were not mentioned in this document. **11a**

It is my feeling that the "big picture" has not yet been painted. Are Elk Hills activities affecting groundwater quality of down-slope water used by others?

In order to determine if groundwater has been contaminated, the characteristics of native water must be defined and direction of groundwater movement must be established. Specifics on proposed actions to accumulate these data were not mentioned in the DSEIS.

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11.a **A draft NPR-1 Groundwater Monitoring Plan was completed by Golder and Associates in 1990 (Golder 1990). The draft plan is currently being revised by the NPR-1 Groundwater Task force. Completion of the revised plan is scheduled for February 1994. It is anticipated that this plan will be reviewed by the California Department of Water Resources and the Kern County Water Agency.**

An analysis of the potential impact of NPR-1's produced water disposal into the Tulare Formation on the south flank of Elk Hills is provided in <u>Appendix D</u> (see <u>Section D.4.2.2</u>). This analysis indicates that no off-site groundwater degradation is occurring.

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My comments on the DSEIS text are as follows:

1. Page 3.1-4. I suggest that you delete the last line of the last paragraph. The California Aqueduct is not a part of geology. 11b

2. Page 3.4-6. I suggest that you delete the word "potable" from the second line of the last paragraph. Aquifers are not identified by water quality that is drinkable. 11c

3. Page 3.4-8. The first paragraph states that, "The thickness of the confined aquifer is variable and has been defined as extending from the base of the E-Clay to the base of fresh water...". The base of fresh water should not limit the lower limit of the confined aquifer, a stratigraphic unit. 11d

4. Page 3.4-8. In the last line of the fourth paragraph, you refer to the San Joaquin Water District. I have never heard of a district with that title. 11e

5. Page 3.4-11. A statement should be included in the second paragraph that composite well structures also provide inflow from the unconfined aquifer into the confined aquifer. 11f

6. Page 3.4-11. In the fifth paragraph it is stated that water quality of the confined aquifer is normally better than that of the unconfined. This is not always true on the west side of the San Joaquin Valley. 11g

7. Page 3.4-11. In the last sentence of the last paragraph native salinity should be noted as a possible source of eastward migrating groundwater. 11h

8. Page 3.4-12. In the fifth sentence of the third paragraph I suggest you delete the parenthetical "(high quality water)". Confined water is not always high quality. 11i

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DOE RESPONSES

11.b It is acknowledged that the California Aqueduct is not a geologic feature. However, it is believed that the description of this facility is appropriate in Section 3.1.1.1 (Physiography) due to the fact that the California Aqueduct roughly marks the surface boundary of two important geomorphic features in the region; the northeast flank of Elk Hills, and the San Joaquin Valley.

11.c The sentence this comment refers to addresses the sediments and aquifers in Kern County containing potable water. This includes the unconfined and confined aquifers as defined by KCWA (1987). In terms of hydrologic terminology, it is acknowledged that aquifers are not normally defined by water quality. However, given that DWR/KCWA (1977) has defined the confined aquifer as, "extending from the base of the E-clay to the base of fresh water (2,000 ppm TDS)", it is believed the text in Section 3.4.2.1 of the DSEIS is appropriate. (See the response to comment 9.d).

11.d See the response to comment 9.d.

11.e The San Joaquin Water District is located in Lodi, California.

11.f It is acknowledged that composite wells in the San Joaquin Valley can provide inflow from the unconfined aquifer into the confined aquifer. However, the text this comment refers to addresses "natural geologic conditions" which affect groundwater movement in the sediments of the western San Joaquin Valley.

11.g Maps published by the Kern County Water Agency (KCWA) show that groundwater quality in the confined aquifer is generally better than that of the unconfined aquifer in most areas of the San Joaquin Valley. As this comment points out, this is not always the case on the west side of the San Joaquin Valley. For example, the most recent Kern County Water Agency Water Supply Report (KCWA 1991) indicates that water quality of the unconfined aquifer along the northeast flank of Elk Hills ranges from approximately 500-2,000 ppm TDS, whereas confined aquifer water quality in the same area is approximately 500-3,000 ppm TDS.

11.h The referenced sentence does suggest "native salinity" (connate water) as a possible source of eastward migrating groundwater.

11.i The text on p. 3.4-12 of the DSEIS has been revised as the comment suggested.

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DOE RESPONSES

Comment		Response	
9. Page 3.4-12. In the first sentence of the last paragraph, I suggest you delete the word "saturated". Groundwater is saturated.	11j	11.j	The text on p. 3.4-12 of the DSEIS has been revised as the comment suggested.
APPENDIX D			
10. Page D-3. In the second paragraph I have the same comment as given for comment 4.	11k	11.k	See the response to comment 11.e.
11. Page D-3. In the third paragraph I would like to point out that crop irrigation recharge exceeds natural infiltration from the Kern River by a 5:1 ratio.	11l	11.l	It is acknowledged that crop irrigation contributes greatly to San Joaquin Valley groundwater recharge. However, the statement this comment refers to is accurate during "wet year" conditions.
12. Page D-4. My definition of the confined aquifer in the southern San Joaquin Valley is that portion of the Tulare Formation that underlies the Corcoran Clay.	11m	11.m	DOE acknowledges the commentors' definition of the "confined aquifer". Please refer to the response to comment 9.c.
13. Page D-4. I suggest you delete the word "Saturated" from the subtitle for D.3.3.1. (See comment #9).	11n	11.n	See the response to comment 6.j.
14. Page D-5. Can you provide a map for the location of water supply well 61WS-8R?	11o	11.o	The location of water supply well 61WS-8R, as well as all other active and abandoned NPR-1 water supply wells, have been provided in Figure 3.4-7.
15. Page D-5. In the third sentence of the fourth paragraph, delete the word "saturated" (see comment #9).	11p	11.p	The text on p. D-5 of the DSEIS has been revised as suggested.
16. Page D-5. Can you provide a map of the 20 data points used by Rector to construct elevation surfaces of undifferentiated Tulare Zone groundwater?	11q	11.q	See the response to comment 6.k.
17. Page D-5. I suggest you delete the word saturated from the third sentence of the second full paragraph.	11r	11.r	The word, "saturated", was not used in the second full paragraph on page D-5 of the DSEIS.
18. Page D-5. In the sixth paragraph, Kern River is not the greatest source of groundwater recharge in the valley (See comment #11).	11s	11.s	The text on p. D-5 of the DSEIS has been revised to reflect the historic contribution of the Kern River to groundwater recharge.
19. Page D-7. In the D.3.3.2 Subtitle and following text I suggest you delete the words "saturated" and "unsaturated" when referring to groundwater.	11t	11.t	See the response to comment 6.j.

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20. Page D-16. With reference to paragraph 2, groundwater underlying alluvial soils at NPR-1 is not usually considered to be "high quality". 11u

APPENDIX G

21. Page 5-7. The recommendations in the second paragraph are too limited. A definite time schedule and budget should be established for work to be performed by designated qualified people; the highest priority should be to identify native groundwater conditions. Initial monitoring should include down-slope NPR-1 property boundaries and might include cooperative activities with adjacent land owners. 11v

I thank you for the opportunity to comment on your Draft Supplemental EIS. If you would like to discuss any of my comments further I can be reached at (805)322-8206.

Sincerely,

Michael R. Rector

Michael R. Rector
Registered Geologist #78
REA #646

DOE RESPONSES

11.u The text on p. D-16 of the DSEIS has been revised by deleting the reference to high quality groundwater underlying alluvial soils.

11.v The Long Range Plan is not a definitive document in terms of project details. The NPR-1 Groundwater Task Force has established a schedule for completing the Groundwater Protection Management Plan and Groundwater Monitoring Plan by February 1994.

COMMENT LETTER 12

DOE RESPONSES

12. No response is required.

UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SECRETARY
Office of Environmental Affairs
600 Harrison Street, Suite 515
San Francisco, California 94107-1376

ER92/443

July 16, 1992

Mr. James C. Killen
Technical Assurance Manager
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

The Department of the Interior has reviewed the Draft Supplemental Environmental Impact Statement for the Petroleum Production at Maximum Efficient Rate Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California and has no comments.

Thank you for the opportunity to review this document.

Sincerely,

Patricia Sanderson Port
Regional Environmental Office

cc: Director, OEA (w/orig. incoming)
State Director, BLM, Sacramento

COMMENT LETTER 13

DOE RESPONSES

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105

July 30, 1992

James C. Killen, Technical Assurance Manager,
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, CA 93276

Dear Mr. Killen:

The Environmental Protection Agency (EPA) has reviewed the Supplemental Draft Environmental Impact Statement (SDEIS) for the proposed operations entitled **Petroleum Production at Maximum Efficient Rate, Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California.** Our review is provided pursuant to the National Environmental Policy Act (NEPA), Council on Environmental Quality (CEQ) regulations (40 CFR Parts 1500-1508), and Section 309 of the Clean Air Act.

The Department of Energy (DOE) has been directed by Public Law 94-258 (Naval Petroleum Reserves Production Act of 1976) to continue operating Naval Petroleum Reserve No. 1 at the Maximum Efficiency Rate (MER), which is defined as "the maximum rate that optimizes ultimate hydrocarbon recovery and economic return...consistent with...all...laws and regulations, including federal, state, and local laws pertaining to the environment." Within that context, and because of declining production rates, the DOE is proposing to enhance the recovery of hydrocarbon reserves by expanding operations within NPR-1. This expansion would involve drilling additional wells for production as well as for injection; constructing and operating compression and processing facilities; expanding waterflood operations; construction and operation of a 42 megawatt cogeneration facility; construction and operation of a butane isomerization facility; construction and operation of a 148 well, 500 acre, 625 million BTU/hour steamflood project; construction and operation of facilities to increase gas compression capabilities by approximately 46,250 horsepower; and would include "activities to permit third parties to construct, operate and maintain pipeline projects, geophysical surveys, and other projects/activities on NPR-1 lands."

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In addition to the Proposed Action (identified as the preferred alternative), the DSEIS discusses two alternatives: "No Action" (Alternative 1) and a "Modified Proposed Action" (Alternative 2). No Action would essentially preclude further development at NPR-1, but would continue production of oil and gas at a naturally declining rate. The Modified Proposed Action eliminates the gas processing, steam injection, and cogeneration project aspects of the proposed action. It is uncertain whether Alternative 2 would meet "legislated MER requirements." DOE is undertaking studies to determine the feasibility of carrying this alternative forward. 13G-1

From a NEPA perspective, there are several instances in the DSEIS in which outdated information is referred to, especially in the Air Quality Section. In addition, in discussing the Proposed Action, the document often implies that certain environmental protection programs are linked only to that alternative. For example, on page 4.1.5-3, the document speaks of the Wildlife Management Plan as providing benefits to the proposed action whereas the Plan is not mentioned by name in the discussions of the other alternatives. While this may simply be a product of the organization of the document, it is misleading to suggest that such plans are connected to the proposed action. Further, it is not clear in the DSEIS that there is an actual need for the project. Given that the "legal" requirement to produce NPR-1 at the MER was based on "cold war" perspectives that may no longer be applicable and that military programs are actively and substantially being reduced, the purpose and need for the project should be re-evaluated and presented clearly in the FSEIS. 13G-2

From the environmental and related technical information provided in the DSEIS, it appears that in some instances there may be actual conflicts between operating at the MER (implementing the preferred alternative) and adherence to environmental laws such as compliance with the conformity provisions of the Clean Air Act (CAA) and in terms of complying with the provisions of the Endangered Species Act. In addition, EPA is very concerned with the large amount of fresh water that would be required to support enhanced recovery of hydrocarbon resources; with the potential for additional groundwater contamination; with the major increase in surface disturbance that would take place; with the increase in the generation of hazardous wastes; and with the rapidly declining biodiversity and carrying capacity of the Reserve. Our specific concerns are discussed further in the attached comments. 13G-3

As a result of our review, we have assigned the Proposed Action (Preferred Alternative) a rating of EO-2, Environmental

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13.G-1 Projects are approved and funded based on their contributions toward meeting MER requirements (maximum level of production that is economic and does not cause detriment to ultimate recovery). If Alternative 2 is selected as the course of action at NPR-1 and either the gas processing, steam injection, or cogeneration projects of the proposed action are later determined to be necessary to meet MER, appropriate project approvals and permits would be pursued at that time.

13.G-2 The DSEIS was intended to include the Wildlife Management Plan in the proposed action and all alternatives. In the case of the no action alternative (Alternative 1) this was accomplished by stating in Section 4.2.1.5 of the DSEIS that all mitigation measures agreed upon with FWS during the 1987 Section 7 Consultation would continue to be practiced. The Wildlife Management Plan was included in FWS's 1987 Biological Opinion and therefore it would be included in the no action alternative. Likewise, the Wildlife Management Plan was included in the modified proposed action (Alternative 2). Section 4.2.2.5 of the DSEIS states that this alternative is the same as the proposed action, except that it excludes the SOZ Steam Expansion, Gas Processing Expansion, and Cogeneration Projects. The proposed action includes requirements of the 1987 Opinion, and therefore, it also includes the Wildlife Management Plan.

Sections of 4.2.1.5 and 4.2.2.5 of the DSEIS have been revised to clarify the inclusion of the Wildlife Management Plan for both Alternative 1 and Alternative 2.

Regarding outdated information in the Air Quality section, refer to the responses to comments 13.A-1, 13.A-5, and 13.A-6. See Section 1.1.2 of the SEIS and the responses to comments 13.G-5 and 13.N-6 for discussions of the purpose and need for the proposed action.

13.G-3 The proposed action would not conflict with any environmental laws or regulations. The Naval Petroleum Reserves Production Act of 1976 requires that production at NPR-1 be carried out in accordance with all applicable environmental laws and regulations. It is stated on p. 1-3 of the DSEIS that the proposed action includes compliance with such requirements. Compliance with the Clean Air Act is discussed in the response to comment 13.A-1. DOE currently is operating under the 1987 Biological Opinion (see Appendix I.3). DOE is in the process of completing a Section 7 consultation with the FWS to obtain a new Biological Opinion. A final draft of the new Biological Opinion was provided to DOE in May 1993 (see Appendix I.1). The 1987 Opinion, and the final draft Opinion, both concluded no jeopardy. DOE will continue compliance with the 1987 Opinion until the final Opinion is completed at which time DOE will conform with new requirements (See Appendix I.2). The final Opinion or its status will be addressed in the Record of Decision. See also the response to comment 13.B-6. With regard to the other environmental concerns mentioned in this comment, refer to responses to comments 13.W-4, 13.W-12, 13.B-1, 13.H-2, and 13.B-7, respectively.

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Objections - Insufficient Information. While the No Action Alternative appears to be the environmentally preferable alternative at this point, we do have several concerns with that alternative as detailed in the attached comments. Because of those concerns, we have rated No Action (Alternative 1) as EC-2, Environmental Concerns - Insufficient Information. These ratings are further defined in the attached "Summary of the EPA Rating System," also attached. The limited information available and uncertainties surrounding the specific scope of the Modified Proposed Action (Alternative 2) does not provide a appropriate basis for rating that alternative at this time. 13G-4

Given that the DSEIS has not, in our opinion, clearly defined the true need for increased production specifically from Elk Hills, we suggest that DOE consider a fourth course of action. We recommend that a subsequent alternative (Alternative 3) be developed to include provisions of the No Action alternative for the near term and provisions of the Preferred Alternative for the future. The alternative should/would:

* Place production in correlation with need;

* Immediately allow for enhanced and accelerated restoration of the existing Reserve (such as fully implementing the drainage reclamation program referred to on page 4.1.4-1 and providing additional resources into site and roadway reclamation);

* Allow for less near-term expansion and the activities related to such expansion, thereby providing undisturbed habitat for enhanced species recovery; 13G-5

* Minimize water usage during the current extended drought;

* Minimize aquifer drawdown and provide a respite from wastewater injection;

* Ensure that the activities which would be undertaken on the facility will be in compliance with the conformity provision of the new CAA, and;

* Provide time to undertake needed maintenance of aging equipment and replace marginal machinery with state of art equipment.

We appreciate the opportunity to review your DSEIS. Please send three copies of the Final SEIS to this office at the same time it is officially filed with our Washington, D.C. office. Meanwhile, should you have questions or wish to arrange a meeting

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DOE RESPONSES

13.G-4 The additional information provided and the text revisions made as the result of responding to comments on the DSEIS should result in sufficient information to evaluate the proposed action, and Alternatives 1 and 2.

CEQ regulations require consideration of a range of alternatives and a sharp differentiation between the impacts of each in order to facilitate a final decision. To comply with these requirements, three alternatives have been assessed. The proposed action (the preferred alternative) represents the alternative with the greatest impacts. The no action alternative (Alternative 1) has the smallest impact. The impacts of Alternative 2 (which is the same as the proposed action less the SOZ Steamflood project, the Gas Expansion project, and the Cogeneration project) are greater than no action, but less than the proposed action. The differences in the elements of these alternatives are clearly explained by Table 2.0-1. The differences in the impacts of the three alternatives are clearly explained by Table 2.0-2. The information in these Tables is expanded in the appropriate sections throughout the document.

13.G-5 The text on pages xxvi and 2-1 of the DSEIS has been revised to include a brief discussion of this proposed alternative. In summary, evaluating another alternative in detail should not be necessary. First, the purpose and need for the proposed action is clearly set forth in Section 1.1.1 of the DSEIS by reference to the latest statutory 3-year extension of the Naval Petroleum Reserve Production Act, which authorizes MER production at NPR-1 (the proposed alternative would not meet this purpose and need). Second, analysis of this alternative would provide little, if any, additional information. The foregoing is explained more fully as follows:

A report summarizing the findings of a study of the economic effect of continued MER production of the Naval Petroleum Reserves (NPRs) was published in October 1990, (DOE 1990). The report addressed four criteria: (1) National Economic Impacts; (2) National Energy Strategy; (3) Local and Regional Concerns; and (4) Military Preparedness. The report concluded that continued production of the NPRs has clear advantages. President Bush submitted this report to Congress along with a Presidential Certification that continued production of the NPRs was necessary and in the national interest (Bush 1990). This resulted in Congressional authorization of the most recent 3-year extension of the Naval Petroleum Reserves Production Act, which remains in effect through April 5, 1994, (DOE 1990).

The range of alternatives to be considered in an EIS are established by the goals of the underlying legislation. Congress has directed that MER production be continued at NPR-1. A recent analysis of estimated reserves that would be lost by deferring development at NPR-1 for 10 years clearly establishes that the proposed alternative would result in permanent unfavorable changes in reservoir characteristics that would prevent DOE from achieving MER production (BPOI 1992b) (see also response to comment 13.N-11). Therefore, it is not a reasonable alternative for achieving the goals of the legislation.

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to discuss any of the issues raised in our review, please contact Dr. Jacqueline Wyland, Chief, Office of Federal Activities at (415) 744-1584 or have your staff contact David Farrel at (415) 744-1574.

Sincerely,

Deanna Wieman, Director
Office of External Affairs

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Enclosures (2)

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DOE RESPONSES

Finally, an analysis of this alternative would not generate significant additional information because it falls within the range of alternatives already described and analyzed in the DSEIS (see the response to comment 13.G-4). Environmental impacts for some period of time would be the same as Alternative 1, and then they would be increased to the same level as the proposed action. Ultimate recovery would be less, economic return would be less, and adverse impacts on trade, imports, national debt, local economy, affirmative action, and small business would result. Further, in response to the points made in support for the analysis, please consider that:

- Habitat restoration activities under this alternative would not be accelerated due to the fact the existing facilities would still be required for subsequent use (i.e., well pads, tank settings and secondary roads);
- Increased water usage is forecast to be spread over a number of years, all of which would not likely be impacted by drought;
- NPR-1's use of the Tulare Formation for source water withdrawal and produced water disposal have produced little, if any, measurable effect to on-site groundwater resources and no known effect to off-site groundwater resources;
- The proposed action activities would comply with the conformity provisions of the amended Clean Air Act; and,
- Very little, if any, machinery at NPR-1 is marginal. Most equipment is modern and all is well maintained, due in part to a sufficient cash flow, which would not be the case under the additional alternative.

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DOE RESPONSES

SUMMARY OF RATING DEFINITIONS AND FOLLOW-UP ACTION

Environmental Impact of the Action

LO-Lack of Objections

The EPA review has not identified any potential environmental impacts requiring substantive changes to the proposal. The review may have disclosed opportunities for application of mitigation measures that could be accomplished with no more than minor changes to the proposal.

EC-Environmental Concerns

The EPA review has identified environmental impacts that should be avoided in order to fully protect the environment. Corrective measures may require changes to the preferred alternative or application of mitigation measures that can reduce the environmental impact. EPA would like to work with the lead agency to reduce these impacts.

EO-Environmental Objections

The EPA review has identified significant environmental impacts that must be avoided in order to provide adequate protection for the environment. Corrective measures may require substantial changes to the preferred alternative or consideration of some other project alternative (including the no action alternative or a new alternative). EPA intends to work with the lead agency to reduce these impacts.

EU-Environmentally Unsatisfactory

The EPA review has identified adverse environmental impacts that are of sufficient magnitude that they are unsatisfactory from the standpoint of environmental quality, public health or welfare. EPA intends to work with the lead agency to reduce these impacts. If the potential unsatisfactory impacts are not corrected at the final EIS stage, this proposal will be recommended for referral to the Council on Environmental Quality (CEQ).

Adequacy of the Impact Statement

Category 1-Adequate

EPA believes the draft EIS adequately sets forth the environmental impact(s) of the preferred alternative and those of the alternatives reasonably available to the project or action. No further analysis or data collection is necessary, but the reviewer may suggest the addition of clarifying language or information.

Category 2-Insufficient Information

The draft EIS does not contain sufficient information for EPA to fully assess environmental impacts that should be avoided in order to fully protect the environment, or the EPA reviewer has identified new reasonably available alternatives that are within the spectrum of alternatives analyzed in the draft EIS, which could reduce the environmental impacts of the action. The identified additional information, data, analyses, or discussion should be included in the final EIS.

Category 3-Inadequate

EPA does not believe that the draft EIS adequately assesses potentially significant environmental impacts of the action, or the EPA reviewer has identified new, reasonably available alternatives that are outside of the spectrum of alternatives analyzed in the draft EIS, which should be analyzed in order to reduce the potentially significant environmental impacts. EPA believes that the identified additional information, data, analyses, or discussions are of such a magnitude that they should have full public review at a draft stage. EPA does not believe that the draft EIS is adequate for the purposes of the NEPA and/or Section 309 review, and thus should be formally revised and made available for public comment in a supplemental or revised draft EIS. On the basis of the potential significant impacts involved, this proposal could be a candidate for referral to the CEQ.

•From: EPA Manual 1640, "Policy and Procedures for the Review of Federal Actions Impacting the Environment."

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DOE RESPONSES

EPA COMMENTS ON THE DRAFT SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT FOR PETROLEUM PRODUCTION AT MAXIMUM EFFICIENT RATE, NAVAL PETROLEUM RESERVE NO. 1 (ELK HILLS), KERN COUNTY, CALIFORNIA 001625SD.DF

NEPA

13N-1

XX The first sentence in the Summary of the DSEIS states that "(t)his document provides an analysis of the potential environmental impacts associated with continued operation (highlight added) of NPR-1 as authorized by Public Law 94-258, the Naval Petroleum Reserves Production Act of 1976 (Act)." While this may be an accurate statement from the perspective of persons familiar with operations at NPR-1, the proposed action (preferred alternative) actually includes several new and rather extensive undertakings such as drilling numerous new wells, construction of a co-generation plant, and implementation of enhanced recovery techniques, to mention a few. We recommend that for purposes of clarity the initial text be modified to reflect that the document actually provides an analysis of continuing production of oil and gas reserves at the maximum efficient rate (MER) in accord with Public Law 94-258 (the proposed action), and an analysis of alternatives to the proposed action, which also involve continued operations at NPR-1 but at varying rates of production. The theme of this introduction should then be reflected throughout the document to avoid confusion as to what constitutes operations in terms of the proposed action (preferred alternative) and operations in terms of no action and alternative 2.

This confusion is also evident on page 4.1.4-2 wherein the DSEIS titles section 4.1.4.2.1 "Impacts from Continuation of Current Oil and Gas Activities" and states that "this section addresses the impacts of the proposed action..." It is our understanding that continuation of current oil and gas activities is more in line with the description of the no action alternative since the no action alternative would, by definition, continue production without additional development and without major modifications to current operations.

13.N-1 The text on pages xx, 1-4, 2-1, 2-10, 3.1-1, 4.1.1-1, 4.2-1, and 4.2-6 of the DSEIS has been revised to clarify the scope of the proposed action and alternatives.

The impacts of the proposed action are clearly the sole subject of Section 4.1. Nothing in this Section applies to any of the other alternatives unless otherwise indicated. For groundwater, which is covered by Section 4.1.4.2, the impacts of the proposed action consist of two parts: those that are expected to continue as the result of the continuation of current operations, and additional impacts associated with planned future facility development. These two parts are discussed separately. Section 4.1.4.2.1 discusses the impacts of continuing operations, and Section 4.1.4.2.2 discusses the impacts of future facility development.

The commentor's understanding that the continuation of current oil and gas activities constitutes the no action alternative (Alternative 1) is correct. What apparently is not clear is the relationship between "no action", the proposed action, and the modified proposed action (Alternative 2). As stated in the opening paragraphs of the Summary Section 3.0 and 4.1, which have been revised in response to this comment, the proposed action includes "no action" activities. Therefore, whenever a reference is made to the proposed action, in addition to applying to new development activities, the reference also applies to the continuation of current oil and gas activities that comprise "no action". Similarly the modified proposed action alternative (Alternative 2) also includes "no action" activities (see Sections 2.2 and 4.2.2). Refer also to 13.G-4, 13.N-3, 13.N-4, and 13.N-7 comments and responses.

13N-2

XXX For purposes of clarity, we recommend that the statement which attempts to compare areas of habitat disturbance between alternatives be re-worded as follows:

> "Implementation of Alternative 1, no action, would disturb approximately 741 acres of habitat on and off NPR-1 over the next 30 years. In comparison to no action, the preferred alternative would increase habitat disturbance by 828 acres, Alternative 2 would increase habitat disturbance by 378 acres, and both the proposed action and Alternative 2 would increase 'other areas of significant impacts' accordingly."

13.N-2 The text on p. xxx of the DSEIS has been revised as suggested.

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Table S-1, "Summary of Impacts and Mitigation for Each Major Impact Area of the Proposed Action," presents a very good overview of the proposed action, however, the column entitled "Favorable Impacts/Mitigation Programs" is misleading. The presentation implies that the "Favorable Impacts/Mitigation Programs" are actually linked to implementation of the proposed action (preferred alternative). We assume, however, that many of the programs are ongoing or have no relation to implementation of any specific alternative. This should be made clear in the FSEIS. 13N-3

The DSEIS often compares the proposed action with an action that has taken place in the past or uses the proposed action as a basis for comparing other alternatives. For example, under Impact Area 2 (Waste), the document compares the proposed drilling program with the past program, stating that the proposed program would be significantly smaller. This is also in evidence on page 4.1.2-1 wherein the DSEIS states that "the proposed action would sharply reduce well-drilling activity...and the volume of spent drilling fluids requiring disposal." This infers that implementing the proposed action is the key in reducing the level of activity in the field...which is not true in comparison with the no action alternative. Such comparisons are also presented on pages 4.1.4-2 and 4.1.4-11. Discussions should not compare past activities with the proposed action, but should consistently compare the relative impacts and merits of the alternatives with no action as the base for comparison. This would give the reader a clearer picture of the extent of activities being proposed under each alternative. 13N-4

Also in Table S-1, in the impacts discussion of Item 9, the text compares the drilling program of the proposed action with that which took place in the past rather than comparing proposed activities with the no action alternative. This could give the false impression that the proposed action is favorable because it reduces hazardous operations on NPR-1. In actuality, implementing the proposed action would not reduce hazardous operations on NPR-1 and would, in fact, increase such operations in comparison to the appropriate baseline. 13N-5

P 1-3 The three year extension of Public Law 94-258 granted in April of 1991 was based on "economic and military preparedness criteria." In clarifying the rationale for the true need for the resources at this time we recommend that the FEIS discuss whether or not the latest developments in world-wide politics and military strategies have been considered and whether the significant reductions in our military forces have been factored into the decision to extend extraction of petroleum resources at MER. This discussion should be included in the purpose and need section of the FSEIS. 13N-6

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DOE RESPONSES

13.N-3 The text on p. xxvi of the DSEIS has been revised to address the incorporation of safety and environmental projects in the alternatives.

13.N-4 The CEQ regulations for NEPA (40 CFR 1502.14) state that an environmental impact statement, "...should present the environmental impacts of the proposal and the alternatives in comparative form...". This comparison is to be based on the environmental effects of alternatives, including the proposed action, as described in the section on environmental consequences (40 CFR 1502.16). DOE believes that <u>Sections 2.0 and 4.0</u> of this SEIS adequately satisfy these requirements.

Given that the proposed action consists in part of continuing past activities, it is appropriate to discuss and compare the impacts of past activities with those of the proposed action in order to fully describe the impacts of the proposed action. (See also the response to comment 13.G-4).

13.N-5 The text in item 9 of <u>Table S-1</u> of the DSEIS has been revised to recognize the increased risk of hazardous operations which the proposed action would have in comparison to the no action alternative.

13.N-6 The text on p. 1-3 of the DSEIS has been revised to better describe the subject of reauthorization of continued MER production.

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P 1-12 Under the heading "Summary of Proposed Action" the DSEIS discusses two "scenarios": the "maintenance case" - which assumes that production would continue on NPR-1 without additional development; and the "full development case" - which assumes additional development and application of recovery techniques. Inasmuch as the DSEIS defines the No Action Alternative (1) as that alternative which "provides for the continued production of NPR-1 by operating and maintaining existing wells and facilities, but without...further development..." (page 2-1), and on page 2-13 defines the Proposed Action as the Preferred Alternative, it is unclear how the proposed action's "maintenance case" differs from the no action alternative, and whether the Preferred Alternative is actually the "full development case" scenario discussed as being but one "scenario" of the proposed action. 40 CFR 1502.14 specifies that an EIS present the alternatives "in a comparative form, thus sharply defining the issues and providing a clear basis for choice among options by the decisionmaker and the public." The manner in which the preferred alternative, no action alternative, and the proposed action are presented in this document does not provide sufficient clarity to accommodate the requirements of 40 CFR 1502.14. We recommend that the document be reformatted as previously suggested to more clearly identify the proposed action (and preferred alternative) as "full development" and the no action alternative (to be used as the basis for comparing all alternatives) as the "maintenance case." If our understanding of the maintenance case" is correct, it should not be linked to discussion of the proposed action/preferred alternative. 13N-7

P 4.1.2-7 The DSEIS lists a number of "mitigation activities" which "focus on remediating impacts associated with past and current operations." Its stated that the activities are included in the Long Range Plan and the proposed action. The FSEIS should clarify whether these mitigations would be implemented if the proposed action was not the selected action. In addition, referring to the statement on page 4.1.2-6, wherein it is indicated that "proposed facility developments would undergo future project-specific environmental analysee which would address additional mitigation measures..." it is unclear whether each "mitigation activity" listed on page 4.1.2-7 would be prefaced by a NEPA document inasmuch as an appropriate level of detail is not provided in the DSEIS to assess the effects of each of the actions listed. The FSEIS should provide additional information to help clarify the specific NEPA process to be used for individual activities being proposed on NPR-1. 13N-8

P 4.1.3-1 We assume the dates signifying onset of construction activities presented on this page (1989) and on page 4.1.3-3 (1990) have been inadvertently included in this document and that the activities noted have not been initiated. The FSEIS should include an updated version of this section. 13N-9

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DOE RESPONSES

13.N-7 The Long Range Plan (LRP) is the basis for both the proposed action and no action alternative descriptions and analyses. The proposed action is the LRP "full development" scenario and Alternative 1, the no action alternative, is the LRP "maintenance case" scenario. Text revisions have been made on pages 1-12, 2-1, and 4.2-1 of the DSEIS to clarify this. DOE believes that this document satisfies the comparison requirements of 40 CFR 1502.14 (see Tables 2.0-1 and 2.0-2). See also the response to comment 13.G-4.

13.N-8 All components of the proposed action, including mitigation activities, have been appropriately described in Sections 1.2, 3.1.3, 3.2 and Appendix G, and their impacts have been appropriately included in the impact descriptions in Sections 3.4.2.4, 4.1, 4.2.2, and Appendix D. Therefore, no further comprehensive environmental analyses are necessary or planned for these activities unless there is a change in scope. The listing of mitigation initiatives in Section 4.1.2.3 of the DSEIS is a compilation of all of the initiatives planned site-wide which are expected to mitigate waste generating impacts of the proposed action. Text revisions in Section 4.1.2.3 of the DSEIS have been made to clarify the foregoing.

13.N-9 The projects described on p. 4.1.3-1 and included in Table 4.1.3-1 (p. 4.1.3-3) of the DSEIS have not been initiated to date, with the exception of three 1500 hp compressor engines installed in April, 1992 for the 19R Closed-Loop Gas-Lift project.

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P 4.2-1 The DSEIS suggests that "up to 500 million barrels of oil and 250 billion cubic feet of gas would not be recovered" if the no action alternative was implemented. While this is accurate in the short-term, we wonder if there would be any effort to recover these resources in the more distant future when demand is greater. We recommend that the FSEIS discuss such a scenario. 13N-10

P 5-2 The DSEIS states that 1.2 billion dollars in federal revenues would be lost if the no action alternative rather than the preferred alternative was implemented. We question the actual loss of such revenue given that:

1) the resource remains ultimately recoverable; and
2) the position elucidated in the document assumes that the resource would never be recovered and correlates that non-recovery to a market value. A similar position could be taken which assumes that the resource could be recovered during a period when the demand and related value were higher, thereby suggesting that the federal government might not lose revenue dollars by adopting the no action alternative. 13N-11

We recommend that the FSEIS address these issues to the extent practicable.

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DOE RESPONSES

13.N-10 The no action alternative (LRP "maintenance case") assumes no further development at any time in the future. Under this scenario substantial quantities of hydrocarbons would never be recovered. The question posed is could the maintenance case (Alternative 1) be implemented for some period of time which would be followed by full development (the proposed action)? This is the same question posed by comment 13.G-5. See the responses to comments 13.G-5 and 13.N-11.

In summary, the result of maintenance only for a period of time followed by full development would be a recovery greater than perpetual maintenance, but less than continuing full development. This is because any change in production sequence would result in lower recovery in comparison to continuing full development.

13.N-11 Improved oil recovery methods account for the majority of oil produced at NPR-1. Improved recovery methods supplement the natural reservoir forces and energy, increasing ultimate recovery from the reservoir. The primary improved oil recovery methods used in the NPR-1 reservoirs are waterflooding and gas injection.

NPR-1 waterflood and gas injection programs are expensive to operate and hydrocarbons recovered by these methods have a reduced profitability. In the case of waterflooding, water initially is injected around the periphery of the reservoir so that a water front moves inward toward the center of the reservoir sweeping oil into production wells. A characteristic of waterflooding is that water injection points and oil production points are continuously changing over time as the water front moves inward into new areas of the reservoir and other areas are swept clean. Stated in other words, it is necessary to continuously develop a waterflood project in order to maintain it, and it is for this reason that the proposed action includes well drilling, well conversions, waterflood pumping equipment, pipelines, wastewater disposal equipment, including PWI, etc.

To proceed, as suggested, with a strategy of allowing waterflood activities to cease, followed by reinitiation of waterflood development and operations at a later date, would result in unfavorable changes in reservoir conditions while the waterflood is shut-in. This would make it physically impossible to recover some hydrocarbons. It also would necessitate expensive mothballing activities initially, "very" expensive start-up expenses later, and a more extensive development program and expenses to recover other hydrocarbons. Given the inherent reduced profitability of waterflood recovery methods, the additional expenses would render these hydrocarbons uneconomic to recover. The result of the foregoing is that ultimate recovery would be reduced, thus wasting federal resources (BPOI 1992b).

In the case of gas injection, gas originally produced from a reservoir is reinjected back into the reservoir to maintain reservoir pressure and energy needed to push oil toward production wells. At NPR-1, areas have been identified as needing gas injection and the required facilities are included in the proposed action. If these facilities are not installed and operated on a

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BIODIVERSITY/THREATENED & ENDANGERED SPECIES

XXX The DSEIS indicates that implementing the preferred alternative would more than double the current amount of disturbed habitat and that alternative 2 would increase habitat disturbance by 51%. Given that populations of threatened & endangered species are rapidly declining on the Reserve, the FSEIS should discuss the implications involved with expanding the amount of habitat disturbance in terms of the Endangered Species Act and the provisions of the MER which state that development must be "consistent with...all...laws and regulations, including federal, state, and local laws pertaining to the environment." 13B-1

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timely basis, as would be the case under the no action alternative, reservoir pressures would fall, and light hydrocarbons would come out of solution causing the viscosity of remaining hydrocarbons to increase. Increased viscosity would impede flow which would cause overall recovery to decrease, thus wasting federal resources.

13.B-1 The DSEIS (p. xxviii) estimates current development at NPR-1 to be about 6,546 acres. The proposed action would result in 1,569 acres of additional disturbance (see Table 1.3-2). This is an increase of 24%. Furthermore, 1,045 acres of land would be revegetated. If revegetation is successful on all 1,045 acres (which is anticipated), then the net increase in developed area will be 524 acres. This is an increase of 8%. The effects of implementing Alternative 2 would be smaller. These calculations do not include seismic surveys because the effects of seismic surveys are much smaller in magnitude than development of habitat for petroleum extraction and because they are only temporary in nature.

The comment states that populations of endangered and threatened species are rapidly declining. The NPR-1 and NPR-2 kit fox populations declined appreciably from 1980-1985, was relatively stable from 1985-1989, and declined from 1989-1991 (Winter 1992 trapping results on NPR-1 are significantly greater than Winter 1991 trapping surveys; see Section 3.5.3.2, Population Dynamics of the San Joaquin Kit Fox on NPR-1). A similar trend of greater kit fox abundance in the early 1980's compared to the late 1980's also has been observed by the California Department of Fish and Game in the McKittrick/Taft and Elk Horn Plain areas, which are located approximately five and ten miles from the boundaries of NPR-1, respectively (EG&G 1992).

The situation on NPR-1 for the other threatened and endangered species is less clear. Blunt-nosed leopard lizard sightings declined between 1979 and 1984, but were higher during the 1989 survey (see Section 3.5.3.2). Giant kangaroo rat burrow counts and sightings of San Joaquin antelope squirrels declined between 1984 and 1989 (see Section 3.5.3.2). While these results suggest that concern is warranted, the data does not suggest that the populations of threatened and endangered species occurring on the Reserve are rapidly declining (other than the kit fox from 1980-1985 and 1989-1991). Alternative explanations are that the observed fluctuations may be attributed to normal differences in the way surveys were conducted and recorded, normal variations in population size, or other factors unrelated to changes in the amount of habitat disturbance (e.g., climatic variation). Recent information indicates that at least one threatened species, Hoover's wooly-star, appears to be increasing on NPR-1.

The disturbance of additional habitat on NPR-1 is not inconsistent with the Endangered Species Act as established in FWS's 1987 non-jeopardy Biological Opinion. This issue currently is being evaluated in an on-going Section 7 consultation with FWS. A final draft Biological Opinion has been received (see Appendix I.1). The final draft Biological Opinion concludes nonjeopardy. DOE is still consulting with FWS regarding some of the requirements. The final Opinion or its status will be addressed in the Record of Decision. While habitat alteration

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P 1-39 The FSEIS should explain what constitutes "successful revegetation" and should describe the process that would be used to ensure that vegetation is successfully reestablished. 13B-2

P 1-40 The FSEIS should describe the effects geophysical sound waves have on animals residing on the reserve, particularly those species designated as threatened or endangered. 13B-3

Table 2.0-1 The discussion in Element 20, Endangered Species Program, indicates that the program under alternatives 1 and 2 would be "approximately (highlight added) the same as proposed action." The FSEIS should briefly identify the major differences. 13B-4

P 3.5-1 The discussion on terrestrial biota on this page and on page 3.5-13 indicates that one of the possible factors in the reduction of kit fox populations is an increase in coyote abundance. This statement appears to be in conflict with the statement on page 3.5-6 (which reflects the information presented in figure 3.5-1), namely that coyote populations have decreased since 1984. The FSEIS should clarify these important statements. 13B-5

P 3.5-13 The DSEIS indicates that the "FWS concluded in their 1987 Opinion that, although 'there are no assurances' that development activities will not 'eventually contribute to the extirpation' of the kit from the site, development activities are 'not likely to jeopardize the continued existence' of the species." It is unclear, however, whether the Opinion considered the proposed actions presented in this EIS. The FSEIS should provide an updated FWS Opinion (results of the consultation process required to undertake this project, as suggested on pages 3.5-14 and E-5), given that kit fox populations have declined approximately 85% in the last ten years and have continued to decline since the 1987 Opinion. 13B-6

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and fragmentation undoubtedly affect endangered species on NPR-1, the available evidence does not suggest that habitat alteration is likely to jeopardize the existence of any of the endangered species found on NPR-1. The decline in the abundance of the endangered kit fox does not appear to be linked significantly to petroleum development. Given the low abundance of the kit fox on NPR-1, local extirpations are increasingly likely. However, these events are probably more likely to be driven by stochastic processes rather than by habitat alteration resulting from oil-field development.

13.B-2 See the response to comment 4.c.

13.B-3 The effect of geophysical sound waves on threatened and endangered species are not known to have been scientifically studied. Geophysical sound effects on NPR-1 species are believed to be minimal given that pre-activity surveys are conducted to site geophysical projects away from sensitive habitat if possible, and because geophysical sounds likely are attenuated by NPR-1's numerous drainages and steep topography. Geophysical projects have been included in past proposed actions which were the subjects of formal Section 7 consultations with FWS; the effects of geophysical sound waves have not been an area of concern in these consultations. The proposed action also includes geophysical projects and the potential impacts of geophysical sound waves on NPR-1 threatened and endangered species will be addressed, if appropriate, during the ongoing Section 7 process.

13.B-4 The text in Element 20 in Table 2.0-1 of the DSEIS has been revised to identify the differences in the endangered species program associated with the proposed action and alternatives.

13.B-5 Coyote abundance appears to have increased from 1979 to 1984 (see Table 3.5-2). Beginning in 1984, coyote abundance appears to have declined (see Figure 3.5-1). The text on p. 3.5-13 of the DSEIS has been revised appropriately.

13.B-6 The text on pages 3.5-14, 4.1.5-4, 4.1.5-13, 4.2-5, 4.2-11, and E-5 of the DSEIS has been revised to update the discussions on compliance with the Endangered Species Act. Currently, NPR-1 is operating under the 1987 nonjeopardy Biological Opinion. The 1987 Biological Opinion was based on a wide range of ordinary oil-field activities needed to comply with MER requirements contained in the Naval Petroleum Reserves Production Act: total disturbances over the life of the MER project were projected to be 4,032 acres (see Appendix I.3, page 3). The proposed action of this SEIS is based on lifetime disturbences of 4,796 acres (3,227 + 1,569 = 4,796; see Tables 1.3-2 and 3.5-1) for MER under the Naval Petroleum Reserves Production Act. The SEIS includes essentially the same activities described in the 1987 Opinion with the primary differences being that the SEIS includes steamflood and third-party projects which were not included in the 1987 Opinion. To cover the additional scope of the SEIS, DOE reinitiated consultation with FWS in October 1991, and FWS completed a partial draft Biological Opinion in December 1992, which also concluded nonjeopardy. A final

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Although the Summary of the DSEIS suggests that "NPR-1 supports a diverse variety of flora and fauna" the fact that four federally endangered species, one state threatened animal, one federally threatened plant and 27 other plant and animal species "that have been categorized at various levels of concern" are known to be present suggests that NPR-1 may not continue to support such a diversity unless actions, such as conducting operations at a rate that would encourage optimal species and habitat recovery, are implemented. Expanding oil and gas recovery operations, as described in the DSEIS, would not appear to encourage biodiversity. 13B-7

P 3.5-34 The DSEIS suggests that oil and oil-field chemicals that have been spilled or otherwise released could have been "inhaled or ingested by kit foxes through contaminated drinking water or prey," and that "oil-field wastewater often contains high concentrations of dissolved solids, salt, and various other minerals and can cause death, nervous disorders, tissue damage, and decreased reproduction in...wildlife if ingested." The FSEIS should expand upon these statements and detail the specific measures that would be (or are being) taken to prevent ingestion of such chemicals by threatened and endangered and other species. 13B-8

P 4.1.5-3 Given that past activities have had a variety of negative impacts on animal communities, including questionable impacts on threatened and endangered species, the statement that the proposed action would continue to have similar impacts suggests that an alternative action may be preferable. For example, the DSEIS states that with the implementation of the proposed action, "animals within construction areas would be killed during construction or would disperse to other areas; dispersing individuals tend to have a lower survivorship," and that "they could ingest oil-field chemicals present in sumps or assimilated by forage which might cause or contribute to death, disease or diminished ability to avoid predation." Death, reduced survivorship, and diminished avoidance of predation all equate to reduced populations. Inasmuch as the four animal species that are currently listed as threatened/endangered" are likely to be affected by the proposed action," (p 4.1.5-4) the FSEIS should detail the consultation process undertaken with the U.S. Fish and Wildlife Service, should provide a list of their 13B-9

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draft nonjeopardy Opinion has been received (see Appendix I.1). The final Biological Opinion and related DOE commitments, or their status, will be addressed in the Record of Decision. DOE will comply with all requirements of the new Biological Opinion when it is issued. Until then, DOE will continue to comply with all requirements of the 1987 Biological Opinion (See Appendix I.2). In addition, projects with impacts that are not covered by the 1987 Opinion will be subjected to Section 7 of the Endangered Species Act before they are incurred.

It should be noted that concurrent with the significant increase in precipitation during the 1991-1993 water years, the number of San Joaquin kit foxes trapped on the NPR-1 study area increased from 2 in winter 1991 to 16 in winter 1992. The percentage of radiocollared female kit foxes that showed evidence of reproducing increased from 18% in spring 1991 to 100% in spring 1992 (see Section 3.5.3.2).

13.B-7 Factors affecting biodiversity, including habitat disturbance and reclamation, will be addressed in the ongoing Section 7 consultation with FWS (see the response to comment 13.B-6). It is noteworthy that the 1987 non-jeopardy Biological Opinion was based on habitat disturbances greater than would occur under the proposed action (i.e., the lifetime disturbances anticipated during the 1987 consultation process exceeded the lifetime disturbances that are now anticipated and included in the proposed action). NPR-1 is complying with all requirements in the 1987 Opinion.

13.B-8 The text on pages 3.5-34 and 3.5-35 of the DSEIS has been revised to more fully describe the studies conducted to investigate the potential effects of oil-field chemicals on wildlife.

13.B-9 See the responses to comments 13.B-6 and 13.B-7.

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recommended and required actions, should identify and quantify the impacts expected from other activities which would be undertaken in the region, and should discuss in detsil the plans which would be undertaken at NPR-1 to ensure to the maximum extent possible the survivorship of the species in question. This is especially important because "the FWS believes that (other nearby) projects will result in significant cumulative effects to the kit fox, blunt-nosed leopard lizard, and giant kangaroo rat."

In addition, given that "programs to mitigate the effects of NPR-1 activities on terrestrial biota have been in effect for a number of years..." and that species populations have continued to decline throughout that period of time, the FSEIS should discuss the potential for enhancsd and accelerated mitigation programs to assist in reestablishing the carrying capacity of the immediate area. For example, on page 4.1.5-10, the DSEIS suggests that reclamation efforts between 1985 and 1988 resulted in a low of 115 acres being reclaimad in 1985 and a maximum of 200 acres being reclaimed in 1988. Based on figures presented in the DSEIS that each wellsite and access road encompasses approximately 2.2 acres, reclamation of 200 acres accounts for only nine wellsites. It was also noted that the average plant cover was only 6% in 1990. We encourage continued monitoring of reclaimed sites and recommend that the FSEIS provide more details on strategies to ensure enhanced and accelerated revegetation of disturbed sites. The discussion should also detail the strategies used at NPR-1 to re-plant sites contsining minimal vegetation, should identify the levels at which replanting is undertaken, and should discuss the role erosion plays over time in terms of successful (or unsuccessful) revegetation. 13B-10

We share your concern that NPR-1 is regionally significant because "based on the 1979 estimate, it contains 8% of the remaining undeveloped habitat in the southern San Joaquin Valley." In the thirteen years since that estimate, it would seem plausible that the extent of undeveloped habitat within the southern San Joaquin Valley has continued to decline. This would seem to add impetus to undertaking accelerated and enhanced restoration efforts on the Reserve.

In terms of providing data which projects future restoration efforts (should the proposed action be implemented), we do question whether one can assume that continuing to implement the current habitat reclamation program would be successful (as suggested on page 4.1.5-13) given that the most recent plant cover on average was estimated at only 6% . The FSEIS should either provide information on an enhanced strategy for restoration or provide figures which relate more appropriately to the level of successful reclamation realized in the near past. 13B-10

P 4.2.1.5 The FSEIS should include the results of the toxicology study which is being undertaken to determine the extent to which oil-field chemicsls may be entering the tissue of NPR-1 kit fox prey. The results should be discussed in terms of the extent to which oil-field activities indirectly impact the kit fox and should provide strategies to eliminate the intrusion of such chemicals into the food chain of the kit fox, if the study indicates their presence. 13B-11

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13.B-10 The status of species populations throughout the period of time referred to was discussed in the response to comment 13.B-1. Some populations have apparently declined, some have apparently increased, and some apparently have been relatively stable. Below normal precipitation probably has been the most significant factor contributing to population declines. No significant link between species status and oil-field operationshas been established (see the responses to comments 13.B-8 and 13.B-11).

With regard to the portion of this comment concerning habitat reclamation, see the response to comment 4.c.

13.B-11 The text on p. 4.2-4 of the DSEIS has been revised to discuss the results of the referenced toxicology study.

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P 5-2 The DSEIS suggests that impacts from implementing the no action alternative would include disturbance to various habitats from new construction. Our understanding of the no action alternative is that no new construction would occur. Please clarify this in the FSEIS. 13B-12

P E-5 The DSEIS states that "the kit fox population in the NPR-1 study area began stabilizing at or about the same time the (coyote) control program was put in place..." While this may be so, figure E.3-1 shows a long term continual increase in kit fox mortality from predation. This seems to suggest that even though fewer coyotes are using the kit fox as food source (since there are fewer coyotes on the reserve) they have, in fact, focused on the kit fox as a major food source, since kit fox mortality rates have continued to increase. The FSEIS should discuss this implication and its relationship to the possible declination of other food sources for the coyote as well as to the possibility that over time, disruption to kit fox habitat has placed them in a more precarious relationship with the coyote. 13B-13

HAZARDOUS MATERIALS/WASTE

XXVII The FSEIS should clarify what is meant by the statement that many of the 106 "older inactive waste sites" have been addressed. 13H-1

Table 2.0-2 The discussion in Element 2d, Hazardous Waste, states that hazardous waste from construction and operations would increase above the current level of approximately 19,800 lbs/yr to as much as approximately 500,000 lbs/yr. The constituents of this increase, approximately 26 times that which is currently generated, should be detailed and discussed in terms of applying waste minimization (source reduction) techniques. 13H-2

P 3.1-15 The FSEIS should reference descriptions of the "other additives" present within the oil waste fluid mixtures. 13H-3

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13.B-12 The text on p. 5-2 of the DSEIS has been revised to describe habitat disturbances expected to occur from maintenance, repair and new construction activities of the proposed action.

13.B-13 It should be noted that kit foxes are not a food source for coyotes (see Section 3.5.3.2). Although data on kit fox mortality due to coyote predation has varied during the period 1980 to 1989, the data are not sufficient to draw accurate conclusions regarding trends in the rate of coyote predation on kit foxes over time. For example, in Table 3.5-6, the cause of death could not be determined for 32.3% of total kit fox deaths between 1980 and 1988.

13.H-1 The text on p. xxvii of the DSEIS has been revised to clarify the nature of remedial investigations and actions taken for these historic waste sites.

13.H-2 Based on this comment regarding Table 2.0.2 of the DSEIS, the text in Table 2.0-2, item 2.d, Hazardous Waste, Table S-1, item 2, Waste, and the text on pages 4.1.2-2, 4.1.2-4 (Table 4.1.2.2-2), 4.1.2-5, and 4.1.2-7, have been revised. At the time the DSEIS was prepared, only limited conceptual design information was available. The expected wastestreams from the operation of the cogeneration plant were not well understood. As a result, the cogeneration plant's projected annual waste stream of 500,000 pounds was recognized as "potentially hazardous" in the DSEIS.

Recently, additional preliminary design efforts were undertaken to address potential waste streams from the cogeneration plant (BPOI 1993). This evaluation determined that the conclusions regarding the potentially hazardous nature of the cogeneration plant's waste streams in the DSEIS were conservative. None of the liquid waste streams from the demineralizing system, generator blowdown, or system losses are now expected to be hazardous. Only nominal quantities of hazardous waste are expected from the operation of this facility. Therefore, the projected increase of up to 500,000 pounds/year of hazardous waste generation as a result of undertaking the proposed action has been eliminated from the SEIS text. Please refer to Sections 1.2.2.13, 4.1.2.2, and 4.1.2.3 for additional information.

13.H-3 The text on p. 3.1-15 of the DSEIS has been revised to provide a description of other additives likely to be present within oil-field waste fluids.

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P 3.2-17 The FSEIS should identify the materials currently being used as corrosion inhibitors since (we assume) arsenic is no longer being used. 13H-4

P 3.4-6 The FSEIS should describe the areal extent of the hydrocarbon stains referenced in the DSEIS, identify the specific source of contamination, and discuss what is being done to eliminate the contamination and control the source. 13H-5

P 4.1.2-2 The discussion and figures which supposedly reflect "the site's annual hazardous waste stream" should be clarified in the FSEIS. Table 2.0-2 suggests that the proposed action would increase this waste stream to as much as 500,000 pounds annually yet the discussion on this page refers to 19,800 pounds, that which is currently being generated. 13H-6

WATER RESOURCES

XXVII Wetland resources have not been identified as being present on NPR-1. The FSEIS should either discuss wetland resources or confirm that none exist on the Reserve. 13W-1

Table S-1 The FSEIS should discuss the extent to which groundwater mining would occur, especially with the proposed increase in use of groundwater resources, and should describe how this would affect other aquifers, if at all. 13W-2

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13.H-4 The text on p. 3.2-17 has been revised. Corrosion inhibitors currently used in NPR-1 operations contain no arsenic.

13.H-5 The text on p. 3.4-6 of the DSEIS has been revised to provide a discussion on stream bed hydrocarbon stains. Hydrocarbons are known to be present in portions of four stream beds in Section 26S on the northeast flank of Elk Hills. The hydrocarbon stains are believed to have occurred from historic discharges into drainages downstream of wells drilled prior to the 1960's and consist of hardened asphalt brea of unknown thickness and approximately 2' to 10' in width.

A follow-up investigation is planned to begin immediately to determine the full extent of hydrocarbon staining present in the northeast flank drainages. All hydrocarbon stains identified will be cleaned up in accordance with applicable requirements.

13.H-6 The text on p. 4.1.2-2 of the DSEIS has been revised to clarify the projected increase in the site's annual hazardous waste volume. See also the response to comment 13.H-2.

13.W-1 The text in the Summary, Section 3.4.1, and Section 4.1.4 of the DSEIS has been revised to address wetland resources. A preliminary evaluation of potential wetlands on NPR-1 has been provided in Appendix J.

13.W-2 The text in Table S-1 and Sections 3.4.2.4 and 4.1.4.2.2 of the DSEIS has been revised to address the potential effect of NPR-1 sourcewater withdrawals on local aquifers. As discussed by Phillips (1992), sourcewater withdrawals since 1979 have not produced significant declines in Tulare Formation groundwater elevations along the south flank over an area of several miles. Over a 9-year span, from 1982 to 1991, the water table elevation in Section 18G increased 3 feet between wells 86WS-18G and 45WS-18G. Over a 2-year span, from 1990 to 1992, the water table elevation decreased 5 feet between wells 282-14B and 43WS-14B. Over a 10-year span, from 1980 to 1990, the water table elevation between two wells 100 feet apart on the far west end of the south flank decreased 34 feet.

Given the high withdrawal rates, these changes are not significant which demonstrates that NPR-1's groundwater withdrawal rates from the Tulare Formation along the south flank are within the safe yield of the aquifer. As a result, there has been no significant mining of groundwater from the Tulare groundwater aquifer and local aquifers should not be affected. (See also the response to comment 6.a and revised text in Appendix D, Section D.4.2.2.)

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The discussion included as Item 4b, Groundwater, suggests that an analysis to assess the risks associated with hydrologic flow uncertainties is underway and, "based on preliminary results it appears that groundwater monitoring wells could be needed on the northeast portion of the site." We recommend that this analysis and any necessary mitigation measures be developed and presented in the FSEIS, and that decisionmaking on this EIS be delayed until the results of the analysis are available. 13W-3

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P 1-34 The nature of the "water-treatment chemicals" and the environmental impacts (including byproducts) of using "selective catalytic reduction with ammonia injection" should be provided in the FSEIS. 13W-4

P 1-37 Implementing the preferred alternative would increase water requirements by 74,800 barrels per day by April 1995 (also note that the April 1990 figure presented is outdated). This water would come from WKWD. The FSEIS should outline the impacts which would be realized by other WKWD water users should supplies be increased to NPR-1. Is the "reduction in water deliveries to other westside oil companies" (the source of additional supplies from WKWD) permanent, or would these other oil companies also be preparing to enhance recovery operations thereby requiring additional water sources in the near future? The FSEIS should also discuss the implications involved in terms of impacts and alternative sources should WKWD not be able to supply needed water. 13W-5

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13.W-3 The potential need for groundwater monitoring on the northeast flank of NPR-1 is to assess the potential effects of historic NPR-1 operations that occurred many years ago (Golder 1990), and has very little to do with the potential impacts of the proposed action. Furthermore, water quality in the vicinity of NPR-1's northeast flank may have been impacted by natural groundwater flow (Waldron 1989), or by activities other than NPR-1 operations. Therefore, it is not appropriate to link a decision on the proposed action to the ongoing analysis of the extent of the need to monitor groundwater on the northeast flank of NPR-1. (See the responses to comments 3.a, 9.d and 11.a for additional information on the development and implementation of NPR-1 groundwater monitoring plans).

13.W-4 As a result of the data obtained from the preliminary design analysis of the cogeneration plant's water and waste streams, the use of water-softening agents such as sodiumzeolite are no longer required. Originally, in the cogeneration plant's conceptual design, it was thought a water softener system along with a cation anion exchanger demineralizing system would be required. As discussed in Section 1.2.2.13, the only treatment system being proposed now is a demineralizer system. As discussed in Section 4.1.2.2, the only chemical additives that would be added to the feedwater may be small amounts of antiscaling and biocide agents. The use of these additives would not be expected to present an environmental disposal problem as their nature and use is consistent with Class II injection fluid criteria. The text on p. 4.1.2-5 of the DSEIS has been revised (see also the response to comment 13.H-2).

Selective catalytic reduction with ammonia injection is an air emission control process. There are no potential impacts to groundwater from this process.

13.W-5 The text on pages 3.4-19 and 4.1.4-10 of the DSEIS has been revised to discuss NPR-1's purchase of fresh water from the West Kern Water District.

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P 3.4-12 The magnitude of the effect of disposing 2348 million barrels of oil field waste water in percolation sumps, stream channels, and ditches is unclear. The FEIS should succinctly describe the effects such disposal practices would have had on soil and groundwater resources in the vicinity of NPR-1, especially in light of the fact that "Rector (1983) has interpreted the direction of groundwater flow to be from the Elk Hills into the adjacent valleys." 13W-6

P 3.4-14 The discussion on this page suggests that "sometimes well operations result in the accumulation of oil in well cellars which, if not removed could eventually degrade groundwater." The FSEIS should evaluate operational modifications which could be accomplished to eliminate such accumulations and should discuss the reasons such accumulations would not be removed (promptly). 13W-7

P 3.4-19 Note that the UIC program does not allow the use of unlined sumps for disposel of oil and gas related wastes. All sumps receiving wastes should be closed or lined. The FEIS should address and resolve this issue. Refer also to the parallel discussion on page 4.1.4-5. 13W-8

P 4.1.4-6 The discussion concerning consumption of freshwater at NPR-1 suggests that "existing systems should be capable of providing requirements associated with the continuation of current operations." The information provided in this section should be more definitive, i.e., is the existing system capable, or will modifications be required? In addition, the DSEIS states that 29,000 barrels per day were required in 1988, and that the requirements "have been increasing" but does not provide current requirement figures. The FSEIS should include current data wherever possible. 13W-9

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13.W-6 The 2,348 million barrels of oil-field wastewater disposed to the surface is an estimate that applies to the Buena Vista and Midway Valley portions of Kern County, including but not just NPR-1. The portion of this estimated to have been disposed of to the surface on NPR-1 is explained in Section D.4.1 as being approximately 10,000 barrels/day, or approximately 36.5 million barrels. The impacts of NPR-1 surface disposal and mitigation measures are explained under Produced Water Disposal in Sections 3.4.2.4, 4.1.4.2, and 4.1.4.3. Surface effects, if any, are to be surveyed and if appropriate studied, sampled, and remediated in accordance with CERCLA requirements. Groundwater effects are to be addressed pursuant to groundwater monitoring protection and monitoring plans that currently are under development as required by DOE Order 5400.1. Rector's interpretation that NPR-1 groundwater flows into adjacent valleys is not supported by other investigations (e.g., Bean and Logan 1983, Milliken 1992). NPR-1 groundwater protection and monitoring will be designed to address this inconsistency. There currently is no significant evidence that past NPR-1 surface disposal practices have had any effect on valley groundwater aquifers.

13.W-7 The text on p. 3.4-14 of the DSEIS has been revised to describe NPR-1's well cellar inspection and corrective action programs.

13.W-8 As explained in Sections 3.4.2.4, 4.1.4.2.1, D.4.1, D.4.5.1, and D.5.2.4, sumping practices at NPR-1 are conducted in accordance with Waste Discharge Requirements (WDRs) issued by the Central Valley Regional Water Quality Control Board, and not under the authority of the UIC program. It is important to note that the WDRs only restrict unlined sumping onto alluvial soils (which comprise only a very small portion of NPR-1). Consequently, all sumps on or near alluvial soils either have been lined, or taken out of service. Unlined sumping onto Tulare soils is not restricted. Nevertheless, in recognition of the risks involved with "any" sumping, sumping has been limited to only that which has been necessary as the result of emergency and off-normal circumstances. In addition, a sump closure program is in progress to phase-out or reduce the total number of sumps and amount of water sumped. As a result, many sumps have been eliminated, and sumping has been reduced to approximately 1,000-2,000 barrels/day, or less. The sump closure program is still in progress, and continued improvements are anticipated.

13.W-9 See the response to comment 13.W-5.

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P 4.1.4-8 The DSEIS discusses a project to recycle approximately 50,000 barrels/day of wastewater and suggests that additional similar projects are planned to reduce disposal and possibly groundwater withdrawals, "pending the results of the first project" (this project is also discussed on pages XXVIII, 3.4-22 and 5-1). Given that the success of the first project has not been verified to date, the FSEIS should also discuss water needs and disposal impacts without the recycle project(s) and, depending upon the impacts, the success of the first project should be verified before a record of decision (ROD) is prepared for the alternatives evaluated in this EIS. 13W-10

13.W-10 The impacts of the proposed action if the produced water recycling initiative is totally unsuccessful have been evaluated (Milliken 1992), and are insignificant. See also Sections 4.1.4.2.2 and 4.1.4.2.3 and D.4.2.2 and the responses to comments 13.W-2, 13.W-6, and 13.W-12.

P 4.1.4-12 The FSEIS should define what is meant by using "generally acceptable methods that pose minimal threats to underlying and peripheral groundwaters" to dispose of fluids that are "confirmed to be nonhazardous." Also, the FSEIS should define what is meant by "rare instances" when drilling fluids could test hazardous. 13W-11

13.W-11 The text on p. 4.1.4-12 of the DSEIS has been revised to discuss NPR-1's drilling fluid waste disposal practices.

A drilling fluid is considered hazardous if it contains an additive with constituents that exceed the regulatory levels in Title 22 CCR. There are no drilling fluids presently being used at NPR-1 that contain hazardous constituents that exceed the regulatory levels. If a hazardous drilling fluid is required for future NPR-1 operations, the spent fluids would be contained and disposed of off-site at a permitted facility. This is not known to have occurred at NPR-1 since about 1983.

P 6-1 The FSEIS should discuss the short-term requirements for water and use of the aquifers for disposal versus the long-term productivity of the region's water resources. 13W-12

13.W-12 The text on p. 6-1 of the DSEIS has been revised to discuss short and long term uses of water to support NPR-1 operations along with the potential effects of such use.

P 7-1 The FSEIS should consider inclusion of freshwater resources in the discussion of irreversible and irretrievable commitments of resources. 13W-13

13.W-13 The text on p. 7-1 of the DSEIS has been revised to include the consumptive use of fresh water.

P D-3 Figures included in the DSEIS indicate that approximately 357 million gallons of wastewater were disposed of in sumps during 1979. The text indicates that wastewater production is increasing but does not supply current figures. These figures should be included in the FSEIS. 13W-14

13.W-14 Table 1.2-1 provides an estimate of NPR-1 produced water production. Peak production is expected to be approximately 181,000 barrels/day. In recognition of the risks associated with sumping, NPR-1 has limited sumping to only emergency and off-normal situations. Even though wastewater production is increasing, sumping has decreased significantly. Currently, sumping is approximately 1,000-2,000 barrels/day in comparison to approximately 21,000 barrels/day in 1979. See also the responses to comments 13.W-6 and 13.W-8.

On other pages in this appendix, the DSEIS indicates that there may be a link between sumps on the Reserve with brine-contaminated wells in the San Joaquin Valley. DOE should commit to making every effort to ensure that use of sumps is minimized and that those used are lined to prevent intrusion of low quality water into nearby watervells. 13W-15

13.W-15 This comment has been addressed in the responses to comments 13.W-6, 13.W-8, and 13.W-14.

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AIR QUALITY

Table S-1 The document should discuss each of the anticipated emissions increases in relation to the conformity provisions [§176(c)] of the new Clean Air Act (CAA). Please note that the CAA mandates that proposed activities will not 1) cause or contribute to any new violation of any standard in any area; 2) increase the frequency or severity of any existing violation of any standard in any area; or 3) delay timely attainment of any standard or any required interim emission reductions or other milestones in any area. The DSEIS does not acknowledge the new CAA and therefore it is unclear whether or not the acknowledged increases in emissions would conform as required. For example, on page 4.1.3-3 the DSEIS states that there would be net increases in TSP and PM10 emissions from increased truck traffic delivering liquid products associated with increased production at the new fourth gas plant. The FSEIS should discuss these increases (and other sources of increased PM10 emissions as suggested in the document) in relation to the conformity provisions of the new CAA. It is unclear from the information presented in the DSEIS whether the existing SIP takes into account the new emissions which would result from the proposed action (refer also to page 4.1.3-19). 13A-1 13A-1

P 3.9-5 The DSEIS states that NPR-1 reported that 3,748,000 miles of vehicle travel is completed per year on the Reserve. The FSEIS should include details on existing and/or proposed programs which NPR has established or will establish to reduce the vehicle miles travelled (VMT) and reduce air emissions from these mobil sources. 13A-2

P 4.1.3-10 It appears that the Caline 3 model was used to model transportation emissions. This model is outdated and modeling should be accomplished using the dated Caline 4 model. The data and resulting discussions should be included in the FSEIS. Refer also to page B-85. 13A-3

P 4.1.3-13 The FSEIS should explain how and when NPR-1 intends to "reduce emissions from the tank settings with high release records..." In addition, the document suggests a high level of uncertainty associated with emissions from anode bed wells. Methane, one of the primary pollutants emitted from anode bed wells, is considered a greenhouse gas which could contribute to global warming. Reductions of methane emissions is advisable to the extent possible. The FSEIS should discuss this situation in greater detail. 13A-4

P B-28 The DSEIS indicates that a revised "attainment plan with provisions for attainment of PM10 standards is due in mid-1990." The FSEIS should reflect the current status of the "attainment plan." 13A-5

Table B.7, Hazardous Air Pollutants, does not reflect information contained in the Clean Air Act of 1990, as amended. The table and associated text should be revised to reflect information contained in §112 of the Act. 13A-6

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DOE RESPONSES

13.A-1 The text on pages 4.1.3-3, 4.1.3-10, B-28 and B-29 of the DSEIS has been revised. To the best of our knowledge, the existing SIP sufficiently allows for all emissions associated with the proposed action, with the exception of TSP/PM-10.

The existing SIP does not include TSP/PM-10 because it was not a regulated pollutant until the passage of the 1990 Amendments to the Federal Clean Air Act. The KCAPCD currently is developing an appropriate TSP/PM-10 plan to address the requirements of the amended Act. The plan is to be completed in 1993, and when it is adopted by CARB, it will be submitted to EPA for promulgation and inclusion in a new SIP. NPR-1 is coordinating with KCAPCD to ensure that the emissions associated with the proposed action are included in the new SIP.

13.A-2 The text on p. 4.1.3-19 of the DSEIS has been revised to address NPR-1's new employee van pool program and other initiatives that will reduce mobile source emissions at NPR-1.

13.A-3 Given that there is only one important intersection at NPR-1 which receives very little traffic, and virtually no backed up traffic, the results from Caline 4 would not be significantly different than the results of Caline 3.

13.A-4 The text on p. 4.1.3-13 of the DSEIS has been revised to describe programs to reduce emissions at tank settings and to discuss in greater detail emissions from anode bed wells.

13.A-5 See the response to comment 13.A-1.

13.A-6 The list of hazardous air pollutants on Table B.7 (p. B-30) of the DSEIS has been revised to

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DOE RESPONSES

reflect designations in Section 112 of the Clean Air Act of 1990.

OPERATIONS

Table 8-1 It should be made clear in the FSEIS (within the "Favorable Impacts/Mitigation Programs" section of Item 8, "Socioeconomics") that the preferred action would alleviate the "steep production decline" only for a finite period of time and that production would soon decline at the same rate currently being experienced, if not more rapidly. 130-1

13.O-1 Over the economic life of the field, the decline rate for no action would always be greater than the decline rate for the preferred action. Regardless of the production scenario (preferred action or no action), the field eventually will be depleted essentially to zero production. The difference is that given its more gradual decline rate, the preferred action has a longer economic life and a significantly greater recovery of hydrocarbons and economic return.

Table 8-1 In discussing risks, Item 9 includes a statement that suggests that the number of blowouts would decline due to a reduction of reservoir pressures. The discussion, however, does not acknowledge the difference in reservoir pressures that would be experienced from steam and waterflood injection. The FSEIS should provide a brief discussion of the relationship between anticipated blowout rates and injection. 130-2

13.O-2 See the response to comment 13.N-5.

The California Division of Oil and Gas (CDOG) has the primary responsibility for Class II (Oil and Gas) injection wells in California, and it issues permits for all injection wells related to oil and gas activities. DOE should work closely with CDOG on all aspects of its injection program and make sure it acquires the appropriate CDOG permits.

The FEIS should also provide updated information concerning the Tulare Formation being "an EPA Class II exempt aquifer since the 1950s." Since EPA did not exist in the 1950s, the Tulare may have been exempted by the State at that time. 130-3

13.O-3 The text on pages xxiv, xxviii, and Table S-1 of the DSEIS has been revised to discuss the exemption of the Tulare Formation aquifer pursuant to the Safe Drinking Water Act. NPR-1 works very closely with the Division of Oil and Gas regarding the permitting and operation of all NPR-1 wells.

P 1-5 The FSEIS should provide figures which discriminate between abandoned wells and shut-in wells on NPR-1. In addition, the FSEIS should discuss the feasibility of re-entering shut-in wells as an option to drilling new wells to increase production. 130-4

13.O-4 The text on pages 1-5, 1-21, and 1-23 of the DSEIS has been revised to differentiate between shut-in and abandoned wells.

Figure 1.2-1 It is unclear whether this figure depicts projected oil production at NPR-1 with or without implementation of the preferred action. We suggest that the figure be redrawn as a comparison of production for all of the alternatives. 130-5

13.O-5 See revised Figure 1.2-1, which compares alternative production scenarios.

Page 1-32 The power source for the 10 proposed 1000 horsepower compressors and three 1500 horsepower compressors should be identified in the FSEIS. 130-6

13.O-6 The text on p. 1-32 of the DSEIS has been revised to identify the power source of the compressors.

P 1-39 The FSEIS should describe the Reserve's monitoring program in terms of ensuring that third party developers conduct activities in an environmentally responsible manner and should describe the enforcement mechanism used to ensure that developers are held responsible for impacts to the environment. 130-7

13.O-7 The text on p. 1-40 of the DSEIS has been revised to provide a description of the monitoring program for third-party activities.

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Page 2-10 The FSEIS should explain what is meant by the statement that "MER strategy is also consistent with that which is generally pursued (highlight added) within the private sector of 130-8

the oil-field industry." The explanation should describe the differences and provide the rationale for the differences. 130-8

P 3.2-16 The DSEIS mentions the presence of "pinholes" in the sides of a drilling fluid tank but does not indicate what is being done to curtail these leaks and to prevent other tanks from experiencing similar problems in the future. The FSEIS should expand the discussion to address these issues. 130-9

P 3.9-1 In discussing historical risks, the DSEIS states that the number of incidents (spills) "has increased steadily since 1983" and that "this increase may be attributed, in part, to increasing corrosion associated with aging equipment..." The FSEIS should provide information on any programs in place to repair and or replace aging equipment before accidents occur. 130-10

We also question the rationale for the contention that "the increasing age of equipment is not expected to be a serious problem." This statement appears to contradict the statement above. The FSEIS should clarify this contradiction and provide information on the schedule for replacing older equipment which could fail and result in pollution episodes. The FSEIS should also discuss the Reserve's plan for minimizing and/or eliminating waste streams, i.e., identify source reduction efforts. 130-11

P 4.1.3-20 The DSEIS suggests that worker exposure to benzene during spills and associated clean-up efforts could be higher than the OSHA's permissible exposure limits (PEL's), and indicates that procedures "would be (highlight added) incorporated into the SPCC plan so that the oil-spill cleanup crew arriving at the spill site would begin cleanup operations from the upwind side of the spill." The FSEIS should indicate why safety procedures are not already incorporated in the SPCC plan, and should discuss the precautions that would be taken if cleanup must be conducted downwind of the emission source. 130-12

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DOE RESPONSES

13.O-8 The term "Maximum Efficient Rate" (MER) is interpretative, and interpretations differ within government and industry. Examples of these differences are illustrated in a lengthy technical paper prepared for the Department of Interior (USGS 1976). The meaning of MER at NPR-1 is described by the Naval Petroleum Reserves Production Act of 1976, Public Law 94-258 (DOE 1985b). See also Sections 1.1.3 and 1.5 of this document.

Due to the complexity of the subject, it is not practical or reasonable to attempt to describe all of the potential differences in how different members of government and industry might interpret the meaning of MER. It is known, however, that DOE's interpretation is the same as, or very consistent with other interpretations. In addition, it is believed that DOE's interpretation does not differ significantly from the great majority.

13.O-9 As a matter of standard practice, NPR-1 tank farms, tank settings, and pipelines are inspected on a regular basis to identify any facility problems. Facility leaks are promptly reported to BPO1 Environmental Services for appropriate action.

The text on page 3.2-16 of the DSEIS has been revised to update the status of the 18R drilling fluid tanks.

13.O-10 The text on p. 3.9-1 of the DSEIS has been revised to provide information on preventative corrosion control programs.

13.O-11 Due to the institutionalization and success of the NPR-1 corrosion control program (see the response to comment 13.O-10), and the oil spill control program (see Sections 3.2.5.1, 4.1.2.3 and 4.1.9, and Project P49202 in Table 1.2-10), it is not anticipated that aging equipment will be a serious problem.

13.O-12 The text on p. 4.1.3-20 of the DSEIS has been revised to address worker protection standards and safety measures implemented during spill response activities.

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P 4.1.4-2 While we agree that when production declines and wells are plugged and abandoned there will be less equipment in use, we do not necessarily agree that maintenance of the equipment would diminish. In fact we support your earlier statement that corroding equipment in a mature field needs enhanced maintenance to minimize spill occurrences. 13O-13

P 4.1.4-11 The FSEIS should define how "spills would be minimized," and should define "regularly" as in "producing well cellars would be monitored regularly." 13O-14

DOE RESPONSES

13.O-13 The text on p. 4.1.4-2 of the DSEIS has been revised to explain the decline in NPR-1 oil spill frequencies over time and to address corroding equipment that needs maintenance.

13.O-14 The text on p. 4.1.4-11 of the DSEIS concerning monitoring of producing well cellars has been revised to identify producing well cellar monitoring frequencies.

Spills would be minimized as explained in the SPCC plan (BPOI 1992c), which comprehensively addresses the subject, including corrosion control, maintenance, repair, replacements, and secondary containment. See also the responses to comments 13.O-10 and 13.O-11.

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*Copies of correspondence and unpublished documents cited in this list may be obtained upon request from James C. Killen, Technical Assurance Manager, U.S. Department of Energy, P.O. Box 11, Tupman, California 93276.

APPENDIX I

ENDANGERED SPECIES ACT CONSULTATIONS

I-1 1993 FINAL DRAFT BIOLOGICAL OPINION

DRAFT

Fish and Wildlife Enhancement
Sacramento Field Office
2800 Cottage Way, Room E-1803
Sacramento, California 95825-1846

In Reply Refer To:
1-1-80-F-2(R2)

May 28, 1993

Mr. Danny A. Hogan, Director
U.S. Department of Energy
Naval Petroleum Reserves in California
P.O. Box 11
Tupman, California 93276

Subject: Reinitiation of Formal Consultation Concerning Oil Production at Maximum Efficient Rate on Elk Hills Naval Petroleum Reserve, Kern County, California

Dear Mr. Hogan:

This responds to your October 9, 1991, request for reinitiation of formal consultation pursuant to Section 7(a) of the Endangered Species Act of 1973, as amended (Act), on a proposal by the U.S. Department of Energy (DOE or the Department) to continue oil production activities at Maximum Efficient Rate (MER) on Elk Hills Naval Petroleum Reserve (NPR-1 or the Reserve), Kern County, California. At issue are effects of proposed MER production on the federally endangered San Joaquin kit fox (*Vulpes macrotis mutica*), blunt-nosed leopard lizard (*Gambelia silus*), giant kangaroo rat (*Dipodomys ingens*), Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*), Kern mallow (*Eremalche kernensis*), and San Joaquin wooly threads (*Lembertia congdonii*), and the federally threatened Hoover's wooly-star (*Eriastrum hooveri*). Your request for formal consultation was received by this office on October 15,1991.

The Service addressed effects on federally listed species of MER production activities on NPR-1 in two prior biological opinions dated February 1, 1980 (Case No. 1-1-80-F-2) and December 16, 1987 (Case No. 1-1-80-F-2R). The 1980 biological opinion concluded that MER oil production on NPR-1 would jeopardize the continued existence of the San Joaquin kit fox and blunt-nosed leopard lizard, but included six reasonable and prudent alternatives that, if implemented, would allow MER production to continue. The Department agreed to implement these alternatives and to complete a future consultation to evaluate their success in minimizing adverse effects of MER production on federally listed species.

The subsequent 1987 biological opinion concluded that MER production on NPR-1 would not jeopardize the continued existence of the San Joaquin kit fox, blunt-nosed leopard lizard, and giant kangaroo rat--which was listed as federally endangered in 1988. This conclusion was based, in part, on development and implementation by DOE of a comprehensive mitigation program designed to minimize adverse effects of MER production on federally listed species. In addition to this program, the 1987 opinion required the Department to implement several reasonable and prudent measures, including replacement of endangered species habitat lost as a result of project related actions.

The 1987 biological opinion also cited the Department's intent to develop an updated Environmental Impact Statement (EIS) concerning future oil production activities on NPR-1. The intent to develop such an update resulted from planning activities conducted concurrently with the 1987 consultation that determined that future oil development activities on NPR-1 could exceed some environmental impacts projected in the Department's original EIS completed in 1979 (DOE 1979). Accordingly, the Department published a Notice of Intent to prepare a supplemental EIS on NPR-1 activities in the Federal Register on April 4, 1988, and completed a draft supplemental EIS (DSEIS) in May 1992. It is this supplemental EIS, together with Federal listing of several plant species--the Hoover's wooly-star, San Joaquin wooly-threads and Kern mallow on July 19, 1990--that necessitates reinitiation of formal consultation and preparation of this revised biological opinion.

This biological opinion is based on the DSEIS (DOE 1992); a biological assessment prepared for currently proposed activities on NPR-1 (DOE 1991); several other reports (see Literature Cited section); meetings and discussions between the Service, Department, Chevron U.S.A. (Chevron), and EG&G Energy Measurements (EG&G), the Department's biological contractor; and information in our files.

Biological Opinion

It is our biological opinion that continued petroleum production on Elk Hills Naval Petroleum Reserve at Maximum Efficient Rate is not likely to jeopardize the continued existence of the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, San Joaquin wooly-threads, Kern mallow, or Hoover's wooly-star. Critical habitat has not been determined for these species; therefore, none will be adversely modified or destroyed.

Description of the Proposed Action

Elk Hills Naval Petroleum Reserve (or Naval Petroleum Reserve No. 1) was established in 1912 for national defense purposes but was largely maintained in reserve shut-in status until 1976. Because of oil shortages in the early 1970's, Congress passed the Naval Petroleum Reserve Production Act in 1976, which provided for oil production on NPR-1 at the "Maximum Efficient Rate." Maximum Efficient Rate under this statute was defined as the maximum rate that optimizes both economic return and hydrocarbon recovery. The proposed action addressed in this biological opinion is continuing MER production on NPR-1 in compliance with the Naval Petroleum Production Act and as described in the DSEIS (DOE 1992).

NPR-1 consists of approximately 47,409 acres about 25 miles southwest of Bakersfield, California. Of this, 37,049 acres (78 percent) are administered by the Department of Energy; the balance of 10,360 acres (22 percent) is owned

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by Chevron (DOE 1992). To the south of and partially contiguous with NPR-1 lies Buena Vista Naval Petroleum Reserve (NPR-2). Of approximately 30,000 acres comprising NPR-2, DOE administrates about 10,000 acres and the balance is owned by private oil companies. The government's share of NPR-2 has been developed under lease by private oil companies since the 1920's. Together, NPR-1 and NPR-2 constitute what is known as the Naval Petroleum Reserves in California (NPRC).

Topographically, Elk Hills consists of a ridge about 16 miles long by six miles wide that runs east to west in the southern San Joaquin Valley. The central portions of the reserve consist of steep, rugged terrain grading to level or gently sloping terrain along the north and south sides. NPR-1 is surrounded on three sides by extensively developed oil and gas fields and some agricultural lands. On the north side, NPR-1 is immediately contiguous with a large area (approximately 30,000 acres) of relatively undisturbed endangered species habitat known as the Lokern Road area. Vegetation on NPR-1 consists primarily of saltbush scrub and grassland habitats.

Elk Hills is the seventh largest oil field in the United States (DOE 1991). It is a highly profitable field, cumulative net government revenues exclusive of Chevron's share from 1976 to 1990 totalling $11.6 billion (DOE 1992). Hydrocarbon products recovered or produced on NPR-1 include crude oil, natural gas, and natural gas liquids including propane, butane, and natural gasoline. Of estimated original recoverable oil reserves on NPR-1, 860 million barrels have been produced--630 as the result of MER production since 1976 (DOE 1992). Oil production on NPR-1 peaked in 1981 at approximately 180,000 barrels per day and averaged approximately 74,000 barrels per day in Fiscal Year 1991 (DOE 1992). The Department estimates that oil production on NPR-1 could continue to be profitable until 2010 to 2025, perhaps longer (DOE 1992).

Activities necessary to achieve and maintain MER production on NPR-1 were first described in the original project EIS (DOE 1979). These activities have resulted in the construction of numerous oil production, processing, and storage facilities, associated infrastructure, and administrative facilities on NPR-1 since 1976 (see Environmental Baseline section). Because of evolving conditions, however, including better technical understanding of oil and gas reservoirs beneath NPR-1, the Department now proposes several new facilities believed to be necessary to maintain MER production through the 1990's and into the next century. These are described in the DSEIS (DOE 1992) and are summarized below.

To maintain hydrocarbon production on NPR-1 at Maximum Efficient Rate, the Department proposes to conduct the following <u>ongoing</u> activities (DOE 1992) (those not pertaining to biological issues are omitted).

(1) Continued operation and maintenance of all existing facilities, including production of approximately 80,000-99,000 barrels of oil, 415 million cubic feet of natural gas, and 768,000 gallons of natural gas liquids per day.

(2) Drilling, redrilling or deepening approximately 382 existing wells (including 148 for the steamflood operation described below), performance

of approximately 2,663 remedial jobs on existing wells, and abandonment of approximately 1,080 existing wells.

(3) Investigating, remediating, or otherwise managing numerous old and inactive waste sites.

(4) Activities to permit third parties to construct, operate, and maintain pipeline projects, geophysical surveys, and other projects on NPR-1 lands. Approximately 3-4 third-party projects are anticipated per year.

(5) A program to initiate revegetation on approximately 1,045 acres of previously disturbed lands no longer needed for production operations.

(6) Continued annual maintenance of the NPR-1 perimeter firebreak. This activity was addressed in prior biological opinions dated June 3, 1987 (Case No. 1-1-87-F-40), August 20, 1991 (Case No. 1-1-91-F-18), and June 16, 1992 [Case No. 1-1-91-F-18(R)].

In addition, the Department proposes to initiate the following new activities to maintain MER production on NPR-1 (DOE 1992).

(1) Construction and operation of a phased multi-year steamflood operation consisting of 148 wells on an approximately 500-acre area (referred to as the SOZ Steam Flood Project). This project represents an expansion of a 59-acre pilot steamflood project initiated in 1987 and addressed under a prior biological opinion (Case No. 1-1-85-F-22).

(2) Construction and operation of a 3-acre, 42-megawatt cogeneration facility.

(3) Construction and operation of a 5-acre butane isomerization facility.

(4) Construction and operation of a fourth gas compression and processing facility.

(5) Construction and operation of facilities to increase gas compression capacity for gas-lift and gas injection projects, and to increase waterflooding capacity.

To mitigate for adverse effects on federally listed species of ongoing and new MER production activities on NPR-1, DOE proposes to continue implementing the mitigation program developed under previous NPR-1 consultations. This program consists of the following components.

Wildlife Management Plan

This Plan was developed in 1987 to mitigate the effects of routine NPR-1 operation on endangered species and other wildlife; it requires or encourages the following: (i) conducting pre-activity surveys prior to surface disturbing activities; (ii) revegetation of disturbed areas; (iii) monitoring endangered species populations; (iv) controlling coyote populations as appropriate; (v) implementing operating guidelines; (vi) studying conservation and habitat restoration techniques; (vii) developing information and education programs for NPR-1 employees and contractors; and (viii) participating in endangered species recovery programs (O'Farrell and Scrivner 1987). Some activities conducted under the Wildlife Management Plan are discussed further below.

Endangered Species Research and Monitoring Program

In 1979 DOE initiated an endangered species research and monitoring program on NPR-1 and NPR-2 and hired EG&G Energy Measurements, Inc. (EG&G) as its sole biological consultant. In part, EG&G was tasked with implementing reasonable and prudent alternative no. 1 in the Service's 1980 biological opinion--which required an evaluation of effects of oil field development on NPR-1, "basic research" on endangered species including collection of "baseline population and distributional" data, and development of methods to "increase carrying capacity" and "promote the conservation" of endangered species on NPR-1.

Based on this rather broad charge, since 1979 EG&G has conducted extensive endangered species activities on behalf of the Department and has become an integral component of DOE's overall program on NPR-1 and NPR-2. From approximately 1979 to 1980, EG&G conducted site wide surveys on the Reserves to inventory endangered species populations (Thom Kato, EG&G, pers. comm.). From approximately 1980 to 1987, EG&G gathered extensive data concerning kit fox distribution, abundance, mortality factors, and reproductive success within "developed" and "undeveloped habitats on the Reserves (see Project Effects section). These data were reported in numerous topical reports prepared in 1986 and 1987 and in a biological assessment prepared in support of the 1987 formal consultation and biological opinion.

Operationally, EG&G's role on the Reserves is currently divided into seven program "elements" (Thom Kato, EG&G, pers. comm.). These are (1) endangered species monitoring, including monitoring of kit foxes, lagomorphs, small mammals, coyotes, and other federally listed species; (2) pre-activity surveys on NPR-1; (3) habitat reclamation and management (discussed below); (4) research and development (discussed below); (5) general program assistance, including section 7 consultation support; (6) assistance with third party projects on NPR-1 and NPR-2; and (7) endangered species support activities on NPR-2. An eighth program element previously included through approximately 1990--investigation of relationships between oil field materials and practices and wildlife--was placed as a task in the research and development element in Fiscal Year 1992, evidently because most tasks associated with this element either have been completed or deferred.

Under Element 4--research and development--EG&G has conducted or proposed to conduct a variety of projects that are either independent of or indirectly related to other program tasks. Justification for these "optional" studies derives in large part from language in the Service's prior biological opinions requiring or recommending, for example, development of methods to "increase carrying capacity" on NPR-1 (1980 opinion) and to conduct artificial kit fox den studies (1987 opinion). Projects conducted or ongoing under this element include, but are not limited to, a kit fox supplemental feeding study, a kit fox relocation project, a giant kangaroo rat habitat reclamation study, and a burn area re-seeding study. Projects proposed but not conducted to date include a kit fox artificial den study and a study of Bakersfield kit foxes associated with the relocation project (William Lehman, USFWS, pers. comm.).

Beginning in Fiscal Year 1993, EG&G plans to re-direct its endangered species program in certain respects (Thom Kato, EG&G, pers. comm.). Planned changes to the program include decreased emphasis on baseline monitoring of kit fox life history data--a primary activity since 1980--and increased emphasis on baseline monitoring of other federally listed species, publication of existing data, and increased coordination with recovery planning and other researchers.

In late 1988, the Department established an interagency committee to assist in managing its endangered species programs on NPR-1 and NPR-2. Known informally as the Elk Hills Endangered Species Ad Hoc Advisory Committee, this group is composed of representatives from DOE, Bechtel Petroleum Operating, Inc. (DOE's Unit Operator), EG&G, Chevron, the Service, California Department of Fish and Game, and recently the California Energy Commission. The committee meets four times per year.

Habitat Reclamation and Compensation

Both prior biological opinions concerning MER production on NPR-1 discussed in detail the issue of habitat losses resulting MER production and compensation for such losses. A reasonable and prudent alternative in the 1980 opinion required DOE to "prepare a Master Plan for the restoration of disturbed habitat on NPR-1." The terms and conditions within the 1987 opinion required the Department to (1) complete an inventory of previously disturbed parcels at NPR-1 that could be rehabilitated to offset habitat loss associated with project activities, and (2) to develop a 10-year program to restore on-site disturbed acreage equivalent to that lost as a result of project activities.

Pursuant to these requirements, the Department in 1988 completed detailed disturbance mapping of NPR-1 based on current aerial photography, and in 1985 initiated a habitat reclamation program on NPR-1 and NPR-2. To date, 1,176 previously disturbed acres on the Reserves have been replanted, including 1,051 acres on NPR-1 and 125 acres on NPR-2 (EG&G unpublished data). While this represents all lands currently available for reclamation (i.e., lands that are abandoned and meet all reclamation criteria), the Department has identified an additional 1,639 acres on the Reserves still in use at this time that are planned for abandonment and reclamation between 1992 and 2025 (DOE 1991, DOE 1992); of these, 626 acres would be replanted by 1998 (DOE 1991). This would yield a total of 2,815 acres revegetated as a result of the Department's reclamation program through 2025. In addition, 1,465 acres of disturbed lands on NPR-1 have revegetated naturally (EG&G unpublished data).

The issue of how the Department's habitat reclamation program relates to its overall obligation to compensate for habitat losses on NPR-1 resulted in considerable discussion during the current consultation. Based on the requirement within the 1987 opinion to restore "equivalent on-site acreage" DOE questioned whether its habitat reclamation program alone was not sufficient to compensate for MER related disturbances, provided equivalent acreage was revegetated. However, for the following reasons the Service did not consider habitat reclamation alone to be adequate. First, the 1987 biological opinion states that equivalent on-site acreage should be restored "at a minimum." Second, both prior opinions also mention other compensation methods, including zoning for no development, purchase of off-site habitats, and contribution of funds. Third, "equivalent" reclamation (at a 1:1 ratio) would not be consistent with San Joaquin Valley compensation policy as developed by the Service and California Department of Fish and Game through numerous prior projects--which typically requires a 3:1 compensation ratio for permanent habitat impacts and a 1.1:1 ratio for temporary impacts in saltbush scrub habitats. Finally, in previous projects, revegetation of disturbances resulting from a project typically is not credited to the compensation obligation for that project but is considered a separate mitigation measure.

On the other hand, the Service recognizes that DOE has in good faith expended considerable effort and expense on its habitat reclamation program based in part on the Service's recommendations and requirements. Because of this, the Service has worked with the Department to develop a compensation program for NPR-1 that would utilize standard compensation policies, recognize the Department's reclamation efforts, and encourage continuation of such efforts.

The resulting program is based on the following assumptions: (1) because MER development has primarily been considered a single integrated project under this and prior biological opinions, and not as a series of separate projects, the habitat compensation obligation for MER development should apply retro-actively to 1976; (2) that habitat disturbances resulting from MER development should be compensated at the same rate as other San Joaquin Valley habitat losses; (3) that habitat disturbances on NPR-1 that have recovered naturally should not count as credits toward DOE's compensation obligation, since they are fortuitous and not the result of its reclamation program; and (4) that all acres revegetated or planned for revegetation under the DOE's reclamation program should be credited toward its compensation obligation, even though many reclaimed areas were disturbed after MER development began. The latter assumption is also based on the fact that the Department's reclamation program is a relatively large-scale, systematic effort being applied to a wide variety of disturbances on NPR-1. We therefore regard it as a programmatic effort rather than merely a project effort.

Finally, to satisfy DOE's compensation obligation, the Service and Department have discussed conceptually the possibility of placing portions of NPR-1 into protected status for the primary purpose of endangered species management. The Service considers this a suitable strategy because significant areas of NPR-1 are relatively undisturbed (especially along its periphery); and because NPR-1 and undisturbed portions of NPR-2 are contiguous with other important native habitats, including the Buena Vista Valley and the Lokern Road area.

Based on the above discussion, the Department, by letter of June __, 1992, has agreed in principle to compensate for habitat losses associated with MER development on NPR-1 by placing into protected status a total of 5,058 acres of undisturbed lands on NPR-1 and NPR-2. This figure is based on estimated temporary disturbance of 1,326 acres and estimated permanent disturbance of 2,129 acres resulting from MER development, utilizing standard compensation ratios and minus all acres revegetated or planned for revegetation under DOE's reclamation program (i.e., 1,326 temporary acres X 1.1 = 1485.6 acres; 2,129 permanent acres X 3 = 6,387 acres; 1485.6 + 6,387 = 7,872.6 total compensation acres - 2,815 reclaimed acres = a balance of 5057.6 acres to be placed into protected status). The derivation of temporary versus permanent disturbances is explained in the Project Effects section below.

Other Mitigation

To protect federally listed plants on NPR-1, in its June _, 1992, letter, the Department also has agreed to the following measures.

(1) To the maximum extent possible, populations of the Hoover's wooly-star, Kern mallow, and San Joaquin wooly-threads will be avoided during routine NPR-1 operations and during siting of planned new facilities. This will be accomplished through control of routine traffic on NPR-1, and, where appropriate and feasible, through minor re-location of new facilities.

(2) If populations of federally listed plants cannot be avoided during construction activities because of legitimate technical considerations, the following measures will apply. For temporary impacts (for example, pipelines), the top 3 to 6 inches of soil will be stockpiled during project activities and then will be returned to its original location after completion of project activities. For permanent facilities that impact endangered plant populations (with the exception of well sites), the Department will notify the Service's Sacramento Field Office in writing of the reasons why such populations cannot be avoided. Site disturbance may proceed upon written or verbal concurrence from the Service.

Species Account/Environmental Baseline

Biological information on the San Joaquin kit fox and blunt-nosed leopard lizard is available in the Recovery Plans for these species (O'Farrell 1983, USFWS 1985). Recovery Plans have not yet been completed for the giant kangaroo rat, Tipton kangaroo, or Hoover's wooly-star. However, biological information on the giant and Tipton kangaroo rat can be found in Williams (1979) and Williams (1985), respectively. Botanical information on Hoover's wooly-star, Kern mallow, and San Joaquin wooly-threads can be found in Taylor and Davilla (1986).

Existing Facilities

Existing operational facilities on NPR-1 include the following (DOE 1991): (1) 1,253 active wells (production, water source, gas injection, waterflood injection, wastewater disposal injection, and steam injection); (2) 1,055 existing wells that are shut-in (idle) or abandoned; (3) approximately 2,500 miles of pipelines and 1,000 miles of roads; (4) one crude oil tank farm; (5) 121 tank settings; (6) five LACT (lease automatic custody transfer) facilities used to separate oil from water and transfer oil to Chevron and Department purchasers; (7) 45 product storage tanks; (8) four gas-processing plants used to separate natural gas liquid products from natural gas; (9) five wastewater disposal facilities; (10) two gas injection plants; (11) 11 gas compression plants; (12) one steam injection facility used for thermally enhanced oil

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recovery; (13) several emergency wastewater sumps and two landfill facilities; (14) three building complexes for offices, maintenance, and storage; and (15) a variety of other supporting systems and infrastructure.

The majority of waste materials generated on NPR-1 are non-hazardous and include produced water, spent drilling fluids, and solid wastes such as paper, construction debris, and garbage (DOE 1991). Hazardous materials utilized or generated on NPR-1 include used oil, lubricants, and batteries; herbicides and pesticides; solvent wastes; and crude oil (DOE 1991). Most produced water is re-injected on-site into subsurface formations; drilling fluids are placed into an on-site landfill in Section 10G (another landfill in Section 27R is currently being formally closed); and solid wastes are taken to approved off-site landfills. Hazardous wastes are removed to off-site disposal facilities or are recycled (DOE 1991).

Despite careful handling, spills of oil or other chemicals occasionally occur on NPR-1. Since 1989, these have been handled in accordance with a Spill Prevention Control and Countermeasure Plan (BPOI 1989), which provides for an emergency response team, cleanup procedures, and documentation. Nonetheless, an unquantified number of acres on NPR-1 has been affected by such spills since 1976 and the Department currently is cleaning up approximately 70 sites known to have been contaminated by chromium, arsenic, and other materials (51 of these sites already have been remediated) (DOE 1991).

Endangered Species Surveys/Status

In 1979, when the Department began its endangered species program on NPR-1, kit foxes were numerous and widely distributed within the Reserve. In 1984, kit fox dens were observed on all but two sections (DOE 1991). However, since 1979 the kit fox population on the NPR-1 "study area" has declined from a high of 144 animals in the winter of 1981-1982 to a low of just 12 animals in the winter of 1991-1992. In addition, kit foxes have disappeared from the central upland portions of NPR-1--where most oil development has occurred--and now appear to be confined to the flatter peripheries of NPR-1. This decline and the status of kit foxes on NPR-1 is discussed in detail in the Project Effects section.

Distribution of other federally listed species on NPR-1 typically is more restricted than that of kit foxes. From 1979 to 1987, a total of only 136 blunt-nosed leopard lizards were observed in only 28 of NPR-1's 74 sections (DOE 1991). Leopard lizards typically are found in washes and areas of low relief around the periphery of the Reserve, especially in the Buena Vista Valley along the NPR-1/NPR-2 border; however, leopard lizards also have been observed in six sections in the NPR-1 central uplands. Recorded leopard lizard densities on NPR-1 vary from 0.16 to 0.24 individuals per acre (DOE 1991).

Giant kangaroo rat burrow systems have been observed in 30 sections of NPR-1 (DOE 1991). Like the leopard lizard, the majority of these burrow systems occur in the Buena Vista Valley, though a few burrows also have been observed in the central uplands. In recent surveys, however, many of these burrow systems have been found to be inactive, possibly because of drought conditions from 1987 to 1991. Giant kangaroo rat burrows on NPR-1 were observed at elevations ranging from 316 to 1,510 feet.

The California Aqueduct is cited in Williams (1985) as the approximate line between the ranges of the Tipton kangaroo rat and the short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*). Consequently, Tipton kangaroo rat distribution on NPR-1 is confined to those small portions of the Reserve east of the aqueduct. During a three-night trapping census conducted in 1988, six to 12 Tipton kangaroo rats were captured per night in this area (DOE 1991).

Initial field surveys for the Hoover's wooly-star and other federally listed plants were conducted on NPR-1 in spring 1988 (EG&G 1988, DOE 1991). A total of 28 Hoover's wooly-star populations were observed, primarily restricted to alluvial fans along the lower flanks of the Reserve in Sections B4, B10, G12, R7, R8, R10, R12, R13, R32, S17, S18, S20, S21, S22, S23, and S26 (DOE 1991). Further surveys were conducted in 1991 and additional wooly-star populations were observed in Sections B3, B12, B13, G1, G10, S25, S27, S30, S31, and Z14 (EG&G unpublished data). Hoover's wooly-star populations on NPR-1 tend to occur in areas where other vegetation is sparse such as washes and formerly disturbed but currently unused sites (e.g., the NPR-1 firebreak and abandoned roadways). Four populations were found at or above 1,000 feet in elevation.

The Kern mallow, San Joaquin wooly-threads, and California jewelflower (*Caulanthus californicus*) were not observed during these surveys. However, apparently suitable habitat for Kern mallow was observed in the northwestern portion of NPR-1 (Sections 12Z, 13Z, and 14Z), and the species likely exists here in low numbers or may become established within the foreseeable future (DOE 1991). Potential habitat for San Joaquin wooly-threads also was observed along the northern flanks of NPR-1, but these habitats may be suboptimal because of the dense cover of red brome present (DOE 1991). Based on these data the Service concludes that the Kern mallow and San Joaquin wooly-threads may be present within NPR-1 and may be affected by proposed project activities within the remaining life of the NPR-1 oil field. Suitable habitat for the California jewelflower probably does not exist on NPR-1 (DOE 1991).

<u>Effects of the Proposed Action on Listed Species</u>

Adverse effects of continued MER production on NPR-1 on the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, Kern mallow, San Joaquin wooly-threads, and Hoover's wooly-star may result from numerous sources. During construction activities, individual animals may be directly injured or killed by vehicle strikes resulting from construction related traffic, through inadvertent crushing or entombment in collapsed dens or burrows, or through entrapment in construction related holes or trenches.

Also during construction, individual mallow, wooly-threads, or wooly-star populations may be crushed or damaged by vehicle traffic or destroyed by grading, pipeline trenching, and related disturbances. Seedbanks of these plants also may be buried or otherwise destroyed. Other forms of death or injury to federally listed species may result from wildfires inadvertently ignited during welding operations and inundation during release of hydrostatic pipeline test water.

Individual kit foxes, leopard lizards, kangaroo rats, and plant populations also may be subject to harm and mortality during routine day-to-day operations on NPR-1. Factors contributing to such harm and mortality include routine vehicle traffic, routine grading associated with well drilling and access road construction, oil spills or improperly maintained oil sumps, contamination by commonly used oil field chemicals, habitat degradation (discussed below), and other routine operations. Individual kit foxes, leopard lizards, and kangaroo rats also may be subject to harm or mortality during trapping operations associated with DOE's endangered species research and monitoring program.

In addition, individual kit foxes, leopard lizards, and kangaroo rats may be subject to harassment during NPR-1 construction and other activities resulting from increased levels of human disturbance, destruction or excavation of dens and burrows, entrapment in open pipes and construction related trenches, and other factors. Some animals may escape direct injury during such activities but become displaced into adjacent areas. These animals may be vulnerable to increased predation, exposure, and stress through disorientation and loss of shelter.

To date, effects discussed above have been substantially minimized by the Department's endangered species mitigation program. A key component of this program is the practice of conducting pre-construction surveys prior to all surface disturbing activities. Based on available data, the Service concludes that DOE has done a good job of implementing its pre-construction survey program. In 1980, 74 percent of all NPR-1 projects were conducted without pre-construction surveys, while in 1984 and 1985 all projects conducted on NPR-1 were preceded by surveys (Kato 1986). Pre-construction surveys continue to be implemented on NPR-1 on a regular basis (Thom Kato, EG&G, pers. comm.). However, some problems exist in ensuring that recommendations resulting from such surveys actually are implemented. For example, in Fiscal Year 1991 recommendations were not implemented in 22 of 175 projects (12.6%) for which pre-construction surveys were conducted.

Since 1980 a total of 48 San Joaquin kit foxes, 7 blunt-nosed leopard lizards, and 72 giant kangaroo rats have been killed or injured as a result of the factors discussed above (EG&G unpublished data). Of these, 11 San Joaquin kit foxes, 2 blunt-nosed leopard lizards, and 6 giant kangaroo rats have been killed or injured as a result of the Departments's endangered species research program. No Tipton kangaroo rats are known to have been killed or injured during MER activities on NPR-1.

Based on radio-collar data, 291 kit foxes were recovered dead on NPR-1 from 1980 to 1988. Of these, cause of death for 29.9 percent was classified as predation (primarily by coyotes), 24.7 percent as probable predation, 10.0 percent as vehicle strikes, and 3.1 percent as other causes (DOE 1991). Cause of death for 32.3 percent of kit foxes recovered could not be determined. Excluding these foxes, 80.7 percent of foxes for which cause of death could be determined were killed by predation, 14.7 percent by vehicle strikes, and 4.6 percent by other causes (DOE 1991). Mortality sources other than predation and vehicles included disease, shooting, drowning, and burying.

Following is a detailed discussion of the effects of past and proposed future MER activities on NPR-1 on the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, federally listed plants, and their habitats.

San Joaquin Kit Fox

EG&G has studied the San Joaquin kit fox population on NPR-1 intensively since 1980 on a 28,480-acre area encompassing the southern half of the Reserve and 2,880 acres in adjacent Buena Vista Valley known as the NPR-1 study area. The NPR-1 study area contains 16,640 acres defined as "developed" habitat and 11,840 acres defined as "undeveloped" habitat; a square mile containing more than 15 percent of developed land (oil wells, roads, etc.) is defined as developed, and a square mile containing 15 percent or less of developed land is defined as undeveloped (DOE 1991). Studies conducted by EG&G on NPR-1 have included monitoring of kit fox population size, reproductive success, diet, mortality factors, movement patterns, and den characteristics. In part, their purpose has been to determine effects of MER related oil development on the resident kit fox population.

Between 1981 and 1991, EG&G has estimated the San Joaquin kit fox population on the NPR-1 study area and on NPR-2 twice annually based on intensive trapping sessions and capture-recapture data (once annually since Fiscal Year 1992). In 1988, trapping sessions were extended to include the entire civil boundaries of NPR-1 in an effort to detect differences in kit fox abundance or distribution between the study area and the Reserve as a whole.

During the period since detailed studies began (1980), the minimum known kit fox population within the NPR-1 study area declined from a high of 165 foxes in the winter of 1981-1982 to 44 foxes in the winter of 1985-1986 (DOE 1991). Similarly, the minimum known population size declined from a high of 167 foxes in the summer of 1982 to 55 foxes in summer 1985 (DOE 1991). The population appeared to stabilize at 40 to 50 kit foxes through approximately 1990, but recent evidence suggests the population has again declined. In winter 1991 the minimum population size for the NPR-1 study area was estimated at just 12 kit foxes (EG&G unpublished data).

This San Joaquin kit fox population decline on NPR-1 was discussed at length in the Service's 1987 biological opinion and remains a subject of concern. It has been discussed in the biological assessment (DOE 1991), DSEIS (DOE 1992), a preliminary DSEIS prepared by Argonne National Laboratory (Argonne 1990), numerous Elk Hills Endangered Species Advisory Committee meetings, as well as other documents and forums. However, the exact cause of the decline has proven difficult to determine.

Several factors have been considered in attempting to explain this decline, including: (1) the effects of MER development; (2) the endangered species research program; (3) effects of an extended drought in California; and (4) other natural factors.

<u>MER Development</u>. As required under the Service's 1980 biological opinion, the Department attempted to determine the effects of MER development on kit foxes

through studies conducted by EG&G from 1980 through 1986. Based on these studies, EG&G and DOE concluded that the NPR-1 kit fox decline has occurred at similar rates in developed and undeveloped habitats (DOE 1991). This conclusion in turn suggests that MER development has not affected the NPR-1 kit fox population in a significant manner.

However, several factors suggest that these conclusions may not be accurate. First, the kit fox population on NPR-2--where little oil development occurred compared to NPR-1 during the same time period--has declined significantly less than on NPR-1. The NPR-2 kit fox population numbered 177 animals in the summer of 1983 and 113 in the summer of 1989 (EG&G unpublished data). Based on winter data, the NPR-2 kit fox population appears even more stable compared to NPR-1 (119 foxes in the winter of 1983-1984 and 131 in the winter of 1988-1989) (DOE unpublished data). These data suggest that some factor or factors on NPR-1 has affected the kit fox population in a relatively greater fashion than on NPR-2.

Second, circumstantial evidence suggests that the kit fox decline on NPR-1 has been greater in the central upland portions of the Reserve, where most oil development has occurred, than in the flatter lands along its periphery, which are relatively undeveloped. This change in distribution is demonstrated by the fact that few foxes have been captured in the central uplands in recent years, where they were relatively numerous in the early 1980's. By far most kit foxes currently are captured in the flatter undeveloped periphery of the Reserve (Thom Kato, EG&G, pers. comm.). Other circumstantial evidence also suggests effects of NPR-1 oil development on kit foxes--kit fox den densities are lower in developed areas than undeveloped areas on both NPR-1 and NPR-2, and some measures of reproductive success (e.g., number of litters per square mile) are lower in developed areas than undeveloped areas (DOE 1991).

Third, the definitions of "developed" and "undeveloped" habitats as determined by EG&G for the Department's kit fox studies may not be sufficiently refined to detect subtle differences in effect between the two habitat types. This criticism has been raised by the California Energy Commission (CEC 1992) and others (William Lehman, U.S. Fish and Wildlife Service, pers. comm.). For example, according to EG&G's definitions, a square mile with 16 percent of its land developed would be classified as "developed" even if the disturbances are consolidated in one corner and 84 percent of the square mile is contiguous suitable habitat. This tends to underestimate the effects of oil development on constituent wildlife populations because many lands that are essentially undisturbed habitat are classified as developed. The Service therefore questions the accuracy of the Department's conclusions with respect to the effects of oil development on kit fox populations based on this definition scheme.

Several factors with respect to MER development can probably be eliminated as causing the kit fox decline on NPR-1. First, it is unlikely that den loss has contributed significantly to the decline. Between 1980 and 1986, only 5 known kit fox dens were destroyed inadvertently as a result of the MER production and another 20 were intentionally excavated to avoid burial of resident foxes (DOE 1991). However, these losses appear to be relatively insignificant since during the same period approximately 946 dens were known to be utilized by kit foxes (Berry et al. 1987).

Contamination of kit foxes by heavy metals commonly associated with oil fields also appears to be minimal. Kit fox hair samples collected from kit foxes on NPR-1 developed lands, NPR-1 undeveloped lands, NPR-2, Camp Roberts, and the Elkhorn Plain were analyzed by Oak Ridge National Laboratory in Oak Ridge, Tennessee (EG&G unpublished data). Results indicated that kit foxes on NPR-1 exhibited little evidence of contamination by the elements studied, including arsenic, barium, vanadium, chromate, or uranium. Although a few foxes showed high tissue concentrations of some elements, most levels were associated with background soil concentrations or were highest in undeveloped reference sites. Heavy metal concentrations evidently were not great enough to account for the kit fox decline on NPR-1.

<u>The Endangered Species Research Program</u>. The intensive kit fox research and monitoring program conducted on NPR-1 by EG&G has occasionally been cited as a possible contributor to the NPR-1 kit fox decline (e.g., O'Neil and Greer 1988). Throughout the life of the program, approximately two thousand kit foxes have been captured and 486 foxes have been radio collared (Thom Kato, EG&G, pers. comm.). All foxes captured, whether collared or not, have been equipped with individually numbered ear tags. Research factors possibly contributing to the kit fox decline include lowering of kit fox survivorship as a result of wearing radio collars, spread of disease through trapping and handling, and loss of kit foxes to research accidents.

Through approximately 1987 EG&G used relatively heavy radio collars (4 ounces for adults, 2 ounces for pups). These collar weights exceeded the maximum of 5 percent of body weight recommended by Cochran (1980); during EG&G studies, kit foxes were equipped with collars weighing 2.4 percent to 7.9 percent of body weight for the majority (86%) of all kit foxes collared between 1980 and 1992 (DOE 1991). Since 1987, EG&G has utilized considerably lighter collars (Thom Kato, EG&G, pers. comm.).

Several studies have been conducted in an effort to determine the effects of EG&G's radio-collar program on kit foxes. In 1988 Pat O'Brien of Chevron U.S.A. conducted an analysis comparing survivorship of kit foxes on NPR-1 that were radio collared to foxes that were ear tagged only (Tom O'Farrell, EG&G, pers. comm.). Researchers at Argonne National Laboratory conducted a similar analysis about the same time (O'Neil and Greer 1988). The O'Brien study found no significant difference between ear-tagged and radio-collared foxes. The Argonne study found what the authors felt were possible, but unconfirmed, effects of radio-collars on kit foxes.

At the Service's request, EG&G considerably expanded these studies in 1992. Utilizing EG&G data from 1980 to 1992, Dr. Brian Cypher evaluated effects of radio collars on numerous parameters, including collar to body weight ratio, collar design (heavy or light), survival period, and recapture interval, again comparing radio collared kit foxes to kit foxes with ear tags only. With one exception, no differences in survivorship were observed between radio-collared and ear-tagged foxes. Based on these results, and with reference to the large data set and thoroughness of EG&G's study, the Service concludes that EG&G's

kit fox radio collar program has not significantly contributed to the kit fox decline on NPR-1.

However, Dr. Cypher found that kit fox pups radio collared prior to the month of July tended to survive for shorter periods than pups collared after July (EG&G unpublished data). This result probably has not significantly affected kit fox status on NPR-1 but may have important implications in how kit fox radio collar programs are managed on NPR-1 and elsewhere.

Effects of the Drought. By the early 1990's, endangered species populations throughout the San Joaquin Valley were exhibiting declines likely associated with California's five-year drought that lasted from 1987 to 1992. For example, surveys conducted on NPR-1 in 1991 found that most previously active giant kangaroo rat precincts were no longer occupied (EG&G, unpublished data). Similar giant kangaroo rat declines were observed in the Carrizo Plain (Dan Williams pers. comm.), and leopard lizards reportedly did not reproduce in the Carrizo Plain and elsewhere in 1991 (Dave Germano pers. comm.). Similarly, little kit fox reproduction was observed on NPR-1 in 1991 (EG&G, unpublished data). This exceptionally harsh five-year drought has often been cited as a primary or contributing factor in the kit fox decline on NPR-1. The principal result of the drought thought to affect kit foxes was reduction in availability of prey species (typically, small mammals and lagomorphs).

Since 1983, EG&G has conducted a bi-annual census of lagomorphs on NPR-1 and NPR-2, and, like the kit fox, lagomorphs have declined significantly on both Reserves (DOE 1991). On NPR-1, lagomorphs also were censused during road counts from 1980 to 1983 and declined annually over this period. Similarly, the California Department of Fish and Game (CDFG) has conducted two annual spotlighting routes near NPR-1 (the "Taft" and "McKittrick" routes) in which both kit foxes and lagomorphs have been censused since approximately 1970 (CDFG unpublished data). Results of CDFG data also indicate significantly declining lagomorph numbers along these routes, together with a decline in kit fox numbers that appears to strongly "mimic" the pattern of lagomorph decline. These data suggest that a decline in prey availability caused by the drought may be a primary contributor to the kit fox decline on NPR-1.

However, based on other available data this conclusion cannot be considered certain. For example, the lagomorph and kit fox decline on NPR-1 began prior to 1987, when the five-year drought began; while on NPR-2, where the kit fox decline has been less pronounced, lagomorph densities did not begin to decline until 1987, when the drought began (DOE 1991). Furthermore, in an analysis of EG&G data (kit fox numbers versus lagomorph numbers) on NPR-1 and NPR-2 conducted in 1991, the General Accounting Office (GAO) found that between 1984 and 1989 the estimated number of lagomorphs per kit fox was higher on NPR-1 than on NPR-2 (GAO unpublished data). This suggests that prey availability alone can not account for the perceived differences between kit fox numbers on NPR-1 and NPR-2, and that some other factor or factors may have contributed to apparently differential kit fox declines on the two Reserves.

CDFG data suggest another pattern with respect to fluctuating kit fox numbers. According to the graph of these data (DOE 1991), in 1970 kit fox and lagomorph numbers appear to have been declining from earlier highs in the late 1960's.

Their numbers then appear to have remained relatively low from approximately 1972 to 1979, when they began to incline sharply to highs in the early 1980's that were unequaled within the study period. The early 1980's is precisely when EG&G began its systematic counts of kit foxes and lagomorphs on NPR-1 and NPR-2.

This suggests that EG&G initiated its kit fox census on NPR-1 and NPR-2 when lagomorph numbers were at an unusual high, resulting from natural cyclic fluctuations or to some other factor such as rainfall. This in turn suggests that (1) kit fox numbers were unusually high in 1979 or 1980, when EG&G census activities began (likely due to high lagomorph numbers); (2) that this high represented a cyclic fluctuation rather than average kit fox carrying capacity on NPR-1; and (3) that the initiation of intensive MER activities on NPR-1 and the observed kit fox decline on the Reserve was coincidental, not causally related.

Other Natural Factors Other factors possibly contributing to the NPR-1 kit fox decline include coyote predation and disease. Since 1980, coyotes have been responsible for most known kit fox mortalities on NPR-1 (80.7 percent of all dead foxes for which a cause of death could be determined) (DOE 1991). However, based on other studies this appears to be the normal interaction between kit foxes and the larger, more aggressive coyote (e.g., Linda Spiegel, CEC, pers. comm.); and EG&G data indicate that coyote numbers on NPR-1 declined contemporaneously with kit fox numbers. Though coyote predation may have exacerbated kit fox problems originally caused by other factors, no data we reviewed suggest that kit fox-coyote interactions can account for the kit fox decline on NPR-1.

In 1981, 1982, and 1984, the kit fox population on NPR-1 was studied for the presence of disease by analyzing kit fox blood serum for the presence of 10 infectious pathogens (DOE 1991). Despite the occurrence of antibodies for canine parvovirus, tularemia, canine distemper, and canine hepatitus in kit fox blood samples, little clinical evidence of disease has been noted in the NPR-1 kit fox population (DOE 1991). Disease can therefore be largely ruled out in explaining the observed kit fox decline on NPR-1.

Summary The above discussion illustrates that the relationship between kit foxes, oil development, and other environmental factors on NPR-1 is complex. In short, it is difficult to ascribe the San Joaquin kit fox decline on NPR-1 conclusively to any single factor.

Nevertheless, several observations seem important. First, lagomorph and kit fox numbers appear to have declined jointly--if differentially--throughout the general area, not just on NPR-1. Second, although the disappearance of kit foxes from the central upland porz ionsof NPR-1 has been pronounced and contemporaneous with intensive oil developments--suggesting a direct relationship--CDFG data suggest that kit fox presence in the central uplands in the early 1980's may have been the result of unusually optimal conditions at that time. If this is true, then kit foxes may not normally occupy this portion of NPR-1 because of natural factors (e.g. relatively steep terrain), and this area may have been the first to be abandoned when environmental conditions deteriorated--possibly, at least in part, because of the drought.

On the other hand, oil development in the central uplands may have contributed to the adverse conditions--already marginal because of natural factors--that eventually caused kit foxes to abandon the area. In this respect, the Service considers EG&G data suggesting that kit fox declines have been equivalent in developed and undeveloped habitats on NPR-1 to be inconclusive.

Third, the fact that kit fox declines on NPR-2 have been less severe than fox declines on NPR-1 may be significant and is difficult to explain. Several differences between the two Reserves that may account for this fact have been cited--e.g., intensive oil development on NPR-1 and overall gentler topography on NPR-2--but here again results are inconclusive.

Based on existing data, the only factors that probably can be ruled out as causing or significantly contributing to the NPR-1 kit fox decline is coyote predation, disease, and the endangered species research program. Conversely, it seems likely that the decline may have resulted from a combination of the other effects discussed--e.g., the drought, natural cyclic fluctuations, oil field developments, and naturally marginal conditions in the central uplands of the Reserve. Continued monitoring of the kit fox population on NPR-1 in the immediate future--especially in light of the end of the drought in the winter of 1992-1993--will be critically important in better understanding the respective roles of the factors discussed above in the NPR-1 kit fox decline.

Based on the above discussion, the Service concludes as follows with respect to the San Joaquin kit fox: (1) that MER oil production probably is not solely responsible for the kit fox decline on NPR-1 but likely has been a contributing factor; (2) that intensive oil developments in the NPR-1 central uplands likely has contributed to the disappearance of the kit fox from this portion of the Reserve; (3) that proposed new developments in the NPR-1 central uplands, as described in the DSEIS (DOE 1992), will contribute to substantial continuing habitat losses and adverse effects in this area and may inhibit recolonization or effective future use of the area by kit foxes; and (4) that the latter effect is not likely to jeopardize the continued existence of the species because the central uplands probably represent marginal kit fox habitat except in optimal conditions, and provided that DOE implements the habitat compensation program described on pages 6 through 8 above.

Giant and Tipton Kangaroo Rats

Specific effects to giant kangaroo rats potentially resulting from continuing MER production on NPR-1 include (1) destruction of giant kangaroo rat burrow systems during construction of proposed facilities in Townships G, R, and S and by third-party pipelines; (2) removal of food sources (grasses and seeds) during construction activities; (3) alteration of soil conditions--e.g., soil compaction--making it more difficult for kangaroo rats to construct burrows; (4) accidental oil spills or wastewater discharge; (5) disturbance; and (6) accidental death or injury during EG&G's trapping and research activities (DOE 1991). In 1986, for example, 12 kangaroo rats (species not identified) were killed when a DOE lessee discharged wastewater into a natural drainage adjacent to NPR-1. Furthermore, O'Farrell et al. (1987) reported that 99 percent of all giant kangaroo burrow systems on NPR-1 occurred at least 300 feet away from well pads, and numerous well pads may be constructed in known giant kangaroo rat habitats in Sections 6-7G, 14R, 20R, 25R, 28R, 26-27S, and 36S during continuing MER production.

However, construction of the larger facilities currently proposed--e.g., the fourth gas plant, butane facility, and cogeneration plant--is not expected to affect known giant kangaroo rat populations, and pre-construction surveys and flexibility in well pad location should minimize impacts to giant kangaroo rats elsewhere (DOE 1991). Furthermore, the majority of these wells would be constructed in the central upland portions of NPR-1 where giant kangaroo rats are relatively uncommon. Third-party pipelines--expected to disturb a total of 101 acres--may directly effect some giant kangaroo rat habitat in the Buena Vista Valley and other peripheral areas on the Reserve.

The Tipton kangaroo rat, which is present only in Section 23S east of the California Aqueduct, should not be affected by any planned DOE activities on NPR-1 because no development is planned in that area.

Blunt-nosed Leopard Lizard

Specific effects of continuing NPR-1 activities on blunt-nosed leopard lizards are expected to be similar to those cited above for giant kangaroo rats. In addition, because of better climbing abilities, leopard lizards are vulnerable to entrapment in well cellars, and, because of their fondness for washes, are vulnerable to accidental wastewater discharges and oil spills, which tend to occur in washes. Both such forms of leopard lizard mortality have been documented either on or adjacent to NPR-1 in the 1980's (DOE 1991). In 1992, an aestivating leopard lizard was inadvertently unearthed during gravel mining on NPR-1 but this lizard was unharmed and was returned to its habitat (EG&G unpublished data). Other forms of potential leopard lizard effects on NPR-1 include vehicle strikes and destruction of small mammal burrows during construction activities and third-party projects such as seismic surveys and pipelines.

However, most construction of relatively large new facilities will occur in the central upland portions of the Reserve where little leopard lizard habitat exists, and pre-construction surveys and flexibility in well location should minimize leopard lizard effects during DOE and third-party projects elsewhere on the Reserve.

Hoover's Wooly-star and Other Federally Listed Plants

Potential effects of proposed project activities on Hoover's wooly-star would include (1) destruction of plants and plant habitats during grading, trenching and other construction activities; (2) crushing of individual plants and plant populations during off-road vehicle use and seismic surveys; (3) inundation of plant populations resulting from oil spills or hydrostatic water releases; and (4) destruction of plant populations resulting from man-caused fires. No known populations of Kern mallow or San Joaquin wooly-threads currently exist on NPR-1. However, similar adverse effects to these species might occur as a result of MER activities should they later be found or become established on NPR-1.

Adverse effects to federally listed plants would be minimized because (1) most proposed new activities would occur in the NPR-1 central uplands where Kern mallow and San Joaquin wooly-threads populations are not likely to exist; (2) populations of these species and Hoover's wooly-star would be avoided to the maximum extent practicable, as described on page 8 above; and (3) where plant populations are not avoidable, DOE would implement other mitigation measures such as stockpiling of topsoil.

Habitat Disturbance

As of June 1988, an estimated 6,077 acres of native habitat originally existing on NPR-1 have been disturbed either permanently or temporarily as a result of oil development activities since the 1920's (EG&G unpublished data; this represents a minor adjustment to the figure provided in DOE 1991). Of these, an estimated 2,474 acres have been disturbed since the inception of MER production in 1976. In 1992, an additional 5 acres were disturbed by a water well project addressed under a separate biological opinion (Case No. 1-1-92-F-39), for a combined total of 2,479 acres on NPR-1 disturbed since the inception of MER production.

The Department estimates that habitat disturbance on NPR-1 resulting from proposed <u>new</u> facilities between 1989 and 2025 will total 878 acres (DOE 1991). This will result from proposed work on 382 wells (579 acres), gas operations expansion (15 acres), and construction of the cogeneration facility (3 acres), the butane isomerization facility (5 acres), steam generators for the SOZ Steam Flood Project (210 acres), gas compression facilities (10 acres), gas injection facilities (4 acres), and pipeline replacement and maintenance activities (50 acres) (DOE 1991). Of this, 750 acres would be affected by 1998.

Adding past MER disturbances to anticipated future disturbances yields total estimated habitat disturbance on NPR-1 resulting from DOE activities through the life of MER production (1976-2025), or 3,818 acres (2,474 + 878 = 3,351). In addition, non-Federal third party pipeline projects are expected to disturb 101 acres through the year 2025 (DOE 1991). Because the Department has indicated its willingness to consider these as DOE disturbance for the purpose of this consultation (Jim Killen, DOE, pers. comm.), total disturbance resulting from DOE and related activities during MER production is 3,452 acres.

In addition, 547 acres within the NPR-1 civil boundaries have been disturbed in the past by activities not constructed or undertaken by the Department. These include 133 acres disturbed by the California Aqueduct, 45 acres occupied by the town of Taft, and 369 acres of agricultural lands not owned by DOE (EG&G unpublished data). An estimated 79 acres have been disturbed since 1988 as a result of third party projects on NPR-1 (DOE 1991). However, these disturbances are either the result of non-DOE projects or are addressed and mitigated under separate biological opinions. Finally, third party seismic surveys are expected to result in minor temporary disturbances of 3,390 acres through 2025 (DOE 1991).

Because of the scope and extended time frame of oil development activities on NPR-1, determining which of the above disturbances are permanent and which are temporary is complex. Also complicated is determining which disturbances occurred prior to initiation of MER production and which occurred afterward. On December 15, 1992, representatives from the Service, EG&G, and Chevron met to discuss this issue and settled on certain approaches to derive reasonable estimates of these disturbance figures. EG&G subsequently computed acreage estimates, which were utilized in developing the habitat compensation program described on pages 6 through 8 above. These estimates are as follows (an explanation of how they were derived is available in Service files).

Estimated temporary disturbance on NPR-1 resulting from past MER development totals 1,014 acres, while estimated permanent disturbance totals 1,460 acres. Estimated temporary disturbance resulting from proposed new activities totals 312 acres, and estimated permanent disturbance totals 669 acres. Temporary disturbance throughout the life of MER development (1976-2025) totals 1,326 acres and permanent disturbance totals 2,129 acres. Of disturbed acres revegetated by the Department (or planned for revegetation), 1,995 acres were disturbed prior to onset of MER production, and 1,120 acres were disturbed afterward.

Conclusions

Based on the above discussion, the Service concludes that DOE's proposed continuation of the oil development program on NPR-1 at Maximum Efficient Rate will not appreciably reduce the likelihood of survival and recovery of the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, Hoover's wooly-star. Kern mallow, or San Joaquin wooly-threads. This conclusion is based on (1) continuing implementation by DOE of its endangered species protection program described on pages 4 through 8 above; (2) implementation of the habitat compensation program described on pages 6 through 8; and (3) the fact that most proposed future MER-related disturbances would occur in the central upland portions of NPR-1 where few populations of threatened and endangered species currently exist.

Cumulative Effects

Cumulative effects are those impacts of future State and private actions that are reasonably certain to occur. Future Federal actions will be subject to the consultation requirements established in section 7 of the Act and, therefore, are not considered cumulative to the proposed action.

Our agency is aware of other projects currently under review by State, county, and local authorities where biological surveys have documented the occurrence of the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, Hoover's wooly-star, Kern mallow, and San Joaquin wooly-threads. These projects include urban, mineral, and energy development, and flood control and reservoir construction.

However, we do not anticipate that the project under evaluation in this biological opinion, considered together with other non-Federal actions, would appreciably reduce the likelihood of survival and recovery of the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, Hoover's wooly-star, Kern mallow, or San Joaquin wooly-threads.

Incidental Take

Section 9 of the Endangered Species Act prohibits any taking (i.e., to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such conduct) of listed fish and wildlife species without special exemption. Under the terms of sections 7(b)(4) and 7(o)(2) of the Act, taking that is incidental to and not a purpose of the agency action is not considered prohibited taking within the bounds of the Act, provided that such taking is in compliance with this Incidental Take Statement. The reasonable and prudent measures described below are non-discretionary and must be undertaken by the agency, the applicant, or made a binding condition of any grant or permit issued to the applicant, as appropriate.

San Joaquin kit foxes, blunt-nosed leopard lizards, giant kangaroo rats, and Tipton kangaroo rats may be taken incidentally during continued MER production and proposed construction of new facilities on NPR-1. Project actions that may result in the mortality, harm, or harassment of these species have been previously discussed in this biological opinion. Mitigation measures proposed by the Department will substantially reduce but not eliminate the potential for incidental taking of these species during proposed NPR-1 activities.

Based on information provided in the project biological assessment (DOE 1991), information on past incidental takings on NPR-1 provided by EG&G, information in our files, and through prior consultations, the Service anticipates that the following numbers of kit foxes, leopard lizards, and kangaroo rats may be subject to harm or mortality during proposed NPR-1 project activities.

(1) San Joaquin kit fox (total = 16)

(a)	Road kills	8 foxes
(a)	Other routine operations	4 foxes
(b)	New construction	2 foxes
(c)	Third party projects	2 foxes

(2) Blunt-nosed leopard lizard (total = 20)

(a)	Routine operation	4 lizards
(b)	New construction	5 lizards
(c)	Firebreak maintenance	6 lizards
(d)	Third party projects	5 lizards

(3) Giant kangaroo rat (total = 40)

(a)	Routine operation	4 rats
(b)	New construction	4 rats
(c)	Firebreak maintenance	20 rats
(d)	Third party projects	12 rats

(4) Tipton kangaroo rat (total = 7)

(a)	Routine operation	2 rats
(b)	New Construction	0 rats
(c)	Third party projects	5 rats

These incidental take limits shall be subject to the following conditions: (a) vehicle related injury or mortality shall apply to these limits only if DOE activities are demonstrably responsible; (b) injury or mortality resulting from EG&G trapping and handling activities shall not apply to these limits; (c) transfer of limits from one category to another is allowable _if_ written approval from the Service is obtained, with the exception that limits may not be transferred from third party projects to another category; and (d) the Service retains the discretion to determine to which category a taking applies should any such assignment be in dispute.

The Service considers the number of animals subject to harassment from noise, vibrations, displacement, capture, or excavation of dens and burrows resulting from DOE activities to be impractical to estimate. Therefore, we authorize harassment of all federally listed wildlife species inhabiting NPR-1, _provided_ that (1) any such harassment is the result of bona fide project activities; (2) that it is inadvertent or for the express purpose of removing individual animals from construction areas to safe locations; and (3) that all terms and conditions specified below are fully implemented.

The Service states that the following reasonable and prudent measures are necessary and appropriate to minimize the potential for incidental take of the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, and Tipton kangaroo rat during NPR-1 activities.

(1) The potential for harm or mortality to federally listed wildlife species and their habitats shall be minimized during proposed DOE activities.

(2) The potential for harm or mortality to federally listed wildlife species and their habitats shall be minimized during non-Federal third party projects permitted but not conducted by DOE.

In order to be exempted from the prohibitions of Section 9 of the Act, the following terms and conditions, which implement the reasonable and prudent measures described above, must be complied with.

(1) The potential for harm or mortality to federally listed wildlife shall be minimized _during DOE projects_ by implementing the following procedures.

  (a) The Department shall continue to implement fully the endangered species protection program described on pages 4 through 8 of this biological opinion. This program is hereby incorporated into these terms and conditions as a requirement of the proposed action.

  (b) The Department shall continue to conduct pre-activity surveys prior to all surface disturbing activities on NPR-1. This consultation shall be reinitiated if more than five percent of such projects per fiscal year are conducted without such surveys.

(c) Biological monitors shall be present on NPR-1 construction sites during all critical construction activities occurring within or adjacent to endangered species habitat. Activities for which such monitors shall be present include surveys or flagging necessary to determine and delineate specific construction areas, pipeline alignments, and location of access routes and storage areas; grading and trenching activities if they occur in sensitive wildlife areas, as determined by biological monitors; checking of pipes, pipeline trench segments, and similar structures for entrapped wildlife; removal of entrapped wildlife; backfilling pipeline trench segments; den and burrow excavations, if necessary; and other activities as determined by monitoring biologists to be necessary. To the extent possible, biological monitors shall be readily available during periods when not actually present on construction sites. Biological monitors may allow exceptions to this term and condition on a case-by-case basis if, in their best professional judgement, and based on identifiable circumstances, its conditions are unnecessary to protect endangered wildlife.

(d) The Department shall make every reasonable effort to avoid damage or destruction of San Joaquin kit fox dens, giant and Tipton kangaroo rat burrows, and burrows potentially utilized by leopard lizards during proposed MER activities on NPR-1. Such avoidance measures may include minor re-location of project facilities and minimization of construction impacts to the least possible area. When project activities must unavoidably occur within populated wildlife areas, as determined by monitoring biologists (e.g., areas with numerous small mammal or kangaroo rat burrows), biologists shall carefully monitor actual trenching and grading activities to determine whether federally listed species actually are taken, how many are taken, and other specific effects.

(e) Known San Joaquin kit fox dens shall not be damaged or destroyed by project related actions unless written or verbal concurrence is obtained from the Service's Sacramento Field Office prior to such effects. If concurrence cannot reasonably be obtained in a timely manner (e.g., on weekends), destruction of known kit fox dens may proceed only if monitoring biologists determine that the den cannot reasonably be avoided and if the Service is verbally notified as soon as possible after the fact. Any known kit fox den that must be destroyed shall first be monitored for three consecutive nights by a qualified biologist to ensure that it is not occupied by kit foxes, and then shall be excavated by or under the direct supervision of a qualified biologist and backfilled to preclude later use by kit foxes. Destruction of all known kit fox dens shall be documented in the annual report.

Potential San Joaquin kit fox dens may be excavated without prior notification to the Service, provided that a qualified biologist has

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determined that the den is not a known kit fox den. Alternately, excavation of potential kit fox dens need not be conducted prior to construction activities, provided that no evidence of kit fox use of such dens is observed after three consecutive nights of monitoring, and that construction operations over such dens occur no more than 24 hours after such dens are last determined to be unoccupied.

(f) San Joaquin kit foxes, blunt-nosed leopard lizards, and giant and Tipton kangaroo rats may from time to time be captured and relocated from construction sites, provided (i) that burrows of these animals cannot reasonably be avoided during construction activities; (ii) that associated conditions and actions deemed appropriate by the Service are satisfied; (iii) that written approval from the Sacramento Field Office is obtained prior to any such capture and removal; and (iv) that any person or persons conducting capture and relocation activities possess an appropriate scientific collecting permit issued by the Service or are otherwise qualified to conduct such activities, as determined by the Service in writing.

(g) At the end of each day during all major NPR-1 construction projects, all open pipeline trench segments and other steep-walled holes or trenches greater than two feet deep shall either be covered with plywood or similar materials, or shall be equipped with escape ramps constructed of wooden planks, earth fill, or similar materials and spaced no further than one-quarter mile apart. Projects to which this term and condition applies include the same as those described in term and condition 1(i).

(h) The areas disturbed by construction related activities and routine day-to-day operation on NPR-1 shall be minimized to the maximum extent practicable. All DOE and contractor vehicles shall be confined to existing primary or secondary roads or to specifically delineated project areas; otherwise, no off road vehicle traffic shall be permitted unless otherwise authorized through formal or informal consultation. If necessary, as determined by monitoring biologists, outside perimeters of construction areas shall be prominently staked, flagged, or demarcated by other appropriate means to maintain construction activities inside designated areas. Construction staging, laydown, and stockpiling areas shall be confined to previously disturbed areas or to specifically delineated construction areas. All flagging shall be removed upon conclusion of construction projects.

(i) Within 60 calendar days following the end of each fiscal year, the Department shall submit to the Service's Sacramento Field Office a brief annual report detailing the following information: (i) a description of all major construction activities undertaken the previous year; (ii) dates that such construction occurred and the number of habitat acres permanently or temporarily disturbed; (iii) pertinent information concerning the Department's success in meeting project mitigation measures; (iv) an explanation of failure to meet such measures, if any; (v) known project effects on federally listed species, including an estimate of the number of kit fox dens and small mammal burrows destroyed, if any; (vi) known occurrences of incidental take of listed species, if any; (vii) habitat reclamation efforts undertaken that year, if any; (viii) results of ongoing monitoring of habitats reclaimed in previous year; (ix) an estimate of habitat acres reclaimed to date; and (x) other pertinent information. The term "major construction activity" in this term and condition shall apply to the proposed gas plant, cogeneration plant, butane isomerization facility, all underground pipelines, and any other facility resulting in permanent disturbance of more than 3 acres at a time, or temporary disturbance of more than 5 acres at a time.

(j) Employees or contractors of DOE shall not be permitted to keep pets on NPR-1 at any time except if confined or leashed. Unsupervised pets on NPR-1 shall be considered a violation of these terms and conditions.

(k) All spills of oil, liquids contaminated by oil or other substances, or hazardous materials within NPR-1 shall be cleaned up immediately if they present a potential hazard to endangered wildlife.

(l) Within nine months of the date of this biological opinion, the Department shall inspect and evaluate all sumps and catch basins on NPR-1 for potential wildlife hazards, and shall submit to the Service a brief report describing (i) the number of such structures currently in use on NPR-1; (ii) the number of such structures that are being closed or retired; (iii) their type and condition; and (iv) remediation plans for any such structures posing identified hazards to wildlife. Remediation needs identified during this process shall be completed within 12 months of the date of this biological opinion.

(m) Within nine months of the date of this biological opinion, the Department shall inspect and evaluate all well cellars or similar structures on NPR-1 for potential wildlife hazards, and shall submit to the Service a brief report describing (i) the number of well cellars or similar structures currently existing on NPR-1; (ii) their type and condition; and (iii) remediation plans for any such structures posing identified hazards to wildlife. Remediation needs identified during this process shall be completed within 12 months of the date of this biological opinion.

(n) Within two years of the date of this opinion, the Department shall place into protected status 5,058 acres of undisturbed endangered species habitat within NPR-1 and NPR-2, if appropriate, preferably along the north side of NPR-1 adjacent to the Lokern Road area. Such habitat shall be protected against major development activities in perpetuity either through conservation easement, transfer of title to a suitable public agency or conservation organization, executive action, or other legally binding instrument acceptable to the Service. If the Department retains title to these compensation lands and if not otherwise provided for, the Department shall enter into written, legally binding agreement with the Service and other affected parties concerning the manner in which compensation lands shall be managed. If the Department does not retain title to the lands, the Department shall provide to the agency or organization accepting such title habitat endowment and enhancement funds in amounts acceptable to the Service. These funds shall be provided within a time frame acceptable to the Service.

Prior to finalization of any land protection mechanism as required under this term and condition, the Department shall submit for the Service's review the following information: (i) a description of lands selected for protection; (ii) the manner in which they would be protected; (iii) Department commitments with respect to how such lands would be managed, if necessary; and (iv) other information as deemed appropriate by the Department or Service. Finalization of the protection program shall not occur until written approval is obtained from the Service that the protection program is acceptable in all pertinent respects. The Service is available to assist the Department in selecting suitable NPR-1 lands for protection and for other assistance as necessary.

(o) If requested, upon completion of any proposed construction project, or at any reasonable time deemed appropriate by the Service, the Department or its contractors shall accompany Service personnel on on-site inspection tours of construction sites or other locations, as requested, to review project impacts to endangered species and their habitats.

(2) The potential for harm or mortality to federally listed wildlife shall be minimized during <u>non-Federal</u> <u>third</u> <u>party</u> <u>projects</u> by implementing the following procedures.

(a) Unless otherwise authorized by the Service in writing, all terms and conditions within this biological opinion shall apply to all third party projects permitted by the Department on NPR-1.

(b) Prior to initiation of any third party project, the Department shall submit to the Service for review and comment a complete description of the project.

(c) If, after appropriate review, the Service determines that additional measures than those included in these terms and conditions are required to minimize incidental take resulting from a proposed third party project, the Department shall implement such measures as the Service deems appropriate through informal consultation. If the Department or its third party permittees are unwilling or unable to implement such measures, the Department shall reinitiate consultation prior to commencement of any such third party project

(d) The Department also shall reinitiate consultation concerning third party projects <u>if</u> (i) anticipated habitat disturbances for such projects (101 acres) are expected to be exceeded by any project or combination of projects; (ii) incidental take limits established in this Incidental Take Statement for third party projects are expected to be exceeded by any project or combination of projects; and (iii) if, after appropriate review, the Service determines that adverse effects of a proposed third party project on federally listed species are inadequately addressed in this biological opinion and requests reinitiation of consultation.

If, during proposed project actions, the amount or extent of incidental take of the San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, or Tipton kangaroo rat is exceeded, the causative action shall cease and consultation shall be reinitiated immediately to avoid violation of section 9 of the Act.

The U.S. Fish and Wildlife Service is to be notified in writing within three working days of the accidental death or injury of a San Joaquin kit fox, blunt-nosed leopard lizard, giant kangaroo rat, or desert tortoise, or of the finding of any dead or injured kit fox, leopard lizard, kangaroo rat, or desert tortoise during construction of the proposed pipelines. Notification must include the date, time and location of the incident or of the finding of a dead or injured animal, and any other pertinent information. The U.S. Fish and Wildlife Service contacts for this information are Mr. William Lehman or Mr. Wayne White (916/978-4866). To determine disposition of dead or injured San Joaquin kit foxes, blunt-nosed leopard lizards, or giant kangaroo rats, the California Department of Fish and Game, Region 4 Office, Fresno should be contacted (209/222-3761).

Conservation Recommendations

Sections 2(c) and 7(a)(1) of the Act direct Federal agencies to utilize their authorities to further the purposes of the Act by carrying out conservation programs for the benefit of endangered and threatened species and the ecosystems upon which they depend. Conservation recommendations have been defined as Service suggestions regarding discretionary agency activities to minimize or avoid adverse effects of a proposed action on listed species or critical habitat, or regarding development of information. Therefore, the Service recommends the following additional actions to protect federally listed species and their habitats during proposed continuing MER activities at NPR-1.

(1) As discussed on page 13 above, the Service questions whether definitions of "developed" and "undeveloped" habitat on NPR-1, as utilized by EG&G in evaluating effects of MER development on the San Joaquin kit fox, are sufficient to detect subtle effects of such development on this species. Therefore, the Department should direct EG&G to re-evaluate such effects utilizing existing data from NPR-1 for the years 1980 to the present and utilizing improved methods to differentiate between developed and undeveloped habitats. Such methods may include applying EG&G's previous definitions to smaller land areas (e.g., to quarter-sections rather than whole sections); developing a broader range of definitions (e.g., heavily

developed, moderately developed, lightly developed, and undeveloped); or other methods or combination of methods.

(2) The Department should direct EG&G to continue monitoring of kit fox and lagomorph population trends and rainfall patterns on NPR-1 and NPR-2. This information, together with the analysis described in conservation recommendation no. 1 and information obtained from CDFG survey routes, should be utilized to further clarify the relative importance of factors potentially affecting kit fox distribution and abundance on NPR-1. In accordance with the concluding paragraph below, the Department should reinitiate consultation concerning MER activities on NPR-1 should any such new information suggest that MER production is resulting in effects to San Joaquin kit foxes not considered in this opinion, or that the conclusions in this opinion with respect to effects of MER production on kit foxes is incorrect or inadequate.

(3) The Department should direct EG&G to increase monitoring of population trends on NPR-1 of other federally listed species--i.e., the blunt-nosed leopard lizard, giant kangaroo rat, Tipton kangaroo rat, Kern mallow, Hoover's wooly-star, and San Joaquin wooly-threads. The Department should reinitiate consultation concerning MER activities on NPR-1 should any new information suggest that MER production is resulting in effects on these species not considered in this opinion or that the conclusions in this opinion with respect to effects of MER production on these species is incorrect or inadequate.

(4) The Department should contribute funds to be utilized for research projects on federally listed San Joaquin Valley species conducted either on NPR-1 but by researchers other than EG&G, or off NPR-1 in adjacent, nearby, or other San Joaquin Valley locations. The rationale for this recommendation is as follows.

First, NPR-1 is a highly lucrative oil field, generating average net revenues of approximately $750 million per year. Second, NPR-1 occupies a key location in the configuration of remaining San Joaquin Valley habitats in Kern County (near or adjacent to the Lokern Road area, Buena Vista Valley, and others) and DOE activities on NPR-1 have resulted in temporary or permanent disturbance to over 6,000 acres of endangered species habitat within this area--by any measure a significant effect. Third, over 3,500 acres of habitat disturbance on NPR-1 resulted from Federal activities conducted prior to the onset of MER development and no mitigation for the effect has been required under this or previous biological opinions. Fourth, in the Service's view, restricting DOE research funds non-competitively to a single group (EG&G) does not result in the greatest benefit to affected endangered species. Finally, as a Federal agency, the Department has significant responsibilities under section 7(a)(1) of the Act to utilize its authorities in carrying out endangered species programs.

Based on these considerations, the Service recommends that DOE contribute a sum of approximately $100,000 per year through the life of the NPR-1 oil field, or until federally listed species affected by DOE activities

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are delisted, whichever comes first, to a suitable interest-bearing account to be administered by the Service for research and management of such species.

This concludes formal consultation on proposed continuing MER production on NPR-1. Reinitiation of formal consultation is required (1) if the amount or extent of incidental take is exceeded; (2) if new information reveals effects of the action that may affect federally listed species in a manner or to an extent not considered in this opinion; (3) if the project is substantially modified in a manner that causes an effect to listed species that was not considered in this opinion; and/or (4) if a new species is listed or critical habitat is determined that may be affected by the action.

We appreciate the cooperation of the Department, Chevron, and EG&G throughout this consultation process. Please contact Bill Lehman or Peter Cross of my staff at (916) 978-4866 if you have questions or information concerning this biological opinion with respect to federally listed wildlife species, and Jan Knight if you have questions or information with respect to federally listed plants.

Sincerely,

Wayne S. White
Field Supervisor

cc: Assistant Regional Director, Ecological Services, Portland, Oregon (Attn: Richard Hill)
Chief, Division of Endangered Species and Habitat Conservation, Washington, D.C.
Mr. Ken Berg, California Department of Fish and Game, 1416 Ninth Street, Sacramento, California 95814
Mr. George Nokes, Regional Manager, California Department of Fish and Game, 1234 E. Shaw Avenue, Fresno, California 93710
Mr. Jim Killen, U.S. Department of Energy, Naval Petroleum Reserves in California, P.O. Box 11, Tupman, California
Mr. Thom Kato, EG&G Energy Measurement, Inc., P.O. Box 127, Tupman, California 93276
Dr. Thomas P. O'Farrell, EG&G Energy Measurements, Inc., 611 Avenue H, Boulder City, Nevada 89005
Ms. Linda Spiegel, California Energy Commission, 4705 New Horizon, Suite 8, Bakersfield, California 93313
Mr. Jim Brownell, California Energy Commission, 1516 Ninth Street, Sacramento, California.

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I-2 APRIL 12, 1993, LETTER FROM FISH AND WILDLIFE SERVICE TO DEPARTMENT OF ENERGY REGARDING THE 1987 BIOLOGICAL OPINION

United States Department of the Interior

TAKE PRIDE IN AMERICA

FISH AND WILDLIFE SERVICE
Ecological Services
Sacramento Field Office
2800 Cottage Way, Room E-1803
Sacramento, California 95825-1846

In Reply Refer To:
1-1-93-I-745

April 12, 1993

Mr. Danny A. Hogan
U.S. Department of Energy
Naval Petroleum Reserves in California
Tupman, California 93276

Dear Mr. Hogan:

This responds to your April 5, 1993, request for clarification concerning whether the biological opinion rendered by the U.S. Fish and Wildlife Service on December 16, 1987 (Case No. 1-1-80-F-2R), for oil development activities on Elk Hills Naval Petroleum Reserve (NPR-1) remains in effect. You requested such clarification relative to the fact that formal consultation on NPR-1 activities was reinitiated by your Department on October 9, 1991, and the latter consultation is not yet completed.

My staff has reviewed your request and advises as follows. The December 16, 1987, biological opinion will remain in effect for all activities specifically described within that opinion until such time as the current consultation [Case No. 1-1-80-F-2(R2)] is completed and the Service renders a revised biological opinion addressing ongoing and new NPR-1 activities as described in your Supplemental Environmental Impact Statement (SEIS). However, newly proposed NPR-1 activities (i.e. activities described in the SEIS that are not addressed in the December 16, 1987, biological opinion) are not covered by the earlier opinion.

I hope this answers your concerns with respect to ongoing Endangered Species Act consultation efforts between our two agencies. If you have questions or desire further information, please contact me or Bill Lehman of my staff at (916) 978-4866.

Sincerely,

Dale A. Pierce

for Wayne S. White
Field Supervisor

cc: Assistant Regional Director, Ecological Services, Portland, Oregon
(ARD-ES; Attn: Richard Hill)

1-3 1987 BIOLOGICAL OPINION

United States Department of the Interior

FISH AND WILDLIFE SERVICE

SACRAMENTO ENDANGERED SPECIES OFFICE
2800 Cottage Way, Room E-1823
Sacramento, California 95825-1846

DEC 16 1987

In Reply Refer To:
TAR/1-1-80-F-2R

Mr. Robert L. Weller
Director, Naval Petroleum Reserves
in California
P.O. Box 11
Tupman, California 93276

Subject: Formal Endangered Species Consultation on the Petroleum Development Program at Maximum Efficient Rate at Naval Petroleum Reserve Number 1 (Elk Hills), Kern County, California

Dear Mr. Weller:

This responds to your request, dated July 1, 1986, for formal consultation pursuant to the Endangered Species Act of 1973, as amended, on the petroleum development program at maximum efficient rate of extraction at the Elk Hills Naval Petroleum Reserve Number 1 (also referred to as "NPR-1" or "petroleum reserve" in the text of this Biological Opinion). It is our Biological Opinion that continued petroleum development at Elk Hills Naval Petroleum Reserve Number 1 under the maximum efficient rate of extraction program is not likely to jeopardize the continued existence of the San Joaquin kit fox, blunt-nosed leopard lizard, or giant kangaroo rat. No critical habitat has been designated for any of these species; therefore, none will be adversely modified or destroyed.

A prior Biological Opinion addressing this program sent to the Department of Energy on February 1, 1980, concluded that construction of a liquid products pipeline, storage and railroad facility, and implementation of the petroleum development program at maximum efficient rate would jeopardize the continued existence of the San Joaquin kit fox and blunt-nosed leopard lizard. Six "Reasonable and Prudent Alternatives" were included in the Opinion that allowed the subject program to continue, provided that the "...USN/DOE would complete a future consultation to examine the aspects of MER." This subject

Biological Opinion examines the ongoing program and success of implementation of measures specified in our 1980 Biological Opinion for the protection of endangered species. Amendments to the Endangered Species Act of 1973 pertaining to the incidental taking (i.e., killing, harming, or harassment) of listed species also needed to be addressed for this project.

This Opinion does not include a review of any on-site projects that may be related to enhanced oil recovery using tertiary recovery techniques such as steam injection. Later biological assessments for such recovery techniques, if proven feasible, should be conducted, and formal consultation initiated with our agency by the Department of Energy.

Rationale

A description of the oil development program at maximum efficient rate of extraction is provided in the project Environmental Impact Statement (Department of Energy 1979). Planned project-related actions to fiscal year 1996 are addressed in a Department of Energy report (Department of Energy 1985a). Your agency provided additional information as enclosures to a letter dated November 4, 1986. Project construction actions, based on available information, are summarized in Table 1.

Briefly, the Naval Petroleum Reserves Act of 1976 (P.L. 94-258) dictated that Elk Hills petroleum reserves be produced at their maximum efficient rate for 6 years. Successive 3-year extensions to this original 6-year program were authorized in 1982 and 1985. Production is currently authorized until April 5, 1988. The Department of Energy currently plans to develop an Environmental Impact Statement addressing the continuing program past this point in time. The Environmental Impact Statement is scheduled for completion during the spring of 1989 (Mr. Carlo Montemagno, Department of Energy, personal communication).

The approximately 4,000 acres to be impacted by the program at NPR-1 represents about 8.6 percent of the 46,096-acre reserve. Approximately 225 acres have been partially reclaimed through 1986. Results of the success of habitat restoration efforts at NPR-1, during 1985 through 1986, are provided in Table 2.

The Department of Energy, as a result of our prior 1980 Biological Opinion, instituted a program to: determine distribution and relative abundance of the San Joaquin kit fox, blunt-nosed leopard lizard, and other selected sensitive species (Mullen 1981, O'Farrell 1980); monitor status of sensitive species and prey (O'Farrell 1984, Harris 1986); mitigate and

Table 1. Construction Projects Associated With the Petroleum Development Program at Maximum Efficient Rate of Extraction at NPR-1*

Activity	No. Actions	Est. Acreage Disturbed*
Well Pad Construction	791 (to current)	1582
	234 (to FY91)**	468
Access Roads to Wells	791 (to current)	363
	234 (to FY91)**	107
Oil Pipelines	unknown	100***
Waterflood System	13	1010
Gas Processing Plant	2	40
LACT Facility	1	40
Waste Disposal Site	1	40
Facilities	unknown	30
Tank Settings	8 (projected; current number unknown)	64
Security Fence/Firebreak	2	188
TOTAL		4032

*Based on available data (1985).
**Estimate does not include additional oil field activities which have resulted in modification of extant habitats, including construction of a limited enhanced oil recovery project (25 acres).
**Approximate - based on available information and contingent upon several variables.
***No reliable estimates available.

Table 2. Qualitative Evaluation of Revegetation Sites Included in the 1985 through 1986 Habitat Restoration Program at NPR-1 (Source: U.S. Department of Energy Data, 1986)*

Evaluation Score	No. of Sites	(%)	Acreage	(%)
Poor	12	7.9	6.4	5.7
Poor-Fair	33	21.7	12.6	11.3
Fair	24	15.8	7.0	6.3
Fair-Good	50	32.9	36.5	32.9
Good	20	13.2	13.2	11.9
Good-Excellent	4	2.6	2.0	1.8
Excellent	9	5.9	33.4	30.1
TOTAL	152		111.1	

*Approximately 300 additional sites totaling 125 acres were included in this program during the 1986 through 1987 Habitat Restoration Program at NPR-1 (Mr. Thom Kato, personal comments). An additional 242 sites totaling 120.4 acres are targeted for rehabilitation during 1987 through 1988 (Dr. Thomas O'Farrell, personal comments).

compensate for adverse effects of projects to listed species (Kato et al. 1985, O'Farrell and Mitchell 1985); and examine the effects of oil production on these species and their habitats (Kato and O'Farrell 1986, O'Farrell et al. 1986). Information and mitigation techniques developed from this program were required for development of a Biological Opinion addressing the overall impacts of the oil production program at maximum efficient rate and detailing an "equitable compensation/ mitigation plan" to assure the continued existence of both the San Joaquin kit fox and blunt-nosed leopard lizard.

The Department of Energy has developed a mitigation plan for the San Joaquin kit fox and blunt-nosed leopard lizard at Elk Hills comprised of several major components. The Department has, in an agency report submitted with this consultation, stated that these "strategies ... will be continued in the future." (O'Farrell et al. 1986, Kato et al. 1986). Briefly, the major protective measures that the Department of Energy has indicated a willingness to continue are:

(1) Initiating pre-construction surveys for listed species for all operational activities that will disturb soil surface and vegetation. This program is specified to include "all construction, electrical, operations, security, safety, service, and maintenance projects, regardless of project size, the presence of facilities or previous disturbances" (correspondence of May 14, 1987, from the Department of Energy, with attachments).

(2) Implementing the remainder of the habitat restoration plan, "...immediately following approval of the entire plan by DOE" (O'Farrell et al. 1986).

(3) Continuing to implement a monitoring program for listed species (O'Farrell et al. 1986).

(4) Continuing to implement operational guidelines designed, in part, to protect listed species and their habitats (O'Farrell et al. 1986).

(5) Designating a qualified individual to supervise implementation of the endangered species program at Elk Hills (O'Farrell et al. 1986).

(6) Maintaining a cooperative agreement with the Department of Agriculture (Animal Damage Control) to allow for periodic coyote control activities (O'Farrell et al. 1986).

(7) Developing and implementing an environmental training program, encompassing all facets of endangered species protection during program activities (correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated August 24, 1987).

(8) Participating in pest management agreements to minimize the potential for indirect and direct adverse effects to endangered species (correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated May 14, 1987).

(9) Enforcing speed limits along paved facility roads under the Department's jurisdiction to reduce the potential for kit fox mortality and injury (correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated May 14, 1987).

Measures that the Department of Energy has expressed a willingness to continue for the protection of the blunt-nosed leopard lizard at NPR-1 are:

(1) Initiating pre-construction surveys for all proposed construction and operational activities that will disturb soil profiles and vegetation (correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated May 14, 1987).

(2) Implementing the remainder of the habitat rehabilitation program, contingent upon approval by the Department of Energy (Kato et al. 1986).

(3) Requiring State agencies to abide by U.S. Fish and Wildlife Service stipulations set forth in a separate Biological Opinion (Case No. 1-1-85-F-38) governing application of the insecticide malathion (Kato et al. 1986).

(4) Continuing to implement of operational guidelines designed, in part, to protect listed species and their habitats (Kato et al. 1986).

(5) Regulating use of all insecticides, rodenticides and other potentially toxic substances upon the Department of Energy approval (Kato et al. 1986).

(6) Developing and implementing an environmental training

program, encompassing all facets of endangered species protection during program activities (correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated August 24, 1987).

(7) Enforcing speed limits along paved roads under the Department's jurisdiction to reduce potential for leopard lizard road mortality (correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated May 14, 1987).

A management plan outlining measures to minimize the impacts of development activities on endangered species has identified a need to investigate potential effects of contaminants on San Joaquin kit foxes and their prey (O'Farrell and Scrivner 1987). The Department of Energy has also informed the Service that it is "conducting several programs to investigate, directly and indirectly, any possible toxins damage ...to...the environment" (correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated May 14, 1987).

Specific measures for protection of the giant kangaroo rat are provided in a biological assessment addressing the effects of petroleum production activities on this species and its habitat (O'Farrell and Kato 1987). The Department of Energy, as a portion of the pre-construction survey program being conducted to minimize the potential for incidental taking of the San Joaquin kit fox and blunt-nosed leopard lizard, includes inventories for giant kangaroo rat burrow systems. To date, with the exception of firebreak maintenance actions, none are known to have been destroyed by construction actions at NPR-1 or NPR-2 (O'Farrell 1981, O'Farrell and Sauls 1982, Kato et al. 1985, Kato 1986a).

Assurance of funding and manpower resources necessary for implementation and compliance with this program is not specified. For example, regarding implementation of the habitat restoration program, the Department of Energy has stated that, "DOE will choose the most appropriate strategies, establish priorities, and schedule activities, based on the availability of appropriate funding and the evolving needs of the endangered species conservation program at NPR-1" (O'Farrell and Mitchell 1985). The Department of Energy reiterated this intention in correspondence dated May 14, 1987, stating that "reclamation strategies will be based on the availability of parcels and the technical and economic feasibility of restoration."

The San Joaquin kit fox is widely distributed at NPR-1. A series of line transects established at 220-yard intervals walked in

1979 and repeated in 1984 indicate an average relative kit fox den density of about 9 dens per square mile, with an estimated absolute kit fox den density of 84 dens per square mile (O'Farrell 1980, O'Farrell et al. 1986). Den distribution includes areas of high relief and past and current oil development (O'Farrell et al. 1986). In addition to transect surveys for kit fox dens, a live-trapping program to estimate fox population size and distribution was initiated in 1980. Results of this program indicate that the minimum "trappable" kit fox population peaked during 1980 and 1981 at 234 animals, and declined to 57 animals during the summer of 1985 (O'Farrell et al. 1986). Greater numbers of animals were observed in developed areas prior to the winter of 1982 and 1983. This trend was reversed after the summer of 1982, although the authors note that, "...comparisons between estimated numbers [of San Joaquin kit foxes] in developed and undeveloped habitats should be made cautiously" until results of additional studies are obtained (O'Farrell et al. 1986). More recently, investigators have estimated kit fox population declines from a "peak" of 262 animals in 1981, to 56 animals in 1985. Similar declines were noted from both developed and undeveloped portions of the facility (i.e., sections or half-sections of the facility defined as having greater or less than 15 percent of the land surface disturbed by oil field development), leading authors to conclude that "whatever was causing the decline in the kit fox population was acting equally (or in a manner that cannot be construed as different) on both the developed and undeveloped areas" (Harris et al. 1987).

Lagomorph populations, the principal prey of kit fox at Elk Hills, declined approximately 25 percent between 1980 and 1984; kit fox prey composition shifted to include a significantly higher proportion of kangaroo rats during this period (O'Farrell et al. 1986). Separate lagomorph density estimates were not initially obtained for undeveloped versus developed portions of NPR-1 (Harris 1986). However, more recent information available indicates no appreciable difference in lagomorph density between these areas (Attachment A to correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated May 14, 1987).

Numbers of kit fox litters produced in developed and undeveloped habitats at Elk Hills followed a similar pattern to population declines. Litters produced per 1,000 acres of undeveloped habitat increased from 0.45 to 0.89 between 1982 and 1984, but declined to 0.45 between 1984 and 1985. Litters produced per 1,000 acres within developed habitats declined from 0.67 to 0.15 between 1982 and 1985 (O'Farrell et al. 1986). Litter sizes did not significantly vary between areas. The authors concluded that "[no] evidence was gathered showing that the presence of oil field developments and activities in portions of NPR-1 inhibited kit fox reproduction" (O'Farrell et al. 1986). More recent information, however, has documented lowered rates of pregnancy in yearlings, reduced success of females to raise pups, a reduction in the number of kit fox litters produced per square mile, and imbalanced sex ratios on developed portions of the facility when compared to undeveloped petroleum reserve areas (Zoellick et al. 1987). Such noted disparities in kit fox reproductive success between developed and undeveloped portions of the petroleum reserve "may have been linked to declines in prey base, increases in coyote predation in developed habitats, habitat degradation caused by oil field production activities, or resulted from unknown causes" (correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated May 14, 1987).

Coyote predation accounted for 54 percent of total kit fox mortality. Vehicles accounted overall for 11 percent of kit fox mortality. Vehicle-related mortality was significantly higher in developed (16 percent) than in undeveloped (4 percent) portions of the reserve. Approximately 31 percent of recovered animals (70) died from unknown causes (O'Farrell et al. 1986). More recently, Berry et al. (1987) estimated that 15 percent of the kit foxes found dead in developed portions and 9 percent of the kit foxes found dead in undeveloped portions of NPR-1 were killed by vehicles. Cause of death could not be determined in these cases because of advanced carcass decomposition or recovery of only the animal's radio collar (Berry et al. 1987). Deaths of remaining recovered kit foxes included injuries incurred during or prior to trapping (three animals), transmitter accident (one animal), pneumonia (two animals), shooting (one animal), entrapment in a landfill (one animal), and drowning in water pipelines (2 animals) (Berry et al. 1987).

Results of a series of inventories of public and private lands within the San Joaquin Valley (O'Farrell et al. 1980, O'Farrell and Sauls 1981, O'Farrell and McCue 1981, O'Farrell et al. 1981, Rhoads et al. 1981, O'Farrell 1982, Hall 1983, Larry Seeman Associates 1986), and extending into adjacent valleys and plains (Balestreri 1981, Jones and Stokes Associates, Incorporated, 1983, ECOS Management Criteria, Incorporated, 1986, Kato 1986b) have consistently demonstrated the need for protection of extant habitats within the southern portions of the San Joaquin Valley containing relatively high numbers of animals. The need for instituting protective management here is underscored in the San Joaquin Kit Fox Recovery Plan, which recommends the protection of approximately 35,000 acres of public and private lands surrounding both Department of Energy and Bureau of Land Management lands in the Elk Hills (O'Farrell 1983). The U.S. Fish and Wildlife Service has previously emphasized the importance of NPR-1 to the protection of the San Joaquin kit fox in our prior 1980 Biological Opinion.

The blunt-nosed leopard lizard is peripherally distributed at NPR-1. Transect surveys conducted at 220-yard intervals walked in 1979, indicated that the species was distributed in more level areas and wash systems in the southern, northwestern and northeastern portions of the petroleum reserve (O'Farrell 1980). Additional studies have confirmed the distribution of this species on more level portions of the reserve and a heavy reliance upon wash systems (Mullen 1981, Kato and O'Farrell 1986).

Most blunt-nosed leopard lizard observations have taken place on portions of the petroleum reserve subject to little, if any, oil development. Pre-construction surveys for projects at Elk Hills conducted between 1980 and 1984 further reinforce this opinion. Only 6 projects out of a total of 385 "major" construction project sites surveyed during this time needed to be modified to avoid impacts to the blunt-nosed leopard lizard (Kato et al. 1985). No data are available quantifying tolerance to oil field activities. Mullen (1981), stated that "While it is not believed that the species survival will be threatened by oil-related activities on NPR-1, alterations of habitat of the magnitude anticipated could have local effects on population densities and overall effects on the total numbers of C. silus supportable on remaining available habitat." He noted no direct instances where oil development had resulted in the death of a leopard lizard, although one specimen captured had its forefeet and claws coated with what appeared to be oil residues (Mullen 1981). Five individual leopard lizards were recovered dead during a subsequent radiotelemetry study utilizing nine individual animals at NPR-1 (Kato and O'Farrell 1986). Two of the leopard lizards died in pools of oil formed by an oil pipeline leak into a wash; the remaining three died of causes unrelated to oil field development (Kato and O'Farrell 1986).

The general distribution of the giant kangaroo rat at NPR-1 roughly coincides with that of the blunt-nosed leopard lizard. The majority of known giant kangaroo rat colonies are distributed on level lands and gentle slopes peripheral to development, in the southwestern and northeastern portions of the reserve. Smaller, scattered giant kangaroo rat colony sites are also located, however, on level areas in more rugged terrain

(O'Farrell et al. 1987). Pre-construction surveys of petroleum development projects at the petroleum reserve have not documented any conflicts with these colony sites (Kato et al. 1985). However, the recent unauthorized discharge of oil-laden waters into a natural wash system entering the Buena Vista Valley adjacent to the reserve during the spring of 1986 resulted in the death of at least 12 giant kangaroo rats. Unauthorized off-road vehicle use for seismic testing during oil field exploration in the Buena Vista Valley also resulted in the destruction of several giant kangaroo rat burrow systems during 1986 (George Sheppard, Bureau of Land Management, personal comments).

The San Joaquin kit fox may be adversely affected both directly and indirectly as a result of continuing petroleum development activities at NPR-1. Mortality may result from ingestion of toxicants, crushing by vehicles, predation by coyotes or other predators, or through overall reduction in prey base populations or predator-avoidance areas as extant habitats are destroyed from ongoing development.

Individual foxes may be killed from entrapment in burrows during construction activities. For example, five kit fox dens are known to have been accidentally collapsed during construction of well pads during implementation of this reserve-wide avoidance program (Kato et al. 1985). Given the close association of this species at NPR-1 with oil facilities, undocumented mortality of animals from similar construction actions or during subsequent maintenance activities is high, although pre-construction surveys significantly lower the potential for inadvertent mortality or injury of animals. Results of more recent pre-construction surveys have shown a dramatic decrease in loss of kit fox dens through accident, and an ability to modify projects in a manner to preclude the necessity of intentional excavation (Kato 1986a). Expansion of pre-construction surveys to include all potentially impacting project actions on the kit fox (Enclosure 6 to correspondence from the Department of Energy to the U.S. Fish and Wildlife Service, dated May 14, 1987), should further reduce this risk.

San Joaquin kit foxes will continue to be vulnerable to mortality from vehicular use associated with oil field construction and maintenance vehicles. Vehicle-related mortality of kit foxes is significantly higher (16 percent versus 4 percent) in developed than undeveloped portions of the petroleum reserve. The Department of Energy has estimated that, under the continuing oil production program at maximum efficient rate, "...about five fox will be killed by vehicles each year" (O'Farrell et al. 1986). Given the overall decline in the fox population at Elk Hills (as evidenced by the estimated changes in numbers of "trappable" animals) and estimated recent declines in numbers of litters of kit foxes produced per 1,000 acres of developed and undeveloped habitats, this source of mortality continues to significantly threaten the long-term survival prospects of the kit fox population.

Although pre-construction surveys have been initiated as a part of the endangered species protection program at NPR-1, five kit fox dens, including at least one multiple entrance den, are known to have been inadvertently destroyed from oil activities. An additional 19 kit fox dens (including at least 3 multiple hole dens) and 12 other dens not having characteristics consistent with known kit fox dens were excavated prior to initiation of construction actions to prevent possible kit fox mortality from entrapment (Kato et al. 1985). Although individual animals may not have been killed during these actions, the loss of the denning sites may have indirectly affected the constituent kit fox population by reducing escape cover from predators such as coyotes. Kit fox populations may also have been reduced by loss of natal or pupping dens that "...may represent ancestral breeding or rearing sites that may be important to successful reproduction of the species" (O'Farrell et al. 1986). The number of known kit fox dens destroyed is roughly equivalent to the average den density over 0.4 square miles of the reserve, based on prior systematic inventories conducted for the Department of Energy (O'Farrell 1980). Kit fox dens intentionally excavated or inadvertently destroyed were not replaced with artificial denning areas (Thom Kato, EG&G Energy Measurements Group, personal comments).

No kit foxes are known to have been killed on NPR-1 from entrapment in spilled oil. Approximately 1,648 oil spill "incidents" occurred at the reserve between 1980 and 1986. Spills were typically small, averaging between about 1,000 and 6,000 square feet each year (Department of Energy data). However, two kit foxes "...were found dead in spilled oil on NPR-2" (O'Farrell et al. 1986), the result of illegal discharges from private companies (DOE correspondence to USFWS, dated December 3, 1987). Potential mortality to kit foxes exists at NPR-1 as well, particularly for larger oil spills entering wash systems or other areas regularly traversed by foraging adults or emigrating juveniles.

In addition to oil spills, the Department of Energy has acknowledged that chromium spills have been identified at 53 sites at the reserve and that "[a]n evaluation is being performed on cleanup methodologies at this time" (Department of

Energy data). Storage of potentially contaminated drilling muds and use of open sumps for storage of waters separated from oil at the Lease Automatic Custody Transfer System units may also be mechanisms for directly or indirectly providing toxicants to the kit fox. O'Farrell and Scrivner (1987), discussing the need for further development studies on the San Joaquin kit fox at the petroleum reserve, have stated that "there were surprisingly high levels of vanadium in the feces, and further studies were warranted based on the potential threat of toxicity to kit foxes and their prey. Levels of selenium in hair and feces of foxes did not suggest selenosis, but concentrations in soft tissues were relatively high. Additional data are needed before the role of selenium as a potential contaminant can be evaluated. Chromium has also been found in high concentrations in the surface soils of several well pads on NPR-1 and may pose a threat to wildlife, including kit foxes". The opportunity for direct and indirect mortality of kit foxes at Elk Hills Naval Petroleum Reserve Number 1 from ingestion of heavy metals and other contaminants is potentially significant and warrants further investigation.

Predation by coyotes has been determined to be the greatest source of known mortality to kit foxes at Elk Hills (O'Farrell et al. 1986). Reasons for this high level of mortality are uncertain, but such mortality could be indirectly related to implementation of measures such as boundary fence construction and prohibition of firearms and trapping (O'Farrell et al. 1986). Implementation of a coyote control program at NPR-1 during 1985 killed 34 coyote adults and 6 pups. An additional 47 coyote fetuses were found in adult females killed during March 1986. Sixty-four coyotes were also removed during 1986 (U.S. Department of Agriculture 1986). Results of success of this program remain unclear; even with coyote control, coyote predation on kit fox still represented a significant source of mortality (Harris 1986). Timing and scope of any future control effort should be based upon results of planned and ongoing monitoring studies at the reserve, including potential kit fox predators, with timely review and input from our agency.

The San Joaquin kit fox population has been subject to ongoing loss of extant habitats on NPR-1. This habitat supplies a prey base of lagomorphs and rodents, and provides cover and locations for construction of burrows for predator avoidance and raising of young. We believe that loss of extant habitats totaling about 4,000 acres corresponds to a reduction in the number of kit foxes that can be maintained at the petroleum reserve. To date, approximately 225 acres of previously disturbed lands at NPR-1 have been subject to habitat restoration and rehabilitation efforts to offset kit fox habitats lost during the oil production program at maximum efficient rate of extraction (Table 2). Given the widespread distribution of this species at the petroleum reserve, we believe that any extant habitats lost to oil field developments correspond to a loss of kit fox habitat. Specified objectives of the oil extraction program at Elk Hills are not related to surface developments (wells and support facilities) but are tied to maximum efficient extraction of subsurface petroleum reserves. Projections for future developments at Elk Hills under this program are speculative and may significantly underestimate future habitat loss just as projections considered in our 1980 Biological Opinion substantially underestimated actual development.

Although information addressing effects of the program does not clearly demonstrate that recent precipitous declines in the San Joaquin kit fox population at NPR-1 are specifically related to this loss of habitat at current levels of disturbance, there are no assurances that ongoing project actions and concomitant habitat loss will not eventually contribute to the extirpation of the San Joaquin kit fox at the petroleum reserve. As the facility kit fox population has declined (for whatever reasons), extirpation becomes an increasing possibility. Judicious management of program activities in a manner that precludes this population loss and maximizes the opportunity for species' recovery is of paramount importance. Maintenance of extant habitats and institution of an aggressive program to offset completely incremental habitat loss from project actions should be an integral component of this process. At present rates of program implementation, we estimate that it will require over 40 years to restore an equivalent amount of on-site habitat to that lost in the last 10 years. Additional habitat will also be lost during this time frame, although acreage figures are not available. To date, no attempt has been made by the Department of Energy to determine locations and amounts of facility-wide disturbed areas that can be rehabilitated nor to outline specifically "target" restoration acreage figures on other than a year-to-year basis (Lt. Carlo Montemagno, Department of Energy, personal communications of August 11, 1987). Clearly, given the precarious status of the kit fox at the facility, such a program requires significant clarification and acceleration.

Several aspects of the petroleum development program have directly and indirectly benefited the San Joaquin kit fox. Information obtained from the ongoing funding of research activities on the Reserve has significantly contributed to the increased understanding of the life history and ecology of the San Joaquin kit fox. This information can be used towards the development of conservation-oriented management plans for perpetuating extant populations and associated habitats. Construction of a perimeter fence has restricted trespass and limited vehicle use. Prohibition of livestock grazing has reduced competition for available forage between sheep and lagomorph and rodent prey species. Restrictions on rodenticide use may reduce kit fox death from secondary poisoning potentially resulting from ingestion of contaminated prey remains. Prohibition of hunting prevents the opportunity for deliberate or accidental shooting of kit foxes and helps to maintain a lagomorph prey base. Prohibition on agricultural development also precludes conversion of kit fox habitat.

The blunt-nosed leopard lizard may be adversely affected by ongoing project actions at NPR-1 by crushing of individual animals from vehicle use along existing access roads or cross-country, by entrapment of individual animals or crushing of their eggs during construction activities, or by entrapment of animals in pools of oil during spills or accidental discharge of oil-laden waters into natural drainage systems. The species may also be affected through ongoing loss and disruption of habitat from oil-associated developments.

An estimated 446 acres, or 6 percent of the extant blunt-nosed leopard lizard habitat on NPR-1, have been disturbed by oil field activities to date (Kato and O'Farrell 1986). Reduction in habitat from petroleum field development has been recognized in the Biological Assessment for this species, which states, "the most significant potential effect of MER activities on the blunt-nosed leopard lizard will be the modification or loss of habitat due to construction activities in large washes and low foothill areas near the perimeter of NPR-1" (Kato and O'Farrell 1986). Minimizing impacts to wash systems during construction activities and implementation of an ongoing reclamation program are methods currently employed at the reserve for the protection of the blunt-nosed leopard lizard and its habitats.

The blunt-nosed leopard lizard is tolerant of comparatively light levels of oil development. Previous investigators have observed leopard lizards in oil fields abandoned 20 or more years prior to study initiation (Chesemore 1980) or in oil field areas with adjacent unmodified wash systems or undeveloped habitats (Mullen 1980). At the same time, investigators have concluded that intense oil development results in extirpation of the constituent leopard lizard population (Chesemore 1980). Attempts to determine the relationship between oil field development and leopard lizard abundance have been inconclusive, however, (O'Farrell and Kato 1980, Chesemore 1980) more recent surveys of intensively developed oil fields in the Belridge and Midway-Sunset Fields have documented the occurrence of the species along transmission line routes traversing substantially unaltered habitats but have not documented this species on neighboring lands within identical topography subject to intensive oil development (CWESA 1985, Dames and Moore 1986a, 1986b).

The heavy reliance of this species on wash systems on NPR-1 makes it highly vulnerable to local extirpations from any actions that may modify drainage systems or introduce contaminants into such systems. Authors noted that "...two blunt-nosed leopard lizards were found dead in pools of oil on NPR-1..." (Kato and O'Farrell 1986). An additional two leopard lizards were also recovered dead from a small oil spill near the vicinity of Maricopa, Kern County, during the summer of 1986 (Larry Owens, Fish and Wildlife Service, personal comments). Although the species may be distributed peripherally at Elk Hills to areas of oil field development, waste discharge or oil spills into drainage systems may directly affect lizards in areas several miles downslope from the source of impact. Measures proposed by the Department of Energy to "take action" against oil companies situated off-site to curtail illegal disposal of contaminants into wash systems crossing the southwest portions of the reserve, although ambiguously presented in the Biological Assessment (Kato and O'Farrell 1986), represent a positive step towards minimizing leopard lizard mortality on NPR-1. We also recommend additional protective measures need be undertaken for actions originating on NPR-1, including continued implementation of a program to modify or eliminate uncovered sumps which may be present on portions of the petroleum reserve where the blunt-nosed leopard lizard has been previously verified or the species is likely to occur, and immediate containment, cleanup, and rehabilitation of wash systems contaminated with oil or other toxic substances.

Several additional measures implemented at the petroleum reserve may indirectly benefit the species by excluding land uses incompatible with the perpetuation of the species. These positive measures include requiring the California Department of Food and Agriculture to abide by stipulations set forth in a prior Service Biological Opinion for controlling the beet leafhopper (Case No. 1-1-185-F-38 to the U.S. Bureau of Land Management); fencing the reserve boundary and prohibiting "casual" off-road vehicle travel; prohibiting livestock grazing, hunting, trapping and agricultural development; limiting application of insecticides, rodenticides or other toxic substances; and maintaining a qualified individual to oversee implementation of various ongoing and planned measures at the petroleum reserve for the protection of federally-listed species and their habitats.

The giant kangaroo rat may be adversely affected by direct mortality, displacement, exposure to toxicants, trapping and suffocation in oil spills, or loss of habitat. Measures under way at the reserve to avoid or lessen impacts to the San Joaquin kit fox and blunt-nosed leopard lizard, also "target" the giant kangaroo rat. Twelve giant kangaroo rat burrow systems were observed during these pre-construction surveys; no adjustments to planned project actions were required to avoid impact to these burrow systems (Kato et al. 1985). Although oil development activities adjacent to giant kangaroo rat colony sites are currently dispersed, future development, particularly on more level portions of the reserve, could adversely impact this species.

Incidental Take

San Joaquin kit foxes, blunt-nosed leopard lizards, and giant kangaroo rats may be taken incidentally during construction and operation activities. Means by which killing, harming or harassing may occur have been previously discussed in the "Rationale" portion of this Biological Opinion.

Although no density estimates have been obtained for portions of NPR-1 known to contain this species, from other field surveys, however, we estimate a leopard lizard density of less than 0.5 lizards per acre. Incidental mortality of blunt-nosed leopard lizards from construction projects can be substantially reduced through continued implementation of pre-construction surveys. This will not, however, eliminate the potential for incidental take for several reasons: (1) many construction projects may occur during the late fall or winter, when leopard lizards are inactive underground, cannot be located, and are highly susceptible to entombment; (2) leopard lizards may utilize road edges or other artificially created "open" areas for territorial display and thermoregulation where potential for mortality from construction or maintenance vehicles exists; (3) leopard lizards may indirectly be taken by reduction of insect prey base populations accompanying spraying of pesticides to control vegetation; and (4) the species is heavily dependent upon natural wash systems which may convey drainages on the facility and may be subject to contamination by crude oil from accidental spills.

The giant kangaroo rat population present within the Buena Vista Valley, partially included within the project area, represents one of a very few "core" population areas remaining for this species. No population density estimates are available for this area.

Estimates of the "trappable" San Joaquin kit fox population at NPR-1 indicate that the reserve has the potential to support in excess of 200 individual animals, although the current kit fox population appears to be substantially reduced. Locations of kit fox dens and sightings also confirm that the species is widespread on the reserve, and occurs within portions of NPR-1 subjected to comparatively intensive petroleum development. Information from studies conducted for the Department of Energy at NPR-1 and NPR-2 (Buena Vista Reserve) and results of other inventories on public and private lands clearly show that the San Joaquin kit fox may be vulnerable to incidental take from a variety of activities associated with petroleum development at maximum efficient rate.

The Department of Energy has estimated that approximately five kit foxes per year may be killed at NPR-1 from vehicle mortality alone (O'Farrell 1986). The Department has subsequently stated, however, that "DOE will not include road kills along California Route 119 and Elk Hills Road as part of their tally of deaths due to MER" (Department of Energy correspondence to the U.S. Fish and Wildlife Service, dated May 14, 1987). Consequently, we believe that incidental mortality of San Joaquin kit foxes on other portions of the facility subject to more stringent controls may be significantly reduced over the projected rate of five deaths per year estimated by the Department of Energy through vigorous implementation of existing programs at the petroleum reserve, and through implementation of measures identified in this Biological Opinion.

The San Joaquin kit fox may also be incidentally taken as a result of prior and ongoing habitat alteration resulting from project-related activities. The Department of Energy has estimated that "...loss of habitat associated with MER resulted in a decrease in carrying capacity of five or fewer fox" (O'Farrell et al. 1986). This estimate may not reflect the relative importance that specific habitat areas may have had for the rearing or pups or for predator avoidance, nor does it address ongoing habitat loss from project actions, and the large disparity between habitats lost and habitats undergoing reclamation. The ability of this species to tolerate lower levels of oil field development at the petroleum reserve is based, in part, upon the availability of a plentiful prey supply and the "...availability of large undisturbed areas..." (O'Farrell et al. 1986). Authors have further recognized the ongoing loss of kit fox habitats to date as "...probably the most serious direct effect of MER." We concur, and believe that incidental take of this species as a result of habitat alteration can be reduced to zero animals through implementation of an aggressive restoration program.

Other potential sources of incidental take of endangered species at the petroleum reserve include: (1) mortality by ingestion of contaminants or entrapment in oil; (2) mortality, injury, or displacement of individual animals resulting from grass fires inadvertently started from oil activities; (3) mortality to individual animals from off-road vehicle driving by testing or maintenance equipment; and (4) mortality, injury, or displacement of individual animals during periodic facility perimeter firebreak maintenance actions.

Based on the foregoing analysis, we anticipate incidental take of the blunt-nosed leopard lizard, giant kangaroo rat, and San Joaquin kit fox at NPR-1 for project actions relating to petroleum development at maximum efficient rate of extraction through fiscal year 1989 as follows:

(1) blunt-nosed leopard lizard (total 9)

(A) facility construction and maintenance activities: 1

(B) oil spills, deposition of wastewaters or other contaminants into wash systems: 2

(C) use of pesticides for weed control, rodent control, or pest insect control directly related to this project: 1

(D) vehicle mortality: 2

(E) death or injury from ingestion or inhalation of toxic substances: 1

(F) death or injury due to fire: 1

(G) death or injury due to firebreak maintenance: 1

(2) giant kangaroo rat (total 54)

(A) facility construction and maintenance activities: 1

(B) oil spills, depositions of wastewaters or other contaminants into wash systems: 1

(C) use of pesticides for weed control, rodent control, or pest insect control for actions directly related to this project: 1

(D) vehicle mortality: 1

(E) death or injury from ingestion or inhalation of toxic substances or gases: 1

(F) death or injury due to fire: 1

(G) firebreak maintenance (harassment: 48; death or injury: 36)

(3) San Joaquin kit fox (total 11)

(A) facility construction and maintenance activities: 5 kit foxes (mortality or injury to a maximum of 1 animal; harassment to a maximum of 5 animals)

(B) oil spills; deposition of wastewaters or other contaminants into wash systems: 1

(C) ongoing alteration of habitat resulting from project-related actions: 0

(D) pesticide use for weed control, rodent control, or pest insect control activities directly related to this project: 1

(E) mortality from vehicular use (both road and off-road): 2 (excluding road mortality that may result from public vehicular traffic on State Route 119 and Elk Hills Road within the petroleum reserve)

(F) mortality or injury from ingestion or inhalation of toxic substances: 1

(G) death or injury due to fire: 1

We specify the following reasonable and prudent measures that are considered appropriate to minimize incidental take:

(1) Replacement of endangered species habitats lost to project-related actions;

(2) Minimizing disturbance to kit fox dens; and

(3) Minimizing construction activities in washes.

To implement these measures, we specify the following terms and conditions that must be met by the Department of Energy:

(1) As a means of protecting the San Joaquin kit fox from incidental take resulting from project-related loss of habitat at NPR-1, concurrently with development of an Environmental Impact Statement addressing future project actions at the petroleum facility, the Department of Energy shall:

(A) complete an inventory and listing of previously disturbed parcels and acreages at Elk Hills Naval Petroleum Reserve Number 1 that may be used for rehabilitation to offset loss of endangered species habitats associated with project-related activities;

(B) develop a 10-year program utilizing information in (A) above to define program tasks using specified time frames and acreages, with the overall objective of restoring (at a minimum) equivalent on-site acreage to that lost from prior project-related actions, and maintaining (at a minimum) this overall acreage on the facility during all future project-related actions; and

(C) examine alternative means to offset kit fox habitat loss at the petroleum reserve related to project activities, including:

(a) contribution of funds to a third party to be used solely for the purchase and protective management of lands for perpetuating the San Joaquin kit fox;

(b) purchase and donation of off-site lands to a third party to be managed for the perpetuation of the San Joaquin kit fox; and

(c) any other means as determined feasible on-site to off-set the on-site loss of San Joaquin kit fox habitats.

Information so obtained shall be provided to this office for review prior to re-initiation of future project actions on federally-listed species.

(2) Prior to any authorization to allow for the destruction of a

San Joaquin kit fox den on the facility, the the Department of Energy shall seek concurrence from the U.S. Fish and Wildlife Service, Sacramento Endangered Species Office. The U.S. Fish and Wildlife Service may require, in such instances, initiation of actions by the Department of Energy to prevent or to mitigate for the subject kit fox den loss.

(3) Construction activity shall avoid disturbance to wash systems along the periphery of the Reserve in blunt-nosed leopard lizard habitat. In those instances where disturbance to wash systems is unavoidable, drainage characteristics of the wash systems shall be maintained in a manner to prevent erosion. Areas disturbed during construction, which are not needed for the facility, shall be reclaimed to pre-impact condition. Reclamation shall be initiated within 90 days following termination of activities.

We hereby specify the following procedures for handling or disposing of any individuals listed species incidentally taken, as well as the following reporting requirements that must be met by the Department of Energy:

(1) The U.S. Fish and Wildlife Service is to be notified within three working days of the finding of any endangered species found dead or injured during this project, with the exception of animals that are included in monitoring and research activities. The U.S. Fish and Wildlife Service contact representatives for for this information are Mr. Ted Rado or Mr. Gail Kobetich (916/978-4866 or FTS 460-4866). Any endangered species found dead or injured will be handled under provisions stipulated in Federal Permit PRT-683011.

(2) The Department of Energy must submit to the U.S. Fish and Wildlife Service, within 1-year of date of issuance of this Biological Opinion, a detailed monitoring and evaluation report that:

(A) describes results of the previous year's project construction, exploration and maintenance actions, and measures instituted to reduce the potential for the incidental taking of the San Joaquin kit fox, blunt-nosed leopard lizard, and giant kangaroo rat;

(B) discusses ongoing actions implemented to reduce likelihood of incidental taking of these species during the next project year, including availability of funding and manpower to implement these measures; and

(C) reviews implementation measures undertaken for other actions specified or recommended in this Biological Opinion for the protection of these species and their associated habitats.

The U.S. Fish and Wildlife Service may propose amendments to current project actions pending results of this report.

Conservation Recommendations

(1) The Department of Energy should continue to provide funding and other resources for studies on the San Joaquin kit fox, blunt-nosed leopard lizard, and giant kangaroo rat unrelated to project actions. Although tangential to petroleum development effects, such work has included a serologic study for disease (McCue and O'Farrell 1986), and a comparative analysis of cranial measurements for the San Joaquin kit fox (Dragoo et al. 1986). Additionally, studies have been undertaken to assess effectiveness of techniques to monitor kit fox population trends (Harris 1987) and causes of mortality (Zoellick 1986). Priority for funding, however, should be lower than for measures specified in prior sections of this Biological Opinion.

(2) The Department of Energy should undertake a study to determine effectiveness of artificial denning structures to offset loss of "natural" kit fox dens resulting from construction or maintenance activities. Results of this study should be conveyed to the U.S. Fish and Wildlife Service for review.

(3) The Department of Energy, as a means of attempting to boost carrying capacity of prey species for the San Joaquin kit fox, should rehabilitate five currently damaged small game drinkers located on the Reserve.

This concludes formal consultation addressing the effects of ongoing petroleum development at maximum efficient rate of extraction. Given the intent of the Department of Energy to develop an updated Environmental Impact Statement addressing future program activities at Elk Hills Naval Petroleum Reserve Number 1, and our requirement that specific information relating to the on-site restoration program be developed and submitted to our office for review concurrently with this effort, we anticipate that the Department of Energy will re-initiate formal consultation for project-related effects to federally-listed species at that time. We would appreciate written notification of your intentions in light of this Biological Opinion. For further discussion, please contact me or Mr. Ted Rado at 916/978-4866.

Sincerely,

Gail C. Kobetich

Gail C. Kobetich
Field Supervisor

cc:
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APPENDIX I

PRELIMINARY EVALUATION OF WETLANDS

PRELIMINARY EVALUATION
U.S. FISH and WILDLIFE SERVICE
NATIONAL WETLANDS INVENTORY MAPS of NPR-1

Prepared for:

U.S. DEPARTMENT OF ENERGY
NAVAL PETROLEUM RESERVES in CALIFORNIA
TUPMAN, CA

Prepared by:

KENNETH G. FRIES
RESEARCH MANAGEMENT CONSULTANTS, INC.
NAVAL PETROLEUM RESERVES in CALIFORNIA
TUPMAN, CA

January, 1993

ERRATA SHEET

Page 6, end of paragraph 1:

Subsequent to the completion of this report, the Environmental Protection Agency and U.S. Army Corps of Engineers published a notice in the Federal Register on January 19, 1993 regarding use of in wetlands delineation manuals (58 FR 4995). The use of the 1989 Federal Wetlands Delineation Manual for wetland determinations has been replaced with the 1987 Corps of Engineers Wetlands Delineation Manual.

Page 11, paragraph 4:

Reference to the 1989 Federal Wetlands Delineation Manual should be replaced with the U.S. Army Corps of Engineers 1987 Wetlands Delineation Manual.

PRELIMINARY EVALUATION
U.S. FISH and WILDLIFE SERVICE
NATIONAL WETLAND INVENTORY MAPS of NPR-1

Introduction

In their review of the Naval Petroleum Reserve No. 1 (NPR-1) Draft Supplemental Environmental Impact Statement (SEIS), the U.S. Environmental Protection Agency (EPA) commented that the Final SEIS, "...should either discuss wetland resources or confirm that none exist on the Reserve" (DOE 1992, EPA 1992). This report responds to EPA's comment and presents the results of a preliminary offsite evaluation of potential wetland resources on NPR-1. This report reviews the U.S. Fish and Wildlife Service (FWS) National Wetland Inventory of potential wetland resources on NPR-1, provides a preliminary evaluation of NPR-1 wetlands identified by FWS that potentially may satisfy criteria for wetland designation, and provides recommendations for follow-up site evaluations.

Methodology

A review of the FWS National Wetland Inventory was conducted to determine if wetland resources have been identified within the boundaries of NPR-1. The National Wetland Inventory (NWI) of NPR-1 consists of portions of five 7 1/2' United States Geological Service (USGS) topographic quadrangles which have been annotated by FWS to identify potential wetland resources. Four NWI maps cover the majority of NPR-1; they are the Tupman Quadrangle, East Elk Hills Quadrangle, West Elk Hills Quadrangle and Taft Quadrangle (FWS 1986 a,b,c,d). Figure 1 shows the areas of NPR-1 that are included within all five NWI maps covering NPR-1.

The methodology employed by FWS in the NWI identification of potential wetlands on NPR-1 was stereoscopic analysis of high altitude aerial photographs. Wetlands were identified based on vegetation, visible hydrology, and geography in accordance with criteria established for conducting the national inventory (FWS 1979). Field verification of the potential NPR-1 wetland areas was not performed by FWS; accordingly, FWS acknowledges the NWI maps covering NPR-1 are "Draft" until onsite and historical analyses are performed.

The potential NPR-1 wetland sites identified in the NWI were reviewed to determine if they represent natural features or man-made, oil-field related features. A partial field reconnaissance and a review of 1991 infrared aerial photographs of NPR-1 was conducted with Department of Energy personnel familiar with NPR-1 facilities to verify the nature of the sites identified in the NWI (DOE 1993, BPOI 1991).

FWS NATIONAL WETLAND INVENTORY MAPS
NAVAL PETROLEUM RESERVE NO. 1

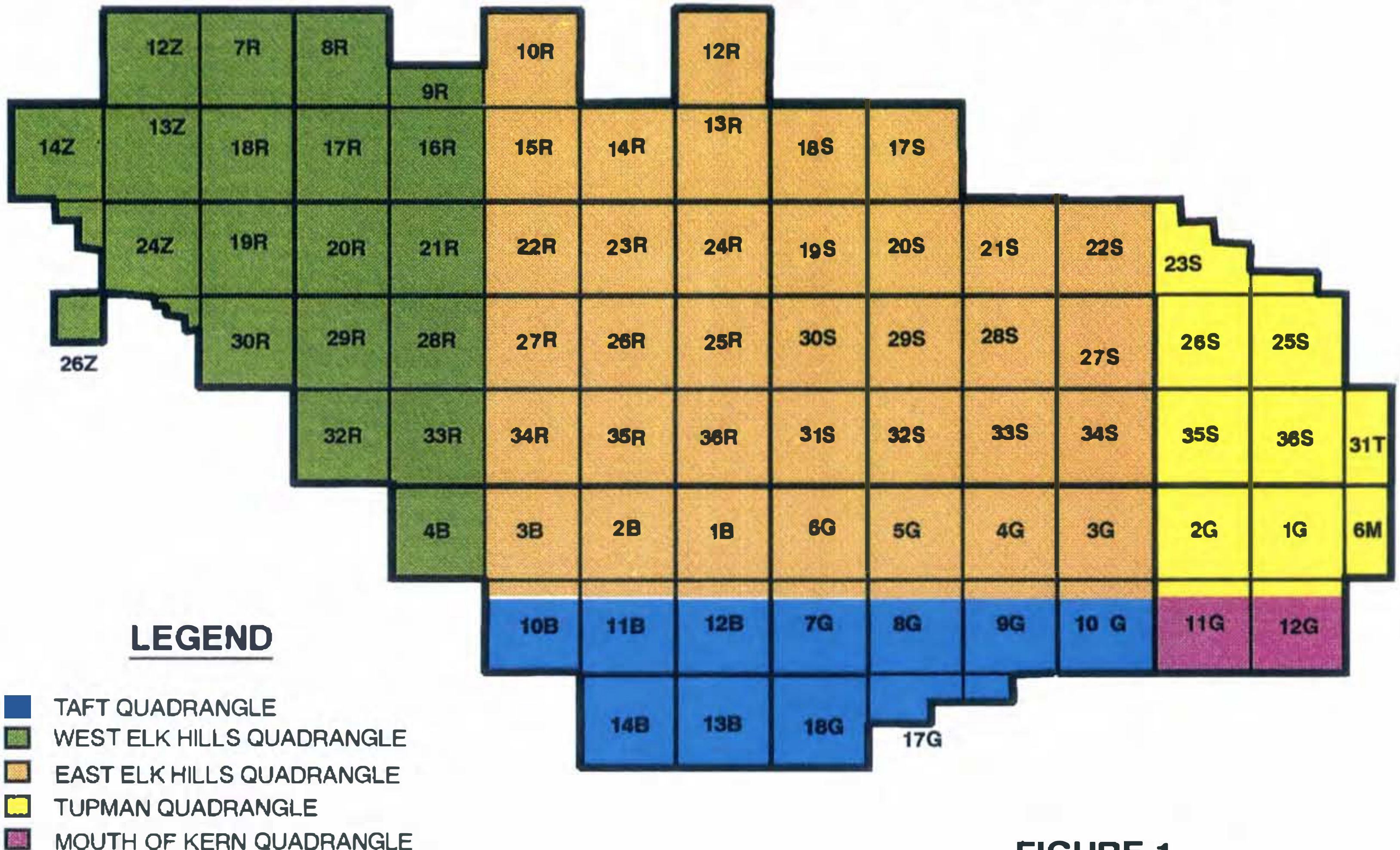

FIGURE 1
Source (FWS 1986 a,b,c,d)

SITE IDENTIFICATION

A total of 33 potential wetland locations on NPR-1 are identified by FWS on the Tupman, East Elk Hills, West Elk Hills and Taft quadrangles of the National Wetland Inventory. FWS classifies all 33 sites either as Palustrine systems (shallow ponds, marshes, swamps or bogs), or Riverine systems (rivers, creeks or streams); 26 sites are classified as Palustrine systems and 7 sites are classified as Riverine systems. Nine (9) distinct Palustrine or Riverine subsystems on NPR-1 are indicated on the NWI maps. Eight (8) Palustrine subsystems are identified as follows: PEMC; PEM1Ch; PUBFh; PUBFx; PUBKx; PUSAh; PUSAx; and PUSCx. One (1) Riverine system is identified as R4SBC. Table 1 provides a description of the Palustrine and Riverine systems preliminarily identified on NPR-1 by the NWI.

Table 1 Description of NPR-1 Wetland Systems and Subsystems Identified by the U.S. Fish and Wildlife Service

Palustrine Systems (shallow ponds, marshes, swamps and bogs)

PEMC	-	Emergent vegetation; seasonally flooded
PEM1Ch	-	Emergent vegetation, persistent; seasonally flooded; diked impoundment
PUBFh	-	Unconsolidated bottom; semi-permanently flooded; diked impoundment
PUBFx	-	Unconsolidated bottom; semi-permanently flooded; excavated
PUBKx	-	Unconsolidated bottom; artificially flooded; excavated
PUSAh	-	Unconsolidated shore; temporarily flooded; diked impoundment
PUSAx	-	Unconsolidated shore; temporarily flooded; excavated
PUSCx	-	Unconsolidated shore; seasonally flooded; excavated

Riverine Systems (rivers, creeks and streams)

R4SBC - Intermittent; streambed; seasonally flooded

Source: (FWS 1979)

The 33 potential wetland sites on NPR-1 are widely scattered and are relatively small in size. Table 2 provides site locations and NWI wetland designations, and identifies the natural or man-made features they represent. Twenty-five (25) of the sites consist of oil-field sumps or gully plugs (man-made obstructions that control precipitation run-off or the spread of potential spills). One (1) site is a diked impoundment that was developed with artificial watering in the early 1960's to enhance wildlife habitat. Six (6) of the NPR-1 sites identified consist of portions of ephemeral stream channels that drain Elk Hills, the most notable of which is Buena Vista Creek on the south flank of NPR-1. One (1) site identified in the NWI is a lowland area associated with the historic channeling of the Buena Vista Slough on the periphery of the northeast flank of NPR-1.

Federal Wetland Definitions

Several definitions of wetlands have been formulated by federal agencies in conjunction with various federal laws, regulations and programs. The definitions that may be applicable to NPR-1 include the regulatory definition adopted by EPA and the U.S. Army Corps of Engineers for administering the Section 404 permit program of the Clean Water Act (40 CFR 230.3(t); 33 CFR 328.3(b)) and the nonregulatory definition developed by FWS for conducting the NWI program (FWS 1979).

The regulatory definition of wetlands used by EPA and the Corps of Engineers for the Section 404 program is as follows: "Those areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions." This definition only applies to vegetated wetlands, which generally consist of swamps, marshes, bogs, or other similar wetland features. To be formally designated as a regulated wetland area, candidate sites must satisfy all applicable hydrologic, vegetative and soil characteristic criteria.

The FWS nonregulatory wetland definition is as follows: "Wetlands are lands transitional between terrestrial and aquatic systems where the water table is usually at or near the surface or the land is covered by shallow water" (FWS 1979). To be classified as a wetland under the FWS system, an area must satisfy **one or more** (emphasis added) of the following characteristics: (1) At least periodically, the land supports predominantly hydrophytes; (2) the substrate is predominantly undrained hydric soil; and, (3) the substrate is nonsoil and is saturated with water or covered by shallow water at some time during the growing season of each year. This definition, which is much broader than the regulatory definition of wetlands adopted by EPA and the Corps of Engineers, also includes nonvegetated wetland areas (mud flats, sand flats, rocky shores, gravel beaches and sand bars).

Table 2 **Potential NPR-1 Wetlands Identified in the U.S. Fish and Wildlife Service National Wetlands Inventory**

Quadrangle	Section	Designation*	Feature
Tupman	23S	PEMC	Buena Vista Slough
Tupman	25S	PUBFx	oil-field sump
Tupman	35S	PUBFh	gully plug
E. Elk Hills	4G	PUBFx	gully plug
E. Elk Hills	18S	PUSAh	gully plug
E. Elk Hills	10R/15R	R4SBC	drainage channel
E. Elk Hills	22R	R4SBC	drainage channel
E. Elk Hills	23R	PUSCx	gully plug
E. Elk Hills	25R	PUSCx	gully plug
E. Elk Hills	26R	PUSAx	gully plug
E. Elk Hills	26R	PEMICh	diked impoundment
E. Elk Hills	27R	PUBFx	oil-field sump
E. Elk Hills	35R	PUBFx	oil-field sumps (2)
W. Elk Hills	8R/17R/20R	R4SBC	drainage channel
W. Elk Hills	9R/16R/21R	R4SBC	drainage channels (2)
W. Elk Hills	30R	PUBFh	oil-field sump
W. Elk Hills	14Z	PUBFx	oil-field sumps (2)
W. Elk Hills	24Z	PUBFx	oil-field sumps (4)
Taft	10B/13B/14B	R4SBC	Buena Vista Creek
Taft	10B	PUBFh	gully plugs (2)
Taft	14B	PUSCx	oil-field sump
Taft	10G	PUBFh	oil-field sump
Taft	10G	PUBFx	oil-field sump
Taft	10G	PUSCx	oil-field sump
Taft	18G	PUBKx	oil-field sumps(2)

* Refer to Table 1 for a description of wetland designations included in this Table.

Source: (FWS 1986 a,b,c,d)

To standardize the various federal wetland definitions, the "Federal Manual for Identifying and Delineating Jurisdictional Wetlands" was developed and adopted in 1989 by EPA, FWS, the Army Corps of Engineers and the U.S. Soil Conservation Service (EPA et al. 1989). The 1989 Federal Manual provides guidance for identifying and delineating wetlands for various management purposes, including the determination of wetlands for jurisdiction under the Clean Water Act, Section 404 permit program. In 1991, revisions to the 1989 Federal Manual were proposed in a draft rulemaking (FR, Vol. 56, No. 157); however, this rulemaking has not been finalized.

Evaluation of NPR-1 Sites

Twenty-six (26) of the 33 sites identified on the NWI maps of NPR-1 likely do not satisfy criteria for regulatory wetland designation. Twenty-five (25) sites are either oil-field sumps or man-made gully plugs; 17 sites are sumps and 8 sites are gully plugs. The 17 sumps identified as potential wetlands by FWS are/were utilized to dispose of saline wastewaters produced in association with NPR-1 oil and gas production; the sumps do not support hydrophytic vegetation and are not frequented by wildlife. The 8 gully plugs identified are man-made features that were constructed to control runoff from infrequent storms and to provide protection from potential spills.

Another potential NPR-1 wetland site identified by FWS which likely does not satisfy regulatory wetland criteria is a diked impoundment that was developed in the 1960's with artificial watering to enhance wildlife habitat. This site supported a dense growth of hydrophytic vegetation until 1990 when the artificial watering was discontinued; the hydrophytic vegetation subsequently has either died or become dormant, and the site probably does not currently satisfy regulatory wetland criteria.

Seven (7) NPR-1 sites identified by FWS possibly may satisfy regulatory wetland criteria. Six (6) of these sites consist of portions of intermittent stream channels which drain the north and south flanks of NPR-1. The most developed of the six stream channels is Buena Vista Creek on NPR-1's south flank (Figure 2). The other five stream channels drain the north flank of NPR-1, and although they are not as well developed as Buena Vista Creek, they may support hydrophytic vegetation in isolated locations (Figures 3 and 4).

The NPR-1 site most likely to satisfy criteria for regulatory wetland designation is the lowland area associated with the Buena Vista Slough on the northeast periphery of NPR-1 (Figure 5). This site is part of a larger system that FWS has identified as potential wetlands. The portion of NPR-1 that lies within this potential wetland system covers approximately five acres.

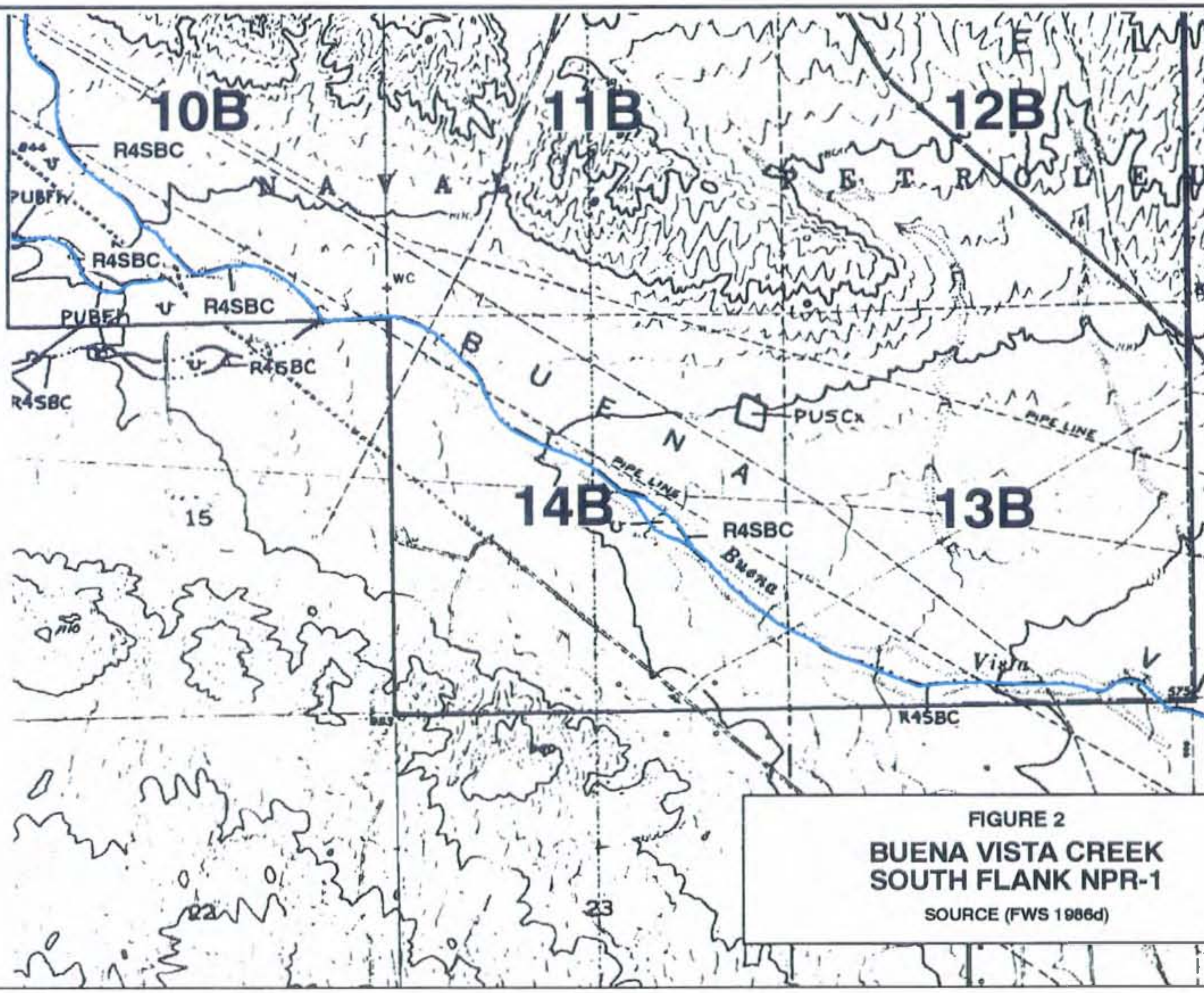

FIGURE 2
BUENA VISTA CREEK SOUTH FLANK NPR-1
SOURCE (FWS 1986d)

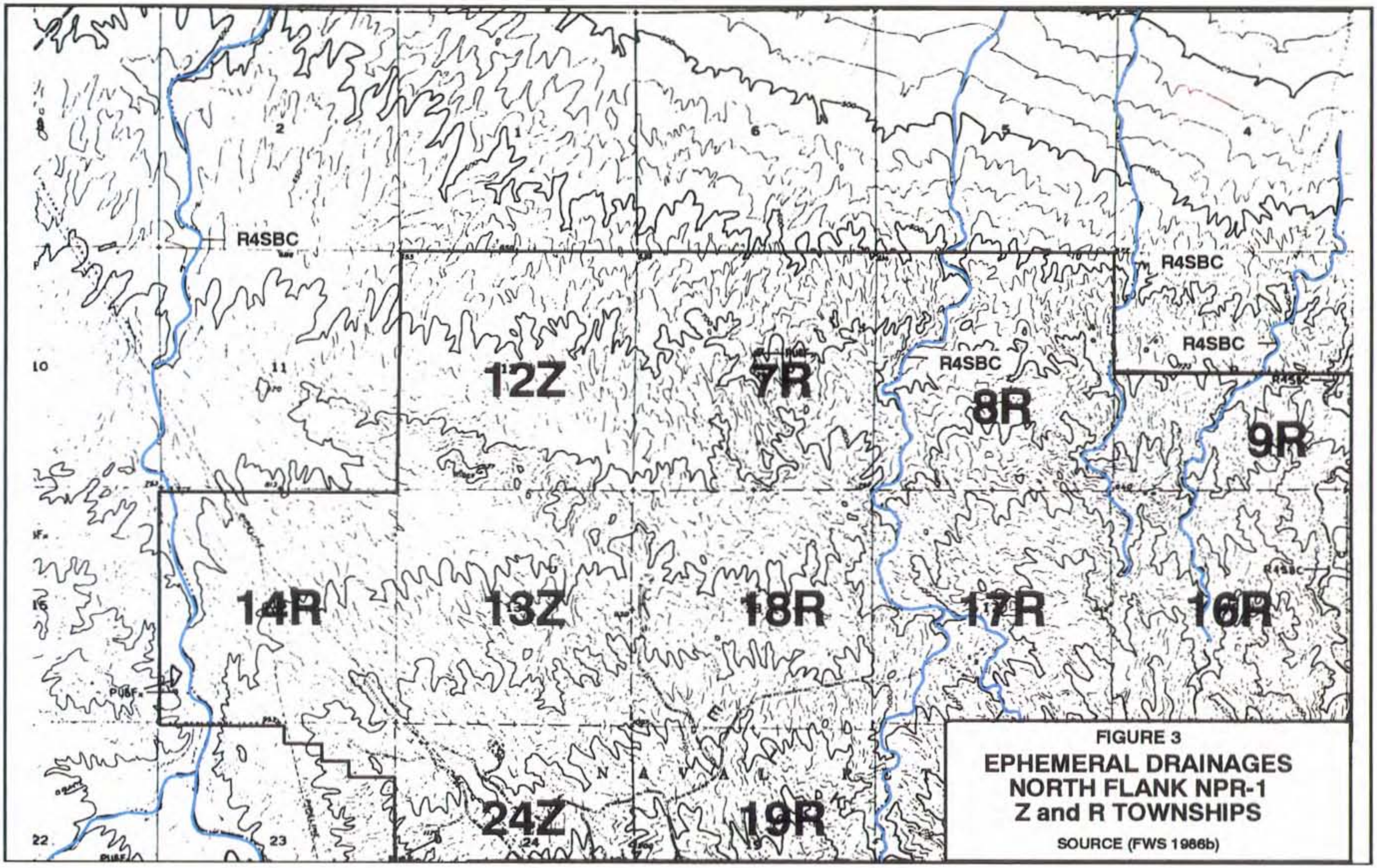

FIGURE 3
EPHEMERAL DRAINAGES
NORTH FLANK NPR-1
Z and R TOWNSHIPS
SOURCE (FWS 1986b)

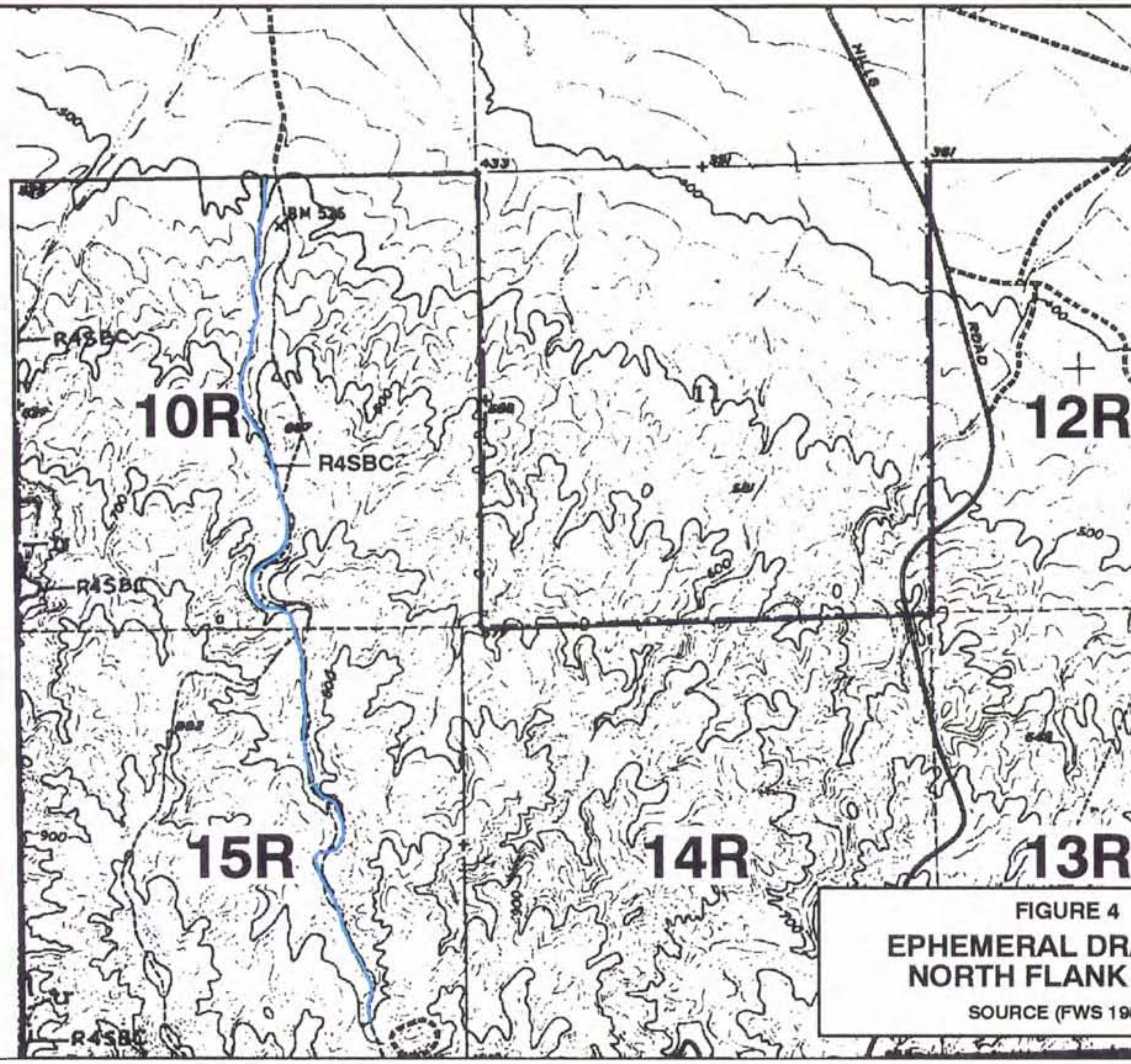

FIGURE 4
EPHEMERAL DRAINAGE
NORTH FLANK NPR-1
SOURCE (FWS 1986c)

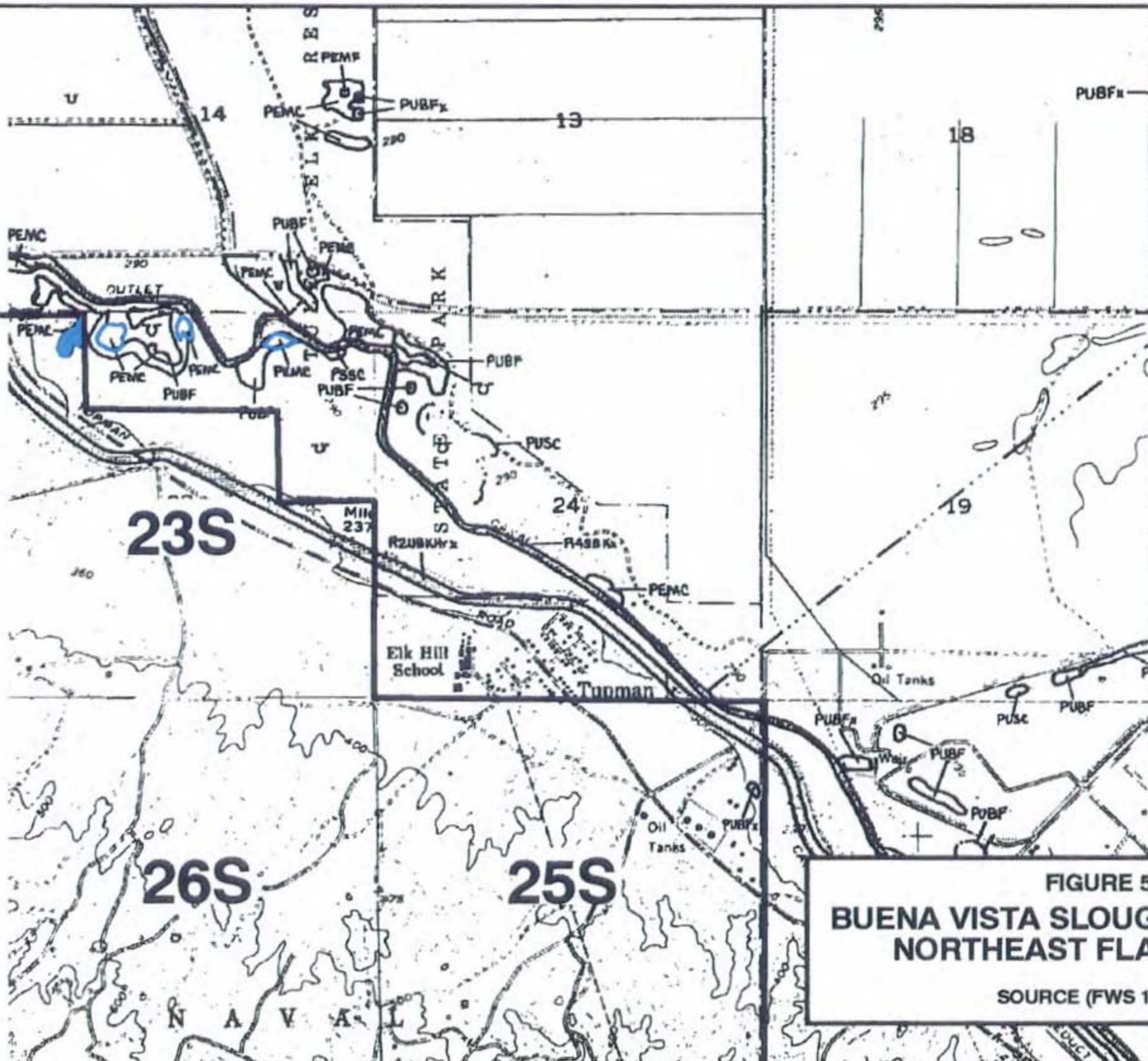

FIGURE 5
BUENA VISTA SLOUGH WETLANDS NORTHEAST FLANK NPR-1
SOURCE (FWS 1986a)

Conclusions/Recommendations

Detailed onsite evaluations are recommended for all potential NPR-1 wetland sites identified in the NWI survey, with the exception of the 17 produced water disposal sumps. This includes the lowland area associated with the Buena Vista Slough on the northeast periphery of NPR-1, the six intermittent stream channels that drain the north and south flanks of NPR-1, the diked impoundment that was artificially watered until 1990, and the eight man-made gully plugs. Although the gully plug sites and the diked impoundment likely do not satisfy wetland designation criteria, a definitive evaluation of these sites by qualified personnel is recommended.

The six NPR-1 stream channels identified as potential wetlands in the NWI possibly may satisfy either regulatory or nonregulatory wetland designation criteria. It should be noted that FWS acknowledges on their Draft NWI maps that intermittent streams may not meet the defition of wetland. Nonetheless, these drainages should also be evaluated to make definitive determinations of their qualification for wetland designation.

The lowland site associated with the Buena Vista Slough should be evaluated for potential wetland designation and its relationship with the larger potential wetland system identified in the NWI.

It is recommended that the detailed evaluations of potential NPR-1 wetland sites be performed by qualified professionals in accordance with the procedures promulgated by the U.S. Army Corps of Engineers in 33 CFR 328.3(b), <u>and</u> the procedures outlined in the 1989 Federal Interagency Wetlands Delineation Manual. Formal adoption of the Federal Wetlands Delineation Manual should be monitored to identify any revisions to the FWS and U.S. Army Corps of Engineers wetland delineation procedures.

It is further recommended that the findings from the onsite evaluations be forwarded to the Corps of Engineers for their review and concurrence prior to formal wetland determinations of NPR-1 sites by DOE. The evaluations also should be forwarded to the U.S. Fish and Wildlife Service for consideration relative to the National Wetlands Inventory.

All natural wetlands preliminarily identified on NPR-1 by the FWS National Wetlands Inventory should be protected from site development activites until future evaluations and appropriate agency reviews are completed. This includes the six drainage channels on the north and south flanks of the Elk Hills, and the lowland site associated with the Buena Vista Slough on the northeast periphery of NPR-1.

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