EPA

United States Environmental Protection Agency
Office of Research and Development
Industrial Environmental Research Laboratory
Cincinnati, Ohio 45268
EPA-600/7-77-080
July 1977

OFFSHORE OIL AND GAS EXTRACTION:
An Environmental Review

Interagency
Energy-Environment
Research and Development
Program Report

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into nine series. These nine broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The nine series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development
8. "Special" Reports
9. Miscellaneous Reports

This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

EPA-600/7-77-080
July 1977

OFFSHORE OIL AND GAS EXTRACTION

AN ENVIRONMENTAL REVIEW

by

N. A. Frazier
D. L. Maase
R. Clark

BATTELLE
Columbus Laboratories
Columbus, Ohio 43201

Contract No. 68-02-1323

Project Officer

Eugene Harris
Resource Extraction and Handling Division
Industrial Environmental Research Laboratory
Cincinnati, Ohio 45268

INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
CINCINNATI, OHIO 45268

DISCLAIMER

FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related pollutional impacts on our environment and even on our health often require that new and increasingly more efficient pollution control methods be used. The Industrial Environmental Research Laboratory-Cincinnati (IERL-Ci) assists in developing and demonstrating new and improved methodologies that will meet these needs both efficiently and economically.

This report reviewed the emission sources and emissions from United States offshore oil and gas exploration, drilling, and processing. The intent of the study was to rank the technological problems associated with the control of pollution from the industry. The findings should be of interest to regulatory agencies, the oil and gas industry, and organizations interested in energy and the environment. The Extraction Technology Branch may be contacted for additional information on this important topic.

David G. Stephan
Director
Industrial Environmental Research Laboratory
Cincinnati

ABSTRACT

A small study was conducted to rank technological problems of controlling emissions to the environment from offshore oil and gas exploration, drilling, and production operations. A firm basis ranking for these problems could not be developed during the study. Conclusions pertain to topics of environmental studies that are believed to be necessary for the identifying and ranking of control technology problems.

CONTENTS

FIGURES

TABLES

TABLES

SECTION I

INTRODUCTION

The objective of this small study was to rank the technological problems of controlling emissions associated with offshore oil and gas exploration, drilling, and production. The information base for the study included literature and reports on emission sources, emissions, control technology, pollution prevention and environmental practices, geographical distribution of offshore activities, impact assessments of offshore lease offerings, environmental problems, the EPA's interim and proposed effluent guidelines and supporting development documents, state regulations, and the USGS's Outer Continental Shelf orders.

SECTION II

SUMMARY AND CONCLUSIONS

Currently applicable Federal regulations, within the scope of this study, are in the form of the U.S. Geological Survey's Outer Continental Shelf Orders and the EPA's interim effluent limitations for Best Practical Control Technology Currently Available (BPTCA) for existing offshore sources. Effluent limitations for Best Available Technology Economically Achievable (BATEA), pretreatment standards, and new sources have also been proposed by the EPA. Applicability of various States' air and water quality criteria or regulations to offshore operations was not readily discernible in the sample of information reviewed.

Existing Federal regulations set limitations on oil that can be discharged to the offshore water environment, specify measures for reducing the probability of accidental oil spills occurring during drilling and production, and require capability for controlling spills in the event of an accident. The technology reflected in the EPA's proposed BATEA effluent limitations is that of no near-offshore discharge of pollutants in produced water and a 30-day average not to exceed 30 mg/l of oil in produced water and deck drainage discharged to far-offshore regions. These effluent limiations, as well as the BPTCA limitations, also call for no discharge of free oil in drilling muds, borehole cuttings, well treatment fluids, and produced sand and establish a minimum for residual chlorine in sanitary effluents.

A firm basis could not be developed during this study as a foundation for ranking other possible pollutants in discharges to offshore waters. This resulted from what was judged to be deficiencies in the formation reviewed concerning the possible pollutants and their fate and effect.

Other possible pollutants could include metals in produced water, drilling muds, and borehole cuttings and chemicals sometimes used in drilling muds or well treatment fluids. The number of possible pollutant species is large and they can occur in a variety of forms, e.g., dissolved, suspended, or settleable solids or simply as metals in rock cuttings from a shale shaker. Technologies involving principles of equalization and sedimentation for removal of solids are widely applied on land but their capabilities are space limited on offshore platforms. Studies to determine the leachability or mobility of metals in borehole cuttings for evaluating one practice for their disposal, viz., discharge to offshore waters, were not noted in the information reviewed.

Produced water is the largest single source of emissions to offshore waters. The amount of water produced can vary widely between fields and reservoirs and during the lifetime of a producing field. Effluent limitations on oil in produced water, which are based on concentrations rather than load, are a reflection of the wide variations in quantities of produced water. Numerous metal species are present in produced water but the concentrations noted in this study for metals of most environmental concern were low. One available technology for achieving no discharge of produced brines to navigable waters is to inject the produced brines into a subsurface formation. If that is not a viable option for technical or geohydrological reasons and if the produced water cannot be discharged offshore because of high metal concentrations, technology for removal of the metal(s) of environmental concern will very likely be a problem, at least within a BATEA frame of reference.

Comparatively little attention and concern in the literature has been given to quantitative evaluations of emissions to the air environment resulting from offshore geophysical exploration, drilling, and production. Sources of these emissions are internal combustion engines, gas in drilling muds, venting of gas during testing and production, and vapors from crude and fuel storage tanks. Technologies for limiting these sources on land--engine exhaust controls, fixed or floating roof storage tanks, and flaring of combustible gases--are available to or being practiced in offshore operations. Evaluations of these sources based on field studies of their emissions and environmental impacts were not noted in the information reviewed.

On the basis of the foregoing discussion, the conclusion of this report is that additional environmental studies of normal (as opposed to accidental) emissions should be conducted before technological problems of controlling sources not now the subject of interim proposed regulations can be identified and ranked. Topics of the studies are given below together with an estimate of their relative priorities, from highest to lowest:

- Field evaluations of the fate and effect of toxic metals in produced waters discharged to offshore waters

- Fate and effect of possible chemical pollutants in drilling muds and water treatment fluids if discharged to offshore waters

- Leachability/mobility of toxic metals in borehole cuttings with an evaluation of the fate and effect of metals released to offshore waters

- Field measurements of sources of air emissions and assessment of their potential for environmental impact.

SECTION III

GEOGRAPHICAL DISTRIBUTION OF OIL INDUSTRY ACTIVITIES IN U.S. OFFSHORE AREAS

Presented in this section is information on the geographical distribution of U.S. oil industry activities in marine areas offshore from the continental United States (see Figure 1). Information presented is in the form of selected statistics on offshore geophysical surveying, drilling, and production.

For purposes of this study, oil industry activities commence by surveying an area of interest by one or more marine geophysical exploration methods. Dependent on those results and geological knowledge of subsurface either a stratigraphic test or an exploratory test may then be drilled. The basic difference between these two tests is that the stratigraphic test is drilled for purposes of acquiring data on the geologic section and on the potential reservoir rock specifically. In contrast, the exploratory test (often called a wildcat) is drilled with the intent of finding oil or gas, although it too provides data on the geologic section and potential reservoir. If the exploratory test is successful, then development wells are drilled and the new field or pool is put on production.

The above description is highly simplified and generalized and the nomenclature built around objectives of drilling and classification of a hole is quite extensive (see Reference (1) for nomenclature used by the American Association of Petroleum Geologists and the American Petroleum Institute). Similarly, geophysical surveying activities range from those conducted at reconnaissance scales for regional studies to detailed surveying of a drilling prospect. As a general rule, mobile drilling rigs or drill ships are replaced by a fixed-platform drilling unit if a new field exploratory test is successful. Development drilling and subsequent production of many (e.g., 12 to 24) wells from a fixed platform is common practice.

GEOPHYSICAL SURVEYING

Geophysical surveys have been conducted in parts of all offshore regions shown in Figure 1. Seismic methods have been and continue to be dominant over all other methods in the number of crew months expended and line miles surveyed. For example, of the 878 geophysical crew months reported in the 5-year interval, 1960 to 1964, 87 percent were for seismic surveys (see Table 1). In the 3-year period, 1972 to 1974, 92 percent of

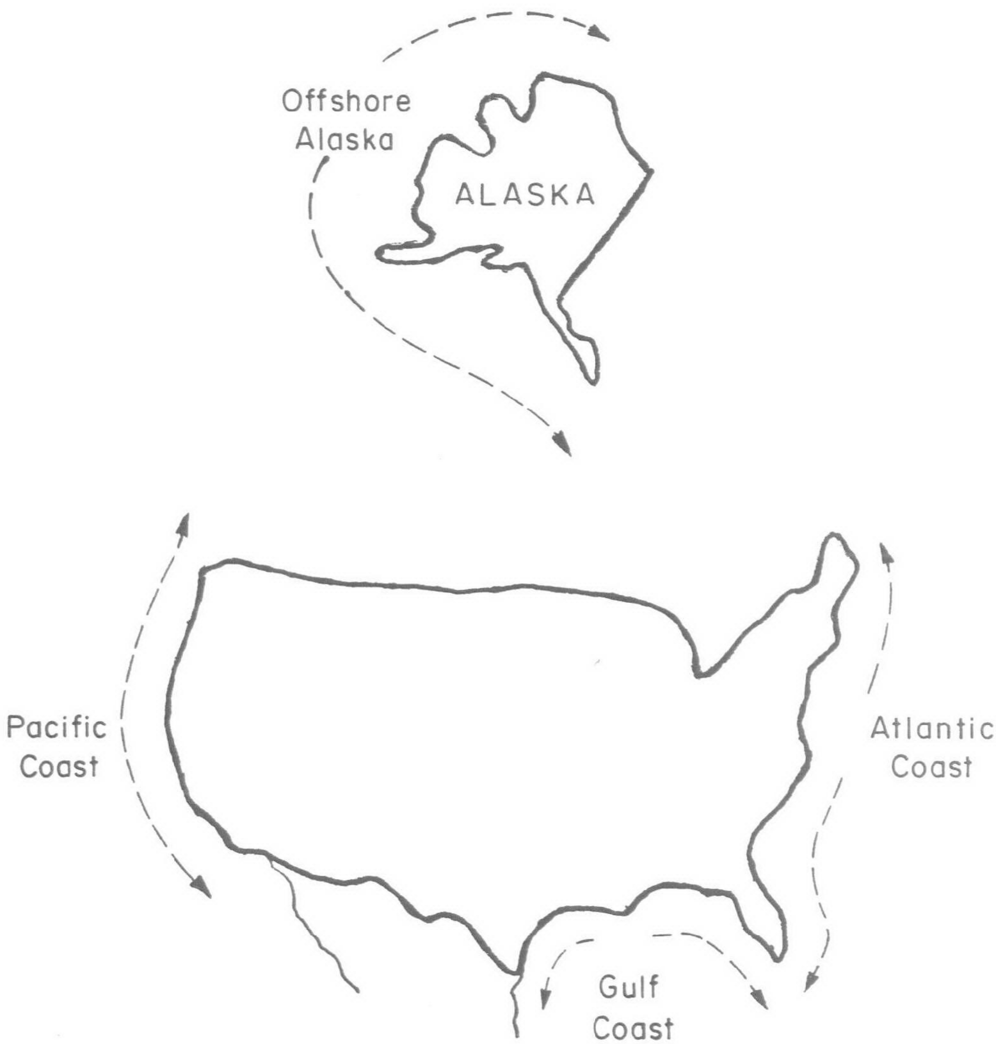

FIGURE 1. U.S. OFFSHORE REGIONS
(No Scale)

TABLE 1. SEISMIC AND GRAVITY OFFSHORE GEOPHYSICAL EXPLORATION ACTIVITY, BY STATE, 1960 to 1964 (Crew-Months)*

Offshore Location of Surveys	Seismic-Gravity								
	1960	1961		1962		1963		1964	
Alaska								5	--
Oregon	4	--	34	--	53	3	39	1	19	1(a)
Washington								4	1(a)
California								17	--
Louisiana	64	2	102	17	83	28	103	20	168	9
Texas	ND	ND	ND	ND	ND	ND	8	ND	40	18
Florida	--	--	--	--	--	--	--	ND	3	15(b)
Atlantic Coast	--	--	--	--	--	--	--	--	17	--
Totals	68	2	136	17	136	31	150	21	273	44

Source: Crew-month data courtesy of Neal Smith, Chairman, Committee on Geophysical Activity, Society of Exploration Geophysicists.

(a) Gravity surveys off Oregon and Washington during 1964 were surface-ship-instrument type. Gravity surveys off other three states were bottom-instrument type.

(b) The 15 crew-months of gravity survey work was distributed along the Gulf Coast of Louisiana, including Florida.

* Reproduced/modified from Reference (2).

the 867 geophysical crew months reported were for seismic surveys (see Table 2). In 1974, 93 percent of the more than 365,000 line miles surveyed included exploration by seismic methods (see Table 3).

Geographically, of the offshore areas shown in Tables 1 and 2, Louisiana led all other areas in the number of seismic crew months expended offshore. However, seismic crew months expended in offshore Louisiana declined from 68 percent to 35 percent of the total seismic crew months in the 1960-1964 and 1972-1974 time intervals, respectively.

Seismic methods of marine petroleum exploration, in contrast to gravity and magnetic methods, involves the use of a man-made energy source. However, in recent years and as shown in Table 3, compressed air and gas exploders have essentially eliminated the use of explosives in the water as the energy source.

EXPLORATORY AND DEVELOPMENT DRILLING

U.S. offshore drilling statistics for the 5-year period 1960-1964 and for the 2-year period 1973-1974 are given in Tables 4 and 5, respectively. Of the 3,625 holes drilled during the earlier of these two periods, about 90 percent were offshore from Louisiana and 8 percent were offshore from California. Average depth of all holes drilled was about 10,000 feet.

During the 1973-1974 time period, a total of 1,950 exploratory and development holes were drilled with 80 percent of the total being offshore from Louisiana, 12 percent offshore from Texas, and 6 percent offshore from California. Average depth of all holes was about 9,100 feet.

An estimate of well drilling activities offshore from California, Texas, and Louisiana for 1975 and 1976 is given below:[3]

	1975			1976			
	Total Wells	Total Wildcats	Total Footage (1000 ft)	Total Wells	Total Wildcats	Total Field Wells	Total Footage (1000 ft)
CA	69	4	271	95	25	70	349
TX	174	54	1558	308	182	126	2674
LA	641	168	6042	704	142	562	6707

The projection of U.S. offshore drilling activity for the 6-year period, 1975-1980 for the U.S. offshore regions, is as follows:[4]

TABLE 2. U.S. OFFSHORE GEOPHYSICAL EXPLORATION FOR PETROLEUM 1972-1974 (CREW MONTHS)[a]

State/Area	Seismic 1972	Seismic 1973	Seismic 1974	Gravity/Magnetics/Other 1972	Gravity/Magnetics/Other 1973	Gravity/Magnetics/Other 1974
Alabama	0	4	2.7	0	0	
Alaska	22	23	54.3	1	1	
Atlantic Coast	2	21	--	0	0	
California	3	27	58.2	2	6	
Florida	27	54	5.9	6	5	
Georgia	3	--	0.2	0	-	
Louisiana	54	99	123.4	0	5	
Maine	1	--	10	0	-	
N. Carolina	--	--	2.3	-	-	
Texas	37	44	103.2	0	0	
Utah	--	--	9[b]	-	-	
Washington	0	--	0	0	-	
Other	--	--	7.7	-	-	
Total	149	272	376.9	9	17	44

(a) Compiled from Geophysics: 39/1, 1974; 39/6, 1974; 40/5, 1975

(b) Great Salt Lake (?)

TABLE 3. TYPES AND METHODS OF U.S. OFFSHORE PETROLEUM SURVEYS: 1974[(a)]

Type/Method	Crew Months	Line-Miles Surveyed
Seismic		
Compressed air	260	237,497
Gas exploder	92	88,144
Implosive	12	7,186
Solid chemical	1	1,238
Other	8	7,719
Remote sensing	2	1,850
Gravity	2	2,600
Gravity/Magnetic	10	8,000
Magnetic	9	11,700
Sonic/velocity logging	21	--

(a) From Geophysics: 40/5, 1975, p 892

TABLE 4. ESTIMATE OF TOTAL U.S. OFFSHORE DRILLING AND PRODUCTION 1960-1964[a]

Region/State	Drilling			Production[c]
	Holes Drilled	Footage Drilled[b]	Average Depth[b]	Crude and Condensate
Alaska	9	92	10.2	
Pacific Coast	276	1,431	5.2	
Washington	1	5	5	
California	275[d]	1,426[d]	5.2[d]	21,100[e]
Gulf Coast	3,340	35,233	10.5	
Texas	64	640	10	minor
Louisiana	3,267	34,497	10.6	636,500
Florida	9	96	10.7	
Total U.S. Offshore	3,625	36,756	10.1	657,600

(a) Basic data from Reference (2)

(b) Thousands of feet

(c) Thousands of barrels

(d) Excludes slant holes drilled from shore installations

(e) Excludes an estimated 150 million barrels from slant holes drilled from shore installations

TABLE 5. TOTAL U.S. OFFSHORE DRILLING ACTIVITY 1973-1974[a]

A. EXPLORATORY DRILLING COMPLETIONS

Region/State	Oil Producers	Gas Producers	Dry Holes	Totals Holes	Totals Footage[b]	Average Hole Depth[b]
Alaska	1	0	10	11	115.8	10.5
Pacific Coast						
California	3	0	4	7	42.8	6.1
Gulf Coast	7	31	537	575	4,894.3	8.5
Texas	6	28	182	216	1,805.9	8.4
Louisiana	1	3	355	359	3,088.4	8.6
N. Gulf of Mexico	0	0	14	14	105.4	7.5
Total U.S. Offshore	11	31	565	607	5,158.3	8.5

B. DEVELOPMENT DRILLING COMPLETIONS

Region/State	Oil Producers	Gas Producers	Dry Holes	Totals Holes	Totals Footage[b]	Average Hole Depth[b]
Alaska	17	0	0	17	140.2	8.2
Pacific Coast						
California	99	1	7	107	345.3	3.2
Gulf Coast	504	382	333	1,219	12,040	9.9
Texas	2	13	4	19	168.4	8.9
Louisiana	502	369	329	1,200	11,871.6	9.9
Total U.S. Offshore	620	383	340	1,343	12,525.5	9.3

C. NO INTENT OF HYDROCARBON PRODUCTION

Region/State	Stratigraphic & Core Tests No.	Stratigraphic & Core Tests Footage[b]	Service Wells No.	Service Wells Footage[b]
Pacific Coast				
California	2	5	18	50
Gulf Coast				
Louisiana	0	0	35	291.2
Texas	0	0	0	0
Total U.S. Offshore	2	5	53	341.2

(a) Compiled from data in : Bulletin, American Association of Petroleum Geologists, Vol. 58, No. 8, 1974, pp 1475-1505 and Vol. 59, No. 8, 1975, pp 1273-1310

(b) Thousands of feet

Offshore Region	Total Holes to be Drilled
Alaska	1017
Pacific Coast	5133
Gulf Coast	9583
Atlantic Coast	57

More than 15 tests(5) drilled in the northeast part of the Gulf of Mexico (offshire Mississippi, Alabama, and Florida) have been unsuccessful since the first Federal lease sale in December, 1973.(6) Areas drilled include the Destin anticline some 50 to 60 miles off the Florida panhandle, reefs and domes south of Mobile, Alabama, and reefs or structures west of St. Petersburg, Florida. Exxon, as operator for a group, has drilled seven unsuccessful tests at the Destin dome, the last of which was plugged and abandoned in mid-1975.(7)

The Atlantic Continental Offshore Stratigraphic Test group (COST) has scheduled two stratigraphic tests in the Atlantic Coast Region. The semi-submersible drill rig was reported undertow on December 5, 1975, to the first location designated as B-2, which is in the Baltimore Canyon area 75 miles east of the New Jersey coast in 290 feet of water. The same rig is to drill the second test, designated as G-1, which is to be located in the Georges Bank area about 100 miles southeast of the Massachusetts coast in 140 feet of water.(8,9) During September, 1975, a total of 1,000 line miles of seismic surveys was conducted in these two areas.(10)

Other U.S. offshore frontier areas which might be drilled in the nearer-term future include the Gulf of Alaska and the Lower Cook Inlet. Industry has nominated 778 tracts comprising more than 44 million acres some 20 to 80 miles seaward from the Carolinas and Georgia.(12) The Blake Plateau area off the Florida coast is in deeper water(5) and presumably drilling activity in this area would be in the more distant future.

The Outer Continental Shelf off south Texas has been the location of some drilling activity. However, the area is apparently either not too promising or of low priority because fewer than one-third of the tracts offered in the Federal lease sale in February, 1975, drew bids.(5) Gas was discovered or at least tested in a well drilled during 1975 about 35 miles southeast of Corpus Christi, Texas.(11)

PRODUCTION

Selected statistics on U.S. offshore production of crude and lease condensate are given in Tables 4 and 6 for the years 1960 through 1965, and 1969 through 1975, respectively. In Table 7, U.S. offshore production is compared to total U.S. production for the years 1969 through 1975.

Referring to Table 6, about 33 percent and 67 percent of 2.85 billion barrels produced in the 5-year period, 1971-1975, were from state and

TABLE 6. U.S. OFFSHORE PRODUCTION OF CRUDE OIL AND LEASE CONDENSATE 1969-1975

A. Production (Thousands of barrels)

	1969 [a]	1970 [a]	1971 [a]	1972 [b]	1973 [b]	1974 [b]	1975 [b]	1971 - 1975
Alaska								
State (Total)	60,955	70,080	66,065	63,744	61,789	60,308	60,293	312,199
California (Total)	95,995	104,390	101,470	95,578	89,028	83,918	79,096	449,090
State	86,140	79,205	70,445	73,015	70,253	67,139	63,661	344,513
Federal	9,855	25,185	31,025	22,563	18,775	16,779	15,435	104,577
Texas (Total)	2,920	2,920	2,920	1,611	1,397	1,081	779	7,788
State	365	730	1,095	751	669	577	353	3,445
Federal	2,555	2,190	1,825	860	728	504	426	4,343
Louisiana (Total)	365,730	398,580	443,840	446,639	426,784	398,329	361,052	2,076,644
State	65,700	64,970	58,035	77,824	53,298	46,825	39,977	275.959
Federal	300,030	333,610	385,805	368,815	373,486	351,504	321,075	1,800,685
Total U.S. Offshore	525,600	575,970	614,295	607,572	578,998	543,636	501,220	2,845,721
State	213,160	214,985	195,640	215,334	186,009	174,849	164,284	936,116
Federal	312,440	360,985	418,655	392,238	392,889	368,787	336,936	1,909,505

B. Percent of U.S. Offshore Production [c]

	1969	1970	1971	1972	1973	1974	1975	1971-1975
Alaska								
State	11.6	12.2	10.8	10.5	10.7	11.1	12.0	11.0
California (Total)	18.3	18.1	16.5	15.7	15.4	15.4	15.8	15.8
State	16.4	13.8	11.5	12.0	12.1	12.3	12.7	12.1
Federal	1.9	4.4	5.1	3.7	3.2	3.1	3.1	3.7
Texas (Total)	0.6	0.5	0.5	0.3	0.2	0.2	0.2	0.3
State	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Federal	0.5	0.4	0.3	0.1	0.1	0.1	0.1	0.2
Louisiana (Total)	69.6	69.2	72.2	73.5	73.7	73.3	72.0	73.0
State	12.5	11.3	9.4	12.8	9.2	8.6	8.0	9.7
Federal	57.1	57.9	62.8	60.7	64.5	64.7	64.1	63.3
Total U.S. Offshore	100	100	100	100	100	100	100	100
State	40.6	37.3	31.8	35.4	32.1	32.2	32.8	32.9
Federal	59.4	62.7	68.2	64.6	67.9	67.8	67.2	67.1

(a) Daily averages times 365 days per year. Daily averages from:
American Petroleum Institute, "Annual Statistical Review, Petroleum Industry Statistics, 1964-1973", September 1974 (API data from U.S. Geological Survey).

(b) Annual production from Bureau of Mines, Petroleum Review, monthly issues.

(c) Totals may not add to 100 percent because of rounding.

TABLE 7. COMPARISON OF U.S. TOTAL AND OFFSHORE PRODUCTION OF CRUDE AND LEASE CONDENSATE 1969-1975[a]

A. Offshore Production: Percent of U.S. Total Production

1969	1970	1971	1972	1973	1974	1975	1969-1975
15.6	16.4	17.8	17.6	17.3	17.0	16.4	17.2

B. 1969 Offshore Production = 100

	1969	1970	1971	1972	1973	1974	1975
U.S. Offshore	100	110	117	116	110	103	95
Total U.S.	641	669	657	656	638	609	581

(a) Based on data and references in Table 6.

Federal leases, respectively. Of that total, 73 percent was from offshore Louisiana, 15.8 percent from California, 11 percent from Alaska, and 0.3 percent from Texas. The vast majority of offshore production in the first half of the 1960's was from offshore Louisiana (Table 4).

In the 1969-1975 period, U.S. offshore production reached a maximum in 1971 when 614 million barrels (Table 6) were produced, continuously declining since then to a low in 1975 when production was 95 percent of 1969 production (Table 7). Within this same time interval, total U.S. production peaked in 1970 at 3,517.5 million barrels, continuously declining since then to 3,052 million barrels in 1975.

Offshore production, as a percentage of total U.S. production during 1969-1975, reached a maximum of 17.8 percent in 1971. This percentage decreased to 16.4 percent in 1975 (Table 7).

SECTION IV

EMISSION SOURCES: NORMAL OFFSHORE OPERATIONS

Information on emission sources associated with normal or "routine" offshore operations of geophysical exploration, drilling, and production is reviewed in this section. Data permitting characteristics of emissions to the air and water environment from the various sources are summarized. Terms such as "major" or "minor" are sometimes used to compare, on a relative basis, sources within an operation without connoting the environmental significance of the sources. For example, although internal combustion engines may be the major source of air emissions to the environment from an operation, the environmental impact of emissions from the engines may be environmentally acceptable, unacceptable, or unknown.

GEOPHYSICAL SURVEYING

Emissions to the Air Environment

Exhausts from internal combustion engines powering geophysical survey boats is the major source of air emissions in offshore geophysical surveying. Horsepower of engines used often range between 500 and 2,500.

Air emissions resulting from geophysical exploration have not been a source of environmental concern in the literature reviewed. Surveys are conducted at considerable distances from shore and ship tracks may range from less than 1 mile to several miles apart. Thus, air emissions from geophysical surveying do not represent many sources emitting in small areas for extended periods of time.

Data on air emissions of geophysical survey boats were not located. Of possible relevance is emission factors of motorships shown in Table 8.

Emissions to the Water Environment

During geophysical exploration, water emission sources include debris, bilge, domestic, and sanitary waste from survey vessels. Exploratory use of propane oxygen guns and/or high-powered oscillators now in use appear to have no adverse affects on the water environment. Bottom sampling/coring does slightly perturb bottom water conditions.[13]

TABLE 8. EMISSION FACTORS FOR MOTORSHIPS[a]

Pollutant		Lb/Mile (Underway)
Particulates		2.0
SO_x[b]		1.5
Carbon Monoxide		1.2
Hydrocarbons		.9
Nitrogen Oxides (NO_2)		1.4
Aldehydes (HCHO)		0.07
	Total	8.07

(a) Accuracy of factors: below average

(b) 0.5 weight percent sulfur in fuel assumed

Source: Compilations of Air Pollutant Emission Factors, Second Edition, U.S. Environmental Protection Agency, Office of Air and Water Programs, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, April, 1973.

On-board domestic waste sources include laundries, gallies, showers, and body wastes. Discussions concerning these waste sources are lacking in the offshore exploration literature. Such sources concentrated in a small area, e.g., harbors and bays, are known to be capable of degrading water quality, if not controlled.(14)

EXPLORATORY AND DEVELOPMENT DRILLING

Air emissions from exploratory and development drilling can result from burning of gas recovered from testing of wells and from internal combustion engines used for powering drill rig equipment. Possible emissions to the water environment include drilling fluids/cuttings, deck drainage, and sanitary wastes. These sources are present throughout offshore oil and gas development, but since they do not appear to be a major source during production, they are only discussed in this section.

Emissions to the Air Environment

Various tests are conducted on a potential oil or gas well. The testing time varies with each well, but the average testing time for an oil well is 2 to 3 hours and for a development gas well, from 2 to 4 hours, and 1 to 7 days for an exploratory well. Because of the short test time required for development wells, the initial production of gas or oil is relatively small, but gas from an exploratory well can flow at a rate from a few thousand cubic feet per day to millions of cubic feet per day.(15)

The oil and gas produced during well testing is passed through equipment such as separators, tank and vent lines, then is disposed of ultimately. Well testing gas is usually burned releasing the products of combustion. Emissions can be visible when flaring gas; however, there are commercially available "smokeless" flares. The quantity of emissions from flaring of natural gas were estimated by assuming the rate of emissions would be similar to those from commercial fired combustion equipment. Table 9 shows the estimated emissions from flaring of natural gas during well testing operations.

The source of power for most drilling rigs is natural gas or diesel fueled internal combustion engines. The exhaust from a diesel fueled engine can be properly adjusted so that it does not emit smoke in violation of air pollution control regulations. Table 10 shows average emission rates from industrial-type diesel engines.

Another source of air emission is gas in the drilling mud. This gas is generally vented to the atmosphere unless H_2S is present in the gas stream in which case the drilling mud can be treated with various chemicals to alter or precipitate the H_2S.(17)

In a producing oil well, the fluid is either naturally flowing, or artifically lifted or pumped to the surface. The oil from a pumping well often has very little gas associated with it, and is usually treated only

TABLE 9. ESTIMATE OF QUANTITY OF EMISSIONS FROM BURNING OF WELL TESTING GAS

Pollutant	Lb/Million Cubic Feet
Particulate	19
Sulfur dioxide (SO_2)[(a)]	.6
Carbon monoxide	20.0
Hydrocarbons (CH_4)	8.0
Nitrogen oxides NO_2	120.0

(a) Based on average sulfur content of natural gas of 2000 grains/10^6 ft^3.

Burning is assumed to be the same as natural gas firing for commercial combustion equipment.

Source: Compilation of Air Pollutant Emission Factors, Second Edition, U.S. Environmental Protection Agency, Office of Air and Water Programs, Office of Air Quality Planning and Standard, Research Triangle Park, North Carolina.

TABLE 10. EMISSION FACTORS FOR DIESEL POWERED INDUSTRIAL EQUIPMENT

Pollutants	Lb/Hour	Lb/10^3 Gal
Particulates	.143	33.5
Oxides of Sulfur	.133	31.2
Aldehydes	.030	7.04
Oxides of Nitrogen	2.01	469.0
Carbon Monoxide	.434	102.0
Exhaust Hydrocarbons	.160	37.5

Source: Supplement No. 4 for Compilation of Air Pollutant Emission Factors, Second Edition, U.S. Environmental Protection Agency, Office of Air and Waste Management, Office of Air Quality Planning and Standard, Research Triangle Park, North Carolina, January, 1975.

for water separation before it is moved into the stock tank. The oil from a flowing well may contain various quantities of gas and generally goes to a separation unit. The resultant gas is either flared or vented.

Hydrocarbon Emission From Storage Tanks--

Storage tanks are used to store crude oil and distillage oil on offshore platforms. However, crude storage tanks that are used usually have a capacity of 10,000 bbl or less since space is at a premium on a platform.[13] The storage tank used would probably be of fixed-roof type whose emissions are greater than those of a floating-roof type. Shown in Table 11 are emission rates from fixed-roof storage tanks for crude and distillate oils. Emissions also occur during the loading and unloading of storage tanks. Factors affecting hydrocarbon vapor emissions are changes in pressure or temperature, and volatility of the liquid stored.

Emissions to the Water Environment

The major emission sources associated with exploratory and development drilling which can influence the aquatic environment include drilling fluids/cuttings, deck drainage, and sanitary wastes. The latter two, deck drainage and sanitary wastes, are considered minor waste sources.[18] Compressor drains, cooling and heating circuit discharges, and domestic water treatment system blowdowns (desalination units) are also a part of offshore operations, but respective emissions are not well defined in the literature. These sources and discharges from crew boats, tugs, and service/supply boats, for the purposes herein, are considered negligible.[19]

Drilling Fluids and Cuttings--

Drilling fluids and bore cuttings constitute the primary source of emissions to the water environment from drilling operations. An integral part of drilling involves the use of drilling mud to prevent blowouts by counterbalancing formation pressures. The mud also acts as a lubricant, provides bore hole side wall control, and is the medium which transports the cuttings to the surface. The time involved in use of drilling muds is relatively short in comparison to the total life of an offshore development with drilling normally varying from less than 10 days to more than 3 weeks per well completion.[16,20] The number of wells completed from one offshore development is increasing and may range from less than 10 to more than 30.

Drilling muds are often organized into two categories--water based and the more expensive oil based fluids. Water-based muds are composed of bentonite or attapulgite clays and a variety of additives to control the pH, corrosion, emulsification, lubrication, and density properties of the drilling fluid. Oil-based muds contain a mixture of organic acids, asphaltic stabilizing agents, and high flash diesel oil.[21] Unrecovered water-based muds are more often disposed of to surface waters than spent oil-based muds which are generally barged ashore for final disposition.[18]

The primary pollutants in drilling muds are oil and grease. Oil-based muds, normally used in deeper/hotter holes, can contain over 50 percent hydrocarbons in the liquid phase.[21] Typical compositions of a gelled

TABLE 11. EVAPORATIVE EMISSION FACTORS FOR FIXED ROOF STORAGE TANKS

	Breathing Loss		Working Loss
Product	New Tank Condition lb/day 10^3 gal	Old Tank Condition lb/day 10^3 gal	lb/10^3 gal throughput
Crude Oil	.15	.17	7.3
Distillate Oil (Diesel fuel)	.036	.041	1.0

Source: Supplement No. 1 for Compilation of Air Pollutant Emission Factors, Second Edition, U.S. Environmental Protection Agency, July, 1973.

seawater mud and a lignosulfonate mud is shown in Table 12. As shown in the table, chromium amounts to about 3 percent of the mud on a dry weight basis. Barite ($BaSO_4$), a major component of drilling muds, is used to control blowouts by increasing the weight (specific gravity 4.5) of mud column. The nature, use and normal concentration of other mud additives is shown in Table 13.

Generally oil and gas production can be expected from depths of 6,000 to 12,000 feet. For a typical depth of 10,000 feet, 7,000 barrels of drilling mud containing about 258 tons of commercial mud components are needed.[22] An example of drilling mud needs is summarized in Table 14. In a typical 10,000 foot development, well cuttings can amount to more than 1,700 bbls (∿700 tons).[16]

To increase production, acid or other fluid and suspended particulate matter may be pumped through the well bore into producing formations. The spent acid returns up the well when production is resumed and is handled as are other fluids from the well. Other procedures to increase productivity and oil recovery include the injection of high-pressure steam, water and/or gas into specially prepared injection wells. The water used for this purpose may be taken from the ocean or from formation water. Water too contaminated to be treated, polished, and discharged can be reinjected into formations.[23]

Deck Drainage--

During drilling and/or workover operations, the potential for accumulation of pollutants which can contribute to deck drainage is greatest. During well completion, much of this material is drilling fluids, the composition of which has previously been discussed. Chronologically most workover operations occur during the production phase of oil and gas development. However, as these operations are short-term in duration (about 1/3 of the time[20] needed to drill the same well, the resulting deck drainage is discussed here.

Well completion activities can result in spillage of drilling fluids. Other sources of spills are valve failures.[13] Acids (hydrochloric, hydrofloric, and various organic acids) employed during workover operations can also contribute to deck drainage. These acids are generally neutralized by other deck wastes and/or brines prior to further handling for disposition. Oil is considered the primary pollutant in deck drainage.

Sanitary Wastes and Refuse--

The largest volume of sanitary wastes and refuse are generated during the well completion phase of oil and gas production. Estimates of permanent inhabitants on the development facilities range from about 12 to more than 80 occupants.[24] Domestic wastes include toilet, kitchen, and laundry inputs. Toilets are usually flushed with site-ambient water.[18] Sixty gallons per day per person (gpcd) with a biochemical oxygen demand of about 0.2 pounds per capita day are considered realistic estimates of domestic occupation waste generation rates.[24] Solid wastes include food packaging and other nondurable goods.

TABLE 12. GELLED SEAWATER MUD - TYPICAL COMPOSITION [23]

Mud Component Used	Weight, lb
Attapulgite Clay	56,300
Caustic (Sodium Hydroxide)	5,500
Organic Polymer	3,700
Ferrochrome Lignosulfonate (Iron-2.6%, Chromium-3.0%, Sulfur-5.5%)	3,300
Pregelatinized Starch	500
Seawater	As Required
Total Mud Components	69,300

LIGNOSULFONATE MUD - TYPICAL COMPOSITION

Mud Component Used	Weight, lb
Barium Sulfate (Weighting Agent)	319,000
Caustic (Sodium Hydroxide)	22,500
Ferrochrome Lignosulfonate (Fe-2.6%, Cr-3.0%, S-5.5%)	29,600
Organic Polymer	4,100
Bentonite Clay in Freshwater, or Attapulgite Clay in Seawater	17,100
Proprietary Defoamer	325
Water	As Required
Total Mud Components	392,625
Total Mud Components, Less Barium Sulfate	72,625

TABLE 13. MUD ADDITIVES [23]

Function		Name	Amount (lb/bbl)
Alkalinity & pH Control	1.	Sodium Hydroxide $NaOH$	0.1-0.3
	2.	Sodium Bicarbonate $NaHCO_3$	0.1-1.5
	3.	Calcium Chloride $CaCl_2$	0.1-3.0
	4.	Calcium Hydroxide $Ca(OH)_2$	0.5-8.0
Bacteriocides			
	1.	Paraformaldehyde $(CH_2O)_x$	0.5-1.0
	2.	Sodium Chloride $NaCl$	5.0-10.0
	3.	Sodium Chromate Na_2CrO_4	0.1-4.0
Calcium Removers			
	1.	Sodium Bicarbonate $NaHCO_3$	0.1-1.5
	2.	Sodium Carbonate Na_2CO_3	0.5-2.0
	3.	Sodium Hydroxide $NaOH$	0.1-3.0
	4.	Organic Phosphate	0.1-0.5
Corrosion Inhibitors			
	1.	Calcium Hydroxide $Ca(OH)_2$	0.5-8.0
	2.	Sodium Chromate Na_2CrO_4	0.1-4.0
	3.	Film Forming Amine	2.0
Defoamers			
	1.	Aluminum Stearate $[CH_3(CH_2)_{16}COO]_3Al$	1.0-10.0
	2.	Alkyl Aryl Sulfonate	0.2-0.3
	3.	Silicones	0.1-3.0
Emulsifiers			
	1.	Calcium Lignosulfonate	1.0-4.0
	2.	Oxyethylated Alkyl Phenol	0.5-3.0
	3.	Ferrochrome Lignosulfonate	0.1-2.0
	4.	Quebracho	0.2-5.0
Filtrate Reducers			
	1.	Bentonite	5.0-10.0
	2.	Sodium Carboxymethylcellulose	0.1-1.5
	3.	Sodium Polyacrylate	1.0-3.0
	4.	Starch	2.0-8.0

TABLE 13. (Continued)

Function	Name	Amount (lb/bbl)
Flocculants		
	1. Acrylamide Polymeric Hydrolite	.005-.01
	2. Bentonite	1.0 -5.0
	3. Lignosulfonate	1.0 -5.0
Foaming Agents		
	1. Alkyl Polyoxyethylene	8.0-16.0
Lost Circulation		
	1. Cottonseed Hulls	3.0-25.0
	2. Cane Fibers	2.0- 6.0
	3. Asbestos	2.0- 6.0
	4. Cellophane	5.0-10.0
	5. Mica	2.0-10.0
Lubricants		
	1. Oxidized Asphalt	3.0-6.0
	2. Carbon Powder	1.0-2.0
Shale Control Inhibitors		
	1. Oxidized Asphalt	3.0-6.0
	2. Calcium Hydroxide	0.5-8.0
	3. Sodium Silicate	0.1-3.0
	4. Calcium Lignosulfonates	0.1-3.0
Surface Active Agents		
	1. Oxyethylated Alkyl Phenol	0.5-3.0
	2. Alkyl Aryl Sulfonate	0.2-0.3
Thinners & Dispersants		
	1. Sodium Tetraphosphate $Na_6P_4O_{13}$	0.1-0.2
	2. Calcium Lignosulfonate	1.0-4.0
	3. Sodium Chromate Na_2CrO_4	0.5-3.0
	4. Quebracho	1.0-10.0
Viscosifiers		
	1. Bentonite	1.0-5.0
	2. Asbestos	2.0-6.0
	3. Sodium Carboxymethyl Cellulose	0.1-1.5

TABLE 14. MUD COMPONENTS USED IN SEAWATER - LIGNOSULFONATE SYSTEMS (16) TO 15,000 FEET. (WEIGHT IN POUNDS)

Component	Interval 0-900 Feet	Interval 900-3500 Feet	Sub-Total 3500 Feet	Interval 3500-10,000 Feet	Sub-Total 10,000 Feet	Interval 10-15,000 Feet	Total 15,000 Feet
Barium Sulfate (Barite)	3,000	3,000	6,000	529,000	535,000	625,000	1,160,000
Bentonitic Clay	10,000	10,000	20,000	36,000	56,000	9,000	65,000
Attapulgite Clay	5,000	5,000	10,000	-	10,000	-	10,000
Caustic	500	500	1,000	20,000	21,000	23,000	44,000
Aromatic Detergent		1,000	1,000	2,000	3,000	-	3,000
Organic Polymers		1,000	1,000	3,000	4,000	-	4,000
Ferrochrome Lignosulfonate				26,000	26,000	69,000	95,000
Sodium Chromate						2,000	2,000
Totals	18,500	20,500	39,000	616,000	655,000	728,000	1,383,000

1/ It is emphasized that these are "typical" values and quantities may vary by as much as 50% from well to well.

PRODUCTION

During the production phase of offshore development, major air emission sources include separator associated vents/flares, diesel engine emissions, and storage tank losses. Coproduced brine constitutes the major source of discharge to the water environment. Deck drainage and sanitary wastes are not considered a major source during production.

Emissions to the Air Environment

The normal operation on a production platform consist mainly of handling production from oil and/or gas wells and separation of oil, gas, and water phases. Most air emissions attendant with production operations are from oil/water/gas/separators, diesel engines, and petroleum storage tanks. Gas from the separators is generally flared, although if the methane is too low, or the quantity is insufficient to be flared, it is then vented.

Most of the air pollutants associated with the production of oil or gas or emitted into the atmosphere as a result of venting or burning vapors and liquid waste. The air pollutants most often emitted into the atmosphere are unburned hydrocarbons, products of combustion, products of incomplete combustion, and acid gases such as hydrogen sulfide and sulfur dioxide. The concentration of air pollutants from gas or oil production varies greatly with location and concentration of the producing facilities.

Emissions to the Water Environment

Coproduced water constitutes the major source for emissions to the water environment during production. Deck drainage pollutants should be less available than during development drilling. As manpower needs are also relatively low, sanitary effluents are also considered less important during normal production operations. During well workovers, however, both deck drainage and sanitary waste sources may become as important as during well drilling operations.

Coproduced Basic Sediment and Water (BW&W)--

The major waste stream from offshore production is the coproduced "brine" water. Sand may also be produced along with oil normally at rates from near 0 to 1 barrel/2,000 barrels of liquid.[21] As reported, coproduced formation water can range from 2 to 98 percent of oil production. Based on a 1963 study, an estimate of 3.2 times the amount of oil produced is often used as a basis for treatment cost projections.[20] More recent estimates of coproduced water range from less than 25 percent[25] through about 50 percent[22,26] to more than 100 percent of the oil produced[18], with age of a well being a major factor influencing the quantities of coproduced water. Shown in Table 15 are data on coproduced water discharges in the Gulf of Mexico.

More than 700 platforms and nearly 250 rigs are operating in the Gulf of Mexico.[20] More than 2,000 wells are in state waters and 6,000 wells are on the Outer Continental Shelf (OCS).[18] The reported number of

TABLE 15. LOCATION AND ESTIMATED SIZE OF GULF OF MEXICO OFFSHORE PRODUCED WATER DISCHARGES[21] (Louisiana and Texas)

Capacity, (Produced Water, bpd)	Coastal[a]	Offshore (State and OCS)[b]
1,000	434	393
2,000	146	132
5,000	115	71
10,000	70	36
40,000	40	0
	805	632

(a) 606 Discharge points in Louisiana and 199 in Texas.
(b) 452 Discharge points in Louisiana and 180 in Texas.

possible separate discharge points in the Gulf range from a total of 1,098[27] to 1,437 for OCS--Louisiana alone.[21] A breakdown of the former estimate is as follows:

	Coproduced Water Discharges[27]		
	Texas	Louisiana	Total
State	296	475	771
OCS	10	317	327
Total	306	792	1,098

Another reference indicates that out of the 1893 OCS-Louisiana developments, only 214 discharge 180,000 bbls/day to the Gulf. As reported, a total of 420,000 bbls/day is coproduced with 240,000 bbls/day being piped to shore prior to separation.[26] The disposition of water transported to shore and of near-shore coproduced waters are not specifically addressed in the recent literature. However, the Interstate Oil Compact Commission states that 72 percent of a U.S. total of 25 million bbls/day of coproduced water is reinjected for either secondary recovery or disposal. Rivers received 12 percent and 12 percent is reused or transported to "approved disposal sites".[33] Total OCS coproduction of brine water in the Gulf is reported to be about 605,000 bbls/day with 305,000 bbls/day transported to shore.[22]

Offshore oil production and consequently coproduced brine water production in other U.S. coastal areas is not as extensive as the Gulf. Except for one facility, all brine production off California is piped ashore for treatment and disposal. Brine is coproduced at nine platforms offshore from California and the BS&W is transported with the oil for phase separation on shore. After separation, the brine water is disposed of by subsurface injection. In Alaska's Cook Inlet, 14 multiple well platforms on four oil fiels and one gas field pump BS&W to land for separation prior to disposal to the Inlet's surface waters.[18,21]

The Bureau of Land Management indicates that coproduced formation water contains an average of 112,513 mg/l of total dissolved solids (TDS) with ranges normally between 61,552 and 270,400 mg/l.[22,23,25,28,29] Coproduced brine water also contains suspended and settleable solids and hydrocarbons. Concentrations of oil and grease in coproduced water range from less than 100 to more than 1,000 mg/l, averaging 196 mg/l.[21] The average oil and grease results from a 1974 EPA Survey[18] compares favorably with this estimate (see Table 16). In Table 17, the averages of selected constituents of an oil field brine are compared with those of seawater. The range of constituents in California and Texas offshore produced formation water is presented in Table 18. A breakdown of total solids in representative offshore brines is shown in Table 19. As shown in these tables, TDS can approach 100 pounds per barrel and the major component, chloride, normally ranges from about 12 lbs/bbl to 50 lbs/bbl. Average TDS of open ocean water is about 35,000 mg/l ($\sim$12 lbs/bbl) with a chloride content of 19,000 mg/l ($\sim$6.7 lb/bbl). At 50 ppm effluent oil concentrations, the loss of oil to the water environment has been estimated at nine barrels for each million barrels of oil produced.[30]

TABLE 16. PRODUCED FORMATION WATER COMPOSITION [18, a]

Parameters	Average
Oil and Grease (Influent)	202 mg/l
Cadmium	0.0678 mg/l
Cyanide	0.01 mg/l
Chlorides	61,142 mg/l
Mercury	Trace
Total Organic Carbon	413 mg/l
Salinity	110,391 mg/l
API Gravity	33.6 degrees
Suspended Solids	73 mg/l

(a) 25 Discharges analyzed in 1974 EPA survey, Gulf of Mexico.

TABLE 17. COMPARISON OF SEAWATER AND OILFIELD BRINE [25]

	Seawater (mg/l)	Oilfield Brine (mg/l)
Na^{+1}	10,600	12,000-150,000
K^{+1}	400	30- 4,000
Ca^{+2}	400	1,000-120,000
Mg^{+2}	1,300	500- 25,000
Cl^{-1}	19,000	20,000-250,000
Br^{-1}	65	50- 5,000
I^{-1}	0.05	1- 300
HCO_3^{-1}	?	0- 1,200
SO_4^{-2}	2,700	0- 3,600

TABLE 18. RANGE OF CONSTITUENTS IN OFFSHORE PRODUCED FORMATION WATER (21)

Parameter	California[a] Range mg/l	Texas Range, mg/l[a]
Arsenic	0.001-0.08	0.01-0.02
Cadmium	0.02 -0.18	0.02-0.193
Total Chromium	0.02 -0.04	0.10-0.23
Copper	0.05 -0.116	0.10-0.38
Lead	0.0 -0.28	0.01-0.22
Mercury	0.0005-0.002	0.001-0.13
Nickel	0.100-0.29	0.10-0.44
Silver	0.03	0.01-0.10
Zinc	0.05 -3.2	0.10-0.27
Cyanide	0.0 -0.004	(b)
Phenolic Compounds	0.35 -2.10	53
BOD_5	370- 1,920	126-342
COD	340- 3,000	182-582
Chlorides	17,230-21,000	42,000-62,000
TDS	21,700-40,400	806-169,000
Suspended Solids	1-75	12-656

(a) Some data reflect treated waters for reinjection.

(b) Not available.

TABLE 19. CHEMICAL CONTENT OF REPRESENTATIVE OFFSHORE BRINES [16,a]

	High Solids		Average Solids		Low Solids	
Component	mg/l	Percent of Total	mg/l	Percent of Total	mg/l	Percent of Total
Iron	153	0.057	15	0.011	139	0.226
Calcium	17,000	6.287	4,675	3.294	772	1.254
Magnesium	2,090	0.773	1,030	0.726	152	0.247
Sodium	84,500	31.250	49,120	34.612	22,651	36.800
Bicarbonate	37	0.014	100	0.070	933	1.516
Sulphate	120	0.044	0	-	188	0.305
Chloride	166,500	61.575	86,975	61.287	36,717	59.652
Total Solids	270,400	100%	141,915	100%	61,552	100%

(a) From U. S. Geological Survey, Oil and Gas Supervisor, Gulf of Mexico Area New Orleans, Louisiana.

SECTION V

EMISSIONS SOURCES: ACCIDENTS DURING DRILLING AND PRODUCTION

Accidents during drilling and production can result in the emissions to the air and water environment. Past major accidents have resulted in environmental damage and strong public concern. Human error has been shown to account for most accidental emissions. The distance to shore from an accident is perhaps the single most important factor relating to the potential for environmental damage from accidental emissions.

EMISSIONS TO THE AIR ENVIRONMENT

Blowouts will emit hydrocarbons directly into the atmosphere and with additional hydrocarbons emitted by evaporation of oil that is dispersed on the water. The rate of emission depends upon the chemical composition of the crude oil and increases as the fraction of light ends in the crude oil increases. Also, should a fire occur with the blowout, the products of combustion--CO, NO_x, SO_x and particulates--are released into the atmosphere.

Emissions from blowouts shown in Table 20 below represent complete combustion of crude oil. In reality, the combustion would probably be incomplete, and materials such as nitrous monoxide, sulfur monoxide, petroleum particulates, and other partially oxided matter would probably be emitted into the atmosphere. At this time, there is no reliable method to estimate the quantities of emissions from the incomplete combustion of crude oil.

The average composition of natural gas delivered to pipe lines in the United States is shown below.

Methane	CH_4	72.3%
Ethane	C_2H_6	14.4%
Carbon Dioxide	CO_2	0.5%
Nitrigen	N_2	12.8%

Small amounts of sulfurs and other materials could also be present. If a gas well is not burning, these constituents would be released into the atmosphere. If the gas well were on fire, emissions would consist almost entirely of carbon dioxide and water. The nitrogen would remain as N_2 and sulfur present would be oxidized to SO_2. Quantities of emissions resulting from the blowout of a gas well are given in Table 21.

TABLE 20. ESTIMATE OF QUANTITIES OF EMISSIONS FROM BLOWOUTS FROM CRUDE OIL

	Emissions, pounds per barrel of oil discharged(26)		
	Fires(a)	Evaporation	Total
Particulate	1	--	1
SO_2 (b)	19	--	19
HC	0.1	38	38.1
CO	0.91	--	0.01
NO_x	2.5	--	2.5

(a) Burning assumed to be the same as residual oil firing in industrial burners. Emission factors from "Compilation of Air Pollutant Emission Factors", (revised), U.S. Environmental Protection Agency, Office of Air Programs, Research Triangle Park, North Carolina, April 1973.

(b) Assumes sulfur 2.9 percent

TABLE 21. ESTIMATE OF QUANTITIES OF EMISSION FROM BLOWOUT FROM NATURAL GAS. EMISSIONS, POUNDS PER MILLION CUBIC FEET BURNED(a)

Pollutant	$lb/10^6\ ft^3$ (a)
Particulates	19.0
Sulfur dioxide(b)	.6
Carbon monoxide	20.0
Hydrocarbons	8.0
Nitrogen oxides	80.0

Source: Compilation of Air Pollutant Emission Factors, Second Edition, U.S. Environmental Protection Agency, Office of Air and Water Programs, Office of Air Quality Planning and Standard, Research Triangle Park, North Carolina, April 1973.

(a) Emission factors are from domestic combustion equipment.

(b) Based on average sulfur content of natural gas of 2000 $grains/10^6\ ft^3$.

EMISSIONS TO THE WATER ENVIRONMENT

Accidental oil losses are the cause of the most evident damage to the water environment. However, they contribute only about 10 percent of an EPA estimate of 2.1 million metric tons of oil that man directly introduces to the world's oceans.[31] When other sources such as waste automobile industrial machinery oil and discharges from refinery/petrochemical operations are also considered, the often used Bureau of Land Management estimates of about 5 million metric tons per year can be approached.[16,22,23,28,32] Of this larger estimate, only 2.1 percent ($\sim$103,000 metric tons/year) has been attributed to offshore drilling and production. Accidents, such as blowouts, contribute approximately 600 barrels per day[30] ($\sim$29,500 metric tons/year). During the drilling of 14,000 offshore wells between 1937-1970 (9,000 in OCS), only 25 blowouts were reported.[33] As a further reference, natural seepage to oceans is estimated to contribute less than 0.1 to 0.2 million metric tons per year to the oceans.[34]

Oil spill statistics reported in 1974 range from a fraction of a barrel to over 150,000 barrels. Most spills are near the low end of this range. In 1972, 96 percent of spills were less than 24 barrels. In 1970 and 1972, three spills were reported each year which accounted for two-thirds of the total accidentally spilled oil in the United States for those years. The very large spills account for most of the reported losses. For example, the single Torrey Canyon accident (1967) resulted in the release of twice as much oil as was spilled in the United States in 1970. The U.S. Geological Survey reports that in the period of 1964 to the first quarter of 1974, a total of 44 oil spill incidents connected with Federal OCS oil and gas operations in the Gulf of Mexico involved 50 barrels or more, and one spill of greater than 50 barrels occurred in the California OCS. The individual incidents included above represent platform fires and blowouts, storm or ship damage to platforms, OCS pipeline failures, and OCS barge leaks.[25]

OCS-Gulf of Mexico statistics indicate that one well blowout occurs for every 2,860 wells drilled and approximately 2,100 barrels are lost in the blowout.[25] Chances of accidents during drilling and workover operations are greater than during normal production operations.[13,20,30] Most of these events have been associated with human error.

Cause of Spills

The accidental release of oil or gas in OCS drilling and production can be a result of the following: human error, equipment failure, natural hazards, or combination of these causes. Federal and industry regulations are aimed at minimizing the number and severity of such accidents.

Fires on drilling or production platforms can be ignited by a variety of events. The proximity of combustible hydrocarbon liquids or vapors to arcing electrical devices or overheated mechanical equipment is the most common cause of ignition. More rarely, lightning or static electricity may be the ignitor.[16,22,23] If a secondary combustible fluid is ignited, as opposed to the hydrocarbon being produced on the platform, a fire may be rapidly controlled with only minor damage. Once a well or storage tank becomes involved, damage is usually major. Release of large amounts of hydrocarbons to the marine environment does not always occur, however. Most fires are extinguished quickly with little damage or release.[16,22,23] If a blowing well is releasing mostly or entirely natural gas, the ocean pollution is usually minimal. An extinguished well may become reignited during repair; however, oil or gas fires fed by large amounts of condensate are usually left burning while control procedures are planned and executed. While adding pollutants to the air, marine releases are minimized and the fire hazard of large amounts of floating oil is minimized.

Surface and subsurface currents, ice, and storm surges can be the cause of accidental release of petroleum to the marine environment. The primary natural hazards in currently developed OCS areas are hurricanes and earthquakes and resulting tsunamis.

Earthquake damage can result from structural failure caused by dynamic shaking or foundation failure due to loss of soil stability or strength. Modern structural techniques can protect structures in Gulf and Atlantic areas and in many areas of the Gulf of Alaska; however, some unstable soil types in this area remain unsuitable for platform drilling and production.

To date no incidences of oil spillage resulting from damage caused by a tsunami have been recorded. Most production to date has been from areas where these seismically-induced events are relatively rare. Large underwater storage tanks and tankers in birth are the most vulnerable to tsunami damage.

Developments in the Gulf of Mexico have provided extensive experience with and explosure to hurricanes. In the past, storage tanks have been the primary cause of loss from hurricane damage. With the transition to pipeline transfer of the oil produced, the number of such tanks and thus the loss has been minimal. While physical damage can occur to the platform, little if any oil may be lost. Current OCS procedures call for the advance evacuation procedures in or adjacent to a projected hurricane path. All surface equipment and wellhead controls are shut-in before evacuation.

Spill Movement

Oil spilled onto the surface of the sea spreads and is transported by the winds and ocean movements. From the time of the spill, oil begins to weather. Oil that has been in the water for some time (weathered) is different from fresh oil. The volatile and soluble components decrease or are lost with time, with toxicity usually being reduced. However, weathered oil may still be toxic to birds and marine organisms and can remain for long periods of time in sediments.

The rate and direction of movement and spread of an oil slick from its source is dependent on the following variables which are listed generally in order of importance[35]:

- Wind direction and speed
- Sea state
- Surface currents
- Latitude
- Surface temperature
- Oil density and viscosity at temperature
- Volatility
- Inherent tendency toward emulsification with sea water
- Volume--rate of discharge at source
- Interfacial and surface tension, spreading pressure.

The probability of a spill reaching land is determined by a similar list of factors plus the added condition of distance from the source to landfall and the physiography of the shoreline. The season of the year and ambient weather conditions are important in determining the extent of the shoreline, if any, that will be affected. The trajectory of hypothetical spills in the Atlantic Ocean have been plotted with respect to distance from shore.(13) The probability of these spills reaching the shore is recorded in Table 22. Similar analyses have been done of other existing or proposed offshore oil production areas. In some areas, spills will almost always reach shore if the accident occurs near enough to land. In other areas, spills will infrequently or never reach shore. Each shoreline must be specifically analyzed to project the probability of offshore oil spill reaching shore under the range of weather and sea state conditions which are normal to that area.

TABLE 22. PROBABILITIES OF OIL SPILLS COMING ASHORE FROM HYPOTHETICAL SPILL SITES IN THE ATLANTIC OCEAN

Shore Point	Season[1]	Distance from Shore: 10 Miles East	25 Miles East	50 Miles East	75 Miles East	100 Miles East	125 Miles East	Center of EDS
Nantucket	Spring	65%	45%	30%	25%	20%	20%	15% (EDS 1)
	Autumn	30	10	5	0-5	0-5	Near 0	Near 0 (EDS 1)
Nantucket Shoals	Spring	50	50	35	30	20	20	20 (EDS 2) 35 (EDS 3)
	Winter	5	5	5	5	5	4-5	Near 0 (EDS 2) Near 0 (EDS 3)
Davis South Shoal	Spring	55	50	35	25	20	-	50 (EDS 4)
	Winter	10	10	5	5	5	-	5-10 (EDS 4)
Great South Bay[2] (Long Island)	Summer	95-100	75	10	-	-	-	10 (EDS 5)
	Winter	30	15	Near 0	-	-	-	Near 0 (EDS 5)
Atlantic City	Spring	-	20	25	15	-	-	20 (EDS 6)
	Winter	-	0-5	0-5	0-5	-	-	0-5 (EDS 6)
Fenwick Island	Spring	-	15	20	20	-	-	20 (EDS 7)
	Winter	-	0-5	0-5	5	-	-	5 (EDS 7)
Chincoteague Inlet	Spring	-	5	15	25	-	-	20 (EDS 8)
	Autumn	-	0-5	0-5	0-5	-	-	0-5 (EDS 8)
Cape Henry, Va.	Spring	-	Near 0	Near 0	Near 0	-	-	Near 0 (EDS 9)
	Autumn	-	Near 0	Near 0	Near 0	-	-	Near 0 (EDS 9)
Cape Romain, S.C.	Spring	-	95	65	Near 0	-	-	95 (EDS 10)
	Autumn	-	Near 0	Near 0	Near 0	-	-	Near 0 (EDS 10)
Savannah	Spring	-	95-100	95	80	20	-	95-100 (EDS 11)
	Autumn	-	20	5	Near 0	Near 0	-	5 (EDS 11)
Fernandina Beach, Fla.	Spring	-	95	60	25	0-5	-	90 (EDS 12)
	Winter	-	15	10	Near 0	Near 0	-	15 (EDS 12)
Daytona Beach, Fla.	Summer	-	-	-	-	-	-	50 (EDS 13)
	Autumn	-	-	-	-	-	-	Near 0 (EDS 13)

\- Computer model not run at this point.

1 Two seasons are listed for each area. In the first season, oil spilled has the highest probability of reaching shore; in the second season, oil spilled has the lowest probability. Probabilities are intermediate in the unlisted seasons.

2 The estimates for Great South Bay are distances south of the bay rather than east.

Source: Massachusetts Institute of Technology Department of Ocean Engineering.

SECTION VI

POLLUTION CONTROL

Offshore pollution control measures are required by state and Federal agencies. Federal regulatory bodies include the United States Geological Survey and the Environmental Protection Agency. A summary of the Federal and state regulations and/or standards is included in the appendix. The primary emissions to the environment, requiring control, occur during drilling and production operations. Prevention and control are emphasized. Further control of normal operation emissions appear economically limited by associated facility space/structure constraints.

GEOPHYSICAL SURVEYING

Discharges to the environment during geophysical exploration are not of expressed concern in the oil and gas literature. Air emissions from survey boats can be minimized by adjustment and timely maintenance of the engines. Sanitary wastes from survey boats can be a problem in harbors but onboard reduction, containment, and discharge to shore-based sanitary treatment systems has reduced discharges to the water environment. Oily discharges should not be a problem as the U.S. Coast Guard has established standards which make it illegal to discharge oil of any kind within U.S. territorial waters.[22]

EXPLORATORY AND DEVELOPMENT DRILLING

Pollution control practices are applied during offshore exploratory and development drilling to both minimize the accident potential and emissions from normal operations. Measures to minimize potential for blowouts and/or fires are most important to safe environmentally sound operations. During drilling of development wells and/or workover operations, the primary emissions to the air environment result from well testing and internal combustion engines. The major emissions to the water environment being controlled include the surface water disposal of drilling fluids/cuttings, deck drainage, and sanitary wastes.

Control of Accidental Emissions to the Environment

Modern practice in exploratory drilling is to use a variety of blowout preventors to minimize the chances for loss of life, destruction of the rig, loss of the well, and loss of products that can cause damage to the environment.[20] In addition, API issued specifications in November, 1973, covering design, manufacture, testing, installation, and operation of subsurface safety valves (surface and subsurface controlled).[13] The USGS requires the use of these criteria.

To minimize the potential for accidental losses of oil to the environment, the U.S. Geological Survey has established offshore development and operation criteria. These OCS orders, which are summarized in the appendix, are in some cases specific to the area of development. OCS Order #2 requires that the surface casing must be set to protect all fresh water aquifiers. In California, a minimum surface casing depth of 1,000 feet is required. OCS Order #2 also specifies the number and type of blowout preventors required. Under an assumption that half of the cost of these blowout preventors is attributable to environmental protection, the cost per "typical rig" has been estimated at 0.25 million.[20] OCS orders #5 and #8 require installation of various surface and subsurface controls to reduce the likelihood of well and/or equipment failures. Pressure measurement at the drill bit can also reduce the chances of blowouts.[13] OCS Order #7 provides for an approved emergency oil pollution clean-up plan.

A number of choices are available to deal with accidental release of oil into the environment--a spill. Present technology offers the following options: (a) do nothing, (b) set fire to the oil or gas if it is not already afire, (c) physical containment and removal, (d) dispersal, or (e) sinking.[13] Each of these alternatives is appropriate under selected conditions. To date, no environmental damage has been observed to occur from the accidental release of natural gas beyond the physical effects and/or fire damages associated with blowouts. The following discussions deal with the alternate techniques available for clean up of oil and oil products.

Leaving spills can be a viable or preferable option in offshore waters, even though the same spill would require cleanup in a nearshore environment. Small and rapidly spreading spills may not only be difficult to treat with cleanup techniques but may be best left untreated. Such would be the case of a small spill far offshore in rough seas under adverse weather conditions.

Burning of spilled oil is most often applied in conjunction with some type of containment technique. Burning of oil on water is incomplete and produces large amounts of black smoke. This contribution to air pollution may be intolerable nearshore but may not be considered prohibitive in an offshore context. The burning of spilled oil as a means of removal does not at present appear to be of widespread practicability.

Chemical agents can be applied to sink spilled oil, but the mass does not remain stable and may move both vertically and horizontally. It is also not chemically or biologically inert and the potential exists for increasing or prolonging total toxicity by the introduction of the sinking chemicals. The use of chemical dispersants presents the same sorts of potential problems. In general, chemical depressants received a bad name in the early period of their testing and development (such chemicals were used in the Torey Canyon Spill). Several of the compounds and subsequent emulsion products proved to be more toxic than the oil. Present generation chemicals are significantly less toxic and are currently being used successfully in Europe, particularly in the rough waters of the North Sea, where physical approaches are often ineffective, without lasting ecological damage.

Physical recovery approaches range from devices and/or chemicals which surround, draw together, lift off, or sponge up the oil from the water surface. Success in use of these techniques is a function of the seas and the time to deployment. Physical recovery is generally the best approach to clean up in the nearshore area. The inland waters are frequently calmer and deployment time of the large amounts of necessary equipment can be minimal with required prior planning. Physical recovery nearshore remains difficult in wave breaking stretches along the beaches where absorbent materials for later recovery may be required.

Opinions differ concerning the relative merits of chemical dispersants vs. physical containment and recovery. Further ecological and physiochemical evidence from areas in which the various techniques have been applied is required.

Control of Normal Operational Emissions to the Air Environment

Most regulations require some control device to minimize the loss of organic vapors into the atmosphere. Control equipment such as floating roof and vapor recovery systems are used to control emissions from storage tanks. The painting of storage tanks is also required as a means of reducing losses.

Exploration and development drilling is generally thought to have a relatively low potential for contribution to the air pollution problem. Diesel engines can be adjusted so that visible emissions are within regulations. The oil produced during well testing is not a substantial quantity and can be discharged into holding tanks.

Control of Normal Operational Emissions to the Water Environment

Emissions to the water environment which are being controlled include drilling fluids/cuttings, deck drainage, and sanitary wastes. Criteria and effluent regulations have been established or proposed to limit discharges to the environment (see the appendix). Treatment costs are, comparably, higher than for more stringent onshore requirements.

Drilling Fluids and Cuttings--

The handling, treatment, and disposition methods for drilling fluids/cuttings is regulated both by laws and the high cost of drilling muds. Shale shakers, disilters, and desanders are used to separate the mud from cuttings. The separated cuttings are normally dumped over the side following a washing with a solvent-water mixture to cleanse them of surface oil (always necessary when an oil-based mud is employed). The environmental effects of this disposal approach is believed to be negligible.[18]

Perhaps the major problem with the offshore dumping of waste muds and cuttings is the increase of down current turbidity. For each well drilled, it is reported that 300 tons of turbidity-producing materials are discharged.[16] However, this estimate may be high as waste muds are commonly left in dry holes and often used to fill the annulus between the casing and tubing of completed production wells. Onshore it was recommended that drilling mud not be discharged to surface waters.[36]

Deck Drainage--

Deck drainage is controlled as OCS Order #7 requires that offshore facilities must be curbed and have gutters and surge tanks to control storm drainage. Installation costs have been estimated at near $100,000 per offshore facility.[20] Deck drainage can be treated by gravity separation and/or by the coproduced water treatment system.[18] Spend acid and fracturing fluids are also usually handled by the brine water treatment system. Drip pans and separate sumps can be used to eliminate lubricating oils and other oily wastes from the deck drainage.[18,26] Waste crank case oils can also be separately contained and transported to shore for further disposition.[21]

Sanitary Wastes--

Since 1970, the offshore oil and gas industry has been required to provide sewage treatment as its necessity, at least nearshore, is readily apparent.[24] Sewage treatment normally provided is physically very similar to the common septic tank but with the addition of chlorination.[16] Package type extended aeration treatment units are also used. Recommended sizing criteria for offshore aeration systems is 10-20 lbs BOD/1,000 ft^3, with clarification retentions of 4 to 6 hours (surface overflow rate <1,000 gpd/ft^2) and 30 minute chlorine contact retention (4 times average flow).[24]

OSC Order #8 requires that sanitary effluents have a BOD <50 ppm, suspended solids <150 ppm and a chlorine residual of about 1.0 mg/l. Such effluent requirements are not considered stringent and generally should not be difficult to meet. However, as the offshore sewage treatment plants are often small and since their use due to operations can vary greatly, the treatment plans are susceptible to overloading and/or "shock" loads (especially hydraulic) and can be "killed" by toxic cleaners.[24] On an average basis, BOD and SS removal ranges around 90 percent[18]; well within OSC Order #8 criteria. Recent EPA standards for offshore sanitary wastes are less restrictive (see the appendix).

Representative costs for offshore sewage treatment have been summarized as follows[18]:

Gal/Day	Number of People	Total Annual (1973) Costs ($1,000)
2,000	25	6,010
4,000	50	7,660
6,000	75	9,360

Solid wastes are compacted and/or incinerated in burn baskets suspended from the platform. Incombustibles are transported to shore for landfill disposal.(16)

PRODUCTION

Pollution control practices are applied during offshore production to both minimize the accident potential and normal operation emissions to the environment. Control of accidental emissions has been discussed previously. Flares/vents and evaporative losses from storage tanks are considered the primary air emissions requiring control during production. During normal operations, the possible emissions to the water environment requiring control include treated coproduced brine discharges and generally of lesser importance deck drainage and sanitary wastes.

Control of Normal Operational Emissions to the Air Environment

The production of oil and gas is generally thought to have a relatively low potential for contribution to the air pollution problem. Control of evaporation from storage tanks is required. Reflection painting of tanks to reduce insolation is often required. "Smokeless" or nonluminous flares are commercially available. The hydrocarbon emission rate is estimated to be about 2×10^{-3} percent of the oil produced.(26) Power demands are normally less than during drilling. Diesel engines can be adjusted so that visible emissions are within regulations.

Control of Normal Operational Emissions to the Water Environment

Coproduced brines are the primary source of potential discharge to water environment requiring control during production and regulations exist for controlling associated effluent oil concentrations. Deck drainage and sanitary wastes are also controlled during production and well workover operations.

Environmental control practices on offshore facilities are dictated in part by proximity of the development to the coast line. For example, the production stream from the oil well in the Santa Barbara Channel is piped to shore where the oil/water/gas separation is performed. When platforms are some distance from shore, the phase separation is normally conducted at the platform and only the gas and oil are shipped to land. Separate losses of oil to the water environment, when controlled, have been estimated to average about 4×10^{-3} percent of production.

Coproduced Basic Sediment and Water--

The total dissolved solids content of coproduced waters is normally much higher than ambient surface waters but the major pollutant of expressed concern is the oil concentration in coproduced waters. As inferred from Table 23, metals and cyanides are not considered a major problem.

TABLE 23. A COMPARISON OF PROPOSED TOXIC EFFLUENT STANDARDS AND SURVEYED PRODUCTION PLATFORMS FOR TOXICANTS IN PRODUCED FORMATION WATER[36]

	Proposed Toxic Effluent Standards[a]							Surveyed Production Platform	
	Concentration, mg/l			Maximum pounds/day				Concentration, mg/l	
Toxicant	Low[b] Flow All Waters	Medium[c] Flow Fresh (Tidal)	High[d] Flow Fresh (Tidal)	Stream	Lake	Estuary	Coastal	Mean	Range
Cadmium	0	0.004 (0.032)	0.040 (0.320)	12.96	10.8	86.4	102.6	0.068	0.50-.262
Mercury	0	0.002 (0.010)	0.020 (0.100)	1.62	1.35	27.0	32.4	--	Traces
Cyanide	0	0.010 (0.010)	0.100 (0.100)	--	--	--	--	0.010	0.010

(a) Proposed EPA regulations (38 FR 35388, December 27, 1973).

(b) Less than 10 cfs.

(c) Less than 10x waste stream.

(d) More than 10x waste stream.

A wide range of control and treatment technologies have been employed to reduce oil emissions. Heater-treaters for oil/water separation are commonly used to separate "tight oil emulsions" and downhole chokes can also be used to reduce formation of emulsions.[13] Treatment approaches ending in a surface discharge include simple gravity separation, parallel and loose media coalescers, and flotation cells. Gravity separation approaches are the most prominent.

USGS OCS Order #8 requires that production waste water discharges must average less than 50 ppm oil with a maximum value less than 100 ppm. The U.S. EPA's interim BPTCA and proposed BATEA effluent limitations on oil and grease that be discharged to near-offshore and far-offshore waters are given in the appendix.

The proposed BATEA limitations provide for no discharge to near-shore waters of pollutants in produced waters. For far-offshore waters, BATEA would limit discharges of oil and grease in produced waters to 30 mg/l (average for 30 consecutive days) compared to BPTCA limits of 48 mg/l in both offshore categories. Other sources of oil and grease discharges affected by the BPTCA and BATEA limitations are deck drainage, drilling muds, drill cuttings well treatment fluids, and produced sand.

The requirement and characteristics of offshore treatment approaches can be summarized as follows:

- Tanks--the most widely used technology; often an effective separation device; large area requirement limits capacity

- Flotation systems--either diffused gas or roto/disperser systems offer good performance; they require electrical energy, but have a relatively low operating cost

- Plate coalescers--require little space and no electrical energy; subject to upset due to rapid changes in flow-rate; also frequent cleaning results in high operating costs

- Fibrous and loose media coalescers--require frequent backwashing or filter changing creating a secondary disposal problem

- Chemicals--coagulating agents, demulsifiers, or polyelectrolytes can serve to increase separation efficiencies.

Much work is reported in the literature concerning removal efforts, costs, and problems in the application of the various configurations of treatment equipment for control of oil discharges.[13,18,20,21,27,37] The best removal efficiencies are reported with air flotation cells with a final discharge concentration of about 30 ppm.[38] However, parallel plate coalescers, with an average discharge oil concentration of about 50 ppm[21], require the least area[18]. Flotation equipment requires about twice the area while loose and fibrous media coalescers need facility areas on the order of 10 times that of parallel plate coalescers.(18) Backwash wastes from coalescer operations offshore also contribute to disposal problems.(21)

The major factor which appears to dominate the final wastewater oil concentration is most often the available retention time provided. An offshore facility retention time, which can be "economically" provided, is often considered as constrained by space (generally surface area) and/or weight. For the Gulf of Mexico, the reported maximum storage capacity on an individual platform is 10,000 barrels. Onshore where treatment space area is less limiting, effluent oil concentrations below 10 mg/l can be routinely achieved with large retention capacities; often greater than 40,000 bpd.(13) The retention capacity of most offshore equipment is nearer to 1,000 bpd. To enhance oil/water separation, additional chemical treatments can be used to artificially increase retention capacities. However, for the treatment capacities normally provided offshore, only a 15 to 20 percent increase in removal efficiencies can be gained.(18)

A review of recently collected offshore effluent data indicates that test and laboratory variations can mask the field operation removal efficiency differences in treatment system types.(18,21) It is believed that differences in sample collection, preparation, and analysis procedures account for much of the noted variability. However, the observed greater variability of test results as compared to treatment type performance variability supports an opinion that effluent oil concentrations are dominately controlled by offshore facility space constraints. A review of the cost components in recent reports(18,21,27), which contain estimates of treatment costs, further support this observation. As needed, treatment retention capacities increase in order to comply with established discharge criteria offshore space requirements control treatment costs as unit space costs average about $350 per square foot (for facilities at 200-foot depths).(18) As an example, the following summary of BPT annual costs is given below.

	BPT Annual Costs (10^3 Dollars)			
	Parallel Plate Coalescer		Flotation	
(10^3 BPD)	Platform[a]	Total	Platform[b]	Total
1	110.3	143.3	201.3	238.0
2	183.8	236.8	297.8	349.5
5	332.5	398.5	735.0	870.0
10	551.3	632.0	1,102.5	1,315.5
40	3,018.8	3,191.8	3,937.5	4,413.5

(a) 2.5 x (sum of parallel plate coalescer area and surge tank area) x $350/ft^2 @ offshore depths of ~200 ft.

(b) 2.5 x (sum of flotation unit, surge tank and generator area) x $350/ft^2 @ offshore depths of ~200 ft.

BPT brine disposal costs have been estimated to run about 2 percent of net oil sales for onshore operations.(26)

Subsurface Injection of Coproduced Brine--

As an alternative to a surface discharge, coproduced bines can be injected into a subsurface formation. Brines may also be reinjected into the oil reservoir for the purposes of secondary recovery. Current industry practice is to apply minimal or no treatment to reinjection water prior to disposition. If treatment is required, it normally consists of addition of a corrosion inhibitor and a bacteriocide. Water used for reinjection must also be free of suspended matter, chemically stable, and be anoxic. A typical injection system consists of a surge tank, flotation cell, filters, retention tank, injection pumps, and well.(21)

As is the case for oil well development casing needs, extensive geologic and engineering studies are required to minimize the potential of damage to freshwater horizons.(38) For wastewater flows of 5,000 to 10,000 bpd, costs for reinjection offshore have been estimated at $1 million and $40 thousand for capital and operation maintenance costs, respectively. Coastal reinjection costs are near $0.25 million and $20 thousand.(36) Reported ratios of offshore subsurface reinjection costs to surface treatment costs range from less than 6.5 to about 9.0.(18,27) Costs of onshore reinjection are roughly comparable to the cost of the offshore surface discharge.

Treatment costs of deep well injection could be reduced as the secondary oil recovery efforts increase. However, the deeper well oil formation reinjection operation requirements must be considered. A comparison of reported surface discharge treatment costs and shallow well injection costs is shown below.

	Total Annual Costs (10^3 1973 Dollars)		
	Surface Discharge(a)	Shallow Well Injection	
(10^3 BPD)	Treatment	Onshore(b)	Offshore(c)
1	--	20.5	--
5	10-40	24.6	139
10	15-65	30.2	176
40	30-140	--	289

(a) Range of costs associated with use of parallel plate coalescers, flotation systems with or without equalization and desanding.
(b) With standby lined pond.
(c) With filtration and desanding.

Sand Disposition--

As essentially no sand is coproduced with oil offshore of Alaska, its disposal has not been a problem. Sand from offshore California is separated on land. Separated sand in the Gulf operations is normally disposed to surface water, but the sand must be purged of surface oil prior to discharge to ambient waters.

REFERENCES

1. Wagner, Fred J., "North American Drilling Activity in 1974", Bulletin, AAPG, (8) August, 1975, 1273-1310.

2. Battelle-Columbus Laboratories, "Development Potential of U.S. Continental Shelves", U.S. Department of Commerce, Environmental Science Services Administration, April, 1966.

3. Oil and Gas Journal, December 26, 1976, p 114.

4. Battelle-Columbus Laboratories, "The Economic Impact of Environmental Regulations on the Petroleum Industry--Phase II Study", Draft Final Report to American Petroleum Institute, February 13, 1976.

5. King, Robert E., "World-Wide Offshore Oil and Gas Prospects and Potential", Ocean Industry, April, 1976, pp 37-43.

6. Oil and Gas Journal, December 12, 1973, p 23.

7. Oil and Gas Journal, June 16, 1975, p 41.

8. Oil and Gas Journal, October 20, 1975, p 39.

9. Oil and Gas Journal, December 15, 1975, p 41.

10. Oil and Gas Journal, January 19, 1976, p 20.

11. McNabb, Dan, "Gas Find Reported on South Texas OCS", Oil and Gas Journal, October 27, 1975, pp 46-47.

12. Oil and Gas Journal, November 17, 1975, p 37.

13. Council on Environmental Quality, "OCS Oil and Gas--An Environmental Assessment, A Report to the President", Volumes 2-5, U.S. Government Printing Office, April, 1974.

14. "Offshore Segment of the Oil and Gas Extraction Point Source Category", Federal Register, 40 (179), Part 435, 42543-42550, 42573-42577, September 15, 1975.

15. U.S. Department of the Interior, "Draft Environmental Statement--Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf", Volume 2; DES-74-90.

16. U.S. Department of the Interior, "Final Environmental State--Proposed 1974 Outer Continental Shelf Oil and Gas General Lease Sale, Offshore Louisiana", Volume 1, FES-74-41.

17. Bettge, G. W., "Zinc Carbonate Can Control H_2S in Drilling Mud", Oil and Gas Journal, August 18, 1975, pp 128-132.

18. U.S. Environmental Protection Agency, "Draft Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category", October, 1974.

19. Smith, R. S., "Support Facilities Affect Platform Structural Design", Oil and Gas Journal, August 18, 1975, pp 120-126.

20. Battelle-Columbus Laboratories, "The Economic Impact of Environmental Regulations on the Petroleum Industry--Phase II Study", Draft Final Report to American Petroleum Institute, February 13, 1976.

21. Battelle-Columbus Laboratories, "Cost of Implementation and Capabilities of Available Technology to Comply with P.L. 92-500", Report to National Commission of Water Quality, Volume I, Industry 3 - Petroleum and Gas Extraction, July 3, 1975.

22. U.S. Department of the Interior, "Final Environmental Statement--Proposed 1975 Outer Continental Shelf Oil and Gas General Lease, Offshore Central Gulf", Volume 2, DES 74-110.

23. U.S. Department of the Interior, "Final Environmental Statement--Proposed 1974 Outer Continental Shelf Oil and Gas General Lease Sales, Offshore Texas", Volume I, FES 74-14.

24. Lintfield and Hunter, Inc., "Treatment of Domestic Sewage at Offshore Locations", Proceedings of the 8th Mississippi Water Resources Conference, April 10-11, 1973.

25. U.S. Department of the Interior, "Draft Environmental Impact Statement--Outer Continental Shelf, Northern Gulf of Alaska", June, 1975.

26. Battelle-Columbus Laboratories, "Environmental Considerations in Future Energy Growth, Volume I: Fuel/Energy Systems, Technical Summaries and Associated Environmental Burdens", Report to U.S. EPA, April, 1973.

27. Brown and Root, Inc., "Potential Impact for Produced Water Discharges From Offshore and Coastal Oil and Gas Extraction Industry", October, 1972.

28. U.S. Department of the Interior, "Draft Environmental Statement--Proposed 1975 Outer Continental Shelf Oil and Gas General Lease, Offshore Central Gulf", Volume I, FES 74-110.

29. U.S. Department of the Interior, "Draft Environmental Statement--Proposed Increase in Acreage to be Offered for Oil and Gas Leasing on the Outer Continental Shelf", Volume I, DES 74-90.

30. Kash, D. K., et al., "Energy Under the Oceans--A Technology Assessment of the Outer Continental Shelf Oil and Gas Operations", University of Oklahoma Press, 1973.

31. "Assessing Potential Ocean Pollutants", A Report of the Study Panel on Assessing Potential Ocean Pollutants to the Ocean Affairs Board Commission on Natural Resources, National Research Council, National Academy of Sciences, Washington, D.C., 1975.

32. U.S. Department of the Interior, "Final Environmental Statement--Proposed 1975 Outer Continental Shelf Oil and Gas General Lease, Offshore, Texas", Volume I, FES 74-63.

33. "Water Problems Associated with Oil Production in the United States", Interstate Oil Compact Commission (prior to 1970).

34. "Man's Impact on the Global Environment--Assessment and Recommendations for Action", Report of the Study of Critical Environmental Problems (SCEP), MIT Press, 1970.

35. Battelle Memorial Institute, Richland, Washington, "Oil Spillage Study Literature Search and Critical Evaluation for Selection of Promising Techniques to Control and Prevent Damage", November 20, 1967.

36. Reid, G. W., et al., "Brine Disposal Treatment Practices Relating to the Oil Production Industry", Oklahoma University, May, 1974.

37. Smith, R. S., "Water Treatment Design Important", Oil and Gas Journal, September 1, 1975, pp 113-116.

38. "Environmental Conservation, The Oil and Gas Industries", Volume 2, National Petroleum Council's Committee on Environmental Conservation, February, 1972.

39. "Outer Continental Shelf Resource Development Safety, A Review of Technology and Regulation for the Systematic Minimization of Environmental Intrusion", Panel on Operational Safety Offshore Resource Development for U.S. Geological Survey, December, 1972.

40. Code of Federal Register, Title 30 Mineral Resources, revised as of July 1, 1975, Part 250, pp 565-581.

41. U.S. Department of the Interior, Proposed OCS Orders for Gulf of Alaska, Federal Register, Volume 40, No. 3, January 6, 1975, pp 1086-1107.

42. Bureau of National Affairs, Inc., Environmental Reporter, State Water Laws.

APPENDIX

OFFSHORE REGULATIONS AND DISCHARGE LIMITATIONS

The majority of regulations which are designed to control oil and gas production waste emission to the air and water environment fall into three broad categories: USGS OCS orders, EPA effluent guidelines, and State requirements. As gleaned from short review of these "regulations", the OCS orders apply only to the waters in areas beyond the historic state limits, and state requirements to areas with state U.S. EPA effluent limitations are subcategorized by near-offshore (state waters) and far-offshore (seaward from state waters).

OCS ORDERS

Originally, the USGS OCS orders related primarily to safety. Lack of specific guidance, standards, tests, etc. rendered the OCS orders inadequate to protect the public interest.[39] Recent updates of the OCS orders are more specific. The "USGS Area Supervisor" is solely empowered by law to judge the "substantialness" of waste emissions to the air and water environment.

The OCS orders for the Gulf, West, and Alaska coasts are basically similar.[39-41] In fact, the first nine orders relate to the same subjects as follows:

- Marking of wells, platforms, and structures
- Drilling procedures
- Plugging and abandonment of wells
- Suspensions and determination of well producibility
- Installation of subsurface safety devices
- Procedures for completion of oil and gas wells
- Pollution and waste disposal
- Approval procedure for installation and operation
- Approval procedure for oil and gas pipelines.

The West Coast OCS order #10 concerns drilling of twin case holes. The Gulf OCS orders #10-12 relate to sulfur drilling off Louisiana and Texas, interim oil and gas production rates, and public inspection of records.(39) Topics of Alaska OCS orders #11 and #12 generally correspond to the same numbered orders for the Gulf of Mexico.

Operator reports and on-site inspections are employed for improving compliance with OCS orders. The frequency rate for inspections is approximately one every 9 months.(28) The warnings and suspensions issued by the USGS area inspectors in the Gulf during December 1, 1972, through September 30, 1974, are as follows:

	Warnings	Suspensions
Drilling	48	34
Workover	9	6
Production	3,525	2,294

All malfunctions reported as identified during special inspections averaged about 4 percent of the equipment tested during 1971-1973.(29)

EPA REGULATIONS AND EFFLUENT LIMITATIONS

There are no EPA standards governing air emission attendant with offshore drilling and production. Legislation addressing nondegradation could perhaps be utilized, but impact of the exhaust from stationary power units and service vessels is generally thought to be insignificant.(23) With regard to water quality, the EPA in September, 1975(14), established a point source category for offshore oil and gas extraction and issued in interim final form BPTCA effluent limitations and guidelines for two existing source subcategories: (1) near offshore (state water, i.e., territorial seas excluding Great Lakes), and (2) far-offshore (Federal waters, i.e., all waters seaward from the territorial seas). These effluent limitations are given in Table 24. The term "M10" refers to offshore facilities manned by 10 or more persons on a continuous basis. M9IM refers to offshore facilities continuously manned by 9 or less persons, or intermittently manned by any number of persons.

The EPA in September, 1975(14), proposed effluent limitations pertaining to the near and far-offshore subcategories for BATEA, and pretreatment standards, and new sources. The proposed BATEA effluent limitations are shown in Table 25. Proposed limitations for new sources are the same as those for BATEA.

STATE REGULATIONS TO CONTROL AIR EMISSIONS

No state regulations specifically designed to control air emissions from offshore drilling operations were located. Regulations such as open burning restrictions, visible emissions, and volatile organic substance

TABLE 24. BPCTA EFFLUENT LIMITATIONS: NEAR- AND FAR-OFFSHORE

Pollutant Parameter Waste Source	Oil and Grease: Maximum for any 1 d, Milligram Per Liter	Oil and Grease: Average of Daily Values for 30 Consecutive Days Shall Not Exceed Milligram Per Liter	Residual Chlorine Minimum for any 1 d, Milligram Per Liter
Produced Water	72	48	NA
Deck Drainage	72	48	NA
Drilling Muds	(a)	(a)	NA
Drill Cuttings	(a)	(a)	NA
Well Treatment	(a)	(a)	NA
Sanitary			
M10	NA	NA	(b)1
M91M(c)	NA	NA	NA
Domestic(c)	NA	NA	NA
Produced Sand	(a)	(a)	NA

(a) No discharge of free oil.

(b) Minimum of 1 mg/l and maintained as close to this concentration as possible.

(c) There shall be no floating solids as a result of the discharge of these wastes.

TABLE 25. PROPOSED BATEA EFFLUENT LIMITATIONS

	Oil and Grease		
	Maximum for any 1 d, Milligram Per Liter	Average of Daily Values for 30 Consecutive Days Shall Not Exceed Milligram Per Liter	Residual Chlorine Minimum for any 1 d, Milligram Per Liter
	Near-Offshore		
Deck Drainage	72	48	NA
Drilling Muds	(a)	(a)	NA
Drill Cuttings	(a)	(a)	NA
Well Treatment	(a)	(a)	NA
Sanitary			
M10	NA	NA	(b)1
M91M	NA	NA	NA
Domestic(c)	NA	NA	NA
Produced Sand	(a)	(a)	NA
Produced Water	No discharge of waste water pollutants to navigable waters(d).		
	Far-Offshore		
Produced Water	52	30	NA
Deck Drainage	52	30	NA
Drilling Muds	(a)	(a)	NA
Drill Cuttings	(a)	(a)	NA
Well Treatment	(a)	(a)	NA
Sanitary			
M10	NA	NA	(b)1
M91M(c)	NA	NA	NA
Domestic(b)	NA	NA	NA
Produced Sand	(a)	(a)	NA

(a) No discharge of free oil.

(b) Minimum of 1 mg/l and maintained as close to this concentration as possible.

(c) There shall be no floating solids as a result of the discharge of these wastes.

(d) In the event that a permit under Sec. 1421(b)(2) of the Safe Drinking Water Act is refused and there is no other reasonable means of disposal available that would comply with the BATEA standard for State waters, then the BATEA standard for Federal waters shall apply.

storage are most often utilized to control, reduce, or eliminate emissions from onshore oil and gas drilling operations.

"Open burning" means the burning of any material such that the products of combustion are emitted directly into the atmosphere without passing through a stack or flare. Most states prohibit the open burning of oil wastes. "Volatile organic substance" means any organic substance, mixture of organic substances, including but not limited to, petroleum crudes, petroleum fractions, petrochemicals, solvents, diluents, and thinners.

Visible emission regulations are expressed as percent opacity or Rengelmann number. The following table shows the Rengelmann number vs. percent opacity:

Ringelmann Number	Percent Opacity
.5	10
1.0	20
1.5	30
2.0	40
3.0	60
4.0	80
5.0	100

Most states use the 20 percent opacity for all sources, although some states still permit higher emission for older equipment. "Opacity" means the characteristic of a substance which render it partially or wholly opague to transmittance of light and causes obstruction to an observer's view.

STATE CRITERIA AND REGULATIONS TO CONTROL WATER EMISSIONS

The water criteria and regulations of nine states were sampled and briefly reviewed.(42) The "regulations" are summarized as they relate to oil, settleable solids, turbidity, and heavy metals. Applicability of criteria to oil and gas extraction in offshore waters was often not readily discernible.

Oil

Alaska--

Public water supply--below normally detectable amounts.

Swimming--no visible concentrations of oil sludge that may adversely affect use indicated.

Fish and wildlife--none permitted.

Shellfish--no visible evidence of wastes. Less than acute or chronic problem levels.

Agriculture--none in sufficient quantities to cause soil plugging.

Industrial--no visible evidence.

California--

Varies from basin to basin, but generally of following type. The waters shall be free from floating debris, oil, scum, grease, or other carried or floating materials. Phenolic compounds must be less than 0.5 and 1.0 mg/l 50 and 10 percent of the time sampled, respectively.

Florida--

Free from floating debris, oil, scum, and other floating materials attributable to municipal, industrial, agricultural, or other discharge in amounts sufficient to be unsightly or deleterious. Shall not exceed 15 mg/l or that no visible oil defined as iridescence be present to cause taste and odors or interfere with other beneficial uses.

Georgia--

All waters shall be free from oil, scum, and floating debris associated with municipal or domestic sewage, industrial waste, or other discharges in amounts sufficient to be unsightly or to interfere with legitimate water uses.

Louisiana--

There shall be no slicks of free or floating oil present in sufficient quantities to interfere with the designated uses, and emulsified oil cannot be present in sufficient quantities to interfere with the designated uses.

Massachusetts--

Bathing, shellfish, industrial waters none allowable. In recreational boating and secondary contact recreation, aesthetic enjoyment waters none allowable except those amounts that may result from the discharge from waste treatment facilities providing appropriate treatment.

New York--

In waters for recreation and fishing, none which are readily visible and attributable to sewage, industrial wastes or other wastes of which deleteriously increase the amounts of these constituents in receiving waters after opportunity for reasonable dilution and mixture with the wastes discharged thereto.

None alone or in combination with other substances or wastes in sufficient amounts or at such temperatures as to be injurious to fish life, make the waters unsafe or unsuitable as a source of water supply for drinking, culinary or food processing purposes, or impair the waters for any other best usage as determined for the specific waters which are assigned to this class.

Texas--

Substantially free from oil.

Settleable Solids

California--

(Statement varies among the 32 regional water boards but generally limits settleable solids as follows.) Less than the concentration that would change the physical nature of the stream bottom or adversely affect the aquatic environment.

Florida--

Minimum conditions of all waters; all waters shall be free from settleable substances--substances attributable to municipal, industrial, agricultural, or other discharges that will settle to form putrescent or otherwise objectionable sludge deposits.

Georgia--

All waters of the state shall be free from materials associated with municipal or domestic sewage, industrial waste, or any other waste which will settle to form sludge deposits that become putrescent, unsightly, or otherwise objectionable.

Louisiana--

None that will produce distinctly visible turbidity, solids or scum, nor shall there be any formation of slimes, bottom deposits, or sludge banks, attributable to waste discharges.

Massachusetts--

Public water supplies and recreation--none allowable. All other classifications which are sludge deposits, solid refuse, floating solids, oils, grease, and scum--non allowable except those amounts that may result from the discharge from waste treatment facilities providing appropriate treatment.

New York--

In Public Water Supply and Shellfish waters--none attributable to sewage, industrial wastes, or other wastes. All other classes--none which are readily visible and attributable to sewage, industrial wastes, or other wastes, or which deleteriously increase the amounts of these constituents in receiving waters after opportunity for reasonable dilution and mixture with the wastes discharged thereto.

New Jersey--

None noticeable in the water or deposited along the shore or on the aquatic substrate in quantities detrimental to the natural biota. None which would render the waters unsuitable for the designated uses.

Texas--

All waters of the state shall be essentially free of floating debris and settleable suspended solids conducive to the production of predescribable sludge deposits or sediment layers which would adversely affect benthic biota or other lawful uses. Essentially free of settleable suspended solids conducive to changes in the flow character of stream bottoms, to the untimely filling of reservoirs and lakes, which might result in unnecessary dredging costs.

Turbidity

Alaska--

Swimming--25 JTU (Jackson Turbidity Units)

Fish and wildlife--25 JTU

Shellfish--25 JTU.

California--
Light penetration shall not be significantly impaired by suspended or floating matter of other than natural origin. There shall be no turbidity other than of natural origin that will cause substantial visible contrast with the natural appearance of the water.

Louisiana--
No discharges that will produce distinctly visible turbidity, solids or scum, nor shall there be any formation of slimes, bottom deposits, or sludge bank attributable to waste discharges.

Massachusetts--
Freshwater--none in such concentrations that would impair specified usages.

New Jersey--
None noticeable in the water or deposited along the shore or on the aquatic substrate in quantities detrimental to the natural biota. None which would render the waters unsuitable for the designated uses.

Metals

Alaska--

USPHS Standards		Class B water supply
All toxic materials, including metals	Narrative statement	Recreation Growth propogation of fish and other aquatic wildlife, agriculture, industry.

All toxic materials, including narrative statement, shellfish metals, pesticides (heavy metal constituents) 0.001 of the LC_{50} for the most sensitive organisms on 96-hr exposure.

California--

Effluent Quality Requirements for Ocean Waters of California(18)

	Unit of Measurement	Concentration not to be Exceeded More Than: 50% of Time	10% of Time
Arsenic	mg/l	0.01	0.02
Cadmium	mg/l	0.02	0.03
Total Chromium	mg/l	0.005	0.01
Copper	mg/l	0.2	0.3
Lead	mg/l	0.1	0.2
Mercury	mg/l	0.001	0.002
Nickel	mg/l	0.1	0.2
Silver	mg/l	0.02	0.04
Zinc	mg/l	0.3	0.5

Florida--

Metal	Criteria Value in mg/l
Copper	0.50
Zinc	1.0
Chromium (hexavalent)	0.50
Chromium (total)	1.0 (in effluent) 0.05 (after mixing)
Lead	0.05
Iron	0.30

Louisiana--

All toxic materials, including metals: 0.1 48-hr TLM.

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-77-080	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Offshore Oil And Gas Extraction An Environmental Review		5. REPORT DATE July 1977 issuing date
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) N. A. Frazier, D, L. Maase, R. Clark		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Battelle Columbus Laboratories Columbus, Ohio 43201		10. PROGRAM ELEMENT NO. EHE 623
		11. CONTRACT/GRANT NO. 68-02-1323
12. SPONSORING AGENCY NAME AND ADDRESS Industrial Environmental Research Laboratory-Cin.,OH Office of Research and Development U.S. Environmental Protection Agency Cincinnati, Ohio 45268		13. TYPE OF REPORT AND PERIOD COVERED Final
		14. SPONSORING AGENCY CODE EPA/600/12
15. SUPPLEMENTARY NOTES		

16. ABSTRACT

Reported are the results of an environmental review of emission sources and emissions associated with U.S. offshore oil and gas exploration, drilling, and production. The purpose of the review was to rank technological problems of controlling these emissions. Existing or proposed effluent limitations reflect BPTCA and BATEA technologies for controlling oil in effluents to near and offshore waters. No firm basis could be developed for ranking technological problems of controlling other possible emissions to the environment. Conclusions of the small study are that additional information is needed on the fate and effect of other possible pollutants, mainly metals, that might be in discharges to offshore waters and on quantitative evaluations of air emission sources. In the information reviewed, greatest environmental concern was with accidental spills of oil that can occur during drilling and production. Little or no environmental concern with air emission sources was noted in the information reviewed.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Offshore Structures, Exploration, Vapors, Production, Drilling, Air, Water, Gases, Emission, Offshore Drilling, Oil Recovery, Air Pollution, Water Pollution		13B

18. DISTRIBUTION STATEMENT Release to the public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 68
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

☆U.S. GOVERNMENT PRINTING OFFICE: 1977— 757-056/6481