DE82 011237

THE IMPACT OF AIR POLLUTION CONTROL REGULATIONS ON THERMAL ENHANCED OIL RECOVERY PRODUCTION IN THE UNITED STATES

J. F. Norton, et al

Radian Corporation
Sacramento, California

March 1982

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
NTIS®

FOSSIL ENERGY

DOE/SF/01863-1
(DE82011237)

THE IMPACT OF AIR POLLUTION CONTROL REGULATIONS ON THERMAL ENHANCED OIL RECOVERY PRODUCTION IN THE UNITED STATES

Final Report

By
James F. Norton
James D. Rouge
Pamela K. Beekley
Stuart N. Husband
C. W. Arnold
William R. Menzies
Howard W. Balentine

March 1982
Date Published

Work Performed Under Contract No. AC03-78SF01863

Radian Corporation
Sacramento, California

U. S. DEPARTMENT OF ENERGY

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Printed Copy A13
Microfiche A01

Codes are used for pricing all publications. The code is determined by the number of pages in the publication. Information pertaining to the pricing codes can be found in the current issues of the following publications, which are generally available in most libraries: *Energy Research Abstracts, (ERA); Government Reports Announcements* and Index (*GRA* and I); *Scientific and Technical Abstract Reports (STAR);* and publication, NTIS-PR-360 available from (NTIS) at the above address.

DOE/SF/01863-1
(DE82011237)
Distribution Category UC-92a

THE IMPACT OF AIR POLLUTION CONTROL REGULATIONS ON THERMAL ENHANCED OIL RECOVERY PRODUCTION IN THE UNITED STATES

Final Report

By
James F. Norton
James D. Rouge
Pamela K. Beekley
Stuart N. Husband
C. W. Arnold
William R. Menzies
Howard W. Balentine

Radian Corporation
3401 La Grande Boulevard
Sacramento, California 95823

Gary Peterson, *Technical Project Officer*
San Francisco Operations Office
1333 Broadway
Oakland, California 94612

Work Performed for the Department of Energy
Under Contract No. DE-AC03-78SF01863

Date Published—March 1982

UNITED STATES DEPARTMENT OF ENERGY

ACKNOWLEDGEMENTS

The authors wish to thank Gary Peterson of the U.S. DOE for his guidance in performing this study. We would also like to express our appreciation to the staffs of the Kern County Air Pollution Control District and the other Districts for providing us with the permit information files we needed to develop the computerized inventory of TEOR equipment and associated control systems. We extend our gratitude to the oil producers and their environmental staffs for supplying Radian with information on control systems. We also want to thank the vendors and suppliers of steam generation equipment and control systems for the information and data they provided.

The principal authors would like to thank several other members of the Radian staff for their fine technical contributions to this study: C. William Arnold, William R. Menzies, Stuart N. Husband, Michael J. Kowalski, Howard W. Balentine, and Greg P. Behrens. The efforts of the Radian staff that assisted in the production of this report are also acknowledged.

FOREWARD

This report summarizes the results of a two and one-half year program funded by the Department of Energy (DOE). Most of the work involved with this program was conducted between June 1978 and January 1981, when the air pollution control regulations that are expected to most drastically affect future Thermal Enhanced Oil Recovery (TEOR) viability were adopted in California. Several draft and interim reports were prepared during the period and are available from Radian Corp. Volume IV presents the impact assessment of the existing non-attainment regulations on TEOR production. Volume IV (Parts 1 and 2) was originally published on October 23, 1979. Volume III, originally published on November 21, 1979, contains the information submitted to the California Air Resources Board (CARB) relating to the impact that the Kern County New Source Review Rule (210.1) was anticipated to have on future TEOR production in Kern County. This information was presented at a CARB hearing on November 27, 1979, at which time the current Kern County Rule 210 was adopted.

The majority of the information used to evaluate air pollution control technology for steam generators and steam drive wells was developed during the preparation of Volumes II and IV. Assessments of SO_2 and hydrocarbon control technologies are presented in Parts 1 and 2 of Volume IV. The technical notes on NO_x and particulate matter control technologies, which were prepared in 1979, are contained in Volume II. A technical note describing the atmospheric dispersion modeling study is also presented in Volume II.

This final report is the only report resulting from this contract available from DOE. The other reports mentioned are available from Radian Corp.

This report presents an overview of the impact of air pollution regulations on TEOR production and summarizes the assessment of air pollution control systems presented in the latter volumes of this report. The following three phase analysis is presented in this report:

* Phase I - The cost of previous NSR and Retrofit Rules on TEOR production;
* Phase II - The maximum potential increase in TEOR production; and
* Phase III - The maximum TEOR production increase achievable by 1990.

The analysis for this report was substantially completed by March 1981; however, preparation of the final report has taken several months.

THE IMPACT OF AIR POLLUTION CONTROL REGULATIONS ON THERMAL ENHANCED OIL RECOVERY PRODUCTION

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

FIGURES

FIGURES (Continued)

TABLES

TABLES (Continued)

TABLES (Continued)

TABLES (Continued)

TABLES (Continued)

ABBREVIATIONS

A	Attainment
AC	authority to construct
AFBC	atmospheric fluidized bed combustion
APCD	air pollution control district
API	American Petroleum Institute
AQMD	air quality management district
BACT	best available control technology
bbl	barrel
BOPD	barrels of oil per day
Btu	British thermal unit
CAA	Clean Air Act
CAAQS	California Ambient Air Quality Standards
CARB	California Air Resources Board
$CaSO_4$	calcium sulfate
CCCOP	Conservation Committee of California Oil Producers
CDM	climatological dispersion model
CEC	California Energy Commission
Co.	county
CO	carbon monoxide
CO_2	carbon dioxide
cu.	cubic
DHSG	downhole steam generator
DOE	Department of Energy
DPC&E	Department of Pollution Control and Ecology
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
F	Fahrenheit
FGD	flue gas desulfurization
ft.	foot

ABBREVIATIONS (Continued)

g	gram
gal.	gallon
H_2	hydrogen
HC	hydrocarbon
HEAF	high efficiency air filter
hr	hour
H_2O	water
H_2S	hydrogen sulfide
l	liter
L.A.	Los Angeles
LAER	lowest achievable emission rate
lb	pound
LNB	low NO_x burner
mg	milligram
MM	million
N_2	nitrogen
NA	non-attainment
NAAQS	National Ambient Air Quality Standards
NAP	non-attainment plan
Na_2CO_3	sodium carbonate or soda ash
NaOH	sodium hydroxide or caustic
neg	negative or negligible
NH_3	ammonia
NH_4HSO_4	ammonium bisulfate
NO_x	nitrogen oxides
NO_2	nitrogen dioxide
NSR	new source review
O_2	oxygen
O_3	ozone
OCS	outer continental shelf
Pb	lead
PM	particulate matter
PO	permit to operate
ppm	parts per million
PSD	Prevention of Significant Deterioration

ABBREVIATIONS (Continued)

psig	pounds per square inch gauge
RACT	reasonably available control technology
RCRA	Resource Conservation and Recovery Act
SCF	standard cubic foot
SCM	suggested control measures
SCR	selective catalytic reduction
SIP	state implementation plan
SNR	selective non-catalytic reduction
SO_x	sulfur oxides
SO_2	sulfur dioxide
S/O	steam to oil ratio
syn-gas	synthesis gas
TACB	Texas Air Control Board
TEOR	thermal enhanced oil recovery
TiO_2	titanium dioxide
TSP	total suspended particulate
V_2O_5	vanadium pentoxide
WHVR	wellhead vapor recovery
WPT	Windfall Profits Tax
yr	year

SYMBOLS

&	and
@	at
¢	cent
o	degree
$	dollar
μ	micron
$\$10^3$	thousands of dollars
$\$10^6$	millions of dollars
-	minus or decreased by
/	per
%	percent
+	plus or increased by

ABSTRACT

This study assesses the impact of air pollution control regulations on the costs of present and future thermal enhanced oil recovery (TEOR) production. The conclusions of this study indicate that lengthy permitting processes, limited control system availability, and costly control system requirements complicate regulatory compliance and constrain TEOR production expansion.

Seven heavy oil production areas with potential for increased TEOR production were selected for detailed analyses. Five of these areas are in California: central Kern County, western Kern County, Coalinga, San Ardo, and Los Angeles Basin. The other two areas are the Slocum field in Texas and the Smackover field in Arkansas.

Air pollution control rule and regulation requirements were determined for each production area. State-of-the-art air pollution control technology was assessed and costs were estimated for the control systems needed to comply with previous new source review (NSR) and retrofit rules in each area.

For each California production area, the maximum potential increase in TEOR production was estimated, based on available emission offsets. Potential increases in the Texas and Arkansas fields were not projected because production is expected to decrease in these areas.

Costs were calculated for the control systems required to allow the maximum increase in TEOR production. An air quality impact analysis was performed for the four largest production areas in California. The results of this analysis allowed estimation of the air quality changes associated with the maximum TEOR production increase and compliance with retrofit and NSR rules.

Constraints to the maximum increase in TEOR production include logistical constraints, such as water availability and solid waste disposal site availability, and regulatory constraints, such as permitting requirements, the need for high efficiency pollution control systems, and the availability and distribution of emission offsets. In view of all logistical and regulatory constraints, the maximum increase in TEOR production achievable by 1990 was projected.

This report was submitted in fulfillment of Contract No. ET-78-C-03-1863 by Radian Corporation under the sponsorship of the U.S. Department of Energy. This report covers the period September 15, 1978 to July 31, 1981.

UNITED STATES DEPARTMENT OF COMMERCE
National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161

September 9, 1985

Dear NTIS Customer:

Each year NTIS reviews product prices to ensure they cover all costs involved in acquiring, controlling, and distributing these products. Although costs for postage, printing, supplies, and materials--and the other costs associated with maintaining a collection of some two million reports--have increased over the past several years, NTIS avoided major price increases by implementing many internal cost reductions. As a result, most product prices have remained the same for almost three years.

Despite further cost-cutting measures already taken this year--and others planned for the coming year--product prices must be increased for NTIS to catch up with these rising costs while at the same time remaining self-supporting. Therefore, prices for certain products and services will increase on October 1, 1985; and others are slated for increase on January 1, 1986. The major demand price schedules effective October 1, 1985, are shown on the reverse. You will be notified of any price changes for subscription products at renewal time.

As part of our continuing review of practices and procedures, we took a hard look at product delivery and realized we could--and should--make a change for improved service. Thus, we are pleased to be able to announce an important improvement in the NTIS delivery program:

> For customers in the United States, all orders for demand reports will be shipped via First Class Mail (or equivalent), beginning October 1, 1985, as part of the regular NTIS service. This expedited delivery service should reduce delivery time from 2 to 14 days.

Thank you for your continued interest in NTIS. If you have any questions or comments concerning our products and services, please let us know.

Melvin J. Josephs

Melvin J. Josephs
Associate Director for
Program and Product Management

NTIS DOMESTIC PRICE SCHEDULES EFFECTIVE OCTOBER 1, 1985

STANDARD PRICE DOCUMENTS AND MICROFICHE

"A" Code Price Schedule

Price Code	Price
MICROFICHE	
A01	$5.95
PAPERCOPY	
A02 and A03	$ 9.95
A04 and A05	11.95
A06 through A09 (Inclusive)	16.95
A10 through A13 (Inclusive)	22.95
A14 through A17 (Inclusive)	28.95
A18 through A21 (Inclusive)	34.95
A22 through A25 (Inclusive)	40.95
A99	1/

EXCEPTION PRICED DOCUMENTS AND MICROFICHE

"E" Code Price Schedule

Price Code	Price
E01	$ 7.50
E02	10.00
E03	11.00
E04	13.50
E05	15.50
E06	18.00
E07	20.50
E08	23.00
E09	25.50
E10	28.00
E11	30.50
E12	33.00
E13	35.50
E14	38.50
E15	42.00
E16	46.00
E17	50.00
E18	54.00
E19	60.00
E20	70.00
E99	1/

COMPUTER PRODUCTS SOFTWARE AND DATA FILES

"T" Code Price Schedule

Price Code	Price
T01	$ 145.00
T02	160.00
T03	275.00
T04	370.00
T05	460.00
T06	535.00
T07	610.00
T08	685.00
T09	760.00
T10	835.00
T11	910.00
T12	985.00
T13	1,060.00
T14	1,135.00
T15	1,210.00
T16	1,285.00
T17	1,360.00
T18	1,435.00
T19	1,510.00
T99	1/

1/ CONTACT NTIS FOR PRICE QUOTE

1.0 EXECUTIVE SUMMARY

1.1 Background

Enhanced oil recovery (EOR) techniques are sophisticated production methods used to recover oil reserves that generally could not be economically recovered by primary or secondary production techniques. The application of EOR techniques in heavy oil fields is expected to provide much of the future U.S. oil production. Thermal enhanced oil recovery (TEOR) techniques, such as steam processes and in situ combustion, are expected to be the predominant EOR techniques used to increase production from heavy oil reserves.

U.S. heavy oil reserves are primarily concentrated in southern California. The major TEOR production areas are in Kern, Fresno, and Monterey Counties; the Los Angeles Basin; and the California Central Coast region. Other heavy oil reserves in Arkansas, Texas, and Louisiana may also be developed.

Decontrol of heavy oil prices in 1978 spurred increased interest in TEOR production. Until that time, regulated oil prices and air pollution control regulations, among other issues, had constrained TEOR production. Regulatory constraints had their most significant effects in California.

The purpose of this study is to assess the impact of air pollution control regulations on the costs of TEOR production and future TEOR potential production. Lengthy permitting processes, limited control system availability, and costly air pollution control system requirements complicate regulatory compliance and constrain TEOR production expansion. The nine steps used in this study to assess the impact of air pollution control regulations on TEOR production are:

1) Characterize TEOR production technology and surface facilities.

2) Select production areas for detailed analyses.
3) Determine the air pollution control rule and regulation requirements.
4) Assess the state-of-the-art air pollution control technology.
5) Estimate the costs of controls to comply with the previous new source review and retrofit rules.
6) Estimate the maximum potential increase in TEOR production on the basis of emission offsets.
7) Calculate the costs of air pollution control requirements for the maximum increase in TEOR production.
8) Analyze the change in air quality resulting from compliance with new source review requirements and retrofit rules.
9) Project the maximum TEOR production achievable by 1990, in view of all logistical and regulatory constraints.

1.2 Thermal Enhanced Oil Recovery Technology

TEOR is the most successful EOR technique currently in use and the technique most likely to achieve large increases in heavy oil production in the near future. TEOR involves the addition of heat to the reservoir to increase oil recovery, primarily by reducing the viscous forces that impede the flow of oil through the reservoir to the production well. Two processes typically used to add heat to the reservoir are steam stimulation and in situ combustion. Steam stimulation involves (1) the production of steam on the surface in steam generators fired by crude oil or other fuels, and (2) the injection of steam into the heavy oil reservoir to reduce oil viscosity. In situ combustion involves the generation of heat within the reservoir by burning some of the oil in place. Combustion is sustained by injecting compressed air into the reservoir. The emphasis in this report is on steam stimulation processes.

The two principal types of atmospheric emissions from steam stimulation TEOR production are: (1) air contaminant emissions from combustion equipment used to generate steam or used to treat the crude oil, and (2) emissions from noncombustion equipment associated with oil production. The primary source of combustion emissions is the steam generating equipment that burns a portion of the produced crude oil or some other fuel. Combustion emissions also result from other crude-fired process equipment, such as crude heaters, and from other, gas-fired equipment.

Depending on the fuel composition and combustion conditions, a variety of pollutants can be emitted to the atmosphere when produced crude is burned. The major pollutants from crude-fired steam generators are sulfur oxide (SO_x), nitrogen oxides (NO_x), and particulate matter (PM). If steam generators are gas-fired, the primary pollutant is NO_x. Other pollutants emitted in smaller quantities from combustion sources include hydrocarbons (HC), carbon monoxide (CO), and minute amounts of other compounds. Major sources of HC emissions are evaporative losses from storage tanks and wellhead casing vents, and fugitive emissions from production equipment.

In situ combustion processes also have two principal types of air emissions: (1) combustion emissions released from the crude oil production wells, and (2) exhaust emissions from the combustion of fuel used to power the air compressors (unless compressors are electrically powered).

1.3 Production Areas Selected for Analysis

Seven heavy oil production areas were selected for detailed analyses. Five of these areas are in California: central Kern County, western Kern County, Coalinga, San Ardo, and Los Angeles Basin (see Figure 1-1). The other two areas are the Slocum field in Texas and the Smackover field in Arkansas. The potential for increased heavy oil production using TEOR methods was the primary criterion for the selection of areas for detailed analyses.

1.4 Air Pollution Control Regulations

The regulatory agencies that promulgate air pollution control regulations which impact TEOR production in California include: (1) the United States Environmental Protection Agency (EPA), (2) the California Air Resources Board (CARB), and (3) the local California air pollution control districts (APCDs). In addition to EPA, Texas and Arkansas have state agencies regulating TEOR: the Texas Air Control Board and the Arkansas Department of Pollution Control and Ecology.

The federal Clean Air Act (CAA), as amended in 1970 and 1977, is the driving force behind air pollution control regulations in each of the areas analyzed in this study. The U.S. EPA developed National Ambient Air Quality Standards (NAAQS) for various criteria pollutants under the 1970 CAA. Texas and Arkansas adopted the NAAQS developed by EPA, but California adopted more stringent standards for several pollutants as part of the California Ambient Air Quality Standards (CAAQS). NAAQS and CAAQS are presented in Table 1-1.

Each region in the U.S. has been categorized as either attainment or non-attainment for each NAAQS. This categorization method is specific to each region and for each

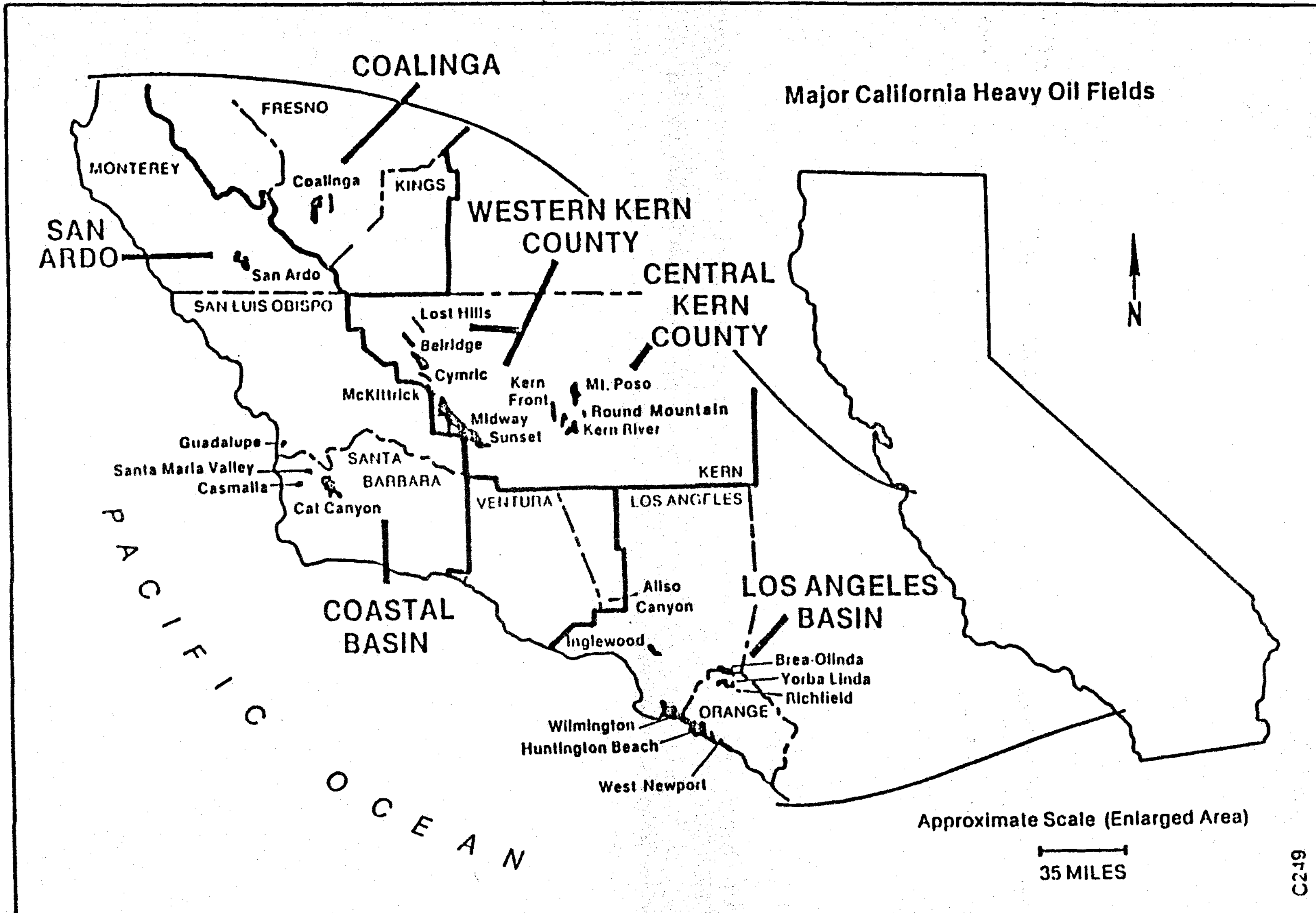


Figure 1-1. Locations of the California Heavy Oil Fields Selected for Detailed Analyses in this Study.

TABLE 1-1.

NATIONAL AND CALIFORNIA AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time[a]	NAAQS[b] Primary ppm	NAAQS[b] Primary µg/m³	NAAQS[b] Secondary ppm	NAAQS[b] Secondary µg/m³	CAAQS[c] ppm	CAAQS[c] µg/m³
TSP	12 Months (Geometric)		75		60		60
	24 Hour		260		150		100
SO_2	12 Months	0.03	80	-	-	-	-
	24 Hour	0.14	365	-	-	0.05[d]	131[d]
	3 Hour	-	-	0.5	1,300	-	-
	1 Hour	-	-	-	-	0.05[d]	1,310[d]
NO_2	12 Months	0.05	100	0.05	100	-	-
	1 Hour	-	-	-	-	0.25	470
H_2S	1 Hour	-	-	-	-	0.03	42
CO	12 Hour	-	-	-	-	10	11,000
	8 Hour	9	10,000	9	10,000	-	-
	1 Hour	35	40,000	35	40,000	40	46,000
O_3	1 Hour	0.12	240	0.12	240	0.10	200
Pb	3 Months		1.5	-	-	-	-
	30 Day	-	-	-	-	-	1.5
Sulfate	24 Hour	-	-	-	-	-	25[d]

[a]Arithmetic averages unless otherwise indicated.

[b]National Ambient Air Quality Standards.

[c]California Ambient Air Quality Standards.

[d]California standard that the California courts repealed in 1980.

pollutant. For example, a region can be attainment for one pollutant and non-attainment for another pollutant. Non-attainment areas must provide mechanisms and strategies for attaining the NAAQS for total suspended particulate (TSP), SO_2, NO_X, CO, and ozone (O_3) by 1982. CO and O_3 compliance may be delayed until 1978 under special circumstances.

The CAA requires that each state develop and implement a plan to achieve and maintain the NAAQS. This plan, the state implementation plan (SIP), describes state regulations and other control measures needed to demonstrate attainment or maintenance of the NAAQS. Control measures may include motor vehicle, stationary, and area source emission reduction strategies, in addition to preconstruction review requirements for new stationary sources. If EPA approves a state's SIP, EPA may delegate responsibility for the control of new and existing emission sources to the state. However, if an EPA-approved SIP is not developed and transportation control measures are deemed necessary, EPA may impose federal sanctions, such as the denial of federal grants, a ban on construction of major new and modified sources, or withholding of federal funds. Federal sanctions are lifted as soon as EPA's requirements for transportation control measures are met and a SIP is approved.

For stationary sources, the SIP control measures include two regulatory mechanisms: (1) the preconstruction review of new or modified sources (new source review (NSR) rules), and (2) the control of emissions from existing equipment (retrofit rules). In general, for the NSR rules, the level of control is a function of the size of the source. For the retrofit rules, control levels required are primarily a function of air quality and the cost-effectiveness of the candidate control technologies.

SIP requirements include the application of best available control technology (BACT) or controls that reflect the lowest achievable emission rate (LAER) for new or modified equipment. In addition, reasonably available control technology (RACT) may be required on existing equipment.

The 1977 amendments to the CAA required that NAAQS attainment areas provide adequate safeguards to preserve the air quality in these areas. These requirements, known as Prevention of Significant Deterioration (PSD) requirements, place emphasis on preconstruction review of new or modified sources. Each SIP must include PSD provisions which require BACT, monitoring of existing air quality where ambient air quality data is lacking, and a method for monitoring PSD increment consumption. Increments represent the maximum level of air quality deterioration allowed for a specific pollutant in an area which is nonattainment for that pollutant.

In California, local regulatory agencies, under the guidance of CARB, and EPA develop and enforce air pollution control regulations. The regulations applicable to TEOR production are identified in Table 1-2.

1.5 Air Pollution Control Systems

The major pollutants associated with TEOR production are SO_2, NO_x, PM, and HC. Most of the SO_2, NO_x, and PM emissions are produced during combustion in the steam generators, and HCs are emitted primarily from uncontrolled wellhead casing vents.

The analysis of applicable air pollution control systems was based on several design cases. Four PM and SO_2 control cases were analyzed: (1) a single 25 MM Btu/hr (heat output) steam generator, (2) a single 50 MM Btu/hr (heat output) steam generator, (3) a group of six 50 MM Btu/hr steam generators with flue gases ducted to a common stack, and (4) a group of ten 50 MM Btu/hr steam generators with a common stack. The NO_x control system analysis was limited to the first two cases, because

TABLE 1-2.

CALIFORNIA AIR POLLUTION REGULATIONS APPLICABLE TO TEOR EQUIPMENT[1]

APCD	SOURCE	Sulfur Dioxide(SO_2)	Oxides of Nitrogen(NO_x)	Particulate Matter (PM)	Hydrocarbons (HC)
Kern County	New	NSR[2]-BACT[3], LAER[4], and offsets	NSR-BACT, LAER, and offsets	NSR-BACT, LAER, and offsets	NSR-BACT, LAER, and offsets
	Existing	Rule 424 - SO_x emissions from steam generators	Rule 425 - NO_x emissions from steam generators	Rule 424 - PM emissions reduced in conjunction with SO_x emissions reductions from steam generators	Rule 411.1 - HC emissions from wellhead casing vents
Fresno County	New	NSR-BACT, LAER, and offsets	NSR-BACT, LAER, and offsets	NSR-BACT. LAER, and offsets	NSR-BACT, LAER, and offsets
	Existing	None[5]	None	None	None
Monterey Bay Unified	New	NSR-BACT	NSR-BACT	NSR-BACT	NSR-BACT LAER and offsets
	Existing	None	None	None	Rule 427 - HC emissions from steam drive crude oil production wells
SCAQMD	New	NSR-BACT[6] and offsets	NSR-BACT and offsets	NSR-BACT and offsets	NSR-BACT and offsets
	Existing	None	None	None	None

[1] TEOR equipment includes steam generators with heat input capacities greater than 15 MM Btu/hr, and wellhead vapor recovery systems.
[2] NSR = new source review.
[3] BACT = best available control technology.
[4] LAER = lowest achievable emission rate.
[5] None indicates that only general air pollution control regulations apply to existing TEOR production.
[6] In the SCAQMD, BACT is defined as equivalent to LAER for the other study APCDs.

NO_x control systems are an integral part of each steam generator. HC controls were evaluated based on analysis of a 32-well wellhead vapor recovery (WHVR) system.

The results of the steam generator control system analysis are presented in Table 1-3. The removal efficiency, developmental status, and costs for each control system or series of control systems are shown. SO_2 control technology is the most developed at this time, with commercially available systems achieving 90 to 95 percent SO_2 removal.

Significant developmental activity is underway in the NO_x control area. Commercially available technology is represented by O_2 controllers with low NO_x burners (LNBs) that achieve 30 percent NO_x removal. Selective non-catalytic reduction (SNR) systems that would provide a 50 percent reduction in steam generator NO_x emissions are currently under development. As shown in Table 1-3, application of SNR has a very significant impact on costs for control systems. Selective catalytic reduction (SCR) systems, with 85% NO_x removal efficiency, currently represent innovative technology under development. As with SNR, application of SCR has a significant impact on control system costs.

At present, limited PM control is achieved with wet scrubbers that are applied to steam generators for SO_2 control. A variety of high-efficiency PM control systems are under development, but commercial systems are not currently available.

The costs of SO_2, NO_x, and PM control systems with high pollutant removal efficiencies are particularly significant when summed (see Table 1-3). In progressing from commercially available systems to high-efficiency control systems (especially for NO_x and PM), costs of controls are expected to increase threefold or fourfold.

TABLE 1-3.

SUMMARY OF CONTROL SYSTEM REMOVAL EFFICIENCIES, DEVELOPMENTAL STATUS, AND COSTS FOR STEAM GENERATOR APPLICATIONS

Control System	Removal Efficiency	Developmental Status	Early 1979 Costs (10^3 \$/MM Btu/hr Input)
SO_2 Scrubbers (NaOH, Na_2CO_3, and Dual Alkali)	90-95% SO_2 25% PM	Commercially Available	1.66- 3.68
O_2 Controller & Low NO_x Burner (LNB)	30% NO_x	Commercially Available	0.71- 1.48
O_2 Controller, LNB, and Selective Non-Catalytic Reduction (SNR)	50% NO_x	In Development	6.94- 7.96
O_2 Controller, Low NO_x Burners, and Selective Catalytic Reduction (SCR)	85% NO_x	Innovative Technology	7.89-11.60
High Efficiency Particulate	99% PM	Innovative Technology	0.36- 1.56
O_2 Controller, LNB, Moderate SCR, SO_2 Scrubber, and High Efficiency Particulate Control System	-	Developmental Status Varies	9.91-16.84

A WHVR system applied to 32 steam drive wells was analyzed. This type of system is representative of those currently used in TEOR fields. The cost analysis, shown in Table 1-4, reflects a credit for the HCs recovered, and indicates a control system cost of $0.05 per pound of HCs removed from the wellhead vents.

1.6 Part I Analyses - Cost of Previous NSR Rules and Retrofit Rules

In order to obtain permits to construct new TEOR facilities, oil producers have had to install air pollution controls on the new and existing TEOR facilities to comply with new source review (NSR) requirements. CARB recently adopted Rule 424 and 425 for the Kern County APCD. These rules have required the TEOR producers to install SO_2 and NO_x controls on existing steam generators. In addition, the Kern County APCD adopted Rule 411.1 which requires that WHVR systems be installed on all steam drive wells in Kern County. Also, the Monterey Unified APCD prohibits fuel combustion sources from emitting any more SO_2 than would be emitted if the source were burning 0.5% sulfur fuel.

In this study, the costs of these air pollution control rules and regulations to TEOR producers were analyzed. This cost analysis focused on the four California production areas with the greatest steam generation capacity. These are the central Kern County fields, the western Kern County fields, the Coalinga field, and the San Ardo field. Data gathered from district permit files and information supplied by oil producers were used to develop inventories of the TEOR facilities and associated control systems for each of the four production areas. Emission rates for the TEOR steam generators were estimated in two ways. If an emission limitation was specified in the

TABLE 1-4.

COSTS[1] AND HC EMISSIONS FROM WELLHEAD CASING VENTS EQUIPPED WITH A REPRESENTATIVE WHVR SYSTEM[2]

Total Capital Costs/WHVR System[2]	$273,000
Total Annual Costs/WHVR System[2]	$137,300 - $165,200
HC Emissions (lb/hr)	0
HC Removed[3] (lb/hr)	333
Cost Effectiveness ($/lb of HC removed)	$0.05

[1]Costs estimated in terms of early 1979 dollars.

[2]For a typical wellhead HC collection system servicing 32 wells.

[3]Assumes 100% control.

Authority to Construct (AC), this emission limitation was used to estimate the generator's maximum emission rate. If no emission limitation was specified, the estimated emission rate was based on the control efficiency of the control systems specified in the AC and the uncontrolled emission rates.

Results of the cost analyses for Kern County are presented in detail because Kern County currently produces 90% of the California TEOR crude oil, and is expected to produce 90% of the national TEOR crude oil by 1990. Results of the cost analyses for the other production areas are also presented, but not in as much detail as those for Kern County. The methodologies used in the Kern County cost analyses were also used for the other production areas.

1.6.1 The Kern County Fields

Costs and emissions were estimated for permitted steam generators that must comply with the previous NSR and retrofit rules in Kern County. The control systems, their costs, and the feasibility of their installation were evaluated for Rules 424, 425, and 411.1. The installation costs for SO_2 scrubbers, NO_x controls, and WHVR systems were estimated for TEOR production equipment permitted prior to September 12, 1979, pursuant to the Kern County NSR rule and the EPA NSR and PSD rules.

A computerized data base was developed for all steam generators, heaters, and heater treaters permitted in Kern County (i.e., with either ACs or POs) as of September 12, 1979. Approximately 1,350 oil-fired steam generators, heaters, and heater treaters were permitted in Kern County by this date. For each piece of TEOR equipment, the size, make, fuel, fuel sulfur content, control systems, control system efficiency, and location were obtained from the Kern County APCD's permit files. Computer programs were written to calculate emissions and sort the steam generating equipment by area and permit status.

The permitted TEOR steam generation capacities in central and western Kern County are estimated to be capable of producing 144,000 and 205,000 BOPD, respectively. These figures represent net oil production and therefore take into account the amount of produced oil which is burned in the steam generators to enhance production. Capital and annual costs for NO_x, SO_x, and particulate controls were developed. NO_x costs included the costs associated with three levels of control (e.g., Stage I controls if ambient NO_x levels remain the same and Stage II and III controls if ambient NO_x levels increase significantly). Costs are based on the assumptions that the required control technology performs as projected and is available in sufficient quantities to comply with the respective regulation schedules. The capital and annual costs to comply with the regulations for the Stage I Control levels are $285 to $498 million and $126 to $271 million, respectively, for all of Kern County. If the ambient NO_2 concentrations exceed 85 percent of any NO_2 standard the Stage II Control level would result in capital and annual expenditures of $330 to $728 million and $138 to $371 million, respectively. If the ambient NO_2 concentrations exceed any national or California NO_2 standard, the capital and annual expenditures required for compliance with the Stage III regulations in Kern County are estimated to be $795 to $1,132 million and $340 to $350 million, respectively. Summary costs of controls required to comply with previous Kern County rules are presented in Table 1-5. Based on estimated potential Kern County TEOR production for permitted steam generators, the costs for controls under compliance with the Stage I Control level are estimated to be $0.98 to $2.12 per net barrel of oil produced. At the Stage II Control level, costs of controls are estimated to be $1.08 to $2.91 per net barrel of oil produced.

TABLE 1-5.

TOTAL CAPITAL AND ANNUAL COSTS FOR CONTROL SYSTEMS NEEDED TO COMPLY WITH PREVIOUS REGULATIONS, RULES 424 AND 425, AND PARTICULATE OFFSET REQUIREMENTS IN KERN COUNTY

Control Level	County Area	Capital Costs In MM Dollars	Average Annual Costs		
			MM Dollars	Dollars/bbl Oil Burned	Dollars/bbl Oil Produced
STAGE I	Central Kern	155 - 242	67.4 - 127	2.17 - 4.10	1.28 - 2.41
	Western Kern	130 - 256	58.7 - 144	2.34 - 5.77	0.78 - 1.92
	TOTAL	285 - 498	126 - 271	2.25 - 4.85	0.98 - 2.12
STAGE II	Central Kern	180 - 357	73.8 - 179	2.38 - 5.79	1.40 - 3.40
	Western Kern	150 - 371	63.7 - 192	2.55 - 7.70	1.08 - 2.91
	TOTAL	330 - 728	138 - 371	2.47 - 6.64	1.08 - 2.91
STAGE III	Central Kern	443 - 567	188 - 260	6.08 - 8.40	2.51 - 4.95
	Western Kern	352 - 565	152 - 270	6.09 -10.87	2.03 - 3.61
	TOTAL	795 - 1,132	340 - 530	6.08 - 9.49	2.66 - 4.16

If the Stage III Control level is required, the control costs per net barrel of oil produced are estimated to be \$2.66 to \$4.16. The above costs are in 1979 dollars. Assuming an average inflationary rate of 10 percent per year over the last two years, these estimates would have to be increased by 21 percent to give costs in 1981 dollars. If the average barrel of heavy oil is worth \$25.00, the costs of controls alone represent between 3.2 and 13 percent of the oil's value. Hence, these control costs may adversely impact TEOR fields with marginal production levels and may ultimately contribute to their abandonment.

Rules 424 and 411.1 include compliance schedules, and Rule 425 includes several potential compliance schedules. The compliance schedule for Rule 424 requires initial emission reductions by July 1, 1982 and ultimate emission reductions by July 1, 1984. Rule 425 requires Stage I Control level compliance by July 1, 1982, and requires compliance with progressively more stringent control levels within 18 months after the corresponding changes in ambient NO_2 concentrations. Rule 411.1 requires final compliance by March 1, 1982. Rule 210.1 (New Source Review) does not have a compliance schedule since compliance is required upon construction of the new or modified source. Special conditions in the ACs issued in September 1979 may require installation of control equipment on existing equipment to provide emission offsets. Table 1-6 summarizes the compliance schedules for Rules 424, 425, and 411.1.

Each compliance schedule, in turn, requires submission of a compliance plan by a certain date. However, repeated revisions of the regulations can result in modification of the required control levels, making preparation of a compliance plan very difficult. The complexity and magnitude of this task, especially in the case of small producers, could result in significant delays in any proposed expansion of TEOR facilities subject to NSR. NSR requirements include demonstrating compliance

TABLE 1-6.

COMPLIANCE SCHEDULES AND EMISSION LIMITS FOR RULES 424, 425, and 411.1

RULE AND COMPLIANCE INCREMENTS	COMPLIANCE DATE(S)[1]	EMISSION LIMITS
Rule 424 (SO_x)		
1. Submit Compliance Plan	7/1/80	--
2. Submit Verification of Purchase Orders	7/1/80	--
3. Submit Status Reports	7/1/81, 7/1/82, 7/1/83, 7/1/84	--
4. Demonstrate Compliance	7/1/82 7/1/84	0.25 lbs S/MM Btu 0.12 lbs S/MM Btu
Rule 425 (NO_x)		
1. Stage I Control Level Compliance	7/1/82	0.30 lbs NO_x/MM Btu
2. Stage II Control Level Compliance	18 months following a Stage II air quality change	0.25 lbs NO_x/MM Btu
3. Stage III Control Level Compliance	18 months following a Stage III air quality change	0.14 lbs NO_x/MM Btu
Rule 411.1 (HC)		
1. Submit Compliance Plan	1/1/80	--
2. Submit Verification of Purchase Orders	7/1/80	--
3. Initiate Onsite Construction	10/1/80	--
4. Complete Onsite Construction	10/1/81	--
5. Demonstrate Compliance	3/1/82	93% Control

[1] Compliance date for steam generators installed before September 12, 1979.

with all other applicable rules before any new permit application can be deemed complete by the APCD.

Availability of Technology

In many cases, the required control technology has yet to be demonstrated. Assuming, for discussion purposes, that all required technology has been demonstrated, one to four years could pass before the control systems are commercially available in sufficient quantities to satisfy the applicable compliance schedules. Given these uncertainties, many oil producers may question risking not only new ventures, but also those projects for which they currently have only ACs. Progressive tightening of regulations may result in the permanent abandonment of projects which currently are on hold due to the lack of high efficiency control technology. Table 1-7 provides a summary of control equipment which must be installed to demonstrate compliance with the applicable regulations.

In addition to the delays caused by revision of regulations and corresponding changes in compliance schedules and emission limitations, the actual permit review process in Kern County has been significantly impacted by the magnitude of applications received over the last four to five years. These phenomena have resulted in significant delays in the issuance of Authorities to Construct (ACs). The processing delays resulting from large influxes of applications are compounded by the following factors:

- compliance schedule submittal requirements for Rule 424 and 411.1;
- inadequate demonstration of the technology needed to satisfy regulatory requirements;

TABLE 1-7.

AVERAGE MONTHLY CONTROL EQUIPMENT INSTALLATION
REQUIRED TO COMPLY WITH RULES 424, 425, and 411.1

RULE/CONTROL EQUIPMENT	TOTAL EQUIVALENT CONTROL SYSTEMS TO BE INSTALLED[1]	EQUIVALENT UNITS TO BE INSTALLED PER MONTH (AVERAGE)
Rule 424 (SO_x)		
SO_2 Scrubbers	291	6.9
Rule 425 (NO_x)		
Stage I[2] - LNBs and	805	42.4
SNR	276	14.5
Stage II[3] - SNR or	717	39.8
SCR	223	12.4
Stage III[3] - SCR	561	31.2
Rule 411.1		
WHVR Systems	261	18.6

[1] An equivalent control system is an SO_x or NO_x system installed on a 50 MM Btu/hr output steam generator or a WHVR system applied to 32 production wells.
[2] TEOR producers have 19 months to comply with the Stage I Control level.
[3] TEOR producers have 18 months to comply if Stage II or III Control levels are required.

- submittal of applications for retrofit controls needed on existing equipment to satisfy emission offset requirements contained in ACs issued in September, 1979;
- control system manufacturing lead time which may range from 6 to 18 months depending on the type of control system; and
- control system installation, start-up, and compliance testing requirements which may range from 3 to 6 months depending on how much pre-installation work can be completed prior to equipment arrival.

Table 1-8 illustrates the time requirements and potential delays associated with complying with Kern County APCD regulations.

1.6.2 The Coalinga and San Ardo Fields

As mentioned previously, results of the cost analyses for two other TEOR production areas are also presented in this report. However, the Coalinga field and the San Ardo field cost analyses were not presented in as great a detail as the Kern County analyses. Table 1-9 summarizes the permitted steam generation capacities, estimated net TEOR production rates, and average annual control costs for the central Kern County fields, the western Kern County fields, the Coalinga field, and the San Ardo field.

1.7 Part II Analyses - The Maximum Potential Increase In TEOR Production

In this study, the maximum potential increase in TEOR production was estimated based on the offsets which can be

TABLE 1-8.

TIME REQUIREMENTS AND POTENTIAL DELAYS ASSOCIATED WITH COMPLYING WITH KERN COUNTY APCD RULES[1]

ACTIVITY	TIME REQUIREMENTS AND POTENTIAL DELAYS
AC issued under NSR in September 1979	
a. SO_x controls for emission offsets	Rule 424 limits were not established until October 1980 - 13 months delay
b. Submittal of SO_x control plan for emission offsets	3 months preparation by applicant 3 months review by APCD
c. Request and review bids and issue Purchase Order for SO_x controls	3 months
d. Manufacturing and delivery of SO_x controls	12 to 18 months depending on type of SO_2 scrubber
e. Installation, start up, and request for compliance testing	3 to 6 months
f. Concurrent with step c; request and review bids and issue Purchase Order for NO_x controls for steam generators	3 to 6 months; (If SCR is required, a potential delay of 2 to 4 years could occur as this technology is still being demonstrated)
g. Manufacturing and delivery of steam generator and NO_x controls	3 to 6 months for steam generator with SNR 12 to 18 months for steam generator with SCR
h. Installation, start up, and request for compliance testing	3 to 6 months

[1] Assuming steps a, b, c, d, and e are conducted concurrent with steps f, g, and h, the total time requirement is 24 to 33 months for a SNR control system and 42 to 76 months for a SCR control system.

TABLE 1-9.

PERMITTED STEAM GENERATION CAPACITIES, ESTIMATED TEOR PRODUCTION RATES (NET) AND AVERAGE ANNUAL CONTROL COSTS FOR FOUR CALIFORNIA PRODUCTION AREAS

			CONTROL COSTS IN $/BBL OF OIL PRODUCED (NET)		
				Average Annual Costs of Controls Needed to Comply with Rule 424, Rule 425, and Particulate Offset Requirements	
Production Area	Permitted Steam Generation Capacity (MM Btu/hr)	Estimated TEOR Production (Net BOPD)[a]	Average Annual Costs of Controls Needed to Comply With Previous NSR Rule	Stage I Control	Stage III Control
Central Kern County	27,850	144,000	0.51-1.02	1.28-2.41	2.51-4.95
Western Kern County	22,470	205,000	0.41-1.01	0.78-1.92	2.03-3.61
Coalinga	3,700	39,700	1.36-3.15[b]	NA	NA
San Ardo	4,135	33,800	1.69-4.60[b]	NA	NA
TOTAL	58,155	422,500			

[a]The net barrels of oil produced per barrel of oil burned were assumed to be 1.7 for central Kern County, 3.0 for western Kern County, 3.52 for the Coalinga field, and 3.08 for the San Ardo field.

[b]Average annual control costs for the Coalinga and San Ardo fields are shown to vary (by almost threefold) due to the variability in the current control status of equipment in these fields. Many of the steam generators in the Coalinga and San Ardo fields currently have SO_2 control systems applied. Because installation of SO_2 control systems represents a large portion of the average annual control costs, generators with SO_2 control systems will have lower control costs than generators which must be equipped with SO_2 control systems.

made available by installing high efficiency air pollution control systems on permitted TEOR facilities. The analyses assumed that the availability of emission offsets is the only constraint to increasing TEOR production. Of the seven areas selected for detailed analyses in this study, only the five production areas in California are expected to have a large potential for increasing TEOR production. For this reason, maximum potential TEOR production was estimated only for the five California areas.

Future TEOR projects in California may be reviewed by three air pollution control agencies before they are approved: the local district, California Air Resources Board (CARB), and the Environmental Protection Agency (EPA) Region IX office. The NSR review of the local districts and the CARB focuses on the local district's regulations. These regulations primarily are based on the non-attainment review requirements of the federal Clean Air Act. The EPA Region IX office reviews the projects for compliance with both the federal non-attainment requirements and the Prevention of Significant Deterioration (PSD) regulations.

In most cases, the local California air pollution control district's rules are more restrictive than the federal regulations. Hence, the projects that meet the control requirements and offset requirements of the local district are usually below the minimum emission levels mandated by federal requirements. If the project must be reviewed under the EPA's new source review requirements, the review is usually abbreviated. In California, the maximum increase in potential TEOR production generally is most constrained by the regulations of the local districts, which affect the availability of emission offsets for new TEOR projects.

In the Part II Analyses, the maximum increase in steam generator capacity that could be installed in the five California production areas and the Texas and Arkansas fields was estimated. The emissions, costs, and TEOR production were then estimated for the Maximum Increase in TEOR Production Case for each production area. The change in air quality predicted if the maximum TEOR production is attained and the retrofit rules are implemented was also examined. The methodology used in the Part II Analyses is shown in Figure 1-2.

Complex photochemical dispersion models would have to be used to fully assess the changes in air quality which might be expected in the five California production areas if the retrofit rules are implemented and the maximum potential expansion of TEOR production occurs. In order to use the photochemical models, large-scale validation studies with field monitoring of ambient pollutant concentrations and meteorological data would be needed for each area. A photochemical modeling study of the five production areas would require millions of dollars to complete. Because of costs, a much simpler and less costly approach for estimating change in air quality was selected. The annual concentrations of SO_2, NO_2, and directly-emitted PM from steam generators were predicted using the climatological dispersion model (CDM), an EPA-approved Gaussian model. The dispersion model predicts annual arithmetic mean concentrations for non-reactive pollutants.

The change in air quality expected due to the implementation of the retrofit rules and the maximum expansion of TEOR production was estimated by predicting the concentrations of SO_2, NO_2, and directly-emitted PM for two situations. A 1978 Baseline Case and a Maximum Increase in TEOR Production Case were studied. The 1978 Baseline Case was selected because the retrofit rules and the more stringent NSR regulations had not yet been adopted in 1978. The Maximum Increase in TEOR Production Case studied the impact of TEOR production after the retrofit rules have been met and the maximum TEOR production increases have occurred. Case I and Case II maximum production scenarios were modeled for the Maximum Increase in TEOR Production Case.

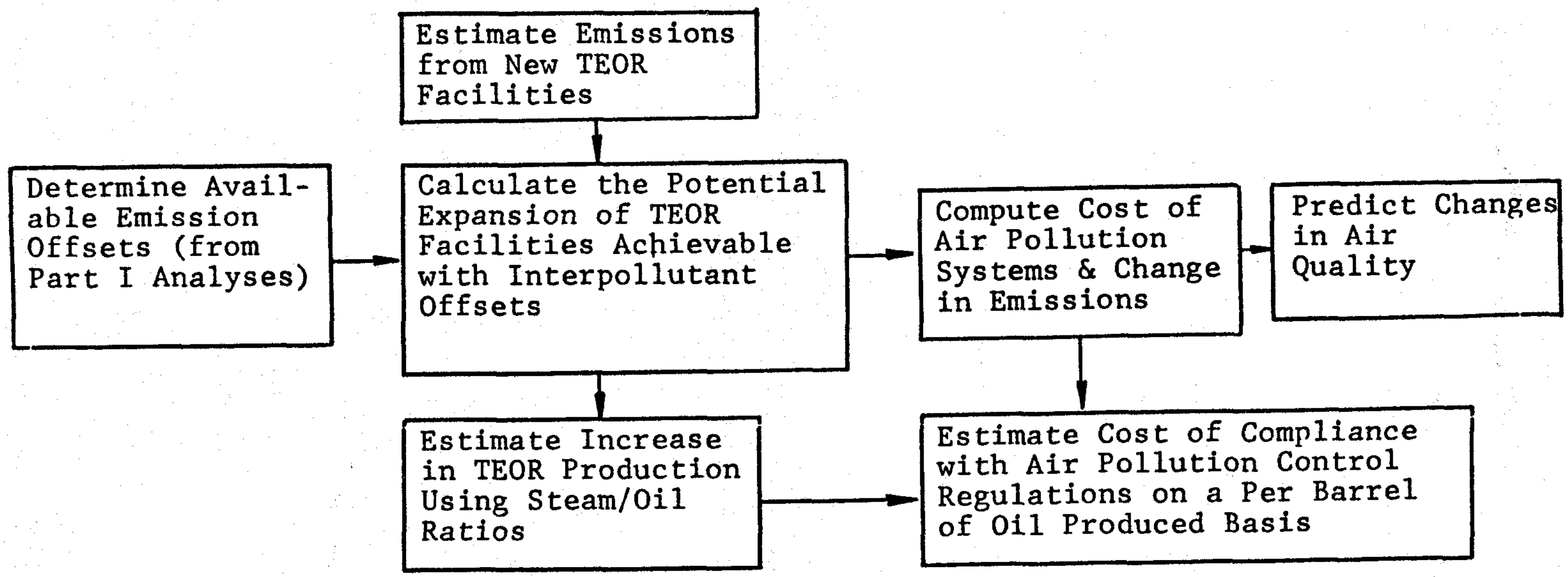


Figure 1-2. METHODOLOGY USED TO ANALYZE THE MAXIMUM INCREASE IN TEOR PRODUCTION ON THE BASIS OF AVAILABLE EMISSION OFFSETS (PART II ANALYSES).

The Case II maximum production scenario was modeled since it incorporates more restrictive NO_x regulations than the Case I scenario.

The Kern County NSR rule and the retrofit rules 424, 425, and 411.1 severely limit the emission offsets available for future TEOR projects. The recently revised Kern County NSR rule requires that PM and NO_x emissions be offset, in addition to SO_2 emissions. The emission reductions made by the TEOR producers to comply with the retrofit rules cannot be used as emission offsets to comply with the NSR rule.

Assuming that high efficiency NO_x control systems are commercially available at reasonable costs, then the availability of NO_x emissions offsets for future TEOR projects will depend on the control levels which must be met to comply with Rule 425 in Kern County. At the Stage I Control level, the NO_x emissions from steam generators permitted by September 12, 1979, must average 0.30 lbs/MM Btu before emission reductions can be counted for emission offsets. On the other hand, if the Stage II Control level must be met, the NO_x emissions from the steam generators must be reduced to 0.25 lbs/MM Btu before any offsets can be obtained. The availability of NO_x emissions offsets will significantly affect the Maximum Increase in TEOR production Case for Kern County.

Emission reductions required to maximize emission offsets and expansion of steam generation capacity in four of the five TEOR production areas in California were determined. The Los Angeles Basin was excluded from the emission reductions determinations, because there are few potential emission offsets in the Los Angeles Basin (due to the use of natural gas rather than crude oil in the existing TEOR steam generators). The steam generation capacity that must be retrofit with air pollution control systems to obtain these emission reductions was also determined. The results of the emission reductions and retrofit determinations are shown in Table 1-10 for four California production areas.

Next, the maximum potential expansion of TEOR facilities in each of the four production areas was determined, based on the emission reductions determined previously. The result of this determination are presented in Table 1-11.

Using the appropriate steam/oil ratios, the potential increases in TEOR production associated with maximum expansion can be calculated. The maximum potential increase in TEOR production based on available emission offsets in four of the California production areas is shown in Table 1-12. The costs of the air pollution controls required to achieve this maximum increase in TEOR production are also presented in this table.

For Kern County Case I, the capital costs for installing SO_2, NO_x, HC, and particulate control systems on new TEOR facilities and on existing facilities to provide offsets for the new facilities range from $960 to $1,242 million and from $525 and $683 million for the central and western Kern County fields, respectively. The average annual costs are expected to range from $412 to $579 million and from $223 to $315 million for the respective production areas. Over 70 percent of these costs are for the SCR controls systems installed on new and existing steam generators.

Assuming a gross to net oil production ratio of 1.7 to 1.0 and an 0.8 capacity factor, the potential increase in TEOR production from an additional 640 equivalent 62.5 MM Btu/hr (heat input) steam generators in central Kern County fields would be about 207,200 BOPD. On the basis of available emission offsets, about 343 equivalent 62.5 MM Btu/hr (input) steam generators could be installed in the future in western Kern County fields for Case I. Assuming a net production of 3 barrels of oil per barrel of oil burned and an 0.8 capacity factor, the potential

TABLE 1-10.

EMISSION REDUCTIONS AND RETROFIT REQUIREMENTS FOR MAXIMUM EXPANSION OF STEAM GENERATION CAPACITY IN FOUR CALIFORNIA PRODUCTION AREAS

Pollutant	Central Kern County: Emission Reduction (Tons/yr)		Central Kern County: Capacity to be Retrofit (MM Btu/hr)		Western Kern County: Emission Reduction (Tons/yr)		Western Kern County: Capacity to be Retrofit (MM Btu/hr)		Coalinga: Emission Reduction (Tons/yr)	Coalinga: Capacity to be Retrofit (MM Btu/hr)	San Ardo: Emission Reduction (Tons/yr)	San Ardo: Capacity to be Retrofit (MM Btu/hr)
	Case I	Case II	Case I	Case II	Case I	Case II	Case I	Case II				
SO_2	8,370	8,370	2,110	2,110	4,890	4,890	1,130	1,130	2,830	652	5,830	3,570
NO_x	10,010	6,320	7,060	4,460	5,370	5,100	3,790	3,600	3,090	2,180	5,450	3,840
PM	110	850	280	2,200	60	110	160	280	40	102	70	179
HC	930	12,000	20[1]	263[1]	500	1,130	11[1]	29[1]	297[1]	7[1]	524[1]	12[1]

[1] Number of wells.

TABLE 1-11.

MAXIMUM POTENTIAL EXPANSION OF TEOR PRODUCTION IN FOUR CALIFORNIA PRODUCTION AREAS

Expansion Category	Central Kern County Fields[1]	Western Kern County Fields[1]	Coalinga Field	San Ardo Field
Generating Capacity MM Btu/hr	40,000	21,400	12,400	21,800
Equivalent 62.5 MM Btu/hr Generators	640	343	198	349
Number of Production Wells	7,120	5,270	3,097	3,907
Net Oil Production (BOPD)	207,200	196,000	132,600	145,000

[1]Maximum expansion is the same for Case I and Case II.

TABLE 1-12.

MAXIMUM POTENTIAL INCREASE IN TEOR PRODUCTION BASED ON AVAILABLE EMISSION OFFSETS (PART II ANALYSES)

Production Area and Case	Maximum Potential Increase in TEOR Production Based on Available Emission Offsets		Average Annual Costs of Air Pollution Controls Required to Achieve the Maximum Increase in TEOR Production ($/Net Bbl Oil Produced)
	Additional Steam Generation Capacity Required for Maximum Production (MM Btu/hr)	Net Oil Production Increase (BOPD)[a]	
Central Kern County			
Case I (Stage I Control Level)	40,000	207,200	6.93-9.02
Case II (Stage III Control Level)	40,000[b]	207,200[b]	≈6.93-9.02
Western Kern County			
Case I (Stage I Control Level)	21,400	196,000	2.96-4.38
Case II (Stage III Control Level)	21,400[b]	196,000[b]	≈2.96-4.38
Coalinga	12,400	132,600	2.68-3.67
San Ardo	21,800	145,000	3.10-4.54
TOTAL	95,600	680,800	

[a] Net crude oil production per barrel of oil burned was assumed to be 1.7 for the central Kern County fields, 3.0 for the western Kern County fields, 3.52 for Coalinga, and 3.08 for San Ardo.

[b] Requires particulate and hydrocarbon emissions to be controlled to offset NO_x emission increases.

increase of TEOR production in western Kern County fields would be about 196,000 BOPD.

For Kern County Case II, the availability of NO_x emission offsets is expected to be most critical constraint to increasing future steam generation capacity if (1) the producers in Kern County are required to meet the Stage II Control level of Rule 425 before any NO_x offsets can be created, and (2) interpollutant offsets are not allowed. Almost all of the already permitted steam generators in central and western Kern County must be retrofit with SCR systems to meet the Stage II Control level. Direct emissions offsets would then be available for an additional 422 equivalent 50 MM Btu/hr (output) steam generators in central Kern County and 292 equivalent 50 MM Btu/hr (output) steam generators in western Kern County. As in Case I, no reductions in current SO_2, NO_x, PM, and HC emissions levels can be expected from compliance with Rule 210.1 because of the 1.0 to 1.0 emission offset ratio assumed for new projects. If interpollutant offsets are allowed, the steam generation capacity in the two production areas could be increased to the capacity given for Case I.

Assuming that interpollutant emission offsets are allowed, the capital and annual costs for installing and operating air pollution controls for Case II would be about the same as for Case I. The cost of NO_x controls are from 10 to 20 percent lower for Case II than for Case I. However, the lower costs of NO_x controls for Case II are compensated for by the increased costs for PM and HC controls needed to give interpollutant offsets for the increase of NO_x emissions. The costs of controls for Case II, on a dollar per barrel basis, are thus expected to be approximately the same as the costs for Case I.

The capital and annual costs for the air pollution control systems needed to maximize TEOR production in the

Coalinga field are 304 to 395 million dollars, and 130 to 178 million dollars per year, respectively. Using a net oil production ratio of 3.52 barrels of oil produced per barrel of oil burned and a capacity factor of 0.8, the new 198 equivalent 50 MM Btu/hr (output) steam generators in the Coalinga field would produce 132,600 BOPD (net).

The capital costs of the air pollution controls needed for the maximum increase in TEOR production in the San Ardo field are expected to be between $530 and $693 million. About 70 percent of these costs would be incurred for the NO_x control systems. The annual costs for controls of all pollutants are projected to be from 232 to 339 million dollars. If high efficiency control systems are applied to all the steam generation capacity in the San Ardo field, emission offsets would be available for an additional 349 equivalent 62.5 MM Btu/hr (input) steam generators. The maximum increase in TEOR production in the San Ardo field on the basis of emission offsets would be 145,000 BOPD (net). These numbers are based on a net production factor of 3.08 barrels of oil produced per barrel of oil burned and a capacity factor of 0.8.

In central Kern County, the average annual costs of controls needed to comply with previous NSR rules ranged from $0.51 to $1.02 per barrel of oil produced (net). These costs are expected to increase significantly for controls required to achieve the maximum increase in TEOR production, to approximately $6.93 to $9.02 per net barrel of oil produced. In western Kern County, average annual control costs for previous NSR rule compliance were $0.41 to $1.01; costs for the maximum production increase ranged from $2.96 to $4.38 per barrel of oil produced (net). In the Coalinga field, the average annual control costs for previous NSR rule compliance ranged from $1.36 to $3.15 per net barrel of oil produced, and costs of controls for the maximum increase in TEOR production rose to $2.68 to $3.67 per barrel of oil produced (net). Average annual costs for controls in the San Ardo field were $1.69 to $4.60 per barrel of oil produced (net) to comply with previous NSR rules; costs for the maximum production increase ranged from $3.10 to $4.54 per net barrel of oil produced.

An air quality impact analysis was performed for the four largest TEOR production areas in California. This analysis compared SO_2, NO_x, and PM concentrations for a 1978 Baseline Case to similar concentrations for a Maximum Increase in TEOR Production Case. The results for the central and western Kern County, Coalinga, and San Ardo production areas are discussed below.

After compliance with Case II control levels and Rule 424, SO_2 emissions from oil field equipment in central Kern County are expected to be reduced by a factor of two relative to levels for the 1978 Baseline Case. NO_2 concentrations are expected to be reduced by a similar factor. If the PM emission reductions associated with road paving are not considered, the concentration of directely-emitted PM is expected to increase by about 50 percent, but only in areas within a few miles of the oil fields. Paving of roads in the oil fields is expected to reduce PM emissions in the immediate vicinity of the fields, but the impact of road paving was not considered in the modeling analysis.

Air quality in western Kern County is expected to follow trends similar to central Kern County. SO_2 emissions are expected to be reduced to 50 percent of the 1978 Baseline Case levels. Assuming Stage III control of NO_2, the NO_2 concentrations are expected to be significantly reduced relative to the 1978 levels. Again, the impact of road paving on PM emissions was not considered.

As would be expected, the area of peak concentrations of SO_2, NO_2, and directly-emitted PM decrease slightly in the Eastside Coalinga field as controls are installed on existing steam generators in the field to offset steam generators being installed in the Westside Coalinga field. The emissions of these pollutants are also dispersed over a greater area. As new steam generation capacity is being installed with high efficiency control systems in the Westside Coalinga field, a small increase in the SO_2, NO_2, and directly-emitted particulate concentrations may occur. Even though the increase in SO_2 predicted for the Westside Coalinga area is small, the PSD increment may be major constraint to future TEOR expansion in the Coalinga field. The annual Class II PSD increment for SO_2 is 20 μg/m, which is a little higher than the SO_2 increase predicted for the Westside Coalinga field. No increase in PM concentrations is expected for the Coalinga field, even though the concentrations of directly-emitted PM are expected to increase from the 1978 Baseline Case to the Maximum Production Increase Case. The PM emissions reduction expected from road paving in the Coalinga field was not considered in the modeling exercise. The producers will probably attempt to develop the leases in the fields so that there is no net increase in emissions in order to avoid EPA PSD reviews. However, since the steam generators which are available for control to provide offsets are not in the part of the Coalinga field where new capacity is needed, this strategy may not be feasible, and the federal PSD regulations may constrain future TEOR expansion in the Coalinga field.

The SO_2 and NO_2 concentrations for the San Ardo field Maximum Increase in TEOR Production Case are expected to be 50 percent of SO_2 and NO_2 concentrations for the 1978 Baseline

Case. Again, road paving was not considered in the modeling analysis. The directly-emitted PM concentrations are expected to be slightly higher than PM concentrations in 1978.

1.8 Part III Analysis - Maximum TEOR Production Increase Achievable by 1990

Based on the sum of all the potential available emission offsets in each production area, 1990 California TEOR production was projected to have the potential to increase by 860,000 BOPD (net) over the production rate in 1978. This maximum TEOR production increase will require 96,000 MM Btu/hr of new steam generation capacity to be designed, permitted, constructed, and operated. However, the maximum TEOR production increase may be constrained because emission offsets are not evenly distributed between the individual producers. Additionally, the offsets available to a given producer may not be proportional to the oil resources available for development.

Several other constraints exist that will affect the maximum TEOR production increase achievable by 1990. Three types of environmental constraints are anticipated: air pollution control regulations, water availability, and solid waste disposal site availability. Regulatory constraints include permitting requirements, the need for high efficiency control technologies, and the availability and distribution of emission offsets.

Because permitting requirements and permitting delays represent major constraints to TEOR production expansion, the steam generation capacity with POs and ACs in 1981 is an excellent indicator of the most readily achievable potential to increase TEOR production. The amount of additional steam generation capacity that could be permitted, constructed, and operated to increase 1990 TEOR production may be determined by reviewing historical permitting trends in the light of identified constraints.

Construction and operation of all of the permitted steam generation capacity in the five California heavy oil production areas could increase TEOR production by 442,500 BOPD (net). This nearly doubles the 1978 production rate. Results of the Part III Analyses indicate that the maximum TEOR production increase achievable by 1990 is approximately equal to this production increase, unless additional increases in TEOR production are achieved by:

1) The use of more fuel-efficient steam stimulation technology, thereby reducing the amount of crude oil that must be burned (e.g., produced crude-fired downhole steam generators).

2) Increase of total (gross) heavy oil production to levels high enough to offset the increased amounts of crude oil that must be burned to raise production.

3) Use of an alternative fuel, thereby reducing or eliminating the need to burn produced crude oil.

Recommendations for actions to maximize TEOR production include economic incentive programs, removal of economic disincentives, promotion of the development of alternative fuel technologies and needed air pollution control technologies, streamlining of permitting and approval procedures, allocation of sufficient quantities of alternative fuels, and development of fuel transportation systems.

1.9 Conclusions

The results of this study indicated the following general conclusions regarding TEOR production increases in the United States:

(1) Almost 90% of the crude oil currently produced using TEOR techniques was produced in California. Kern County currently produces 90% of the TEOR crude oil in California and is projected to produce nearly 90% of the national TEOR crude oil by 1990.

(2) The maximum TEOR production projected to be achievable by 1990 is approximately equal to the maximum level of production that could be achieved by the steam generators which already have permits. Construction and operation of all the permitted steam generation capacity in the five California production areas could increase TEOR production by 442,500 BOPD (net). This nearly doubles the 1978 production rate.

(3) Under the present regulatory conditions, large-scale expansion of California TEOR production by 1990 is not expected to be achievable. The regulatory constraints to significant expansion of TEOR production in California include delays in obtaining permits and the level of air pollution control required. Permitting, constructing, and operating a significant increase in total steam generation capacity may require as long as seven

years, once necessary air pollution control systems are commercially available. Commercial availability of high efficiency NO_x and particulate control systems is not expected until the mid-1980's.

(4) Since 1978, a large amount of steam generator capacity has been permitted in Kern County. However, most of this new steam generator capacity has yet to be constructed because of the producers' inability to comply with the EPA's PM offset requirements and the Kern County APCD's retrofit rules.

(5) If the ambient NO_2 concentrations in Kern County deteriorate to levels near or above the national ambient air quality standards, most of the steam generation capacity recently permitted in Kern County will have to be shut down and existing steam generators retrofitted with high-efficiency NO_x control systems. Since the required level of NO_x control can not be achieved through commercially available control systems, many existing steam generators may also have to be shut down.

(6) The Kern County APCD retrofit rules (i.e., Rules 424, 425, and 411.1) have substantially increased costs of producing crude oil using existing steam generation capacity. These retrofit rules may preclude a large-scale expansion of TEOR production in the next few years as a result of the costs of retrofit rules.

(7) The lack of commercially available high-

efficiency NO_x control systems is expected to delay the Kern County producers' ability to comply with Kern County APCD's NO_x retrofit rules. Similarly, this lack of commercially available NO_x control systems is expected to significantly delay future TEOR expansion.

(8) The lack of high-efficiency particulate control technology for crude oil-fired steam generators is expected to delay operations of many permitted steam generators. Expansion of TEOR production will require the development and commercial availability of high-efficiency particulate control systems.

(9) The availability of solid waste disposal sites for SO_2 scrubber wastes is expected to become a major constraint to complying with the Kern County APCD SO_2 control rule (i.e., Rule 424). Estimates indicate that current waste disposal site capacities will be exceeded as a result of the oil producers complying with Rule 424. Additional new steam generators will further increase the demand for waste disposal capacity.

(10) The costs of air pollution control systems have drastically increased during the last two years. These costs are expected to provide a large economic disincentive for future TEOR production expansion. The average annual costs of air pollution regulations under previous new source review requirements ranged between \$1.69 and \$4.60 per net barrel of oil produced by TEOR techniques. These costs are expected to increase substantially due to

the higher level of control required for both new and existing steam generators in the Maximum Increase in TEOR Production Case, to approximately \$2.68 to \$9.02 per net barrel of oil produced.

(11) Maximizing 1990 TEOR production will require either an increase in gross TEOR production or a reduction in the amount of crude oil burned in steam generators. As previously concluded, increased gross TEOR production may not be possible. Consequently, increases in crude oil production will most likely come from increasing net production. Net crude oil production may be increased by using alternative fuels, such as natural gas, coal, or synfuels, in TEOR steam generators.

2.0 INTRODUCTION AND METHOD OF ANALYSIS

2.1 Introduction

U.S. oil production continues to decrease as production resulting from natural forces and water flooding declines. New, more sophisticated production methods must be used to recover the remaining oil. Enhanced oil recovery techniques are expected to provide much of the future U.S. production. In the near future, steam processes and in situ combustion are expected to be the largest contributors to increases in enhanced oil recovery. Thermal enhanced oil recovery (TEOR) methods will be used to recover heavy oil reserves that generally could not be recovered by other techniques.

Most of the U.S. heavy oil reserves are in southern California. Sixty percent of the oil recovered by TEOR methods in 1977 was from the southern portion of the San Joaquin Valley in Kern and Fresno Counties. The other major potential California TEOR production areas are in the Los Angeles Basin, Monterey County, and along the California Central Coast. Ninety percent of the future U.S. TEOR production is expected to be supplied by these California reserves. Some of the heavy oil reserves in Arkansas, Texas, and Louisiana may also be developed.

In the past, regulated oil prices and strict air pollution control regulations have constrained TEOR production of heavy oil. In 1978, the President of the United States decontrolled heavy oil prices, thereby encouraging TEOR production. In the last few years, many new air pollution control requirements have been established for TEOR facilities. Local and state air pollution control agencies have been adopting and implementing regulations to meet the Clean Air Act requirements for areas not meeting the federal primary air quality standards. These regulations require controls on existing as well as new TEOR facilities. In addition, the Environmental Protection Agency has been administering New Source Review (NSR) regulations and Prevention of Significant Deterioration (PSD) regulations, which also include environmental requirements for TEOR facilities.

Prior to the late 1970's, few air pollution control systems were required on TEOR facilities in most of California. Recently, the local air pollution control agencies have adopted rules which require field-wide reduction of emissions from TEOR facilities. These emissions reductions not only increase the costs of maintaining current TEOR production, but also reduce the emission offsets available for future TEOR projects.

In addition, the local districts have adopted new source review rules which establish the preconstruction review requirements for future TEOR facilities. These rules require stringent controls on new facilities and emission reductions for most pollutants which would be emitted from new TEOR facilities.

2.2 The Present Study

The purpose of this two and one-half year study is to assess the impact of air pollution control regulations on the costs of TEOR production and future TEOR potential production. This volume (Volume I) summarizes the findings of the study. The appendices to Volume I are included in Volume II. The report entitled, The Impact of Proposed NO_x Control Regulations on Thermally Enhanced Oil Production in Kern County, is presented in Volume III. Volume IV contains the report entitled, The Cost of Non-Attainment Plans on Existing TEOR Production, along with associated appendices.

2.3 Method of Analysis

Air pollution control regulations have a significant impact on the costs of TEOR production and the future TEOR production potential. In the recent past, lengthy permitting processes, limited control system availability, and costly control system requirements have complicated regulatory compliance and constrained production expansion. Some producers claim they cannot install new TEOR production facilities in southern California heavy oil fields because the emissions offsets (i.e., emission reductions from already permitted facilities) needed for new TEOR facilities are not available. It is anticipated that the costs of air pollution control systems required for future TEOR projects will also preclude the development of some of the heavy reserves in California. In order to achieve a large increase in TEOR production in the future, high efficiency air pollution control systems will have to become commercially available at reasonable costs.

The nine steps used to assess the impact of air pollution control regulations on TEOR production are:

1) Characterize TEOR production technology and surface facilities.
2) Select the production areas for detailed analyses.
3) Determine the air pollution control rule and regulation requirements.
4) Assess the state-of-the-art air pollution control technology.
5) Estimate the cost of controls to comply with the previous new source review rules and retrofit rules.
6) Estimate the maximum potential increase of TEOR production on the basis of emission offsets.
7) Calculate the costs of air pollution control

requirements for the maximum increase in TEOR production.

8) Analyze the change in air quality resulting from compliance with new source review requirements and retrofit rules.

9) Project the maximum TEOR production achievable by 1990 in view of all logistical constraints.

In this volume of the report, Section 3.0 briefly discusses three TEOR technologies: the cyclic steam process, the steam drive process, and in situ combustion. Section 4.0 discusses the production areas selected for detailed analysis of the impacts of air pollution control regulations on TEOR production. Each field or group of fields is considered separately. The air pollution control rules and regulations with which TEOR facilities must comply are summarized in Section 5.0. Section 6.0 assesses the state-of-the-art air pollution control technology applicable to TEOR production facilities. In Section 7.0, the Part I Analyses, the cost impact of previous new source review rules and retrofit rules is estimated for four production areas. Section 8.0 estimates the maximum increase in TEOR production that may be achieved via emission offsets (the Part II Analyses). In Section 9.0, the Part III Analyses, the maximum TEOR production achievable by 1990 is projected, based on the air permit process and the projected control system requirements.

The technical notes on NO_x control systems, particulate matter control systems, and the dispersion modeling study are presented in the appendices contained in Volume II.

3.0 TEOR TECHNOLOGIES AND RELATED EMISSIONS

A number of enhanced oil recovery (EOR) techniques which use different mechanisms to produce heavy oil are in various stages of development. However, thermal EOR (TEOR) is the most successful EOR technique to date, and the technique most likely to achieve large increases in oil recovery during the next few years. TEOR involves the addition of heat to the reservoir to increase oil recovery, principally by reducing the viscous forces which restrict the flow of oil through the reservoir to the production well.

Typically, two different methods are used for adding heat to the reservoir: steam stimulation* and in situ combustion. Steam stimulation involves injection of heat generated on the surface into the reservoir. In situ combustion involves the generation of heat within the reservoir by burning some of the oil in place. The combustion process is sustained by injecting compressed air into the reservoir.

3.1 Steam Stimulation Processes

Steam stimulation, the most common method of thermal EOR, results in approximately 90 percent of the national TEOR production. Heat generated on the surface in steam generators is injected into the reservoir in the form of steam and hot water. Usually produced crude is burned as fuel in the steam generators used in TEOR.

There are two steam stimulation processes: steam drive and cyclic steam. In the steam drive process, steam is injected continuously into central injection wells, and oil is recovered from surrounding producing wells. In the cyclic steam process, individual producing wells are alternately steamed and returned to production. Cyclic steam is sometimes

* Steam injection processes are commonly referred to as steam stimulation.

considered merely a stimulation technique and not an EOR process. However, there are many similarities between cyclic steam and steam drive. The two processes are often used sequentially and even simultaneously in the same production pattern so that estimating individual production by each process is difficult. Both processes produce oil in similar ways and use similar equipment. For these reasons, both are considered to be EOR processes in this study.

3.1.1 Steam Drive Process

In a steam drive project, steam is injected continuously into the producing formation through injection wells. An injection well may be a converted producing well or a well drilled and completed especially for steam injection. The flow of the oil is from the injection to the producing wells. The relative locations of injection and producing wells is called the steam drive pattern. Typically, a single pattern in a steam drive project may occupy from 2½ to 5 acres. A project may consist of many contiguous patterns and may cover an entire oil field. Kern River has several large steam drive projects. A five spot pattern, which is common in Kern River, consists of a central injection well surrounded by four production wells. Midway Sunset has more irregular patterns, due primarily to the gradual slope of many of the production reservoir sands.

A steam drive project will have an initial high steam/oil (S/O) ratio which will decrease with time. An injection well may be steamed for as long as two years before an increase in crude production becomes evident. The S/O ratio will then level out with time. Eventually, the S/O ratio will again rise until the project becomes uneconomical. The S/O ratio for steam drive projects in the Kern River and Midway

Sunset fields is about five barrels of steam injected to one barrel of oil produced. The average injection rate for steam drive injection wells in Kern River and Midway Sunset is about 100,000 barrels of steam per well per year.[1]

3.1.2 Cyclic Steam Process

Cyclic steam operation, sometimes called steam soak, involves: (1) injecting steam into a production well; (2) allowing the steam to condense, thereby heating the reservoir; and (3) producing the heated oil. This sequence of events is repeated when production drops significantly. More steam per barrel of crude produced is required for each successive cycle. In most cases, it is economically beneficial to eventually convert cyclic steam projects to steam drive projects. However, the economics of conversion are dependent upon factors such as the age of the project and the natural temperature of the reservoir.

The Midway Sunset field has a significant amount of cyclic steam production. Some Midway Sunset cyclic steam operations have been converted to steam drive, but many cyclic steam projects remain successful due to high natural reservoir forces. In 1977, 64 percent of steam used in Midway Sunset was for cyclic steam operations. This is compared to only 15 percent used for cyclic steam during the same period in Kern River.[1]

3.1.3 Atmospheric Emissions

Two categories of emissions are associated with TEOR production: the first category results from combustion operations used to either generate steam or treat the produced crude oil, and the second category results from noncombustion equipment associated with oil production.

---

[1] Source: California Division of Oil and Gas, Private communication with W. R. Hearn, Radian Corporation, September 1979.

Considerable emissions to the atomsphere result from combustion sources in TEOR fields. The primary source of these emissions is the steam generating equipment which burns a portion of the produced crude. Emissions also result from other oil-fired crude processing equipment, such as crude heaters and heater treaters, and from various types of gas-fired equipment.

The major piece of equipment used in steam injection projects is the once-through steam generator. This device, which was specifically developed for use in the oil fields, is shop-fabricated and then shipped to the site. The unit is generally skid-mounted and requires only fuel, water, and electrical connections. Generators are commonly sold in sizes of approximately 25 MM Btu/hr and 50 MM Btu/hr rated steam output. They are forced-circulation water tube boilers, normally designed to deliver an 80 percent quality steam at pressures up to 1500 psig. Some units are capable of pressures up to 2500 psig. They are generally oil-fired, burning part of the heavy crude produced. A steam generator schematic flow diagram is provided in Figure 3-1.

Depending on the fuel composition and combustion conditions, various pollutants are emitted to the atmosphere when the crude oil is burned. The major pollutants from oil-fired units are sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter (PM). In gas-fired units, the only major pollutant is NO_x. Other pollutants emitted in smaller quantities from combustion sources include hydrocarbons (HC), carbon monoxide (CO), and minute amounts of other compounds.

The quantity of SO_2 (SO_x is mostly SO_2 with some SO_3) emitted is directly related to the fuel sulfur content and can be directly calculated from this variable by assuming complete conversion of fuel sulfur to SO_2. The sulfur contents

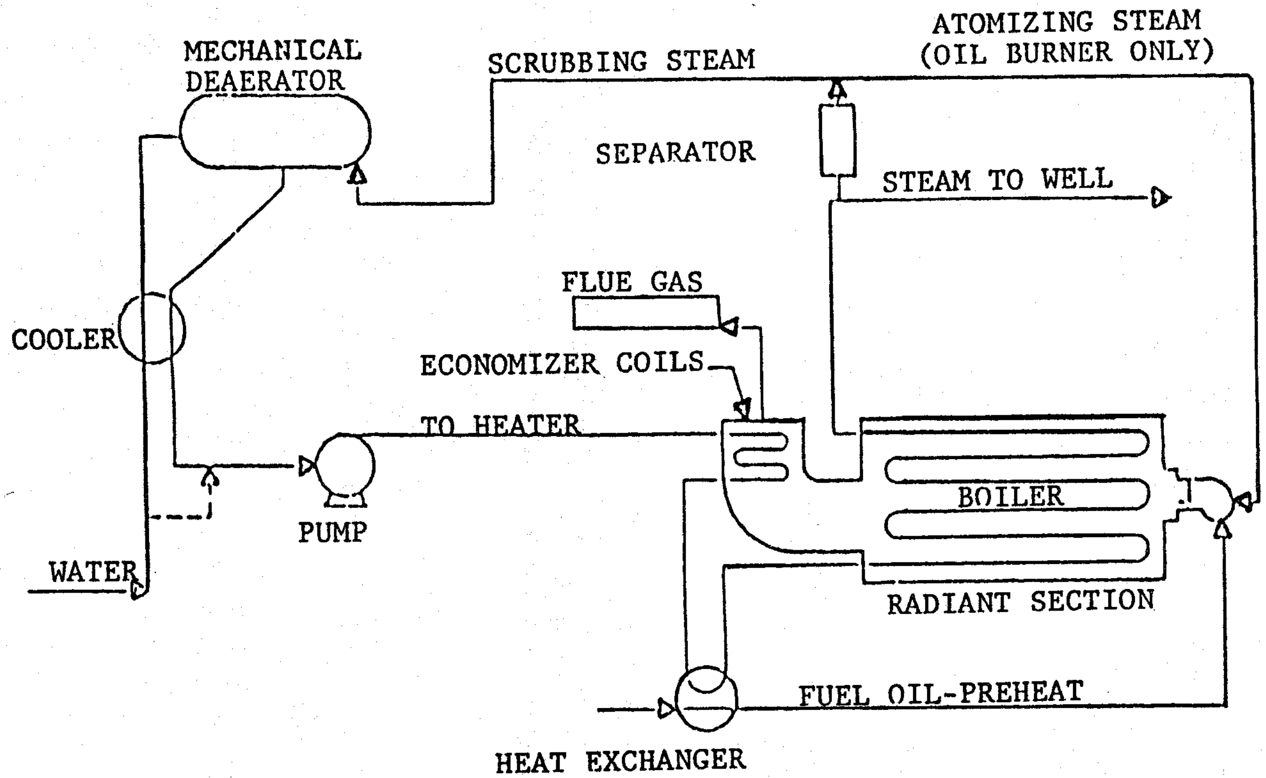


FIGURE 3-1.

SCHEMATIC FLOW DIAGRAM FOR THERMO-FLOOD 50 MM BTU/HR STEAM GENERATOR.

(Source: California Air Resources Board) of crude oils used as a source of fuel typically range between 1.1 and 1.5 percent by weight. The quantities of other pollutant emissions cannot be calculated directly from fuel properties. These emissions are often dependent on the conditions under which combustion takes place and on fuel properties (e.g., ash content, nitrogen content, etc.). Therefore these emissions must be estimated on the basis of experience with similar combustion devices and similar quality fuels. The predominant size of the particulate matter in the uncontrolled flue gas is expected to be less than 3μ.

The wellhead casing vents on production wells associated with steam drive projects are expected to be a large source of HC emissions. Steam which does not condense in the reservoir travels to the surface through the tubing-casing annulus with hydrocarbon vapors and possibly some entrained hydrocarbon liquid. The venting of this annular space prevents any significant back-pressure increase in the producing zone. This allows for greater fluid entry into the production tubing and, therefore, greater oil production. However, air contaminants are also released.

Another source of hydrocarbon emissions related to crude oil production activities is evaporative loss from storage tanks. Tank emissions result from breathing losses (static fluid) and working losses (fluid movements in and out of tanks). The oils produced by thermally enhanced techniques exhibit very low vapor pressures under normal storage conditions. This reduces the potential for large evaporative losses, such as those which occur with lighter, conventionally produced crude oil. Crude oil storage tanks are usually somewhat scattered around the heavy oil fields. Tanks (1000 to 5000 barrel capacity) are generally found in groups of 3 to 6 tanks called "batteries". These tanks aid in measuring the quantity of crude produced and serve as intermediate tankage between the producing well and pipeline transportation.

Fugitive emissions also add to the total amount of hydrocarbons emitted to the atmosphere. Sources of these emissions include leaks from oil field piping, valves, flanges, pump and compressor seals, and water-oil separators.

Storage tank and fugitive hydrocarbon emissions are not considered further in this study because the quantity of these emissions is significantly less than the quantity of wellhead hydrocarbon emissions.

3.2 In Situ Combustion Processes

In situ combustion processes involve the combustion of a portion of the reservoir crude oil in place to provide heat to reduce the vicosity of the crude oil and thereby promote the movement of the oil towards the production wells. Two types of in situ combustion processes have been used. The first type relies on "forward" combustion, where a narrow combustion zone advances in the same direction as the flow of oil. The second type relies on "reverse" combustion where the flow of oil is in the direction opposite the advancing combustion zone. In both cases, the combustion process is sustained by injecting combustion air into the reservoir.

Two categories of air emissions may occur. The first category consists of the exhaust emissions resulting from the combustion of fuel to power the air compressor (unless it is electrically powered). The second category includes combustion air contaminants which are released from the production well along with the produced crude.

4.0 SELECTION OF PRODUCTION AREAS FOR DETAILED ANALYSES

The costs of TEOR production and future TEOR production potential are dependent on several factors: the specific air pollution control regulation requirements, the production from existing TEOR facilities, and the allowable emission rates. Due to the variability of these factors for the areas with TEOR production potential, the analysis of a single production area will not provide sufficient information to assess the impact of the regulations.

For this study, seven fields were selected for detailed analyses. Of the seven fields selected, five are in California; California encompasses the largest heavy oil production areas using TEOR techniques in the United States. In addition, heavy oil produced mainly by TEOR techniques represents over one-half of California's total crude oil production. The other two fields selected for study are in Texas and Arkansas.

The California fields selected as part of this study were the central Kern County fields, the western Kern County fields, the Coalinga field, the San Ardo field, and the Los Angeles Basin fields (see Figure 4-1). The central and western Kern County fields are each a combination of several TEOR fields, but for the purposes of this analysis they were considered as only two fields. The Kern River field in central Kern County, the Midway Sunset field in western Kern County, and the San Ardo field are the three major TEOR fields in the country at this time. Combined production from these three fields was about 70 percent of the national TEOR production in 1977. The Coalinga field represented approximately 1.4 percent of the national TEOR production in 1977, and it is expected to expand TEOR production to represent 5.7 percent in 1990. Approximately 80 percent of the projected 1990

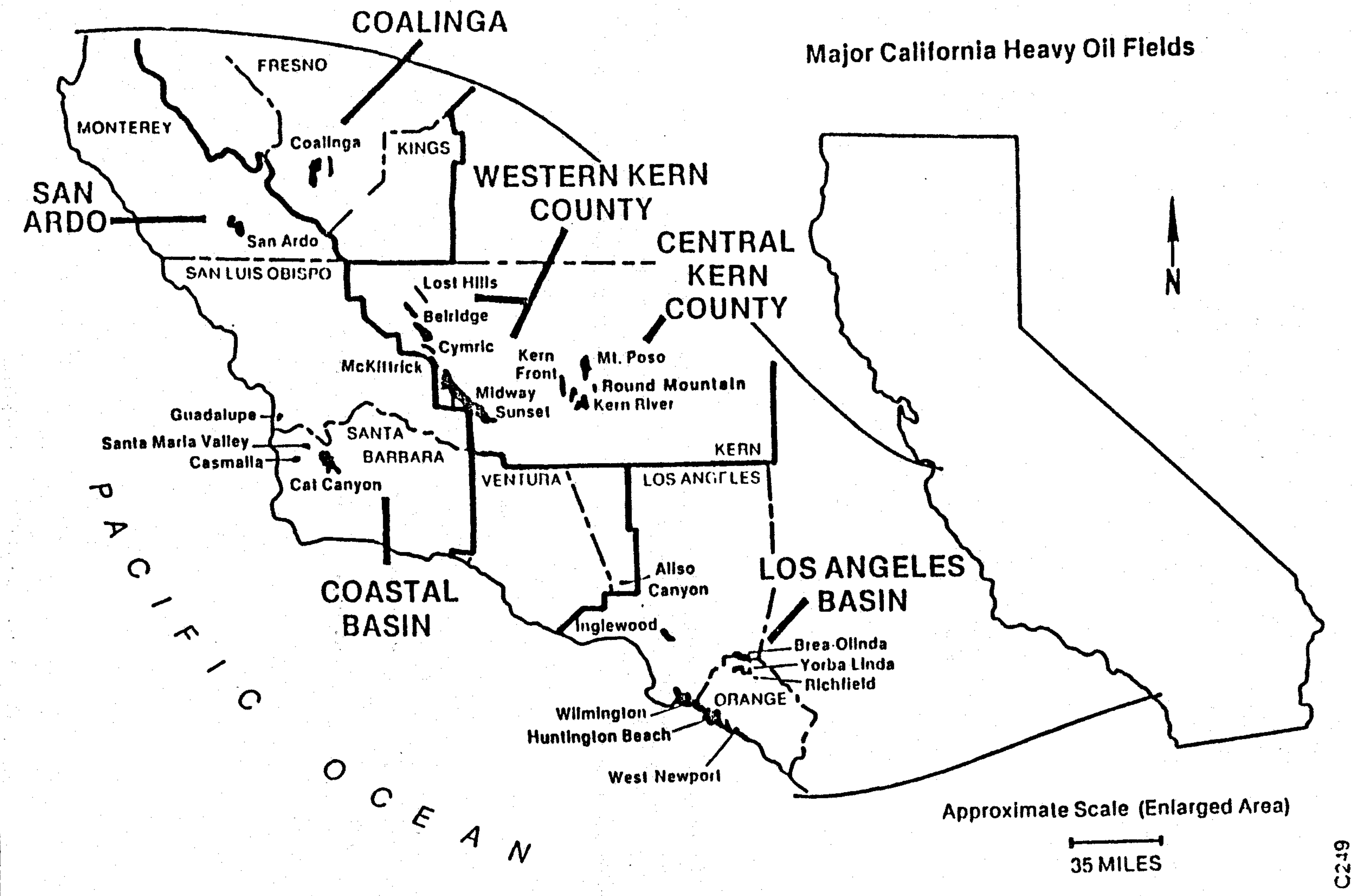


Figure 4-1. Locations of the California Heavy Oil Fields Selected for Detailed Analyses in this Study.

national TEOR production from steam drive projects will be produced in the central Kern County fields, the western Kern County fields, the Coalinga field, and the San Ardo field.

Heavy oil production in the Los Angeles Basin fields and Central Coast fields represented approximately 7 percent of the 1977 national heavy oil production. The Los Angeles Basin fields were selected for detailed analyses because they contain large oil reserves potentially amenable to TEOR methods. A study funded by DOE projected that the Brea Olinda field and West Newport fields would be capable of large production increases through the application of in situ combustion technology.[1] The Wilmington field and other fields appear to have vast reserves amenable to TEOR and other enhanced oil recovery technologies.

The two fields selected for this study which are not in California are the Slocum field in Texas and the Smackover field in Arkansas. Although their current and expected TEOR production levels are not high compared to California fields, these two fields are representative of TEOR fields in which expansion will be limited by the EPA's PSD regulations.

The following subsections describe the seven fields selected for detailed study.

4.1 The Central Kern County Fields

The Kern River field is on the northern border of Bakersfield, California, on the east side of the San Joaquin Valley. The field covers about 10,000 acres in 28 sections. Getty Oil began the first TEOR production in the field in 1961 and has expanded to cover most of the Kern River field. Getty Oil and Chevron control about 80 to 90 percent of the TEOR production

[1] Source: Vello Kuskra, "Discussion of Thermal Oil Recovery Opportunities in California", Lewin and Associates, Washington, D. C., 1977.

in the field, but Santa Fe Energy and Shell also have some TEOR production in the field. The producing sands are called the Kern River Series and range from 500 to 1300 feet in depth. The oil gravity ranges from 12^{o} to 16^{o} API. In 1977, about 55,000 BOPD and 17,000 BOPD were produced by steam drive and steam soak, respectively. This 72,000 BOPD represented 32 percent of TEOR production in California and 31 percent of national TEOR production by steam drive and steam soak methods in 1977.

Other central Kern County fields include the Mount Poso and Kern front fields. The Mount Poso field is about two miles north of the Kern River field while the Kern front field is contiguous with the Kern River field's west boundary. In 1977, the Mount Poso field produced 11,000 BOPD by steam drive and the Kern front field produced 3,000 BOPD by steam soak. Most of the steam generating capacity in other central fields is distributed among many small producers. However, Shell and Chevron control more capacity than the other producers. Of the major TEOR producers in Kern County, only Shell has most of their oil-fired equipment in other central fields.

4.2 The Western Kern County Fields

The major TEOR fields in western Kern County are the Midway Sunset and Belridge fields. The Midway Sunset field is a narrow field 30 miles southwest of Bakersfield, California. The field covers about 58,000 acres in 82 sections and runs along the bottom of the Temblor Range on the west side of the San Joaquin Valley. It is a little over 3 miles wide at its widest point, and is about 29 miles long. The ownership of the field is shared by seven major oil companies, several minor oil companies, and many independents.

Ninety-six percent of the existing production from the Midway Sunset field comes from the shallow sands of the field, which range from the Tulare formation to the Reed Ridge of the

Monterey formation. The depth of the formation ranges from 200 to 4,500 feet. The oil gravity varies from 12° to 26° API, and averages about 16° API. The 1977 production by steam drive reported to the Oil and Gas Journal was 15,000 BOPD.[1] The steep incline of some parts of the formation allows gravity drainage of the oil to the production wells for cyclic steam operations. In 1977, 45,000 BOPD were produced from this field by cyclic steam. Production from the Midway Sunset field represented 26 percent of the TEOR production in California and 25 percent of U.S. TEOR production for steam drive and cyclic steam techniques in 1977.

Western Kern County fields include the Belridge, Cymric, and McKittrick fields, all of which are north of the Midway Sunset field. Belridge field produced 9,000 BOPD by steam drive in 1977. Cymric and McKittrick fields used steam soak methods to produce 1,000 and 5,000 BOPD, respectively, in 1977. The ownership of other western fields is similar to the Midway Sunset field in that it is shared by major, minor, and independent oil companies. Most of the TEOR production in western Kern County fields is the result of cyclic steam (steam soak) operations.

The Midway Sunset field, the largest heavy oil producer in the United States, has nine billion barrels of reserves. Until now, only one billion barrels of the original ten billion have been recovered. Because of its vast reserves, the Midway Sunset field is a key field in the U.S. program to expand enhanced oil production and reduce the demand for foreign oil supplies.

4.3 Coalinga Field

The Coalinga oil field is in the San Joaquin Valley

[1] Source: Dave Noran, "Growth Marks Enhanced Oil Recovery", Oil and Gas Journal, March 23, 1978.

about 50 miles southwest of Fresno, California. The field covers 12,500 acres in 27 sections and consists of two parts, commonly known as the Eastside and Westside. Most of the thermal production is expected in the Westside, which is nine miles long and about one-half mile wide. The depths of the producing sands range from 500 to 3,500 feet. The average oil gravity is about 13° API, but it varies from 11° to 18° API.

In 1978, the Coalinga oil field produced about 3,600 BOPD from steam soak. Conversion of the field to steam drive and expansion of the field are expected within the next few years. The ownership of the Coalinga field is diverse, but the major TEOR producers are Chevron, Santa Fe Energy, and Shell.

4.4 San Ardo Field

The San Ardo field is about 60 miles southeast of Salinas, California, in the Salinas Valley. The field is much more compact than the Coalinga and Kern County fields; it covers 28,000 acres in 16 sections.

The producing sands of the reservoir are the Lombardi (the upper sand) and Aurignac (the lower sand). The Lombardi sand ranges from 1,800 to 2,300 feet in depth, while the Aurignac sand ranges from 2,100 to 2,600 feet. The oil gravity ranges from 10° to 13° API. The majority of the field is owned by Texaco and Mobil. The 1977 TEOR production of 38,000 BOPD from the San Ardo field was produced primarily in the Texaco sections.

4.5 The Los Angeles Basin Fields

The major potential TEOR producers in the Los Angeles Basin are the Wilmington field, the Brea Olinda field, and the Huntington Beach field. The Wilmington field is in Los Angeles

County in the Los Angeles and Long Beach Port areas. Much of this field is offshore and is divided into numerous producing areas on the basis of fault blocks. Many producing zones exist within each area, but the principal heavy oil reserves amenable to TEOR technologies are the two uppermost zones, the Tar and the Ranger. These zones have undergone extensive water flooding (a secondary production technique) since 1960. In 1978, enough steam generator capacity was permitted for the Wilmington field to potentially produce about 2,000 BOPD. A few small steam generators have been permitted to pilot test steam drive in other fault blocks of the field.

The Brea Olinda field covers about 2,300 acres in the northern part of Orange County, California. Union Oil Company owns and produces oil from 700 acres of property in the Brea Olinda field. Waterflooding proved unsuccessful on this property due to reservoir characteristics. Cyclic steam injection caused some stimulation of oil production; however, cyclic steam injection was discontinued due to costs. Union Oil Company began an in situ combustion project in one fault block in 1972 and in an adjacent block in 1973. Two injection wells are operated. A compressor supplies about 5 MM SCF of air per day at 1200 psig to the injection wells. Fireflooding has proved to be technically and economically successful in this portion of the Brea Olinda field. The fireflood is in First Miocene sands which consist of interlayered sands, siltstones, and shales. A system of faults divide the oil sands into blocks. The producing oil sands are 3,400 to 3,700 feet deep and they dip at a 45-degree angle. Gravity of the oil is about 22° API.

Cyclic steam injection began in the Huntington Beach field in 1964. In 1977, heavy oil production by TEOR methods was 1500 BOPD. Presently about 800 MM Btu/hr of steam generation capacity is being installed in the field to expand TEOR production.

4.6 Slocum Field

The Slocum field is in southern Anderson County in northeast Texas. Oil recovery in the field by primary methods has been marginal due to the high viscosity of the oil at reservoir temperatures. Since discovery of the Slocum field in 1955, only about one percent of the original oil in place has been recovered by primary methods. Shell Oil started a TEOR pilot project in 1964. Favorable results from the pilot project caused Shell to expand its TEOR production facilities.

Oil produced in the Slocum field comes from the shallow Carrizo formation which ranges from 500 to 600 feet deep. Throughout the field, a water sand underlies the oil sand. The oil accumulation is bounded by a fault on the north and by the oil-water contact on the other sides. The TEOR method used in this field involves injecting steam directly into the underlying water sand. Oil gravity in the Slocum field is about 19^{o} API.

4.7 Smackover Field

The Smackover field is north of El Dorado, Arkansas, in Union and Quachita Counties. Phillips Petroleum Company started a steam injection pilot project in 1964 after production from primary methods decreased considerably. Based on the pilot project results, a 1,000 acre commercial project was started in 1970 by uniting seventeen individual oil and gas leases. In recent years, TEOR production from the Smackover field has dropped and steam injection has been reduced.

The producing sands are called the Nacatosh sands and their depth ranges from 1,900 to 2,040 feet deep. The formation consists of three general zones, each zone having different producing and lithologic properties. Sand permeability and interbedded shale and sandstone layers vary from zone to zone. The reservoir has a water-bearing zone below the producing sands. Oil gravity in the Smackover field is about 19^{o} API.

5.0 AIR POLLUTION CONTROL REGULATIONS

The cost of TEOR production can be significantly affected by air pollution control regulations. The requirement of additional controls on existing sources or extensive controls on proposed new sources, and the time necessary for regulatory reviews of construction permit applications, can affect the economic feasibility of TEOR facilities. The purpose of this section is to describe briefly the air pollution control regulations applicable to TEOR production.

5.1 Federal Regulations and Regulatory Framework

The federal Clean Air Act (CAA), as amended in 1970 and 1977, is the primary driving force behind air pollution control regulations today. The U.S. Environmental Protection Agency (EPA) developed National Ambient Air Quality Standards (NAAQS) for various pollutants under the authority of the 1970 CAA. Present NAAQS are given in Table 5-1.

Although the NAAQS were intended to include an adequate margin to protect public health, individual states may adopt more stringent standards. In California, this has occurred for several pollutants, as illustrated in Table 5-1.

The entire U.S. has been categorized as either attaining or not attaining each of the NAAQS. Those areas which do not meet a particular NAAQS are designated as non-attainment areas for that pollutant, whereas those which meet a NAAQS are designated as attainment areas. As a result, an area may be an attainment area for some pollutants and a non-attainment area for others. Furthermore, some pollutants, called precursors, are subject to air pollution control regulations because they lead to the formation of one or more of the NAAQS pollutants. For example, hydrocarbons (HC) and oxides of

TABLE 5-1.

NATIONAL AND CALIFORNIA AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time[a]	NAAQS[b]				CAAQS[c]	
		Primary		Secondary			
		ppm	μg/m³	ppm	μg/m³	ppm	μg/m³
TSP	12 Months (Geometric)		75		60		60
	24 Hour		260		150		100
SO_2	12 Months	0.03	80	-	-	-	-
	24 Hour	0.14	365	-	-	0.05[d]	131[d]
	3 Hour	-	-	0.5	1,300	-	-
	1 Hour	-	-	-	-	0.05[d]	1,310[d]
NO_2	12 Months	0.05	100	0.05	100	-	-
	1 Hour	-	-	-	-	0.25	470
H_2S	1 Hour	-	-	-	-	0.03	42
CO	12 Hour	-	-	-	-	10	11,000
	8 Hour	9	10,000	9	10,000	-	-
	1 Hour	35	40,000	35	40,000	40	46,000
O_3	1 Hour	0.12	240	0.12	240	0.10	200
Pb	3 Months		1.5	-	-	-	-
	30 Day	-	-	-	-	-	1.5
Sulfate	24 Hour	-	-	-	-	-	25[d]

[a]Arithmetric averages unless otherwise indicated.

[b]National Ambient Air Quality Standards.

[c]California Ambient Air Quality Standards.

[d]California standard that the California courts repealed in 1980.

nitrogen (NO_x) are considered precursors to ozone and particulate matter. However, control strategies for these precursor pollutants differ significantly among the various control agencies.

The CAA requires that each state government develop and implement a plan to achieve and maintain the NAAQS. This plan, the state implementation plan (SIP), contains state regulations and other control measures necessary to demonstrate attainment or maintenance of the NAAQS. These measures may include motor vehicle, stationary, and area source emission reduction strategies, in addition to preconstruction review requirements for new stationary sources. These SIPs must be periodically revised so as to assure continued progress toward achievement of the standards.

State governments have the primary responsibility for attaining and maintaining the NAAQS. However, if a state has an inadequate SIP, or fails to adequately implement its SIP, the EPA can take actions necessary for the achievement of the standards. On the other hand, the state may delegate responsibility for the control of both new and existing stationary sources to local air pollution control agencies. In California, local agencies are responsible for much of the SIP requirements; in other states, local agencies may not have a major role in the SIP requirements. Depending on the locale, all three levels of government (local, state, and federal) may have CAA or SIP jurisdiction.

Air pollution control regulations fall into three general categories: 1) new source review (NSR) regulations - preconstruction requirements for sources in areas where pollutants do not meet NAAQS; 2) retrofit rules - control requirements applicable to existing sources only; and 3) Prevention of Significant Deterioration (PSD) - preconstruction requirements for sources in areas where pollutants meet the NAAQS. The two categories of rules applicable to new sources (i.e., preconstruction requirements) are described below in more detail with special emphasis on their relationship to TEOR production. Retrofit rules will be discussed for the major TEOR production areas in the latter part of this section.

5.1.1 Non-Attainment Area Requirements

The objective of the non-attainment area requirements is to provide mechanisms and strategies for attaining the NAAQS for total suspended particulate (TSP), SO_2, NO_x, and ozone by 1982 in areas where the NAAQS are exceeded. However, an extension of the CO and ozone standards until 1987 may be allowed under special circumstances.

The 1977 Amendments to the Clean Air Act required submittal of SIPs to the EPA by July 1, 1979. EPA's SIP requirements were amended on August 7, 1980, in light of the Alabama Power Company versus Costle (EPA) court decision. Incorporation of the new provisions into the SIPs was required by May 7, 1981.

For stationary sources, the SIP control measures include two regulatory mechanisms. The first is the preconstruction review of new or modified sources, commonly known as new source review (NSR). In general, the level of control required of a new or modified source is a function of its size. The second mechanism involves control strategies which require that retrofit controls be installed on existing sources (retrofit rules). Control levels for existing sources are a function of the cost effectiveness of a specific control technology relative to other control technologies. In order to attain and maintain the NAAQS, these two stationary source control approaches, in conjunction with mobile and area source control methods, must result in air quality improvement.

5.1.1.1 SIP Requirements for Areas Which Can Show Attainment of NAAQS by 1982

Those areas designated as non-attainment which can show attainment of NAAQS by 1982 must include preconstruction review requirements (the NSR regulations) for all new or modified stationary sources which are determined to be "major". Major stationary sources are generally only those sources which have the "Potential to Emit" greater than 100 tons per year of specified pollutants. The original definition of "Potential to Emit" did not take into account the controls which were to be installed on the new source. The Alabama Power Company versus Costle (EPA) decisions, in part, resulted in the "Potential to Emit" being defined as emissions after controls. The revised SIPs must include provisions for major sources which satisfy the following three requirements:

- the applicant must demonstrate that all other sources owned or operated by the applicant in the state are in compliance with all requirements of the CAA;
- the applicant must install controls which reflect the lowest achievable emission rates (LAER) for those sources; and
- the emissions after control must be offset by reduction in emissions from existing sources or within the respective emission growth allowances so that a net air quality improvement will result. The offset provisions must address not only directly emitted pollutants but also EPA-identified precursors to any pollutants which do not achieve the NAAQS.

In addition to requirements imposed on new or modified stationary sources, reasonably available control technology

(RACT) may be required on existing sources in order to reduce existing emissions which contribute to a non-attainment area's pollutant levels.

5.1.1.2 SIP Requirements for Areas Which Cannot Show Attainment of NAAQS by 1982

If a state can demonstrate to the satisfaction of the EPA Administrator that the primary NAAQS for ozone and/or CO cannot be met by December 31, 1982, despite the implementation of all reasonably available measures, an extension to December 31, 1987, may be granted. Most of the larger metropolitan areas, particularly in California, have requested extensions to 1987 because compliance by 1982 is impossible. The granting of an extension to 1987 results in the imposition of additional non-attainment area requirements. The non-attainment area requirements that must be met by the state include:

- the State must implement all reasonably available control measures on existing sources;
- the state must demonstrate reasonable further progress towards achievement of the primary NAAQS;
- the state must identify and qualify growth allowances for new or modified sources;
- the state must analyze alternative sites, processes, and controls for proposed new or modified sources;
- the state must implement a motor vehicle inspection and maintenance program; and
- the state must implement a permitting system which requires that alternative sites for the major new or modified stationary sources be analyzed.

The requirements that stationary sources must meet do not differ from those discussed in Section 5.1.1.1.

5.1.1.3 Federal Sanctions

The CAA as amended in 1977 includes provisions for the imposition of federal sanctions in the event that the NAAQS are not achieved in a state where transportation control measures are deemed necessary and the governor has failed to submit an implementation plan which includes all the elements required by the CAA. These sanctions may include the denial of any project or funding grant other than those for safety, mass transit, or transportation improvement projects related to air quality improvement or maintenance. These sanctions are in the form of denial of sewage treatment improvement or expansion grants, a construction ban on major new or modified sources, and the general withholding of federal funds. Major metropolitan areas of California (including the Los Angeles Basin) are currently under EPA sanctions. Federal sanctions were increased in California because an acceptable motor vehicle inspection and maintenance plan was not developed and implemented.

5.1.1.4 Permit Review Process

The lack of EPA approval of several NSR regulations in major metropolitan areas of California has resulted in EPA review of major new or modified source preconstruction applications, in addition to review by the local air pollution control agency. The required sophistication of the preconstruction application review pursuant to the CAA requirements, the dual review by the EPA and local agencies, and in some cases, the magnitude of the number of applications, have resulted in substantial delays in the construction of new and modified stationary sources.

5.1.2 Attainment Area Requirements

The 1977 amendments to the CAA required that adequate safeguards be implemented to preserve clean air in those areas attaining the NAAQS. These requirements, which were a result of court decisions, are commonly referred to as Prevention of Significant Deterioration (PSD) requirements. Since PSD requirements are only applicable to areas which currently achieve the NAAQS, the emphasis is placed on preconstruction review of new or modified sources. The SIP must also include PSD provisions, which include requirements for best available control technology, monitoring of existing air quality where sufficient data do not exist, and a method for monitoring increment consumption. Increments represents the maximum amount of air quality deterioration for a specific pollutant which is allowed to occur in an area designated as attainment for that pollutant. Increments have been established for sulfur dioxide (SO_2) and total suspended particulates (TSP).

A primary criteria used to determine PSD applicability is whether the proposed source is sufficiently large in terms of emissions to be a new major source or a major modification. If PSD requirements apply to the new or modified source, the air quality impacts of the source must be determined. The existing air quality is defined by current ambient air quality data. If no current data exist, ambient air monitoring (generally for a one year period) may be required. Air quality modeling is used to determine the impact of the new or modified source on ambient air pollutant levels. At this time, the PSD regulations have no provisions requiring emission offsets. However, local regulations currently in development are likely to carry the emissions offsets concept from NSR to PSD regulations. Similar to preconstruction requirements under NSR, major new or modified sources under PSD are required to install air pollution controls. In the case of PSD, best available control technology (BACT) is required.

An area classification system classifies areas according to their air quality. Each area classified differs in the amount of growth allowed before significant air quality deterioration occurs. Significant air quality deterioration occurs if the increase in pollutant levels from the new or modified source exceeds the maximum allowable increase (increments) for that area classification. The baseline concentration is established at the time of the first application in an attainment area after August 7, 1977. To date, PSD increments have been established only for sulfur dioxide (SO_2) and total suspended particulates (TSP). The August 7, 1980 PSD amendments did not include increments for NO_2, CO, and ozone; however, the amendments did include de minimus levels below which PSD requirements are not applicable.

5.1.3 Federal Regulations

Federal regulations, as they relate to TEOR production are highlighted below:

1) The Clean Air Act requires development and implementation of SIPs which will allow achievement and maintenance of NAAQS and prevention of significant deterioration in areas with clean air. These requirements can be administered at the local level, with corresponding requirements for controls on both existing and new sources, once the SIP is approved. In the interim, dual review of preconstruction applications by EPA and local air pollution control agencies may be required.
2) Until an acceptable SIP is approved, the EPA

sanctions in California which preclude construction of major new or modified stationary sources will continue to cause considerable delays in project approval in areas covered by the sanctions.

3) The EPA requires permits to construct for new or modified stationary sources under either NSR or PSD regulations. Both NSR and PSD regulations require that controls be applied to new and modified facilities. Control requirements are both technology-forcing and expensive, and considerable time delays result from the dual permit review process.

5.2 California State Regulations

In California, the California Air Resources Board (CARB) has the primary responsibility to develop and implement the California SIP. CARB has retained primary responsibility for developing the necessary mobile source control strategies and has required the various local air pollution control districts (APCDs) to establish stationary source control strategies. CARB assumes both supervisory and technical roles. If the CARB determines that the APCD rules are not sufficient to attain or maintain the NAAQS, the CARB may take corrective action which may include adoption of rules for the APCD.

The CARB is developing and implementing a mobile source control strategy for reducing HC and CO emissions in the state, and is also developing a statewide non-attainment plan (NAP) for attaining and maintaining the NAAQS for TSP. The mobile and stationary source control strategies together make up the NAP. Failure to implement adequate mobile source strategies will require greater control of stationary sources. To date, the EPA has not approved California's SIP, which includes the TSP NAP. The lack of an inspection/maintenance program for motor vehicles in the Los Angeles, San Diego, and San Francisco metropolitan areas is the major reason EPA has not given its approval. As a result, the EPA has imposed sanctions prohibiting construction of any major new or modified stationary sources in these areas.

CARB has also taken a strong role in the development and adoption of stationary source control measures. CARB's efforts have been in both the area of retrofit rules and the area of preconstruction review. Until early 1980, the CARB had developed and, in some cases, adopted various "model rules" for reducing emissions from existing sources in specific APCDs. Since early 1980, various APCDs have worked with the CARB to develop model rules called, "Suggested Control Measures", for the implementation of control strategies identified in the SIP. This effort has lead to the development of a "model" PSD rule which will serve as a guideline rule for the APCDs to use in development of their respective PSD rules. Since much of the CARB's authority for the control of stationary sources has been delegated to the respective APCDs, the CARB has limited its activities to assisting the APCDs with the development and implementation of the various non-attainment plans (NAPs). Although the CARB does not have permit authority for either NSR or PSD application, the CARB does in many cases have responsibility of approving certain NSR exemptions. This approval of NSR exemptions, however, has rarely resulted in any significant delays.

The revised California SIP is directed at attaining and maintaining only the NAAQS. In addition, CARB and the local APCDs are responsible for developing plans to meet the CAAQS. The CAAQS for SO_2 and sulfates were recently repealed by a California court ruling. As a result of the court ruling, the less stringent NAAQS standard for SO_2 applies. No NAAQS standards exist at this time for sulfates.

The key impacts of California state regulations on expanded TEOR production can be summarized as follows:

1) The CARB develops, in cooperation with the APCDs, suggested control measures which will satisfy the State Implementation Plans. The suggested control measures require considerable controls on existing sources and this limits the availability of emission offsets needed for new sources in non-attainment areas.
2) The CARB is responsible for developing mobile source control measures. The level of success in implementing these measures directly impacts the level of control required by stationary sources since the upper emission ceilings are fixed.
3) The CARB has taken and probably will continue to take an active role in the development of NSR and PSD regulations. These regulation requirements directly impact the level of TEOR production expansion.

5.3 Local California Air Pollution Control Agency Regulations

The air pollution control districts (APCDs) and air quality management districts (AQMDs) in California are local agencies primarily responsible for developing and enforcing specific air pollution regulations for the control of stationary sources. Each of the local agencies develop non-attainment plans (NAPs) which demonstrate how the NAAQS and CAAQS will be met through the control of emissions from stationary sources. Control strategies in the NAPs include both regulations designed to reduce emissions from existing sources and regulations for minimizing emissions from new or modified sources. The

APCDs and AQMDs of primary interest in this report are the Kern County, Fresno County, Monterey Bay Unified, and the South Coast agencies. All of these agencies have prepared NAPs for ozone. Both the Kern County APCD and the South Coast AQMD have prepared NAPs for SO_2. The South Coast AQMD was also required to prepare an NAP for TSP and NO_x. The attainment status of the APCDs and AQMDs studied is presented in Table 5-2.

Since TEOR production equipment has associated air contaminants, it is subject to NSR and PSD requirements in the case of new or modified projects, and emission control retrofit requirements in the case of existing projects. New source review regulations include requirements for emission control equipment on new or modified sources consistent with Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) definitions. Also, emission offsets may be required for net emission increases of non-attainment pollutants. A summary of the local air pollution regulations applicable to new and existing TEOR production equipment is presented in Table 5-3. In this table, the air pollution regulations affecting existing TEOR equipment are the regulations which require retrofitting of emission control systems on existing equipment. In addition to the local regulations, federal NSR and PSD regulations currently apply to proposed new or modified sources in the districts.

5.3.1 Kern County APCD (Kern River, Other Central, Midway Sunset, and Other Western Fields)

Kern County's air pollution control regulations have been amended several times to address the increasing development of conventional steam stimulation oil production facilities. Heavy oil fields in Kern County have hundreds of steam generators with permits to operate (POs) and hundreds more with pending authorities to construct (ACs). Consequently,

TABLE 5-2.
ATTAINMENT STATUS FOR EACH OF THE STUDY AREAS[a]

		Pollutant							
		Ozone		TSP		SO_2		NO_x	
APCD	FIELD	NAAQS	CAAQS	NAAQS	CAAQS	NAAQS	CAAQS	NAAQS	CAAQS
Kern	Kern River	NA	NA	NA	NA	NA	NA	NA	NA
	Other Central								
	Midway-Sunset	NA	NA	NA	NA	A	NA	A	A
	Other Western								
Fresno	Coalinga	NA	NA	NA	NA	A	A	A	A
Monterey	San Ardo	NA[b]	NA[b]	A	NA	A	A	A	A
SCAQMD	Brea Olinda	NA	NA	NA	NA	A	A	NA	NA

[a]A = Attainment, NA = Non-attainment.

[b]Projected status: There are no violations of current standards in Monterey County (CARB, 1978). However, neighboring counties have monitored violations.

TABLE 5-3.
CALIFORNIA AIR POLLUTION REGULATIONS APPLICABLE TO TEOR EQUIPMENT[1]

APCD	SOURCE	Sulfur Dioxide(SO_2)	Oxides of Nitrogen(NO_x)	Total Suspended Particulate (TSP)	Hydrocarbons (HC)
Kern County	New	NSR[2]-BACT[3], LAER[4], and offsets	NSR-BACT, LAER, and offsets	NSR-BACT, LAER, and offsets	NSR-BACT, LAER, and offsets
	Existing	Rule 424 - SO_x emissions from steam generators	Rule 425 - NO_x emissions from steam generators	Rule 424 - TSP emissions reduced in conjunction with SO_x emissions reductions from steam generators.	Rule 411.1 - HC emissions from wellhead casing vents.
Fresno County	New	NSR-BACT, LAER, and offsets	NSR-BACT, LAER, and offsets	NSR-BACT LAER, and offsets	NSR-BACT, LAER, and offsets
	Existing	None[5]	None	None	None
Monterey Bay Unified	New	NSR-BACT	NSR-BACT	NSR-BACT	NSR-BACT LAER and offsets
	Existing	None	None	None	Rule 427 - HC emissions from steam drive crude oil production wells
SCAQMD	New	NSR-BACT[6] and offsets	NSR-BACT and offsets	NSR-BACT and offsets	NSR-BACT and offsets
	Existing	None	None	None	None

See next page for notes

TABLE 5-3. (Continued)

Notes:

[1]TEOR equipment includes steam generators with heat input capacities greater than 15 MM Btu/hr, and wellhead vapor recovery systems.

[2]NSR = new source review.

[3]BACT = best available control technology.

[4]LAER = lowest achievable emission rate.

[5]None indicates that only general air pollution control regulations apply to existing TEOR production.

[6]In the SCAQMD, BACT is defined as equivalent to LAER for the other study APCDs.

the Kern County NAP addresses both retrofit rules for existing sources and preconstruction rules for new or modified sources. The NAP as a whole was established on the premise that the existing sources must first be controlled before new sources can be built.

5.3.1.1 Retrofit Rules

Kern County APCD or the CARB on behalf of the Kern County APCD has adopted three retrofit rules which directly impact existing oil production from steam stimulation techniques in Kern County: Rule 424 (Sulfur Compounds from Oil Field Steam Generators); Rule 425 (Oxides of Nitrogen Emissions from Steam Generators used in TEOR); and Rule 411.1 (Steam Drive Wells - Crude Oil Production).

5.3.1.1.1 Rule 424 - Sulfur Compounds from Oil Field Steam Generators

Rule 424 governs the emissions of sulfur compounds from steam generators, of which the primary constituent is SO_2. It was adopted on March 23, 1979, by the CARB for Kern County as a control strategy to attain the NAAQS for TSP. SO_2 emitted to the atmosphere is throught to form sulfate aerosols, a constituent of TSP. Rule 424 addresses this precursor relationship by controlling SO_2 emissions from oil field steam generators. Under the March rule, steam generators issued an authority to construct (AC) after February 21, 1979 are classified as "new". The rule requires existing steam generators to attain compliance with a two-phase sulfur compound emission limitation. The first phase requires that after July 1, 1982, emissions must be reduced to not exceed 0.25 pounds of sulfur per million Btu of heat input. The second phase requires further reductions to 0.12 pounds of sulfur per million Btu of heat input by July 1, 1984. In turn, all new oil field steam generators (those installed after September 12, 1979) must meet an emission limitation of 0.06 pounds of sulfur per million Btu of heat input (equivalent to about 90 percent SO_2 scrubbing efficiency when burning 1.1 percent sulfur fuel). On September 26, 1979, the CARB amended Rule 424 by adding a small producer provision to the rule. The provision allows small producers an additional six months (until January 1, 1985) for final compliance with the 0.12 pounds of sulfur per MM Btu emission limitation on existing generators.

Rule 424 sets forth averaging requirements for new and existing steam generators. The averaging provision allows one or more affected generators within a 15-mile diameter circle to average their emissions in demonstrating compliance with the rule.

The language in the averaging provision created confusion between the CARB and the oil producers over its interpretation. The CARB's intent appears to be that existing steam generators which have been scrubbed or are designated to be scrubbed to meet NSR requirements cannot be counted towards complying with the averaging provision of Rule 424. Also, the averaging provision of Rule 424 does not apply to new steam generators; sulfur emissions from each individual new steam generator cannot exceed 0.06 pounds of sulfur per MM Btu. Therefore, it appears that the CARB's intent was that only sulfur emission reductions from existing unscrubbed steam generators can be averaged to allow compliance with Rule 424.

Reductions of sulfur emissions for Rule 424 cannot be be used as emission offsets for future generators. The rationale behind this interpretation is derived from Rule 210.1 - Standard for Authority to Construct (New Source Review, see Section 5.3.1.2.1). NSR provides that emission reductions resulting from regulatory requirements (whether district, state, or federal) cannot be allowed as emission offsets, unless an application incorporating these offsets was filed before the effective date of the regulation. The CARB applied the same rationale to reductions of PM. Reductions of PM from SO_2 scrubbing for Rule 424 cannot be used as emission offsets.

At an Executive Officer's hearing on May 23, 1980, the CARB staff proposed amendments to clarify the averaging provision of Rule 424 and to change the small producer and cogeneration provisions. However, the oil producers proposed further modifications to Rule 424 beyond the legal authority of the Executive Officer. These producer-proposed modifications included:

1) defining an existing steam generator as one which had an AC prior to September 12, 1979 (instead of February 21, 1979);
2) omitting all reference to new steam generators;
3) developing a new emission limitation which takes into account SO_2 emission reductions from new source review and uses averaging language similar to that in the May 23, 1980 CARB staff report; and
4) delaying Rule 424 compliance plan submittal.

On July 23, 1980, the CARB delegated responsibility to the Executive Officer to prepare a report and consider these amendments to Rule 424 in a public hearing. The staff brought recommendations before an Executive Officer hearing October 28, 1980.

On October 28, 1980, the CARB revised Rule 424. The principal changes included: 1) lowering of the emission limitation for existing steam generators from 0.12 to 0.11 pounds of sulfur per MM Btu; 2) allowing emission reductions used for offsets on existing sources to be used in the averaging of emissions (the reductions can not be used in future offsets); and 3) changing the averaging region from a 15-mile radius region to the central and western Kern County fields, as in Rule 210.1 (NSR).

During the year which preceded the final revisions, the pending regulations had a significant impact on new TEOR projects. In order to be issued Permits to Construct for new steam generators under NSR requirements, the applicants were required to offset increased SO_2 emissions, in addition to applying BACT. However, since a definition of "existing sources" was still pending, the applicants were unable to determine what had to be done to provide the required offsets. Although Kern County issued Authorities to Construct during this period, the permits were conditional; construction could not begin until an acceptable emission offset plan was submitted.

5.3.1.1.2 <u>Rule 425 - Oxides of Nitrogen Emissions from Steam Generators Used in Thermally Enhanced Oil Recovery</u>

Rule 425 governs the emissions of NO_x from oil field steam generators. It was adopted by the CARB for the Kern County APCD on March 6, 1980, as a control strategy to attain and/or maintain the NAAQS for NO_2, ozone, and TSP. CARB considers NO_x emissions as a precursor to both the nitrate fraction of TSP and ozone formation. The simultaneous adoption of Rule 425 and the amendments to Rule 210.1 (NSR) provides for reducing NO_x emissions from steam generators and allows the oil producers to obtain NO_x emission offsets for future generators. Rule 425 classified "existing" steam generators as those having an AC prior to September 12, 1979 consistent with the Rule 210.1 baseline emission accumulation date.

Rule 425 establishes NO_x emission limitations based on ambient air concentration. Stricter limitations are required if the NAAQS or CAAQS for NO_2, an hourly average of 0.25 ppm, is exceeded or nearly exceeded. After July 1, 1982, NO_x emissions (as NO_2) must be limited to 0.30 pounds per MM Btu of heat input from existing steam generators. For small producers, the limitation is 0.35 pounds of NO_2 per MM Btu.

Events which may cause more stringent emission limitations are called air quality changes in these regulations. Current air quality represents the first stage. A second stage air quality change is the occurrence of a twelve-month moving average NO_2 concentration which exceeds 0.045 ppm or the occurrence of an hourly average NO_2 concentration which exceeds 0.20 ppm (80 percent of the CAAQS) for three or more discontinuous station hours. Eighteen months after a second stage air quality change occurs, the NO_x emission limitation for existing steam generators becomes 0.25 pounds per MM Btu of heat input.

A third stage air quality change is the occurrence of a twelve-month moving average NO_2 concentration which exceeds 0.053 ppm or the occurrence of an hourly average NO_2 concentration which equals or exceeds 0.25 ppm (the CAAQS) for three or more discontinuous station hours. Eighteen months after a third stage air quality change occurs, the NO_x emission limitation for existing steam generators becomes 0.14 pounds per MM Btu of heat input.

An oil producer may average NO_x emissions from all existing steam generators in the same stationary source (central or western Kern County fields) to comply with the emission limitations.

Reductions of NO_x emissions required by the emission limitations of Rule 425 may be used as offsets or banked for use in future projects. To obtain the offsets, the applicant must complete installation of all necessary control equipment and request the district to perform source tests required for issuance of a permit to operate prior to a second and/or third stage air quality change.

5.3.1.1.3 Rule 411.1 - Steam Drive Wells - Crude Oil Production

Kern County APCD Rule 411.1 (Steam Drive Wells - Crude Oil Production) sets forth control requirements for steam drive (first line) production wells. The current rule, as adopted on June 26, 1979, requires that HC emissions from both new and existing wellhead casing vents be reduced by at least 93 percent by weight. Oil producers must document full compliance by March 1, 1982. Wellhead vapor recovery (WHVR) systems are expected to achieve control levels necessary for compliance with Rule 411.1. Vapor recovery units consist of collection lines from wellheads and air- or water-cooled heat exchangers to condense steam and condensible hydrocarbons.

The CARB staff proposed to extend the final compliance date six months, to October 1, 1981. However, the CARB did not have sufficient opportunity to consider the extension. The Board requested that the Kern County APCD consider such a change.

5.3.1.2 Preconstruction Rules

Two types of preconstruction rules are applicable in Kern County. PSD is under the jurisdiction of the EPA pending adoption of a PSD rule by Kern County (see Section 5.1.2 for details). Kern County APCD administers the NSR regulations which apply to new sources in non-attainment areas. However, EPA has not approved Kern County's NSR rule.

5.3.1.2.1 Rule 210.1 - Standard for Authority to Construct (New Source Review)

Kern County APCD Rule 210.1, Standard for Authority to Construct, sets forth procedures and requirements for all affected sources undergoing new source review. Since its original adoption by the Kern County APCD on December 28, 1976, Rule 210.1 has been amended several times by the CARB in an attempt to meet state and federal requirements. The most recent CARB revisions occurred on September 12, 1979 and March 6, 1980. These recent revisions to Rule 210.1 made the rule considerably more stringent through the addition of emission offset requirements for new or modified sources over a specified emission limit. The revisions also required application of BACT to sources which had not previously had this requirement. As will be noted, emission offset requirements represent the single most significant factor affecting expanded TEOR production.

5.3.1.2.2 Permit Review Process

As previously mentioned, the actual review of permit applications required pursuant to federal NSR regulations may cause significant delays and levels of uncertainty. Until the Kern County NSR rule is approved by the EPA, the EPA will continue to review and issue NSR permits in Kern County. The local NSR review process has become a major point of concern on the part of oil companies operating TEOR facilities within Kern County. Up until 1975, permits were either issued or denied by the Kern County APCD within thirty days of receipt. A steady series of regulatory revisions by the Kern County APCD, the CARB, and the EPA has resulted in review delays in the order of two to three years. The first major cause for delays came as a result of the imposition of dual Kern County APCD and EPA application review in 1976 following EPA disapproval of the Kern County NSR regulation. The PSD requirements in the 1977 Clean Air Act Amendments stimulated submittal of a large number of applications for new or expanded facilities prior to the March 1978 deadline when PSD regulations went into effect. Approximately 500 applications were received almost simultaneously by the APCD, and this brought about the need for a cumulative air quality impact analyses study which postponed review for one and one-half years. Violation of the SO_2 NAAQS in late 1978 further complicated application review with the imposition of Rule 424 (Sulfur Compound Emissions from Steam Generators) in early 1979. In mid-1979, the pending imposition of a federal construction ban as a result of the lack of an acceptable SIP stimulated another large influx of applications prior to the construction ban effective date. The large potential emissions of NO_x associated with the apparent expansion of TEOR activity brought about significant tightening of Rule 210.1 and adoption of Rule 425 (NO_x Emissions from Steam Generators). The cumulative effect of these regulatory changes and large influxes of applications was to further delay the review process. These regulatory changes have also caused the oil companies to modify their approach to new or expanded operations. Figure 5-1 summarizes this lengthy process by presenting a time table for a typical steam drive TEOR project.

5.3.1.2.3 Definition of Stationary Sources

Rule 210.1 provides that a stationary source includes structures, buildings, facilities, or installations owned by a single entity, regardless of whether they are on a single property or contiguous properties, or on one or more properties wholly within the western Kern County or central Kern County oil fields. Rule 210.1 requires aggregation of stationary sources if they are dependent on one another, involve the use of a common product, or result in the production of a common product. Applying this definition to TEOR, all of an oil producer's TEOR production equipment in either the central or western Kern County fields are considered one stationary source. EPA suggests revision of this definition of a "Stationary

FIGURE 5-1.

TIME TABLE FOR A TYPICAL STEAM DRIVE TEOR PROJECT

Oil company prepares preliminary engineering study for a new TEOR project. (3 months)

If project appears feasible, negotiations with the APCD begin to determine BACT requirements. (3 months)

Upon negotiation of control requirements, the oil company prepares engineering design specifications. (3 months)

Year 1

Bids for equipment are requested and reviewed. (2 months)

Equipment contracts are awarded - applications for Permits to Construct submitted - review is concurrent with equipment manufacturing. (up to 18 months)

Year 2

Delivery for steam generator. (4-6 months)
Delivery for single-pass FGD unit. (6-18 months)
Delivery for dual-pass FGD unit. (18 months)
Delivery for wellhead vapor recovery unit. (18 months)

Delivery of equipment - construction begins. (3 to 4 months)

Construction is completed.
Compliance testing begins and final negotiations with APCD are completed. (2 months)

Year 3

Compliance demonstrated.
Equipment begins operating on regular basis. (1 year)

Oil production begins to increase. (One year of steam drive is typically required before production begins to increase.)

Year 4

Cumulative time may be up to 47 months. This assumes that Permit to Construct application review is concurrent with equipment manufacturing.

Source" because the definition allows offsets to be used within a source to avoid NSR requirements. Even if the revision to Kern County's NSR Rule suggested by EPA is made, it will not impact the results of this analysis significantly because the maximum level of control was assumed in all cases in order to allow maximum expansion of TEOR production.

5.3.1.2.4 Precursor Relationships

A precursor is a directly emitted air contaminant which forms or contributes to the formation of another pollutant (called a secondary pollutant) for which a NAAQS has been adopted. On September 12, 1979, the CARB amended precursor relationships in Kern County's air pollution regulations. NO_x was defined as a precursor to ozone and to the nitrate fraction of TSP. SO_2 was defined as a precursor to the sulfate fraction of TSP. The precursor-secondary-air-contaminant relationships in Kern County are presented in Table 5-4. The effects of these precursor relationship amendments on the offsets provisions of the new source review rule and the LAER are discussed below.

5.3.1.2.5 New Source Review Control Levels

A key element of the Kern County NSR Rule 210.1 is the requirement for air pollution controls on new or modified sources. The two levels of control discussed in this section, BACT and LAER, are common to the control required under EPA regulations, but the application is distinct. Under the EPA preconstruction review, LAER is required for sources of non-attainment pollutants. Similarily, BACT is required for sources of attainment pollutants. In the case of the Kern County Rule 210.1, either level of control may be applicable to a new or modified source which emits a non-attainment

TABLE 5-4. PRECURSOR-SECONDARY-AIR-CONTAMINANT RELATIONSHIPS IN KERN COUNTY

Precursor	Secondary Air Contaminant
Hydrocarbons and substituted hydrocarbons (Reactive organic gases)	a. Ozone
	b. The organic fraction of total suspended particulate (TSP)
Nitrogen oxides (NOx)	a. Nitrogen dioxide (NO_2)
	b. The nitrate fraction of total suspended particulate (TSP)
	c. Ozone
Sulfur oxides (SOx)	a. Sulfur dioxide (SO_2)
	b. Sulfates
	c. The sulfate fraction of total suspended particulate (TSP)

pollutant. The requirements for these two levels of control are discussed in the following subsections.

5.3.1.2.5.1 Best Available Control Technology (BACT)

All new stationary sources or modifications resulting in a net increase of 150 pounds or more per day of a criteria pollutant (except CO) are required to implement BACT. The application of BACT must achieve maximum reduction of emissions consistent with energy, environmental, and economic considerations. Taking those factors into account may preclude the use of readily available, yet unduly stringent, control technologies. However, in no case may the level of control realized by BACT be less restrictive than any applicable federal New Source Performance Standard.

5.3.1.2.5.2 Lowest Achievable Emission Rate (LAER)

New stationary sources or modifications resulting in a net increase of 200 pounds per day or more of non-attainment pollutants or precursors to those pollutants are required to meet the LAER. CO emissions come under this requirement only if modeling predicts violations of its NAAQS. LAER does not require the consideration of the possible energy, environmental, or economic impacts, but must represent the most stringent level of control specified in the approved implementation plan of any state. Emissions of NO_x, now considered a precursor to ozone (except by the EPA), and TSP may be reviewed under the LAER provision.

The EPA has criticized the exemptions in Kern County's NSR Rule which exclude CO emissions from LAER requirements unless NAAQS violations are predicted. Should this exemption be removed as suggested by EPA, the results of this study would not be significantly affected, because the maximum level of control was assumed in all cases in order to allow maximum expansion of TEOR production.

5.3.1.2.6 Emissions Offsets

The concept of emissions offsets has become an established regulatory tool for reducing overall emissions in non-attainment areas. Rule 210.1 requires offsets for proposed increased emissions from all new stationary sources and modifications in areas where the NAAQS was exceeded more than three times within the three years prior to the filing of the application for an AC. This provision also applies to precursors of the NAAQS pollutants. Therefore, net emission increases over 200 pounds per day of SO_2, NO_x, PM, and hydrocarbons must be offset in Kern County.

The CARB recently changed Kern County's baseline emissions date from December 28, 1976 to September 12, 1979. For modifications, the net increase in emissions must take into account all net emission changes represented by the source's ACs since September 12, 1979. The date change was made on March 6, 1980, at the same time as the adoption of Rule 425 (NO_x Emissions from Steam Generators used in Thermally Enhanced Oil Recovery). Concern by oil producers regarding their ability to obtain NO_x offsets for net emission increases since December 28, 1976, and the CARB's concern regarding increased NO_x emissions from permitted generators led to the change in the emission baseline date and the adoption of Rule 425 to regulate NO_x emissions.

The CARB modified the emission offset ratios provisions of Rule 210.1 on March 6, 1980. Specific offset ratios for heavy oil production were promulgated. An offset ratio of 1.0 to 1.0 may be used if new emissions and offset emissions are owned by the same company (intracompany) within the same oil field (e.g., central Kern County fields or western Kern County fields). If new emissions are offset by emission reductions from a different company (intercompany) within the same oil field, new emissions must be offset at a 1.2 to 1.0 ratio (i.e., emission reductions must be 20% greater than the new emissions). For new and offset emissions in different fields (cross-county), new emissions must be offset at a 1.5 to 1.0 ratio, regardless of the companies involved.

PM emission offset requirements are undergoing significant changes. Historically, PM emissions resulting from new steam generators could be offset by paving dirt roads. The proposed federal revisions to the TSP NAAQS would differentiate PM by size, thus focusing control of PM on the control of respirable PM (less than 3 microns in size). This proposed change in the TSP NAAQS caused CARB to raise the issue of the historical method of offsetting combustion PM emissions (predominantly smaller than 3 microns) with reduction of PM emissions from unpaved roads (predominantly larger than 3 microns). The proposed change in PM offset requirements would substantially increase the control requirements for combustion PM emissions and reduce the availability of PM offsets.

In addition to direct pollutant-for-pollutant offsets, the regulation allows interpollutant offsets. NO_x and SO_2 emissions are thought to form atmospheric nitrate and sulfate aerosols, both of which are constituents of TSP. NO_x and hydrocarbons also participate in photochemical reactions to form ozone and other oxidants, so NO_x and hydrocarbons are considered precursors to ozone. This interdependent relationship among primary pollutants, which may result in the formation of secondary pollutants, led to interpollutant offset ratios.

Table 5-5 gives the interpollutant offset ratios in effect in Kern County. The pollutant in the first column, "New Emission", represents emissions from the proposed new or modified source required to be offset. The next four columns, labeled TSP, NO_x, SO_2, and NMHC (non-methane hydrocarbons), give the required emission reductions from existing sources, either by reducing the directly-emitted pollutant or its precursor. For example, one ton per year of new NO_x emissions can be offset by reducing existing SO_2 emissions by 0.7 tons per year plus reduction of NMHC by 3 tons per year. Each directly-emitted pollutant may be offset through intracompany trade-offs by the same pollutant at a ratio of 1.0 to 1.0, or by a combination of other pollutants in the ratios shown in Table 5-5. The CARB intends to update these factors annually as more data become available.

Consideration of the precursor relationship of NO_x to particulate and ozone has resulted in more stringent NO_x control measures than would be required if NO_x were not a precursor to particulate matter or ozone. The NAAQS for NO_x is not currently being violated in Kern County, but violations of the TSP and ozone standards are the bases for the requirement that no increase of NO_x emissions be allowed (LAER and offsets).

One important feature of this emission offset concept is that the emissions which are offset may not be "double counted". For example, if existing NO_x emissions are being controlled in order to offset particulate, ozone, and NO_x emissions, additional existing NO_x emissions have to be abated to offset new NO_x emissions. More existing NO_x must be abated to offset new TSP emissions, and still more existing NO_x must be abated to allow for ozone (a secondary pollutant).

The emissions offset portion of Kern County's NSR

TABLE 5 - 5. INTERPOLLUTANT EMISSION OFFSET RATIOS (INTRACOMPANY[1]).

For One Ton/Yr of New Emissions	Ton/Yr of Offsets Required			
	SO_2	NOx	TSP	NMHC[2]
SO_2	1.0	*	*	*
NOx	0.7 + 3 NMHC	1.0	0.2 + 3NMHC	7
TSP	4	16	1.0	55
NMHC[2]	*	0.5	*	1.0

*Means no interpollutant offsets allowed.

[1]Intracompany offsets mean within the same company as opposed to intercompany offsets where offset emissions for a new or modified source are obtained from a different company.
[2]NMHC = non-methane hydrocarbons.

rule has received the most criticism from the EPA. Although the major EPA criticisms are considered, it is not anticipated that the revisions suggested by the EPA will significantly affect the conclusions of this study since this study was based on worst case assumptions. The EPA-suggested revisions and the impacts of these revisions can be summarized as follows:

1. Rule 210.1 only requires emission offsets in areas where the NAAQS was exceeded more than three times within three years prior to application submittal. The EPA requires NSR be applied to all major sources in non-attainment areas, regardless of the number of times the NAAQS was exceeded. If the NAAQS are exceeded at least once a year there is no difference between the Kern County and the EPA NSR rules. However, if the NAAQS was not exceeded in each of the prior three years, Kern County's rule would allow considerably more TEOR expansion since emission offsets would not be required. In the latter case, the revisions to Kern County's NSR Rule suggested by the EPA would not impact the results of this study because the study analysis assumed worst case.
2. Kern County's baseline emissions date of September 12, 1979 (as revised by the CARB on March 6, 1980) is considerably less stringent than the EPA baseline emissions date of December 1976. The comparison between the two rules is complicated by the adoption on March 6, 1980 of Rule 425 (NO_x Emissions from Steam Generators used in Thermally Enhanced Oil Recovery). However, even with considerable controls on existing facilities, the emission increases since

December 1976 will not be fully controlled. In light of the other revisions being suggested by the EPA, the impact of this revision is not considered to be very significant.

3. The offset ratios contained in Rule 210.1 allow emission offsets to be obtained at a considerable distance from the proposed source. The EPA, however, only allows offsets at the same source "or in the immediate vicinity" for CO, PM, and SO_2, and as close to the new source as possible for HC sources. The suggested revision would reduce the availability of SO_2 emission offsets. The definition of "stationary source" must also be changed so that all facilities operated by a company within a region of Kern County are not considered a single source. If changed, this definition would allow each facility a 150 pound per day increase without coming under NSR. The net result would be a greater relaxation of the rule requirements with a corresponding positive impact on TEOR expansion.
4. Kern County's provisions for interpollutant offsets are not being approved by the EPA. Elimination of interpollutant offsets would have the greatest impact on TEOR expansion. This impact stems from the fact that NO_x emission reductions are assumed to be utilized to both offset new NO_x emissions and to reduce formation of TSP and ozone, which are secondary pollutants. The impact on TEOR expansion is the greatest when second and third stage air quality

changes occur since many emission offsets are no longer available. The impact on TEOR expansion in Kern County is expected to be significant and is quantified in the three analyses sections of this report.

5.3.1.2.7 Innovative Control Technology

A new or modified source which uses innovative control technology may be exempt from the new source review provision requiring offsets for net emission increases. Innovative control equipment results in a significantly lower emission rate than that which occurs with the use of previously recognized LAER. The applicant must show, through air quality modeling, that the new or modified source with innovative control technology will not cause a violation of any NAAQS at maximum ground level impact. The innovative control technology should serve as a model for emission control technology on similar sources. The exemption from offsets applies only to air contaminants controlled by the innovative control equipment.

5.3.2 Fresno County APCD (Coalinga Field)

Air emissions from TEOR production and facilities in the Coalinga field are regulated primarily by the Fresno County APCD's New Source Review rule (Rule 210.1 - Standards for Authority to Construct). Retrofit rules in Fresno County pertain to controlling fugitive HC emissions from oil production (e.g., leaking valves and flanges) and are very maintenance oriented. The fugitive HC control strategy was promulgated in Fresno County's ozone NAP.

Fresno County APCD's current NSR rule was adopted on May 22, 1979 and became effective on June 21, 1979. It contains provisions for applying BACT and LAER to new stationary sources and modifications and for offsetting cumulative net increases in emissions.

A stationary source includes structures, buildings, facilities, or installations that are owned or operated by a single entity and are on one or more bordering (contiguous) properties within the Fresno County APCD. Applying this definition to the Coalinga field, an oil producer may operate several steam generators in the field and have them considered separate stationary sources if they are on non-adjacent properties..

Fresno County APCD's precursor-secondary-air-contaminant relationships are identical to those of Kern County (see Table 5-4). SO_2 and NO_x emissions are precursors to the sulfate and nitrate fractions of TSP, respectively, and NO_x is also a precursor to ozone. Fresno County is a non-attainment area for ozone and TSP.

BACT is required for all new stationary sources and modifications which result in a net emission increase of 50 kilograms (110 pounds) per day or more of any air contaminant (except CO) for which a CAAQS or NAAQS exists. BACT also applies to precursors of such air contaminants. LAER is required for all new stationary sources and modifications which result in a net emission increase of 90 kilograms (198 pounds) per day or more of any non-attainment air contaminant or precursor to such contaminants. The definitions of BACT and LAER in Fresno County are identical to those of the Kern County APCD.

Net emissions increases subject to LAER must offset the amount of emission increase (after applying LAER) above 90 kilograms per day. An emission offset ratio of 1.2 pounds of offset emissions to 1.0 pound of new or modified source emissions may be used provided that:

a. the offset source is upwind of the new or modified source and is in the same or adjoining counties; or

b. the offset source is within a 25 kilometer (15.5 miles) radius of the new or modified source.

The applicant must use air quality modeling to determine an acceptable offset ratio for offset sources outside the areas described above. An acceptable offset ratio will show a net air quality benefit in the area affected by the new or modified source. Using innovative control equipment may exempt an applicant from offset provisions in Fresno County provided that no NAAQS are violated.

Rule 210.1 provides for interpollutant offsets for precursors of the same secondary air contaminant. The Fresno County Air Pollution Control Officer bases the interpollutant offset ratios on existing air quality data after consulting with the Executive Officer of the CARB. To date, no interpollutant offset ratios have been developed in Fresno County.

The net increase in emissions for modifications to existing sources is determined from a baseline date of January 1, 1977. Net emission changes represented by ACs associated with the existing stationary source and issued after January 1, 1977, are accumulated. Emission reductions required by federal, state, or district rules and regulations are not included in determining the net emission change.

5.3.3 Monterey Bay Unified APCD (San Ardo Field)

Air emissions from TEOR production equipment and facilities in the San Ardo field are regulated primarily by the Monterey Bay Unified APCD's NSR rule (Rule 207 - Review of New or Modified Sources) and by federal PSD regulations. The

District also has rules governing sulfur emissions from fuel-burning equipment and HC emissions from steam drive crude oil production wells. Retrofit controls for fugitive HCs are addressed in the District's ozone NAP.

5.3.3.1 Retrofit Rules

Sulfur emissions from existing steam generators are regulated by Monterey Bay Unified APCD Rule 412, Sulfur Content of Fuels, and Rule 413, Removal of Sulfur Compounds. Rule 412 limits the sulfur content of solid or liquid fuels burned in any fuel-burning equipment with a heat input capacity greater than 15 MM Btu per hour to 0.5 percent by weight. However, Rule 413 exempts the source from the provisions of Rule 412 if the sulfur compounds in the combustion gases are removed so that they are equivalent to burning a 0.5 percent sulfur fuel. Rules 412 and 413 require oil producers to retrofit SO_2 scrubbers on their TEOR steam generators. All crude oil-fired steam generators in the San Ardo field had SO_2 scrubbers prior to 1978.

The District recently adopted Rule 427, Steam Drive Crude Oil Production Wells, on January 16, 1980. Rule 427 requires that NMHC emissions from both new and existing wellhead casing vents be reduced by at least 98 percent by weight. On-site construction or installation of control or collection systems on existing steam drive wells was required by December 31, 1980. Oil producers must document full compliance by February 28, 1981. Rule 427 defines a steam drive well as any crude oil production well influenced by a steam injection well which produces oil that is at least 15^{O}F higher in temperature than the temperature of the oil in the original reservoir.

Steam drive wells in the San Ardo field which were producing in 1978 were already equipped with WHVR systems. Rule 427 is directed towards existing steam drive wells which have not been used for several years and which may be used for production again soon. These steam drive wells were not required to have WHVR systems when they were put in. If these wells were to start production again without vapor recovery, significant quantities of hydrocarbon emissions would be emitted into an ozone non-attainment area.

5.3.3.2 Preconstruction Rules

As in the case of Kern and Fresno Counties, EPA currently has PSD review authority in the Monterey Bay area. The APCD enforces its NSR regulation through Rule 207.

Monterey Bay Unified APCD's current NSR rule was adopted on July 18, 1979 and revised on January 30, 1980. It has provisions for BACT, LAER, and offsets very similar to the NSR rules in Kern and Fresno Counties.

The definitions of stationary source, BACT, and LAER are identical to those of the Fresno County APCD. Monterey Bay Unified APCD's precursor-secondary-air-contaminant relationships are identical to those of Kern and Fresno Counties (see Table 5-4), except that NO_x is not considered a precursor to ozone. Monterey County is a non-attainment area for ozone. Since only HC emissions are considered precursors to ozone, only net increases of HC emissions fall under the LAER and offset provisions.

BACT is required for all new stationary sources and modifications which result in a net emissions increase of 200 pounds per day or more of any air contaminant (except CO) for which a NAAQS exists or any precursor to such air contaminant. LAER is required if the net emissions increase is 200 pounds per day or more of any non-attainment air contaminant or precursors to such air contaminants.

Net emission increases of non-attainment pollutants greater than 200 pounds per day must be offset. An offset ratio of 1.2 pounds of offset emissions to 1.0 pound of new or modified source emissions is used if the offset source is within a 15-mile radius of the proposed new or modified source. For offset sources outside the 15-mile radius, air quality modeling must determine an offset ratio sufficient to show a net air quality benefit in the area affected by the new or modified source. As in Fresno County, no interpollutant offset ratios have been developed for Monterey County.

For modifications to stationary sources, the net increase in emissions takes into account the cumulative net emission changes represented by ACs associated with the source and granted pursuant to Rule 207. The adoption date of Rule 207, July 18, 1979, is the baseline emission date for computing net emission increases from stationary sources. However, major new or modified source emissions not requiring offsets under NSR (i.e., air contaminants which are attainment and are not precursor to any non-attainment air contaminant) are subject to federal PSD regulations. At the present time, emissions of SO_2, NO_x, and PM from major new sources or modifications are subject to PSD regulations in the Monterey Bay Unified APCD. The PSD regulations are currently administered by the EPA and include provisions for control technology review (BACT), air quality impact analysis (modeling), and an ambient air quality analysis (monitoring), in order to verify that the new or modified source will not cause a significant deterioration of the existing air quality.

The majority of provisions in Kern County NSR regulations to which the EPA took exception are not contained in the Fresno or Monterey Counties NSR regulations. Consequently no major changes in these regulations which might adversely impact increased TEOR production are expected to be required by the EPA.

5.3.4 South Coast Air Quality Management District (Brea Olinda Field)

5.3.4.1 Retrofit Rules

The South Coast District's Air Quality Management Plan (AQMP) presents suggested control strategies to attain the NAAQS. Measures pertaining to TEOR production are fugitive HC controls through retrofit and maintenance. The AQMP proposes to require NO_x controls (ammonia injection) on small and medium sized steam generators, industrial boilers, and refinery heaters to reduce NO_x emissions. Although this measure does not specifically address steam generators used in TEOR applications, it appears the SCAQMD policy may require ammonia injection or catalytic reduction systems on TEOR steam generators.

5.3.4.2 Preconstruction Rules

The District adopted the present revised version of the rule, Regulation XIII - New Source Review, on October 5, 1979. NSR in the SCAQMD in many ways is very similar to NSR in the Kern, Fresno, and Monterey Bay Unified APCD's.

A stationary source is defined as any group of air contaminant emitting activities on a single parcel of land or contiguous properties within the District owned or operated by a single entity. The precursor-secondary-air-contaminant relationships in the SCAQMD are identical to those in Kern and Fresno counties (see Table 5-4). BACT in the SCAQMD is defined as LAER (i.e., the definition of LAER in the Kern, Fresno, and Monterey Districts applies to BACT in the SCAQMD).

BACT (LAER) is required for all new stationary sources and modifications which result in a net increase of 68 kilograms (150 pounds) or more per day of any non-attainment air contaminant or precursor to that air contaminant. The exception to this is CO emissions which are allowed a net increase of 340 kilograms (750 pounds) per day.

Net increases of affected air contaminants greater than 68 kilograms per day must be offset. In the SCAQMD, SO_2, NO_x, PM, and HC emission increases may be subject to the BACT (LAER) and offset provisions. An offset factor of offset emissions to new or modified source emissions is determined as follows:

Offset factor = 1.2 + b(x)

Where: x = the distance in kilometers between the new or modified source and the offset source.

b = 0, when x is less than 8 kilometers (5 miles), or

b = 0.01; when x is greater than or equal to 8 kilometers (5 miles).

If the offset source is more than 24 kilometers (15 miles) in the prevailing downwind direction from the new or modified source, air quality modeling is required to show that the offsets will result in a net air quality benefit in the area affected by the new or modified source. Modeling or other analyses approved by the Executive Officer substantiates that the new or modified source will not cause or make measurably worse a violation of any NAAQS. No modeling is required if all offset sources are within 8 kilometers (5 miles) of the new or modified source.

If PM offsets are not available, SCAQMD regulations allow offsets of SO_2, NO_x, or reactive HCs for increased PM emissions. The Executive Officers of the CARB and SCAQMD have the authority to prepare a list of interpollutant offset ratios for the SCAQMD. To date, no interpollutant offset ratios have been developed for the SCAQMD.

As in other APCD regulations, the SCAQMD regulations have an innovative technology exemption from offset requirements. Provisions of the exemption are:

1) the source will have significantly lower emissions than with the use of previously recognized BACT (LAER);
2) the innovative technology can serve as a model for emission reduction technology; and
3) the source will not cause a violation or make an existing violation of an NAAQS measurably worse at the point of maximum ground level impact.

For modifications to existing stationary sources, the net increase (or change) in emissions is summed either within the past five years, or from October 8, 1976, whichever time period is less. In those cases where October 8, 1976 is the baseline date, emission increases of any air contaminant up to 45 kilograms (100 pounds) per day occurring between October 8, 1976 and the date of adoption (October 5, 1979) are forgiven.

Three provisions of the SCAQMD NSR rule are receiving criticism by the EPA.

1. The NSR rule does not require offsets of SO_2, PM, and CO if modeling shows that the increased emissions will not contribute to any violation of NAAQS. EPA requires offsets of any major sources constructed in a non-attainment area. Due to limited availability of emission offsets, a revision pursuant to the EPA requirements

would reduce potential increases in TEOR production.

2. The NSR rule allows offsets to be made anywhere within a large area. It is not necessary that the offsets be upwind or near the source of increased emissions. The EPA requires offsets to be made in the immediate vicinity of the site of increased emissions, though deviations are possible under some circumstances if modeling demonstrates a net air quality benefit or if the offset ratio is increased. As in the above case, such a revision would reduce the availability of emission offsets.

3. The NSR rule allows for offsetting increased emissions of one precursor of the same pollutant. The EPA requires that all offsets must be made for the same pollutant as the increased emissions. In the case of PM, the EPA-suggested revision could significantly reduce the availability of emission offsets thereby reducing the potential expansion of TEOR production.

5.3.5. Summary of Local California Regulations Applicable to TEOR Production

The California APCD's regulations as they affect expansion of TEOR production can be summarized as follows:

1. The NSR and PSD regulations as a whole probably have the greatest impact on TEOR production expansion. This impact is twofold. First, the level of control required of new or modified stationary sources is technology-forcing in most cases, which in turn causes higher costs

and delays in installing new equipment. Secondly, these NSR and PSD regulations limit the availability of emission offsets, which in most cases is the key constraint to expanded TEOR production.

2. The permit processing and procedures cause, in some cases, very considerable delays in obtaining and installing new TEOR equipment. These delays cause increased costs but also increase the uncertainty associated with new projects. Many of these delays are compounded by mass applications on the part of the TEOR producers when attempting to submit applications before new or more stringent regulations go into effect.
3. In Kern County, Rule 424 (Sulfur Compound Emissions from Steam Generators) requires extensive control of existing steam generators which both increases the costs of existing operations and limits the availability of SO_2 offsets. The availability of SO_2 emission offsets is expected to be a key constraint to expanded TEOR production in Kern County.
4. In Kern County, Rule 425 (NO_x Emissions from Steam Generators used in TEOR) requires progressively greater level of NO_x control as the ambient NO_x concentrations increase. In turn, as the level of control required increases, the availability of emission offsets is reduced proportionally.
5. Rule 411.1 (Steam Drive Wells - Crude Oil Production) in Kern County requires control of HC from both new and existing well vents by March 1, 1982. The CARB, in conjunction with various APCD's, is developing "Suggested Control

Measures" for controlling fugitive emissions from oil production facilities, including well vents. Upon promulgation, most APCD's are expected to adopt corresponding regulations. Control technology is currently available which can control well vent emissions and provide economic savings to the industry. Fugitive HC control measures are currently contained in the Fresno and Monterey County Non-Attainment Plans.

6. Dual review by the local APCD and the EPA, coupled with limited CARB approval, significantly increases delays in permit review.

5.4 Texas Regulatory Framework

In Texas, the EPA and the Texas Air Control Board (TACB) have primary responsibility for attaining and maintaining ambient air quality standards. The TACB is responsible for developing, implementing, and enforcing air pollution regulations consistent with Clean Air Act requirements. The TACB is responsible for developing an approval SIP for Texas.

The TACB conducts new source review and permitting programs from a main office and twelve regional offices. New or modified sources must apply for and receive permits to construct and operate from the TACB. Prior to receiving permits, the applicant must demonstrate that the new or modified source complies with applicable rules and regulations in the Texas Clean Air Act.

New source review requirements in the Texas Clean Air Act include emission control requirements (BACT and LAER), preventing significant deterioration of existing ambient air quality, and showing a net decrease of emissions when new or modified sources are permitted in non-attainment areas.

In addition to the new source review by the TACB, federal PSD regulations apply to major new or modified sources in attainment areas. The EPA has PSD review authority in Texas, but the TACB is expected to receive PSD review authority in the near future.

To date, the EPA has conditionally approved the 1979 update to the Texas SIP. Texas (and every other state) is required to submit SIP revisions pertaining to the August 7, 1980 Clean Air Act Amendments regarding PSD and a 1982 SIP update. Revisions to the Texas Clean Air Act coincide with the SIP revisions to make the Texas Clean Air Act consistent with requirements of the federal Clean Air Act.

The TEOR study field in Texas is the Slocum Field in Anderson County, Texas. This area is attainment for all pollutants. Since the Slocum field is in an attainment area for all pollutants, potential expansion of TEOR in the field will require a TACB preconstruction review and an EPA PSD approval, if applicable. Depending on the amount of emissions, some small new sources may be exempt from these regulations.

5.5 Arkansas Regulatory Framework

The Arkansas Department of Pollution Control and Ecology (DPC&E) develops and enforces air pollution regulations in Arkansas. The Department issues permits for new or modified sources. Major provisions of the Arkansas regulations are that new or modified sources may not cause any NAAQS to be exceeded and must comply with all applicable regulations adopted by the EPA pursuant to the federal Clean Air Act. The EPA currently has PSD review authority in Arkansas but Arkansas DPC&E expected to receive PSD review authority in the near future.

The EPA conditionally approved the 1979 update of the Arkansas SIP. The air pollution regulations and control strategies developed in the Arkansas SIP were consistent with federal Clean Air Act requirements at that time. However, recent changes in federal PSD regulation will require Arkansas to revise their SIP including revisions to the Arkansas air pollution regulations.

The TEOR study field in Arkansas is the Smackover field in Union and Quachita counties. This area is attainment for all pollutants and potential expansion of TEOR in the field will require a DPC&E preconstruction review and an EPA PSD approval, if applicable. Some small new sources may be exempt from these requirements if controlled emissions are small.

6.0 AIR POLLUTION CONTROL SYSTEMS

The four air pollutants associated with TEOR production are SO_x, NO_x, particulate matter (PM), and hydrocarbons (HC). SO_x, NO_x, and PM originate primarily from oil-fired steam generators used in TEOR, while HC emissions come primarily from uncontrolled wellhead casing vents. This section describes and analyzes the air pollution control systems applied to TEOR equipment to control these pollutants. Availability, costs (capital and operating), effectiveness, and other factors related to the control systems are considered.

The steam generators used in TEOR are significantly different from conventional utility or industrial boilers in several ways:

- TEOR steam generators produce lower quality steam (80% at 1,000-1,600 psig).
- The boiler feed water used in TEOR steam generators undergoes less pretreatment since the water is not recycled.
- TEOR steam generators are much smaller (maximum 61.5 MM Btu/hr heat input) than conventional boilers.
- TEOR steam generators usually have only one burner, lack super heaters, and have a smaller cross sectional area to volume ratio, and
- TEOR steam generators operate unattended most of the time.

These and other differences in design and operating features make it difficult to apply control systems developed for conventional boilers to TEOR steam generators.

6.1 Method of Cost Analysis

Several design cases were analyzed for this cost study analysis. Four cases were considered for PM and SO_2 emissions: 1) a single 25 MM Btu/hr (heat output) generator; 2) a single 50 MM Btu/hr (heat output) generator; 3) a group of six 50 MM Btu/hr generators with flue gases ducted to a common stack; and 4) a group of ten 50 MM Btu/hr generators with a common stack. Only the first two cases above were analyzed for NO_x emissions because NO_x control systems are integral to the individual steam generators. For HC emissions from TEOR wells, a 32-well vapor recovery system was analyzed.

For each of the selected design cases, the control systems chosen for evaluation represented both existing and emerging technology. The control system analyses were based on the following criteria:

- Availability of the control systems - both the time needed to demonstrate emerging technology and the time needed to deliver existing control systems to the site.
- Applicability of existing and emerging control technologies to both existing and new steam generators.
- Effectiveness of the control systems - the compliance of both existing and new equipment with regulatory requirements.
- Costs of the control systems and the cost impact on the expansion of heavy oil production.

The economic bases used for the cost analyses are described briefly in Table 6-1.

The results of each cost analysis are given in the following subsections for SO_x, NO_x, PM, and HC control systems.

TABLE 6-1.

ECONOMIC BASES USED FOR THE COST ANALYSES

1. All economic data are presented in early 1979 dollars.
2. Capital-related costs are calculated as follows.

Assumptions

- 100% equity financing
- Effective tax rate (state plus federal) = 50%
- Straight line depreciation
- No investment tax credit
- Constant cash flows in every year of operation

Formulas

$$CF = I \times \frac{R\,(1 + R)^n}{(1 + R)^n - 1} = N + D$$

Where

CF = annual cash flow
I = depreciable investment
R = discount factor
n = equipment life in years
N = annual net profit
D = annual depreciation = $^I/_n$

$$N = CF - D$$

$$= I \times \frac{R\,(1 + R)^n}{(1 + R)^n - 1} - \frac{I}{n}$$

$$T = \frac{N \cdot t}{I - t}$$

TABLE 6-1 (cont'd)

ECONOMIC BASES

Where

T = annual taxes (state & federal)

t = effective tax rate

Total annual capital related charges $= N + T + D$

$= CRF \times I$

Where CRF = capital recovery factor

From the above, it can be shown that

$$CRF = \frac{R\,(I + R)^n}{I + R^n - 1} \quad I\,\frac{I}{n} \; + \frac{t}{I-t} \; \cdot \; \frac{R(I + R)^n}{(I + R)^n - I} \quad \frac{I}{n} \; + \frac{I}{n}$$

With $t = 50\%$, $R = 12\%$

and $n = 20$ years,

$CRF = 0.218$

3. A 15 percent contingency was added to all capital investment estimates.
4. Interest on working capital is also a capital-related expense. In this study, working capital is taken as one month of operating costs (includes raw materials, utilities, labor, maintenance, overhead). It is assumed that working capital is borrowed at 10 percent interest.

Additional details are available in Volumes II, III and IV of this report.

6.2 Flue Gas Desulfurization Systems (SO_2 Scrubbers)

All fossil fuel-fired steam generators in Kern County with greater than 15 MM Btu/hr fuel input are required to meet the field-wide, average sulfur compound emission limitations listed in the final version of Rule 424. The required emission limitations are:

• Existing Sources (final requirement) with Authority to Construct issued before 2/21/79.	0.12 lb sulfur per million Btu fuel input by 7/1/84.
• Existing Sources (interim requirement) with Authority to Construct issued before 2/21/79.	0.25 lb sulfur per million Btu fuel input by 7/1/82.
• New Sources with Authority to Construct issued on or after 2/21/79.	0.06 lb sulfur per million Btu fuel input.

Commercial technology is available which can reduce SO_2 emissions to the levels required by Rule 424. This technology has been demonstrated by several producers in Kern County. Options immediately available to producers who must comply with Rule 424 are:

- to install and operate new SO_2 scrubbers,
- to upgrade the removal efficiency of existing SO_2 scrubbers, or
- to burn low sulfur fuels.

Most of the SO_2 emissions reductions needed to comply with

Rule 424 will probably come from the installation of new SO_2 scrubbers.

The crude oil commonly burned in Kern County steam generators has approximately 1.1 to 1.5 weight percent sulfur. Table 6-2 indicates the sulfur removal efficiencies required to meet Rule 424 emission limits.

TABLE 6-2.

SULFUR REMOVAL EFFICIENCY REQUIRED TO MEET RULE 424 EMISSION LIMITS

Fuel Oil Sulfur Content (wt %) [a]	Emission Limit (lb sulfur/MM Btu fuel input)		
	.25	.12	.06
1.1	58%	80%	90%
1.5	69%	85%	93%

[a] Based on the following oil properties: 342 lb/bbl and 6.3 MM Btu/bbl.

Almost all of the SO_2 scrubbers planned for use in the oil fields can achieve 90 percent control and many are capable of achieving up to 96 percent. However, few of the producers have experience in the evaulation, selection, and operation of SO_2 scrubbers.

Upgrading the removal efficiency of existing scrubbers will not contribute significantly toward meeting the required emission limitations. Relatively few scrubbers are currently operating in the fields and the control efficiencies of these scrubbers are generally greater than 80 percent.

The use of low sulfur fuels may help meet the required emission limitations. However, they will not eliminate the need for scrubbing. In order to fully comply with the emission limitations through the use of low sulfur fuel oils, the oil sulfur contents shown in Table 6-3 would be required.

TABLE 6-3.

FUEL OIL SULFUR CONTENT REQUIRED
TO MEET RULE 424 EMISSION LIMITS

	Emission Limit (lb sulfur/MM Btu fuel input)		
	.25	.12	.06
Fuel Oil Sulfur Content (wt %)	0.46	0.22	0.11

Fuel oils with sulfur contents in the 0.1-0.5 wt% range are very expensive compared to crude oil, and their use is not considered further.

6.2.1 Status of Development and Performance

Currently some 100 flue gas desulfurization (FGD) processes are in various stages of development ranging from early developmental stages to full commercialization. Eleven FGD systems are expected to be used for the majority of near-term FGD applications for both utility and industrial boilers and steam generators. The potential application of these processes to steam generators is discussed below.

Two sodium-based scrubbing systems were evaluated to assess costs of controls and potential SO_2 removal efficiencies. The majority of sodium scrubbing systems in use today are in the California oil fields. Most of the recent Authorities to Construct (ACs) issued for steam generators in Kern County include specifications for sodium-based FGD systems.

The two sodium-based FGD systems chosen for study are the sodium hydroxide (NaOH) or caustic system, and the sodium carbonate (Na_2CO_3) or soda ash system. These FGD systems are capable of achieving high SO_2 removal efficiencies over a wide range of inlet SO_2 concentrations. Typically, the SO_2 removal efficiency ranges from 90 to 95 percent for the sodium-based scrubber systems specified in applications for ACs. Available compliance tests for the scrubbers indicate that the SO_2 scrubber systems simultaneously remove about 32 percent of the combustion particulates in the flue gas of a crude oil-fired field steam generator. FGD systems are being installed on steam generators in the following applications:

- scrubber for individual 25 MM Btu/hr (output) steam generators;
- scrubber for individual 50 MM Btu/hr (output) steam generators; and
- scrubber for bank of up to ten or more 50 MM Btu/hr (output) steam generators.

Since these FGD systems have achieved greater than 90 percent SO_2 emission reductions in practice, the Kern County APCD, CARB, and EPA consider high efficiency FGD systems the best available control technology (BACT) for sulfur dioxide emissions from crude oil-fired steam generators. Furthermore, since no other control systems have been able to achieve higher emission reductions, FGD systems are also considered to achieve the lowest achievable emission rate (LAER) for crude-fired steam generators. The two sodium FGD systems are also well suited for retrofit onto existing steam generators. The systems can be easily modularized and a relatively small amount of interface equipment is needed. The effects of the SO_2 scrubber on the steam generator are minimal.

The overall reliability of the two sodium scrubbing systems in industrial boiler applications has generally been quite high. However, since little operating experience with these FGD systems on steam generators exists, the overall reliability of the two systems for TEOR application is not available. The overall reliability of the systems used on TEOR steam generators may be significantly lower than that reported for industrial boiler applications because of typical oil field conditions. The steam generators typically operate unattended much of the time. The technical personnel who supervise the steam generator operations usually have not had extensive training in combustion equipment operation and maintenance in contrast to operators of large industrial and utility boilers.

The wastes from these sodium FGD systems contain sodium sulfite, sodium sulfate, sodium carbonate, sodium hydroxide, trace metals, and trace organics. Disposal of the wastes may be a problem because the wastes are highly soluble. The present trend in Kern County is toward wastewater treatment or holding ponds for evaporation. The scrubber wastes are also injected into deep reservoirs in the oil fields.

It is estimated that up to 75,000 barrels of waste per day may be produced by FGD systems applied to TEOR steam generators. The California State Water Resources Control Board projects that the capacity for disposal on the surface may not be sufficient to handle the waste as volumes increase. It appears that new sites must be developed, existing sites expanded, deep-well injection increased, or different surface disposal techniques adopted to handle expected increases in waste volumes.

Estimates of current disposal costs range from \$0.50 to \$0.65 per barrel of waste water produced, plus a state tax of \$0.175 per [illegible]rrel. This cost does not include transportation costs. If e[illegible]onmentally acceptable alternative methods or expanded faci[illegible]s are not available, the disposal costs are expected to increase significantly. Cost increases could shift SO_2 scrubber system application from the existing caustic and soda ash throwaway systems to systems producing a solid calcium-based waste (e.g., lime/limestone, Chiyoda Thoroughbred 121, or dual alkali).

6.2.2 Costs of FGD Systems

Factors which affect the costs of TEOR steam generator

FGD include the size of the scrubber, type of scrubbing process, concentration of SO_2 in the flue gas, generator utilization factor, and waste volume and disposal method. Each of these factors was considered in developing detailed cost estimates for the two sodium-based throwaway FGD systems.

The capital and annual costs for the SO_2 scrubbers are estimated for the following four steam generator/scrubber applications:

- single caustic scrubber on a 25 MM Btu/hr (output) steam generator;
- single caustic scrubber on a 50 MM Btu/hr (output) steam generator;
- a single soda ash scrubber on five 50 MM Btu/hr (output) steam generators; and
- a single soda ash scrubber on ten 50 MM Btu/hr (output) steam generators.

The scrubber costs were determined for an 80 percent utilization factor, 95 percent SO_2 removal, and for four crude oil sulfur contents (1.1, 1.2, 1.4, and 1.5 wt % sulfur). The capital and annual costs, SO_2 emission removal rate (pounds/hr), and cost-effectiveness ($/pound of SO_2 removed) for the four systems and the four fuels are presented in Table 6-4. Detailed calculation of these costs is given in Volume IV.

Cost-effectiveness ($/pound of SO_2 removed) is a useful method of comparing costs of various control systems under various conditions since it compares costs based on a common denominator. The results listed in Table 6-4 show that two factors significantly affect the cost-effectiveness of the control systems. The first factor is the sulfur content of the fuel burned. The greater the percent weight of sulfur in the fuel, the greater the cost-effectiveness (i.e., lower cost per pound of SO_2 removed).

TABLE 6-4.

COSTS AND SO_2 EMISSIONS FROM STEAM GENERATORS EQUIPPED WITH SO_2 SCRUBBERS

SCRUBBING UNIT/STEAM GENERATOR CONFIGURATION	COST+ OR EMISSION CATEGORY	WEIGHT PERCENT SULFUR IN THE CRUDE OIL 1.1	1.2	1.4	1.5
Caustic scrubber on a single 25 MM Btu/hr output steam generator	Total Capital Cost (10^3 $)	191	191	192	192
	Total Annual Cost* (10^3 $)	111.9-142.5	114.3-147.2	119.2-157.6	121.4-163.3
	SO_2 Emissions (lb/hr)	1.87	2.04	2.38	2.55
	SO_2 Removed (lb/hr)	35.51	38.74	45.20	48.42
	Cost Effectiveness* ($/lb of SO_2 removed)	0.45-0.57	0.42-0.54	0.38-0.50	0.36-0.48
	Incremental Capital Cost (10^3 $/MM Btu/hr input)	6.11	6.11	6.14	6.14
	Incremental Annual Cost* (10^3 $)	3.58-4.56	3.66-4.71	3.81-5.04	3.88-5.23
Caustic scrubber on a single 50 MM Btu/hr output steam generator	Total Capital Cost (10^3 $)	235	236	236	237
	Total Annual Cost* (10^3 $)	155.4-216.6	160.4-226.3	169.6-246.8	174.5-258.3
	SO_2 Emissions (lb/hr)	3.73	4.07	4.75	5.09
	SO_2 Removed (lb/hr)	70.91	77.36	80.25	96.70
	Cost Effectiveness* ($/lb of SO_2 removed)	0.21-0.44	0.30-0.42	0.27-0.39	0.26-0.38
	Incremental Capital Cost (10^3 $/MM Btu/hr input)	3.76	3.78	3.78	3.79

TABLE 6-4. (Cont'd.)

SCRUBBING UNIT/STEAM GENERATOR CONFIGURATION	COST+ OR EMISSION CATEGORY	WEIGHT PERCENT SULFUR IN THE CRUDE OIL 1.1	1.2	1.4	1.5
	Incremental Annual Cost* (10^3 \$/MM Btu/hr input)	2.49-3.47	2.57-3.62	2.71-3.95	2.79-4.13
Soda ash scrubber on a bank of five 50 MM Btu/hr output steam generators	Total Capital Cost (10^3 \$)	821	823	827	829
	Total Annual Cost* (10^3 \$)	557-723	573-755	606-818	623-850
	SO_2 Emissions (lb/hr)	18.7	20.4	23.8	25.5
	SO_2 Removed (lb/hr)	355	387	451	483
	Cost Effectiveness* (\$/lb of SO_2 removed)	0.22-0.29	0.21-0.28	0.19-0.26	0.18-0.25
	Incremental Capital Cost (10^3 \$/MM Btu/hr input)	2.63	2.63	2.65	2.65
	Incremental Annual Cost* (10^3 \$/MM Btu/hr input)	1.78-2.31	1.83-2.42	1.94-2.62	1.99-2.72
Soda ash scrubber on a bank of ten 50 MM Btu/hr output steam generators	Total Capital Cost (10^3 \$)	1,635	1.639	1.647	1.651
	Total Annual Cost*	1,039-1,372	1,072-1,434	1,138-1,561	1,171-1,624
	SO_2 Emissions (lb/hr)	37.3	40.7	47.5	50.9
	SO_2 Removed (lb/hr)	709	774	903	967
	Cost Effectiveness* (\$/lb of SO_2 removed)	0.21-0.28	0.20-0.26	0.18-0.25	0.17-0.24
	Incremental Capital Cost (10^3 \$/MM Btu/hr input)	2.62	2.62	2.64	2.64
	Incremental Annual Cost* (10^3 \$/MM Btu/hr input)	1.66-2.20	1.72-2.29	1.82.250	1.87-260

*Range of costs results from a range of disposal and chemical costs.
+Costs calculated in terms of early 1979 dollars.

The second factor is the economy of scale. The larger the steam generator or grouping of steam generators utilizing one control system, the greater the cost-effectiveness. The cost-effectiveness values range from \$0.17 to \$0.24 per pound of SO_2 controlled for a bank of ten 50 MM Btu/hr steam generators burning 1.5 percent sulfur fuel, to \$0.45 to \$0.57 per pound of SO_2 controlled for a single 25 MM Btu/hr steam generator burning 1.1 percent sulfur fuel.

Total capital and annual costs for the various types and sizes of control systems and combinations of control systems are 8 to 10 times greater for the largest systems than for the smallest systems. However, the quantity of SO_2 removed by the largest control system is twenty times that of the smallest system, thus illustrating the economy of scale. Incremental capital and annual costs in terms of dollars per MM Btu/hr (input) provides another measure of cost-effectiveness. The incremental cost of the largest system considered is approximately one-half of the smallest system considered. Note that the annual costs shown in Table 6-4 can result in a wide range of costs (in \$/pound of SO_2 removal) for a producer in a single field. This cost depends on the cost of waste disposal options, the economy of scale, and other factors. The detailed assessment of SO_2 development status, and more detailed cost data used for the basis of this section are presented in Part I of Volume IV of this report.

6.3 NO_x Control Systems

In the last few years, several NO_x control technologies have emerged in Japan and the United States for large industrial and utility boiler applications. Within the last two years, steam generator manufacturers, control vendors, and oil producers have begun an intensive effort to develop NO_x controls for steam generators. The three basic options are combustion modification, flue gas treatment, and a combination of the first two. Combustion modification technologies focus on techniques to reduce NO_x formation during the combustion process, while fuel gas treatment technologies rely on mechanisms that reduce NO_x emissions in the flue gas from the combustion process.

Some combustion modification techniques developed for industrial and utility boilers are applicable to steam generators. Newly developed crude oil burners (commonly referred to as low NO_x burners) are being marketed for steam generators. These burners use staged combustion and/or flue gas recirculation to reduce the amount of NO_x formed during combustion. Control systems that limit excess oxygen during combustion and lower NO_x emissions have been marketed since 1979. Other techniques, which have been applied to large utility and industrial boilers, are also applicable to steam generators. These techniques include air preheat, load reduction, and burners out of service.

Two flue gas treatment technologies that are being developed for reducing NO_x emissions from steam generators are selective non-catalytic reduction and selective catalytic reduction. Both of these technologies require injection of ammonia (NH_3) into the flue gas which combines with the NO_x to form nitrogen (N_2) and water. The reaction of NO_x with NH_3 can be performed with or without a catalyst. The catalyst allows the reaction to proceed at a much lower temperature.

The combustion modification and flue gas treatment technologies can be applied singly or in combination. However, the combination of these technologies can be expected to create compatibility problems in their application to steam generators, particularly to existing generators. The application of these control technologies in combination is analyzed in this study, even though field testing of the combined technologies is not expected to be completed for several years.

In this section, the state of development, NO_x removal efficiencies, performance, and cost-effectiveness of NO_x controls are discussed. The ability of the various control technologies to meet the applicable control requirements of NSR are also discussed. The technical and economic evaluations were based primarily on two EPA reports in the Technology Assessment Report Series for Industrial Boiler Applications. These reports were NO_x Flue Gas Treatment Report, and the NO_x Combustion Modification Report. Additional information, particularly cost estimates, was obtained from vendors.

6.3.1 Combustion Modification

Combustion modification techniques generate lower levels of emissions by suppressing the formation of NO_x in the steam generator. NO_x is formed by two different mechanisms. The most obvious mechanism is termed "fuel NO_x", that amount of NO_x formed due to the combustion of organic nitrogen in the fuel. The second source, called "thermal NO_x", occurs due to the reaction of nitrogen and oxygen in the combustion air. High NO_x levels can be attributed to combinations of the following factors: high nitrogen levels in the fuel, high excess O_2 concentrations, and high flame temperatures. Additionally, the mixing turbulence and residence time in the boiler have been observed to influence the NO_x level. Combustion modification controls suppress the NO_x formation rate by varying these parameters, as discussed in the following subsections.

6.3.1.1 Low Excess Air (O_2 Control)

Steam generators typically operate with a high percentage of excess air to insure complete combustion of the fuel. Low excess air operation involves operation of the steam generator with less than 3 percent oxygen in the flue gas, while maintaining complete combustion of the fuel. This reduction of oxygen concentration reduces the probability of nitrogen reacting with oxygen to form NO_x. Additionally, the lower flue gas volume results in a slightly increased thermal efficiency due to a smaller heat loss out the stack. An average thermal efficiency increase of approximately one percent has been observed with low excess air combustion.

Currently, O_2 control systems with flue gas O_2 monitors and air flow controls are available for steam generators. These systems are required to prevent substoichiometric combustion resulting in CO, hydrocarbon, and smoke emissions while maintaining low excess air firing conditions. These controls are generally easy to install on existing steam generators, as well as on new ones.

6.3.1.2 Low NO_x Burners (LNBs)

Rapid mixing of oxygen with the fuel promotes NO_x formation due to the increased exposure of oxygen to the fuel bound nitrogen and to the higher temperatures of the primary (initial) flame zone. In addition, thermal NO_x (from thermal fixation of atmospheric N_2) increases with the time that air is exposed to high temperatures. The objectives of modified burner designs for NO_x reduction are to decrease the concentration of air in the higher temperature, primary flame zone and to minimize the time that the combustion gases are exposed to high temperatures. Low NO_x burners are distinguished from one another by the manner in which the fuel and combustion air are injected. They may be categorized as follows:

- Controlled-mixing, atomization systems reduce thermal NO_x by manipulation of flame shape to maximize radiative surface area. This lowers flame temperatures and reduces residence time at high temperatures.
- Divided-flame systems reduce thermal NO_x by

dividing the flame into several, separate smaller flames. This decreases the peak flame temperature and the high temperature residence time.

- Self-recirculation systems reduce thermal and fuel NO_x by recirculating combustion gases into the primary flame zone. Combustion gases are cooler than primary flame zone gases and have a lower O_2 concentration.
- Staged combustion systems reduce thermal and fuel NO_x by injecting substoichiometric amounts of air in the primary flame zone and excess air in the secondary, cooler zone.
- Any combination of the systems described above.

The optimum performance of each type of low NO_x burner requires automatic control of excess combustion air. This necessitates monitoring the flue gas O_2 concentration.

Several manufacturers offer low NO_x burners for 50 MM Btu/hr (output) steam generators. However, low NO_x burners are generally not available for small steam generators. Extensive modifications are needed to retrofit low NO_x burners on small steam generators.

Several oil producers have committed to programs for the demonstration of low NO_x burners equipped with O_2 controllers as BACT to comply with EPA preconstruction review requirements. Several oil producers have also submitted applications to the Kern County APCD for new generators with low NO_x burners equipped with O_2 controllers.

Precise control of fuel and air flow is critical for optimal NO_x reduction and flame stability. For clean fuels (natural gas and distillate oil) which have little fuel-bound nitrogen, low NO_x burners may reduce NO_x levels comparable to reduction levels obtained using selective non-catalytic reduction (SNR) systems. Low NO_x burners produce much higher amounts of "sticky" unburned hydrocarbon particulates than observed for conventional burners. This problem may be exacerbated by the use of O_2 controllers to reduce excess combustion oxygen.

In this study, low NO_x burners were estimated to yield a 30 percent reduction of NO_x emissions as compared to a typical "uncontrolled" burner.

6.3.2 Flue Gas Treatment

The most advanced flue gas treatment technologies are selective non-catalytic reduction (SNR) and selective catalytic reduction (SCR). Both of these technologies lower NO_x emissions by injecting NH_3 into the steam generator to produce nitrogen and water. The catalyst used in the SCR technology allows the reactions to proceed at a much lower temperature. The reactions which are the same for both SNR and SCR are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The first reaction dominates since flue gas NO_x is 90 to 95 percent NO. Any excess NH_3 and the nitrogen and water exit with the flue gas.

Both of these technologies may potentially be applied in conjunction with combustion modification technologies. However, in view of the state of development of the flue gas treatment technologies, the combined applications of these technologies appear to be highly speculative at the present time.

6.3.2.1 Selective Non-Catalytic Reduction (SNR)

Exxon began working on a non-catalytic ammonia injection process in the early 1970's and applied for a process patent. The Exxon patent for the Thermal DeNO$_x$ process includes the use of water-cooled nozzles to minimize the thermal decomposition of NH_3 to NO$_x$. For some SNR applications, H_2 may be injected to lower the NO$_x$ reduction reaction temperature. However, the presence of H_2 does not widen the optimum temperature range. SNR systems using H_2 are not expected to be applied by oil producers for safety reasons.

Struthers Thermoflood, a steam generator manufacturer, is licensed to apply this technology to steam generators. Many oil producers have committed to testing SNR on recently permitted steam generators.

The reaction of NH_3 with NO$_x$ and O_2 to form N_2 and water is optimized at 1770° F $\pm$ 90° F. Above this temperature range, NH_3 conversion to NO$_x$ becomes the predominate reaction. Below this temperature range, the NH_3 reaction with NO$_x$ quickly decreases and large quantities of NH_3 are emitted to the atomosphere. During normal operations, NH_3 concentrations in the flue gas are expected to be less than 50 ppm.

For a clean 50 MM Btu/hr (output) steam generator, the optimal temperature range for SNR is normally found in the transition section between the radiant and convective sections. Figure 6-1 is a schematic of a steam generator showing probe locations. Ammonia is injected through water-cooled nozzles installed in the transition section. The control package for NH_3 injection is complex and involves temperature, flue gas rate, the flows of NH_3 and its dilution gas, and continuous NO$_x$ monitors. It is also subject to relatively frequent failure compared to equipment presently associated with steam generators.

At present, no continuous monitors are available to measure NH_3 concentrations in the flue gas. For large-scale boiler applications, the NO$_x$ concentrations are measured and flue gas volume is calculated. Using these parameters, the NH_3

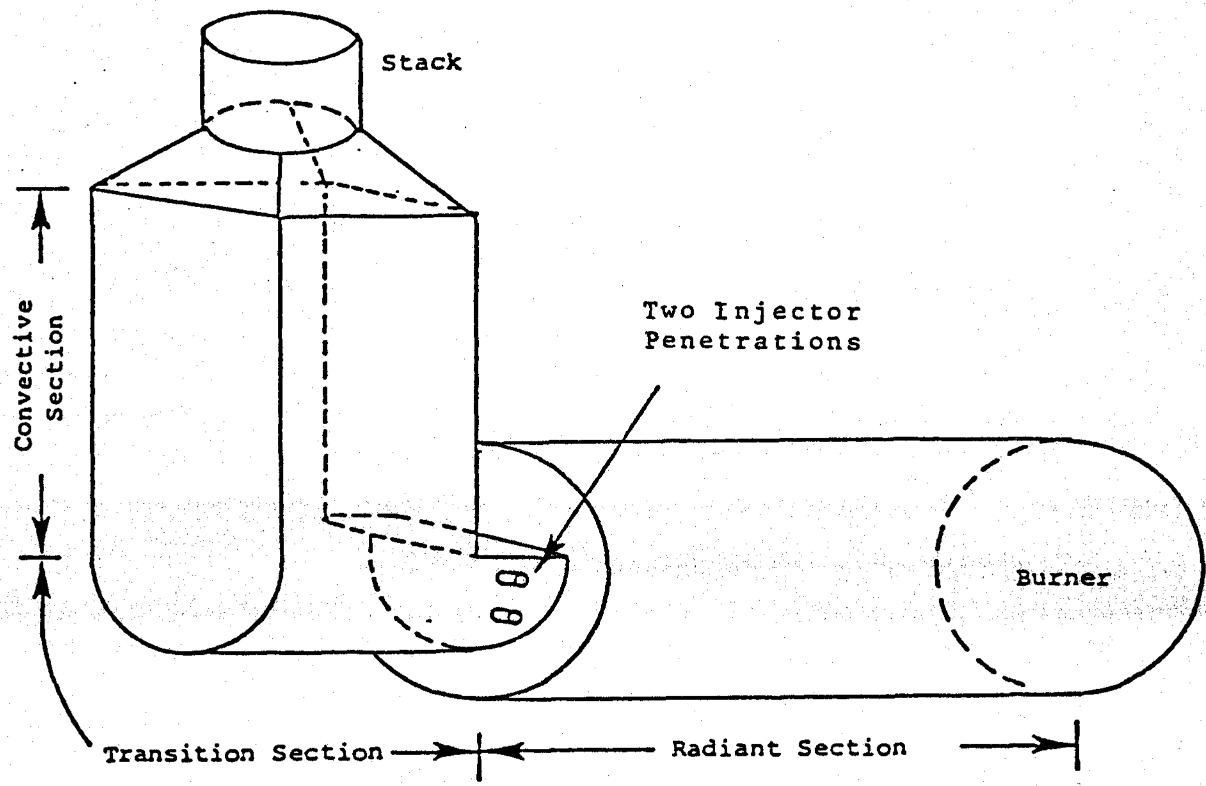


Figure 6-1. Schematic of Steam Generator Showing Probe Locations.

injection rate is determined. As a check on the control system, the exit NO_x concentration is also measured. The control system may require sophisticated electronic instruments which need special air conditioning shelters.

At least one test of this process has been made for a crude oil-fired steam generator in Kern County. However, no continuous, unattended operation of the SNR system was attempted during the test. The NO_x reductions observed during these limited tests ranged from 50 to 70 percent (Exxon, 1978). Even though SNR systems have not been demonstrated under normal operating conditions, the Kern County APCD, as well as many other California APCDs, considers SNR with low NO_x burners and O_2 controllers to be BACT. At present, no test data are available on the removal efficiency of SNR with O_2 controllers and LNBs. For this study, the combined NO_x removal efficiency of the three technologies is estimated as 50 percent of the "uncontrolled" NO_x emissions.

6.3.2.2 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) uses a catalyst to promote the reaction of NH_3 with NO_x to form N_2 and H_2O at a temperature range of 570° - 750° F. The base metal catalysts usually employed are titanium dioxide (TiO_2) and vanadium pentoxide (V_2O_5), both of which are resistant to SO_x poisoning. Other proprietary components are added depending on the requirements of each specific application. Crude oil firing requires a catalytic design capable of treating particulate-laden flue gas. Parallel-flow SCR reactors have been applied to several industrial and utility boilers which burn residual oil in Japan. Most of the installations are expected to achieve NO_x reductions of better than 80 percent. Most of the manufacturers guarantee the catalyst life for one year.

Catalysts can be deactivated by "sticky" combustion particulates and/or oil mist. The problem of catalyst deactivation (poisoning) by combustion particulates is expected to be exacerbated when low NO_x burners with O_2 controls are also installed in the steam generator.

The formation of ammonium bisulfate (NH_4HSO_4) on the surfaces of the convective section may be a problem even though NH_3 concentrations in flue gas treated by a SCR system are expected to be lower than flue gas NH_3 concentrations after treatment in a SNR system. The catalyst converts some SO_2 to SO_3. These higher SO_3 concentrations are expected to contribute to higher potential for NH_4HSO_4 formation.

The design temperature of the catalyst (570^o F to 750^o F) is at an intermediate point in the convective section of a 50 MM Btu (output) steam generator. At present, it appears that the convective section of the steam generator will have to be split into two sections so that the reactor can be inserted. In this configuration, the operation of the catalytic reactor becomes coupled to the operation of the steam generator. As coupled systems, a sophisticated operating feedback system must be developed in order to assure efficient operation of the control system and to protect the catalyst from rapid deterioration during a steam generator malfunction.

The control system should allow the SCR system to operate in an unattended, automatic mode for an extended period of time. This mode of operation is typical of steam generator operations in the field. Steam generator malfunctions which can poison the the catalyst, such as a "flame-out", sooting burners, and temperature excursions, can be extremely costly, because the catalyst portion of the control system is so expensive (about $135,000 for a single 50 MM Btu/hr steam generator).

The instrumentation for the SCR system must also be capable of unattended operation. Typically, NO_x concentrations in the flue gas are measured by a chemiluminescent instrument which is significantly more complex and sensitive than those currently found on steam generators. These instruments, in addition to monitoring NO_x removal performance, provide input signals which control the ammonia injection rate. Long term performance in dust, extreme temperature, and sometimes high humidity may become a critical limitation to SCR control system development for oil field applications. If the SCR system is unable to operate in an unattended mode, the operating costs of the steam generators can be expected to significantly increase to cover the increased costs for personnel.

Although the SCAQMD considers SCR as both BACT and LAER for steam generators with greater than 35 MM Btu/hr heat input, no SCR systems have been developed for steam generators. This is especially true for high nitrogen-, sulfur-, and particulate-emitting crude oil-fired steam generators. One producer in the SCAQMD has committed to a pilot demonstration of an SCR system on a 50 MM Btu/hr (output) steam generator to begin in 1981. However, even if SCR is demonstrated, SCR systems probably will not be commercially available for steam generators until the mid-1980's.

The Ventura County APCD recently accepted a SCR system designed for a 50 MM Btu/hr steam generator as "innovative" technology. This designation resulted due to the complexity of the control system needed for the SCR system, the prevalence of technical problems, and the lack of any existing SCR systems on steam generators. "Innovative" technology status for SCR system seems appropriate for the next few years until SCR has been demonstrated on steam generators.

6.3.3 Costs of NO_x Control Systems

The costs and cost-effectiveness of NO_x controls are estimated for the following cases for 25 MM Btu/hr (output) and 50 MM Btu/hr (output) steam generators:

- O_2 control system (25 and 50 MM Btu/hr steam generators);
- O_2 control and low NO_x burners (25 and 50 MM Btu/hr steam generators);
- O_2 control, low NO_x burners, and SNR (50 MM Btu/hr steam generator only);
- O_2 control, low NO_x burners, and moderate SCR (25 and 50 MM Btu/hr steam generators); and
- Stringent SCR (25 and 50 MM Btu/hr steam generators).

This broad range of options was evaluated since various NO_x control measures may be combined by a given producer to comply with Rule 425 and/or to provide offsets for future expansion. Some options may not be feasible for a specific site because the control measure will not meet the emission limits or will not provide adequate emission offsets.

The detailed cost estimates presented in Appendix A (Volume II) are summarized in this section in Table 6-5. Whenever possible, equipment cost estimates were obtained from vendors. Installation costs are estimated as a percentage of the total equipment costs. Guthrie's cost estimation manual (1974) was used to determine various cost factors in estimating capital costs. Retrofit of controls to existing steam generators in the oil fields is estimated to cost 50 percent more than installing the controls on new steam generators during manufacturing. The same annual labor cost ($8,000) is applied for maintenance of all NO_x control systems. No credits are given for the potential crude oil savings that may be observed for the O_2 control and LNB systems.

TABLE 6-5.

COSTS AND NO_2 EMISSIONS FROM STEAM GENERATORS EQUIPPED WITH NO_x CONTROL SYSTEMS.

Cost[1] or Emission Category	Steam Generator Size (MM Btu/hr)[2]	NO_x Control Systems (Percent NO_x Reduction)				
		O_2 Control[3]	O_2 Controls and LNBs[3] (15%)	O_2 Controls, LNBs, & SNR[3] (50%)	O_2 Controls, LNBs, & Moderate SCR[3]	Strinnent SCR (90%)
Total Capital Cost (10^3 \$)	25	13.3-18.9	64.0-95.6	NA[4]	621-745	667-791
	50	13.0-18.6	89.6-132	188-278	1,030-1,250	1,090-1,310
Total Annual Cost (10^3 \$)	25	15.9-17.4	28.6-37.1		273-305	330-362
	50	15.8-17.2	35.6-46.5	69.9-93.4	434-490	493-549
NO_2 Emissions (lb/hr)	25	12.65	10.42	NA	2.23	1.49
	50	25.30	20.83	14.88	4.46	2.98
NO_2 Removed (lb/hr)	25	2.23	4.46	NA	12.65	13.39
	50	4.46	8.93		25.30	26.78
Cost Effectiveness (\$/lb of NO_2 removed)	25	1.02-1.11	0.92-1.19	NA	3.08-3.44	3.52-3.86
	50	0.51-0.55	0.57-0.74	0.67-0.90	2.45-2.76	2.63-2.93
Incremental Capital Cost (10^3 \$/MM Btu/hr input)	25	0.43-0.60	2.05-3.06	NA	19.9-23.8	21.3-25.3
	50	0.21-0.30	1.43-2.11	3.01-4.45	16.5-20.0	17.4-21.0
Incremental Annual Cost (10^3 \$/MM Btu/hr input)	25	0.51-0.56	1.14-1.48	NA	8.74-9.76	10.6-11.6
	50	0.25-0.28	0.71-0.93	1.12-1.49	6.94-7.84	7.89-8.78

[1]Costs calculated in terms of early 1979 dollars.

[2]Heat output, 80 percent steam generator thermal efficiency.

[3]Cost ranges are the result of cost differences for new and retrofit applications of the NO_x control systems. NO_x control costs for new steam generators are represented by the lower limit of the ranges while retrofit control costs are represented by the upper limits of the ranges.

[4]SNR is not presently expected to be applicable to 25 MM Btu/hr steam generators (NA = not applicable).

The costs for selective non-catalytic reduction (SNR) systems are not shown for the 25 MM Btu/hr steam generator case because of the difficulty of applying this technology to the 25 MM Btu/hr steam generators. Two cases are costed for SCR systems: a moderate case with an 85 percent NO_x removal SCR system equipped with LNB and O_2 control, and a stringent case with a 90 percent NO_x removal efficiency SCR system. For the SCR cases, the costs of splitting the convective section of the steam generators and a bypass valve system are included in the capital costs for new and retrofit applications.

As discussed in Section 6.2, cost-effectiveness proves to be a useful method of comparing costs of different control systems. Table 6-5 illustrates the increased cost-effectiveness of NO_x control systems applied to 50 MM Btu/hr (output) steam generators over 25 MM Btu/hr generators. Retrofitting stringent SCR at 90 percent control efficiency on an existing 25 MM Btu/hr steam generator is four times less cost effective than installing O_2 controls at 15 percent control efficiency on a new 25 MM Btu/hr steam generator. Similarly, for a 50 MM Btu/hr steam generator, stringent SCR is six times less cost-effective than O_2 controls.

Although the less efficient control systems are significantly less expensive and more cost-effective, their application is expected to neither comply with the air pollution regulations, nor provide sufficient NO_x emission control or offsets to allow significant increases in TEOR production.

6.4 Particulate Matter (PM) Control Systems

Specialized technology for the control of PM from TEOR steam generators currently is being developed. This section identifies the state-of-the-art particulate control technology and outlines considerations for the choice of a future level of particulate control. This information was used to estimate the maximum PM offsets available for future TEOR expansion. The analysis was limited to the situation in which particulate control equipment was applied in addition to a wet SO_2 scrubber. It was assumed the FGD systems were installed on steam generators only for SO_2 control.

Offsets for PM have been historically obtained through paving of dirt roads. This practice is no longer acceptable for offsetting fine PM emissions. The CARB considers fine respirable particles a health risk and has established guidelines requiring any increases of fine PM emissions to be offset by equivalent reductions of existing fine PM source emissions. If further expansion of TEOR facilities is to take place, generators must be retrofitted with particulate control equipment which will control fine particles, as well as the larger particles.

The collection of fine particulates from TEOR steam generators creates special problems for conventional particulate control equipment. Particulate scrubbers are only marginally effective for fine particles unless the energy input is extremely high. Traditional dry particulate equipment such as baghouses or electrostatic precipitators (ESPs) cannot be used for this application since the flue gas exits the scrubber in a saturated water vapor condition.

New technology designed to be used following wet SO_2 scrubbers on TEOR steam generators incorporates a variety of collection concepts which include wet filtration, wet electrostatic precipitation, and removal in electrified granular beds.

A unique set of operating parameters exist for particulate control from TEOR steam generators. The flue gas exiting the generator is at approximately 500° F and is laden predominately with fine particulates. The grain loading is 0.03 to

0.07 grains per SCF[1]. The particulates exist together with viscous aerosols, SO_3, and sulfate (Roberts, 1980). A generator rated at 62.5 MM Btu/hr input capacity produces an exhaust flow of about 20,000 acfm. As this exhaust passes through the SO_2 scrubber, it is cooled and exits the scrubber saturated with water vapor. Most particulate control equipment which is considered applicable to TEOR generators is designed to treat the flue gas at the scrubber exit to remove both the remaining particulate matter transmitted through the scrubber and the scrubber "carry over" mist emissions.

In many cases, generators are banked together to take economic advantage of larger-scale control equipment. One SO_2 scrubber and one particulate control device could be used on as many as eight to ten generators. However, in some fields, generators must be controlled individually. Thus, the particulate control equipment should be available in a variety of sizes to meet a large range of flow rates. In addition, generators are moved as steam is needed and may frequently change location within a production area. As a result, the equipment must be skid mounted and must be designed for simple hook-up to the steam generator.

The major TEOR producers are presently investigating a variety of particulate control equipment types for applicability to TEOR steam generators. Table 6-6 contains a list of equipment under consideration by these producers for TEOR applications. The characteristics of each particulate removal process were analyzed to choose a control system to be used in the maximum TEOR production scenario. The dry scrubber was not analyzed since only wet SO_2 scrubbers were assumed to be used on TEOR steam generators.

---

[1]Source test data performed by Anderson 2,000 on HEAF system, July, 1980.

TABLE 6-6.

CHARACTERISTICS[1] OF PARTICULATE CONTROL EQUIPMENT FOR TEOR STEAM GENERATORS

Manufacturer & Characteristics	Anderson 2000 M30, M40	Environmental Resources Co. EGB System	Envirotech Fluid-Ionic EFB System	Kermatrol C-5H-Ht & C-9H-HT	Rockwell International HC-176
Collection Efficiency[2]	94% (to 0.003 gr/SCF)	99.9%	99+%	99.7%	∿99.5% (<0.01 gr/SCF guaranteed)
Commercial installations in similar processes	yes	yes	no	yes	yes
Commercial test installations for TEOR operating to date	yes	no	no	no	no
Flue gas Test Data Available	yes	no	1981	1981	no
Operation behind wet scrubber	yes	yes	yes	yes	no
Skid mounted and mobile	yes	no	no	yes	no
Applicable sizes of TEOR generators (MM Btu/hr output)	25 50 500	25 50 500	50 500	25 50 500	500
Removal mechanism	HEAF[3] Advances fiberglass matt filter	Electrified granulated bed	Wet electrostatic precipitation	HEPA[4] Coated wet filtration	Dry Scrubber with fabric filtration

[1]Due to the stage of development and lack of commercial installations of this equipment, a limited amount of information was available for these units.

[2]Estimates provided by vendors.

[3]HEAF = High Efficiency Air Filter.

[4]HEPA = High Efficiency Particulate Air.

6.4.1 State-of-the-Art Development of Particulate Control Equipment

Particulate control has only recently become a major concern to TEOR producers. Most particulate control equipment for TEOR has been developed since 1979. State-of-the-art technology is still emerging from pilot and commercial testing. For this reason, current information on these systems is fairly limited. To date there have been no permanent commercial installations of control equipment specifically designed to remove only particulate matter. There are, however, some full-scale installations in the field which are being tested to demonstrate performance of these systems under actual operating conditions. Preliminary data from some of these installations show excellent performance (Roberts, 1980).

The first step in optimizing and selecting particulate control technology is to completely characterize the steam generator flue gas, including a particulate size distribution analysis. Because the size distribution of particulate emissions from steam generators is presently unknown, analysis of particulate control efficiencies by particle size range is impractical at this time. In order to perform such analyses, it is necessary to specify a minimum collection efficiency attainable throughout all particulate size ranges.

In this report, the minimum collection efficiency claimed by the vendors is used as worst-case estimate of the overall collection efficiency of the particulate control equipment. This estimate may then be used for gas streams containing any particulate size distribution, thus precluding the necessity of specifying performance on fine particulates separately. Complete characterization data may show collection efficiencies to be somewhat higher in actual flue gas streams, but in the absence of these data the worst-case estimate has been used to calculate future particulate offsets for TEOR.

Some vendors marketing particulate control equipment have issued a performance guarantee for their product. This guarantee states the lowest limit of fraction collection efficiency that the product is guaranteed to exceed. If the equipment does not meet the specified performance, the vendor is expected to allow it to be returned for refund or to make necessary modifications to the equipment so that it will meet the guaranteed performance.

6.4.1.1 The Kermatrol HEPA Wet Filtration System

A representative system was selected in order to facilitate the analysis of particulate control systems. The particulate removal system chosen as representative of future particulate control was the Kermatrol High Efficiency Particulate Air (HEPA) wet filtration system. This system was selected for the following reasons:

- Guaranteed collection efficiency is 99.97 percent for all particles including submicron sizes. This is given as a "worst-case" estimate for a 0.3μ size particle and represents the highest guaranteed collection efficiency of all applicable equipment.
- The process is commercially proven and has been in use in a variety of industries for a number of years. Performance specifications have been met on existing installations in similar applications.
- Filtration is designed for wet conditions similar to those existing in scrubber outlets.
- Units are compact, self-contained, and are skid mounted for mobility.

- Construction materials have already been specified for wet, acidic, and high temperature streams.
- Units are available in sizes applicable to all cases found in TEOR steam generators.
- Capital, operation, and maintenance costs are competitive with other available particulate control equipment based on current data.

This system was chosen for analysis only as a representative system. Data on actual performance on TEOR generators were not available at this time.

Removal of particulates in the Kermatrol process is accomplished by mechanical air filtration through a Kermatrol HEPA filter. The HEPA filter is a micro-fine glass filter which is capable of collecting particulates with an efficiency of 99+ percent. The Kermatrol HEPA filter was developed to meet leak-free conditions in wet and high temperature environments. A leak-free seal, together with a very thin pre-filter membrane coating, is applied to the HEPA filter. The HEPA filter then provides porous mechanical support for the prefilter and backs up any incomplete coverage areas of the prefilter membrane. The membrane is a layer of inert material approximately 25 nanometers thick cast into the support substrate. The pre-filter membrane pores average one nanometer through which essentially molecular flow is established when air passes through the membrane. Particulate interception occurs wholly at the surface of the membrane, thus aiding in the cleaning process. The Kermatrol filter is not affected by wet or acid conditions and can withstand temperatures up to 1000° F.

The average life of the filter varies with exhaust streams, particulate loading, and application. Kermatrol filters have lasted from three to six years under continuous operation in existing field installations. The filter cartridges are mounted in sliding trays. It is not necessary to interrupt operations of the Kermatrol unit to inspect or replace the filters.

The filter is cleaned by two mechanisms. Shakedown of the filter at predetermined intervals releases accumulated dust into a hopper below. Additional cleaning is accomplished with a vacuum nozzle which traverses the filter surface at specified intervals. The exhaust from the vacuum system is cleaned by cyclonic separation and filtration and is then routed back to the main inlet stream, thus creating a closed loop cleaning system. Dust and sludge collected in the hopper are flushed out with water which exits through a trickle valve sump. Resulting sludge is disposed of with the waste from the SO_2 scrubber.

No field installations of Kermatrol exist for TEOR steam generators at this time. One oil producer has purchased a Kermatrol unit to test on a 50 MM Btu/hr generator during 1981. The Kermatrol process has been installed and demonstrated on utility boilers and nuclear waste incinerators, and has performed to specifications in these applications. Kermatrol can make no guarantees as to the life of the Kermatrol system in TEOR steam generator applications because operating parameters are presently severe impediments to wide application of the control system.

6.4.1.2 Retrofit Considerations and Offsets

Retrofit of existing steam generators with particulate controls will be necessary to create offsets for future TEOR expansion. The Kermatrol unit utilizes the existing stack and is ducted in place between the scrubber and the stack. An induced draft fan is included with the Kermatrol unit.

Typical particulate emissions from a 50 MM Btu/hr steam generator average approximately 10 pounds per hour. Sulfur dioxide scrubbers currently operating on TEOR steam generators remove an estimated 32 percent or 3.2 lbs/hr of particulate matter which cannot be used for offset.[1] Therefore, the available emission offsets gained by retrofit are those transmitted through the scrubber. The actual offset is the amount of this particulate matter collected in the particulate control unit. For the above case, this would be 99.97 percent of 6.8 lbs/hr or 6.798 lbs/hr. Residual emissions from new generators equipped with Kermatrol units are expected to average 0.03 percent of 6.8 lbs/hr (or about 0.002 lbs/hr). Retrofit of one existing steam generator creates offset emissions for an additional 2,700 new generators also equipped with high efficiency particulate controls.[2]

6.4.2 Costs of Particulate Control Systems

The costs and cost-effectiveness of particulate controls are estimated for the following four cases for 25 MM Btu/hr (output and 50 MM Btu/hr (output) steam generators:

- one 25 MM Btu/hr generator with an individual particulate control device;
- one 50 MM Btu/hr generator with an individual particulate control device;
- six 50 MM Btu/hr generators banked into a single particulate control device; and
- ten 50 MM Btu/hr generators banked into a single particulate control device.

A detailed economic analysis was conducted for the Anderson 2,000 HEAF system in addition to the Kermatrol System. These control systems were found to be the most cost-effective

[1] Kern County source tests, 1978, 1979.
[2] This estimate is based on the current offset ratio of 1.2 to 1, and an overall control level of 99.97 percent.

particulate control systems based on current data and are applicable to small single generators as well as larger banked generators. Cost data were based upon price information for mid-1980 and best estimates by the manufacturer for similar installations. Costs were then scaled back and put in terms of the first quarter 1979 dollars, in order to provide a cost base consistent with the rest of the report.

The detailed cost estimates presented in Appendix B, Volume II, are summarized in this section. Retrofit costs are assumed to be comparable to costs for new steam generators since the systems are strictly add-on types of systems. Operating costs include power consumption, filter replacement (in the case of throw-away filters), and maintenance costs based on similar installations.

Table 6-7 shows economy of scale for particulate control systems. The cost-effectiveness of the largest particulate control system considered is three times greater than the smallest system considered. Although the total capital and annual costs between the smallest and largest system considered increase by factors of thirteen and seven, respectively, the quantity of particulate removed by the smallest systems considered increase by than that removed by the largest system. Comparison of incremental capital and annual costs (in terms of dollars per million Btu/hr heat input), indicates increases of one and one-half and three times, respectively, between the smallest and largest systems. This further illustrates the economy of scale in particulate controls in TEOR application.

6.5 Hydrocarbon Control Systems

Hydrocarbon (HC) emissions control technology applicable to TEOR is discussed in this section; additional detailed information is given in Volume IV of this report. The

TABLE 6-7.

COSTS[1] AND EMISSIONS FROM STEAM GENERATORS
EQUIPPED WITH HIGH-EFFICIENCY PARTICULATE CONTROL SYSTEMS

Cost or Emission Category	Steam Generator Size[2] and Configuration			
	25	50	Bank of Six 50's	Bank of Ten 50's
Total Capital Cost (10^3 $)	27.2	51.2	246	358
Total Annual Cost (10^3 $)	35.0-48.9	57.7-63.0	165-203	225-339
PM Emissions (lb/hr)	0.03	0.07	0.42	0.69
PM Removed (lb/hr)	3.44	6.88	41.3	68.8
Cost Effectiveness ($/lb of NO_2 removed)	1.45-2.03	1.20-1.31	0.57-0.70	0.47-0.70
Incremental Capital Cost (10^3 $/MM Btu/hr input)	0.87	0.82	0.66	0.57
Incremental Annual Cost (10^3 $/MM Btu/hr input)	1.12-1.56	0.92-1.01	0.44-0.54	0.36-0.54

[1]Costs estimated in terms of early 1979 dollars.

[2]MM Btu/hr output assuming 80% thermal efficiency.

use of wellhead vapor recovery (WHVR) systems for the steam drive process is the HC control technique of primary focus in this study. Historically, the HC-laden steam which did not condense in the reservoir was vented to the atmosphere to minimize reservoir pressure build-up. This vent is now controlled by wellhead steam and HC vapor collection systems. In turn, the collected vapors and steam are condensed, and the water and HCs are separated. The non-condensibles are routed to a nearby steam generator firebox or an incinerator. Such control systems can essentially achieve 100 percent control of HC emissions from wellheads.

Wellhead vents are considered to be by far the greatest source of HC emissions associated with TEOR. Cyclic steam projects were not considered to play as important a role in increasing heavy oil production as steam drive projects. Most existing cyclic steam projects will probably be converted to steam drive which will result in significant increases in wellhead HC emissions. Vapor recovery systems for heavy oil storage facilities were not considered for analysis because heavy crude oil usually exhibits vapor pressures which exempt the storage tanks from control under current regulations. Controls are not expected to be required in the future due to the poor cost-effectiveness of control, as compared to control of other sources of hydrocarbon emissions.

6.5.1 Wellhead Vapor Recovery Systems

A vapor recovery system consists of two major components: a collection system and a condensation system. The collection system consists of piping to each producing well in a steam drive project. The steam and HC vapors with non-condensibles flow from the casing through two or three-inch diameter lines to increasingly larger trunk lines. The number of wells connected determines the size of line necessary to transport the high specific volume fluid. Some systems have trunk lines as large as 12 to 14 inches in diameter. Since some condensation will occur during transport, the lines are designed for gravity flow to the central condensing equipment with no low points in the line. A water leg in the line would create an undesirable pressure increase in the wellhead casing. Sizes of systems vary considerably, but for the average well density found in the study fields, a total of 200 to 300 feet of pipe is required per well.

The condensing and separation equipment is usually near the center of the gathering system. This minimizes the piping requirements, but the topography of the area may not allow this design. The steam and HCs condensed in the line are removed from the vapor steam in a knockout drum. The vapors then are condensed in a heat exchanger. The original systems used shell and tube exchangers to preheat the steam generator feed water. Newer systems use air for cooling, because the demand for existing and planned systems grew faster than the availability of cooling water. Water and condensed HCs are separated by gravity in a separate vessel.

There are many design options for a WHVR system. A single condenser removes an average of 90-95 percent of the condensible fraction of HCs. Heat duties for exchangers serving a typical 32-well system range from 5 to 10 MM Btu/hr.

The exit stream containing water, some condensible hydrocarbons, methane, air, CO_2, and H_2S usually is vented to the atmosphere. In some cases, this stream is routed to an incinerator or steam generator firebox and burned. This effectively reduces hydrocarbon emissions to near zero.

The water recovered from the recovery system is combined with the much greater quantity of waste water produced during crude oil production. The total wastewater stream is handled in oil field wastewater treatment plants.

The liquid HC recovered is a naphtha-like mixture of 30 - 35° API (about 300 lbs/bbl). The condensate is valuable in that it is mixed with the produced crude or burned with crude oil in the steam generators. In the economic analysis in this study, the value of the recovered hydrocarbon condensate is counted against control costs.

The extent to which WHVR is used in the four subject oil fields varies greatly. Kern River field and San Ardo field presently have the most extensive systems for collecting vapors. Midway Sunset field also has a significant number of WHVR systems and has many systems planned. Both Midway Sunset and Kern River fields are in Kern County, and the producers in those fields are required to reduce potential HC emissions 93 percent by 1982, pursuant to Kern County APCD's Rule 411.1.

Only a small portion of the total crude oil produced in the Coalinga field is thermally enhanced oil, and presently there is very little control on the wellhead vapors. Fresno County also has no retrofit regulation for this control method at this time. Monterey County has recently adopted a retrofit rule that requires retrofit of WHVR on wells affected by steam drive. The determination of whether a well is steam driven is made based on the temperature of the produced crude oil.

6.5.2 Costs of WHVR Systems

A representative WHVR system was used to estimate the total control costs. The system collects vapors from 32 steam drive wells. The equipment consists of field piping, two air-cooled heat exchangers with fans and motors, a water-oil separator, a 250-barrel storage tank, condensate and wastewater pumps, electric hook-ups, and instrumentation. The total length of field piping for this case is 9,700 feet.

A system of this size is representative of existing systems in the study fields. Larger systems do exist, but they actually consist of multiples of smaller systems. This fact indicates that the economy of scale for large systems does not have a big impact in this case.

Table 6-8 presents the capital and annual costs for the representative system. The annual cost consists of direct charges, overhead, and capital recovery. The range presented is based on reported capital investments of $7,000-11,000 per well. Direct costs are for operating, labor, maintenance, and power. The capital requirement for the representative system was approximately $8,500 per well which is about the mid-point of the reported change. The total installed cost is the sum of the installed cost for each piece of equipment along with other costs such as engineering, site preparation, and utilities connections.

Maintenance costs include all estimated labor and materials needed to keep the vapor recovery system "leak-free". Leak sources include pump seals, flanges, valves, and other sources of fugitive hydrocarbons. Annual maintenance costs are assumed to be 8 percent of total installed equipment costs.

Opearing labor for one system is assumed to be 2 labor hours per shift, which is equivalent to 1 operator controlling 4 of these 32 well systems. Labor for one person-year is estimated to cost $30,000 and overhead is assumed to be 100 percent of operating labor expenses. A value of $15/bbl is assigned to the condensate recovered, and a credit for this is applied directly to the range of annual calculated costs.

TABLE 6-8.

COSTS[1] AND HC EMISSIONS FROM WELLHEAD CASING VENTS[2] EQUIPPED WITH A REPRESENTATIVE WHVR SYSTEM

Total Capital Costs	$273,000
Total Annual Costs	$137,300 - 165,200
HC Emissions (lb/hr)	∿0
HC Removed[3] (lb/hr)	333
Cost Effectiveness ($/lb of HC removed)	0.05

[1]Costs estimated in terms of early 1979 dollars.

[2]For a typical wellhead HC collection system servicing 32 wells.

[3]Assumes 100% control.

7.0 PART I ANALYSES - COST OF PREVIOUS NSR RULES AND RETROFIT RULES

In order to obtain permits to construct new TEOR facilities, oil producers have had to install air pollution controls on the new and existing TEOR facilities to comply with new source review (NSR) requirements. CARB recently adopted Rule 424 and 425 for the Kern County APCD. These rules have forced the TEOR producers to install SO_2 and NO_x controls on existing steam generators. In addition, the Kern County APCD adopted Rule 411.1 which requires that WHVR systems be installed on all steam drive wells in Kern County. The Monterey Unified APCD prohibits fuel combustion sources from emitting any more SO_2 than would be emitted if the source were burning 0.5% sulfur fuel.

In this section, the costs of these air pollution control rules and regulations to TEOR producers are analyzed. This cost analysis focuses on the four California production areas with the greatest steam generation capacity. These are the central Kern County fields, the western Kern County fields, the Coalinga field, and the San Ardo field. Data gathered from district permit files and information supplied by oil producers were used to develop inventories of the TEOR facilities and associated control systems for each of the four production areas. Emission rates for the TEOR steam generators were estimated in two ways. If an emission limitation was specified in the AC, this emission limitation was used to estimate the generator's maximum emission rate. If no emission limitation was specified, the estimated emission rate was based on the control efficiency of the control systems specified in the AC and the uncontrolled emission rates.

The results presented in Section 6.0 were used to compute the costs of the air pollution control systems for the TEOR facilities. The costs of paving roads to provide particulate offsets for new steam generators are not included in this section.

The costs of road paving are expected to be small compared to the costs of particulate controls needed for the steam generators to comply with the previous NSR rules and retrofit rule requirements.

Using the permitted steam generation capacity and representative steam/oil ratios, the control costs on TEOR production are estimated in dollars per barrel. Finally, the costs of the previous new source review rule and the retrofit rules are presented for each production area.

The oil producers are required to obtain permits for any air pollution control system, even though the control system is required by the regulations. Therefore, the assumption that the costs of all control systems are the result of local air pollution control requirements is consistent with the actual permit conditions under which the producers have been operating. In most cases, the local NSR requirements have been more stringent than the federal requirements.

7.1 The Kern County Fields

In this section, costs and emissions are estimated for permitted steam generators which must comply with the previous NSR and retrofit rules. The control systems, their costs, and the feasibility of their installation are evaluated for Rules 424, 425, and 411.1. The installation costs for SO_2 scrubbers, NO_x controls, and WHVR systems are estimated for TEOR production equipment permitted prior to September 12, 1979 pursuant to the Kern County NSR rule and the EPA NSR and PSD rules. The costs of the SO_2 scrubbers needed to comply with Rule 424 are estimated based on the March 23, 1979 version of the rule (the final version of Rule 424 was not adopted in time to be considered in the analyses). In the case of Rule 425, the costs and feasibility of several control system configurations which would meet the various levels of control required are assessed. Costs associated with the WHVR systems required to comply with Rule 411.1 are also estimated.

7.1.1 Inventory of Combustion Equipment and Emissions In Kern County

A computerized data base was developed for all steam generators, heaters, and heater treaters permitted in Kern County (i.e., with either ACs or POs) as of September 12, 1979. Approximately 1,350 oil-fired steam generators, heaters, and heater treaters were permitted in Kern County by this date. For each piece of TEOR equipment, the size, make, fuel, fuel sulfur content, control systems, control system efficiency, and location were obtained from the Kern County APCD's permit files.

Computer programs were written to calculate emissions from the steam generating equipment. The programs also sorted the steam generators by area within Kern County and by permit status. Four areas within Kern County were defined: the Kern River field, other central Kern County fields, Midway Sunset field, and other western Kern County fields. Three permit status categories were defined: 1) steam generators with POs in 1978; 2) steam generators with ACs but no POs prior to February 21, 1979; and 3) steam generators with ACs but no POs between February 21, 1979 and September 12, 1979. Emissions calculated by the computer program for the four areas in Kern County were used to estimate the emissions reductions required to comply with Kern County APCD's retrofit rules.

Only steam generators with a heat input capacity greater than 15 MM Btu/hr (the minimum size for which Rules 424 and 425 apply) are included in the emission inventory. All the steam generators are assumed to operate 90 percent of the time at 90 percent of maximum load (i.e., 90% x 90% = 80% capacity).

Table 7-1 presents the emission factors and rates used to calculate emissions from a 62.5 MM Btu/hr heat input steam generator. The SO_2 emission factor assumes that all the sulfur in the fuel is converted to SO_2 upon combustion. Crude oil burned in the steam generators is assumed to weigh 342 pounds per barrel and contain 6.3 MM Btu per barrel. The NO_x emission factor is an average of the NO_x emissions measured from 25 and 50 MM Btu/hr output steam generators. Particulate emissions were estimated with a standard emission factor used in the permitting process and previous engineering studies. EPA Publication No. AP-42 is the source of the hydrocarbon emission factor.

The emission limitations or control efficiencies specified in the steam generator ACs were used to calculate controlled emissions from steam generators whenever this information was available. If a control system's efficiency was not specified in the AC, the control efficiencies listed in Table 7-2 were used for calculation. The particulate removal efficiency of 32 percent for SO_2 scrubbers on crude oil-fired steam generators is based on compliance test data for steam generators in Kern County.

Included in the emission inventory are 59.6 equivalent 62.5 MM Btu/hr input steam generators which Getty Oil was forced to shut down in December 1978 as a result of violations of the NAAQS for SO_2. Getty has submitted an application to the Kern County APCD for a phased start-up of these steam generators. SO_2 scrubbers will be installed on all of the steam generators before they can be operated. The SO_2 emission reductions resulting from the operation of these scrubbers are expected to count towards compliance with Rule 424.

TABLE 7-1.

EMISSION FACTORS AND EMISSION RATES USED TO CALCULATE EMISSIONS FROM CRUDE OIL-FIRED STEAM GENERATORS IN KERN COUNTY

POLLUTANT	EMISSION FACTOR (Pounds of Pollutant Per Barrel of Crude Oil Burned)	UNCONTROLLED EMISSION RATE (lbs/hr) FOR A 62.5 MM BTU/HR (INPUT) STEAM GENERATOR[1]	
		CENTRAL KERN COUNTY	WESTERN KERN COUNTY
Sulfur Dioxide (SO_2)	6.84 S[2]	74.6	81.4
Oxides of Nitrogen[3] (NO_x)	3.0	29.8	29.8
Particulate Matter (PM)	0.7	6.9	6.9
Hydrocarbon (HC)	0.042	0.4	0.4

[1]Crude oil is assumed to have a heating value of 6.3 MM Btu/barrel and a density of 342 pounds/barrel.

[2]The sulfur dioxide emission factor assumes that all fuel-bound sulfur is converted to SO_2. S refers to percent sulfur in the crude oil. The sulfur content is assumed to be 1.1 percent for the central Kern County fields and 1.2 percent for the western Kern County fields.

[3]Total NO_x is calculated as NO_2.

TABLE 7-2.

CONTROL EFFICIENCIES ASSUMED FOR STEAM GENERATORS WHICH DID NOT HAVE EMISSION LIMITATIONS OR CONTROL EFFICIENCIES SPECIFIED IN THEIR ACs

CONTROL SYSTEM	POLLUTANT	CONTROL EFFICIENCY (Percent Removal)
SO_2 Scrubber	SO_2	95
	PM	32
NOx Controls		
O_2 Controls	NO_x	15
Low NO_x Burners	NO_x	30
Low NO_x Burners plus Selective Non-Catalytic Reduction	NO_x	50
Low NO_x Burners plus moderate Selective Catalytic Reduction	NO_x	85
Fine Particulate Matter Control System	PM	99

Chevron received ACs dated after September 12, 1979 for steam generating equipment. However, this equipment is included in the inventory because it was reviewed under the version fo Kern County APCD Rule 210.1, Standards for Authority to Construct, in effect prior to September 12, 1979. Due to delays in permit application review, the Kern County APCD Hearing Board issued an order to the District to process Chevron's applications using Rule 210.1 as it existed before September 12, 1979.

Permitted Steam Generator Capacity and Control Systems

In 1977, the central Kern County fields produced 86,000 BOPD by steam injection methods. Of this total, the Kern River field produced 73,000 BOPD by steam injection methods (56,000 BOPD from steam drive and 17,000 BOPD from steam soak). In December 1978, the oil-fired steam generator capacity in central Kern County was approximately 14,630 MM Btu/hr. Getty Oil and Chevron account for 80 to 90 percent of the TEOR production by steam injection in the central Kern County fields, but Santa Fe Energy and Shell also have some TEOR production by steam injection in these fields. By September 12, 1979, the permitted steam generator capacity in the central Kern County fields was nearly double the capacity operating in the fields in December 1978. As shown in Table 7-3, central Kern County had 27,850 MM Btu/hr of steam generator capacity permitted to construct and/or operate by September 12, 1979. This permitted capacity should be capable of producing approximately 144,000 BOPD.[1] Most of the additional generator capacity is from two large Getty projects which were issued ACs in June 1977 and March 1978.

[1] Assuming 1.7 net barrels of oil produced per barrel of oil burned and an 0.80 capacity factor for steam generators.

TABLE 7-3.

STEAM GENERATOR CAPACITY IN KERN COUNTY (MM Btu/hr)[1]

Area	MM Btu/hr of Steam Generator Capacity[2]	
	Operating in 1978	Permitted as of 9/12/79
Central Kern County		
Kern River Field	11,760	21,410
Other Fields	2,870	6,440
Subtotal	14,630	27,850
Western Kern County		
Midway Sunset	5,300	12,860
Other Fields	4,360	9,610
Subtotal	9,660	22,470
TOTAL Kern County	24,290	50,320

[1]Input steam generator capacity.

[2]Only steam generators with heat input capacities greater than 15 MM Btu/hr are included.

As of December 1978, a few SO_2 scrubbers were being tested, but no NO_x control systems were in continuous operation on steam generators in Kern County. By September 12, 1979, over one-half of the steam generator capacity in Kern County (28,940 MM Btu/hr) had been designated to have SO_2 scrubbers installed to meet NSR requirements. In addition, TEOR producers had committed to low NO_x burners (LNBs) and selective non-catalytic reduction (SNR) demonstration programs to comply with Kern County and EPA (NSR) requirements. The producers installed the control systems to comply with BACT requirements, other Kern County NSR requirements (Rule 210.1, adopted October 8, 1976), and EPA Prevention of Significant Deterioration (PSD) regulations. As shown in Table 7-4, 1,310 MM Btu/hr of the steam generator capacity permitted as of September 12, 1979 is committed to LNBs and 1,540 MM Btu/hr is committed to SNR in central Kern County.

The western Kern County fields produced 71,000 BOPD by steam injection methods in 1977. Most of the production came from cyclic steam projects in the Midway Sunset field. The ownership of the Midway Sunset field is shared by seven major oil companies, several minor oil companies, and many independents. Other western Kern County fields include the Belridge, Cymric, and McKittrick fields. In 1977, the fields produced 9,000 BOPD, 1,000 BOPD, and 5,000 BOPD, respectively. The ownership of the other western Kern County fields is similar to the Midway Sunset field; that is shared by major, minor, and independent oil companies.

In 1978, the steam generation capacity in operation in western Kern County fields was 9,660 MM Btu/hr. Over half of the capacity (5,300 MM Btu/hr) was in the Midway Sunset field. With the approval of the "Westside" project in September 1979,

TABLE 7-4.

PERMITTED STEAM GENERATION CAPACITY[1] IN KERN COUNTY
COMMITTED TO CONTROL SYSTEMS TO MEET
NEW SOURCE REVIEW REQUIREMENTS

	Steam Generator Capacity (MM Btu/hr)	
SO_2 Control Systems	Central Kern County	Western Kern County
SO_2 Scrubbers	14,630	14,310
NO_x Control Systems		
Oxygen (O_2) Controls	---	720
Low NO_x Burners (LNB)	1,310	2,050
Selective Non-Catalytic Reduction (SNR)	1,540	3,880

[1]Permitted steam generator capacity includes all steam generators with greater than 15 MM Btu/hr input and an AC or PO issued by the Kern County APCD prior to September 12, 1979.

the steam generation capacity in the western Kern County fields more than doubled. The steam generator capacity permitted in the western Kern County fields was 22,470 MM Btu/hr heat input as of 12 September 1979. This steam generation capacity should be capable of producing 205,000 BOPD (assuming 3.0 barrels of net oil production for each barrel burned). The steam generator capacity in the Midway Sunset field increased by nearly 8,000 MM Btu/hr input while the steam generation capacity in the other fields increased by about 5,000 MM Btu/hr.

In early September 1979, the Kern County APCD issued ACs to TEOR producers in western Kern County for approximately 150 equivalent 50 MM Btu/hr output steam generators. These steam generators are commonly referred to as the "Westside" project. The ACs for the Westside project's generators included a special permit condition which may drastically curtail further heavy oil production. The condition requires that if the ambient NO_2 concentrations in Kern County exceed 85 percent of any California or federal standard, these steam generators must be temporarily shut down. Furthermore, if 100 percent of any standard is exceeded, the steam generators of the "Westside" project must be permanently shut down.

Most of the steam generators in the "Westside" project are committed to SO_2 and NO_x control systems. Over 90 percent of the steam generator capacity is designated to be scrubbed for SO_2. Approximately 60 equivalent 50 MM Btu/hr generators are committed to systems for NO_x control. In western Kern County, 2,050 MM Btu/hr of steam generator capacity are committed to LNBs and 3,880 MM Btu/hr are committed to SNR. Most of the NO_x controls are designated for steam generators in the Midway Sunset field.

7.1.2 Previous NSR Review Rules

The Kern County APCD NSR rules that preceeded the rule adopted by CARB on September 12, 1979, required that major new TEOR facilities install BACT and offset SO_2, PM , and HC emission increases. The capacity of steam generators which installed NO_x and SO_2 control systems to comply with the previous NSR rules was shown in Table 7-4. No steam generators were committed to PM control systems to comply with the previous NSR rules. The costs of WHVR systems were estimated by adding the costs of compliance with the previous NSR rules to the costs of compliance with Rule 441.1 to give total costs for WHVR systems for TEOR facilities permitted as of September 12, 1979. The number of wells committed to WHVR systems was not available at this time but could be obtained by reviewing the Kern County files. The costs of the controls needed to comply with previous Kern County NSR rules for all steam generators with ACs or POs as of September 12, 1979, are presented in Table 7-5.

The capital costs of the SO_2 controls for all steam generators in central Kern County and western Kern County which were permitted as of September 12, 1979, are estimated to be between 44.1 and 63.6 million dollars; capital costs for NO_x controls are estimated to be between 52.3 and 109 million dollars. The average annual costs for SO_2 and NO_x controls for central Kern County and western Kern County production areas were between 0.86 and 1.74 dollars per barrel of oil burned for the central fields and between 1.22 and 3.02 dollars per barrel for the western fields. However, the annual costs for the SO_2 and NO_x control systems of the more recently permitted projects, such as the Westside project, will be much higher as a result of more stringent regulations and additional offset requirements. Annual costs can be expected to range from 3.30 to 5.60 dollars per barrel of oil burned for the SO_2 and NO_x control systems needed to meet BACT requirements for these newer facilities.

TABLE 7-5.

CAPITAL AND ANNUAL COSTS OF CONTROLS NEEDED TO COMPLY WITH THE PREVIOUS NEW SOURCE REVIEW REGULATIONS

Production Area	Pollutant	Capital Costs MM Dollars	Average Annual Costs: MM Dollars	Average Annual Costs: Dollars/bbl Oil Burned	Average Annual Costs: Dollars/bbl Oil Produced
Central Kern County	SO_2	38.3-55.0	24.3-50.7	0.78-1.64	0.46-0.96
	NO_x	5.8-8.6	2.4-3.2	.08-0.10	0.05-0.06
	Subtotal	44.1-63.6	26.7-53.9	0.86-1.74	0.51-1.02
Western Kern County	SO_2	37.5-87.4	24.6-67.4	0.98-2.70	0.33-0.90
	NO_x	14.8-21.8	6.0-7.9	0.24-0.32	0.08-0.11
	Subtotal	52.3-109	30.6-75.3	1.22-3.02	0.41-1.01
	TOTAL	96.4-173	57.3-129	1.02-2.31	0.45-1.01

7.1.3 Rule 424 - Sulfur Compounds from Oil Field Steam Generators

The first version of Rule 424 required that existing steam generators in central and western Kern County must control sulfur emissions to 0.25 pounds of sulfur per MM Btu of heat input by July 1, 1982 and 0.12 pounds of sulfur per MM Btu of heat input by July 1, 1984. The March 23, 1979 version of Rule 424 specifies different emission limitations for "existing" versus "new" steam generators. An "existing" steam generator (for the purposes of Rule 424) is defined as having an AC prior to February 21, 1979. Steam generators with ACs dated on or after February 21, 1979 are defined as "new" steam generators.

The CARB's intent upon adopting Rule 424 was to impose an emission limitation of 0.12 pounds of sulfur per MM Btu of heat input for existing steam generators that are not scrubbed and not designated in the permit files to be scrubbed. Since this emission limitation is a field-wide average, control efficiencies may vary between generators as long as the field-wide average emission level is within the emission limitation.

Compliance with Rule 424 was estimated by controlling SO_2 emissions from existing unscrubbed steam generators with 95 percent efficient scrubbers. Table 7-6 gives the number of unscrubbed steam generators which must install 95 percent efficient SO_2 scrubbers to comply with the 1984 emission limitation of Rule 424.

Steam generators operating in Kern County in 1978 emitted 94,700 tons of SO_2 per year.[1] The central Kern County

[1] These 1978 SO_2 emissions are estimated on the basis of oil-fired steam generators and SO_2 scrubbers with POs in 1978 and an 80 percent capacity factor for steam generators.

TABLE 7-6.

SCRUBBING STATUS OF PERMITTED STEAM GENERATOR CAPACITY[1] IN KERN COUNTY AFTER COMPLIANCE WITH RULE 424

	Number of Equivalent 62.5 MM Btu/hr (input) Steam Generators		
Area	Steam Generators Permitted with Scrubbers For "Previous" NSR Rules	Additional Steam Generators Required to be Scrubbed To Comply with Rule 424	Steam Generators Available to be Scrubbed for Offsets
Central Kern County Fields	234	179	33
Western Kern County Fields	229	112	19
TOTAL	463	291	52

[1] Permitted steam generator capacity refers to the sum capacity of all the steam generators with a heat input capacity greater than 15 MM Btu/hr which had an AC or PO by September 12, 1979.

steam generators emitted 54,600 tons of SO_2 per year while 40,100 tons per year were emitted from the western Kern County fields.

Without Rule 424, the steam generators with ACs or POs as of September 12, 1979 had the potential to emit 101,400 tons of SO_2 per year. The steam generators in central Kern County had the potential to emit 59,600 tons of SO_2 per year. The western Kern County steam generators had the potential to emit 41,800 tons of SO_2 per year. These annual emission rates are equivalent to 0.31 and 0.27 pounds of sulfur per MM Btu of heat input for the central Kern County and the western Kern County fields, respectively.

In these two areas, 463 equivalent 62.5 MM Btu/hr heat input steam generators were committed to SO_2 controls under Kern County's NSR rule and the EPA's PSD Rule (see Table 7-6). This level of control represents estimated capital and annual costs for SO_2 scrubbers in central and western Kern County of \$76 to \$142 million and \$49 to \$118 million, respectively (see Table 7-7). The capital and annual costs in western Kern County are expected to be considerably higher than in central Kern County. Steam generators in western Kern County are typically smaller and more widely distributed, resulting in smaller and less cost effective control systems.

In order to comply with Rule 424, 179 equivalent 62.5 MM Btu/hr steam generators in central Kern County fields must be controlled to meet the 1984 sulfur emission limitation. When the steam generators in central Kern County comply with this emission limitation, the SO_2 emissions from central Kern County steam generators are expected to be about 15,300 tons per year. Installation costs for the SO_2 scrubbers are expected to represent an additional expenditure of \$29 to \$42 million. The additional annual costs are estimated to be between \$19 and

TABLE 7-7.

CAPITAL AND ANNUAL COSTS (IN MILLIONS OF DOLLARS) FOR SULFUR DIOXIDE CONTROLS REQUIRED IN KERN COUNTY TO COMPLY WITH THE PREVIOUS NEW SOURCE REVIEW REGULATIONS AND RULE 424

DESCRIPTION	CENTRAL KERN COUNTY		WESTERN KERN COUNTY		TOTAL KERN COUNTY	
	Capital	Annual	Capital	Annual	Capital	Annual
Previous New Source Review Rules	38.3-55.0	24.3-50.7	37.5-87.4	24.6-67.4	75.8-142	48.9-118
Rule 424	29.3-42.1	18.6-38.8	18.3-42.8	12.0-33.0	47.6-84.9	30.6-71.8
Total	67.6-97.1	42.9-89.5	55.8-130	36.6-100	123 -227	79.5-190

$39 million. The average annual cost per barrel of oil burned would be $0.61 to $1.25 or $.36 to $0.74 per net barrel of oil produced. The average total costs for SO_2 control systems to comply with the previous NSR rules and Rule 424 for the central Kern County fields would then be $1.38 to $3.54 per barrel of oil burned. Based on 1.7 net barrels of oil produced per barrel of oil burned, the average annual costs are $0.81 to $2.08 per net barrel of oil produced.

In western Kern County, the number of SO_2 scrubbers required to comply with Rule 424 is much lower than for central Kern County. A greater percentage of the total equipment was committed to SO_2 scrubbing as part of previous NSR rules in western Kern County. In order to comply with Rule 424, 112 equivalent 62.5 MM Btu/hr steam generators in western Kern County fields must be controlled to meet the 1984 sulfur emission limitation. When the generators in western Kern County comply with the 1984 emission limitation, the steam generators are expected to emit about 11,600 tons of SO_2 per year. The capital and annual expenditures for constructing and operating the additional SO_2 control systems are expected to be from $18 to $43 million and from $12 to $33 million, respectively. The average annual costs per barrel of oil burned and per net barrel oil produced are from $0.48 to $1.32, and from $0.16 to $0.44, respectively. Rule 424 and the previous NSR rules are expected to cost the producers in western Kern County about $0.49 to $1.33 per net barrel of oil produced (costs for SO_2 control systems). The cost of control per barrel of oil burned is expected to be about three times higher than the cost per barrel of oil produced.

The annual costs associated with SO_2 scrubbers will increase by $47 to $85 million for TEOR producers in Kern County who must comply with Rule 424. The producers will need to install and have compliance tests for SO_2 scrubbers on up to 291

TABLE 7-8.

SCRUBBER WASTE VOLUMES ESTIMATED FOR THE STEAM GENERATORS REQUIRED TO COMPLY WITH PREVIOUS NEW SOURCE REVIEW REGULATIONS AND RULE 424 IN KERN COUNTY

Regulation	Volume Acre-Feet Per Year of Scrubber Waste		
	Central Kern County	Western Kern County	Total Kern County
Previous New Source Review Rules	529-1,877	518-1,837	1,047-3,714
Rule 424	405-1,436	253-898	658-2,334
Total	934-3,313	771-2,735	1,705-6,048

equivalent 62.5 MM Btu/hr output steam generators by July 1, 1984. This represents the purchase and installation of SO_2 scrubbers on approximately 7.0 equivalent 62.5 MM Btu/hr output steam generators per month.

The majority of the SO_2 scrubbers proposed for installation to comply with Rule 424 will be either caustic or soda ash "throwaway" systems. Table 7-8 presents the scrubber waste volumes estimated for the SO_2 scrubbers required to comply with previous NSR regulations and Rule 424. These estimates are based on caustic or soda ash systems. The total volume of liquid scrubber waste in Kern County will be approximately 1,700 to 6,000 acre-feet per year. This greatly exceeds the 1984 Class I and II-A site capacity in Kern County, according to California Water Resource Control Board staff. Hence, the availability of waste disposal capacity for liquid scrubber waste may become a severe operating constraint for the permitted steam generators.

7.1.4 Rule 425 Oxides of Nitrogen Emissions from Steam Generators Used in Thermally Enhanced Oil Recovery

Rule 425 requires three levels of NO_x controls which depend on the ambient NO_2 concentrations monitored in Kern County. If the ambient NO_2 concentrations remain below 85 percent of the national and California standards, the TEOR producers must reduce their average NO_2 emissions from steam generators to the Stage I Control level of 0.30 pounds of NO_2 per MM Btu of heat input by July 1, 1982. If the ambient NO_2 concentrations exceed 85 percent of a standard, then the NO_x emissions from steam generators must be reduced to the Stage II Control level of 0.25 pounds of NO_2 per MM Btu of heat input. Upon exceeding the standard itself, the Stage III Control level of 0.14 pounds of NO_2 per MM Btu of heat input would have to be met. The TEOR producers have 18 months following the Stage II or III air quality change to demonstrate compliance with the new emission limits.

The Kern County APCD has established special permit conditions limiting NO_x emissions from the "Westside" project steam generators. If the ambient NO_x concentration exceeds 85 percent of a NO_2 standard, the "Westside" project steam generators must be shutdown. In the case where the ambient NO_2 concentration exceeds 100 percent of the standard, the steam generators must be permanently shutdown. In either case the NO_x emissions increases from the Westside project must be offset by corresponding emission reductions from other equipment.

7.1.4.1 Method of Analyses

The impacts of previous NSR Rules and Rule 425 on TEOR production in Kern County are discussed in this section. Changes in the county's NO_x emissions due to compliance are projected. The TEOR production capital and annual costs associated with Rule 425 are presented and the feasibility of compliance is analyzed. In 1978, oil-fired steam generators were estimated to emit 25,800 tons of NO_x per year from central Kern County fields and 16,100 tons of NO_x per year from western Kern County fields.[1] By September 12, 1979, the steam generators with ACs and POs had the potential to emit 44,530 and 33,050 tons per year of NO_x in the central and western Kern County fields, respectively.

Table 7-9 lists estimates of the amount of steam generation input capacity (in MM Btu/hr) and the percent of the total heat input which must install NO_x control systems in order to comply with the Stage I, II, or III Control levels of Rule 425.

[1] The 1978 NO_x emissions were estimated assuming all uncontrolled steam generators and an 80 percent capacity factor for the steam generators.

TABLE 7-9.

AMOUNT OF STEAM GENERATOR INPUT CAPACITY AND PERCENT OF TOTAL HEAT INPUT WHICH MUST INSTALL NO_x CONTROL SYSTEMS TO COMPLY WITH THE STAGE I, II, OR III CONTROL LEVELS OF RULE 425

		Steam Generator Input Capacity in MM Btu/hr (Percent of Total Heat Input)							
Control Level	Area	Option	Uncontrolled	Controls	O_2 Controls, and LNB	O_2 Controls, LNB, and SNR	O_2 Controls, LNB, and Moderate SCR	Capital Cost (10^6 \$)	Annual Cost (10^6 \$)
Stage I	Central Kern County	1	-	-	18,660 (67%)	9,190 (33%)	-	54.3 - 80.3	23.5 - 31.0
		2	6,430 (23%)	-	1,310 (5%)	20,110 (72%)	-	62.4 - 92.3	23.5 - 31.2
	Western Kern County	1	-	720 (93%)	13,680 (61%)	8,070 (36%)	-	44.0 - 78.2	18.9 - 32.7
		2	4,260 (19%)	720 (3%)	2,240 (10%)	15,250 (68%)	-	49.3 - 75.1	18.9 - 26.4
Stage II	Central Kern County	1	-	-	3,060 (11%)	24,790 (89%)	-	79.0 - 117	29.9 - 39.8
		2	-	-	18,190 (65%)	1,540 (6%)	8,120 (29%)	165 - 208	71.0 - 82.9
	Western Kern County	1	-	450 (2%)	2,020 (9%)	20,000 (89%)	-	63.2 - 95.5	23.9 - 33.0
		2	-	720 (3%)	12,070 (54%)	3,880 (17%)	5,800 (25%)	125 - 193	53.3 - 80.7
Stage III	Central Kern County	-	-		6,440 (23%)	1,540 (6%)	19,870 (71%)	342 - 418	144 - 164
	Western Kern County	-	-	720 (3%)	2,690 (12%)	3,880 (17%)	15,180 (68%)	266 - 387	112 - 158

Separate estimates are listed for central Kern County and western Kern County. Various combinations of NO_x controls are considered. In all cases, NO_x control systems committed to in previous new source review rules are included as a base.

The number of combinations of NO_x control systems complying with Rule 425 are infinite. For the cases presented in Table 7-9, limits were placed on the number of particular NO_x control systems used. For example, only two combinations are presented for compliance with the Stage I Control level in central Kern County.

In one case, a combination wherein 67 percent of the total heat input has low NO_x burners and 33 percent of the total heat input has SNR systems meets the Stage I control level. This combination represents the least number of SNR systems required to meet the Stage I Control level, assuming that all other generator capacity is controlled with low NO_x burners. In the second case, a combination wherein 23 percent of the total heat input is uncontrolled and 72 percent of the total heat input has SNR systems meets the Stage I Control level. This case represents the least number of SNR systems required to meet Stage I Control level, assuming that all other generating capacity remains uncontrolled. Five percent of the generating capacity in central Kern County is already committed to low NO_x burners for previous new source review regulations so this remains unaltered.

The quantity of NO_2 emission offsets that are available for new steam generators varies depending on the NO_x control systems used and the control level requirements. If Stage II or III control levels are required, only emission reductions beyond their respective emission limits are available as offsets.

Taking the control levels into account, NO_x emission offsets are obtained by installing NO_x controls on previously uncontrolled steam generators or by installing more efficient NO_x controls on steam generators which have NO_x controls. For example, SNR could be installed on an uncontrolled steam generator or on a generator that already has low NO_x burners. The difference in NO_x emissions before and after SNR system installation is available as NO_x offsets.

The maximum potential NO_x offsets are estimated by assuming that the most efficient NO_x control systems can be installed on all steam generator capacity. Moderate SCR with low NO_x burners and O_2 controls is the most efficient NO_x control system, with 85 percent NO_x removal. If moderate SCR could be installed on all uncontrolled or low control steam generators in central Kern County, the available NO_x offsets would be approximately 22,400 tons per year for the Stage I Control level. In western Kern County, the available NO_x offsets would be approximately 18,100 tons per year for the Stage I Control level and 5,500 tons per year for the Stage III Control level.

The costs for compliance with the three control levels of Rule 425 were estimated using the specific capital and annual cost ranges developed for each NO_x control technology and the various combinations of NO_x control systems required to comply with Rule 425. Table 7-9 presents the capital and annual cost ranges for each of the Rule 425 control levels and NO_x control system combinations. As expected, costs to comply with the three control levels increase with the stringency of the control level emission limits. Even though SCR is anticipated to be the most efficient NO_x control technology, its use will raise the cost of complying with Rule 425 significantly.

7.1.4.2 The Stage I Control Level

By July 1982, TEOR producers in central and western Kern County are required to meet an average steam generator emission rate of 0.30 pounds of NO_x per MM Btu of heat input. If the ambient levels measured prior to installing and testing control systems do not exceed 85 percent of any NO_x standards, the resulting emission reductions will be available for future TEOR project offsets. In any case, the TEOR producers are required to have the subject NO_x control systems operating by July 1982 to comply with the Stage I Control level of Rule 425.

Theoretically, the producers have many NO_x control system options which would comply with the rule. Existing steam generators which are not already committed to NO_x controls could be retrofitted with O_2 controls, LNBs, SNR, and SCR. However, in order to meet the July 1982 compliance date, the control systems must be commercially available. Some of the LNBs have been field tested for a year or more, but most of the TEOR producers have had limited experience in operating LNBs. Only a few vendors supply LNBs. There are only two licensees of the Thermal De-No_x Process, the only SNR system being marketed for steam generators. Also, data is limited for field tests to demonstrate the Thermal De-NO_x system on steam generators in the typical unattended mode. It is likely that many of the producers will be reluctant to purchase the Thermal De-NO_x systems for retrofit on existing steam generators until the systems are better demonstrated and accepted. In addition, many producers and a few oil field equipment suppliers do not believe that SNR is feasible for existing steam generators in the size range of 20 to 31.5 MM Btu/hr (input). Finally, SCR systems are not expected to be commercially available for steam generators until the mid-1980s. These systems are expected to require several years of development and testing.

The various combinations of NO_x control systems that could theoretically meet the Stage I Control level in central and western Kern County were shown previously in Table 7-9. Data indicate that the retrofit of O_2 controls and LNBs will not be sufficient to meet the Stage I Control level in either the central or western Kern County fields.

It appears that LNBs with O_2 controls are needed on all of the steam generators in Kern County, except for those which the TEOR producer will retrofit with SNR or SCR. If LNBs with O_2 controls are needed to meet the Stage I Control level, systems will have to be installed on each of the approximately 805 equivalent 62.5 MM Btu/hr steam generators which were permitted by September 12, 1979. This means that an average of 42 to 43 steam generators per month (based on 19 months until July 1982) would have to install LNBs to meet the schedule for compliance with Rule 425. This is a conservative estimate because the actual number of permitted steam generators is higher than the number given in terms of equivalent 62.5 MM Btu/hr steam generators.

In order for TEOR producers in central Kern County to comply with the Stage I requirements of Rule 425, an estimated 33 to 72 percent of the permitted steam generator capacity will need to be retrofitted with LNBs, O_2 controls, and SNR systems. This means that 147 to 322 SNR systems would have to be installed in central Kern County fields alone (assuming all the steam generators are 62.5 MM Btu/hr input in size). For western Kern County fields, an estimated 36 to 68 percent of the steam generator capacity will need SNR to comply with Rule 425. The additional steam generator capacity that will require SNR systems to comply with Rule 425 is lower for the western Kern County fields than for central fields. A much higher percentage of the permitted steam generator capacity in western Kern County has already committed to O_2 controls, LNBs, and SNR systems. Approximately 60 SNR systems have already been committed in western Kern County; only about 25 SNR systems have been committed to by TEOR producers in central Kern County. In western Kern County, 129 to 244 equivalent 62.5 MM Btu/hr steam generators will need SNR systems to meet the field wide limitation of 0.30 pounds of NO_2 per MM Btu input.

This means that 276 to 566 SNR systems must be installed and operating in Kern County by July 1982 to meet the Stage I Control level. If producers began installing and testing the SNR systems in January 1981, an average of 14 to 30 SNR systems per month would have to be installed and compliance tested to meet the schedule. Due to both the number of steam generators that need SNR systems to comply with Rule 425 and the general lack of experience with SNR control systems, it is highly unlikely that the producers will be able to meet the Stage I Control level requirements. Furthermore, since the producers have committed the NO_x emission reductions as part of NSR requirements, it is assumed that the emission reductions made in order to comply with the Stage I Control level are not available as emissions offsets for new TEOR projects.

7.1.4.3 The Stage II Control Level

Rule 425 requires that TEOR producers reduce their NO_x emissions to a field-wide average of 0.25 pounds per MM Btu heat input within 18 months after ambient NO_x concentrations exceed 85 percent of any standard. TEOR producers are expected to spend from $142 to $213 million in capital investments and from $54 to $73 million in annual costs to comply with the Stage II Control level of Rule 425. These costs are based on the assumptions that SNR is the NO_x control system applied and that it can be retrofitted to small steam generators. These costs were presented previously in Table 7-9.

Many of the small steam generators are not expected to have the correct temperature range in their transition sections for the application of SNR. In addition, the NO_x emission reductions achievable through retrofit of LNBs, O_2 controls, and SNR systems are not expected to be sufficient to comply with the Stage II Control level. As was shown in Table 7-9, approximately 89 percent of the permitted steam generation capacity in Kern County would have to be retrofit with LNBs, O_2 controls, and SNR to meet the Stage II Control level. Because small steam generators comprise one-fourth of the permitted steam generation capacity in Kern County, retrofitting 89 percent or more of this total capacity with SNR systems appears impossible. The producers are expected to have few, and in many cases no, additional steam generators available for retrofit to provide offsets for new steam generators. In order for TEOR producers to create emission offsets for new steam generators, the permitted steam generators must be retrofit with controls that reduce emissions below 0.25 pounds per MM Btu. Because this emission rate is the best that can be expected for a steam generator with O_2 controls, LNBs, and an SNR system, no offsets are expected to be available unless the producers shut down some of their permitted equipment.

Upon exceeding the Stage II Control level, TEOR producers will have to develop, negotiate, and submit a plan which demonstrates that the Stage II Control level will be met. Until the District accepts the plan, pending ACs can not be approved. This may cause long delays in pending TEOR projects in Kern County.

7.1.4.4 <u>The Stage III Control Level</u>

If the ambient NO_2 concentration in Kern County exceeds a national or California NO_2 standard, Rule 425 requires that emissions from steam generators be controlled to an average level of 0.14 pounds of NO_2 per MM Btu of heat input. Based on an uncontrolled emission rate of 0.48 pounds of NO_2 per MM Btu, a Stage III emission level requires a 70 percent reduction of NO_2 emissions. This high level of emission reduction can only be achieved if SCR is commercially available. At a minimum, it is expected that about 61 to 78 percent of the permitted steam generator capacity in Kern County will have to be retrofit with SCR to achieve the Stage III Control level. The capital costs for the LNBs, O_2 controls, SNR, and SCR systems are anticipated to be from \$608 to \$805 million. The annual operating costs for this equipment are expected to be from \$256 to \$322 million. These costs are over four times the estimated costs to comply with the Stage II Control level.

All of the permitted steam generators are expected to have at least LNBs and O_2 control systems installed in order for the Kern County producers to comply with the Stage III Control level. However, 20 to 40 percent of the permitted steam generation capacity is expected to remain available for the installation of SCR systems to provide offsets for new steam generators. Because the SCR systems have high NO_x removal efficiencies, the control of a single generator can provide offsets for many new steam generators with SCR controls.

No future TEOR expansion can be expected if any ambient NO_2 standards are exceeded in Kern County within the next few years. The SCR systems needed for steam generators to comply with the Stage III Control level will not be commercially available until the mid-1980's. Without SCR controls, TEOR producers could not demonstrate compliance with the Stage III Control level, and the Kern County APCD could not issue permits for new steam generators. If the NO_2 standard is exceeded, the CARB probably will revise Rule 425. This revision could take several months to several years, further inhibiting new TEOR projects. The EPA would have to redesignate the area as a non-attainment area for NO_2 which could require another one to two years. New steam generators would have to install LAER controls for NO_2, and LAER controls for NO_2 may not be commercially available.

If the NO_2 standard is exceeded when SCR is commercially available, the permitting of new steam generators could still be delayed by several years. The TEOR producers would have to develop, negotiate, and obtain the District's approval for their plans to achieve the Stage III Control level. The plan must demonstrate that the Stage III Control level will be met within 18 months after a NO_2 standard is exceeded. Demonstration of compliance with the Stage III Control level within 18 months appears highly unlikely because approximately 560 steam generators would have to be retrofit with SCR.[1]

7.1.5 Rule 411.1 - Steam Drive Wells - Crude Oil Production

Kern County's Rule 411.1 requires that hydrocarbon (HC) emissions from existing steam drive wells be controlled to result in a 93 percent reduction in HC emissions by March 1, 1982. Rule 411.1 requirements are only applicable to "first-line production wells" which are defined as production wells within so many feet of the injection well (depending on the size of the pattern in acres), or production wells in irregular patterns that exhibit a visible vapor plume containing HC when the ambient air

[1]560 steam generators are estimated on the basis that all steam generators which have SCR will be 62.5 MM Btu/hr (output) units.

temperature is $60^{\circ}F$ or more. Due to the impracticality of actually determining the number of "first-line production wells" from the available information, all Kern County TEOR production wells are assumed to be subject to the Rule 411.1 requirements for the purposes of this study. New steam drive wells or wells converted to steam drive are required to comply with the Rule 411.1 requirements upon commencement of steam injection.

An inventory of wellhead casing emissions associated with steam drive production wells was developed from permit data, oil company data, oil field well maps, and steam injection data. The potential hydrocarbon emissions from steam drive production wells were calculated by estimating the number of steam drive production wells and multiplying by the currently used emission factor of 250 pounds per day per well.[1] The number of steam drive production wells in the central and western Kern County fields was estimated from manual well counts of oil field maps. Using these well counts, the well to heat input ratios were calculated (i.e., number of wells supplied with injection steam by each MM Btu/hr of heat input). A list of operating and planned WHVR systems was obtained from the Kern County APCD permit files and data supplied by the TEOR producers. From the wellhead inventory and the average wellhead emission factor, a total uncontrolled emission inventory was estimated. The list of operating and planned WHVR systems and the average number of wellheads serviced by a single WHVR system were used to estimate emission reductions, which then were subtracted from the total uncontrolled inventory. The resulting estimate represented the emissions associated with wellhead vents as currently controlled.

Estimates of the current number of production wells in central and western Kern County are 4,656 and 3,695, respectively. The capital and annual costs estimated for compliance

[1] 250 lbs/day/well is an emission factor used by the Kern County APCD to estimate uncontrolled wellhead vent HC emission.

with Rule 411.1 are: \$32 to \$51 million and \$0.4 to \$4.5 million, respectively, for central Kern County; and \$26 to \$41 and \$0.3 to \$3.6 million, respectively, for western Kern County. The annual costs are lower than would be expected due to credit for recovered hydrocarbons (approximately \$4,200 per year per well).

7.1.6 Fine Particulate Matter Control Requirements

Until last year, TEOR producers have been able to comply with the NSR rule requirements by paving roads to offset increases of particulate emissions resulting from new steam generators. On September 12, 1979 the CARB adopted a guideline for the Kern County APCD NSR Rule 210.1 requiring that fine particulates from combustion be offset by particulates in the same size range. In April of 1981, the CARB decided to delay implemenatation of the fine particulate offset requirement until EPA had adopted its fine particulate ambient air quality standards. EPA is expected to promulgate a fine particulate standard within the next two years. Although CARB has delayed implementation of their fine particulate guideline, the EPA still requires fine particulate offsets. Based on emissions from residual oil-fired boilers, most of the combustion particulates from steam generators are expected to be primarily fine particulates. Road paving is not longer a viable particulate offset because the entrained dust from roads contains predominantly large particulates.

The SO_2 scrubbers installed on the new steam generators are not expected to effectively remove fine particulates from the flue gas. Compliance tests made on SO_2 scrubbers in Kern County within the last two years showed an average reduction of total particulates of about 25 to 35 percent. The

Kern County APCD assumed that scrubbers were capable of achieving a 32 percent total particulate removal efficiency. If 32 percent removal of total combustion particulates is assumed, three existing uncontrolled 62.5 MM Btu/hr steam generators would have to have SO_2 scrubbers retrofit to permit operation of each new 62.5 MM Btu/hr steam generator equipped with an SO_2 scrubber. Since scrubbers are not expected to remove most of the fine particulates, the number of steam generators that must be scrubbed to provide fine particulate offsets for a single new steam generator becomes extremely large. Moreover, almost all of the existing steam generators already have been committed to have SO_2 scrubbers installed to comply with previous NSR requirements and/or Rule 424 requirements.

The Kern County APCD requires that all steam generators issued ACs in September 1979 must comply with the fine particulate guideline. Before the oil producers could begin construction of the steam generators, they must submit "offset" plans to the District. These plans must demonstrate compliance with the fine particulate guidelines. These guidelines affected about 40 percent of the steam generation capacity with ACs as of September 12, 1979. As shown in Table 7-10, less than 1 percent of the steam generator capacity for the Kern River field was affected by the guideline. However, 44 percent of the capacity in other central Kern County fields was affected, and over 60 percent of the steam generation capacity in western Kern County will require fine particulate offsets.

Fine particulate control systems have been developed for large industrial boilers, primarily electric utility boilers. These control systems would have to be reduced in scale and designed to be portable systems that can be operated unattended most of the time in order to be applicable to crude oil-fired steam generators. Several types of high efficiency control

TABLE 7-10.

STEAM GENERATION CAPACITY SUBJECT TO FINE PARTICULATE MATTER OFFSET REQUIREMENTS

Production Area	Field	Steam Generation Capacity (MM Btu/hr)	Percent of Total Capacity[1] with ACs as of 9/12/79 but no PO in 1978
Central Kern County	Kern River	31	< 1
	Other Fields	1547	44
Subtotal		1578	12
Western Kern County	Midway Sunset	5356	71
	Belridge	750	36
	McKittrick	778	64
	Cymric	246	25
	Lost Hills	562	86
	Other	313	100
Subtotal		8005	62
TOTAL Kern County		9583	37

[1] This percentage represents the new steam generation that has been approved for installation since 1978.

systems are being tested for application to steam generators. The testing of these systems is not expected to be completed for one to two years. Several years are expected to pass before high efficiency particulate control systems capable of removing most of the fine particulates from the flue gas of steam generators are commercially available.

In summary, the lack of available fine particulate controls for steam generators will delay the construction of steam generators already permitted. If the fine particulate control problem is not quickly resolved, the local and federal permits to construct the steam generation projects will expire, which will drastically reduce the production achievable by permitted steam generators.

Ironically, most of the applications for the steam generation capacity that are affected by the fine particulate offset guideline were submitted to the air pollution control agencies in 1977. Nearly four years have gone by and another couple of years may pass before the producers can begin the construction of these steam generators. The particulate emissions from oil-fired steam generators with POs in 1978 in the central and western Kern County fields are potentially 6,000 and 3,800 tons per year, respectively. Since 1978, the particulate emissions from new steam generators have had to be offset, therefore no increase has occurred. The particulate emission from the steam generators in central and western Kern County fields after complying with the fine particulate offset guideline will be 7,400 and 4,100 ton per year, respectively.

If fine particulate control systems achieved widespread commercial availability, the total capital cost of particulate controls will be about $5.5 to $7.9 million for the steam generators in Kern County with permits to construct and operate by September 12, 1979. The Kern County producers will have to spend about \$3.5 to \$9.7 million annually to operate the fine particulate controls. These costs are presented in Table 7-11.

7.1.7 Summary of Costs for Retrofit Rules and Previous NSR Rules in Kern County

The permitted TEOR steam generation capacity in central and western Kern County is estimated to be capable of producing 144,000 and 205,000 BOPD, respectively. These figures represent TEOR production and take into account the amount of produced oil which is burned in the steam generators to enhance production.[1] Capital and annual costs for NO_x, SO_x, and particulate controls were developed. NO_x costs included the costs associated with three levels of control (e.g., Stage I controls if ambient NO_x levels remain the same and Stage II and III controls if ambient NO_x levels increase significantly). Costs are based on the assumptions that the required control technology performs as projected and is available in sufficient quantities to comply with the respective regulation schedules. The capital and annual costs to comply with the regulations for the Stage I Control levels are \$285 to \$498 million and \$126 to \$271 million respectively, for all of Kern County. Should the ambient NO_2 concentrations exceed 85 percent of any NO_2 standard, the Stage II Control level would result in capital and annual expenditures of \$330 to \$728 million and \$138 to \$371 million, respectively. If the ambient NO_2 concentrations exceed any national or California NO_2 standard, the capital and annual expenditures required for

[1] The assumptions used are 1.7 bbl net production/bbl burned in central Kern County and 3.0 bbl net production/bbl burned in western Kern County.

TABLE 7-11.

CAPITAL AND ANNUAL COSTS (IN MILLIONS OF DOLLARS) FOR FINE PARTICULATE MATTER CONTROL SYSTEMS NEEDED TO COMPLY WITH THE FINE PARTICULATE GUIDELINE IN KERN COUNTY.

AREA	CAPITAL COST	ANNUAL COST
Central Kern County	0.90 - 1.29	0.57 - 1.59
Western Kern County	4.56 - 6.56	2.88 - 8.09
TOTAL	5.46 - 7.85	3.45 - 9.68

compliance with the Stage III regulations in Kern County are estimated to be $795 to $1,132 million and $340 to $350 million, respectively. Summary costs of controls required to comply with previous Kern County regulations are presented in Table 7-12. Based on estimated potential Kern County TEOR production for permitted steam generators, the costs for controls under compliance with the Stage I Control level are estimated to be $0.98 to $2.12 per net barrel of oil produced. At the Stage II Control level, costs of controls are estimated to be $1.08 to $2.91 per net barrel of oil produced. If the Stage III Control level is required, the control costs per net barrel of oil produced are estimated to be $2.66 to $4.16. The above costs are in 1979 dollars. Assuming an average inflationary rate of 10 percent per year over the last two years, these estimates would have to be increased by 21 percent to give costs in 1981 dollars. If the average barrel of heavy oil is worth $25.00, the costs of controls alone represent between 3.2 and 13 percent of the oil's value. These control costs may significantly impact marginal TEOR fields and may ultimately contribute to their abandonment.

7.1.7.1 Compliance Schedules

Rules 424, 425, and 411.1 include compliance schedules, and Rule 425 includes several potential compliance schedules. The compliance schedule for Rule 424 requires initial emission reductions by July 1, 1982 and ultimate emission reductions by July 1, 1984. Rule 425 requires Stage I Control level compliance by July 1, 1982, and requires compliance with progressively more stringent control levels within 18 months after the corresponding changes in ambient NO_2 concentrations. Rule 411.1 requires final compliance by March 1, 1982. Rule 210.1 (New Source Review) does not have a compliance schedule since compliance is required

TABLE 7-12.

TOTAL CAPITAL AND ANNUAL COSTS FOR CONTROL SYSTEMS NEEDED TO COMPLY WITH PREVIOUS REGULATIONS, RULES 424 AND 425, AND PARTICULATE OFFSET REQUIREMENTS IN KERN COUNTY

Control Level	County Area	Capital Costs In MM Dollars	Average Annual Costs: MM Dollars	Average Annual Costs: Dollars/bbl Oil Burned	Average Annual Costs: Dollars/bbl Oil Produced
STAGE I	Central Kern	155 - 242	67.4 - 127	2.17 - 4.10	1.28 - 2.41
	Western Kern	130 - 256	58.7 - 144	2.34 - 5.77	0.78 - 1.92
	TOTAL	285 - 498	126 - 271	2.25 - 4.85	0.98 - 2.12
STAGE II	Central Kern	180 - 357	73.8 - 179	2.38 - 5.79	1.40 - 3.40
	Western Kern	150 - 371	63.7 - 192	2.55 - 7.70	1.08 - 2.91
	TOTAL	330 - 728	138 - 371	2.47 - 6.64	1.08 - 2.91
STAGE III	Central Kern	443 - 567	188 - 260	6.08 - 8.40	2.51 - 4.95
	Western Kern	352 - 565	152 - 270	6.09 -10.87	2.03 - 3.61
	TOTAL	795 - 1,132	340 - 530	6.08 - 9.49	2.66 - 4.16

upon construction of the new or modified source. Special conditions in the ACs issued in September 1979 may require installation of control equipment on existing equipment to provide emission offsets. Table 7-13 summarizes the compliance schedules for Rules 424, 425, and 411.1.

Each compliance schedule, in turn, requires submission of a compliance plan by a certain date. However, repeated revisions of the regulations result in modification of the required control levels and make preparation of a compliance plan very difficult. The complexity and magnitude of this task, especially in the case of small producers, could result in significant delays in any proposed expansion of TEOR facilities subject to NSR. NSR requirements include demonstrating compliance with all other applicable rules before any application can be accepted by the APCD as complete.

7.1.7.2 Availability of Technology

In many cases, the required control technology has yet to be demonstrated. Assuming, for discussion purposes, that all required technology has been demonstrated, one to four years could pass before the control systems are commercially available in sufficient quantities to satisfy the applicable compliance schedules. Given these uncertainties, many oil producers may question risking not only new ventures, but also those projects for which they currently have only ACs. Progressive tightening of regulations may result in the permanent abandonment of projects which currently are on hold due to the lack of high efficiency control technology. Table 7-14 provides a summary of control equipment which must be installed to demonstrate compliance with the applicable regulations.

TABLE 7-13.

COMPLIANCE SCHEDULES AND EMISSION LIMITS FOR RULES 424, 425, and 411.1

RULE AND COMPLIANCE INCREMENTS	COMPLIANCE DATE(S)[1]	EMISSION LIMITS
Rule 424 (SO_x)		
1. Submit Compliance Plan	7/1/80	--
2. Submit Verification of Purchase Orders	7/1/80	--
3. Submit Status Reports	7/1/81, 7/1/82, 7/1/83, 7/1/84	--
4. Demonstrate Compliance	7/1/82 7/1/84	0.25 lbs S/MM Btu 0.12 lbs S/MM Btu
Rule 425 (NO_x)		
1. Stage I Control Level Compliance	7/1/82	0.30 lbs NO_x/MM Btu
2. Stage II Control Level Compliance	18 months following a Stage II air quality change	0.25 lbs NO_x/MM Btu
3. Stage III Control Level Compliance	18 months following a Stage III air quality change	0.14 lbs NO_x/MM Btu
Rule 411.1 (HC)		
1. Submit Compliance Plan	1/1/80	--
2. Submit Verification of Purchase Orders	7/1/80	--
3. Initiate Onsite Construction	10/1/80	--
4. Complete Onsite Construction	10/1/81	--
5. Demonstrate Compliance	3/1/82	93% Control

[1]Compliance date for steam generators installed before September 12, 1979.

TABLE 7-14.

AVERAGE MONTHLY CONTROL EQUIPMENT INSTALLATION REQUIRED TO COMPLY WITH RULES 424, 425, and 411.1

RULE/CONTROL EQUIPMENT	TOTAL EQUIVALENT CONTROL SYSTEMS TO BE INSTALLED[1]	EQUIVALENT UNITS TO BE INSTALLED PER MONTH (AVERAGE)
Rule 424 (SO_x)		
SO_2 Scrubbers	291	6.9
Rule 425 (NO_x)		
Stage I[2] - LNBs and	805	42.4
- SNR	276	14.5
Stage II[3] - SNR or	717	39.8
- SCR	223	12.4
Stage III[3] - SCR	561	31.2
Rule 411.1		
WHVR Systems	261	18.6

[1] An equivalent control system is an SO_x or NO_x system installed on a 50 MM Btu/hr output steam generator or a WHVR system applied to 32 production wells.

[2] TEOR producers have 19 months to comply with the Stage I Control level.

[3] TEOR producers have 18 months to comply if Stage II or III Control levels are required.

7.1.7.3 Time Delays

In addition to the delays caused by revision of regulations and corresponding changes in compliance schedules and emission limitations, the actual permit review process in Kern County has been significantly impacted by the shear magnitude of applications received over the last four to five years. These phenomena have resulted in significant delays in the issuance of Authorities to Construct (ACs). The processing delays resulting from large influxes of applications are compounded by the following factors:

- compliance schedule submittal requirements for Rule 424 and 411.1;
- inadequate demonstration of the technology needed to satisfy regulatory requirements;
- submittal of applications for retrofit controls needed on existing equipment to satisfy emission offset requirements contained in ACs issued in September 1979;
- control system manufacturing lead time which may range from 6 to 18 months depending on the type of control system; and
- control system installation, start-up, and compliance testing requirements which may range from 3 to 6 months depending on how much pre-installation work can be completed prior to equipment arrival.

Table 7-15 illustrates the time requirements and potential delays associated with complying with Kern County APCD regulations.

TABLE 7-15.

TIME REQUIREMENTS AND POTENTIAL DELAYS ASSOCIATED WITH COMPLYING WITH KERN COUNTY APCD RULES[1]

ACTIVITY	TIME REQUIREMENTS AND POTENTIAL DELAYS
AC issued under NSR in September 1979	
a. SO_x controls for emission offsets	Rule 424 limits were not established until October 1980 - 13 months delay
b. Submittal of SO_x control plan for emission offsets	3 months preparation by applicant 3 months review by APCD
c. Request and review bids and issue Purchase Order for SO_x controls	3 months
d. Manufacturing and delivery of SO_x controls	12 to 18 months depending on type of SO_2 scrubber
e. Installation, start up, and request for compliance testing	3 to 6 months
f. Concurrent with step c; request and review bids and issue Purchase Order for NO_x controls for steam generators	3 to 6 months; (If SCR is required, a potential delay of 2 to 4 years could occur as this technology is still being demonstrated)
g. Manufacturing and delivery of steam generator and NO_x controls	3 to 6 months for steam generator with SNR 12 to 18 months for steam generator with SCR
h. Installation, start up, and request for compliance testing	3 to 6 months

[1] Assuming steps a, b, c, d, and e are conducted concurrent with steps f, g, and h, the total time requirement is 24 to 33 months for a SNR control system and 42 to 76 months for a SCR control system.

7.2 The Coalinga Field

All of the air pollution control systems committed to be installed on TEOR facilities in the Coalinga field were required for compliance with NSR rule requirements. All of the TEOR facilities permitted in the Coalinga field were permitted under the NSR rules adoped by the Fresno County APCD before June 21, 1979. As of June 21, 1979, the Coalinga field had 3,700 MM Btu/hr of steam generation capacity with either ACs or POs. The TEOR producers have committed to install SO_2 scrubbers, LNBs and SNRs. The SO_2 and NO_x (as NO_2) emissions cannot exceed 0.08 and 0.10 pounds per MM Btu (input), respectively. In the spring of 1979 the Fresno APCD began requiring that one already permitted generator be equipped with SO_2 and NO_x control for each new steam generator installed in the Coalinga field.

The costs of air pollution control systems were estimated using costs developed in Section 6.0. A range of costs for SO_2 control systems was obtained by calculating the costs of installing and operating SO_2 scrubbers on 1) an individual 31.5 MM Btu/hr (input) steam generator and 2) a bank of ten 62.5 MM Btu/hr (input) steam generators. The costs of LNB and SNR systems were calculated for individual 31.5 and 62.5 MM Btu/hr (input) steam generators.

The capital costs of the control systems committed to be installed on steam generators permitted in the Coalinga field as of June 21, 1979 would be from $10.5 to $20.5 million. As shown in Table 7-16, the annual costs for these controls are estimated to be between $5.6 and $13 million. The cost of the controls per barrel oil burned would be between $1.36 and $3.15. Steam generators permitted as of June 21, 1979 could potentially produce 39,700 BOPD (net), assuming 3.52 barrels (net) are

TABLE 7-16.

CAPITAL AND ANNUAL COSTS (IN MILLIONS OF DOLLARS) FOR CONTROL SYSTEMS ON PERMITTED TEOR FACILITIES IN THE COALINGA FIELD

CATEGORY	POLLUTANT	CAPITAL	ANNUAL
Controls on TEOR Facilities with ACs as of June 21, 1979	SO_2	5.9-13.8	3.9-10.7
	NO_x	4.6-6.7	1.7-2.3
	PM	-	-
	HC	**	**
TOTAL		10.5-20.5	5.6-13.0

** Costs expected to be small compared to other control systems.

produced per barrel of oil burned. The average annual costs for the control systems installed on the total permitted steam generation capacity (3,700 MM Btu/hr input) are expected to be between $0.39 and $0.89 per barrel of oil produced. However, costs will be several times higher for control systems installed on new steam generators, due to the cost of retrofitting one existing steam generator for each new generator installed.

7.3 The San Ardo Field

As of July 18, 1979 the San Ardo field had 4,135 MM Btu/hr (input) of steam generator capacity with ACs or POs. Rule 413 of the Monterey Unified APCD requires that SO_2 in the flue gases of combustion sources must not exceed the level of SO_2 that would be present in the flue gas if the source was burning 0.5% sulfur fuel. The average sulfur content of the crude oil from the San Ardo field is about 1.2%. To comply with Rule 413, the operators have installed SO_2 scrubbers on all steam generators operating in the field. In the spring of 1979, 375 MM Btu/hr of new steam generation capacity was permitted with SO_2 scrubbers and low NO_x burners (LNBs) to comply with the District's NSR Rule. One producer has installed a WHVR system on all existing production wells. The cost of the system is expected to be insignificant compared to the other air pollution control systems. The cost of the SO_2 controls required to comply with Rule 413 are included with the costs of SO_2 control systems committed to be installed for the new source review regulations.

The capital and annual costs of air pollution control systems committed to steam generators with ACs and POs prior to July 18, 1979 are expected to be from $11.4 to $26.2 million and from $7.8 to $21.2 million, respectively (see Table 7-17).

If all of the permitted steam generation capacity were operated at 80 percent capacity, 12,600 barrels of crude oil would be burned per day. The cost of the control systems per barrel of oil burned would be about $1.69 to $4.60. Assuming a net steam/oil ratio of 3.08 to 1.0, the net oil production would be 33,800 BOPD. The cost of air pollution controls per net barrel of oil produced would be $0.55 to 1.49.

TABLE 7-17.
CAPITAL AND ANNUAL COSTS (IN MILLIONS OF DOLLARS)
FOR CONTROL SYSTEMS ON PERMITTED TEOR FACILITIES
IN THE SAN ARDO FIELD

CATEGORY	POLLUTANT	CAPITAL	ANNUAL
Controls for TEOR facilities with ACs issued prior to July 19, 1979	SO_2	10.9-25.4	7.5-20.8
	NO_x	0.5-0.8	0.27-0.35
	PM	-	-
	HC	-	-
TOTAL		11.4-26.2	7.8-21.2

8.0 PART II ANALYSES - THE MAXIMUM POTENTIAL INCREASE IN TEOR PRODUCTION

In this section, the maximum potential increase in TEOR production is estimated based on the offsets which can be made available by installing high efficiency air pollution control systems on permitted TEOR facilities. The analyses assume that the availability of emission offsets is the only constraint to increasing TEOR production. Of the seven areas selected for detailed analyses in this study, only the five production areas in California are expected to have a large potential for increasing TEOR production. For this reason, maximum potential TEOR production is estimated for the five California areas only. The Texas and Arkansas fields are expected to decline in production rather than increase. Hence, air pollution control regulations are not expected to be a major constraint on production in these two fields. Even though the maximum potential TEOR production is not estimated for the Texas and Arkansas fields, the general impact of the federal air pollution regulations on future TEOR projects in these areas is discussed.

Future TEOR projects in California may be reviewed by three air pollution control agencies before they are approved; the local district, California Air Resources Board (CARB), and the Environmental Protection Agency (EPA) Region IX office. The NSR review of the local districts and the CARB focuses on the local district's regulations. These regulations primarily are based on the non-attainment review requirements of the federal Clean Air Act. The EPA Region IX office reviews the projects for compliance with both the federal non-attainment requirements and the Prevention of Significant Deterioration (PSD) regulations.

In most cases, the local California air pollution control district's rules are more restrictive than the federal regulations. Hence, the projects that meet the control requirements and offset requirements of the local district are usually below the minimum emission levels mandated by federal review. If the project must be reviewed under the EPA's new source review requirements, the review is usually very abbreviated. In California the maximum increase in potential TEOR production generally is most constrained by the regulations of the local districts, which affect the availability of emission offsets for new TEOR projects.

In the Part II Analyses, the maximum increase in steam generator capacity that could be installed in the five California production areas and the Texas and Arkansas fields is estimated. The emissions, costs, and TEOR production are then estimated in the Maximum Increase in TEOR Production Case for each production area. The change in air quality predicted if the maximum TEOR production is attained and the retrofit rules are implemented is also presented.

8.1 Method of Analyses

8.1.1 Analytical Steps Used to Assess the Impact of Air Pollution Control Regulations on Future TEOR Production

For each of the seven production areas, the impact of air pollution control regulations on future TEOR production was analyzed using the following eleven steps:

1. Identify areas which have the potential for a large expansion in TEOR production.
2. Determine the amount of emissions offsets that

are available for new steam generation capacity in areas where the potential exists for large expansion of TEOR production.

3. Estimate the SO_2, NO_x, PM, and HC emissions from new TEOR facilities operating with high efficiency control systems.
4. Calculate the increase of steam generation capacity which could be permitted in the areas solely on the basis of availability of emission offsets.
5. If interpollutant offsets are allowed, evaluate the potential for substituting offsets of one pollutant for another.
6. Compute the total increases of steam generation capacity from Steps 4 and 5 (i.e., the maximum increase in steam generation capacity that could be permitted in an area on the basis of emission offsets only).
7. Compute the costs of air pollution control systems that must be installed on new and existing TEOR facilities to achieve the maximum increase in steam generation capacity.
8. Estimate the maximum increase in TEOR production using representative steam to oil ratios.
9. Calculate the costs of air pollution control systems on a per barrel basis by dividing the cost of Step 7 by the maximum increase in TEOR production estimated in Step 8.
10. Estimate the SO_2, NO_x, PM, and HC emissions that will result from the maximum increase in TEOR production for each area, and from the implementation of the retrofit rules.

11. Use computerized atmospheric dispersion models to predict the air quality expected for the 1978 Baseline Case and that expected if the Maximum Increase in TEOR Production Case were to occur.

In order to assess the maximum increase in potential TEOR production for the five areas, many simplifying assumptions (listed in Table 8-1) had to be made. The effect of these assumptions, as well as other regulatory constraints, are analyzed in the next section, Part III Analyses.

In the next major subsection (8.2), a representative new crude oil-fired facility and its control systems are described. In the following subsection (8.3), the effect of emission offsets on future TEOR production are analyzed for central and western Kern County. The effect of emission offsets on TEOR production in the Coalinga and the San Ardo fields are discussed in the next two subsections (8.4 and 8.5). In Subsection 8.6, the potential for expanding TEOR production in the Los Angeles Basin fields is described. In the last subsection (8.7), the impact of air pollution regulations on TEOR fields in areas attaining the NAAQS (Arkansas and Texas) is briefly discussed.

8.1.2 Analyses of Air Quality Impacts

Complex photochemical dispersion models would have to be used to fully assess the changes in air quality which might be expected in the five California production areas if the retrofit rules are implemented and the maximum potential expansion of TEOR production occurs. These computerized models mathematically simulate the complex atmospheric photochemical conversion of SO_2, NO_x, and HC emissions to secondary particulates, oxidants (ozone, etc.), and NO_2. The PM directly emitted from combustion sources is thought to serve as the catalytic site for these reactions.

TABLE 8-1.

KEY ASSUMPTIONS USED TO ASSESS THE MAXIMUM POTENTIAL INCREASE IN TEOR PRODUCTION

1. The heavy oil reserves amenable to steam drive techniques are unlimited.
2. The air pollution control regulations will not change before 1990.
3. EPA's ban on construction of major projects will be lifted and will not impede future TEOR expansion.
4. The required air permits can be obtained quickly.
5. Only the emissions from oil-fired steam generators and WHVR systems are available as offsets for new TEOR facilities.
6. Emission offsets are optimally distributed among the producers which hold the heavy oil reserves (i.e., the emission offset ratios for the Kern County fields are 1.0 to 1.0 for direct offsets and CARB-developed interpollutant offset ratios, while the emission offsets ratios for the Coalinga and San Ardo fields are 1.2 to 1.0).
7. The high efficiency control systems can be retrofitted to all steam generators (greater than 15 MM Btu/hr heat input) which are not presently controlled by systems having equivalent control efficiencies (e.g., some permitted steam generators are already committed to SO_2 scrubbers with 95 percent or greater SO_2 removal efficiencies).
8. The net barrels of crude oil produced per barrel burned for steam drive projects is 1.7 in central Kern County, 3.0 in western Kern County fields, 3.52 in the Coalinga field, and 3.08 in the San Ardo field.
9. No scrap value is assumed for the existing control equipment (or convective sections) removed to install the high efficiency control systems.
10. The size distribution of steam generators vary among the production areas. Therefore, the size of steam generators used to calculate costs was varied among the production areas.

The available photochemical models are limited to computing the maximum worst case, short-term (a few minutes to a few days) concentrations, and are unable to predict long-term (annual) concentrations. The maximum short-term concentrations predicted by the models are highly affected by the specific configuration of pollutant sources and worst case meterological assumptions. The computerized photochemical models have a wind-field model and atmospheric chemistry model.

Large-scale validation studies with field monitoring of ambient pollutant concentrations and meterological data are needed for each area, in order to use the photochemical models. A photochemical modeling study of the five production areas would require millions of dollars to complete. This sophisticated modeling approach was not selected because of costs. A much simplier and less costly approach for estimating change in air quality has been selected. The annual concentrations of SO_2, NO_2, and directly-emitted PM from steam generators were predicted using the climatological dispersion model (CDM), an EPA approved Gaussian model. The dispersion model predicts annual arithmetic mean concentrations for non-reactive pollutants.

The change in air quality expected due to the implementation of the retrofit rules and the maximum expansion of TEOR production was estimated by predicting the concentrations of SO_2, NO_2, and directly-emitted PM for two situations. A 1978 Baseline Case and a Maximum Increase in TEOR Production Case were studied. The 1978 Baseline Case was selected because the retrofit rules and the more stringent NSR regulations had not yet been adopted in 1978. The Maximum Increase in TEOR Production Case studied the impact of TEOR production after the retrofit rules have been met and the maximum TEOR production increases have occurred. Case I and Case II maximum production scenarios were modeled for the Maximum Increase in TEOR Production Case. The Case II maximum production scenario was modeled since it incorporates more restrictive NO_x regulations than Case I.

The predicted concentrations presented in this study should not be compared to the air quality standards. The predicted concentrations should only be used to compare the 1978 Baseline Case and the Maximum TEOR Production Case for the production areas. This comparison then can be used to estimate general trends in SO_2, NO_2, and PM concentrations which might occur if maximum expansion is realized and retrofit rules are implemented.

Radian did not calibrate nor validate the CDM model for the production areas. Strict calibration and validation would require extensive comparison of the model results with: (1) measured air quality meteorological data, and (2) the steam generation capacity emission source information. These comparisons are extremely time consuming.

Modeling did not predict the impact of paving roads to provide offsets for directly emitted PM. The reduction in ambient particulate concentrations achieved by road paving is highly dependent on the moisture content and composition of the soil, traffic patterns, vehicle type and size, and the geometric configuration of the roads. This information is not readily available for most of the road paving programs. Due to the variablity of the major factors determining the impact of road paving on directly-emitted PM concentrations, the use of representative factors would have been unrealistic and would have increased the uncertainty of the air quality analyses.

Sources other than steam generators were not included in the modeling studies. Other expected sources in the production areas include stationary sources (refineries, manufacturing plants, etc.) and mobile sources (motor vehicles, drilling rigs, etc.)

In order to use the CDM model, an annual meteorological statistical summary, a source deck, and an array of receptors must be developed for each production area modeled.

The meteorological input consists of a statistical summary of the hourly windspeed, wind direction, and atmospheric stability. The diurnal mixing height must also be input to the CDM model. The location and representative emission release characteristics must be prepared and input for each steam generator. Finally, the array of receptors at which concentrations are to be predicted must be selected.

The meteorological inputs for the areas modeled are briefly described in the following subsections. The emission release parameters and receptor arrays used for the study are presented in Appendix C. No loss or decay of the SO_2, NO_x, or directly-emitted PM was assumed for the modeling of the field equipment. In addition, all NO_x is assumed to be converted to NO_2 as soon as it is emitted to the atmosphere.

8.2 A Representative New TEOR Production Facility and Control Systems

Typical production facilities for steam drive projects are multiple units of 62.5 MM Btu/hr (input) steam generators. The basic production unit consists of one 62.5 MM Btu/hur (input) steam generator, two to four injection wells, and the associated production wells equipped with WHVR systems. This study assumes that the producers will install only 62.5 MM Btu/hr steam generators to expand TEOR production. Air pollution control technologies currently considered as LAER or as innovative control technology are assumed to be installed on the already permitted and new TEOR facilities in order to comply with the retrofit rules and NSR requirements. These control levels have been selected for permitted facilities so that the regulatory requirements are met and the maximum amount of emission offsets are available for new TEOR projects. Installing these controls on new TEOR facilities will minimize the emissions from new facilities, and thereby increase the number of new TEOR facilities which can be installed in an area based on the available emission offsets. Hence, the application of high efficiency control technologies for SO_2, NO_x, PM, and HC maximizes the amount of new steam generation capacity that can be developed in a production area on the basis of emission offsets.

A representative new TEOR production unit is assumed to be a 62.5 MM Btu/hr (input) steam generator equipped with a LNB and O_2 controller, a SCR system, a flue gas desulfurization system (an SO_2 scrubber), and a high efficiency PM control system. The NO_x control systems (consisting of the LNB, the O_2 controller, and the SCR system) are assumed to reduce the uncontrolled NO_x emissions by 90 percent. The SO_2 scrubber is assumed to remove 95% of the SO_2 and 32% of the PM in the flue gas. The high efficiency PM control systems are assumed to achieve a 99 percent reduction of the mass of uncontrolled PM that would be emitted from a steam generator burning lease crude.

The NO_x and PM emissions from the 62.5 MM Btu/hr (input) steam generator with the high efficiency controls are expected to be about 4.5 and 0.005 lbs/hr, respectively. The SO_2 emissions from the scrubbers will depend on the sulfur content of the crude oil which varies among the production areas. The HC emissions from a 62.5 MM Btu/hr (input) steam generator are expected to be about 0.4 lbs/hr.

8.3 The Kern County Fields

The Kern County NSR rule and the retrofit rules 424, 425, and 411.1 severely limit the emission offsets available for future TEOR projects. The recently revised Kern County NSR rule requires that PM and NO_x emissions be offset, in addition to SO_2 emissions. As previously mentioned, the emission reductions made by the TEOR producers to comply with the retrofit rules cannot be used as emission offsets to comply with the NSR rule.

If one assumes that high efficiency NO_x control systems are commercially available at reasonable costs, then the availability of NO_x emissions offsets for future TEOR projects will depend on the control levels which must be met to comply with Rule 425. At the Stage I Control level, the NO_x emissions from steam generators permitted by September 12, 1979, must average 0.30 lbs/MM Btu before emission reductions can be counted for emission offsets. On the other hand, if the Stage II Control level must be met, the NO_x emission from the steam generators must be reduced to 0.25 lbs/MM Btu before any offsets can be obtained. The availability of NO_x emissions offsets will significantly affect the Maximum Increase in TEOR Production Case for Kern County. In order to assess the impact of Rule 425 on future expansion of TEOR production in Kern County, two cases are analyzed:

Rule 425, Case I

In Case I, only the Stage I Control level for NO_x emission has to be met. Because much of the permitted steam generation capacity in Kern County must meet NO_x emission levels not far above the Stage I Control level in order to comply with permit conditions, no emission offsets are assumed to result when the steam generators comply with the Stage I Control level.

Rule 425, Case II

In this case, the NO_x emissions from the permitted steam generators must meet the Stage II Control level before any emission offsets can be obtained. Furthermore, the Stage III Control level must be met if a national or California ambient air quality standard is exceeded in Kern County.

Except for the stage of NO_x control required in the two cases, the regulatory requirements of the two cases are the same. The emission offset ratios established under Rule 210.1 are assumed for the Rule 425 analyses: direct pollutant offsets for SO_2, NO_x, PM, and HC (1.0 to 1.0) and interpollutant offsets for NO_2, PM, and HC (CARB-developed relationships).

The steam generators in central Kern County are assumed to burn crude oil with a sulfur content of 1.1 percent, and the steam generators in western Kern County are assumed to burn 1.2 percent sulfur crude oil. The net oil production rate achieved in the Kern River field (1.7 barrels of oil per barrel of crude oil burned) is assumed for the other fields in central Kern County. A net production rate of 3 barrels of oil per barrel of oil burned is assumed to be representative of the western Kern County fields.

To estimate costs, the range of steam generation capacity to be controlled with a single emission reduction system are assumed. For example, an SO_2 scrubber may treat the flue gas from a single 62.5 MM Btu/hr steam generator or a bank of ten 62.5 MM Btu/hr steam generators. SO_2 and PM control systems are assumed to control from one to ten 62.5 MM Btu/hr steam generators and NO_x systems are assumed to control one 62.5 MM Btu/hr generator. The range of steam generation capacity to be retrofitted with a single or collective control system in Kern County is assumed to be 31.25 to 625 MM Btu/hr of generator capacity for SO_2 controls, 31.25 to 62.5 MM Btu/hr of generator capacity for NO_x controls and PM controls in the central fields (Case I) and the western fields (Cases I and II). For PM controls in the central fields (Case II), the capacity range is assumed to be 31.25 to 625 MM Btu/hr of generator capacity.

8.3.1 Emissions, Costs, and Production

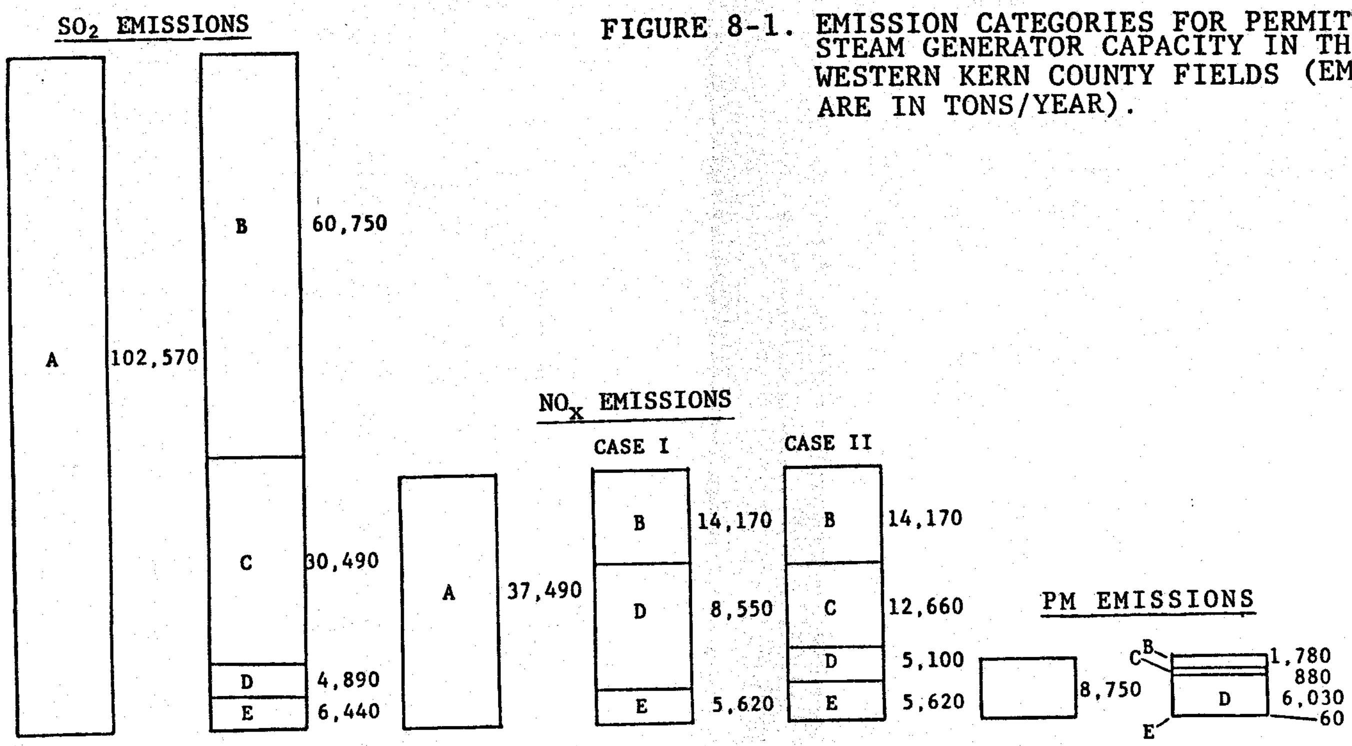
The availability of emission offsets for future increases in TEOR production has been substantially reduced by the retrofit rules which were evaluated in the Part I Analyses in Section 7. Figures 8-1 and 8-2 categorize emissions from permitted steam generator capacity in the western and central Kern County fields. Category D represents the potential emission offsets available after compliance with the retrofit rules. Cases I and II for NO_x control are shown. The emission offsets required for maximum expansion of TEOR production (Case I and Case II) are presented in Tables 8-2 and 8-3.

8.3.1.1 Rule 425, Case I

If high-efficiency control systems are applied to all the steam generation capacity in central Kern County, emissions offsets would be available for 40,000 MM Btu/hr of new steam generator capacity. In western Kern County, emissions offsets would be available for 21,400 MM Btu/hr of new capacity. The availability of SO_2 emission offsets is expected to be the most limiting factor on future TEOR potential for Case I in central and western Kern County. The 640 and 343 equivalent 50 MM Btu/hr (output) steam generators are expected to represent the maximum increase in TEOR production that can be achieved by the central and western Kern County production areas. The maximum TEOR production in these areas is limited by the availability of SO_2 emission offsets, and further limited by the fact that no interpollutant offsets are allowed for SO_2 emission increases.

Compliance with Rule 210.1 is not expected to reduce current SO_2, NO_x, HC, or PM emissions because of the 1.0 to 1.0 emission offset ratio assumed for new projects.

FIGURE 8-1. EMISSION CATEGORIES FOR PERMITTED[1] STEAM GENERATOR CAPACITY IN THE WESTERN KERN COUNTY FIELDS (EMISSIONS ARE IN TONS/YEAR).

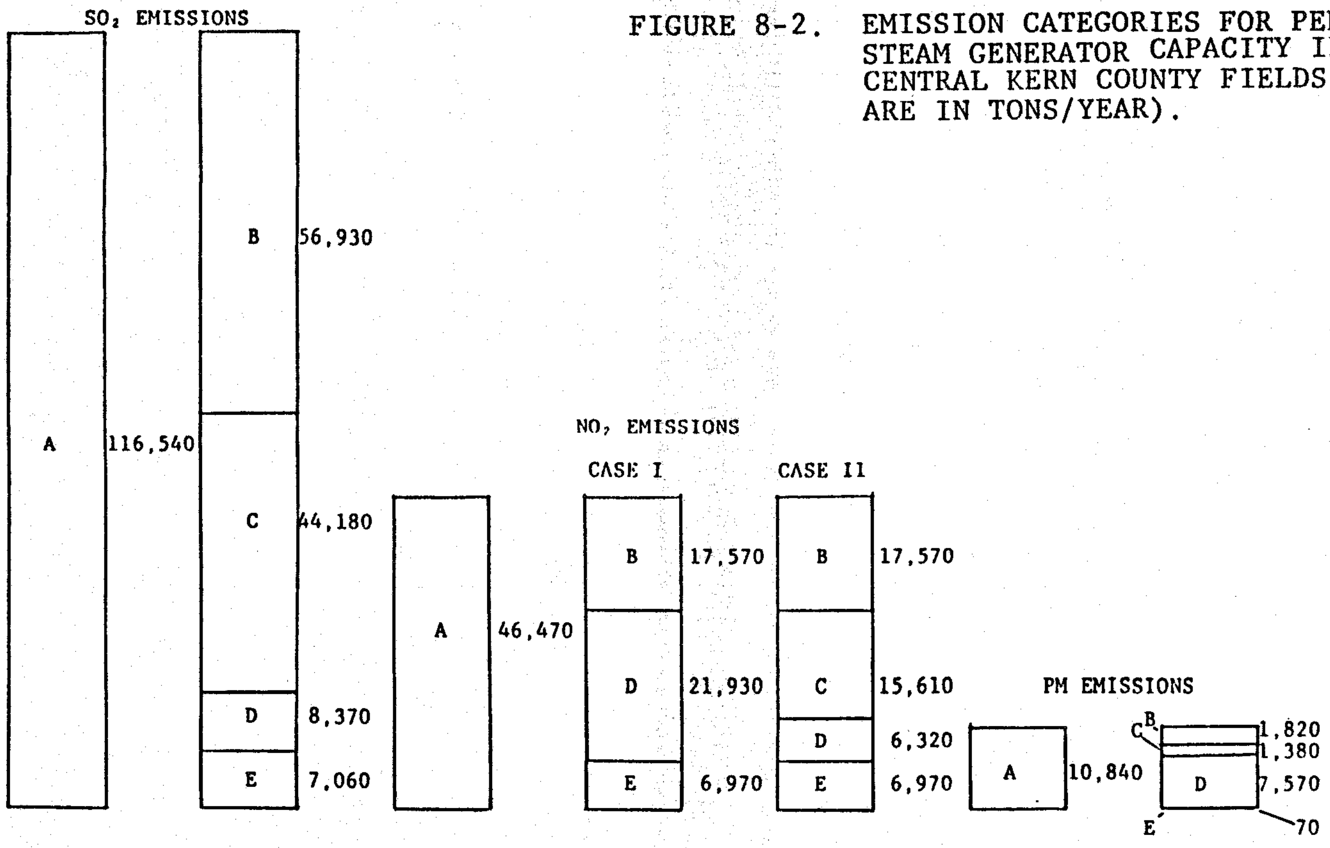


A = Potential uncontrolled emissions.
B = Emission reductions designated in ACs.
C = Additional emission reductions required to comply with retrofit rules.
D = Potential emission offsets from retrofitting pollutant control systems on steam generators. Category D emissions equal the potential offsets in the western Kern County fields.
E = Residual emissions to the atmosphere.

---

[1] Permitted steam generation capacity has ACs dated prior to September 12, 1979.

FIGURE 8-2. EMISSION CATEGORIES FOR PERMITTED[1] STEAM GENERATOR CAPACITY IN THE CENTRAL KERN COUNTY FIELDS (EMISSIONS ARE IN TONS/YEAR).



A = Potential uncontrolled emissions.
B = Emission reductions designated in ACs.
C = Additional emission reductions required to comply with retrofit rules.
D = Potential emission offsets from retrofitting pollutant control systesm on steam generators. Category D emissions equal the potential offsets in the central Kern County fields.
E = Residual emissions to the atmosphere.

[1]Permitted steam generation capacity has ACs dated prior to September 12, 1979.

TABLE 8-2.

EMISSION OFFSETS REQUIRED FOR
MAXIMUM EXPANSION OF
STEAM GENERATION CAPACITY
IN THE CENTRAL KERN COUNTY FIELDS

Pollutant	Emission Reductions (Tons/Year)		Equivalent Capacity (MM Btu/hr) To Be Retrofitted	
	Case I	Case II	Case I	Case II
SO_2	8,370	8,370	2,110	2,110
NO_x	10,010	6,320	7,060	4,460
PM	110	850	280	2,200
HC	930	12,000	20[1]	263[1]

[1] Number of wells.

MAXIMUM EXPANSION OF TEOR FACILITIES
IN THE CENTRAL KERN COUNTY FIELDS

Expansion Category	Expansion[2]
Generating Capacity (Equivalent 62.5's)	640
Number of Production Wells	7,120
Oil Production (BOPD) Net	207,200

[2] Maximum expansion is the same for Cases I and II.

TABLE 8-3.

EMISSION OFFSETS REQUIRED FOR MAXIMUM EXPANSION OF STEAM GENERATION CAPACITY IN THE WESTERN KERN COUNTY FIELDS.

Pollutant	Emission Reduction (Tons/Year)		Equivalent Capacity (MM Btu/hr) To Be Retrofitted	
	Case I	Case II	Case I	Case II
SO_2	4,890	4,890	1,130	1,130
NO_x	5,370	5,100	3,790	3,600
PM	60	110	160	280
HC	500	1,130	11[1]	29[1]

[1] Number of wells.

MAXIMUM EXPANSION OF TEOR FACILITIES IN THE WESTERN KERN COUNTY FIELDS

Expansion Category	Expansion[2]
Generating Capacity (Equivalent 62.5's)	343
Number of Production Wells	5,270
Oil Production (BOPD) Net	196,000

[2] Maximum expansion is the same for Cases I and II.

For Case I, the capital costs for installing SO_2, NO_x, HC, and particulate control systems on new TEOR facilities and on existing facilities to provide offsets for the new facilities range from $960 to $1,242 million and from $525 to $683 million for the central and western Kern County fields, respectively. The average annual costs are expected to range from $412 to $579 million and from $223 to $315 million for the respective production areas (see Table 8-4). Over 70 percent of these costs are for the SCR controls systems installed on new and existing steam generators. The cost of all of the air pollution control systems is estimated to be from $11.80 to $15.40 per barrel of crude oil burned in the central Kern County production fields. In the western fields, air pollution control systems will cost $8.89 to $13.10 per barrel of oil burned.

Assuming a net oil production ratio of 1.7 to 1.0 and an 0.8 capacity factor, the potential increase in TEOR production from an additional 640 equivalent 62.5 MM Btu/hr (heat input) steam generators in central Kern County fields would be about 207,200 BOPD. The costs of the air pollution control systems will range from $6.93 to $9.02 per net barrel of oil produced. On the basis of available emission offsets, about 343 equivalent 62.5 MM Btu/hr (input) steam generators could be installed in the future in western Kern County fields for Case I. Assuming a net production of 3 barrels of oil per barrel of oil burned and an 0.8 capacity factor, the potential increase of TEOR production in western Kern County fields would be about 196,000 BOPD. The costs of air pollution control systems will range from $2.96 to $4.38 per net barrel of oil produced.

8.3.1.2 Rule 425, Case II

The availability of NO_x emission offsets is expected to be most critical constraint to increasing future steam

TABLE 8-4.

CAPITAL AND ANNUAL COSTS (10^6 \$ and 10^6 \$/Year) FOR CONTROLS TO ACHIEVE THE MAXIMUM TEOR PRODUCTION SCENARIO IN THE KERN COUNTY FIELDS (CASE I)

Category	Pollutant	Central Fields Capital	Central Fields Annual	Western Fields Capital	Western Fields Annual	Total Capital	Total Annual
Controls for new steam generators and steam drive wells	SO_2	105-150	66.4-139	56.2-81.0	36.9-77.6	161-231	103-217
	NO_x	660-800	278-314	354-429	149-168	1014-1229	427-482
	PM	22.8-32.8	14.4-40.4	12.2-17.6	7.7-21.7	35.0-50.4	22.1-62.1
	HC	49.8-78.3	0.6-6.8	36.9-58.0	0.5-5.1	86.7-136	1.1-11.9
Subtotal		838-1061	359-500	459-586	194-272	1297-1646	553-773
Controls retro-fitted to obtain offsets	SO_2	5.5-12.9	3.5-9.6	3.0-6.9	1.9-5.3	8.5-19.8	5.4-14.9
	NO_x	116-168	49.0-68.9	62.5-90.2	26.3-37.0	179-258	75.3-106
	PM	0.23-0.24	0.26-0.44	0.13-0.14	0.15-0.25	0.36-0.38	0.41 0.69
	HC	0.14-0.22	-[1]	0.08-0.12	-[1]	0.22-0.34	-[1]
Subtotal		122-181	52.8-78.9	65.7-97.4	28.4-42.6	188-279	81.1-122
TOTAL		960-1242	412-579	525-683	223-315	1485-1925	634-895

[1] These costs are expected to be small compared to all other costs.

generation capacity if (1) the producers in Kern County are required to meet the Stage II Control level of Rule 425 before any NO_x offsets can be created, and (2) interpollutant offsets are not allowed. Almost all of the already permitted steam generators in central and western Kern County must be retrofit with SCR systems to meet the Stage II Control level. Direct emissions offsets would then be available for an additional 422 equivalent 50 MM Btu/hr (output) steam generators in central Kern County and 292 equivalent 50 MM Btu/hr (output) steam generators in western Kern County. As in Case I, no reductions in current SO_2, NO_x, PM, and HC emissions levels can be expected from compliance with Rule 210.1 because of the 1.0 to 1.0 emission offset ratio assumed for new projects.

If interpollutant offsets are allowed, the steam generation capacity in the two production areas could be increased to the capacity given for Case I. In this case, the SO_2 emission offsets can become critical. The maximum utilization of HC and PM emissions offsets would have to be made to allow the NO_x emission increase. Using the interpollutant offsets, the increase of steam generation capacity in the two production areas would result in a slight decrease in SO_2, PM, and HC emissions. However, the NO_x emissions in the areas would slightly increase and exceed the very low Stage III NO_x emission limit if interpollutant offsets are allowed.

Assuming that interpollutant emission offsets are allowed, the capital and annual costs for installing and operating air pollution controls for Case II would be about the same as for Case I. Comparison of Table 8-5 to Table 8-4 shows that the cost of NO_x controls are from 10 to 20 percent lower for Case II than for Case I. However, the lower costs of NO_x contols for Case II are compensated for by the increased costs for PM and HC controls needed to give interpollutant offsets for the increase of NO_x emissions. The costs of controls

TABLE 8-5.

CAPITAL AND ANNUAL COSTS (10^6 \$ and 10^6 \$/Year) FOR CONTROLS TO ACHIEVE THE MAXIMUM TEOR PRODUCTION SCENARIO IN THE KERN COUNTY FIELDS (CASE II).

Category	Pollutant	Central Fields Capital	Central Fields Annual	Western Fields Capital	Western Fields Annual	Total Capital	Total Annual
Controls for new steam generators and steam drive wells	SO_2	105-150	66.4-139	56.2-81.0	36.9-77.6	161-231	103-217
	NO_x	660-800	278-314	354-429	149-168	1014-1229	427-482
	PM	22.8-32.8	14.4-40.4	12.2-17.6	7.7-21.7	35.0-50.4	22.1-62.1
	HC	49.8-78.3	0.6-6.8	36.9-58.0	0.5-5.1	86.7-136	1.1-11.9
Subtotal		838-1061	359-500	459-586	194-272	1297-1646	553-773
Controls retro-fitted to obtain offsets	SO_2	5.5-12.9	3.5-9.6	3.0-6.9	1.9-5.3	8.5-19.8	5.4-14.9
	NO_x	73.6-106	31.0-43.5	59.4-85.7	25.0-35.1	133-192	56.0-78.6
	PM	1.3-1.9	0.8-3.4	0.23-0.24	0.26-0.44	1.5-2.1	1.1-3.8
	HC	1.8-2.9	0.02-0.25	0.20-0.32	-[1]	2.0-3.2	0.02-0.25
Subtotal		82.2-124	35.3-56.8	62.8-93.2	27.2-40.8	145-217	62.5-97.6
TOTAL		920-1185	395-557	522-679	221-313	1442-1864	616-871

[1]These costs are expected to be small compared to all other costs.

on a dollar per barrel basis are thus expected to be about the same for Case II as for Case I.

8.3.2 Air Quality Impact

The meteorological data used to model the central Kern County sources was measured at the Bakersfield airport. Meteorological data used to model western Kern County sources were measured at an ambient air monitoring site near Fellows. The files of the Kern County APCD were used to prepare an emissions inventory for all of the oil field equipment operating in central and western Kern County in 1978. A Case II emissions inventory was developed for all of the oil field equipment permitted in Kern County by September 12, 1979, plus all of the steam generators that possibly could be installed for Case II. The emission rates for the permitted and operating steam generators were estimated using the fuel characteristics, the expected removal efficiencies of the control systems, and the representative emission release characteristics (e.g., stack height, flue gas velocity, and temperature, etc.) described in Appendix C. These parameters were estimated on the basis of other published information and information obtained from the producers. The locations of the permitted oil field equipment were estimated from the Kern County APCD files and published dispersion modeling reports. The new steam generators for Case II were arbitrarily located near existing equipment within the oil fields.

8.3.2.1 Central Kern County Fields

After compliance with Case II controls levels and Rule 424, the SO_2 emissions from oil field equipment in central Kern County are expected to be drastically lower than levels for the 1978 Baseline Case. Rule 424, with its 64 percent reduction of steam generator SO_2 emissions, is expected to singlehandedly reduce the impact of the oil field equipment SO_2 emissions on air quality. As seen in Figure 8-3, the impact of SO_2 emissions from oil field equipment is expected to be reduced by at least a factor of two with the implementation of Rule 424 in central Kern County.

The CDM results indicate that the impact of the oil field equipment on NO_2 concentrations may be reduced by as much as a factor of two if the TEOR producers are required to meet the Stage III control level for Rule 425. Figure 8-4 indicates that in the central Kern County fields the maximum NO_2 concentrations, as well as the extent of the NO_2 concentrations, are expected to be much lower for Case II than for the 1978 Baseline Case. Because of the complex reaction of NO_x with HCs, SO_2, and ozone in the atmosphere, the precise impact of the reduced NO_x emissions on air quality can only be assessed with large-scale field studies and photochemical modeling.

The CDM results suggest that the concentration of directly-emitted PM around the central Kern County fields would be increased if the maximum TEOR production for Case II was achieved. The reduction of PM which results from road paving was not considered in the modeling exercise. Hence, the CDM results show only the increased concentrations of directly emitted particulates from oil field equipment in the central Kern County fields.

As indicated by Figure 8-5, only small increases of directly-emitted PM are predicted for the areas located a few miles from the fields. Paving of roads in the oil fields is expected to reduce the PM emissions in the immediate vicinity of the fields. Hence, the impact of increased TEOR production in the central Kern County fields is overestimated in the modeling results.

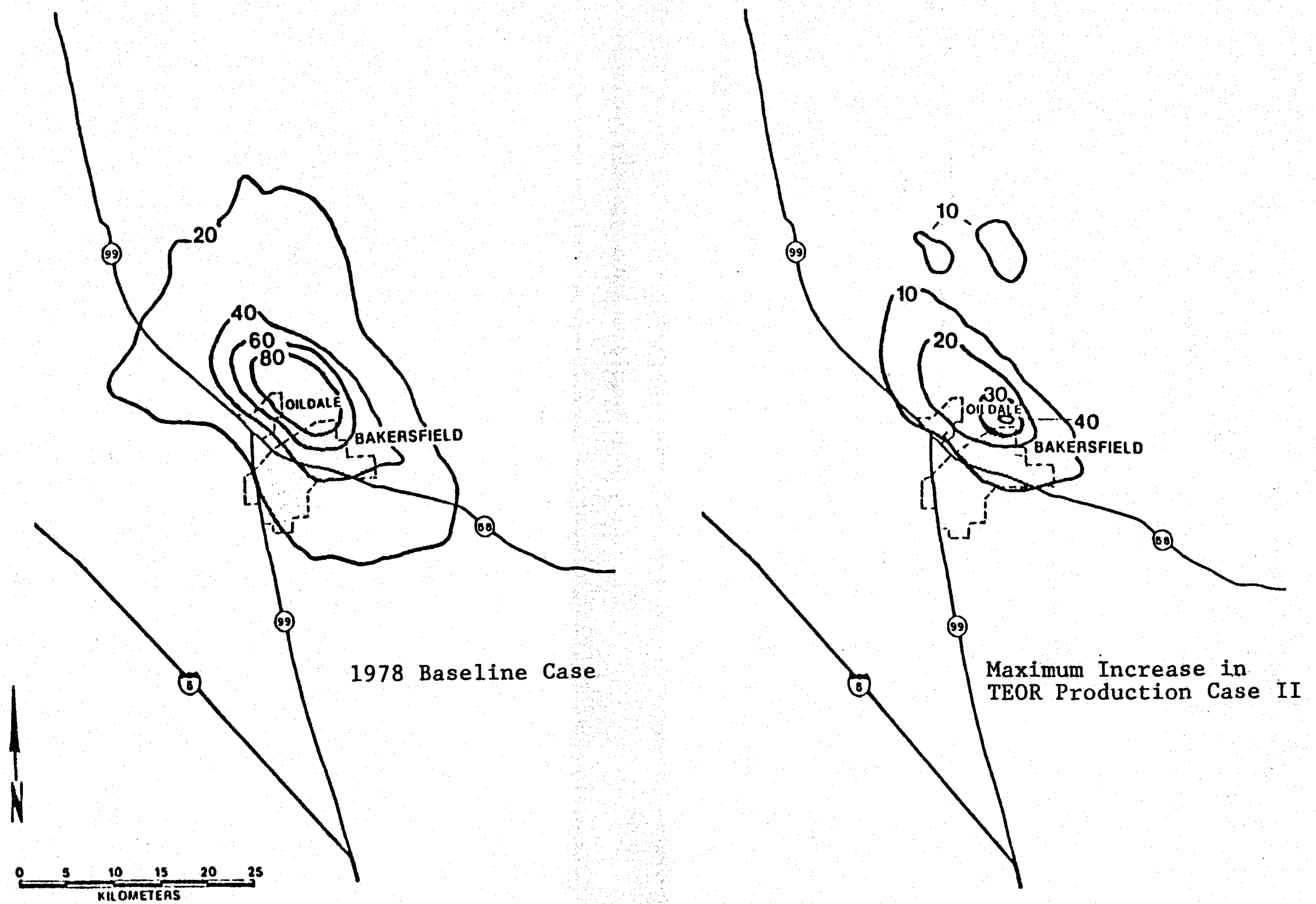


Figure 8-3. ANNUAL SO_2 CONCENTRATIONS ($\mu g/m^3$)
FOR CENTRAL KERN COUNTY FIELDS.

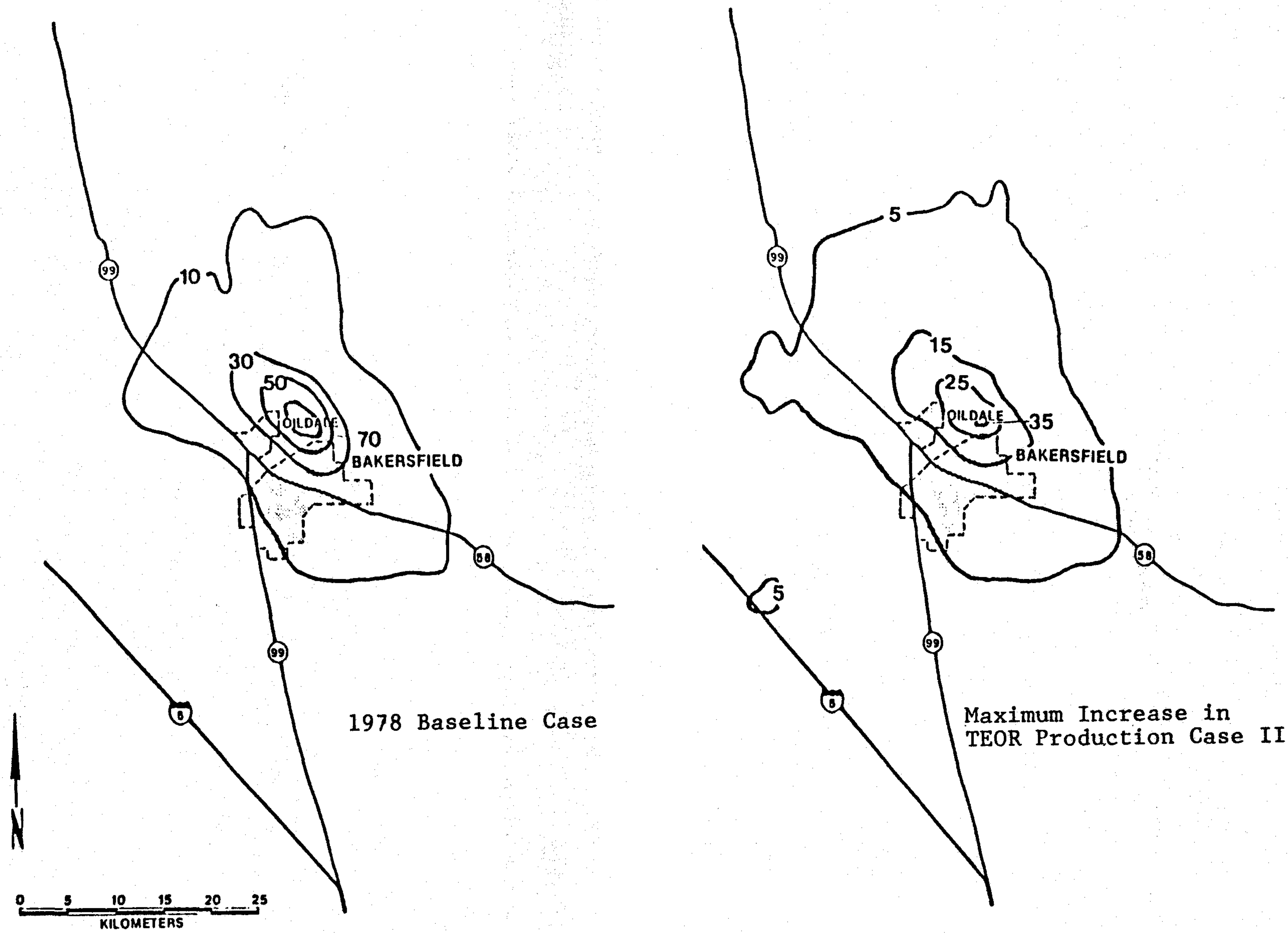


FIGURE 8-4. ANNUAL NO_2 CONCENTRATIONS ($\mu g/m^3$)
FOR CENTRAL KERN COUNTY FIELDS.

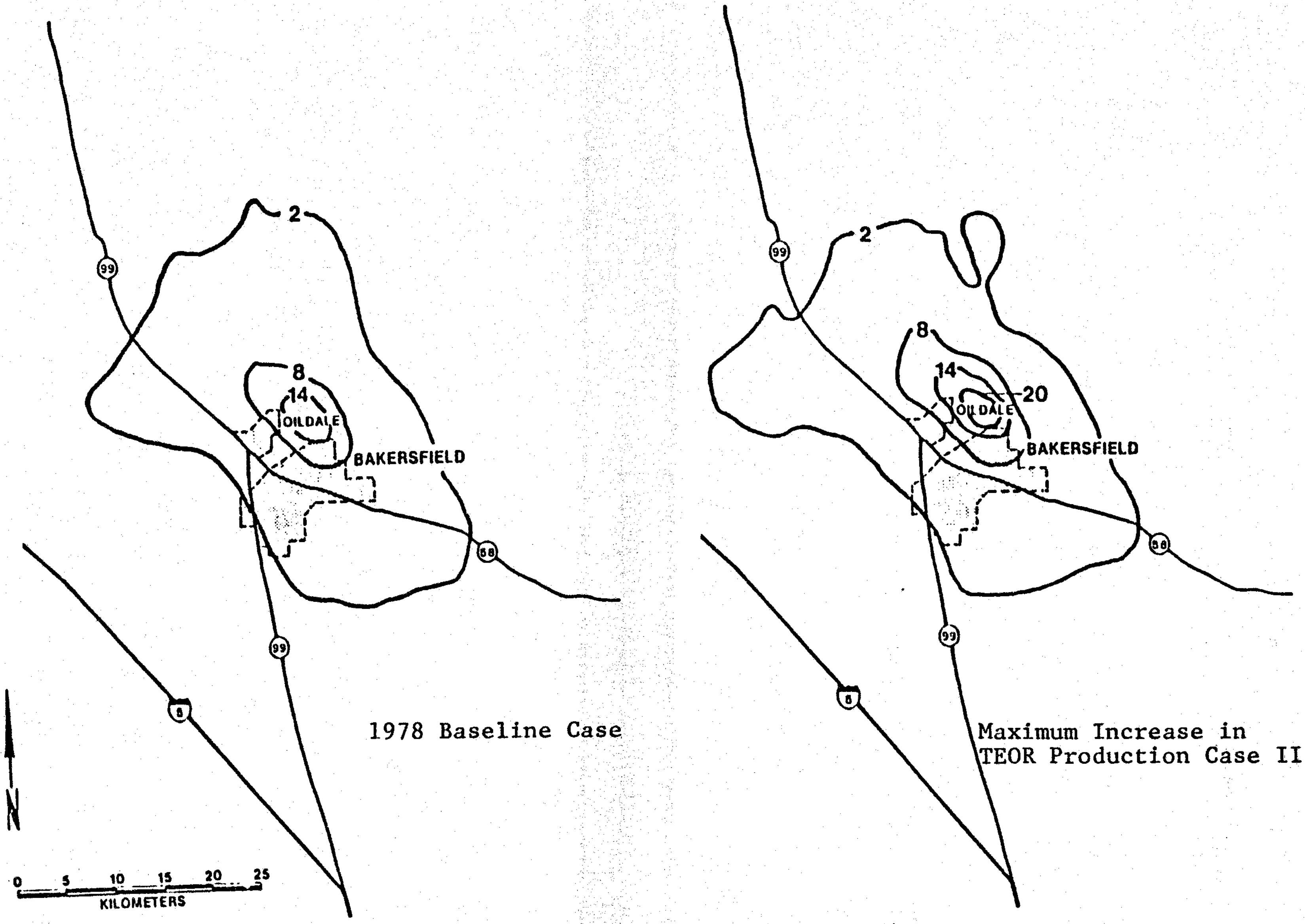
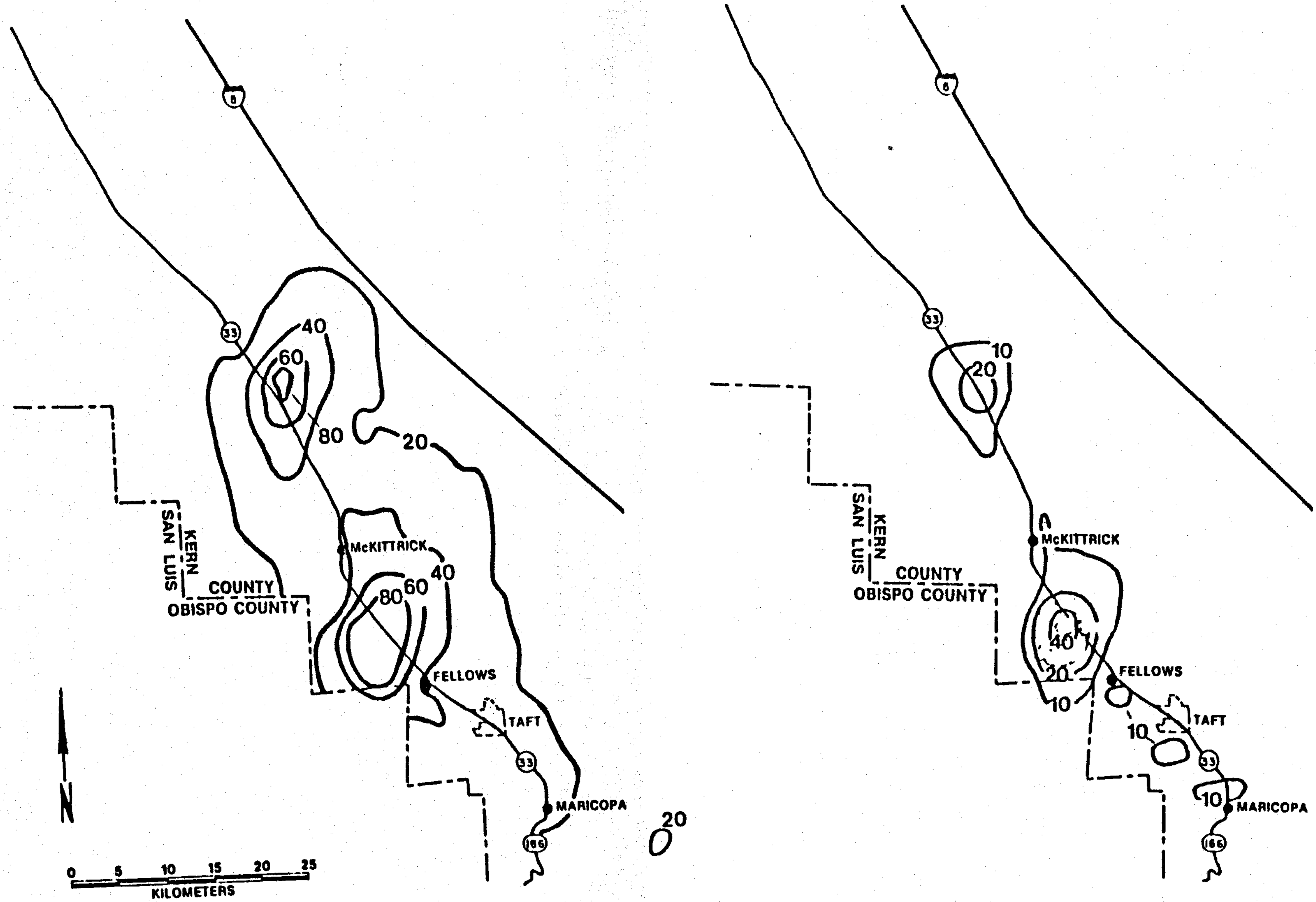


FIGURE 8-5. ANNUAL DIRECTLY EMITTED PARTICULATE MATTER CONCENTRATIONS ($\mu g/m^3$) FOR CENTRAL KERN COUNTY FIELDS.



1978 Baseline Case

Maximum Increase in TEOR Production Case II

FIGURE 8-6. CALCULATED SO_2 CONCENTRATIONS ($\mu g/m^3$) FOR WESTERN KERN COUNTY FIELDS.

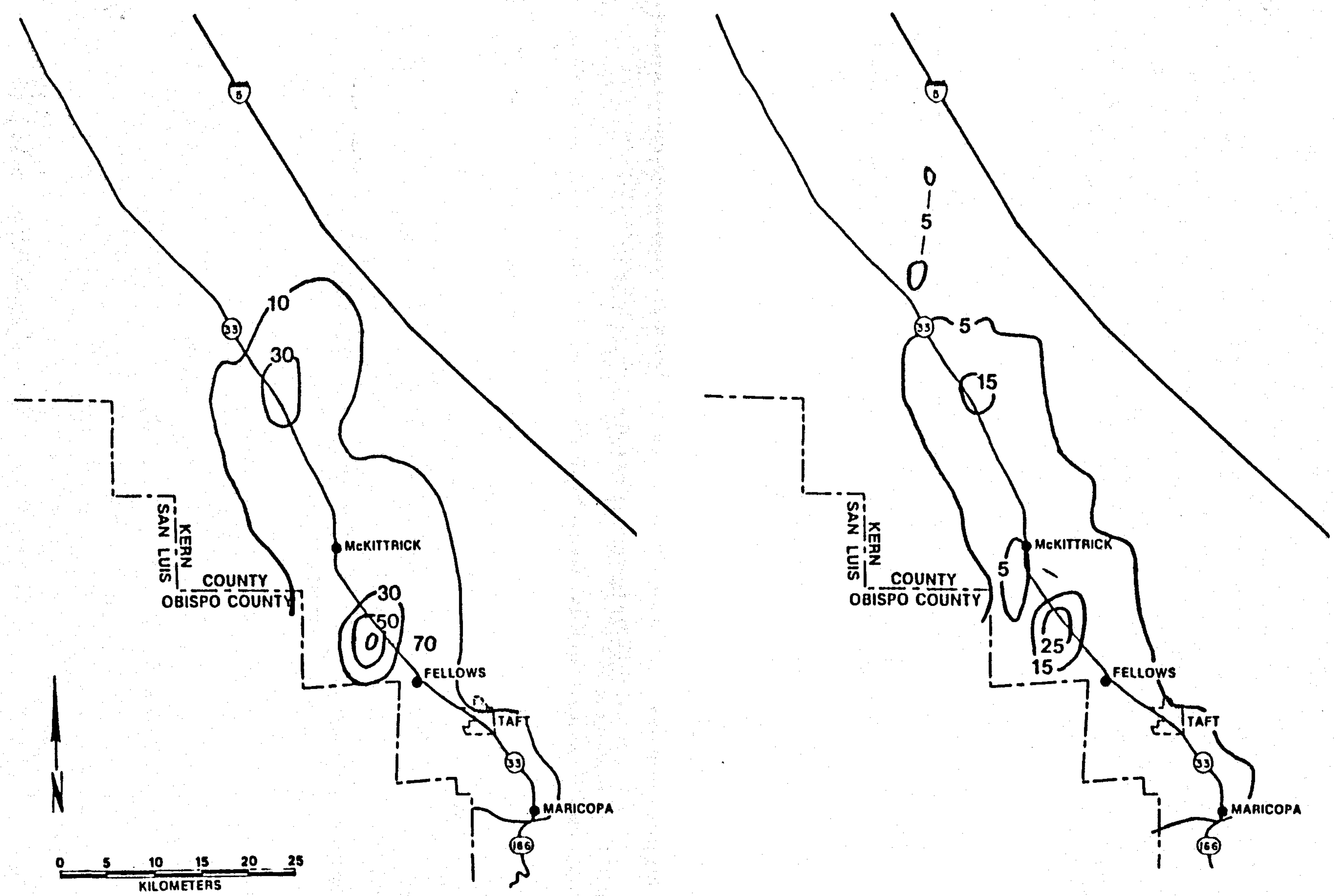
8.3.2.2 Western Kern County Fields

The impact of oil field equipment on air quality in western Kern County fields is expected to follow the same general trends as seen for central Kern County fields. SO_2 emissions from oil field equipment are expected to be reduced to less than one half of the 1978 level, as seen in Figure 8-6. In the immediate vicinity of the fields, the NO_2 concentrations are expected to be significantly reduced if the Stage III control level must be achieved (see Figure 8-7). The directly-emitted PM emissions from oil field equipment in Case II will have a greater impact on ambient PM concentrations in the immediate vicinity of the TEOR fields than the emissions calculated for equipment operated in 1978 (see Figure 8-8). Road paving was not considered in the modeling performed for the two cases.

8.4 The Coalinga Field

The method used to calculate the maximum potential increase in TEOR production for the Coalinga field was similar to the method used for the Kern County fields. The following major assumptions were made specifically for the Coalinga field:

- No banked emissions offsets existed on June 21, 1979. Offsets for new generators (ACs issued on or after June 21, 1979) must be obtained by controlling emissions from already permitted steam generators (ACs issued before June 21, 1979);
- The sulfur content of the crude oil is 1.2 percent;
- The net crude oil production per barrel of crude oil burned is 3.52 bbl;
- Emission offsets are on a lb per lb basis rather than an equipment basis where retrofit of one



1978 Baseline

Maximum Increase in TEOR Production Case II

FIGURE 8-7. CALCULATED NO_2 CONCENTRATIONS ($\mu g/m^3$) FOR WESTERN KERN COUNTY FIELDS.

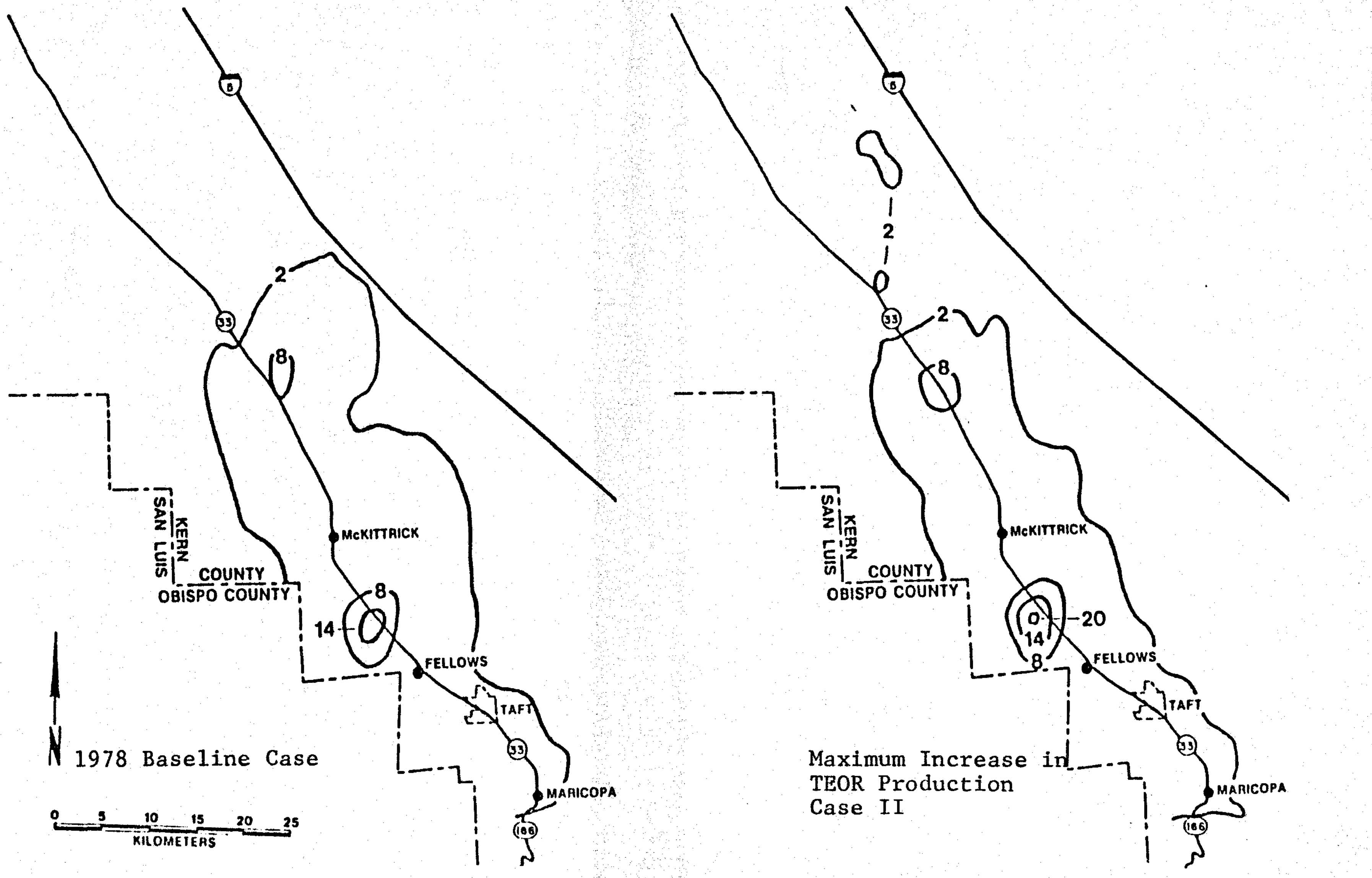


FIGURE 8-8. CALCULATED DIRECTLY-EMITTED PARTICULATE MATTER CONCENTRATIONS ($\mu g/m^3$) FOR WESTERN KERN COUNTY FIELDS.

permitted steam generator would allow one new generator; and

- No interpollutant offsets are allowed.

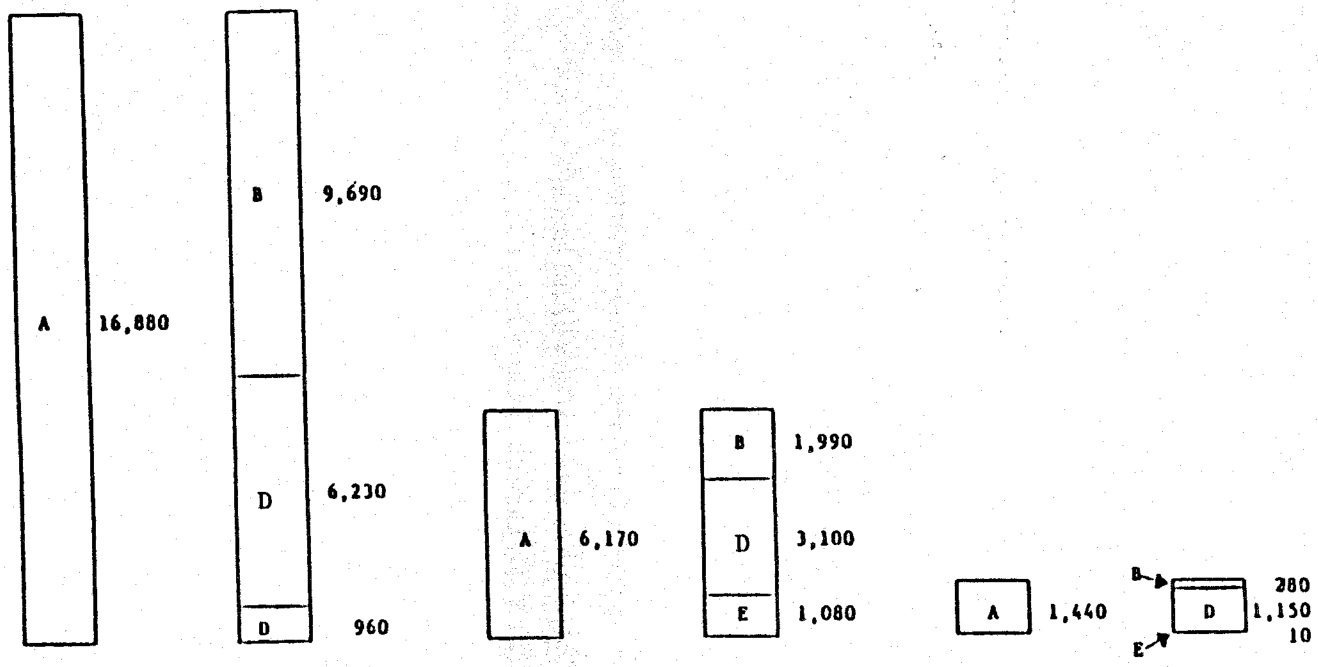
The Fresno County NSR Rule requires that all new sources are to offset emissions on a pound per pound basis. However, if the new TEOR facilities are considered to be a modification of an existing source, the emissions from the already permitted TEOR facilities have to be reduced to the level of emission from the source as of May 22, 1978. For the Part II Analyses, all new TEOR facilities were assumed to be new sources under the Fresno County NSR Rule in order to estimate the maximum TEOR potential for the Coalinga field on the basis of emission offsets.

In order to estimate control costs for new steam generators, it was assumed that individual 31.25 or 62.5 MM Btu/hr generators were retrofitted with control systems for SO_2, NO_x or PM. Another option evaluated was banks of 2 to 10 generators (125 to 625 MM Btu/hr capacity) with individual NO_x control systems and common SO_2 and PM control systems.

8.4.1 Emissions, Costs, and Production

The emission offsets available for expansion of the steam generation capacity in the Coalinga field are illustrated in Figure 8-9. The potential SO_2, NO_x, and PM emission offsets available for future steam generation capacity are as follows: 6,230 tons of SO_2 emissions per year; 3,100 tons of NO_2 emissions per year; and 1,150 tons of PM emissions per year. Table 8-6 shows that the amount of generator capacity which must be retrofitted with NO_x control systems for maximum expansion is 3 times the amount of capacity which must be retrofitted with SO_2 control systems. If high-efficiency control systems are applied to all steam generation capacity in the Coalinga field, emission

FIGURE 8-9. EMISSIONS CATEGORIES FOR PERMITTED[1] STEAM GENERATOR CAPACITY IN THE COALINGA FIELD (EMISSIONS ARE IN TONS/YR).



A = Potential uncontrolled emissions.
B = Emission reductions designated in ACs.
C = Additional emission reductions required to comply with retrofit rules.
D = Potential emission offsets from retrofitting pollutant control systems on steam generators. Category D emissions equal the potential offsets in the Coalinga Field.
E = Residual emissions to the atmosphere.

---

[1]The permitted steam generation capacity in the Coalinga field has an AC dated prior to June 21, 1979.

TABLE 8-6.

EMISSION OFFSETS REQUIRED
FOR MAXIMUM POTENTIAL EXPANSION OF STEAM
GENERATION CAPACITY IN THE COALINGA FIELD

Pollutant	Required Emission Reductions (Tons/Yr)	Equivalent Capacity (MM Btu/hr) To Be Retrofitted
SO_2	2,830	652
NO_x	3,090	2,180
PM	40	102
HC	297	7[1]

[1]Number of wells.

MAXIMUM POTENTIAL
EXPANSION OF TEOR FACILITIES
IN THE COALINGA FIELD

Expansion Category	Expansion
Generating Capacity (Equivalent 62.5's)	198
Number of Production Wells	3,097
Oil Production (BOPD) Net	132,600

offsets would be available for installation of 198 equivalent 50 MM Btu/hr (output) steam generators, in addition to the generators with ACs as of June 19, 1981.

The capital and annual costs for the air pollution control systems needed to maximize TEOR production in the Coalinga field are 304 to 395 million dollars per year, and 130 to 178 million dollars per year, respectively (see Table 8-7). The annual costs are about $9.44 to $12.90 per barrel of oil burned. Using a net oil production ratio of 3.52 barrels of oil produced per barrel of oil burned and a capacity factor of 0.8, the new 198 equivalent 50 MM Btu/hr (output) steam generators would produce 132,600 BOPD. The costs of air pollution control equipment would be $2.68 to $3.67 per net barrel of oil produced.

8.4.2 Air Quality Impact

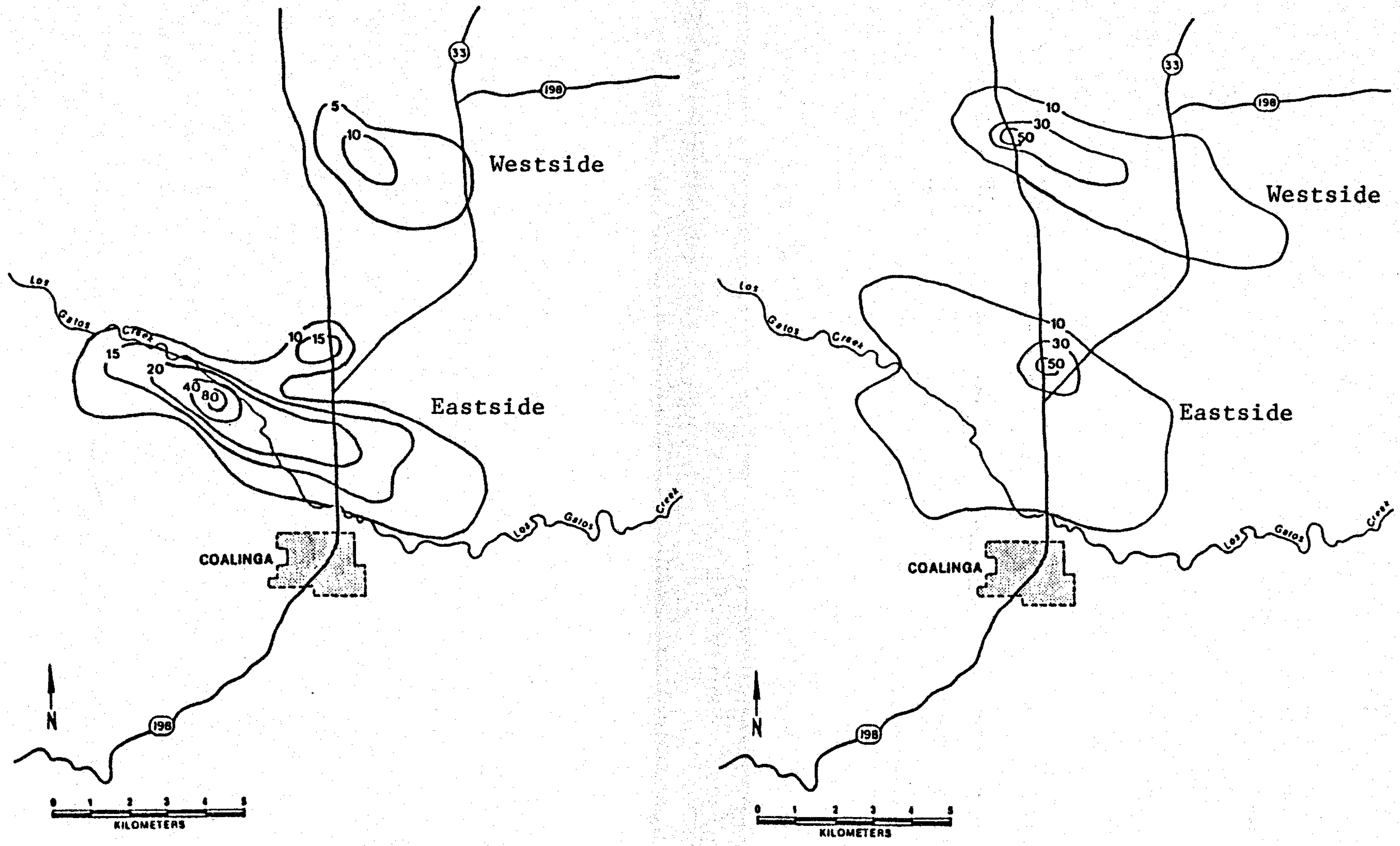
The meteorological data used to model the Coalinga field was obtained from a monitoring station operated in the field between November 1975 and October 1976. The emissions inventory for the 1978 Baseline Case was developed using the files of the Fresno County APCD. In 1978, 27 equivalent 62.5 MM Btu/hr input steam generators were operating primarily in the Eastside Coalinga field. The locations of permitted oil field equipment were estimated using published dispersion modeling reports. The steam generators for the Maximum Increase in TEOR Production Case were arbitrarily located near existing equipment in the Westside Coalinga field. The 58 new steam generators were modeled for the Maximum Production Increase Case. The SO_2, NO_2, and directly emitted PM concentrations predicted for the Coalinga field 1978 Baseline Case and the Maximum Production Increase Case are illustrated in Figures 8-10, 8-11, and 8-12.

TABLE 8-7.

CAPITAL AND ANNUAL COSTS (10^6 \$ AND 10^6 \$/YEAR) FOR CONTROLS TO ACHIEVE THE MAXIMUM TEOR PRODUCTION SCENARIO IN THE COALINGA FIELD

Category	Pollutant	Capital Costs	Annual Costs
Controls for new steam generators and steam drive wells	SO_2	32.4 - 46.8	21.3 - 44.8
	NO_x	204 - 248	85.9 - 97.0
	PM	7.1 - 10.1	4.5 - 12.5
	HC	21.7 - 34.1	0.3 - 3.0
Subtotal:		265 - 339	112 - 157
Controls retrofitted to obtain offsets	SO_2	2.5 - 4.0	2.4 - 3.1
	NO_x	36.0 - 51.9	15.1 - 17.1
	PM	0.08 - 0.09	0.09 - 0.16
	HC	0.05 - 0.08	-[1]
Subtotal:		38.6 - 56.1	17.6 - 20.4
TOTAL:		304 - 395	130 - 178

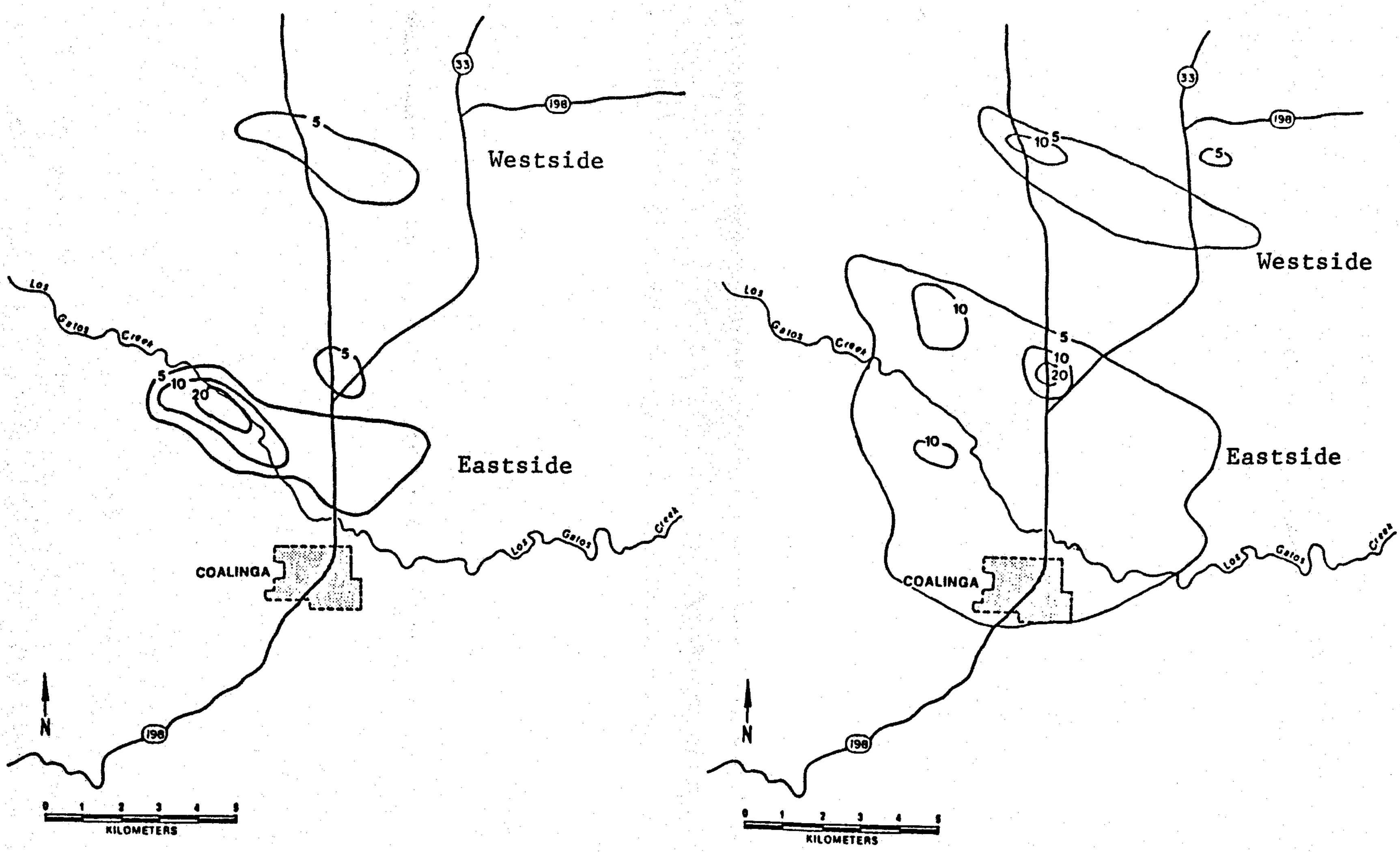
[1] These costs are expected to be small compared to all other costs.



1978 Baseline Case

Maximum Increase in TEOR Production Case

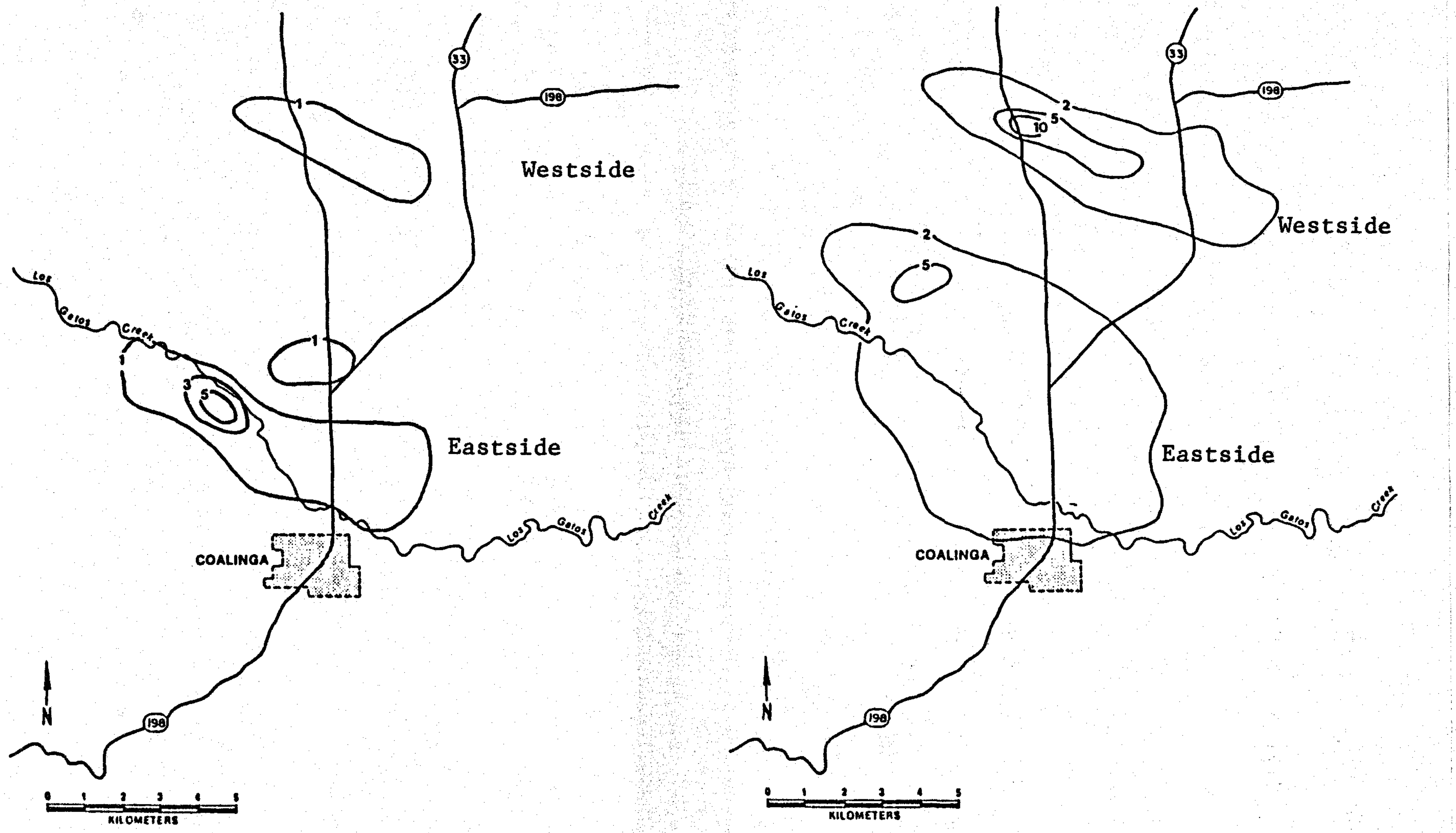
FIGURE 8-10. ANNUAL SO_2 CONCENTRATIONS ($\mu g/m^3$) FOR THE COALINGA FIELD.



1978 Baseline Case

Maximum Increase in TEOR Production Case

FIGURE 8-11. ANNUAL NO_2 CONCENTRATIONS ($\mu g/m^3$) FOR THE COALINGA FIELD.



1978 Baseline Case

Maximum Increase in TEOR Production Case

FIGURE 8-12. ANNUAL DIRECTLY-EMITTED PARTICULATE MATTER CONCENTRATION ($\mu g/m^3$) FOR THE COALINGA FIELD.

As would be expected, the area of peak concentrations of SO_2, NO_2, and directly-emitted PM decrease slightly in the Eastside Coalinga field as controls are installed on existing steam generators in the field to offset steam generators being installed in the Westside Coalinga field. The emissions of these pollutants are also dispersed over a greater area. As new steam generation capacity is being installed with high efficiency control systems in the Westside Coalinga field, a small increase in the SO_2, NO_2, and directly emitted particulate concentrations may occur. Even though the increase in SO_2 predicted for the Westside Coalinga area is small, the PSD increment may be major constraint to future TEOR expansion in the Coalinga field. The annual Class II PSD increment for SO_2 is 20 µg/m, which is a little higher than the SO_2 increase predicted for the Westside Coalinga field. No increase in PM concentrations are expected for the Coalinga field, even though the concentrations of directly-emitted PM are expected to increase from the 1978 Baseline Case to the Maximum Production Increase Case. The PM emission reduction expected from road paving in the Coalinga field was not considered in the modeling exercise. The producers will probably attempt to develop the leases in the fields so that there is no net increase in emissions in order to avoid EPA PSD reviews. However, since the steam generators which are available for control to provide offsets are not in the part of the Coalinga field where new capacity is needed, this strategy may not be feasible, and the federal PSD regulations may constrain future TEOR expansion in the Coalinga field.

8.5 The San Ardo Field

The maximum potential increase in TEOR production in the San Ardo field is expected to be affected primarily by the federal PSD regulations rather than the NSR Rule of the Monterey Unified Bay APCD. The San Ardo field is non-attainment area for only one of the NAAQS, oxidants (ozone). The District requires HC offsets but not NO_x offsets for the attainment of the NAAQS for ozone.

In order to avoid full PSD review, the oil producers in the San Ardo field are expected to overcompensate when they offset any SO_2, NO_x, HC, and directly-emitted PM emission increases from future TEOR projects.

The specific assumptions made for the San Ardo field which differ from the assumptions made for the Kern County fields are as follows:

- The emission increases of SO_2, NO_x, PM, and HC from a new TEOR project will be completely offset in order for the producers to avoid full PSD review;
- The emission offset ratio is 1.2 to 1.0 and no interpollutant offsets are allowed;
- The producers do not have existing emission offsets which they can use for new projects;
- The sulfur content of crude oil is 1.4 percent; and
- 3.08 net barrels of oil are produced per barrel of oil burned.

For estimating the control costs of new steam generation capacity, the range of steam generating capacity to be retrofitted with single or collective control systems were assumed to be 62.5 to 625 MM Btu/hr of generator capacity for SO_2 and PM controls, and 62.5 MM Btu/hr of generator capacity for NO_x controls.

8.5.1 Emissions, Costs, and Production

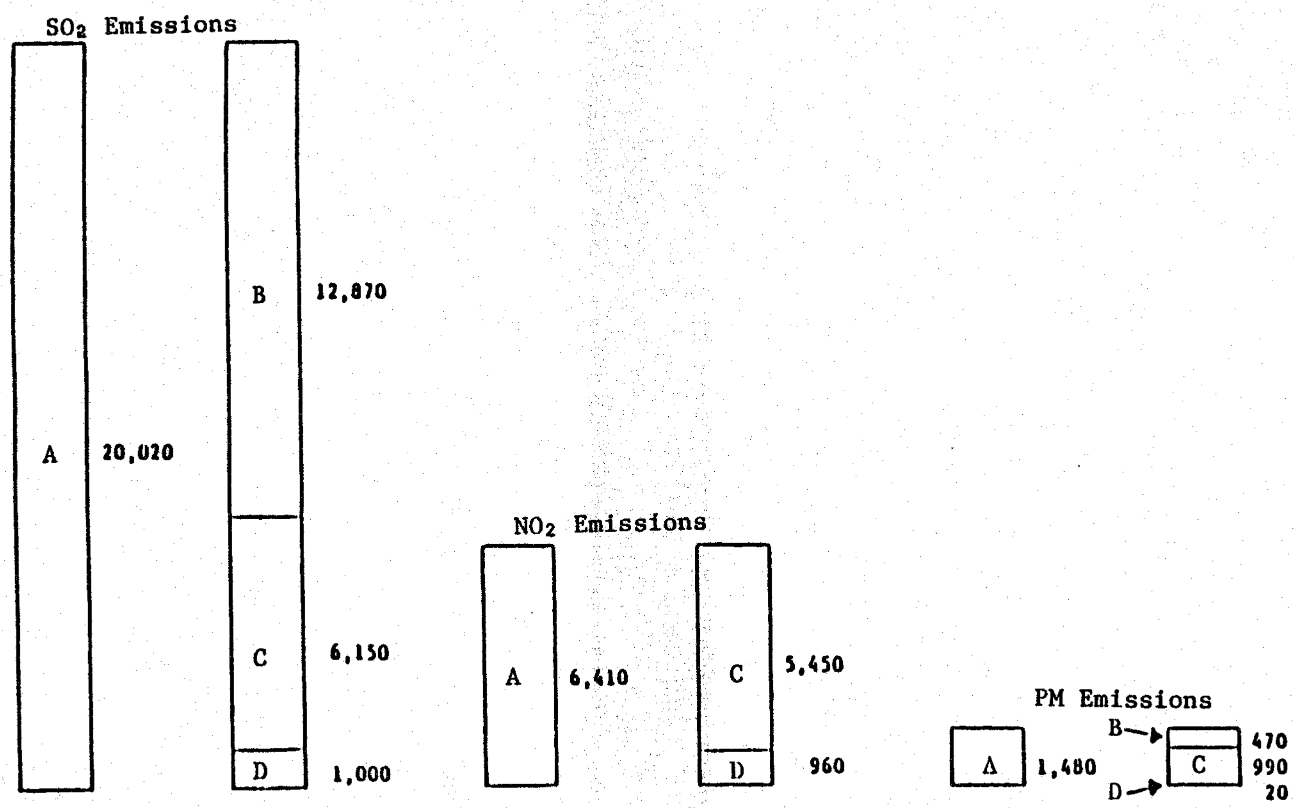
The availability of NO_x and SO_2 emissions offsets are expected to limit future TEOR expansion in the San Ardo field. The potential SO_2, NO_x, PM, and HC emission offsets are shown in Category D of Figure 8-13. The emission offsets required for the Maximum Increase in TEOR Production Case for the San Ardo field are presented in Table 8-8. The SO_2 and NO_x emission offsets (in tons/yr) required for the maximum amount of new steam generation capacity are within 10 percent of each other. If high efficiency control systems are applied to all the steam generation capacity in the San Ardo field, emissions offsets would be available for an additional 349 equivalent 62.5 MM Btu/hr (input) steam generators. This number is based on a net production factor of 3.08 barrels of oil produced per barrel of oil burned and a capacity factor of 0.8. The maximum increase in TEOR production in the San Ardo field on the basis of emission offsets would be 145,000 BOPD (net).

The capital and annual costs for the Maximum Increase in TEOR Production Case are summarized in Table 8-9. The capital costs of the air pollution controls needed for the maximum increase in TEOR production in the San Ardo field are expected to be between \$530 to \$693 million. About 70 percent of these costs would be incurred for the NO_x control systems. The annual costs for controls for all pollutants are projected to be from \$232 to \$339 million dollars. The annual costs of the air pollution controls systems per barrel of oil burned would be between \$9.56 and \$14.00. The air pollution control systems would cost the producers about \$3.10 to \$4.54 per barrel of oil produced, assuming 3.08 barrels of oil (net) are produced for each barrel of oil burned.

8.5.2 Air Quality Impact

The San Ardo field's SO_2 and NO_2 concentrations would be reduced substantially if the Maximum Increase in TEOR

FIGURE 8-13. EMISSION CATEGORIES FOR EXISTING STEAM GENERATORS IN THE SAN ARDO FIELD (EMISSIONS ARE IN TONS/YEAR).



A = Potential uncontrolled emissions.
B = Emission reductions designated in the permit files.
C = Potential emission offsets from retrofitting pollutant control systems on steam generators. Category D emissions equal the potential offsets in the San Ardo field.
D = Residual emissions to the atmosphere.

---

[1]An existing steam generator in the San Ardo Field has an AC dated prior to July 18, 1979.

TABLE 8-8.

EMISSION OFFSETS REQUIRED FOR MAXIMUM EXPANSION OF STEAM GENERATION CAPACITY IN THE SAN ARDO FIELD

Pollutant	Required Emission Offsets (Tons/Year)	Equivalent Capacity (MM Btu/hr) To Be Retrofitted
SO_2	5,830	3,570
NO_x	5,450	3,840
PM	70	179
HC	524	12[1]

[1]Number of wells.

MAXIMUM INCREASE IN TEOR PRODUCTION FOR THE SAN ARDO FIELD

Expansion Category	Expansion
Generating Capacity (Equivalent 62.5's)	349
Number of Production Wells	3,907
Oil Production (BOPD) Net	145,000

TABLE 8-9.

CAPITAL AND ANNUAL COSTS (10^6 \$ AND 10^6 S/YEAR) FOR CONTROLS TO ACHIEVE THE MAXIMUM TEOR PRODUCTION SCENARIO IN THE SAN ARDO FIELD

Category	Pollutant	Capital	Annual
Controls for new steam generators and steam drive wells	SO_2	57.6 - 82.5	39.7 - 86.2
	NO_x	360 - 436	151 - 171
	PM	12.4 - 17.9	7.9 - 22.0
	HC	27.3 - 43.0	0.4 - 3.8
Subtotal:		457 - 579	199 - 283
Controls retrofitted to obtain offsets	SO_2	9.4 - 21.9	6.5 - 18.0
	NO_x	63.4 - 91.4	26.6 - 37.5
	PM	0.15 - 0.16	0.16 - 0.28
	HC	0.08 - 0.13	-[1]
Subtotal:		73.0 - 114	33.3 - 55.8
TOTAL:		530 - 693	232 - 339

[1] These cost are expected to be small compared to all other costs.

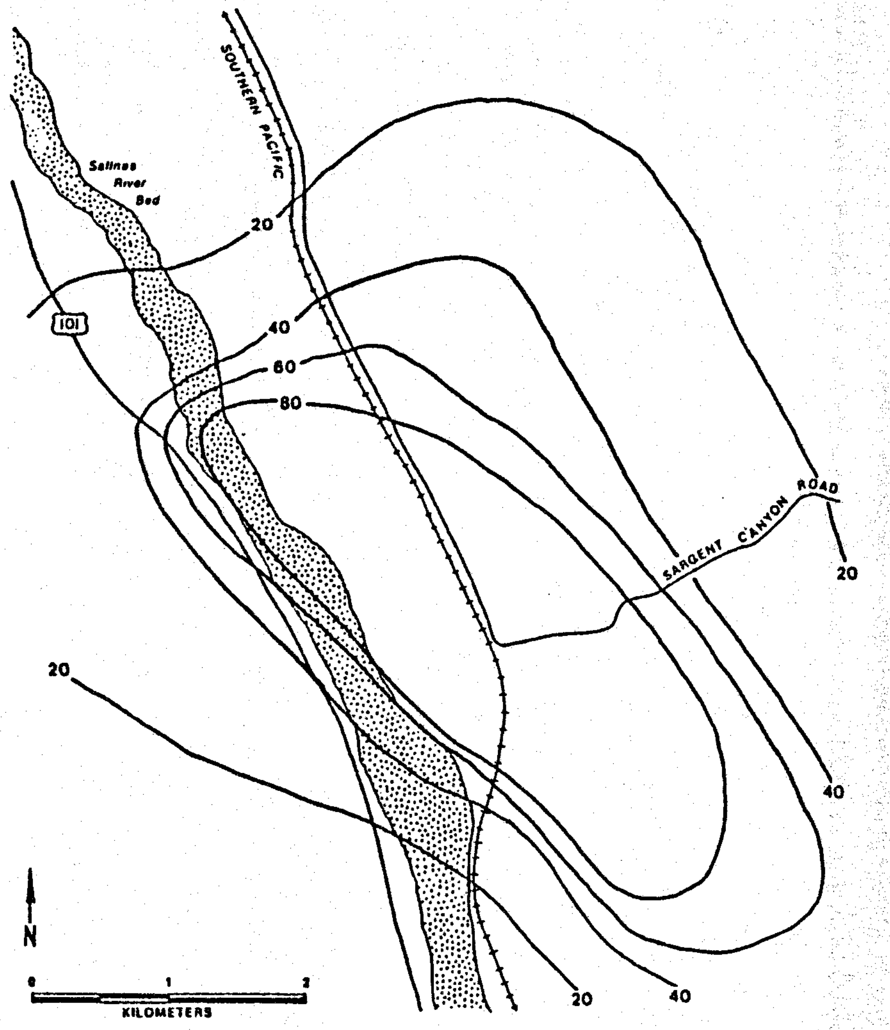
Production Case were to occur. The SO_2 and NO_2 concentrations around the San Ardo field for the Maximum TEOR Production Increase Case would be one-half the levels predicted for the 1978 Baseline Case (see Figures 8-14 and 8-15). The directly emitted PM concentrations are slightly higher for the Maximum Increase in TEOR Production Case than the 1978 Baseline Case without consideration of road paving offsets. This increase in PM concentrations is indicated in Figure 8-16.

8.6 The Los Angeles Basin Fields

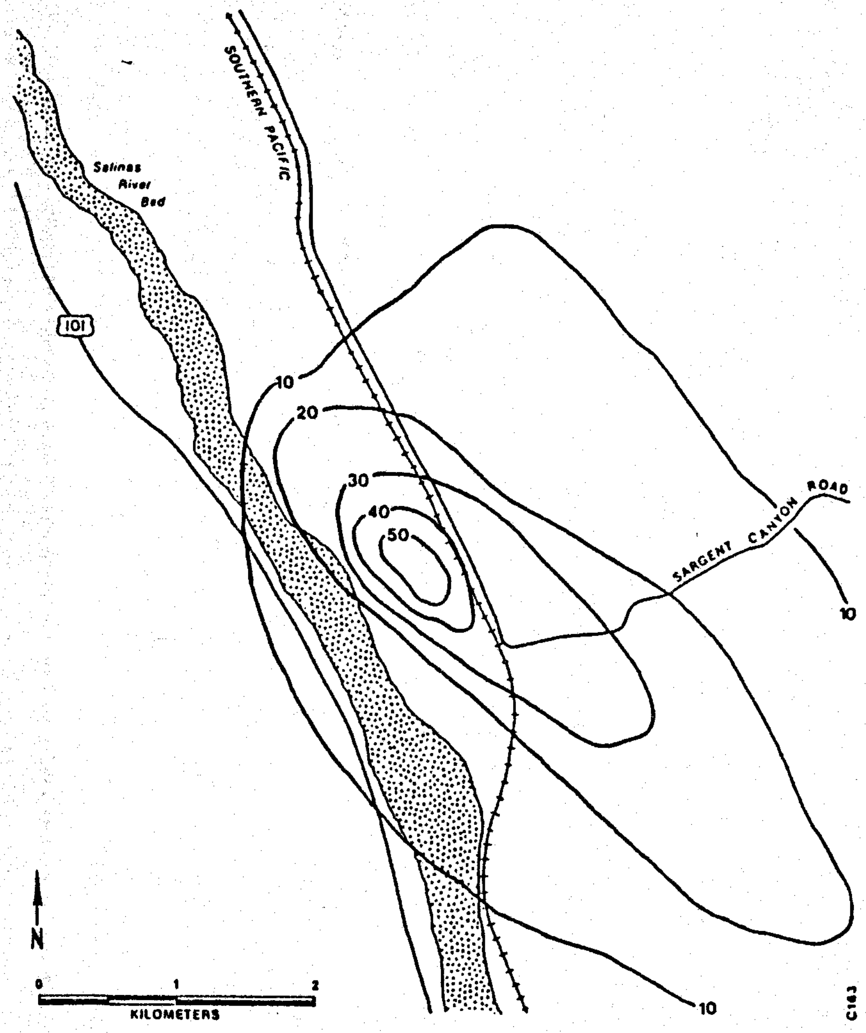
Possibly the greatest increas in TEOR production could be achieved in the Los Angeles Basin if the emission offsets for the new TEOR projects could be found. As noted in this portion of the analyses, little steam generation capacity exists in the Los Angeles Basin. The steam generators in existence already have low emission levels because they are burning primarily natural gas with a few burning distillate oil. In general, the other stationary sources operated by the producers are also well controlled. The pollutants emitted from crude oil-fired steam generators are generally several times higher than the same steam generators burning natural gas. Because of the paucity of emission offsets, little or no increase in TEOR projects in the Los Angeles Basin is anticipated.

8.7 The Arkansas and Texas Fields

The Smackover field is north of El Dorado, Arkansas, in Union and Quachita Counties. Phillips Petroleum Company started a steam injection pilot project in 1964 after production from primary methods decreased considerably. Based on the pilot project results, a 1,000 acre commercial project was started in 1970 by uniting seventeen individual oil and gas leases. The

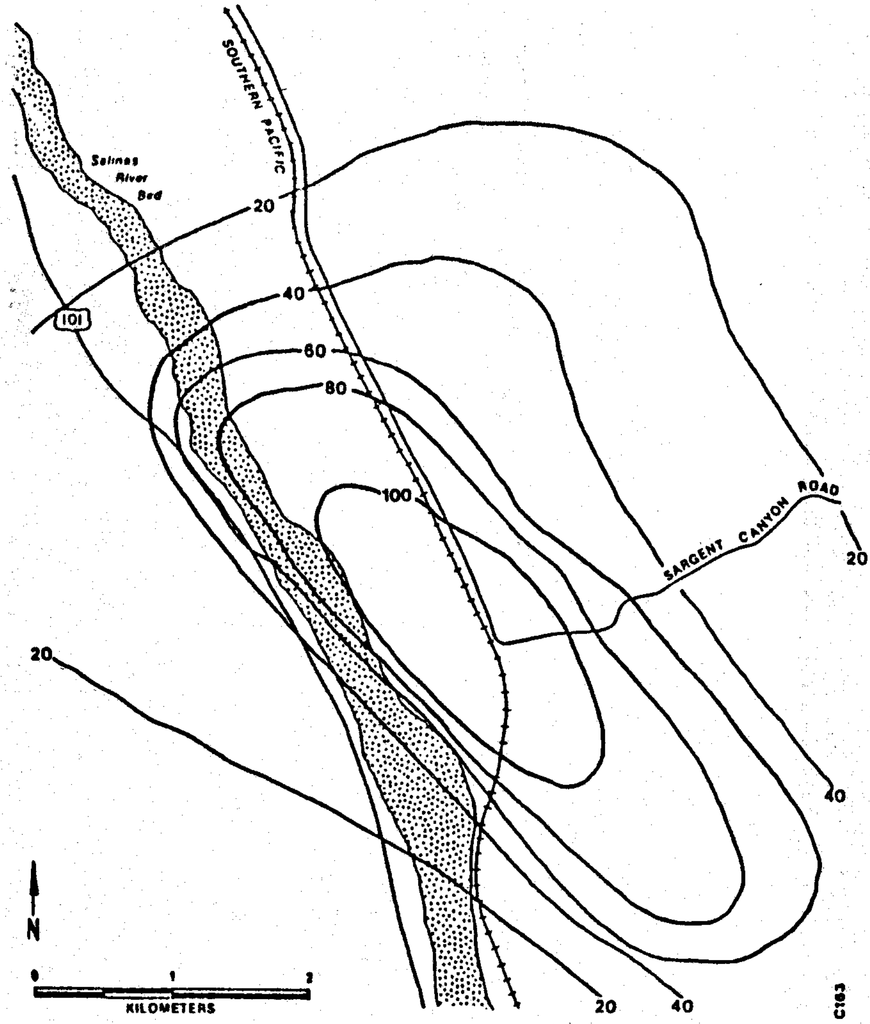


Annual SO_2 Concentrations ($\mu g/m^3$) Resulting from Emissions from Oil Field Sources in the San Ardo Field - 1978 Baseline Case

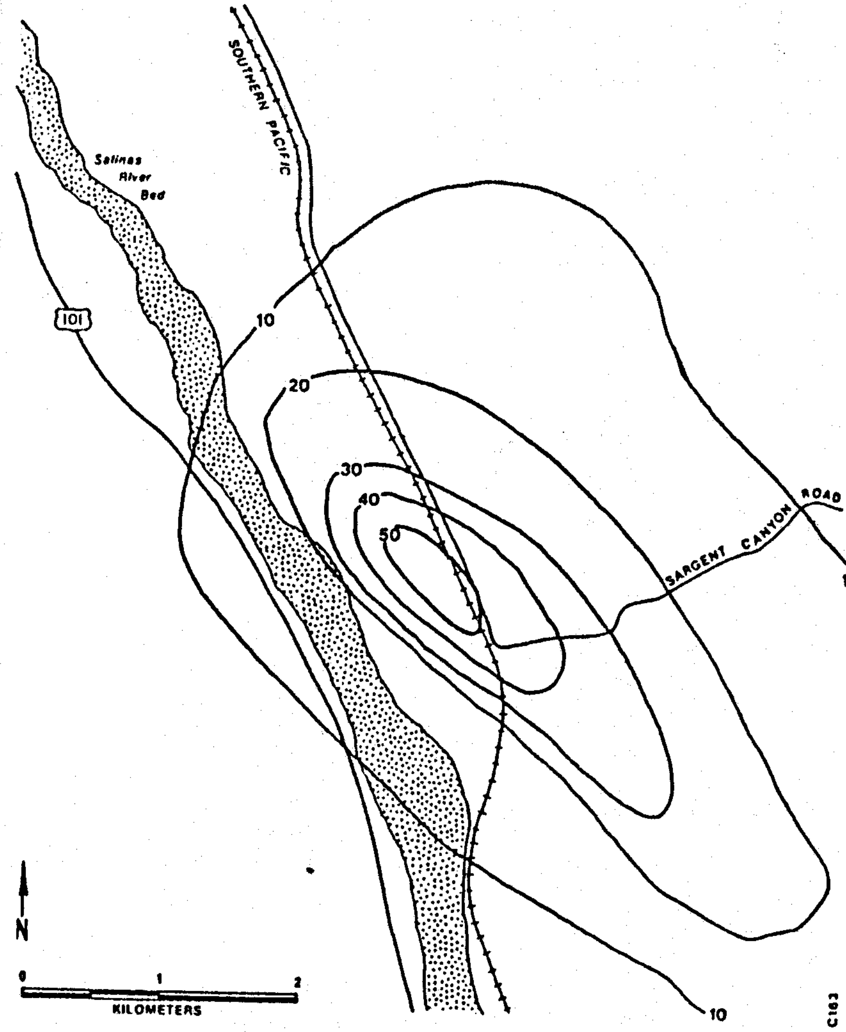


Annual SO_2 Concentrations ($\mu g/m^3$) Resulting from Emissions from Oil Field Sources in the San Ardo Field - Maximum Increase in TEOR Production Case

FIGURE 8-14. ANNUAL SO_2 CONCENTRATIONS ($\mu g/m^3$) FOR THE SAN ARDO FIELD.

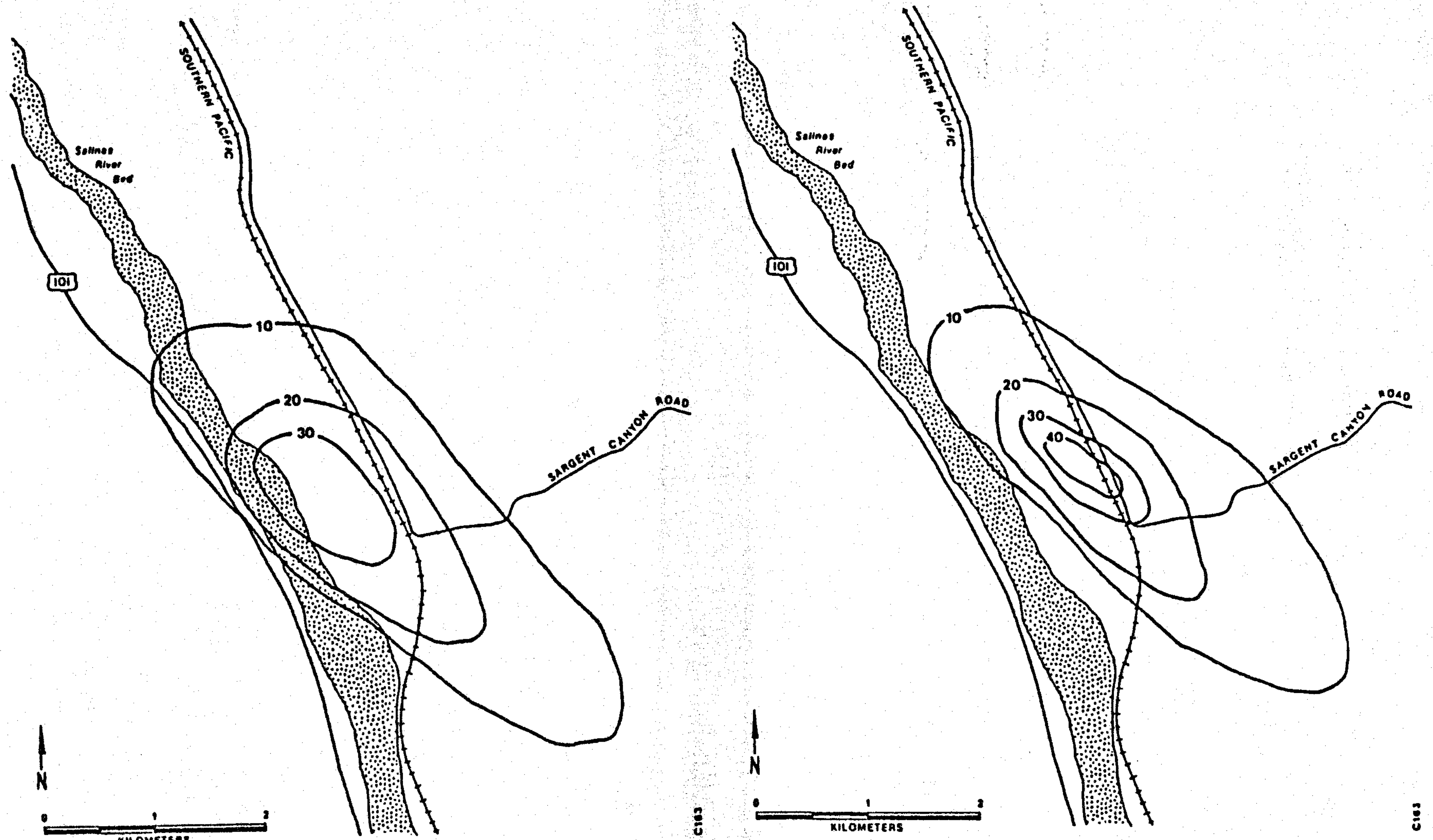


Annual NO_2 Concentrations ($\mu g/m^3$) Resulting from Emissions from Oil Field Sources in the San Ardo Field - 1978 Baseline Case



Annual NO_2 Concentrations ($\mu g/m^3$) Resulting from Emissions from Oil Field in the San Ardo Field - Maximum Increase in TEOR Production Case

FIGURE 8-15. ANNUAL NO_2 CONCENTRATIONS ($\mu g/m^3$) FOR THE SAN ARDO FIELD.



1978 Baseline Case

Maximum Increase in TEOR Production Case

FIGURE 8-16. ANNUAL DIRECTLY-EMITTED PARTICULATE MATTER CONCENTRATIONS ($\mu g/m^3$) FOR THE SAN ARDO FIELD.

steam injection project is operated by Phillips and has four 25 MM Btu/hr steam generators that fire natural gas with crude oil standby. In recent years, TEOR production from the Smackover field has dropped and steam injection has been reduced.

The Slocum field is in Southern Anderson county in northeast Texas. Oil recovery in the field by primary methods has been marginal due to the high viscosity of the oil at reservoir temperatures. Since discovery of the Slocum field in 1955, only about one percent of the original oil has been recovered by primary methods. Shell Oil started a TEOR project in 1964. Favorable results from the pilot project caused Shell to expand its TEOR production facilities. By 1969, Shell operated a 20 pattern, 100 acre project with steam production from thirteen steam generators. The steam generators were originally fired with natural gas, but five generators were later permitted to also fire crude oil. The Slocum field's steam injection has been curtailed in the past few years. Recent information indicates that only one steam generator was operating in early 1980.

Expansion of TEOR production in Texas and Arkansas primarily will be limited by the EPA's Prevention of Significant Deterioration regulations since both fields are designated attainment areas for all pollutants.

In order to avoid full PSD review, the producers are expected to design their projects so that there will be no net increase in pollutant emissions. Unless the emissions from new projects are offset at the new project site, the PSD increments for SO_2 and particulates are expected to become the major constraint to future TEOR expansion in Texas and Arkansas.

9.0 PART III ANALYSIS - MAXIMUM TEOR PRODUCTION INCREASE ACHIEVABLE BY 1990

In Section 8.0, California TEOR production was projected to have the potential to increase by 680,000 BOPD (net) over the production level achievable by steam generation capacity already permitted. But this potential increase in TEOR production was projected solely on the basis of available emission offsets. Achieving this maximum TEOR production increase will require 96,000 MM Btu/hr of new steam generator capacity to be designed, permitted, constructed, and operated. Several constraints exist which must be overcome before this increased steam generation capacity can be successfully installed and operated.

Up to the present, obtaining air permits and the associated costs of controls have been major constraints to the expansion of steam stimulation oil production in California. In some instances, several years have been required to obtain permits to construct planned steam stimulation projects. In some cases, special provisions in the permits that have been issued have prevented the producers from beginning construction until new control systems are commercially developed. Due to the dual preconstruction review process (i.e., review by both the local air pollution control district and EPA Region IX), producers frequently cannot begin construction on steam stimulation projects which have been permitted by the local district because the EPA PSD permit process takes several months longer than the local district process. Upon issuance of the appropriate preconstruction permits, the producers have between one and two years to begin construction. Once construction is completed and the steam stimulation project is in operation, it may take two to three years before an increase or "kick" in oil production is observed. Since most of the maximum TEOR production increase deemed achievable by 1990 will result from steam stimulation, the delays and associated costs of new projects are expected to have the single most significant impact on future TEOR production.

Because obtaining the preconstruction air permits has been such a long process and a major constraint to the feasibility of steam generation projects, the steam generation capacity with permits to construct in 1981 is an excellent indicator of the most readily achievable potential to increase steam stimulation production. The amount of additional steam generation capacity that could be permitted, installed, and operated to increase 1990 TEOR production can be determined by reviewing historical permitting trends in the context of identified constraints. As previously noted, the constraints to achieving a maximum increase in TEOR production by 1990 include permitting delays, the need for high efficiency control technologies, and the availability and distribution of emission offsets. These constraints will be discussed in detail in this section, as will recommendations for overcoming these constraints.

9.1 Constraints to Achieving Maximum TEOR Production Increase by 1990

Achieving increases in TEOR production in California will require the installation of a large number of new steam generators. Three types of environmental constraints are anticipated: air pollution control regulations, water supply, and solid waste disposal. These constraints, particularly the air pollution control regulations, are expected to severely limit the achievement of substantial increases in heavy oil production. This section of the report describes the anticipated constraints due to air pollution control regulations in detail.

9.1.1 Permit Review Process

As described in Section 5.0, the federal air pollution control regulation requirements are the driving force behind regulations adopted by the local California air pollution control districts. Although new source review authority has been delegated to the Kern County APCD by the EPA, the EPA still has authority for Prevention of Significant Deterioration (PSD) regulations for NO_2. Kern County is designated an attainment area for NO_2. PSD is primarily a preconstruction review strategy for attainment pollutants required pursuant to the 1977 Clean Air Act Amendments. New sources or modifications to existing sources resulting in a net increase in NO_2 emissions of 40 tons per year or greater are considered "significant" and are subject to preconstruction review and permitting required by the EPA. PSD preconstruction review includes ambient air quality impact analysis, application of best available control technology, and one year of ambient air monitoring, if acceptable ambient air quality data does not exist. Satisfaction of these requirements typically requires between 6 months and 2 years, depending on whether or not sufficient ambient air quality data exists.

At this time, Kern County is an attainment area for only NO_2. The KCAPCD has requested that Kern County be redesignated as an attainment area for CO and SO_2. In the event that this redesignation occurs before PSD authority is designated to the KCAPCD, construction of new steam generators may be delayed due to lack of sufficient CO and SO_2 monitoring data for many of the Kern County fields.

Those areas designated as non-attainment which may show attainment by 1982 (attainment is anticipated in Kern County for ozone) must include preconstruction review requirements for all new or modified stationary sources that have the potential to emit greater than 100 tons per year. These New Source Review (NSR) requirements are as follows: 1) The applicant must demonstrate that all sources owned or operated by the applicant are in compliance with all applicable state and federal regulations, 2) the applicant must install controls which represent the lowest achievable emission rates (LAER), 3) the resulting emissions after control must be offset so that a net air quality improvement will result. Although ambient air quality monitoring is not required for pollutants that are non-attainment, the need for obtaining offsets typically results in significant delays in obtaining NSR permits.

Large increases in application submittals, repeated revisions to the KCAPCD NSR rule, and backlogs in permit processing have historically resulted in delays in obtaining permits. Delays may be as long as three years.

The CAA, as amended in 1977, included provisions for the imposition of federal sanctions in states where the NAAQS are not attained and an SIP including all the elements required by the CAA has not been approved by the EPA. These sanctions may include the denial of any project or funding grant other than those for safety, mass transit, transportation improvement, or projects related to air quality improvement or maintenance. These sanctions are in the form of denial of sewage treatment improvements or expansion grants, a construction ban on major new or modified sources, and the general withholding of federal funds. If the implementation plan requirements for Kern County are not met by November 7, 1981, the CAA requires that federal sanctions be imposed. Imposition of federal sanctions will delay indefinitely the installation of any significant number of new steam generators in Kern County.

The EPA and the CARB propose to adopt a fine particulate ambient air quality standard. This proposed change in the TSP NAAQS would differentiate PM by size, thus focusing control on respirable PM (less than 3 microns in size). This proposed change in the TSP NAAQS caused CARB to raise the issue of the historical offsetting of combustion PM emissions (predominantly smaller than 3 microns) with reduction of PM emissions from unpaved roads (predominantly larger than 3 microns). Although the CARB has postponed the implementation of their "fine particulate" (i.e., smaller than 3 microns) guidelines, EPA requires that new PM sources be offset with equivalent-size PM reductions. The proposed change in PM offset requirements would substantially increase the control requirements for combustion PM emissions and reduce the availability of PM offsets of 3 microns or smaller. The limited availability of PM offsets would, in turn, limit potential TEOR production.

9.1.2 Air Pollution Control Technology

The potential constraints associated with air pollution control technology encompass three principal issues: 1) the feasibility of applying existing and innovative control technology to crude oil-fired steam generators; 2) the time needed for the application and demonstration of these technologies; and 3) the time needed for manufacturing sufficient control systems to satisfy the demand for these control systems. In order to maximize 1990 TEOR production, both new and existing steam drive projects must include the best concievable control technology in order to minimize emission increases and, in turn, offset those emission increases. Furthermore, should ambient air quality deteriorate, the dependence on high efficiency control technology becomes even greater.

SO_x Control Technology

As presented in Section 6.2, currently available SO_2 scrubbers are capable of achieving 96 percent SO_2 removal.

However, delivery of SO_2 scrubbers currently requires 6 to 18 months after placing a purchase order. Compliance with Rule 424 for permitted equipment alone will require installation of seven SO_2 scrubbers per month until mid-1984. In order to control and offset the new steam generator SO_2 emissions associated with the maximum TEOR production, an additional 950 SO_2 scrubbers will have to be installed in Kern County alone. Consequently, the availability of SO_2 scrubbers for installation may delay achievement of maximum TEOR production.

In addition to the potential limited availability of SO_2 scrubbers, disposal of scrubber waste could become a constraint to the operation of the SO_2 scrubbers. Current disposal facilities are not adequate to handle wastes from those SO_2 scrubbers currently planned. Lack of sufficient disposal facilities could force a shift to more costly and complex control systems, further delaying maximum TEOR production.

NO_x Control Technology

Case 1

In the Case 1 analysis, no air quality change was assumed. Even in this case, high efficiency NO_x control systems (i.e., low NO_x burners, O_2 control, and Selective Catalytic Reduction) are necessary to achieve the maximum production expansion. However, some expansion (i.e., less than maximum) would be allowed if Selective Non-Catalytic Reduction (SNR) systems were applied. But even SNR availability is considered critical during the next few years. With only SNR available, no production expansion would be allowed by 1990 if either a Stage II or III air quality change took place.

Case 2

In Case 2, where a Stage III air quality change takes place, SCR will be necessary in order to provide emission offsets for any new projects.

Demonstration of SCR is not expected before 1983, which means the technology would not be commercially available until 1985. Delivery delays of 6 to 18 months, similar to SO_2 scrubbers, are not unlikely. If Stage III control levels are required, compliance for already permitted steam generators is not expected to be achieved without SCR systems. Installation of SCR systems on both existing and new generators could delay maximum TEOR production by at least four years, once the technology is adequately demonstrated. Integration of LNBs, O_2 controls, and SCR may cause additional operational complications which may further contribute to delays.

PM Control Technology

PM control technology is described in Section 6.4. Currently, little control of steam generator PM emissions beyond that achieved by SO_2 scrubbers (i.e., 25% removal) is required. An extensive steam generator test program is near completion which should provide information on the extent and size distribution of steam generator PM emissions. Historically, offsets for steam generator emissions have been obtained by paving roads. However, the difference in particle size between combustion emissions and unpaved road fugitive emissions is such that this practice is expected to be disallowed in the very near future. Offsets for the fine combustion PM (less than 3 microns in size) are not expected to be available in sufficient quantities unless steam generators use high efficiency particulate control systems. Existing high efficiency particulate control systems (i.e., 99%+ removal) are being evaluated in steam generator applications. They are expected to achieve control efficiencies similar to those achieved in industrial applications. These high efficiency control systems are not expected to be widely available in the near future. With only 25 percent control achievable through the application of SO_2 scrubbers, no 1990 expansion in TEOR production is expected beyond that which is currently permitted, unless high efficiency particulate controls are immediately available.

HC Control Systems

As described in Section 6.5, HC control systems for wellhead casing vents are currently available. Wellhead vapor recovery systems which incinerate non-condensable HC emissions from steam generators are technically capable of 100% control efficiency. The control efficiency beyond the required 93% control efficiency is available to provide new project offsets (i.e. approximately 7% of uncontrolled HC emissions). Delivery of wellhead vapor recovery systems currently requires approximately 18 months after order placement. This delivery time and the number of systems which must be installed on both existing and new TEOR projects may delay achievement of maximum TEOR production by at least three years.

Summary

Due to the lack of high efficiency PM and NO_x control systems, little TEOR production expansion is expected by 1990, based on the time period projected between application for Authority to Construct and actual production. The retrofit requirements for Rule 424, 425, and 411.1 are expected to limit staff, equipment, and funds for the development and commercialization of the control systems. SNR may allow some TEOR expansion if only Stage I NO_x control levels are required. If Stage II or Stage III control levels are required, no significant increase in TEOR production will occur beyond that already permitted.

9.1.3 Emission Offsets

Determination of emission offset availability for each TEOR producer in Kern County is beyond the scope of this study. Consequently, it was assumed that all oil producers would cooperate in making the maximum emission offsets available to those producers with insufficient emission offsets. Obviously, emission offsets are not equally distributed among all oil companies in Kern County. As a general rule, the larger the existing operations in Kern County, the larger the amount of potential emission offsets are available for a particular oil producer. Should the oil producers not cooperate in making emission offsets available, many new steam projects could be prevented from being initiated. Delays in negotiating exchange of emission offsets alone could impede achievement of maximum TEOR production.

In addition to the issue of distribution of emission offsets, maximum TEOR production in 1990 is limited principally by availability of SO_2 emission offsets. Delays in installing SO_2 controls on existing equipment will in turn delay achievement of the maximum production goal. Availability of high efficiency NO_x controls will also significantly impact achievement of maximum TEOR production. As previously discussed, high efficiency NO_x control technology application is not expected until the mid-1980's. Consequently, the availability of NO_x controls is expected to delay achievement of the maximum TEOR production by at least three to four years. Availability of PM and HC emission offsets is also expected to cause delay.

The CARB, in conjunction with the local APCDs, is currently developing the Suggested Control Measures (SCMs) that focus on oil production operations. These SCMs will include measures requiring some degree of control on produced water storage, produced crude storage, oil/water separators, fugitive emissions, and wellhead emissions. In non-attainment areas, the historical trend has been to retrofit control technology developed for new sources on existing sources in order to achieve the NAAQS. In this analysis, BACT and innovative control technology has been applied to some existing sources in order to provide sufficient offsets for new steam drive projects. Future revisions to current regulations could require BACT or innovative control technology and thereby reduce the availability of emission offsets. This could preclude some future TEOR production expansion, particularly in the case of SO_2 controls.

Continued use of interpollutant offset provisions as currently allowed in the Kern County NSR Rule will relieve, to some degree, the limited availability and distribution of emission offsets. However, due to the significantly higher ratio of offsets required for interpollutant offsets, extensive use of interpollutant offsets in itself will limit growth. Limited use of the interpollutant offset provisions will somewhat compensate for the lack of uniform distribution of potential offsets.

9.2 Actions Necessary to Maximize 1990 TEOR Production

If unconstrained by air pollution control regulations and other factors such as logistics, costs, etc., the conventional TEOR methods are projected to be capable of increasing gross heavy oil production to 680,000 BOPD by 1990. If permitting constraints are considered, but their impact is minimized by considering only the steam generation capacity with permits in 1981, estimates indicate that TEOR production can be increased by 442,500 BOPD (net) by 1990. This nearly doubles the 1978 TEOR production. Additional increased net heavy oil production could be accomplished by three different methods. One method would be to burn produced crude oil in a more efficient manner (e.g., produced crude-fired downhole steam generators). Another method would be to increase total (gross) production enough to offset the amount of crude oil burned. Finally, a third method would be to use an alternative fuel, thereby reducing or eliminating the need to burn crude oil.

These methods were used in the following discussion to address the courses of action for maximizing heavy oil production in the selected U.S. TEOR production areas. Using the above approaches, courses of action are recommended. Recommendations will focus on those actions that can be taken by the Department of Energy (DOE). These actions include measures that are within the authority of the DOE and the local, state, or other federal agencies that can be influenced by the DOE. Five categories of measures were considered in developing recommended courses of action:

- Imposing economic incentives or removing economic disincentives;
- Promoting the development or application of the technology needed to implement promising alternative fuels, including associated air pollution control technology;
- Streamlining and facilitating the permitting regulatory review, and approval requirements;
- Encouraging the allocation of the required alternative fuel to the TEOR producers, including insuring sufficient uninterruptible supply; and
- Encouraging the development of any fuel transportation systems necessary to implement a promising alternative fuel.

The Windfall Profit Tax (WPT) is presently a disincentive to using a fuel other than produced crude in steam generators. As currently applied, the WPT must only be paid on crude oil that is shipped out of a field. Any crude oil that is burned in steam generators or other combustion devices within the field is not subject to the WPT. Consequently, any alternative TEOR production option that burns an alternative fuel is penalized by the WPT that must be paid on the amount of produced crude replaced by the alternative fuel. Assuming an average of one barrel of oil is burned for every four total barrels of oil produced and a WPT of approximately $3.00 per barrel of oil, this represents an approximate disincentive of $0.75 per barrel of oil produced, if a fuel other than produced crude is burned. Although this represents, on the average, only 3 percent of the average value of heavy oil, in some cases this might mean that an otherwise viable project is not cost effective. This is not to advocate elimination of the WPT. The economic disincentive associated with the WPT can be minimized by giving a producer credit for any increase in WPT that would occur as a result of replacing produced crude with an alternative steam generator fuel.

Although there may be insufficient incentive for the industry as a whole to promote the development of an emerging technology such as downhole steam generators, several courses of action can be taken by either the DOE or by other governmental agencies at the encouragement of the DOE. These courses of action include direct economic assistance or subsidy for developing and demonstrating emerging technology. Other measures might include permit or emission offset exemptions or partial exemptions, as is the case with cogeneration and biomass-based technologies. Currently, several cogeneration projects are being considered in Kern County because the producers lack sufficient emission offsets. The partial exemption from emission offsets is the principal reason why cogeneration is being considered. This course of action need not result in a significant deterioration in ambient air quality if only demonstration projects are exempted from a portion of the regulatory requirements.

The third course of action would consist of measures similar to those implemented by the California Energy Commission (CEC) for the siting of power plants and "fast track" measures being implemented at a federal level. The purpose of these measures is not to bypass the regulatory permitting processes but to facilitate and streamline the processes in order to reduce the lead time for obtaining construction and operation approval. In many cases, simple allocations may be sufficient. Elimination of dual review by local air pollution control agencies and the EPA could also significantly reduce lead time. However, the dual review process will be eliminated only with the delegation of pre-construction review authority to the local agencies. Delegation will occur only with adoption of NSR and PSD rules by the local agencies which are acceptable to the EPA. The legislation of formal processing procedures could also facilitate the review process (e.g., California AB884 requirements adopted in 1978 limiting review time frame to one year).

Three alternatives to burning crude oil in steam generators involve fuels that are expected to have limited availability. These three alternatives are conventionally fired natural gas, natural gas cogeneration, and coke gasification. If these alternatives are to be implemented to any significant level, natural gas, or petroleum coke will be required in very substantial quantities. In both cases, the quantity of fuel, as well as a year-around supply is important. Seasonal supply interruption of either fuel would necessitate the use of either residual or crude oil as standby fuel, and therefore would require additional air pollution control equipment. Installation of this additional air pollution control equipment will reduce the alternative's attractiveness. Implementation of the two natural gas alternatives will require substantial changes in the current allocation and pricing structure. Similarly, implementation of the coke gasification alternative will require the diversision of petroleum coke away from the metallurgical industry.

Three alternatives to burning crude oil in steam generators require the transportation of solid fuel by rail system (i.e., coke gasification, coal AFBC, and coal-oil mixture). Implementation of these alternatives to their maximum potential is likely to exceed the current railroad system capacity. Dedicated coal or coke trains may interfere with the current use of the existing rail system. Furthermore, the current rail system may require expansion in order to transport the fuel to the oil fields where it is burned. Depending on the extensiveness of these changes, the necessary lead time to complete the required changes may significantly delay implementation of these options. Legislative action may be required to facilitate the expansion and/or modification of the current rail system. Furthermore, support from state and federal transportation agencies will be necessary to expedite any transportation system modification or expansion.

In conclusion, construction and operation of all of the permitted steam generation capacity in the five California heavy oil production areas could increase TEOR production by 442,500 BOPD (net). Results of the Part III Analyses indicate that the maximum TEOR production increase achievable by 1990 is approximately equal to this production increase, unless additional increases in TEOR production are achieved by:

1) The use of more fuel-efficient steam stimulation technology, thereby reducing the amount of crude oil that must be burned (e.g., produced crude-fired downhole steam generators).
2) Increase of total (gross) heavy oil production to levels high enough to

offset the increased amounts of crude oil that must be burned to raise production.

3) Use of an alternative fuel, thereby reducing or eliminating the need to burn produced crude oil.

Recommendations for actions to maximize TEOR production include economic incentive programs, removal of economic disincentives, promotion of the development of alternative fuel technologies and needed air pollution control technologies, streamlining of permitting and approval procedures, allocation of sufficient quantities of alternative fuels, and development of fuel transportation systems.

10.0 CONCLUSIONS

This section describes some general conclusions regarding increases in TEOR crude oil production in the U.S. Kern County crude oil production increases were emphasized because Kern County is expected to produce nearly 90 percent of the U.S. TEOR crude oil by 1990. The general conclusions of the study are as follows:

(1) Almost 90% of the crude oil currently produced using TEOR techniques was produced in California. Kern County currently produces 90% of the TEOR crude oil in California and is projected to produce nearly 90% of the national TEOR crude oil by 1990.

(2) The maximum TEOR production projected to be achievable by 1990 is approximately equal to the maximum level of production that could be achieved by the steam generators which already have permits. Construction and operation of all the permitted steam generation capacity in the five California production areas could increase TEOR production by 442,500 BOPD (net). This nearly doubles the 1978 production rate.

(3) Under the present regulatory conditions, large-scale expansion of California TEOR production by 1990 is not expected to be achievable. The regulatory constraints to significant expansion of TEOR production in California include delays in obtaining permits and the

level of air pollution control required. Permitting, constructing, and operating a significant increase in total steam generation capacity may require as long as seven years, once necessary air pollution control systems are commercially available. Commercial availability of high efficiency NO_x and particulate control systems is not expected until the mid-1980's.

(4) Since 1978, a large amount of steam generator capacity has been permitted in Kern County. However, most of this new steam generator capacity has yet to be constructed because of the producers' inability to comply with the EPA's PM offset requirements and the Kern County APCD's retrofit rules.

(5) If the ambient NO_2 concentrations in Kern County increase to levels near or above the national ambient air quality standards, most of the steam generation capacity recently permitted in Kern County will have to be shut down and existing steam generators retrofitted with high-efficiency NO_x control systems. Since the required level of NO_x control can not be achieved through commercially available control systems, many existing steam generators may also have to be shut down.

(6) The Kern County APCD retrofit rules (i.e., Rules 424, 425, and 411.1) have substantially increased costs of producing crude oil using existing steam generation capacity. These

retrofit rules may preclude a large-scale expansion of TEOR production in the next few years as a result of the costs of retrofit rules.

(7) The lack of commercially available high-efficiency NO_x control systems is expected to delay the Kern County producers' ability to comply with Kern County APCD's NO_x retrofit rules. Similarly, this lack of commercially available NO_x control systems is expected to significantly delay future TEOR expansion.

(8) The lack of high-efficiency particulate control technology for crude oil-fired steam generators is expected to delay operations of many permitted steam generators. Expansion of TEOR production will require the development and commercial availability of high-efficiency particulate control systems.

(9) The availability of solid waste disposal sites for SO_2 scrubber wastes is expected to become a major constraint to complying with the Kern County APCD SO_2 control rule (i.e., Rule 424). Estimates indicate that current waste disposal site capacities will be exceeded as a result of the oil producers complying with Rule 424. Additional new steam generators will further increase the demand for waste disposal capacity.

(10) The costs of air pollution control systems have drastically increased during the last two years. These costs are expected to

provide a large economic disincentive for future TEOR production expansion. The average annual costs of air pollution regulations under previous new source review requirements ranged between \$1.69 and \$4.60 per net barrel of oil produced by TEOR techniques. These costs are expected to increase substantially due to the higher level of control required for both new and existing steam generators in the Maximum Increase in TEOR Production Case, to approximately \$2.68 to \$9.02 per net barrel of oil produced.

(11) Maximizing 1990 TEOR production will require either an increase in gross TEOR production or a reduction in the amount of crude oil burned in steam generators. As previously concluded, increased gross TEOR production may not be possible. Consequently, increases in crude oil production will most likely come from increasing net production. Net crude oil production may be increased by using alternative fuels, such as natural gas, coal, or synfuels, in TEOR steam generators.

REFERENCES

Ando, J. "NO_x Abatement for Stationary Sources in Japan", EPA-600/7-79-205, August 1979.

Arthur G. McKee and Company, Coal--An Alternate Fuel for Thermal Enhanced Oil Recovery Steam Generation, December 1978.

California, State of, Air Resources Board. Public hearing to consider adoption of a regulation controlling emissions of sulfur compounds from steam generators used in oil field operations in the Kern County Air Pollution Control District, Staff Report 79-7-1, Sacramento, CA, February 1979.

California, State of, Air Resources Board. Public hearing to consider amendments to the rules and regulations of the Kern County Air Pollution Control District and revision of the Kern County air quality maintenance plan/non-attainment plan, Sacramento, CA, July 20, 1979.

California, State of, Air Resources Board. "Resolution 79-10", Sacramento, CA, March 23, 1979.

California, State of, Air Resources Board. Suggested Control Measure for the Control of Oxides of Nitrogen Emissions from Electric Utility Gas Turbines, Sacramento, CA, October 1980.

California, State of, Air Resources Board, Technical Services Division. Annual Summary of 1977 Air Quality Data: Gaseous and Particulate Pollutants, Sacramento, CA, 1978.

California, State of, Department of Conservation, Division of Oil and Gas. Private communication with W. R. Hearn, Radian Corporation, September 1979.

California, State of, Department of Conservation, Division of Oil and Gas. 65th Annual Report of the State Oil and Gas Supervisor, 1979.

"Carter Orders Decontrol of Heavy Crude," Oil and Gas Journal, August 27, 1979.

"Congress Technicians Slash Forecast," Enhanced Recovery Week, October 27, 1980.

Conservation Committee of California Oil Producers. Annual Review of California Oil and Gas Production - 1978, Los Angeles, CA, 1979.

REFERENCES (Continued)

"Downhole Generator Passes California Test," Enhanced Recovery Week, September 15, 1980.

Engineering Science, Inc. Emission Inventory and Documentation for Kern County Portion of San Joaquin Valley Air Basin, Arcadia, CA, December 1977.

"Exxon Corporation Stationary NO_x Emissions Significantly Reduced at Plant," Air and Water Pollution Report, February 20, 1978.

Fanaritis, J. P. and J. D. Kimmel. "Review of Once-through Steam Generators," Journal of Petroleum Technology, April 1965.

Fresno County Air Pollution Control District. Draft Air Quality Maintenance Plan and Non-attainment Plan for Fresno County, Fresno, CA, September 1978.

Guthrie, K. M. Process Plant Estimating, Craftsman Book Company of America, 1974.

Grumwald, Crawford, and Associates. The Non-attainment Area Plan for the Kern County Portion of the San Joaquin Valley Air Basin, Hanford, CA, September 1978.

Henwood, Mark. Thermal Enhanced Oil Production in California - Coal's Potential Role, California Energy Resources Conservation and Development Commission, September 1977.

Jones, G. D. and K. L. Johnson. Technology Assessment Report for Industrial Boiler Applications: NO_x Flue Gas Treatment, EPA-600/7-79-178g, Radian Corporation, Austin, TX, December 1979.

Kato, G. A., et. al. "Field Testing: Applications of Combustion Modification to Control Pollutant Emissions from Industrial Boilers - Phase II," EPA-600/2-76-086a, NTIS-PB 253500/AS, April 1976.

Kern County Air Pollution Control District, Rules and Regulations of the Kern County Air Pollution Control District, Bakersfield, CA.

Kuskra, Vello. "Discussion of Thermal Oil Recovery Opportunities in California," Lewis and Associates, Washington, D.C., 1977.

REFERENCES (Continued)

Lim, K. J., et. al., Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modification, EPA-600/7-79-178f, December 1979.

Marshall, W. M., Shell Oil Company. Private communication with J. F. Norton, Radian Corporation, June 7, 1979.

Monterey Bay Unified Air Pollution Control District, Draft Non-attainment Air Quality Plan for the Monterey Bay Area, Salinas, CA, 1978.

Monterey Bay Unified Air Pollution Control District, Rules and Regulations for the Monterey Bay Unified Air Pollution Control District, Salinas, CA, May 1978.

Noran, Dave. "Growth Marks Enhanced Oil Recovery," Oil and Gas Journal, March 23, 1978.

Radian Corporation. Project 1 - California Heavy Oil Production Task 1 Interim Report, Austin, TX, November 1980.

Rakow, M. S. and M. Calderon. "The Dynacracking Process - An Update," Chemical Engineering Progress, February 1981.

Roberts, Daryl, Shell Research and Development Co. Private communication with J. R. Boettcher, Radian Corporation, July 21, 1980.

Sandia National Laboratories. Project Deep Steam Preliminary Field Test, Bakersfield, California, April 1981.

Segnar, C. N., Chevron USA, Inc. Private communication with J. F. Norton, Radian Corporation, May 16, 1979.

Stelton, R., et. al., Potential Use of California Lignite and Other Alternative Fuels for Enhanced Oil Recovery, Acurex Corporation, Mountain View, CA, February 1979.

United States Energy Research and Development Administration, Management Plan for Enhanced Oil Recovery, 2 vols., February 1977.

United States Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Publication No. AP-42, including Supplements 1-12, August 1977.

Wilson, Howard M. "Heavy Crude Decontrol Sparks Mixed Emotions," Oil and Gas Journal, September 3, 1979.

Wittig, D. E., "Thermal Recovery Equipment Kern River Field, California," presented at the International NOMADS Petroleum Exposition, 1976.

☆U.S. GOVERNMENT PRINTING OFFICE: 1981-740-145/2814