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SUPPLEMENT

Air Quality Analysis of the Potential Impact of Offshore Oil and Gas Development in Central and Northern California

for

U.S. Department of the Interior
Bureau of Land Management

CONTRACT No. AA551-CT9-23

environmental resources group
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July 1980

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PREFACE

This supplement to POCS Reference Paper No. 53-5 ("Air Quality Impact of Proposed OCS Sale No. 53 Offshore Central and Northern California") was prepared by Environmental Resources Group with the support of Form & Substance, Inc.

POCS Reference Paper No. 53-5 assessed the potential air quality impacts associated with projected Lease Sale No. 53 oil and gas development and production activities. The objective of this supplementary study is to assess the degree of impact reduction expected to be afforded by the Department of the Interior's (DOI) final national OCS air quality regulations.

The study consists of three elements:

(1) A thorough review and summarization of DOI's final regulations;

(2) Recalculation of peak annual emissions for eachof the five proposed lease tract zones, incorporating mitigation mandated by DOI's new regulations; and

(3) Remodeling of selected cases to determine incremental onshore impacts with the DOI regulations in force.

The revised results are presented in Chapters VIII through XI of this supplementary volume. Throughout this report reference is made to Chapters I through VII which comprise POCS Reference Paper No. 53-5, and contain data germane to this supplementary evaluation.

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VIII. REVISED AIR QUALITY REGULATORY CONSIDERATIONS: THE DEPARTMENT OF THE INTERIOR'S FINAL NATIONAL REGULATIONS

A. Introduction

The Outer Continental Shelf Lands Act Amendments of 1978 give the Department of the Interior (DOI) responsibility for regulation of OCS air pollutant emissions [§ 5(a)(8)]. Pursuant to this mandate, DOI published proposed OCS air quality regulations on May 10, 1979 (44 FR 27448). These proposed regulations were the subject of considerable discussion, with comments and criticisms filed by state and local governments, OCS oil producers, and other interested parties (see Chapter III). On March 7, 1980, after nearly a year of review, hearings and comments, DOI published its final OCS air quality regulations (45 FR 15128). In addition, DOI also published (45 FR 15147) draft air quality regulations applicable only to OCS activities offshore California. This was done in response to comments made by Californiats state and local governments regarding DOI's proposed regulations.

This chapter discusses the regulation of OCS air pollutant emissions. Section VIII.B provides a detailed description of the regulatory approach finally adopted by DOI. Section VIII.C is a discussion of DOI's proposed California regulations. (A full discussion of DOI's proposed national regulations is presented in Chapter III.) Finally, Section VIII.D discusses the implications of these regulations for OCS development offshore California.

B. Department of the Interior (DOI) Final National Regulations

1. Introduction

DOI has established a three-step review process for air pollutant emissions arising from OCS oil and gas development and production activities (see Figure VIII-1). The first step is a determination of whether the projected emissions of a facility exceed the applicable regulatory threshold, termed "emission exemption level". Facilities whose emissions are below these levels are exempt from further review. The second step of the regulatory review requires air quality modeling to determine whether a proposed facility would have a "significant" onshore impact (i.e., produce maximum onshore pollutant concentrations in excess of DOI's significance levels). Facilities which do not produce significant onshore impacts are exempt from further review. Finally, facilities with significant onshore impacts must mitigate their impacts through emission controls and/or offsets depending upon whether they affect attainment or nonattainment areas, and the magnitude of the projected impact.

This chapter describes this three-tier review process (i.e., threshold, significance and mitigation) as well as regulations pertaining to temporary activities, cumulative impacts and DOI's proposed regulations for the California OCS.

2. Regulatory Approach and Definitions

DOI's regulations were formulated primarily on a facility-specific basis: each proposed OCS facility is reviewed individually to determine whether it alone would cause significant onshore air quality impacts. The regulations recognize that under some conditions this facility-specific approach might not indicate significant onshore impacts. For example, several proximate OCS facilities might, cumulatively, produce a significant onshore impact, even though none of the individual facilities alone would produce such impacts. Hence, the regulations also contain provisions pertaining to cumulative impacts.

The DOI regulations include definitions of salient terms and some of these are discussed immediately below. The quoted text was taken directly from DOI's regulations (45 FR 15143). These definitions, in conjunction with the understanding that the regulatory review generally applies on a facility-specific basis provide a context for the discussion of the regulations which follows subsequently.

Air Pollutant refers to airborne agents (or combinations thereof) for which the Environmental Protection Agency (EPA) has established ambient air quality standards (e.g., CO, TSP, SO_2, NO_x, VOC).

"Best Available Control Technology (BACT) means an emissions limitation based on the maximum degree of reduction for each air pollutant subject to regulation, taking into account energy, environmental and economic impacts and other costs." BACT is to be verified on a case-by-case basis.

"Facility means any installation or device permanently or temporarily attached to the seabed on the OCS which is used for exploration, development and production activities and which emits or has the potential to emit any air pollutant from one or more sources." All equipment directly associated with any processes of a facility is considered a part of the facility, although the definition seems to exclude crew and supply boats. Vessels used to transfer product from OCS facilities are considered part of the facilities while physically attached to them (e.g., emissions associated with tanker loading would be considered as part of a facility's emissions, but tanker transit emissions would not). Emissions associated with an Offshore Storage and Treatment (OS&T) vessel or a gas processing platform would be considered as if the emissions were from the platform(s) they served.

"Projected Emissions means emissions, either controlled or uncontrolled, from a source or sources." This definitions appears to be consistent with the decision in Alabama Power Company vs. Costle (see p. 111-10) and means that OCS lessees may include the effects of emission control equipment in preparing their applications. Hence, in many instances lessees may "voluntarily" choose to install emission control equipment in order to have projected emissions below the applicable emission exemption level (see Section VIII.B.3, below) and thereby avoid further regulatory review.

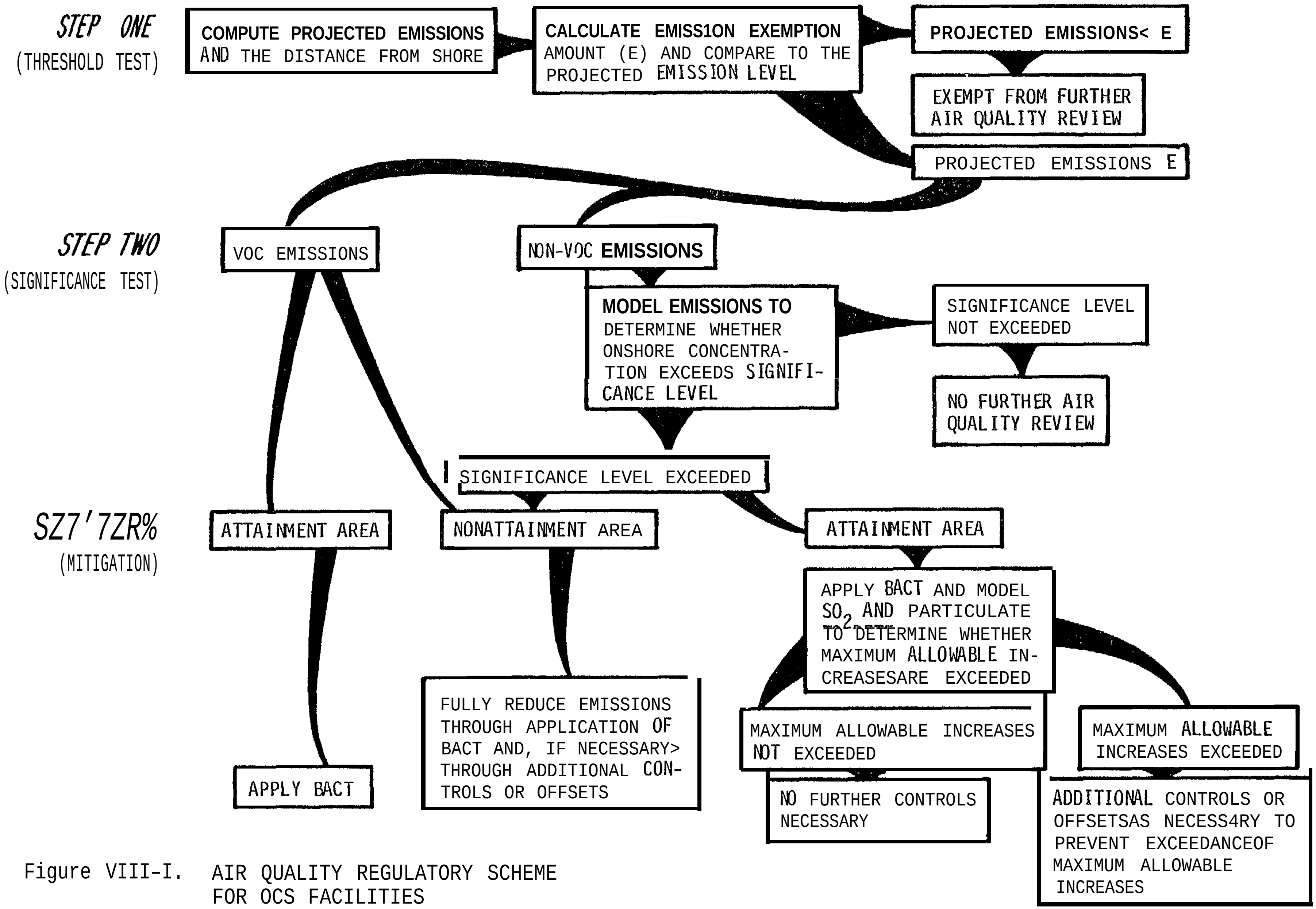

Figure VIII-I. AIR QUALITY REGULATORY SCHEME FOR OCS FACILITIES
Source: 45 FR 15141

"Source means an emission point. Several sources may be included within a single facility."

"Temporary Facility means activities associated with the construction of platforms on the OCS or with facilities related to exploration for or development of OCS oil and gas resources which are conducted in one location for less than three years."

"Volatile Organic Compound means any organic compound which is emitted to the atmosphere as a vapor." However, certain compounds specified by EPA as unreactive (e.g. , methane, ethane, Freons, and 1,1,1-trichlorethane) are excluded from this definition.

3* Emission Exemption Levels

DOI has established emission exemption levels for carbon monoxide (CO), total suspended particulate (TSP), sulfur dioxide (S02), nitrogen oxides (NO_x) and volatile organic compounds (VOC). Facilities with projected emissions below these levels are exempt from further regulatory review. The emission exemption levels, "E", are a function of the distance, "D", from the proposed facility to the nearest onshore area of a state, expressed in statute miles. The exemption level for CO is given by

$$E = 3400 D^{2/3};$$

for all other regulated pollutants, the exemption level is determined by

$$E = 33.3 D.$$

E is to be expressed in tons per year and is based upon the highest projected annual emissions for each pollutant.

The determination of emission exemption levels comprises the first step of DOI's regulatory review. It seems likely that OCS lessees would often choose to include emission control equipment as a part of their initial facility designs in order to avoid any further air quality regulatory review. In fact, in some instances the projected emissions associated with facilities which are expected to be constructed pursuant to Lease Sale No. 53 are below the exemption levels, or could be brought below them with the application of relatively modest control measures.

Those facilities whose projected emissions exceed the emission exemption levels must respond to the second step of DOI's regulatory review--a determination of whether their emissions would produce significant onshore impacts.

4. Significance Levels

For any facility with projected emissions in excess of the applicable exemption level, the lessee would be required to employ a DOI-approved air quality computer simulation model to determine whether the emissions of pollutants other than VOC could cause significant onshore impacts; VOC impacts are deemed significant if emissions are in excess of the exemption level.

The test of significance is whether the maximum modeled onshore concentrations of the lessee's projected emissions would be above the DOI significance levels presented in Table VIII-1. If the modeled onshore concentrations of any pollutants were below the significance levels, the lessee would be exempt from further regulatory review for that pollutant, and mitigation of impacts or installation of emission control equipment would not be required. For modeled concentrations above the significance levels the lessee would be required to employ emission controls.

5. Mitigation of Significant Impacts

The third stage of the regulatory review process, mitigation of significant onshore air quality impacts, is the most complex for two reasons: (1) the mitigation requirements differ depending upon whether an onshore attainment or nonattainment area is affected (attainment areas are currently in compliance with the national ambient air quality standard for a given pollutant; nonattainment areas are not); and (2) mitigation requirements vary slightly for the various pollutants.

a. Mitigation in Attainment Areas

i. VOC. NO_x and CO Emissions

DOI's regulations require that projected emissions of VOC, NO_x and CO which could significantly affect onshore air quality in an attainment area "shall be reduced through the application of BACT" (45 FR 15145). No controls beyond BACT are required for these pollutants.

ii. TSP and S07 Emissions

DOI's regulations also require that BACT be employed in those instances where TSP and S02 emissions could have significant onshore effects; however, further controls may also be required. The lessee must model TSP and $S0_2$ emissions with a DOI-approved model after the application of BACT, and compare the estimated onshore concentrations with the maximum allowable increases for TSP and S02 listed in Table VIII-2. The maximum allowable increases listed in Table VIII-2 were adopted from EPA's Prevention of Significant Deterioration (PSD) program which was developed to maintain air quality in attainment areas (see p. III-6). The PSD program presently specifies maximum allowable increases for only two pollutants (TSP and S02), and DOI has paralleled the EPA regulatory approach.

Except for temporary facilities, if the estimated onshore TSP and/or S02 concentrations exceeded the maximum increments, the lessee would be required to use further controls and/or emissions offsets, so that the maximum allowable increases were not exceeded.

iii. Summary of Requirements in Attainment Areas

If the projected emissions of any pollutant from an OCS facility (including temporary sources) would cause significant onshore effects, the lessee would be required to employ BACT; no further controls would be required for VOC, NO_x and CO emissions unless the cumulative impact provisions of the regulations were invoked. However, additional controls beyond BACT might be required for TSP and S02 emission sources if the modeled onshore concentrations of these pollutants were in excess of the maximum allowable concentration increases.

b. Mitigation in Nonattainment Areas

DOI's regulations state that the "...'projected emissions of [any air pollutant] from any facility, except a temporary facility, which significantly affect the [air quality of a nonattainment area] shall be fully reduced'" (45 FR 15145). [It is apparently the intent of the regulations, although it is not clear from the manner in which they were drafted, that VOC emissions which could significantly affect a nonattainment area for ozone also be "fully reduced" (VOC emissions are a precursor of ozone), even though the affected onshore area may be in compliance with the national ambient air quality standard for hydrocarbons (Goll, 1980).] The regulations further require that BACT be installed. If BACT does not "fully reduce'* the lessee's projected emissions then additional reductions must be obtained through additional emissions controls or through the acquisition of offshore and/or onshore offsets.

The DOI regulations do not include an explicit definition of the phrase "fully reduced." However, EPA's offset policy in nonattainment areas requires that new sources employ emissions controls and offsets such that there is no net increase in air pollutant emissions. The DOI regulations apparently impose a similar restriction on OCS lessees whose projected emissions significantly affect onshore nonattainment areas. Given such a stringent regulatory requirement it seems likely that OCS lessees would "choose" to install whatever equipment is required so that their projected emissions would be below the applicable emission exemption level, or such that there would be no significant onshore impact. Such an approach would appear to be much less difficult than "fully reducing" projected emissions.

Finally, in the event an OCS facility's emissions significantly affect both an attainment and a nonattainment area, the more stringent mitigation requirements would be applicable.

6. Monitoring Requirements

OCS lessees would be required to monitor their emissions in a manner prescribed or approved by DOI, and to report monitoring results to DOI on a monthly basis. Communication with one of the authors of DOI's regulations suggests this requirement might be met in a number of ways (Goll, 1980). In situations where an OCS lessee is just below either an emission exemption level or an onshore significance level, precise in-stack monitoring or its equivalent might be required. If an OCS lessee is claiming an unusually large emission reduction or is employing an innovative control technology, sophisticated monitoring requirements might be imposed. However, in many instances preventive maintenance and accurate records thereof would satisfy the monitoring requirements. In no case could DOI require monitoring of ambient onshore air quality, since it has no such onshore authority.

Table VIII-1. DOI SIGNIFICANCE LEVELS[1] (National[2] and Proposed California[3])

Air Pollutant	Averaging Time (hours): Annual		24		8		3		1	
	National	Calif.	National	Calif.	National	Calif.	National	Calif.	National	Calif.
Sulfur Dioxide (SO_2)	1	1	5	2	--	--	25	--	--	25
Total Suspended Particulate (TSP)	1	1	5	2	--	--	--	--	--	--
Nitrogen Oxides (NO_x)	1	1	--	--	--	--	--	--	--	10
Carbon Monoxide (CO)	--	--	--	--	500	500	--	--	2000	2000

1. All values are in micrograms per cubic meter ($\mu g/m^3$). "--" indicates that no standard exists.
2. The National values that have been formally adopted are applicable to all OCS activities.
3. The California values have been proposed, but not adopted, for OCS activities offshore California.

Table VIII-2. DOI MAXIMUM ALLOWABLE POLLUTANT CONCENTRATION INCREASES[1]

Air Pollutant	Averaging Time: Annual[2]	24-hour	3-hour
Class I[3]			
TSP	5	10	--
SO_2	2	5	25
Class II[3]			
TSP	19	37	--
SO_2	20	91	512
Class III[3]			
TSP	37	75	--
SO_2	40	182	700

1. All concentrations are in micrograms per cubic meter ($\mu g/m^3$). "--" indicates that no standard exists.

2. TSP values are geometric means; SO_2 values are arithmetic means.

3. The Environmental Protection Agency's Prevention of Significant Deterioration (PSD) program recognizes three classes of attainment areas. See Chapter III for a full explanation of PSD regulations.

7. Cumulative Impacts

DOI's regulations require that:

> If, during the review of a new, modified, or revised exploration plan [DOI] determines or an affected State submits information to [DOI] which demonstrates, in the judgement of [DOI], that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then [DOI] shall require the lessee to submit additional information to determine whether emission control measures are necessary (45 FR 15145).

In addition, the cumulative impact provision provides that the lessee shall have an opportunity to present information which demonstrates that the exempt facility does not significantly affect onshore air quality.

Due to both the brevity and generality of the cumulative impact provision, it is not possible to determine a priori what emission controls might be required if it is invoked. However, the general intent of the provision seems to be as follows. In any localized OCS production area there may be some number of platforms whose cumulative (and individual) emissions would not cause significant onshore impacts (i.e., the modeled onshore concentration of any pollutant would not exceed the applicable DOI significance level.) If it is assumed that an OCS lessee proposes an additional platform in this region, and the platform's emissions in conjunction with the emissions of the pre-existing platforms would cause a significant impact, the cumulative impact provision could be invoked. It appears that under this provision the OCS lessee who proposed this last platform could be required to install emission control equipment on this platform and/or the pre-existing platforms such that there would be no significant onshore impact; this provision could apparently apply even if the proposed platform's emissions were below the relevant emission exemption levels and/or did not result in modeled onshore concentrations above the significance levels (Goll, 1980). Alternatively, the lessee might obtain offsets onshore to mitigate impacts. Thus, it is apparently the intent of DOI's regulations that the responsibility for installation of emission control equipment and/or obtaining emission offsets would fall upon that proposed additional platform in an area which sufficiently adds to the area's air pollutant emissions to cause significant impacts. Those platforms which were installed earlier apparently would be exempt from further mandatory emission controls.

A precise understanding of the scope and applicability of the cumulative impact provision will emerge only with practical experience and through litigation.

8. Temporary Activities

DOI's regulations define as temporary those activities occurring at a single location for less than three years. (Exploration, drilling and platform installation are activities which in most instances are likely to be defined as temporary.) If temporary emissions cause significant onshore impacts the use of BACT would be required. This provision is applicable in both attainment and nonattainment areas. No control beyond BACT would be required for temporary activities.

c. Proposed California Regulations

Concurrent with its publication of final OCS air quality regulations, DOI also published proposed regulations which would be applicable only to OCS activities offshore California (45 FR 15147). The California regulations were proposed in response to comments made by state and local governments in California pertaining to DOI's proposed OCS air quality regulations.

The proposed California regulations are identical to the final national regulations except for two distinctions. First, the proposed California regulations include a more stringent emission exemption level. For NO_x, S02, VOC and TSP, the proposed California emission exemption level is given by

$$E = 15.3\ D,$$

where E is the emission exemption level in tons per year, and D is the distance of the facility from the closest onshore area, expressed in statute miles. The national emission exemption level is

$$E = 33.3\ D.$$

Hence, the proposed California standard is slightly more than twice as stringent.

The second difference is that DOI has proposed more stringent significance levels for California. These levels are about two percent of California's ambient air quality standards, which parallels the approach used in formulating the national regulations. Table VIII-1 presents both the proposed California and the national significance levels.

With the two exceptions outlined above, the proposed California regulations are identical to, and would be implemented in the same manner as, DOI's final national regulations. The national regulations are applicable in California until (or unless) DOI adopts final California regulations.

D. Regulatory Implications for OCS Lease Sale No. 53

The foregoing sections of this chapter have delineated the major provisions of DOI's OCS air quality regulations. This final section summarizes these regulations and their implications for OCS Sale No. 53. The implications of DOI's proposed California regulations, if they were adopted in their present form, are also discussed.

1. DOI's Final OCS Air Quality Regulations

DOI's regulations include an emission exemption level which is generally a linear function of distance from the shore--at three miles from shore the exemption level is 100 tons per year, at six miles it is 200 tons per year. Proposed platforms or facilities with projected emissions above the emission exemption level would be subject to DOI's regulatory review. Those with emissions below the levels would be exempt from further scrutiny.

DOI's OCS air quality regulations would be implemented on a facility-specific basis: each facility would be assessed individually to determine whether its, and only its, projected air pollutant emissions would cause "'significant" onshore impacts. Incremental onshore pollutant concentrations are "significant" if they exceed DOI's specified significance levels (see Table VIII-1), as determined by air quality modeling using DOI-approved models. Only in the event of significant onshore impacts would mitigation be required. For pollutants impacting attainment areas, BACT would have to be employed to reduce emissions. Pollutant emissions impacting nonattainment areas would have to be controlled with BACT and additional controls and/or offsets as needed to "fully reduce" emissions. While the DOI regulations are not explicit, "fully reduce" appears to mean a combination of controls and/or offsets such that there is no net increase in air pollutant emissions.

Temporary activities (i.e., those with a duration of less than three years in a single location) would be required to employ BACT if modeling revealed that resulting onshore pollutant concentrations would exceed the significance levels.

Very briefly stated, DOI's regulations require that each individual proposed facility employ air quality modeling to determine whether its emissions, and only its emissions, would cause significant onshore impacts. Mitigation in the form of emission controls and/or offsets would be required in instances where significant impacts would otherwise occur.

The regulations also recognize that a number of proximate facilities may cumulatively have a significant impact, even though none of the individual facilities in and of itself would cause such impacts. The regulations imply that further controls (i.e., beyond those required of individual facilities) might be required in such instances. However, this section of the regulations was drafted broadly and does not precisely indicate the form such controls might assume.

Some examples may clarify the implications of these regulations for Lease Sale No. 53. For instance, platforms in the Bodega Zone would be exempt from regulatory review since even their uncontrolled emissions are well below the applicable emission exemption levels (see Section IX.C.3). For platforms in any of the other zones, it seems likely that in most cases OCS lessees would prefer to comply with the regulations through the installation of control equipment, and thereby attain emissions rates below the emission exemption levels. The controls and impacts likely to be associated with Lease Sale No. 53 activities are fully discussed in Chapters IX and X.

2. DOI's Proposed California Regulations

DOI's proposed California regulations are identical to the final national regulations except for two provisions: the emission exemption levels are lower by roughly 50 percent and the significance levels are also somewhat more stringent. For two reasons these regulations could, if implemented, provide some increased protection for California's air quality. First, the lower emission exemption level would likely result in fewer proposed facilities being exempt from regulatory review. Second, and more importantly, the significance levels for many pollutants would be lower and a short-term criterion for NO_x would be added. These more stringent significance levels mean that mitigation would be required at lower projected emission levels for facilities offshore California than would be required elsewhere on the OCS. For example, in both the Point Arena and Eel River Zones, BACT would be mandatory for VOC emission sources; under DOI's current regulations, controls less intensive than what might be considered as BACT would be sufficient to bring platforms in these zones below the VOC emission exemption level where no further regulatory review (or emission controls) is required. In all zones, emissions of SO_2 and NO_x could still be brought below the applicable emission exemption levels, but more controls would be required to achieve this than under the present regulations, providing some added protection for California's air quality. Unless OCS lessees "chose" to install considerable VOC emission control equipment, some platforms in the Santa Maria and Santa Cruz Zones would have significant onshore VOC impacts (i.e., in the absence of controls their VOC emissions would exceed DOI's emission exemption level and therefore would be deemed to have "significant" onshore impacts) and mitigation would be required; this is particularly important since some of the affected onshore sites are not currently meeting the national ambient air quality standard for ozone.

Whether the additional protection provided by the proposed California regulations, if adopted by DOI, would assuage the OCS-related air quality concerns of state and local governments, and other groups in California remains moot. However, comments received by DOI during the review period for these regulations should do much to illuminate this issue.

E. References

Department of the Interior. 1979. Oil and Gas and Sulphur Operations in the Outer Continental Shelf. Proposed Rule. 44 Federal Register 27449.

Department of the Interior. 1980. Oil and Gas and Sulphur Operations in the Outer Continental Shelf. Final Rule. 45 Federal Register 15128.

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IX. REVISED EMISSION INVENTORIES

A. Introduction

This chapter discusses the development of revised emission inventories for each of the zones scheduled to be leased as a part of OCS Lease Sale No. 53. The purpose of this emission inventory revision is to assess the degree of emission reductions afforded by DOI's final OCS air quality regulations. The results presented in this chapter are based upon the initial emission inventory (Chapter V) and the salient features of DOI's regulations (Chapter VIII).

The DOI regulations require different levels of controls for temporary activities and production operations (see Chapter VIII). Therefore, temporary and production emissions are discussed individually with regard to the methodology used to revise emissions, and in terms of final results.

This chapter is comprised of two sections. The first (Section IX.B) deals with. the assumptions and regulatory interpretations which were required to develop the methodologies utilized to revise both temporary and production emission estimates. The second (Section IX.C) presents the revised emission estimates for the peak emission years for each zone.

It should be noted that the revised emission inventories depend upon the assumptions and rule interpretations made for this study. Should any of the assumptions or conditions on which this study is based change, the resulting emissions could be significantly different from those predicted here. Also, the uncertainties associated with the resource recovery and operating techniques of the major oil companies (see Chapter V) are also applicable to this report. Therefore, although the emission estimates presented in this section are a bit more refined than the original values presented in Chapter V, the results should still be taken as approximations of the emissions which could occur from Lease Sale No. 53 OCS operations and not as exact predictions.

B. Emission Reduction Methodology

1. Temporary Emissions

Modeling of the initial emission estimates (see Chapter VI) indicated that temporary emissions from short-term preproduction activities such as exploration, drilling, testing, platform and pipeline installation could be high enough to adversely affect the air quality of adjacent onshore areas. With the final DOI regulations requiring emission controls on temporary facilities which cause significant onshore impacts, it is necessary to carefully review the nature of temporary emission sources, the magnitude of their emissions, the resultant onshore impacts, and potential mitigation strategies.

The approach used to evaluate emissions from temporary facilities involved four basic steps:

(1) Identification of zones in which a significant onshore impact due to temporary activities had been predicted;

(2) Identification of the air pollutants of concern;

(3) Identification of the specific temporary activities producing large quantities of problem pollutants; and

(4) Development of feasible scenarios for application of control technologies.

The results of the computer simulation modeling described in Chapter VI were examined to identify those zones in which uncontrolled emissions from temporary activities associated with lease tract development produced a significant onshore impact. (Onshore impacts are "significant" when they exceed DOI's significance levels as discussed in Section VIII.B.4.) This review indicated that significance levels would be exceeded for the annual averaging times for SO_2 or NO_2 in four of the five zones. However, there were no exceedances of the significance levels for SO_2 concentrations averaged over either a 24-hour or a 3-hour period in any of the zones. [Although DOI's proposed California regulations (see Section VIII.C) are not being addressed in this report, it should be noted that the proposed California one-hour average significance level of 10 $\mu g/m^3$ for NO_2 would be exceeded in all zones.]

In reviewing the emission sources in each zone to determine what type of activities were responsible for producing emissions which adversely impacted onshore air quality, it was noted that temporary emissions generated during platform and/or pipeline installation were strongly correlated with high onshore NO_2 levels. SO_2 concentrations, on the other hand, were generally correlated with long-term production activities, rather than temporary activities. Potential problems in each zone are discussed in detail in Section IX. C.

The DOI regulations require that BACT (Best Available Control Technology) be applied to those temporary facilities "significantly" affecting onshore air quality. To comply with the DOI regulations, control of NO_x emissions (with BACT) from the temporary sources associated with platform or pipeline installation would be required. Sources which would likely require controls include the following: derrick, lay, and jet barges; and tugboats (crew boats and supply boats seem to be exempt from controls, as discussed in Section VIII.B.2). BACT is to be determined on a case-by-case basis (see Section VIII.B.2). Based upon studies by the California Air Resources Board, a technically and economically feasible BACT has been assumed to involve such combustion modification techniques as EGR (Exhaust Gas Recirculation) or catalytic conversion which reduce NO_x emissions from diesel engines by up to about 90 percent. A value of 55 percent was calculated as the reduction in emissions necessary for compliance with the New Source Performance Standard (see Section IX.A.2) and the proposed California standard for existing diesel engines of 3 grams of NO_x (expressed as NO_2)/Joule output (CARB, 1979) and was assumed to be a reasonable definition of BACT for reciprocating diesel engines.

2. Production Activities

The original analysis of the potential impacts which could result from OCS Lease Sale No. 53 oil and gas development was developed on a zone-by-zone "worst-case" cumulative basis. In contrast, the recently published DOI final OCS air quality regulations, as discussed in Chapter VIII, apply on a facility-specific basis. This difference in approaches creates complexities when determining the effect the DOI regulations would have on the previously estimated emission levels. It is not possible to simply apply reductions to each zone's predicted maximum emission levels and analyze the resulting emission quantities. Rather, the emissions predicted to occur from each zone must first be distributed among the projected facilities, and any required reductions then applied individually to each facility.

The revision of the estimated emissions for each zone requires some interpretation' of provisions in the DOI regulations, as well as a number of assumptions concerning future platform placement, production-related emission locations, and other operational data. This section presents the interpretations and assumptions made, and discusses the manner in which they relate to the development of the revised emission inventories presented in Section IX.C.

It should be noted that because of uncertainties associated with production scenarios and industry operations, some simplified assumptions have have been made. However, to the extent possible, the assumptions and interpretations made are consistent with existing OCS production practices and the DOI regulations.

The following six basic steps were used to revise the estimates for peak emissions from each zone:

(1) Determination of the emissions associated with each projected facility in a given lease zone;

(2) Determination of the emission exemption level for each facility based on the DOI regulations;

(3) Based upon data from (1) and (2) above, a determination of the minimum reductions necessary to achieve emission rates below the applicable exemption levels; or

(4) A review of the original modeling results (Chapter VI) to determine if facilities with annual emission levels greater than the applicable DOI exemption levels would cause a significant onshore impact;

(5) Application of the emission reductions which are needed to comply with DOI's regulations for facilities with significant impacts; and

(6) Summation of the calculated facility emissions to obtain revised zone emissions.

The above steps summarize the methodology used in this study to determine the effect the new DOI regulations would have on emissions levels during the peak emission years which were identified in Chapter V. A detailed discussion of this methodology follows.

a. Facility Emission Estimates

The primary step in the analysis of each zone was a determination of the projected emissions associated with each individual facility in the peak emission year. While outwardly this may seem relatively simple, a number of critical assumptions and rule interpretations are required to complete the task.

DOI's definition of a single facility (see Section VIII.B.2) includes any multiple devices or installations which are directly related to the production of oil or gas at a single site. This specifically includes any offshore storage and treatment (OS&T) facilities which may be associated with a producing platform. Also, any emissions occurring during tanker loading while the tanker is physically attached to the facility would be included in the facility's annual emission inventory. The definition is relatively simple to interpret for the case of one platform with an attached OS&T: all production emissions associated with the platform, processing and storage emissions associated with the OS&T, and tanker loading emissions occurring while the tanker is attached to the OS&T would be included in the annual total emissions of the single platform. However, based on the development scenarios for OCS Lease Sale No. 53 (USGS, 1978), it is predicted that one OS&T or processing platform may store and/or process the production from a number of platforms. In such cases, since the regulations do not specifically deal with one OS&T associated with multiple platforms, it has been assumed that the emissions which would occur on the OS&T (i.e., power generation, evaporative, processing, tanker loading) would be uniformly distributed among the associated platforms. Since there is no realistic method of predicting whether any projected platform within a zone would produce more or less oil and gas than another, the zone's production was also assumed to be evenly distributed among all platforms. Based on these two assumptions, all offshore emissions associated with production power generation, evaporative losses, gas processing, oil processing and tanker loading, as presented in Chapter V, were assumed to be evenly associated with each producing facility, which according to development scenarios for Lease Sale No. 53 encompasses production platforms, deep water platforms and floating production systems. The actual emissions per facility in each zone are more fully discussed in Section IX.C.

b. Determination of Emission Exemption Levels

After determining the predicted emissions for each facility, the next step was to establish each facility's emission exemption levels based on the DOI regulations. Since the emission exemption levels developed by DOI are based on each facility's distance from shore (see Section VIII.B.3), assumptions regarding the placement of the contemplated platforms were required.

As the future location of each platform cannot be predicted accurately, facilities were assumed to be at the same locations selected for modeling in Chapter VI. This approach best demonstrates the potential mitigating effects of DOI's regulations, since the only changed element of the air quality modeling analysis was emission rate changes due to the regulations themselves. Section IX.C presents a full discussion of the types, locations, and allowable emission levels for each facility in each zone.

c. Comparison of Projected Emissions and Emission Exemption Levels

As outlined previously, the third step in determining the potential emission reductions which would result from the DOI regulations was to compare the estimated "uncontrolled" emissions per facility with the predicted exemption levels for that facility. If the estimated emissions were found to be below the exemption level, no emission reductions were applied.

d. Determination of Significant Impacts and Mitigation Requirements

The DOI regulations state that non-volatile organic compound (non-VOC) emissions associated with a facility (see Section VIII.B.2) that exceed the exemption level for that facility must be modeled to determine if the onshore impacts would exceed the DOI significance levels (see Section VIII.B.4). For these cases, to the extent possible, the modeling results presented in Chapter VI were utilized. However, the modeling efforts in Chapter VI were generally based on emission inputs from a number of platforms, whereas impacts from a single facility were required for this revision. Thus, when necessary, emissions associated with a single facility were modeled. If the modeling results indicated that a significant impact would not occur, no reductions were applied to that particular facility.

For the cases of non-VOC emissions which exceeded the DOI exemption levels and caused a significant impact onshore (and VOC emissions which would exceeded the exemption levels), the emissions per facility were assumed to be reduced just to the DOI exemption levels. This approach is realistic since it seems likely that many OCS lessees would choose this relatively simple means of complying with the DOI regulations. In addition, the approach also provides a '*worst-case" analysis, since it generally assumes the highest emission rates permitted under DOI's regulations.

A review of available emission control measures (see Chapter VII) indicates that in many cases, the technology currently exists to reduce the estimated facility emission rates below the DOI exemption levels. In addition, DOI's definition of "projected emissions" (see Section VIII.B.2) allows total estimated emissions per facility (by which exemption from air quality review is determined) to be either controlled or uncontrolled. Therefore, it is expected that in many cases the operators of each facility would voluntarily apply the emission control measures necessary to bring annual emissions below the exemption levels, and thereby be exempt from further air quality review, rather than be required to apply BACT or perhaps fully reduce the emissions through further controls and/or emission trade-offs.

The actual mitigation techniques which were assumed to be used to reduce emissions per facility vary among zones and pollutants. VOC emissions were assumed to be reduced primarily through controlling evaporative losses. NO_x and SO_x emissions occurring during production which would need to be mitigated were assumed to be reduced through a conversion from diesel-fired turbines to natural gas-powered turbines. This seems to be a reasonable assumption since many operators convert to natural gas once production begins (Energy Resources Co., 1977). The actual reductions obtained for each facility and the measures assumed to result in the reductions for each zone are discussed in Section IX.C.

e. Revision of Zone-Wide Emission Projections

Once the emission reductions described above were applied to each corresponding facility, it was a relatively straightforward process to develop the revised zone-wide peak emission levels. The total emission reductions associated with each facility and emission category (power generation, evaporative losses, etc.) were totalled for each zone. Emissions not specifically covered by the DOI regulations (support activity, tanker transit, etc.) were assumed to remain the same as those estimated in Chapter V. The combination of the reduced emissions in each emission category and those emissions not regulated in the DOI rules became the revised emission inventory for each zone. These revised estimates are presented in Section IX.C along with a more specific discussion of the resulting emission inventory for each zone. Chapter X presents the expected changes in onshore impacts due to the revised emissions.

C. Revised Emission Inventories

This section presents revised emission inventories for each zone which reflects the emission-reducing effects of DOI's final air quality regulations. The structure of DOI's regulations necessitated that temporary and production emissions be treated separately and the discussion of each zone's emission is divided accordingly. It should also be noted that the DOI regulations concerning hydrocarbon emissions are written for volatile organic compounds (VOC) rather than total hydrocarbons. As a result, whenever it has become necessary to revise the hydrocarbon emission estimate presented in Chapter V, an estimate of the reactivity of the hydrocarbons has been included.

1. Eel River Zone

a. Temporary Emissions

As shown in Table IX-1, results of the initial Climatological Dispersion Model (CDM) modeling effort indicated the level of NO_x emitted on an annual basis from the installation of one platform would have a significant impact upon the onshore air quality in the Eel River area. Therefore, based on requirements of the DOI regulations, BACT was assumed to be applied to the principal temporary NO_x emission sources--the derrick barge, lay barge, jet barge and tugboats. Assuming BACT provides a 55 percent emission reduction (see Section IX.B.1), the resultant offshore NO_x emissions are projected to be 342 tons/year in 1985, 372 tons/year less than first estimated. The revised estimates are shown in Table IX-2 and can be compared with the corresponding uncontrolled emissions presented in Tables V-13 and C-2.

Table IX-1. SUMMARY OF CDM MODELING RESULTS SHOWING POSSIBLE ONSHORE IMPACTS OF UNCONTROLLED OFFSHORE EMISSIONS[1]

Zone	Highest Onshore Concentration of a Pollutant Associated with Offshore Activities ($\mu g/m^3$)	
	NO_2	SO_2
Eel River	2.9	1.1
Point Arena	BSL[2]	1.1
Bodega	4.4	BSL
Santa Cruz	BSL	BSL
Santa Maria	1.5	BSL

1. Adapted from Table VI-1.
2. "BSL" means Below Significance Level.

Table IX-2. MAXIMUM CONTROLLED ANNUAL OFFSHORE NITROGEN OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT--EEL RIVER ZONR (MEAN RESOURCE ESTIMATE-PEAKE MISSIONY EAR, 1985)

Source/Activity	Emissions, tons/year[1]
Platform Installation	
Derrick Barge[3]	81
Tugboats[3,4]	203
Support Activity[5]	33
Supply Boat	
Crew Boats	
Pipeline Installation	
Tugboats[7,3]	12
Lay Barge[3]	3
Jet Barge[3]	5
Support Activity[5]	5
Supply Boat	
Crew Boat	
TOTAL FOR OFFSHORE OPERATIONS	342

1. All values given are based upon the level of activity required in 1985 for peak construction activities. These may be compared with data in Table V-13.

2. One platform was assumed to be installed.

3. Nitrogen oxide emission reductions of 55 percent are assumed achievable by utilizing combustion modification techniques such as exhaust gas recirculation (EGR) or catalytic conversion. Emissions of carbon monoxide and particulate were not assumed to be reduced by either strategy.

4. It was assumed that there would be four tugboats per platform-installed. On an annual basis, all tugboats were assumed to be maneuvering near the platform.

5. Emissions associated with supply and crew boats are not subject to DOI regulations and remain unchanged. Assumptions used to calculate these emissions are presented in Table C-2.

6. It was assumed that there would be 13 miles of pipeline laid in a straight route to shore.

7. It was assumed that there would be one lay barge assisted by two tugboats and one jet barge, also assisted by two tugboats. The two barges would operate about two miles apart and would progress with the pipeline installation at the rate of one mile per day.

b. Production Emissions

In order to estimate the potentially most severe onshore air quality impacts, a worst-case scenario was devised which assumed that the two platforms operating in the zone would be as close to the shoreline as possible (i.e., three miles offshore) and would have identical emissions, as shown in Table IX-3 (The assumption of point source at the three-mile limit provides a worst-case scenario: the maximum allowable emissions increase linearly with distance from the shore, while the concentrations predicted by the Gaussian dispersion equation used in the CDM model decrease at a greater than linear rate as a function of distance from the pollutant-emitting source.) Based upon the air quality review procedure outlined in the DOI regulations, platforms located three miles from shore would have an emissions exemption level of 100 tons/year for all regulated pollutants except CO, which has an exemption level of 7,072 tons/year (see Section VIII.B.3). It is evident from Table IX-3 that projected uncontrolled emissions from either platform would exceed these limits for all pollutants except for CO and TSP. Since the initial air quality modeling (see Section VI.A.4) suggested there would be an adverse impact onshore from NO_x and SO_x emissions, and since VOC emissions must be reduced to less than 100 tons/year (VOC impacts are deemed "significant" if the exemption level is exceeded), it was assumed that the platform operator would reduce the emissions of all three pollutants to below the exemption levels to avoid the application of BACT and/or total reduction of emissions through further controls and/or offsets. Based on the levels of uncontrolled emissions presented in Table IX-3, this necessitates reducing VOC emissions from stationary sources at each platform by no less than 462 tons/year, NO_x by 58 tons/year, and SO_x by 33 tons/year.

SO_x could probably be reduced readily by switching from diesel fuel to gas for the power-generating turbines (see Section VII for a discussion of potential control measures). If this were done, SO_x from this specific source could be reduced by 99.8 percent, to less than one ton/year. Combustion-related emissions of other pollutants would also be reduced by fuel switching. Based upon a comparison of emission factors for diesel and gas-fired turbines presented in Table VII-4, VOC emissions from power generation would be decreased by 40 percent, NO_x by 21 percent, CO by 32 percent, and TSP by more than 99.9 percent.

Fuel switching would not be sufficient by itself to reduce NO_x to an acceptable level. However, the added control measure of water injection into the combustion chamber could be used to provide an additional 33 percent reduction. Thus, fuel switching and water injection could provide more than the 47 percent reduction in power generation-related NO_x emissions necessary to reduce the total platform generated emissions to less than the DOI exemption level.

VOCS from gas processing could be reduced by 90 percent through the installation of a vapor recovery system. (An added benefit of a vapor recovery system would be a similar reduction in hydrogen sulfide emissions.) Evaporative losses could be reduced by about 70 percent through stringent operating and maintenance procedures (Radian Corp., 1978). The total decrease in emissions expected from implementation of these measures would be 462 tons VOC/year, or 82 percent. These reductions would be sufficient to bring the platforms' emissions below the emission exemption level.

Table IX-4 summarizes maximum annual controlled emissions for the Eel River Zone expected as a result of incorporating three mitigation measures--fuel switching, water injection and vapor recovery.

2. Point Arena Zone

a. Temporary Emissions

The CDM modeling results of the projected maximum emissions from development in the Point Arena Zone, presented in Table VI-1, indicate there would be no significant impacts for NO_2, SO_2 or TSP. The modeling was designed to be extremely conservative. All emission sources were assumed to be located at a single point as close to the shoreline as possible (i.e., at the boundary of the zone, three miles offshore). It follows that temporary sources, which would produce fewer emissions, would not have a significant impact on onshore air quality and would not have to apply BACT. Thus, the estimated emissions associated with these temporary sources would remain unchanged.

b. Production Emissions

As was stated in Section IX.B.2, the approach used to estimate the emissions on a per platform basis assumed all platforms would be emitting equal quantities of a given air pollutant, and the emissions occurring on an OS&T would also be distributed equally among the production platforms. The resultant emissions per platform are presented in Table IX-5.

In accordance with the DOI regulations, a platform situated three miles offshore would be allowed to emit up to 100 tons per year of all pollutants except CO (which has a much greater allowable limit) and still be exempt from regulatory review. In order for such a platform to emit less than the exemption amount (which is assumed to be the action planned by the platform operator to avoid additional air quality reviews), VOC emissions shown in Table IX-5 would have to be controlled by about 80 percent. Even though each platform is expected to exceed the 100 ton/year exemption for NO_x, the worst-case CDM modeling showed the anticipated onshore impact of these emissions not to be significant (see Table VI-l). Therefore, in accordance with Step Two of the Air Regulatory Scheme for OCS Facilities presented in Figure VIII-1, no control of NO_x emissions from production-related facilities would be needed in the Point Arena Zone.

The CDM modeling of projected emissions from production activities in the zone did indicate there could be an exceedance of the annual SO_2 significance level (see Table IX-l). This modeling too, assumed that the emissions from three production platforms and an OS&T were emitted from a single point three miles offshore. However, the DOI regulations generally require only an evaluation of the onshore impact resulting from the emissions from a single platform and its associated OS&T. The SO_x emissions associated with three platforms were predicted to increase the onshore ambient S02 concentration by only 1.1 $\mu g/m^3$ (0.1 $\mu g/m^3$ higher than the significance level).

Table IX-3. MAXIMUM UNCONTROLLED ANNUAL EMISSIONS FROM EACH PLATFORM ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE

(MEAN RESOURCE ESTIMATE, PEAX PRODUCTION YEAR - 1987)

	Emissions (tons/year)[1]					
Source/Activity	Voc	NO_x	So_x	CO	TSP	H_2S
Offshore Sources Common To All Scenarios[2]						
Development Drilling	0.4	5	3	1	0.5	—
Support Activity[3]	1	30	3	24	2	--
Power Generation	14	107	82	34	14	-
Evaporative Losses	213				--	--
Gas Processing	335	46	48			12
TOTAL EMISSIONS	563	88	136	59	16	12
TOTAL EMISSIONS SUBJECT TO DOI REGULATIONS	562	S8 ,	133	35	14	12

1. Based on annual emission data presented in Tables V-68 (reactive hydrocarbons), V-13 (nitrogen oxides), V-14 (sulfur oxides), V-15 (carbon monoxide), V-16 (total suspended particulate) and V-56 (hydrogen sulfide).

2. All emissions are divided equally between the two platforms operating in the zone.

3. Support activities include the movement of supply boats and crew boats, mobile sources which would not be subject to DOI regulations.

Table IX-4. MAXIMUM CONTROLLED ANNUAL OFFSHORE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE

(MEAN RESOURCE ESTIMATE, PEAK PRODUCTION YEAR- 1987)

	Emissions, tons/year[1]			
Source/Activity	Voc	NO_x	SO_x	H_2S
Offshore Operations Common to Scenarios 1, 2 and 3				
Development Drilling	0.8	10	5	
Supportive Activity[2]	2	60	6	--
Production Power Generation[3,4]	17	39	0.3	
Evaporative Losses[5]	115			
Gas Processing[5,6]	67	91	97	1
TOTAL	202	260	108	1
TOTAL PER PLATFORM SUBJECT TO DOI REGULATIONS	100	100	54	1

1. Based on emissions presented in Table IX-3.

2. Consists of mobile sources not subject to DOI regulations.

3. Emission reductions of 11 cons/year VOC (40%), 45 Cons/year NO_x (21%) and 164 tons/year SO_x (99.8%) assumed achievable by switching from diesel fuel to natural gas.

4. Emission reductions of 70 tons/year NO_x (33%) assumed achievable by combustion modification technique such as water injection.

5. Emission reductions of 301 tons/year (71%) assumed acheivable by utilizing the best available operating and maintenance procedures.

6. Emission reductions of 603 cons/year VOC (90%) and 11 tons/year H_2S (90%) assumed achievable by installation of vapor recovery systems.

Table IX-5. MAXIMUM UNCONTROLLED ANNUAL EMISSIONS FROM EACH FACILITY ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - POINT ARENA ZONE

(MEAN RESOURCE ESTIMATE, PEAK PRODUCTION YEAR - 1989)

	Emissions, tons/year[1]					
Source/Activity	Voc	NO_x	So_x	CO	TSP	H_2S
Offshore Operations Common to all Scenarios						
Development Drilling	0.5	7	4	2	0.5	—
Production Power Generation	11	97	68	27	10	—
Oil Processing	0.3	4	—	0.7	0.7	--
Evaporative Losses	130	—	—		--	--
Subtotal-Offshore Emission per Facility Common to All Scenarios	142	108	72	30	11	--
Scenarios 1 & 2						
Offshore Operations						
Tankers at OS&T	109	1	9	0.02	0.3	—
Gas Processing	212	29	31	—	—	7
TOTAL-SCENARIOS 1 & 2						
FOR PLATFORM WITH DRILLING	463	140	40	30	12	7
FOR PLATFORM WITHOUT DRILLING	462	133	112	28	11	7
Scenario 3						
Offshore Operations						
Tankers at OS&T	108	2	13	0.02	0.7	7
Gas Processing	212	29	31	--	—	—
TOTAL-SCEMR1O 3						
FOR PLATFORM WITH DRILLING	462	141	44	30	12	7
FOR PLATFORM WITHOUT DRILLING	461	134	116	28	11	7

1. Based on annual emissions data presented in Tables V-22 through v-25 and Table V-57. All emissions are divided equally among the three-platforms operating in the zone. Emissions from mobile tankers and support vessels would not be subject to DOI regulations and have therefore been omitted from this listing.

It therefore appears reasonable to expect that a single production platform would not produce a significant onshore increase in the ambient concentration of SO_2. Again, by complying with Step Two of the Air Regulatory Scheme for OCS facilities, it would appear that no control of SO_x emissions from production activities would be required in the Point Arena Zone, unless the cumulative impact provision of DOI's regulations were invoked (see Section VIII.B.7).

The control of VOC emissions would probably be accomplished by installing vapor recovery systems on the gas processing plant and on the tanker loading operations, and by utilizing sound, established operating and maintenance procedures on a continuous basis. If these measures were applied, gas processing related emissions (including hydrogen sulfide) and evaporative losses would be reduced by about 90 percent and 75 percent, respectively.

The projected maximum controlled emissions from development in the Point Arena Zone are presented in Table IX-6. The emissions presented in this table would be associated with three producing facilities predicted for this zone in 1989. It should be noted that substantial emissions would still be generated by mobile supply and crew boats which would support the development activities, but would not be subject to the DOI regulations. (The values in Table IX-6 can be compared with Tables V-21 through V-25.)

3. Bodega Zone

a. Temporary Emissions

For the worst-case scenario in the CDM modeling efforts for the Bodega Zone (see Table VI-l), it was assumed that construction activities would be three miles offshore. The results indicated the NO_x emissions associated with installation of one platform could produce a significant impact on the onshore air quality. However, the zone does not physically extend closer to land than 15 miles. Remodeling of the original, uncontrolled projected emissions was thus deemed necessary. The results of generating the same level of NO_x at a distance of 15 miles--the boundary of the tract nearest shore--reduced the onshore impact by a factor of 9 to 0.5 $\mu g/m^3$. According to the DOI regulations, this is not a significant onshore impact. Therefore, no mitigation of temporary emissions would be required, and the original emission estimates, given in Tables A-20 and A-21 remain valid.

b. Production Emissions

The production platform and OS&T are both expected to be no closer to shore than 15 miles. As such the exemption level of CO would be 500 tons/year for all pollutants of concern except carbon monoxide, which would be exempt for emissions up to 20$679 tons/year. The maximum emission estimates for this zone as shown in Tables V-30, V-31, V-32, V-33 and V-68 are well below the exemption levels. In addition, the modeling results presented in Tables VI-1 and VI-3, indicate production activities would not have a significant impact on onshore air quality. Thus, no mitigation measures would be required, and the initial emission estimates remain unchanged.

Table IX-6. MAXIMUM CONTROLLED ANNUAL OFFSHORE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - POINT ARENA ZONE

(MEAN RESOURCE ESTIMATE, PEAR PRODUCTION YEAR - 1989)

	Emissions, tons/year[1]					
SOURCE	VOC	NO_x	SO_x	CO	TSP	H_2S
Offshore Operations Common to all Scenarios						
Development Drilling	1	14	7	3	1	—
Supportive Activity[2]	14	838	57	128	37	--
Production Power Generation	34	291	204	80	36	—
Oil Processing	1	12	—	2	0.9	--
Evaporative Losses3	167	—		—	--	
(Subtotal-Emissions from Common Offshore Operations)	217	1,155	268	213	75	—
A. Scenarios 1 and 2						
Offshore Emissions						
Gas Processing	64	87	92	—		2
Tankers at OS&T[5]	33	3	26	0.1	1	—
Tankers in Transit[6]	58	50	274	0.1	16	—
Subtotal	155	140	392	0.1	17	2
TOTAL-SCENARIOS 1 & 2	372	1,295	660	213	92	22
B. Scenario 3						
Offshore Emissions						
Gas Processing[4]	64	87	92	--	--	2
Tankers at OS&T[5]	32	6	38	0.1	2	—
Tankers in Transit[6]	0.3	5	31	0.1	2	—
Subtotal	96	98	161	0.1	4	2
TOTAL-SCENARIO 3	313	1,253	429	213	79	2

Table IX-6 (continued).

1. Based on the annual emissions data presented in Tables V-68 (reactive hydrocarbons), V-22 (nitrogen oxides), V-23 (sulfur oxides), v-24 (carbon monoxide), V-25 (total suspended particulate), and V-56 (hydrogen sulfide) in the original report. Assumes three facilities producing oil and gas for the year 1989.

2. Supportive activity involves mobile sourc--supply boats and crew boats--which would not be subject to 'the DOI regulations.

3. Emission reductions of 223 tons/year VOC (57%) assumed achievable by utilizing stringent, technically feasible operating and maintenance procedures.

4. Emission reductions of 572 tons/year VOC (90%) assumed acheivable by installation of a vapor recovery system. Hydrogen sulfide emissions are also expected to be reduced by a similar percentage (as a secondary benefit).

5. Emission reductions of 293 tons/year VOC (90%) in Scenarios 1 and 2 and 291 tons/year in Scenario 3 assumed achievable by installation of a vapor recovery system.

6. Emissions from mobile sources such as tankers in transit would not be subject to DOI regulations.

4. Santa Cruz Zone

a. Temporary Emissions

The worst-case approach used in the CDM modeling (see Table VI-1) involved evaluating the impact of not only the installation of a platform, but also the production activities occurring on four other platforms and an OS&T. Even at this level of activity, the air quality onshore was not found to be significantly affected (i.e., modeled concentrations were not in excess of DOI's significance levels) by the projected annual maximum emission rates of any of the non-VOC pollutants. The assumed locations of the platforms and the calculated increases in NO_x and SO_x concentrations onshore are illustrated in Figures VI-1 through VI-3; as many as five platforms could be considered as contributing to the observed maximum onshore concentration increases. Again, it should be emphasized that the DOI regulations apply to the onshore impact resulting from a specific, individual facility. It is reasonable then that if emissions from several facilities would not have a significant onshore impact, emissions relating to a single facility would not result in significant onshore concentration increments. Thus, emission control equipment would not be required and projected emissions presented in Chapter V remain unchanged.

b. Production Emissions

In 1990, the predicted peak production year for this zone, five platforms and an OS&T would be operating throughout the Santa Cruz Zone. For impact assessment purposes, these facilities were located throughout the zone in such a fashion as to create a worst-case scenario for the air quality modeling (see Section VI.A.4.d). For consistency with these initial efforts, the platforms have been assumed to be located in the same places. Table IX-7 lists the platforms by assigned numbers and their allowable annual emissions based upon the DOI exemption levels. The locations of the platforms are graphically illustrated in Figure IX-1.

In order to calculate the contribution of each platform to the total projected emissions from development throughout the zone, as originally presented in Tables V-38 through V-42, several assumptions about the level of activity at any specific platform had to be made. In Transportation Scenarios 1, 2 and 3, the emissions associated with the platforms differed only in whether drilling was occurring or not; all other activity levels--and emissions--were identical. For these scenarios, emissions occurring at the OS&T could be equally distributed among the five platforms. On the other hand, in Scenario 1A, it was assumed that gas processing would occur onshore and the OS&T would not be necessary. However, the pumps, compressors, power generators, etc. that were originally on the OS&T, and were still required offshore were all assumed to be placed on the floating production system. The maximum annual uncontrolled emissions from each platform, based on these assumptions, are presented in Table IX-8.

Only uncontrolled VOC emissions would be in excess of the emission exemption quantities presented in Table IX-7. Since the onshore area adjacent to this zone (San Francisco Bay Area) is an oxidant nonattainment area, the

DOI regulations might require that emissions be "fully reduced" through application of BACT, and further controls and/or offsets (see Section VIII. B.5.b). However, it is assumed that the platform operator would prefer to apply enough control measures to bring VOC emissions below the exemption levels and avoid further air quality review.

Probable, effective mitigation measures for hydrocarbon emissions could include the installation of a vapor recovery system for the gas processing facility, installation of a vapor recovery system for tanker loading; and continuous, strict utilization of the best known regular operating and maintenance procedures. Depending upon need, the expected emission reductions could be up to 90 percent of gas processing losses, and 75 percent of evaporative losses. VOC emissions were recalculated, taking into consideration these necessary control measures. The emission reductions required for each facility are presented in Table IX-9, and the resultant maximum controlled annual emission rates for the entire zone are given in Table IX-10.

5. Santa Maria Zone

a. Temporary Emissions

The CDM modeling study for the Santa Maria Zone was done in the same manner as for the Santa Cruz Zone, i.e. , a worst-case approach estimated the impact on onshore air quality of all activities occurring in the zone in the year of maximum emissions. Based upon USGS projections (see Chapter II), two platforms would be installed in 1989. In addition, nine production platforms, one floating production system, two OS&Ts, and a gas processing platform would be operating throughout the entire zone. Examining the graphic plots of the platform locations and the areas of maximum onshore air quality effects (presented in Figures VI-4 through VI-6) suggests that emissions from as many as five platforms could interact to produce maximum onshore NO_x concentrations which would exceed the annually-averaged DOI significance levels.

In order to evaluate the onshore air quality impact produced by emissions from the installation of a single platform, the CDM model was rerun with the input being only the projected uncontrolled emissions related to the installation of one platform three miles offshore--as near Santa Maria as physically possible. The results of this worst-case scenario indicate the maximum increase in NO_x could be over $4\ \mu g/m^3$, well above DOI's significance level. In fact, the onshore increment would not be below the significance level unless the installation were occurring at least seven miles from shore. Therefore, based on the requirements of the DOI regulations, BACT would need to be utilized on temporary sources within seven miles of the coast throughout the Santa Maria Zone. Assuming BACT to be applied to all barges and tugboats, the reduction in offshore NO_x emissions is projected to be 347 tons/year per platform in 1989 (a total of 694 tons/ year). The revised emission estimates, given in Table IX-11 can be compared with Table C-22 in Appendix C.

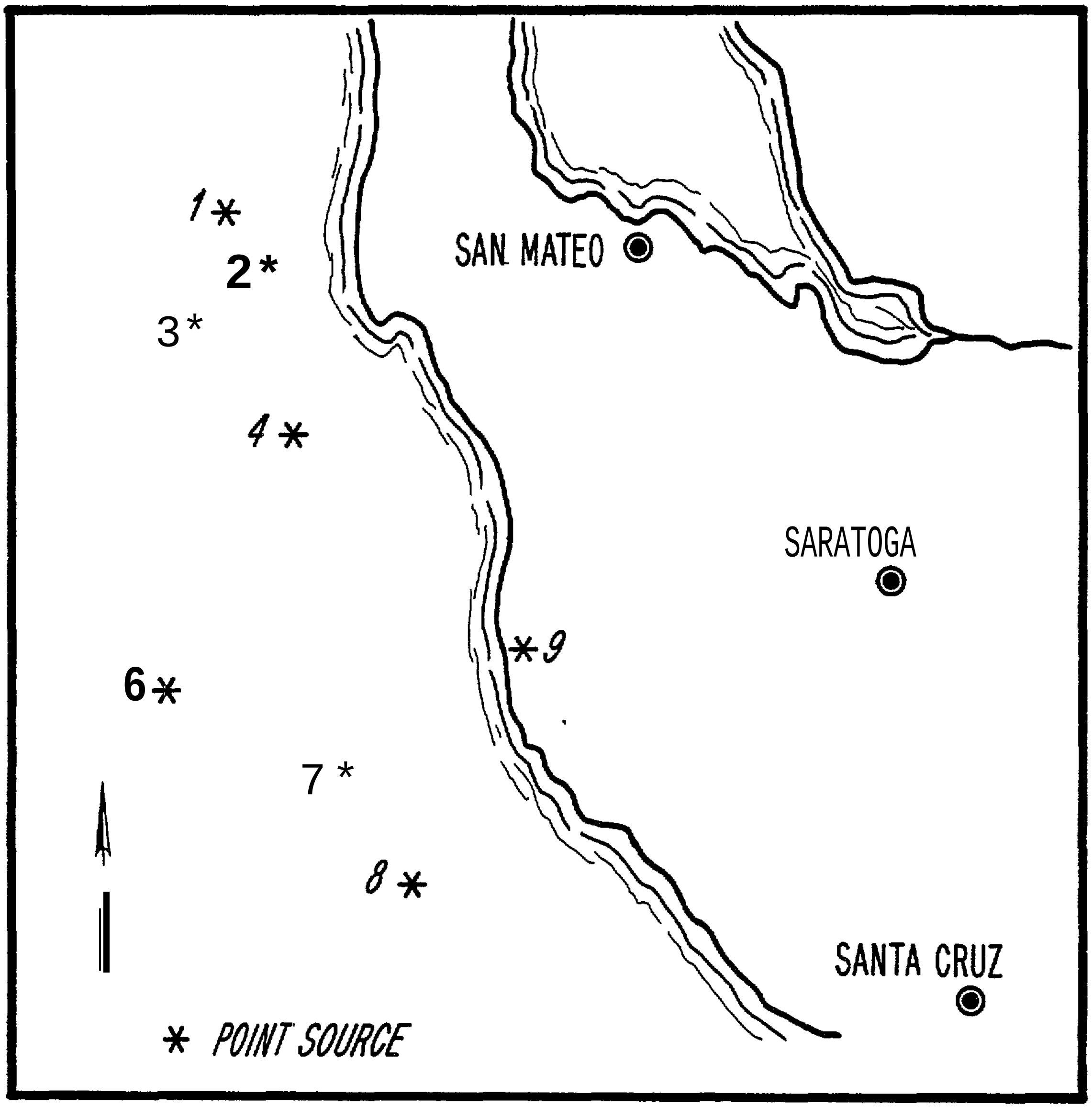

Figure IX-1. EMISSION LOCATIONS IN MODELING ANNUAL AVERAGES FOR THE SANTA CRUZ OCS ZONE

Table IX-7. EMISSION EXEMPTION LEVELS FOR PLATFORMS IN THE SANTA CRUZ ZONE

Platform Site[1]	Distance from Shore, miles[2]	Exemption Level tons/year[3] VOC, NO_x, SO_x or TSP	CO
1	4.2	140	8,851
3 or 8	5.8	193	10,976
4	5.4	180	10,465
6	11.2	373	17,020
7	6.7	223	12,084

1. Numbers refer to locations of platforms selected for use in air quality modeling. The sites are shown in Figure IX-1.
2. Distances refer to locations of platforms from shore as selected for air quality modeling.
3. Based on the DOI regulations which relate emission exemption levels to the distance from the facility to shore (see Section VIII.B.3).

Table IX-8. MAXIMUM UNCONTROLLED ANNUAL EMISSIONS FROM EACH TYPE OF PLATFORM ASSOCIATED WITH LEASE SALE No. 53 OIL AND GAS DEVELOPMENT - SANTA CRUZ ZONE

(MEAN RESOURCE ESTIMATE, PEAK PRODUCTION YEAR - 1990)

Site[5]	Source/Activity in Scenario 1	Emissions, tons/year[1]					
		VOC	NO_x	SO_x	CO	TSP	H_2S
3,7 or 8	Production Platform (with drilling)						
	Development Drilling	1	16	8	3	0.5	--
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	26	--	--	--	--	
	Oil & Gas Processing & Handling[2]	136	31	19	4	2	3
	TOTAL	167	83	30	17	6	3
1 or 4	Production Platform (without drilling)						
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	26	--	--	--	--	--
	Oil & Gas Processing & Handling[2]	136	31	19	4	2	3
	TOTAL	166	67	22	14	6	3
6	Floating Production System						
	Power Generation	4	36	3	10	4	
	Evaporative Losses	26	--	--	--	--	--
	Oil & Gas Processing & Handling[2]	136	31	19	4	2	3
	TOTAL	166	67	22	14	6	3

Table IX-8 (continued).

Site[5]	Source/Activity in Scenario 1A	Emissions, tons/year[1]					
		Voc	NO_x	SO_x	CO	TSP	H_2S
3,7 or 8	Production Platform (with drilling)						
	Development Drilling	1	16	6	3	0.5	--
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	30	--	--	--	--	--
	Pipeline Losses[3]	15	--	--	--	--	--
	TOTAL	50	52	9	13	4	--
1 or 4	Production Platform (without drilling)						
	Power Generation	4	36	4	10	4	--
	Evaporative Losses	30	--	--	--	--	--
	Pipeline Losses[3]	15	--	--	--	--	--
	TOTAL	49	36	4	10	4	--
	Floating Production System						
	Power Generation	13	119	28	20	8	--
	Evaporative Losses	127	--	--	--	--	--
	Pipeline Losses[3]	15	--	--	--	--	--
	TOTAL	155	119	28	20	8	--

Table IX-8 (continued).

Site[5]	Source/Activity in Scenario 2	Emissions, tons/year[1] VOC	NO_x	SO_x	CO	TSP	H_2S
3,7 or 8	Production Platform (with drilling)						
	Development Drilling	1	16	6	3	0.5	--
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	26	--	--	--	--	--
	Oil & Gas Processing & Handling[4]	277	29	15	5	2	3
	TOTAL	308	81	24	18	6	3
1 nr 4	Production Platform (without drilling)						
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	26	--	--	--	--	--
	Oil & Gas Processing & Handling[4]	277	29	15	5	2	3
	TOTAL	307	65	18	15	6	3
6	Floating Production System						
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	26	--	--	--	--	--
	Oil & Gas Processing & Handling[4]	277	29	15	5	2	3
	TOTAL	365	18	15	26	8	3

Table IX-8 (continued).

Site[5]	Source/Activity in Scenario 3	Emissions, tons/year[1] VOC	NO_x	SO_x	CO	TSP	H_2S
3,7 or 8	Production Platform (with drilling)						
	Development Drilling	1	16	6	3	0.5	--
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	26	--	--	--	--	--
	Oil & Gas Processing & Handling[4]	177	23	20	4	2	3
	TOTAL	208	75	29	17	6	3
1 or 4	Production Platform (without drilling)						
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	26	--	--	--	--	
	Oil & Gas Processing & Handling[4]	177	23	20	4	2	3
	TOTAL	207	59	23	14	6	3
6	Floating Production System						
	Power Generation	4	36	3	10	4	--
	Evaporative Losses	26	--	--	--	--	--
	Oil & Gas Processing & Handling[4]	177	23	20	4	2	3
	TOTAL	207	59	23	14	6	3

Table IX-8 (continued).

1. Based on annual emissions data presented in Tables V-68 (reactive hydrocarbons), V-39 (nitrogen oxides), V-40 (sulfur oxides), V-41 (carbon monoxide), v-42 (total suspended particulate), and V-56 (hydrogen sulfide). Emissions from mobile sources--tankers in transit and support vessels--would not be subject to DO I regulations, and have therefore been omitted from this tabulation.

2. Included in these processing and handling emissions are activities which would actually occur at the OS&T, but which would directly relate to and support production at che platform: oil & gas processing, power generation, evaporative losses and pipeline leases. For this projections, each platform was assigned an equal share of the emissions generated at the OS&T.

3. Pipeline losses are distributed equally among all platforms. This assumes equal production and therefore an equal contribution to emissions.

4. Included inthese processing and handling emissions are activities which actually would occur at the OS&T, but which would directly relate to production at the platform: oil & gas processing, power generation, evaporative leases, tanker loading losses and pipeline losses. For this projection, each platform was assigned an equal share of the emissions generated at the OS&T.

5. Refer to Figure IX-9 for location of sites.

b. Production Emissions

Presented in Table IX-12 are the estimated uncontrolled offshore emissions associated with each facility predicted to be located in the Santa Maria Zone for the predicted peak production year of 1991, assuming the USGS mean resource estimate. These values have been adapted from Tables V-46 through V-SO, and Table V-56. No onshore emissions are included as the DOI rules apply only to offshore activities. As discussed in Section IX.B.2, a number of assumptions have been made in determining the uncontrolled emissions per facility from the zone-wide emissions. It was assumed that each production facility (production platform, floating production system) would produce the same quantity of oil and gas. It was also assumed that the processing, storage and loading emissions, which would physically occur at the two OS&Ts and the gas processing platform, would be equally distributed between the 13 production facilities. Based on these assumptions, the emissions associated with power generation, evaporative losses, gas and oil processing, and tanker loading would be equally divided among the 13 production facilities in order to determine the projected annual emissions per facility. The emissions occurring from development drilling would be distributed among the three facilities on which (based on USGS scenarios) drilling is predicted to occur. Emissions associated with support boats and tanker transit would not be included in the emissions per facility since they are not considered in the DOI regulations.

Figure IX-2 presents the assumed locations of the 11 production platforms, 2 floating production systems, 2 OS&Ts, and 1 gas processing platform which are predicted by USGS to exist in 1991. These are the locations assumed for modeling purposes in the initial study (see Section VI.C.6.e) and are therefore assumed for this revision. Based on the locations shown in Figure IX-2, the DOI exemption levels for each facility have been calculated. The DOI exemption level, the proposed California exemption level and the assumed distance from shore for each platform are included in Table IX-13.

A comparison between the uncontrolled emissions for each facility shown in Table IX-12, and the DOI exemption levels presented in Table IX-13, indicates that the only pollutants which would exceed the applicable emission exemption levels are VOCS. According to the DOI regulations, if annual emissions from a facility adjacent to a nonattainment area for ozone (as are portions of Santa Barbara County) are higher than the exemption levels, those emissions might have to be *'fully reduced" through installation of BACT and further controls and/or offsets, if necessary (see Section VIII.B. 5.b). However, rather than being required to mitigate VOC emissions it is expected that, if technically possible, the operator of each facility would choose to reduce the facility's VOC emissions to below the DOI exemption level, and thereby avoid further regulatory review. Therefore, the estimated emission reductions for the Santa Maria zone are based on the assumption that emissions from any facility with uncontrolled VOC emissions below the DOI exemption level would remain the same, and that facilities with uncontrolled VOC emissions above the DOI exemption level would voluntarily reduce their VOC emissions to just below the exemption level.

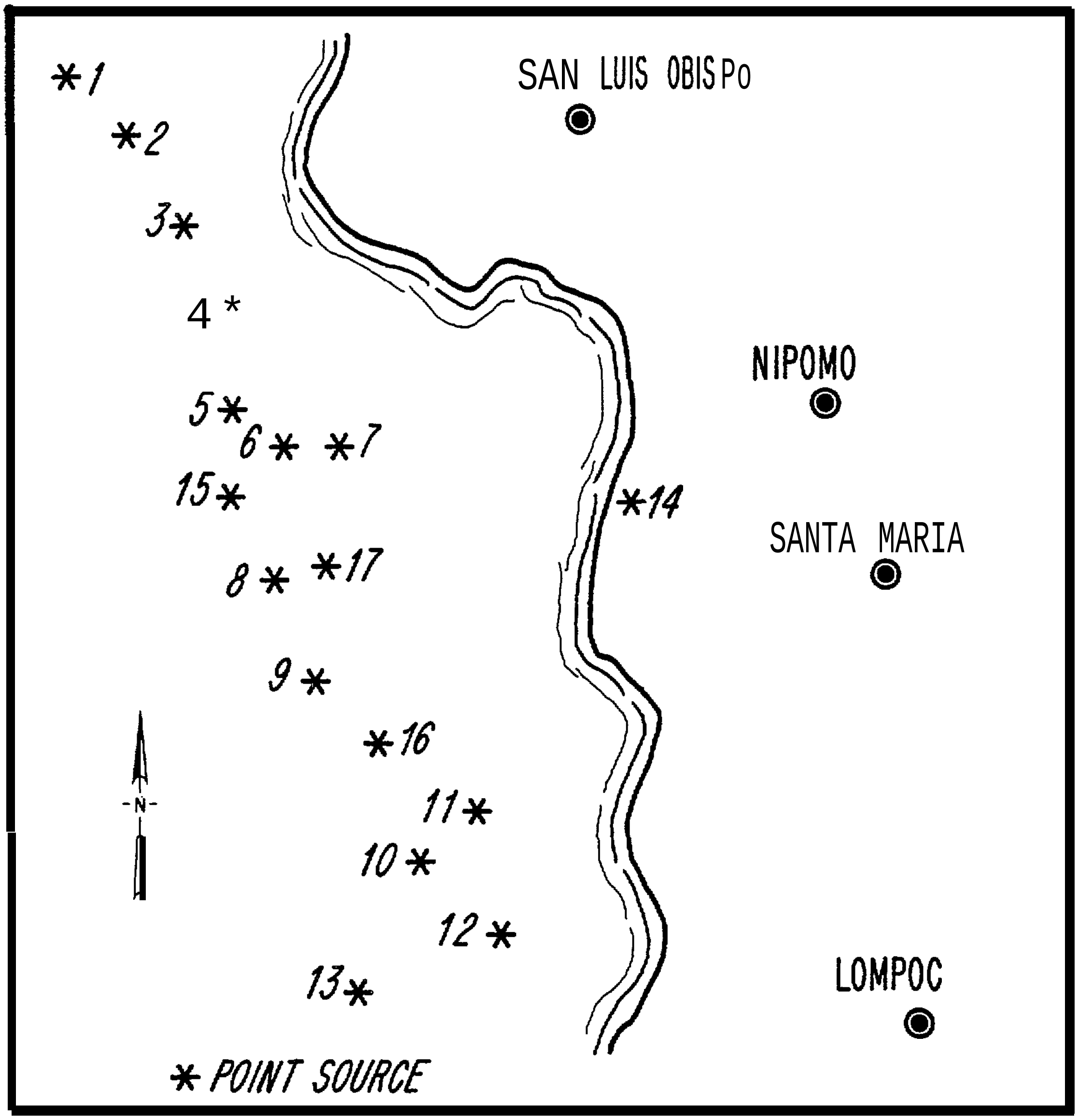

Figure IX-2. EMISSION LOCATIONS IN MODELING ANNUAL AVERAGES FOR THE SANTA MARIA OCS ZONE

Table IX-9. MINIMUM VOLATILE ORGANIC COMPOUND EMISSION REDUCTIONS NEEDED FOR EACH FACILITY TO MEET DOI EXEMPTION LEVELS[1]--SANTA CRUZ ZONE

Site[2]	Reductions (tons/year)		
	Scenario 1	Scenario 2	Scenario 3
1	26	167	67
3	--	115	15
4	--	127	27
7	--	85	--
8	--	115	15
TOTAL-Zone Wide Reduction	26	609	124

1. Based "on data presented in Tables IX-7 and IX-8.

2. Refer to Figure IX-1 for location of facilities.

Table IX-10. MAXIMUM CONTROLLED ANNUAL OFFSHORE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT--SANTA CRUZ ZONE[1]

(MEAN RESOURCE ESTIMATE, PEAK PRODUCTION YEAR - 1990)

	Emissions, tons/year[1]					
Source	Voc	NO_x	So_x	CO	TSP	H_2S
<u>Scenario 1</u>						
<u>Offshore Sources</u>						
Development Drilling	2	21	11	5	1	--
Power Generation	30	263	177	70	21	--
Oil & Gas Processing	477	74	69	2	0.8	17
Evaporative Losses (from pipelines)	82	--	--	--	--	--
Evaporative Losses (all other sources)	220	--	--	--	--	--
Support Activity	6	268	18	41	12	--
TOTAL	809	626	275	118	41	17
<u>Scenario 1A</u>[2]						
<u>Offshore Sources</u>						
Development Drilling	2	21	11	5	1	--
Power Generation	30	263	177	70	27	--
Evaporative Losses (from pipeline)	82	--	--	--	--	--
Evaporative Losses (all ocher sources)	247	--	--	--	--	--
Support Activity	6	268	18	41	12	--
TOTAL	366	552	206	116	40	--

Table IX-10 (continued).

Source	Emissions, tons/year[1]					
	VOC	NO_x	SO_x	CO	TSP	H_2S
Scenario 2						
Offshore Sources						
Development Drilling	2	21	11	5	1	--
Power Generation	26	216	152	60	23	--
Oil & Gas Processing	48	74	69	2	0.8	2
Evaporative Losses (from pipeline)	41	--	--	--	--	--
Evaporative Losses (all other sources)	66	--	--	--	--	--
Tankers at OS&T	715	24	2	4	1	--
Tankers in Transit	23	37	3	5	2	--
Support Activity	5	268	18	41	12	--
TOTAL	736	640	255	117	40	2
Scenario 3						
Offshore Sources						
Development Drilling	2	21	11	5	1	--
Power Generation	26	281	152	60	23	--
Oil & Gas Processing	477	9	69	2	0.8	17
Evaporative Losses (from pipeline)	41	--	--	--	--	--
Evaporative Losses (all other sources)	122	--	--	--	--	--
Tankers at OS&T	239	4	28	0.05	2	--
Tankers in Transit	0.3	4	28	0.05	2	--
Support Activity	5	268	18	41	12	--
TOTAL	912	587	306	1-8	41	17

Table IX-10 (continued).

1. Compiled from annual emissions data presented in Table IX-8 for the operation of two production platforms with drilling, two production platforms without drilling, a floating production system and an OS&T.

2. Gas and oil processing would occur onshore.

Table IX-11. MAXIMUM CONTROLLED ANNUAL OPFSI1OKE NITROGEN OXIDE IMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT--SANTA MARIA ZONE[1]

(MEAN RESOURCE ESTIMATE, PEAK EMISSION YEAR - 1989)

SOURCE/ACTIVITY	Emissions, tons/year SCENARIO 1	SCENARIO 1A	SCENARIO 2	SCENARIO 3
A. Platform Installation				
Derrick Barge	81	81	80	81
Tugboats[3]	203	203	203	203
Supply Boats[4]	138	138	138	138
Crew Boats[5]	6	6	6	6
B. Production Platform (with drilling)[6]				
Development Drilling	12	12	12	12
Power Generation	56	68	56	56
C. Production Platform (without drilling)[7]				
Power Generation	56	68	56	56
D. Floating Production System[8]				
Development Drilling	3	3	3	3
Power Generation	56	281	56	56
E. Offshore Storage & Treatment (OS&T)[9]				
Power Generation	117	--	53	53
Oil Processing	12		12	12
F. Alternative Gas Processing Platform[10]				
Power Generation	92	--	92	92
Gas Processing	0.6	--	0.6	0.6
G. Onshore Gas Processing Plant[11]				
Oil Processing	--	24	--	--
Gas Processing (power generation)	--	176	--	--

Table IX-11 (continued)

SOURCE/ACTIVITY	SCENARIO 1	SCENARIO 1A	SCENARIO 2	SCENARIO 3
		Emissions, tons/year		
Ii. Supportive Activity				
Supply Boats[12]	1,102	1,102	1,102	1,102
Crew Boats[13]	45	45	45	45
I. Tankers[14]	--	--	110	29

1. Nitrogen oxide emissions were assumed to be at the highest level in 1989.

2. Two platforms were assumed to be installed. Values are given on a "per platform" basis.

3. It was assumed that there would be four tugboats/platform installed. On an annual basis, all four tugboats were assumed to be maneuvering near the platforms; stationary annual emissions were not considered significant.

4. It was assumed that there would be one supply boat per platform installed.

5. It was assumed that there would be one crew boat per platform installed.

6. [t was assumed that there would be four platforms drilling simultaneously. Emissions are on a "per platform" basis.

7. It was assumed that there would be five production platforms. Emissions are on a "per platform" basis.

8. [t was assumed that there would be one floating production system in this year.

9. In Scenarios 1, 2 and 3, it was assumed that there would be two offshore storage and treatment (OS&T) facilities. In Scenario 1A, there would be none due to the addition of the onshore oil/gas processing plant.

Table IX-1 1 (continued).

10. In Scenarios 1, 2 and 3 it was assumed that there would be one alternate gas processing platform. In Scenario 1A, there would be no alternate gas processing platform due to the addition of the onshore gas/oil processing plant.

11. For Scenario 1A, the oil/gas processing plant would be located two miles inland near the Santa Maria River.

12. Emissions for all six boats are given. On an annual basis, it was assumed that 90 percent of the pollutants from the supply boats would be emitted while the sources are mobile (line sources) between the zone and Santa Barbara. Approximately 10 percent of the pollutants would be emitted while the sources are stationary; emissions would be distributed equally among the platforms.

13. Emissions for all fuur bests are given. On an annual basis, 80 percent of crewboat emissions were assumed to be line sources extending from the zone to shore with 10 percent of total emissions occurring at each end of the route as stationary sources.

14. Emission value includes all activities occurring at the OS&T and all activities occurring in transit off the coast of California.

Table IX-12. MAXIMUM UNCONTROLLED ANNUAL EMISSIONS FROM EACH TYPE OF PLATFORM ASSOCIATED WITH LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT--SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE, PEAK PRODUCTION YEAR--1991)[1]

		Emissions, tons/year[1]					
Site[2]	Source/Activity	VOC	NO_x	SO_x	CO	TSP	H_2S
Scenario 1							
1,3,5,7,9 11,12,16,17	Production Platform (without drilling)						
	Power Generation	7	57	40	16	7	
	Evaporative Leases	76	--	--	--	--	
	Power Generation (oil pumping)	1	12	6	3	1	
	Evaporative Losses (oil pipeline)	11	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	neg.	0.5	0.2	
	TOTAL	220	88	64	20	8	4
2,8	Production Platform (with drilling)						
	Development Drilling	1	11	6	3	0.7	
	Power Generation	7	57	40	16	?	
	Evaporative Losses	76	--	--	--	--	
	Power Generation (oil pumping)	1	12	6	3	1	
	Evaporative Losses (oil pipeline)	11	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	neg.	0.5	0.2	
	TOTAL	221	99	70	25	9	4

Table IX-12 (continued)

Site[2]	Source/Activity	Emissions, tons/year[1]					
		VOC	NO_x	SO_x	CO	TSP	H_2S
13	<u>Floating Production System (without drilling)</u>						
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Power Generation (oil pumping)	1	12	6	3	1	
	Evaporative Losses (oil pipeline)	11	--	--	--	--	
	Gas Processing	--	--	--	--	--	
	Oil Processing	--	--	--	--	--	
	TOTAL	95	69	46	19	8	
15	<u>Floating Production System (with drilling)</u>						
	Development Drilling	7	11	6	3	0.7	
	Power Generation	1	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Power Generation (oil pumping)	1	12	6	3	1	
	Evaporative Losses (oil pipeline)	11		--	--	--	
	Gas Processing	--	--	--	--	--	
	Oil Processing	--	--	--	--	--	
	TOTAL	96	80	52	22	9	

Table IX-12 (continued)

Site[2]	Source/Activity	Emissions, tons/year[1]					
		VOC	NO_x	SO_x	CO	TSP	H_2S
Scenario 1A							
1,3,5,7,9, 11,12,16,17	Production Platform (without drilling)						
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Power Generation (oil pumping)	1	12	6	3	1	
	Evaporative Losses (oil pipeline)	11	--	--	--	--	
	Gas Processing[3]	--	--	--	--	--	
	Oil Processing[3]	--	--	--	--	--	
	TOTAL	95	69	46	19	8	
2,8	Production Platform (with drilling)						
	Development Drilling	1	11	6	3	0.7	
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Power Generation (oil pumping)	1	12	6	3	1	
	Evaporative Losses (oil pipeline)	11	--	--	--	--	
	Gas Processing[3]	--	--	--	--	--	
	Oil Processing[3]	--	--	--	--	--	
	TOTAL	96	80	52	22	9	

Table IX-12 (continued)

Site[2]	Source/Activity	Emissions, tons/year[1]					
		Voc	NO_x	SO_x	CO	TS P	H_2S
13	Floating Production System (without drilling)						
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Power Generation (oil pumping)	1	12	6	3	1	
	Evaporative Leases (oil pipeline)	11	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	TOTAL	220	88	64	20	8	4
15	Floating Production System (with drilling)						
	Development Drilling	1	11	6	3	0.7	
	Power Generation	?	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Power Generation (oil pumping)	1	12	6	3	1	
	Evaporative Losses (oil pipeline)	11	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	'TOTAL	221	99	70	23	9	4

Table IX-12 (continued)

Site[2]	Source/Activity	VOC	NO_x	SO_x	CO	TSP	H_2S
		Emissions, tons/year[1]					
Scenario 2							
1,3,5,7,9, 11,12,16,17	Production Platform (without drilling)						
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	.-	.-	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	'Neg.	0.5	0.2	
	Tanker Loading	62	1	5	Neg.	0.3	
	TOTAL	270	77	63	17	8	4
2,8	Production Platform (with drilling)						
	Development Drilling	1	11	6	3	0.7	
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	Tanker Loading	62	1	5	Neg.	0.3	
	TOTAL	271	88	69	20	8	4
13	Floating Production System (without drilling)						
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	.-	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	Tanker Loading	62	1	5	Neg.	0.3	
	TOTAL	270	77	63	17	8	4

Table IX-12 (continued)

Site[2]	Source/Activity in Scenario 1	Emissions, tons/year[1] VOC	NO_x	SO_x	CO	TSP	H_2S
15	Floating Production System (with drilling)						
	Development Drilling	1	11	6	3	0.7	
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	.-	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	Tanker Loading	62	1	5	Neg.	0.3	
	TOTAL	271	88	69	20	8	4
Scenario 3							
1,3,5,7,9, 11,12,16,17	Production Platform (without drilling)						
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	Tanker Loading	63	1	7	Neg.	0.5	
	TOTAL	271	77	65	17	8	4
2,8	Production Platform (with drilling)						
	Development Drilling	1	11	6	3	0.7	
	Power Generation	7	57	40	16	7	
	Evaporative Leases	76	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	Tanker Loading	63	1	7	Neg.	0.5	
	ToTAL	272	88	71	20	8	4

Table IX-12 (continued)

Site[2]	Source/Activity in Scenario 1	Emissions, tons/ year[1] VOC	NO_x	SO_x	CO	TSP	H_2S
13	Floating Production System (without drilling)						
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	Tanker Loading	63	1	7	Neg.	0.5	
	TOTAL	271	77	65	17	8	4
15	Floating Production System (with drilling)						
	Development Drilling	1	11	6	3	0.7	
	Power Generation	7	57	40	16	7	
	Evaporative Losses	76	--	--	--	--	
	Gas Processing	125	17	18	Neg.	Neg.	4
	Oil Processing	0.1	2	Neg.	0.5	0.2	
	Tanker Loading	63	1	7	Neg.	0.5	
	TOTAL	272	88	71	211	8	4

1. Emissions presented in Tables V-46 through V-50 and Table V-56 are assumed to be distributed equally among all production facilities. A production facility is defined as a production platform or floating production system. It should be noted that a portion of the estimated emissions associated with each facility would physically occur on an OS&T or the gas processing platform. Emissions from mobile sources--tankers in transit and support vessels--are not subject to DOI regulations and have therefore been omitted from this tabulation.
2. Refer to Figure IX-2 for location of facilities.
3. Oil and gas processing could occur onshore in Scenario 1A. Therefore, the associated emissions would not be included in the annual total.

Table IX-13. DOI EKE5S1ON EXEMPTION LEVELS FOR THE SANTA MARIA ZONE—1991
(MEAN RESOURCE ESTIMATE)

			Exemption Levels (tons/year)[2] VOC, NO_x, SOY, TSP		
Site[1]	Platform Type	Distance From Shore	Federal	Proposed ' i a	CO
1	Production Platform	7.7	256	118	13,258
2	Platform w/drilling	5.8	192	89	10,976
3	Production Platform	4.2	141	64	8,851
4	OS&T 3	4.6	154	70	9,404
5	Production Platform	6.9	231	106	12,323
6	Gas Processing Plant[3]	7.3	243	112	12,795
7	Production Platform	6.2	205	95	11,475
8	Platform w/drilling	10.2	339	156	15,991
9	Production Platform	8.8	295	135	14,492
10	OS&T 3	6.5	218	99	11,842
11	Production Platform	4.8	160	73	9,675
12	Production Platform	5.0	166	76	9,942
13	Floating Platform	10.0	333	153	15,781
14	Onshore Gas Processing				
15	Floating Platform w/drilling[5]	12.0	400	184	17,821
16	Production platform[5]	7.0	233	107	12,442
17	Production Platform[5]	9.0	300	138	14,711

1. Refer to Figure IX-2 for location of platform. Figure IX-2 is identical to Figure VI-4 except chat it includes additional platforms as explained in note (5) below.
2. DOI exemption formulae are presented in Chapter VIII.
3. OS&Ts and gas processing platform are not considered as a "facility" (see Chapter VIII for definition). However, their locations and hypothetical emission exemption levels are presented for reference.
4. Onshore facilities are not covered by DOI regulations.
5. Figure VI-4 which presents initial modeling platform placements waa prepared for 1989 when only 13 platforms would exist. This study is based on the estimated peak production year of 1991, a year in which 16 platforms would exist. Therefore, these platforms have been added to Figure VI-4.

Table IX-14. VOLATILE ORGANIC COMPOUND EMISSION REDUCTIONS NECESSARY AT EACH FACILITY TO ACHIEVE DOI EXEMPTION LEVELS[1]--SANTA MARIA ZONE

Site[3]	Platform Type	Emission Reductions (tons/year)[2] Scenario 1	Scenario 2	Scenario 3
1	Production Platform (without drilling)	--	15	16
2	Production Platform (with drilling)	29	79	80
3	Production Platform (without drilling)	79	129	130
5	Production Platform (without drilling)	--	39	40
7	Production Platform (without drilling)	15	65	66
11	Production Platform (without drilling)	60	110	111
12	Production Platform (without drilling)	54	104	105
16	Production Platform (without drilling)	--	37	38
	TOTAL (Zone-Wide Reduction)	236	578	586

1. Based on data presented in Tables IX-12 and IX-13.

2. Reductions required to just meet DOI exemption levels.

3. Refer to Figure IX-2 for location of facilities.

Table IX-15. MAXIMUM ANNUAL CONTROLLED EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT--SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE, PEAK PRODUCTION YEAR--1991

Source/Activity	Emissions (tons/year) VOC	NO_x	SO_x	CO	TSP	H_2S
Offshore Activities Common to All Scenarios						
Development Drilling	3	M	18	8	2	--
Supportive Activity	22	1,029	70	129	45	--
Production Power Generation	86	738	518	203	91	--
Subtotal	111	1,801	606	340	138	--
Scenario 1						
Evaporative Losses[2]	894	--	--	--	--	--
Power Generation (Oil Pumping)	16	160	84	34	17	--
Evaporative Losses (Oil Pipeline)	141	--	--	--	--	--
Gas Processing	1,472	220	233	Neg.	Neg.	57
Oil Processing	2	30	Neg.	6	3	--
Subtotal	2,525	310	317	40	20	57
TOTAL (SCENARIO 1)	2,636	2,111	923	880	158	57
Scenario 1A[3]						
Evaporative Losses	983	--	--	--	--	--
Power Generation (Oil Pumping)	16	160	84	34	17	--
Evaporative Losses (Oil Pipeline)	141	--	--	--	--	--
Subtotal	1,140	160	84	34	17	--
TOTAL (SCENARIO 1A)	1,251	1,961	690	374	155	--

Table IX-15 (continued)

Source/Activity	Emissions (tons/year) VOC	NO_x	SO_x	CO	TSP	H_2S
Scenario 2						
Evaporative Losses[2]	764	--	--	--	--	--
Gas Processing	1,259	220	233	Neg.	Neg.	44
Oil Processing	2	30	Neg.	6	3	--
Tankers at OS&T	811	7	64	0.1	4	--
Tankers in Transit	148	131	707	5	43	--
Subtotal	2,984	388	1,004	11	50	44
TOTAL (SCENARIO 2)	3,095	2,189	1,610	351	188	44
Scenario 3						
Evaporative Losses[2]	762	--	--	--	--	--
Gas Processing[2]	1,255	220	233	--	--	44
Oil Processing	2	30	--	6	3	--
Tankers at OS&T	775	15	96	0.3	6	--
Tankers in Transit	1	21	137	0.3	8	--
Subtotal	2,795	286	466	7	17	44
TOTAL (SCENARIO 3)	2,906	2,087	1,072	347	155	44

1. Based on emissions presented in Table IX-12 and emission reductions presented in Table IX-14.
2. VOC emission reductions applied.
3. Gas and oil processing would occur onshore.

Table IX-14 presents the facilities which would require VOC emission reductions. Also presented are the required emission reductions for each facility and the estimated zone-wide emission reductions for Transportation Scenarios 1, 2 and 3. Scenario 1A is not included because no emission reductions are expected to be required. This is due to the large quantity of emissions which would effectively be removed from each offshore facility due to the presence of an onshore oil and gas processing plant. Of the three transportation scenarios in which emission reductions would be required, Scenarios 2 and 3 would require the largest quantity of reductions. This is due to the large contribution of VOC emissions from tanker loading operations in Scenarios 2 and 3, which would not occur in Scenario 1.

Emissions of all non-VOC pollutants would be well below the DOI exemption levels for each platform, and in most cases would even be below the more stringent proposed California levels. While it is true that the Santa Maria Zone emissions would be the highest of the Lease Sale No. 53 zones, it should be noted that the DOI regulations apply on a facility-specific basis and that there would be thirteen production facilities over which the zone-wide emissions would occur. Therefore, the non-VOC emissions per facility in this zone would not be as high as may be expected, and do not appear to be affected by 1)01 regulations.

The estimated emission reduction requirements presented in Table IX-14 could be obtained through a number of mitigation measures. (See Chapter VII for a detailed discussion of emission control measures.) The installation of vapor recovery systems on the OS&Ts (where tanker loading physically occurs) could reduce loading VOC emissions by up to 90 percent. A vapor recovery system and proper operation and maintenance procedures could result in gas processing emission reductions of up to 95 percent. Good housekeeping on the platforms and a dedicated maintenance program on valves, wastewater separators, and other sources of fugitive VOCS could reduce evaporative losses by up to 75 percent.

As discussed earlier (see Section V.B.1), most operators of offshore platforms are conscientious in their maintenance and housekeeping operations due to spatial and safety constraints. Because of this, it is probable that the original estimate of VOC emissions associated with fugitive losses and gas processing could be overstated. Therefore, in assessing the total zone-wide VOC emission reductions, it was assumed that the necessary reductions presented in Table IX-14 would be obtained in reductions of evaporative losses and gas processing emissions. These reductions would be applied uniformly to the estimated uncontrolled emissions.

Table IX-15 presents the revised emission inventory for the Santa Maria Zone. Only the VOC emissions required reductions from the levels presented in Table IX-12. However, a reduction in hydrogen sulfide emissions would also occur when evaporative losses in gas processing are reduced. Emissions associated with support activity and tanker transit have not been changed since the DOI regulations do not specifically deal with emissions from mobile sources.

D. References

California Air Resources Board. 1979. Proposed Strategy for the Control of Oxides of Nitrogen Emissions from Stationary Internal Combustion Engines.

Energy Resource Co., Inc. 1977. Atmospheric Emissions from Offshore Oil and Gas Development and Production. Prepared for the U.S. Environmental Protection Agency. EPA-450/3-77-026

Radian Corporation. 1978. Control Techniques for Volatile Organic Emissions from Stationary Sources. Prepared for the U.S. Environmental Protection Agency. EPA-450/2-78-022.

United States Geological Survey (USGS). 1978. Data Requested by the Bureau of Land Management for Preparation of the Draft Environmental Impact Statement for OCS Sale No. 53 Offshore Northern and Central California.

X. REVISED AIR QUALITY IMPACTS

A. Introduction

Based on the new DOI regulations discussed in depth in Chapter VIII and the resulting revised emission inventories developed in Chapter IX, a selected number of the initially-modeled cases have been reanalyzed to determine the effect the DOI regulations would have upon predicted onshore air pollutant concentration increases resulting from projected Lease Sale No. 53 OCS activities. This chapter presents these revised impact estimates. Also included in this chapter is a description of the revised emission data which served as modeling inputs and the methodology used to determine revised onshore impacts.

B. Approach

1. Identification of Cases to be Remodeled

Chapter IX (Revised Emission Inventories) identified the initially-modeled cases in which emissions would be changed pursuant to DOI's recently published OCS air quality regulations. To determine the effect these emission revisions would have on the previously predicted onshore concentration increments resulting from Lease Sale No. 53 OCS projected emissions (see Chapter VI), a number of initially-modeled cases were remodeled. Since the time and resources available for the determination of revised air quality impacts did not permit a complete remodeling of each zone's emissions, only some of the initially-modeled cases were selected for remodeling.

The cases selected for inert pollutant remodeling were those which had manifested the highest onshore impacts during the initial modeling effort, and thereby afforded the best opportunity to assess the impact-reducing effects for inert pollutants of DOI's final national OCS air quality regulations. The cases chosen for long-term (annual) inert remodeling include the revised NO_x emissions associated with platform installation in the Eel River and Bodega zones, SO_x emissions associated with production activity in the Eel River zone, and the NO_x emissions associated with combined production and installation operations in the Santa Maria zone.

Short-term NO_x impacts which would result from platform installation in the Eel River, Bodega, and Santa Maria zones were also remodeled. It should be noted that the validity of short-term modeling results is highly uncertain (see Chapter VI, p. VI-27 for a full discussion of short-term modeling), and for this reason short-term results are given relatively little attention in this study. However, a comparison of the initial and revised short-term modeling results does provide an indication of the impact-reducing effects of DOI's regulations.

The Santa Maria zone was selected as the single reactive pollutant case to be remodeled. Onshore areas which might experience air quality impacts as a result of OCS development in this zone are currently meeting ambient air quality standards for ozone by only a narrow margin; any small increase in onshore ozone levels could cause a violation of these standards. In addition, onshore ozone increments resulting from development of the Santa Maria zone were among the highest predicted by the initial modeling (see Chapter VI.C.6). Hence, remodeling of this zone provided an excellent opportunity to assess for the effect of DOI's air quality regulations on reactive pollutants.

The results of the remodeling are presented zone-by-zone in Section X.C, below.

2. Revision of Emission Input Data

The revised emissions used as inputs for modeling were based on the revised emission inventories presented in Chapter IX and the modeling assumptions described in Chapter VI (see Sections VI.A.2 and VI.C.3). To the maximum feasible extent, the assumptions employed in the revision of modeling inputs and for the modeling itself, are consistent with those used during the initial modeling effort described in Chapter VI. This approach ensures that the revised modeling results will reflect changes which are due to the DOI regulations rather than shifts in modeling or emission inventory approaches.

The initial modeling done for the Eel River and Bodega zones assumed as a worst case that all emissions would occur from a single point source. Therefore, to more accurately assess the effect of the DOI regulations and to minimize the effect modeling assumptions would have on the comparative results, the worst case assumption of a single point source was retained in the remodeling. Table X-1 presents the NO_x and SO_x emissions used for long-term remodeling in the Eel River and Bodega zones. Although the emissions are presented as a single value, it should be noted that the pollutants are actually emitted from a variety of sources. Table X-1 can be compared to Tables C-33 and C-35 which present the emission inputs used for the initial modeling effort.

Table X-2 presents the NO_x emissions utilized for inert long-term remodeling purposes in the Santa Maria zone. The same point and area sources which were assumed for the initial modeling were retained in this study to minimize the effect of modeling assumptions on the results. Table X-2 can be compared to Table C-37 which presents the emission inputs for the initial modeling.

Table X-3 presents the NO_x emissions utilized for short-term inert remodeling of the Eel River and Santa Maria zones' emissions. The values in Table X-3 can be compared with the initial short-term modeling inputs which are presented in Table VI-3.

In addition to some remodeling of inert pollutants, reactive modeling was also redone for the Santa Maria zone. Table X-4 presents the revised pollutant emissions used for this remodeling effort and can be compared with Table C-21 which presents the initial reactive modeling inputs for the Santa Maria zone.

Table X-1. NITROGEN OXIDE AND SULFUR OXIDE EMISSIONS USED TO ESTIMATE REVISED LONG-TERM (ANNUAL) IMPACTS IN THE EEL RIVER AND BODEGA ZONES [1]

Zone	Pollutant	Emissions tons/year	Emissions grams/second
Eel River	Nitrogen Oxides	345	9.9
	Sulfur Oxides	203	5.8
Bodega2	Nitrogen Oxides	692	19.9

1. Based on revised emission estimates presented in Chapter IX.

2. See Section X.C for discussion of Bodega modeling.

Table X-2. REVISED LONG-TERM (ANNUAL) NO_x MODELING EMISSIONS--SANTA MARIA ZONE [1]

POINT SOURCES[2]		EMISSIONS (grams/second)
1	Production Platform	1.74
2	Platform with Drilling	2.1
3	Production Platform	1.74
4	OS&T with Tanker	5.2
5	Production Platform	1.74
6	Gas Processing Platform	2.67
7	Platform with Drilling	2.1
8	Platform with Drilling	2.1
9	Production Platform	1.74
10	OS&T	4.3
11	Platform with Drilling	2.1
12	Production Platform	1.74
13	Floating Production System	5*0
AREA SOURCES[2]		
A		4.10
B		4.10
C		7.30
D		16.41

1. Based on emission reductions discussed in Chapter IX and initial modeling inputs presented in Table C-37.

2. Numerical and alphabetical notations (1, 2, A, B, etc.) refer to symbols in Figure VI-4.

Table X-3. REVISED SHORT-TERM NO_x MODELING EMISSION INPUTS IN THE SANTA MARIA AND EEL RIVER ZONES[1]

Zone	Revised Emissions[2] (lbs/hour)
Eel River	109
Santa Maria	144

1. See Table VI-3 for initial short-term emission inputs.

2. Based on revision of emissions associated with platform installation as presented in Tables IX-2 and IX-11.

Table X-4. MAXIMUM HOURLY REVISED POLLUTANT EMISSIONS – MARIA ZONE[1]

SOURCE/ACTIVITY	TYPE[2]	Emissions (lbs/hour) SCENARIO 1 VOC	SCENARIO 1 NO_x	SCENARIO 1A VOC	SCENARIO 1A NO_x	SCENARIO 2 VOC	SCENARIO 2 NO_x	SCENARIO 3 VOC	SCENARIO 3 NO_x
1. Production Platform (without drilling)[3]	L								
Power Generation		1	14	1	2	1	14	1	14
Evaporative Losses		9	--	10		9	--	9	--
2. Production Platform (with drilling)[3]	S								
Development Drilling		0	6	0.5	6	0.5	6	0.5	6
Power Generation		1	14	1	12	1	14	1	14
Evaporative Losses		8		10	--	5	--	5	--
3. Production Platform (without drilling)[3]									
Power Generation		1	14	1	12	1	14	1	14
Evaporative Losses		5	--	0	--	3	--	3	--
4. OS&T[3,4]	S								
Power Generation		3	30	--	--	2	12	1	12
Evaporative Losses		32	--	--	--	26	--	26	--
Oil Processing		0.3	3	--	--	0.3	3	0.3	3
Gas Processing		84	--	--	--	71	--	71	--
Tanker Loading		--	--	--	--	759	--	759	--
5. Production Platforms (without drilling)[3]	S								
Power Generation		1	14	1	12	1	14	1	14
Evaporative Losses		9	--	0	--	7	--	7	
6. Gas Processing Platforms[3,4]	S								
Power Generation		2	20	--	--	2	20	2	20
Evaporative Losses		12	--	--	--	10	--	10	--
Gas Processing		168	0.2	--	--	141	0.2	41	0.2

Table X-4 (continued)

SOURCE/ACTIVITY	TYPE[2]	Emissions (lbs/hour)							
		SCENARIO 1		SCENARIO 1A		SCENARIO 2		SCENARIO 3	
		VOC	NO_x	VOC	NO_x	VOC	NO_x	VOC	NO_x
7. Production Platform (without drilling)[3]	S								
Power Generation		1	'4	1	12	1	14	1	14
Evaporative Losses		9	1–	0	--	6.C	--	6	--
8. Production Platform (with drilling)	S								
Development Drilling		0.5	6	0.5	6	0.5	6	0.5	6
Power Generation		1	14	1	12	1	'4	1	14
Evaporative Losses		9	--	0		9	--	9	--
9. Production Platform (withouout drilling)	S								
Power Generation		1	14	'	12	1	' :	1	14
Evaporative Losses		9	--	o	--	9	1-	9	--
10. OS&T[3,4]	S								
Power Generation		3	30	-	--	1	'2	1	12
Evaporative Losses		32	--			26	1–	26	--
Oil Processing		0.3	3	--	--	0.3	--	0.3	--
Gas Processing		84	--	--	--	71	--	71	
11. Production Platform (without drilling)[3]	S								
Power Generation		1	14	1	12	1	'4	1	14
Evaporative Losses		6	--	10	--	4	1–	4	
12. Production Platform (without drilling)[3]	S								
Power Generation		1	14	r	'2	1	'4	'	'4
Evaporative Losses		7	--	10	--	4	1–	^	1–
13. Floating Production System (without drilling)	S								
Power Generation		1	14	2	41	1	14	1	4
Evaporative Losses		9	--	41	--	9	--	9	

Table X-4 (continued)

SOURCE/ACTIVITY	TYPE[2]	Emissions (lbs/hour) SCENARIO 1 VOC	SCENARIO 1 NO_x	SCENARIO 1A Voc	SCENARIO 1A NO_x	SCENARIO 2 Voc	SCENARIO 2 NO_x	SCENARIO 3 VOC	SCENARIO 3 NO_x
14. Onshore Oil/Gas Processing plant [5]	S								
Oil Processing		--	--	0.5	7	--	--	--	--
Gas Processing		--	--	370	--	--	--	--	--
Gas Compression		--	--	--	50	--	--	--	--
15. Floating Production System (with drilling)	S								
Development Drilling		0.5	6	0.5	6	0.5	6	'0.5	6
Power Generation "		1	14	--	41	1	14	1	14
Evaporative Leases		9	--	41		9	..	9	--
16. Production Platform (without drilling)[3]	S								
Power Generation		1	14	1	14	1	14	1	14
Evaporative Losses		9	--	10	--	7	--	7	--
17. Production Platform (without drilling)	S								
Power Generation		1	14	1	14	1	14	1	14
Evaporative Losses		9	--	10	--	9	--	9	--
18. Subsea Pipeline	L								
Evaporative Losses		63	--	63	--	31	--	31	
19. Onshore Storage Tanks	S								
Evaporative Losses		--	--	2	--	--	--	--	--
20. Support Activities									
Supply Boats									
In Transit	L	4	189	4	189	4	189	4	189
At Platform	S	4	189	4	189	4	189	4	189
Crew Boats[8]									
In Transit	L	0.5	23	0.5	23	0.5	23	0.5	23
At Platform	S	0.5	23	0.5	23	0.5	23	0.5	23

Table x-4 (continued)

1. Platform number refers to numbers in Figure IX-2.
2. The type of emission source refers to stationary (S) or line (L) sources.
3. Emission reductions due" to implementation of D(3L regulations have been applied.
4. OS&TS and gaa processing platform would not exist in Scenario 1A due to existence of onshore oil/gas processing plant.
5. Storage tanks and onshore oil/gas processing plant would exist only in Scenario 1A. The processing plant would be located approximately Lwo miles inland.
6. In Scenarios 1 and 1A there would be two 16 mile subsea pipelines. In Scenarios 2 and 3 there would he one 16 mile pipeline.
7. Assumes 6 boats at platforms for 30 minutes and in transit for 30 minutes.
8. Assumes 4 boats at platforms for 30 minutes and in transit for 30 minutes.

c. Remodeling Results

A summary of the revised maximum onshore impacts is presented in Table X-5. Because of the simplified modeling assumptions utilized in the original impact analysis, it was not necessary to completely remodel every case. For example, due to the single point source (worst-case) assumption used in the Bodega and Eel River zones, a linear rollback technique based on the revised inputs was utilized. On the other hand, both inert and photochemical impacts were remodeled for the Santa Maria zone using the revised emission inputs.

An evaluation of Table X-5 permits the results stated in Chapter VI to be readily compared to the onshore impacts predicted when offshore OCS Lease Sale No. 53 development is conducted in compliance with the DOI regulations. A discussion of these results for each zone is presented in the following paragraphs.

1. Eel River

It should be first recognized that the initial modeling, utilizing the overly conservative assumption that all emission sources would be located at a single point three miles offshore, would result in an overestimate of the onshore air quality impact. In fact, the onshore impact from NO_x emissions, primarily associated with temporary construction activities, was predicted to exceed the DOI significance levels by a factor of three. The DOI regulations require a potential onshore impact of this magnitude to be mitigated by the installation of BACT on the temporary sources. As discussed in the preceding chapter (see Section IX.C.1), the use of BACT in this zone could reduce the maximum annual NO_x emissions from 717 tons to 345 tons in 1985. Repeating the Climatological Dispersion Model (CDM) run with the emissions input reduced appropriately, as shown in Table X-4, the maximum onshore impact would be reduced by about 50 percent to 1.4 $\mu g/m^3$ of NO_2. Again, even though this is above the significance level, the model is conservative and overpredicts onshore concentrations. However, the modeling results suggest that even with BACT on the temporary sources, it might be possible for the onshore area adjacent to Eel River to detect an increase in the ambient NO_x concentrations resulting from platform and pipeline installation activity emissions.

Short-term NO_x impacts arising from platform installation were remodeled using the PTMTP model (the PTMTP model is described in Section VI.B). The revised maximum one-hour NO_2 concentration is 112 $\mu g/m^3$, less than 50 percent of the initial value, but well above DOI's proposed California one-hour NO_2 significance level of 10 $\mu g/m^3$. As discussed in Section X.B.1, it should be noted that there is considerable uncertainty in short-term concentrations estimated with the PTMTP model.

The annually averaged onshore SO_2 concentration was also initially predicted to exceed the DOI significance level in 1987, the year of maximum production. The emissions which would cause this increased concentration level could be reduced by over 60 percent if gas were substituted for diesel fuel in the offshore power generators. The onshore SO_2 concentration would likewise be reduced by over 60 percent to not more than 0.43 $\mu g/m^3$, well below the DOI significance level.

Table X-5. SUMMARY OF REVISIONS OF INERT ONSHORE IMPACTS RESULTING FROM LEASE SALE NO. 53 OCS ACTIVITIES

	Onshore Impacts, µg/m³					
	Initial Modeling			Revised Modeling[1]		
	NO_2	NO_2	SO_2	NO_2	NO_2	SO_2
Zone	One-hour[2]	Annual[3]	Annual	One-hour	Annual	Annual
Eel River	248	2.9	1.1	112	1.4	0.43
Point Arena[4]	283	0.87	1.1	283	0.87	1.1
Bodega	200	4.4	0.35	40	0.5	0.35
Santa Cruz[4]	283	1.0	0.15	283	1.0	0.15
Santa Maria	283	1.5	0.7	148	1.0	0.7

1. Based on revised modeling inputs discussed in Section X.B.
2. See Table VI-3 for complete table of initial one-hour modeling results.
3. See Table VI-1 for complete table of initial annual model results.
4. No revisions occurred in these zones.

In short, DOI's regulations reduce projected onshore maximum annual SO_2 and NO_2 impacts by roughly 50 percent.

2. Point Arena

The initial modeling work examined the cumulative onshore impact of three platforms and an OS&T operating in this zone. As in the Eel River zone modeling, the overly conservative assumption of all sources being located at a single point three miles offshore was used to estimate worst-case onshore air quality impacts. Since the DOI air quality review is to be performed on a facility-specific basis, it was necessary to determine what emissions from each platform could be expected to contribute to onshore impacts. The only problem originally identified was the long-term (annual) increase in SO_2 levels onshore: the DOI significance level was predicted to be exceeded by up to 10 percent. Evaluating the stationary source emissions from each platform indicated that individually the onshore impact would be only on the order of 0.2 $\mu g/m^3$. Thus, by considering the onshore impact of emissions from sources subject to the DOI regulations, it was found that no offshore installation in the Point Arena zone would have a significant impact on the onshore air quality. Therefore, DOI's final regulations do not alter the initially projected impacts from OCS development in this zone.

3. Bodega

The initial CDM and PTMTP modeling assumed that all emissions occurred three miles offshore--the same conservative approach which was discussed for the Eel River and Point Arena zones. However, the Bodega zone is physically no closer to land than 15 miles. Therefore, the models were rerun to alter this particular input. At 15 miles offshore, even the conservative worst-case approach of assuming all emissions emanating from a single point resulted in no adverse long-term impacts on onshore air quality. Thus, the maximum long-term onshore impact from NO_x emissions is predicted to be 0.5 $\mu g/m^3$. Although it was not modeled, the maximum annual onshore impact from SO_x emissions would be reduced by an equal amount to approximately 0.04 $\mu g/m^3$. (Such a small increase could probably not be distinguished by routine ambient monitoring programs.) Modeled short-term NO_2 concentrations were reduced to 40 $\mu g/m^3$.

Significant onshore NO_2 and SO_2 impacts are not likely to result from development of this zone, primarily because of its distance (15 miles) from the nearest onshore area.

4. Santa Cruz

"The initial modeling indicated there would be no significant (long-term) onshore impacts from inert pollutant emissions. No additional modeling was performed, since under DOI's regulations mitigation (i.e., reductions in emission rates) is required only in the event of significant impacts.

5* Santa Maria

a. Inert Pollutant Modeling

The initial modeling effort to determine the onshore impacts of inert pollutant emissions examined the cumulative impact of the projected development throughout the zone. The overall onshore impact from NO_x emitted by the installation of two platforms, the operation of six production platforms, two OS&Ts and a gas processing platform was 1.5 $\mu g/m^3$--in excess of the DOI significance level.

However, the DOI regulations require that each offshore facility be evaluated separately. Therefore, NO_x emissions from the installation of one platform were calculated and used as input for the modeling of the maximum annual impacts. Using the same conservative, worst-case assumptions which were applied in the Eel River, Point Arena and Bodega zones, the onshore impact was estimated to be 4.2 $\mu g/m^3$, well above DOI's significance level of 1 $\mu g/m^3$. Because of the magnitude of this predicted impact and the possibility of a significant cumulative effect onshore, platform installation emissions were remodeled using a more realistic approach. By changing the assumption about the location of point sources from a single site three miles offshore to a combination of stationary sources and mobile sources (which could move three to four miles about a platform), the CDM modeling results indicated the maximum onshore impact would be decreased to 1.4 $\mu g/m^3$. Because this is still a significant impact, BACT would be necessary for the temporary construction-related sources. A final modeling run using emission rates expected from temporary sources operating with BACT (in compliance with the DOI regulations) along with the emissions initially predicted to occur from production activity in the zone indicated that the onshore impact from NO_x emissions could be reduced to 1.0 $\mu g/m^3$, which would equal the DOI significance level.

The remodeling of one-hour NO_x impacts with PTMTP showed a considerable reduction over the initial modeling results: maximum predicted one-hour onshore NO_2 concentrations decreased from 283 $\mu g/m^3$ to 148 $\mu g/m^3$. Again, it should be noted the results of short-term modeling are highly uncertain.

b. Photochemical Modeling

In the initial Reactive Air Pollutant Transport (RAPT) modeling analysis, the impact of ozone production along four trajectories from the OCS production area to onshore areas was estimated. A summary of the results is presented in Table VI-6 and explanatory text begins on page VI-47. The projected future baseline ozone concentrations at Nipomo, Santa Maria and Santa Ynez were all predicted to exceed either state or federal ambient air quality standards. The initial modeling showed that proposed development could exacerbate these air quality violations by contributing up to 2 pphm (parts per hundred million) of additional ozone.

It was assumed for the purpose of remodeling VOC (VOCs are a precursor for ozone) emissions in the Santa Maria zone that OCS operators would choose to comply with DOI's regulations by installing sufficient VOC emission control equipment to ensure emission rates below the emission exemption levels. This appears to be a reasonable means by which OCS lessees could comply with DOI's regulations. In addition, this approach provides a conservatively high estimate of VOC emissions since the emission exemption level is the highest emission rate permitted under DOI's regulations, A comparison of the revised modeling inputs presented in Table X-4 with the initial modeling inputs presented in Table C-21 shows that the emission reductions (due to DOI's final OCS air quality regulations) are on the order of 10 percent.

The RAPT model which was used for this study is subject to numerous constraints including the fact that it is not particularly sensitive to small changes in emission inputs (see Section VI.C.5). In order to test the ability of the RAPT model to quantify changes in ozone concentration resulting from rather small changes in emissions, an across-the-board 15 percent reduction in emission rates was assumed as input for a rerun of the RAPT model. (This 15 percent reduction is greater than the overall reductions which were developed in the revised emission inventories for the Santa Maria zone.) The results showed only a very slight change in the projected ozone levels. Thus, within the limitations of this model, the onshore areas of Nipomo, Santa Maria and Santa Ynez can still be predicted to be affected by ozone increases of up to 2 pphm due to emissions from development in the Santa Maria zone, even though all operations would be performed in compliance with the DOI regulations. However, it should be noted that under such circumstances the cumulative impact provision of DOI's regulations might be invoked, and this action might result in further emission controls fo-r OCS activities in the Santa Maria zone.

D. Summary of Impacts

The CDM was again used (as in Chapter VI) to estimate annually-averaged concentrations of NO_2 and SO_2 which might be expected from development conducted, in full compliance 'with the final DOI regulations, pursuant to OCS Lease Sale No. 53. Using worst-case assumptions, offshore emission sources should not lead to the violation of any annual ambient air quality standards onshore. In the Eel River and Santa Maria zones, onshore concentration increments of N02 from temporary activities ["temporary activities*' would appear to include barges and tugboats, but not crew or supply boats (see Section VIII.B.2)] offshore could marginally exceed the DOI significance levels even if facilities were operating with BACT in place. SO_x emissions in the Eel River zone could be reduced by switching from diesel fuel to gas which would eliminate the risk of any adverse impact occuring onshore. No offshore site in any other zone would be expected to generate sufficient SO_x to require that mitigation measures be implemented.

The RAPT model was used to simulate ozone and N02 production from potential emissions of VOCS and NO_x in the Santa Maria zone. The amount of NO_x and VOC emission reductions projected to result from implementation of the DOI regulations is not large enough to produce any measurable change in the modeling results. Thus, the onshore impact of photochemical oxidants generated as a result of OCS activities in the Santa Maria zone would be the same as originally described in Chapter VI--an onshore increase of up to 2 pphm. However, if further emission controls were required pursuant to the cumulative impact provision in DOI's regulations, this impact might be reduced.

XI. SUMMARY OF KEY REVISED RESULTS

A. Introduction

In Chapter V, the estimated emissions resulting from projected Lease Sale No. 53 OCS oil and gas development and production were developed. These emissions, based on United States Geological Survey resource estimates and transportation scenarios developed by the Bureau of Land Management, were estimated utilizing the best available emission factors. No consideration, however, was given to the possible mitigating effects of the Department of the Interiorts (DOI) air quality regulations which had not yet been published in their final form. The potential onshore impacts of these "uncontrolled"' emissions were estimated through computer modeling, and the results were presented in Chapter VI.

The main purpose of this supplementary study was to assess the degree of impact reduction afforded by DOI's final OCS air quality regulations which were published after the completion of the initial study. To complete this assignment, three tasks were performed:

(1) A thorough review and summarization of DOI's final regulations;

(2) Recalculation of peak annual emissions for each of the five proposed lease tract zones, incorporating mitigation mandated by DOI's new regulations; and

(3) Remodeling of selected cases to determine incremental onshore impacts with the DOI regulations in force.

This summary chapter is divided into two main parts: Section XI.B briefly characterizes DOI's final OCS air quality regulations; and Section XI.C provides a zone-by-zone summary of the changes in emissions and onshore impacts which are projected to result from implementation of DOI's regulations.

Finally, a comment made in the introduction of the initial study is valid. Studies of this type are necessarily characterized by uncertainties, approximations and a large number of assumptions. Therefore, the data provided and developed in this analysis should be taken to show relative magnitudes and distributions rather than exact determinations of peak emissions and impacts.

B. Summary of Revised Regulatory Considerations

DOI has established a three-step OCS air quality regulatory scheme which is depicted in Figure VIII-1. The first step is a comparison of a proposed facility's projected emissions with DOI's "emission exemption levels" which are generally a linear function of distance from the shore--at three miles the exemption level is 100 tons per year, at six miles it is 200 tons per year. Facilities with projected emissions of any air pollutant [i.e., sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_x), total suspended particulate: (TSP), or volatile organic compounds (VOC)] below the relevant emission exemption level are exempt from further regulatory review.

The second step of DOI's regulations applies only to facilities with emissions above the exemption levels. Such facilities must model their projected non-VOC emissions with a DOI-approved air quality simulation model to determine whether the emissions would cause significant onshore impacts; VOC impacts are significant if they exceed the emission exemption level. Onshore impacts are deemed "significant" if they exceed the DOI significance levels presented in Table VIII-1. For example, the annually averaged NO_2 significance level is 1 $\mu g/m^3$. Hence, if modeling of a proposed facility's emissions resulted in an annually-averaged onshore N02 concentration of 2 $\mu g/m^3$, the impact would be considered significant.

The third and final step of DOI's regulations requires mitigation of significant onshore impacts. Pollutants impacting attainment areas (i.e., areas currently meeting federal ambient air quality standards) would have to be controlled with the Best Available Control Technology (BACT). Pollutants impacting nonattainment areas would also have to be controlled with BACT, and additional controls and/or offsets as needed to '*fully reduce" projected emissions.

DOI's regulations are to be applied on a facility-specific basis--each proposed facility is to be reviewed individually to determine whether it would cause significant onshore impacts. However, since a number of proximate facilities might on occasion cause significant impacts, even though none of the individual facilities alone would cause such impacts, the regulations also provide that additional emission controls might be required to prevent significant cumulative impacts.

Lastly, DOI has published proposed California air quality regulations, which if implemented would be applicable only offshore California. The se proposed regulations are identical to the national regulations except that they include somewhat more stringent emission exemption levels and significance levels.

c. Summary of Revised Impacts

Table XI-1 is a tabular presentation of the major results of both the initial and revised Lease Sale No. 53 air quality analyses. It is structured to facilitate comparison of maximum offshore emissions and related maximum onshore impacts which would occur with and without implementation of DOI's regulations. This section presents a zone-by-zone discussion of the results shown in Table XI-1.

1. Eel River

The uncontrolled emissions of three pollutants, VOC, SO_x and NO_x, would require reductions from the original quantities predicted in Chapter V as a result of the DOI regulations. VOC emissions which were originally estimated at 1,126 tons per year in 1987 would be lowered, per the DOI regulations, to 202 tons per year. (An interesting side benefit of this reduction would be an H2S reduction from 24 to 2 tons per year.) Uncontrolled NO_x emissions which were predicted to reach a level of 714 tons per year, due to

TABLE XI-1. SUMMARY OF EMISSIONS AND ONSHORE IMPACTS WHICH COULD OCCUR AS A RESULT OF OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT AND PRODUCTION - MEAN RESOURCE ESTIMATE

Zone	Pollutant	Maximum Offshore Emissions (tons/year) Year[2]	Scenario[3]	Initial[4]	Revised[5]	Maximum onshore Impacts[1] Initial[4] ($\mu g/m^3$)	Revised[5] ($\mu g/m^3$)	Averaging Period
Eel River								
	Voc	1987	1,2,3	1,126	202	3(6	NM(7	1 hour
	NO_x	1985	1,2,3	714	342	2.9	1.4	Annual
	SO_x	1'387	1,2,3	273	108	1.1	0.43	Annual
	CO	1987	1,2,3	118	118	-- NM(8	--	
	TSP	1985	1,2,3	35	35	0.14	0.14	Annual
	H_2S	1987	1,2,3	24	2	-- NM(8	--	
Point Arena								
	Voc	1989	1,2	1,460	372	3(6	NM(7	1 hour
	NO_x	1989	1,2	1,295	1,295	0.87	0.87	Annual
	SO_x	1989	1,2	660	660	1.1	1.1	Annual
	CO	1989	1,2,3	213	213	-- NM(8	--	
	TSP	1989	1,2,3	92	92	0.13	0.13	Annual
	H_2S	1989	1,2,3	22	2	-- NM(8	--	
Bodega(9								
	Voc	1987	1,2	181	181	2(6	NM	1 hour
	NO_x	1985	1,2,3	729	729	4.4	0.5	Annual
	SO_x	1987	3	66	66	0.35	Neg.	Annual
	CO	1985	1,2,3	117	117	-- NM(8	--	
	TSP	1985	1,2,3	35	35	0.23	Neg.	Annual
	H_2S		--	--	--	-- NM(8	--	

TABLE XI-1 (continued)

Zone	Pollutant	Maximum Offshore Emissions (tons/year) Year[2]	Scenario[3]	Initial[4]	Revised[5]	Maximum Onshore Impacts[1] ($\mu g/m^3$) Initial[4]	Revised[5]	Averaging Period
Santa Cruz								
	VOC	1990	2	1,534	926	1[6]	NM[7]	1 hour
	NO_x	1988	2	1,313	1,313	1.0	1.0	Annual
	SO_x	1990	3	306	306	0.15	0.15	Annual
	CO	1988	1	218	218	-- NM[8]	--	
	TSP	1988	1,2,3	67	67	0.07	0.07	Annual
	H_2S	1990	1,2,3	17'	2	-- NM[8]	--	
Santa Maria								
	VOC	1991	2	3,675	3,096	2[6]	2	1 hour
	NO_x	1989	1	3,662	2,968	1.5	1.0	Annual
	SO_x	1991	2	1,610	1,610	0.7	0.7	Annual
	CO	1989	2	579	579	-- NM[8]	—	
	TSP	1989	2	244	244	0.10	0.10	Annual
	H_2S	1991	1,2,3	57	44	-- NM[8]	--	

1. Refers to maximum impacts predicted in Chapters XI and X. Only the incremental increases are presented. SO_x and NO_x impacts are calculated as SO_2 and NO_2, respectively.

2. Refers to year in which maximum emissions were predicted to occur (see Chapter V).

3. Refers to BLM Transportation Scenario which would result in maximum offshore emissions. Generally, differences between scenarios are not significant. See Section V.B.2 for full description of transportation scenarios.

4. "Initial" refers to emissions and onshore impacts presented in Chapters V and VI, respectively.

TABLE XI-1 (continued)

5. "Revised" refers to emissions and onshore impacts which would occur after the implementation of mitigation measures mandated by the 001 regulations as developed in Chapters IX and X, respectively. In some cases emissions and impacts which would occur after implementation of the DOI rules would be the same as those originally estimated.

6. Refers to maximum ozone concentration increments (in pphm) predicted to occur from offshore activities (see Chapter VI).

7. These trajectories were not remodeled. However, due to the significant reduction in VOC emissions, it is expected that the associated onshore ozone impacts would be similarly reduced.

8. These pollutants were not modeled in either the original study or in the supplemental analysis because of high significance level of CO (500 $\mu g/m^3$), the lack of a significance level for H_2S, and the relatively low level of expected emissions of both pollutants.

9. Emission levels estimated for the Bodega Zone would remain the same as predicted in Chapter V. However, because the original modeling in Chapter VI assumed emissions to occur three miles from shore when actually the zone lies no less than 15 miles offshore, the revised impacts which assume emissions from a point 15 miles offshore are lower than the initial impact estimates.

10. This trajectory was remodeled assuming an overall reduction in VOC emissions of 15 percent (see Chapter X). The sensitivity of RAPT, however, was below the level required to determine if a change in onshore ozone impacts would occur.

the activity associated with platform and pipeline installation in 1985, would be reduced to 342 tons per year. Emissions of sulfur oxides would be lowered to 108 tons in 1987, down from 273 tons in the same year.

Accordingly, the onshore impacts of the three pollutants would be lessened. Although no additional photochemical modeling was done to determine the revised maximum ozone (03) onshore increment (see Section X.B.L), it is expected that the more than 80 percent reduction in VOC emissions would substantially reduce the initially predicted onshore 03 increment of 3 pphm. The maximum annual NO_2 impact would be reduced by over 50 percent, from 2.9 $\mu g/m^3$ to 1.4 $\mu g/m^3$. Although the revised increment is still greater than the DOI significance level of 1 $\mu g/m^3$, it should be noted that it is only a temporary impact and in other years the annual NO_2 average increment would be considerably less. The SO_2 annual concentration increase would be reduced from 1.1 $\mu g/m^3$ to 0.43 $\mu g/m^3$, which is less than half of the DOI significance level.

Emissions of TSP and CO would remain the same as initially estimated and would have minimal onshore impact.

2. Point Arena

Although only VOC emissions would require reductions because of the DOI regulations, emissions of H_2S would also be reduced. This would be due to a decrease in emissions of untreated natural gas which would contain the H2S. The maximum 1989 level of VOC emissions would be reduced from 1,460 tons to 372 tons. This would likely result in a reduction of the originally predicted maximum onshore 03 impact of 3 pphm, although it was not remodeled. H2S emissions would be reduced from 22 to 2 tons in 1989 and would have only a minimal onshore impact at worst.

Emissions and onshore impacts of other pollutants (NO_x, SO_x, CO, TSP) would remain the same as originally estimated. Maximum NO_x emissions of 1,295 tons would result in an annual onshore N02 concentration increase of 0.87 $\mu g/m^3$ in 1989. SO_x emissions in 1989 would remain at 660 tons and could cause an onshore $S0_2$ impact of 1.1 $\mu g/m^3$. Although this increment is greater than the DOI significance level of 1 $\mu g/m^3$, no revision of the predicted emissions occurred, because predicted SO_x emissions from each individual facility would be below the DOI exemption level. However, if the cumulative impact provision of DOI's regulations were invoked, (see Chapter VIII), additional SO_x emissions controls might be required. CO emissions would remain at 213 tons in 1989, and would not cause significant onshore impacts. No CO modeling was done due to the relatively large significance level (500 $\mu g/m^3$ over 8 hours). TSP emissions of 92 tons in 1989 would result in an annual increase of 0.13 $\mu g/m^3$, about 15 percent of the DOI significance level.

3. Bodega

No revisions of Lease Sale No. 53 associated emissions were required in the Bodega zone. Even so, the predicted onshore impacts have been revised. The original modeling assumed, as a worst-case, that all emissions would occur at three miles from shore. However, because the zone is actually 15 miles from shore, the onshore concentration increments have been reduced accordingly.

It is expected that onshore impacts of all pollutants would be insignificant. Although the exact reduction in onshore O_3 concentrations was not calculated, it is expected that a substantial decrease from the 2 pphm value originally predicted would occur. The onshore annual impacts of NO_2 due to the peak emission of 729 tons in 1985 would be reduced from 4.4 $\mu g/m^3$ to 0.5 $\mu g/m^3$. Onshore concentrations of other pollutants (SO_x, CO, TSP) would be practically negligible.

4. Santa Cruz

Reductions of VOC emissions from 1,534 to 920 tons in 1990 would be required in order to comply with DOI's regulations. This would also result in a reduction of H_2S emissions from 17 to 2 tons in the same year. Because of the greater than 40 percent reduction in VOC emissions, it is expected that the original prediction of maximum onshore increase in O_3 of 1 pphm would be significantly reduced.

The emissions and impacts of all other pollutants (NO_x, SO_x, CO, TSP) would remain the same as originally estimated. NO_x emissions of 1,313 tons in 1988 could result in a maximum annual onshore NO_2 increase of 1.0 $\mu g/m^3$, a value that equals the DOI significance level. Maximum SO_x emissions of 660 tons in 1990 could cause an onshore SO_2 concentration increase of 0.15 $\mu g/m^3$; TSP emissions of 67 tons in 1988 could result in a minimal increase of 0.07 $\mu g/m^3$ to existing onshore concentrations.

5. Santa Maria

VOC emissions associated with production and processing activities in 1991 and NO_x emissions associated with platform installation in 1989 would require reductions in order to comply with the DOI regulations. VOCs, which were originally predicted to be emitted at a level of 3,675 tons in 1991 would be reduced to 3,096 tons due to DOI's regulations. Additional photochemical modeling indicated that this reduction is below the sensitivity of the model, and a precise change in onshore O_3 concentrations could not be determined. It is expected, however, that a minimal reduction of the maximum predicted one-hour O_3 impact of 2 pphm would occur. The VOC emission reduction would also result in an associated H_2S reduction from 57 to 44 tons in 1991. NO_x emissions, originally estimated at 3,662 tons in 1989, would drop to 2,968 tons due to the application of BACT on the vessels and equipment used for platform installation, as required by DOI's regulations. This reduction corresponds to a reduction in the maximum onshore concentration increment from 1.5 $\mu g/m^3$ to 1.0 $\mu g/m^3$. SO_x, CO, and TSP emissions and impacts would remain the same as initially predicted. That is, SO_x emissions of 1,610 tons in 1991 could cause a 0.7 $\mu g/m^3$ increase in onshore concentrations and TSP emissions of 244 tons in 1989 could result in a 0.10 $\mu g/m^3$ offshore concentration increment. No modeling of the predicted 579 tons of CO for 1989 was performed because of the high DOI significance level for that pollutant.