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**Evaluation of Environmental
Impacts of Outer Continental
Shelf Petroleum Development in
the Pacific Northwest and Alaska**

June 1979

Prepared for the
U.S. Department of Energy
under Contract EY-76-C-06-1830

Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
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EVALUATION OF ENVIRONMENTAL IMPACTS
OF OUTER CONTINENTAL SHELF PETROLEUM
DEVELOPMENT IN THE PACIFIC NORTHWEST
AND ALASKA

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FOREWORD

The Office of the Assistant Secretary for Environment of the Department of Energy provides environmental policy guidance based on environmental, health, and safety research. The Office of Technology Impacts (OTI) supports the Assistant Secretary through energy systems assessments and policy analyses that concentrate on environmental, health, and safety perspectives. In OTI the Technology Assessment Division (TAD) maintains a state-of-the-art awareness of existing and emerging technologies. Among TAD's responsibilities is the comprehensive assessment of the impacts of technologies as they emerge or are deployed. This report is sponsored by TAD as part of its assessment program.

The scope of this report is to: 1) describe the development of the petroleum reserves on the Oregon, Washington and Alaskan outer continental shelves (OCS); 2) characterize the technology applicable to OCS development; 3) identify the routine discharges to the marine and estuarine environment resulting from the petroleum resource development of the OCS; and 4) discuss any possible ecological impact from these routine discharges.

While it is recognized that accidental spillages of petroleum and hazardous materials do occur in OCS development and production processes and that these spillages may produce dramatic local environmental influence, assessment of impacts for such accidents is beyond the scope of the present work.

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1.0 SUMMARY AND RECOMMENDATIONS

Significant changes in the patterns of the nation's production and consumption of energy are likely to occur during the remainder of this century. The potential environmental impact of these changes will vary in effect and importance from region to region, and from site to site within regions. Mitigating strategies aimed at reducing adverse impacts may be implemented more efficiently and effectively when federal, state and local officials understand the magnitude and significance of these changes.

The scope of this report is to: 1) describe the development of petroleum reserves on the Oregon, Washington and Alaskan outer continental shelves (OCS); 2) characterize the technology applicable to OCS development; 3) identify the routine discharges to the marine and estuarine environment resulting from the petroleum resource development of the OCS; and 4) discuss any possible ecological impact from these routine discharges.

Components of the routine discharges to the marine environment from OCS development include metals in produced water, drilling muds, and borehole cuttings and chemicals in drilling mud. Hydrocarbons and oils are discharged to the oceans from ships' bilges and produced water and to the atmosphere as combustion products from ships and platform power generation sources and as evaporation products from offshore and land-based storage tanks. The number of discharged species is large and they occur as dissolved species, or suspended or settleable solids.

Offshore technologies do exist to assure that the concentrations of discharged pollutants to the oceans and atmosphere be kept to a level that complies to regulatory limits.

Where sufficient effluent data exist, we conclude that long-term ecological effects from routine discharges have not been detected and appear not to occur. However, no environmental data gathered to date are sensitive enough to test a scientific hypothesis of the nature or magnitude of impact that would occur to a site-specific population or ecosystem from this type of release. Short-term effects are localized and short-lived and are therefore ecologically insignificant.

Through the following recommendations, we believe that historical sampling methodology may be altered in the future to provide sufficiently sensitive information to allow the testing of an hypothesis to predict an ecological impact.

1. NOAA/BLM should continue chemical analysis of hydrocarbons and toxic substances in specific regions of the Alaskan OCS. These efforts must be intensified in site-specific areas of known developmental interest.
2. It is necessary to survey specific sites planned for lease activities to record species composition and particularly the occurrence of endangered and/or threatened species and sport and commercially important species. This is particularly important because the habitat diversity found in Alaska is at least as great as that represented in the whole of the lower 48 states.
3. Benchmark studies presently being conducted on the Alaskan OCS by NOAA/BLM do not meet the criteria for testing hypotheses concerning the effects on marine biota, as intended, and should be terminated. Sufficient data appropriate for the testing of these hypotheses must be collected from a given site. The expanse of sampling area must be limited while sampling intensity is increased.
4. At sites of specific interest, field experiments utilizing elevated levels of the hazardous components of the predicted effluents must be conducted to provide an assessment of safe versus toxic levels.
5. Sufficient quantitative data on refinery effluents, the receiving waters or sediments are not available to evaluate impacts from refining operations. Specific chemical data from analyses of refinery effluents and the environment into which they discharge are needed. It is likely that the effects from refineries in shallow water will be greater than those from platforms on the OCS.

6. Government/Industry Research and Development (R&D) and testing programs should be undertaken to insure optimal regulation and rapid development of new equipment and procedures to fill any gaps that are identified in the OCS technology and environmental areas. A comprehensive listing of OCS technology weaknesses has been published by Kash et al. (1973) and divided into three categories: need to be developed, need to be improved, and need to be deployed. The individual items appear to be realistically presented.

2.0 INTRODUCTION

Outer continental shelf (OCS) resources are public resources. Offshore oil and gas production on the OCS is expanding rapidly and may contribute up to 54 billion barrels of oil and 236 trillion ft³ of gas to domestic supplies in the future (Stephens, Braxton and Stephens 1977).

Early oil production in coastal areas started before the turn of the century from piers extending offshore. The first offshore well built on a platform out of sight of land was completed in 1947 off the coast of Louisiana. The first sale for leasing oil and gas right on the OCS to private persons took place in October, 1954.

More than 22,400 wells have been drilled in state and federal offshore areas (Exxon 1978). Of these, well over 10,000 wells are still producing oil or gas. In 1971, offshore wells produced a maximum of about 614 million barrels of oil and 4 trillion cubic feet of gas (Kash et al. 1973). These numbers decreased steadily to about 501 million barrels of oil in 1975. During this six-year period (1971-1975) the contribution of offshore oil to total U.S. production decreased from about 17.8% to 16.4% (Frazier, Maase and Clark 1977).

The purpose of this report is to review the history and prospects for OCS petroleum development in the Pacific Northwest, and Alaska, current OCS oil technology, to describe the routine releases to the marine and estuarine environment from oil technology facilities and to investigate the possible ecological effects to marine and estuarine organisms from continued OCS petroleum development.

3.0 THE DEVELOPMENT OF PETROLEUM RESERVES ON THE OREGON, WASHINGTON AND ALASKA OUTER CONTINENTAL SHELVES

Presently only the Alaskan OCS is of regional interest to the petroleum industry. This hasn't always been the case and in the future, it is possible that the Pacific Northwest OCS could play a part in petroleum resource development.

3.1 OREGON AND WASHINGTON

In the early 1960's several oil companies were interested in the OCS of Washington and Oregon. A federal lease sale of about 600,000 acres occurred in October 1964. The five-year period, 1961 through 1965, was a time of vigorous activity involving geophysical studies and test drilling. By the end of 1966, the oil industry had spent an estimated \$73 million to test promising offshore locations (Newton 1967). Shell Oil Company had expended perhaps 35%, while 16 other companies spent the remaining 65%. Of the 16 firms, Pan American Petroleum, Union Oil Company, and Standard Oil Company of California (now Chevron) were the main contributors.

A promising petroleum producing area is confirmed by examination of geophysical data obtained by the individual petroleum industry drilling operations. Assessment of these geophysical data and well-logs lies solely with the oil company personnel because of its proprietary nature. Recently, some of this information from offshore Oregon and Washington was made public (Ziegler and Cassell 1978). Without this proprietary information many deductions can still be made concerning the offshore prospects by observing the activity of the exploration companies. Newton (1967) published a summary of his observations. They are discussed here briefly.

Cancellations occurred following the drilling of deep holes in the lease block off Willapa, Washington, and in the Alsea, Siletz and Heceta offshore lease blocks off Oregon. Undoubtedly the drilling showed these areas to be unproductive. Just as significant, Standard Oil of California and Union Oil Company retained leases near the hole in the Siletz lease block

on the west flank of Stonewall Bank. Several more examples of lease retentions are covered by Newton (1967). All in all, the geologic findings by these oil companies were partly encouraging and partly discouraging.

Four wells were drilled off the Washington coast and eight exploratory wells were drilled from about 10 to 28 miles off the Oregon coast as shown in Figure 3.1. Table 3.1 contains specific information about each well. Oil traces were found in all offshore basins but every hole was abandoned and filled with cement. In Coos Bay Basin, the Pan American well #112 (Table 3.1) drillstem-tested gas at rates of 49 and 68 MCFGPD (million cubic feet of gas per day) on two tests of a zone that contained gas shows. In Willapa Basin two zones with hydrocarbon shows were drillstem-tested in the Shell well #150 with the deeper zone yielding 10 to 26 MCFGPD and the upper zone yielding only gas cut mud. Oil stained strata in the Shell #072 in Astoria Basin and the Shell #155 in Willapa Basin have sample fluorescence colors of green, green/yellow, and white/yellow, which are indicative of medium-to-high oil gravities, probably comparable to onshore gravities of 38.9° found at Ocean City, Washington, on the east margin of the Willapa Basin (Ziegler and Cassell 1978). These "shows" are of not sufficient quantity to encourage additional expenditure of time and money by the industry. The federal leases terminated in December 1969.

The Pacific Northwest was included on the U.S. Department of Interior's OCS Planning Schedule as late as 1976. In response to a mid-1977 Department of Interior poll, industry ranked offshore Oregon and Washington as its lowest priority OCS area of interest (Ziegler and Cassell 1978). Hence, the Oregon and Washington OCS has now been removed from lease sale consideration as of the August 1977 OCS Planning Schedule (Table 3.2).

The results of drilling in the Northwest OCS to date are not as discouraging to all as they appear to be to some (Newton 1967). Rather, this cycle of exploration helped define the more promising areas for future exploratory effort, and contributed much information to further the technology of marine drilling operations. Sedimentary rocks exist on the shelf in great

FIGURE 3.1. Index Map Offshore Oregon and Washington (Ziegler & Cassell 1978) (reproduced with permission)

TABLE 3.1. Exploratory Drilling in the Pacific Northwest OCS (Ziegler and Cassell 1978)

Company	Location	Lease No.	Abandonment	Water Depth (ft)	Hole Depth (ft)
	Washington				
Pan American Petroleum	Off Hoh Head	P0 141	7/9/67	290	10,368
Shell Oil Company	Off Willapa Bay	P0 150	4/17/66 6/4/66	237	8,666 13,179
Shell Oil Company	Off Copalis Beach	P0 155	8/20/67	230	11,162
	Oregon				
Shell Oil Company	Off Tillamook	P0 72 P0 75	3/14/66 7/2/66	469 408	8,219 10,165
Shell Oil Company	Off Newport	P0 87	8/25/65 10/17/65	321 324	3,348 8,253
Union Oil Company	Off Newport	P0 93	10/13/66	195	10,010
Standard Oil of California	Off Newport	P0 103	8/5/65	419	12,627
Pan American Petroleum	Off Coos Bay	P0 112	5/14/67	356	6,146
Union Oil Company	Off Coos Bay	P0 130	8/24/66	404	12,285

TABLE 3.2. Proposed OCS Planning Schedule - August 1977 (USDI)

SALE AREA	1977					1978					1979					1980					1981																				
	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
CI Cook Inlet		N	S																																						
42 N. Atlantic	F	P		N	S																																				
43 South Atlantic- Georgia Embayment			F	P		N	S																																		
45 Gulf of Mexico				F	P		N	S																																	
65 Eastern Gulf of Mexico					E	H			F	P		N	S																												
51 Gulf of Mexico					E	H			F	P		N	S																												
49 Mid-Atlantic		T				E	H		F	P		N	S																												
48 Southern California										E	H		F	P		N	S																								
58 Gulf of Mexico			C	D	T					E	H		F	P		N	S																								
54 South Atlantic- Blake Plateau		C					T				E	H		F	P		N	S																							
Federal/State Beaufort (near shore)			C	D			T				E	H		F		N	S																								
55 Gulf of Alaska								C	D		T				E	H		F	P		N	S																			
62 Gulf of Mexico										C	D		T			E	H		F	P		N	S																		
46 Kodiak															E	H		F	P		N	S																			
52 North Atlantic											C	D		T			E	H		F	P		N	S																	
53 Central and Northern California			C						D		T							E	H		F	P		N	S																
60 Cook Inlet												C	D		T			E		H		F	P		N	S															
56 South Atlantic- Georgia Embayment													C	D		T			E	H		F	P		N	S															
59 Mid-Atlantic															C	D		T						E	H		F	P		N	S										
66 Gulf of Mexico																C	D		T					E	H		F	P		N	S										
57 Bering-Norton													C				D		T					E	H			F	P		N	S									

C - Call for Nominations
 D - Nominations Due
 T - Announcement of Tracts
 E - Draft Environmental Statement
 H - Public Hearing
 F - Final Environmental Statement
 P - Proposed Notice of Sale
 N - Notice of Sale
 S - Sale

thickness and extend over 9000 square miles off Oregon and Washington. Newton (1978) estimates about 0.5 billion barrels of oil are to be found off Oregon alone and possibly as much as 1.0 billion.

Why was the activity on the Oregon and Washington OCS so short-lived? It was the press of competition for productive lands in California and Alaska, coupled with the drilling of several dry holes, that dampened the activity off the Pacific Northwest.

If a discovery is made in a new area, the whole industry must decide whether or not to rush in and obtain land rather than allow one or two firms to control a significant amount of potential production. This sort of competition can take exploration capital away from one prospective area to another in a short time. This appears to be what happened to Oregon and Washington.

Geophysical exploration began off Oregon in 1961, just two years before the Shell-Standard-Richfield discovery in Cook Inlet, Alaska, and four years before the U.S. Supreme Court awarded submerged lands off southern California to the federal government.

The first federal sale off the coast of southern California was held in December 1966 off Santa Barbara County. By this date, an average of 12 drilling rigs operated in the upper Cook Inlet. The rapid transition of the upper Cook Inlet within a three-year period from a wildcat test to an important producing area points out the necessity of competing in new areas.

3.2 ALASKA

Alaska is currently a hotbed of offshore oil exploration. There are a number of areas either sold or being considered for lease sale. In addition to the lease sales discussed in this section, Table 3.2 shows a near shore sale in the Beaufort Sea (late-1979), and a second lease sale for the Gulf of Alaska (mid-1980). Cook Inlet lands will again be offered in early 1981, followed by the Norton Basin of the Bering Sea in late 1981.

The Proposed OCS Planning Schedule (Table 3.2) is updated periodically and usually contains significant changes.

3.2.1 Upper Cook Inlet

Competitive oil and gas leasing of offshore state lands in upper Cook Inlet began December 1959 (Figure 3.2). Since then 19 such sales have been held in the same location for a cumulative total of 1.9 million acres. The last sale was held in 1974. The upper Cook Inlet has accounted for the majority of the total oil and gas production from state lands with 700 million barrels of oil and 743 billion cubic feet of gas having been produced through 1975 (USDI 1976).

In June 1975 the U.S. Supreme Court held that the State of Alaska did not have rights to lease land in lower Cook Inlet, and that the U.S. Federal Government had paramount rights to the land beneath the waters of that area.

FIGURE 3.2. Oil and Gas Development Areas in the Gulf of Alaska

3.2.2 Northern Gulf of Alaska

A Draft Environmental Statement was issued on the northern Gulf of Alaska in mid-1975. In April 1976, the first federal lease sale was held for lands in the northern Gulf of Alaska (Figure 3.2). Drilling permits were obtained and exploratory drilling began in October 1976. To this date, nine holes have been drilled with no discovery of marketable resources. The last active drill ship, belonging to Exxon, abandoned its last hole on July 9, 1978 and sailed to Brazil. A few years remain on area leases.

The northern Gulf of Alaska lease sale involved 1.8 million acres of ocean bottom located about 22 miles offshore. The estimated peak volume of crude oil produced will be 550,000 bbls/day and about 1 billion cf/day peak gas production (USDI 1976).

Exploratory drilling should be completed at the end of the seventh year following lease issuance. Onsite platform construction and installation (numbering about 22, 18 oil and 4 gas) will begin during the fifth year after the lease sale and continue through the tenth year. Peak oil production is expected to occur 10 to 11 years after the lease sale. The life expectancy of each of the seven oil and gas fields is 25 years and the last platforms will be removed about 40 years after production has commenced.

It is estimated that exploratory wells will range from 70 to 100 and production wells will total 800 for a total of almost 900 wells (USDI 1976). Of these 300 development wells, 640 will be platform wells and 160 will be subsea wells.

There will be 7 to 14 major pipelines totaling 300 miles in length, of which 50 miles will be constructed onshore and 250 miles will be submarine.

Of the total annual production, 120 million barrels will be transported by pipeline from the platform to shore and from the shore-based storage to market by tanker. About 80 million barrels will be loaded directly onto tankers from offshore terminals in the vicinity of the fields.

No petroleum refineries are expected to be constructed in Alaska as a result of the sale. No fabrication of platforms is anticipated to occur in

Alaska. However, three onshore terminal facilities, three support/supply facilities and one LNG plant are planned for construction (Hershman and Feldmann 1978).

The produced natural gas is expected to be marketed.

3.2.3 Lower Cook Inlet

Cook Inlet is a shallow (averaging 200 feet), large tidal estuary that flows into the Gulf of Alaska. In September 1975, the lower Cook Inlet (Figure 3.2) call for nominations was published in the Federal Register, Vol. 40 (184) by the Bureau of Land Management (BLM). The sale was held in October of 1977. Because the lease sale was only the second ever held on the Alaska OCS, and because data from the first sale is not yet available, detailed information useful for projecting future production activities is lacking. However, the resource supply, production and development timetable assumptions which follow are based on interpretation of the upper Cook Inlet geologic data, and the anticipated development requirements of the lower Cook Inlet. The lease sale included about 350,000 acres of the OCS lands in lower Cook Inlet. The USDI (1976) has estimated the minimum and maximum recoverable oil and gas resources within the sale area to be 0.09 to 2.6 billion bbls of oil and 0.6 to 3.3 trillion cf of gas. The estimated peak volume of crude oil produced will be 930,000 bbls/day and the peak gas production will be 465 million cf/day (USDI 1976).

Marathon Oil Company began drilling lower Cook Inlet on July 21, 1978. As of early 1979, Marathon had abandoned its 13,315 foot wildcat well (Oil and Gas Journal 1979). It is expected that about 84 exploratory wells will be drilled. Exploratory drilling will be completed at the end of 1986. Four hundred and forty production wells are anticipated. Peak oil production is anticipated to occur about 1985.

Onsite platform installation should begin about 1981 and continue through 1986. Twenty-three platforms will be required (21 oil and 2 gas). The life expectancy of the oil and gas fields is 25 years, and the last platform will be removed about 40 years after production has commenced.

About 300 miles of pipelines will be constructed of which 100 miles will be onshore. The volume of disturbed sediments from pipeline burial in this site area is estimated to range from 3000 to 8000 yd³/mile (USDI 1976).

Of total peak annual production, all 340 million bbls of oil will be transported to land by pipeline and from shore storage to market areas by tanker. Two new onshore terminals and two production treatment facilities are planned to accomodate the oil brought onshore (Hershman and Feldmann 1978).

No petroleum refineries are expected to be constructed in Alaska as a result of the sale. No manufacturing of platforms is anticipated to occur in Alaska.

The natural gas produced offshore will be marketed, and there will be one liquefied natural gas (LNG) plant constructed onshore around 1984. Two new onshore terminals, and two production treatment facilities are assumed with all other production going to existing facilities (USDI 1976).

3.2.4 Western Gulf of Alaska - Kodiak

A third lease sale is scheduled in Alaskan waters. This will be a joint federal-state sale in the western Gulf of Alaska - Kodiak currently scheduled for October, 1980 (Figure 3.2). This lease sale will involve 3.2 million acres (USDI 1976). Petroleum development in the western Gulf of Alaska depends in large part upon the volume of recoverable oil and gas resources, current technology, economic incentives, and the availability of capital, manpower, equipment, and space.

About 68 exploratory wells are anticipated followed by 400 production wells (USDI n.d.d.). The estimated peak volume of crude oil produced will be 515,000 bbls/day and the peak gas production will be 258 million cf/day (USDI 1976). These estimates are based on interpretation of geologic data and the anticipated development requirements.

Onsite platform installations (numbering about 10) will begin during the fourth year after the lease sale and continue through the ninth year which is also the estimated peak production year. The life expectancy of the oil and gas fields is 25 years, and the last platform will be removed about 40 years after production has started (USDI 1976).

Oil will be transported to shore by pipeline and from shore storage to market areas by tanker.

A total of 450 miles of pipelines will be built, of which 50 miles will be constructed onshore and 400 miles will be submarine (USDI 1976), of which about 300 miles will be buried (USDI n.d.d.).

No petroleum refineries are expected to be constructed in Alaska as a result of the sale.

The produced natural gas will be consumed on the platforms or reinjected into the formation.

The USDI (1976) estimates that a maximum of 10,740 barrels of oil will be spilled in the western Gulf of Alaska during the peak production year (5.7×10^{-5} barrels lost per barrel produced). This does not include 2,100 barrels spilled from the projected blowout of one well sometime during the life of production. A total of 36,000 barrels will be spilled from tankers either in the area, along the transportation routes, or at their final destination. Over the 25-year production life about 433,000 barrels would be spilled by the activity breakdown shown in Table 3.3 and using the projected yearly production.

TABLE 3.3. Anticipated Annual Oil Spillage During Peak Production in the Western Gulf of Alaska (USDI 1976)

<u>Sources</u>	<u>Maximum Annual Spillage (Barrels)</u>	<u>Cumulative 25 Year Total (Barrels)(a)</u>
Pipeline Accidents	3,200	32,000
Formation Water ^(a)	1,440	36,000
Spills from Platform Fires	5,500	55,000
Overflow, Malfunction or Rupture	100	1,030
Minor Spills (less than 50 bbls-all sources)	<u>500</u>	<u>5,130</u>
Subtotal	10,740	129,160
Tankers	<u>30,000</u>	<u>304,000</u>
Total	40,740	433,160

(a)The cumulative totals are not based on peak year production spillage rates, but on the yearly projected production.

4.0 OUTER CONTINENTAL SHELF OIL TECHNOLOGY

Several major individual technologies contribute to the OCS oil technology. Regional exploration is utilized to identify major geologic formations which have a potential for containing oil and gas. When these formations are located, more extensive and detailed site-specific information is developed. If the area is still of interest after evaluating that data, exploratory drilling begins to verify the existence of petroleum and to determine the geometry of the reservoir. Upon determining that commercial quantities of oil and/or gas are present, the wells are completed and production begins. A method for crude petroleum transport will be implemented to move the crude to shore for refining and distribution.

A brief description of these technologies is presented followed by a discussion of the routine releases to the marine and estuarine environments.

4.1 EXPLORATION

Exploratory techniques are employed to locate submarine geological formations that potentially contain oil and gas reservoirs. Exploration is generally divided into three main activities.

1. Regional surveys to identify attractive geological areas;
2. Detailed surveys to evaluate specific tracts; and
3. Exploratory drilling to determine whether oil and gas are actually present and to characterize the geometry of the reservoir.

Industry needs good survey data to determine the value of the tract. Government also must use the data to determine the value of the tract it plans to put up on bids. In addition, the OCS Lands Act requires sufficient data to determine the environmental impact of developing a particular tract, for prescribing and enforcing waste disposal regulations and to conserve the natural resource.

To further guard against adverse environmental impacts during exploration, there are cooperative agreements among the National Marine Fisheries Service, the Bureau of Sport Fisheries and Wildlife, the Bureau of Land Management (BLM), and the Geological Survey concerning pollution, use of explosives, and obstructions to fishing.

The three phases of exploration are briefly described below:

4.1.1 Regional Surveys

Most regional reconnaissance techniques are passive and therefore their physical impacts on the environment are nil. Regional oil exploration is generally carried out utilizing passive techniques. Air- or ship-borne measurements of changes in the earth's magnetic field, local variations in the earth's gravity and the existence of natural oil seeps are techniques commonly employed. Gravimetric methods have been used extensively in locating submarine salt domes in the Gulf of Mexico, and natural seeps gave early indications of oil deposits off southern California.

4.1.2 Site Specific Surveys

When a regional survey indicates that an area warrants further exploration, more intensive techniques are used. Modern seismic survey equipment is self-contained and its use does not create a definable adverse environmental impact. However, seabed sampling and coring does physically impact the immediate location of the sampling.

4.1.2.1 Seismic Surveys

Seismic surveying is frequently the technique of choice for the pre-lease sale phase of exploration. This technique is carried out by one or more ships working as a team. An energy source used to generate sound waves in the water is towed by a surface vessel. The sound waves are reflected and refracted by the subsurface geologic strata. The returning signals are picked up by hydrophones, towed from the same ship or a team ship, and recorded on board for future analysis. From these data, a three-dimensional picture is generated showing the location of geologic structures favorable for harboring oil and gas deposits.

The modern energy sources used to generate sound waves are self-contained. They are either gas-operated guns, sparkers or high-powered oscillators.

4.1.2.2 Bottom Sampling and Coring

A special limited permit from the USGS is required prior to any seabed disturbance. When this activity is permitted, samples obtained, under the close supervision of the USGS, must be made available to them. The permits are restrictive in depth of penetration, varying with type of subsurface material encountered. The purpose of the restrictions is to reduce the possibility of blowouts or other adverse environmental effects and to preclude the testing of potentially productive formations in advance of a lease sale.

4.1.2.3 Hydrocarbon Sniffing

Hydrocarbon sniffing is a technique used to detect remnant traces of the mobile low-molecular-weight hydrocarbons; e.g., methane, ethane, propane, etc., which have migrated up to the sediment water interface. Bubbles may be formed and detected acoustically whereas the solubilized fraction may be detected and measured at sea. This technique has been a bench-top research tool for several years and has been used in terrestrial exploration efforts. Earlier models have been used in offshore seep detection. In the late 1960's almost every major oil company initiated programs for underwater seep detection (Sackett 1977). Water as deep as 185 m may be sampled at ship speeds up to 6 knots. The sample gas is stripped with helium and passed into a gas chromatograph equipped with flame ionization detector.

4.2 EXPLORATORY AND DEVELOPMENT DRILLING

Non-destructive exploration techniques can only indicate potential geologic structures which may contain petroleum hydrocarbons. To further investigate these structures, drill cores must be brought to the surface for qualitative and quantitative evaluation for the presence of petroleum. However, prior to the commencement of drilling activities, interested drillers must obtain a series of permits.

4.2.1 Drilling Permits

Exploratory drilling is not permitted until after a tract has been purchased in a lease sale and all permits obtained. Tracts are granted by the Secretary of the Interior to the highest responsible competitive bidder. Within the Department of the Interior, the Bureau of Land Management (BLM) is directly responsible for administering the leasing system. The BLM issues a call for nominations specifying the general locations where oil and gas reserves look favorable. The Director of BLM then selects the tracts to be sold. OCS lease sales are considered to be major federal actions which could have significant environmental impacts. Therefore, BLM is required to prepare an environmental statement for each proposed sale (USDI 1975; 1976; 1977; n.d.d.). An OCS planning schedule showing the sale areas and proposed timing of each regulatory event is shown in Table 3.2. This schedule calls for 20 months between the call for nominations and the ultimate sale of the tract. The award of a lease assigns to the lessee "the exclusive right and privilege to drill for, mine, extract, remove and dispose of oil and gas deposits, except helium gas, in or under" the area described in the lease agreement.

Detailed regulatory requirements for exploring, developing, producing, and transporting oil and gas on the OCS are set forth in OCS orders for each of the USGS areas. The USGS has broad responsibilities for overseeing these activities. However, other agencies also have inputs. The Corps of Engineers must approve all offshore structures, including movable drill rigs; the Coast Guard sets requirements for marking structures, for specifying personnel safety equipment and procedures, and for monitoring pollution on the OCS. EPA sets pollution standards, issues discharge permits, and consults with the other agencies on questions of environmental impact of OCS operations; and the Occupational Safety and Health Administration (OSHA) develops standards for and conducts inspections of the working environment.

The lessee submits a detailed exploratory drilling plan to the USGS area supervisor which includes pollution prevention and control features.

Upon approval of the lessee's "Permit to Drill," the lessee may proceed.

4.2.2 Exploratory Drilling Platforms

The drilling equipment used for offshore wells is similar to that used on land. In addition, in the offshore environment, a platform is required to support the drill rig and associated equipment. Four basic types of platforms are now being used offshore: barges, drill ships, jack-ups and semi-submersibles. These platforms are briefly described in Section 5.2. Detailed descriptions of these options are published elsewhere. (Kash et al. 1973; ETA Offshore Seminars 1976).

4.2.3 Drilling Muds

Rotary drilling began in 1900. Very often the statement is made that the drilling industry has changed very little since the introduction of rotary drilling. In truth, the drilling business has changed substantially but the process has been evolutionary rather than revolutionary.

Technology is often applied as separate packages rather than total concepts. It is common to consider improvements in muds, bits and other accessory equipment separately. Many believe that any problem in drilling can be related to the high density fluid called drilling mud. Mud cannot be blamed with all the problems; however, mud has been properly termed the heart of the drilling operation.

An exploratory hole is drilled using a rotary drill. Cuttings from the drill bit are removed by the drilling mud which is pumped down through the drill string. The mud washes the cuttings from the bit and the bottom of the hole and carries them back to the surface through the outer annulus of the marine riser. At the surface, the mud enters a shale shaker which removes the suspended cuttings. From the shaker the mud may go to a cyclone separator before it goes back to the mud pit for recycle. In addition to cutting removal, mud acts to prevent blowouts by keeping geologic formation pressures constant thereby preventing the flow of liquids or gases from the formations being drilled; provides drill string lubrication, cooling, corrosion protection; and provides an aid to formation evaluation.

Special muds are generally introduced to combat specific hole problems, to reduce the cost of drilling and to help information evaluation. It is not

uncommon for special muds to be re-introduced after being discarded in prior years. In recent years the industry has moved toward the use of polymers, the re-application of inhibited muds used in past years and new mixtures of inhibited muds (Moore 1974).

Polymer type muds first became popular because of the trend toward low-solids muds. In low-solids, low-weight muds, polymers were used to replace bentonite and other low-gravity solids. In the inhibited muds, the polymers have been used to encapsulate the clay solids to minimize hydration. Moore, (1974) concludes that because changes are still being made and because material costs fluctuate, no recommendation can be made on the general use of polymers.

4.2.4 Blowout Preventers

Since blowouts are dangerous, expensive, environmentally damaging, and attract public attention, a number of safeguards in addition to drilling mud are used to minimize the likelihood of their occurrence. These include setting casing and installing blowout preventers (BOP's). The casings, measuring up to 36 inches in diameter, are cemented into place. The depth required depends upon the sub-surface structural features and pressures expected to be present. Surface casings also provide an attachment for the BOP stack.

Drilling and blowout control technologies have been advancing recently. The blowout rate has been about one for every 500 holes drilled on the OCS for the period of 1953-1971 (Kash et al. 1973). The magnitude of spill estimates often varies over an order of magnitude.

Successful drilling involves a delicate balance between drilling mud weight and downhole pressure. Any sudden loss of mud, increase in downhole pressure or sudden change in drilling rate can mean danger.

During trips--moving the drill string into or out of the well bore--the drilling mud characteristics are very difficult to monitor, leading from vulnerability to danger.

One solution recently put forth involves the development of continuous pressure readout instrumentation for the drill bit face. When a potential blowout is indicated, the first response is generally to increase mud, density

and pumping rate. If this action is not sufficient, the next step is to close any or all of the three hydraulically actuated BOP's. The top two BOP's close around the drill pipe. It is still possible to have a blowout through the drill pipe if the kelly (heavy square or hexagonal steel member connected to drill pipe to turn the drill string) is not attached. Under these circumstances it is necessary to close the third BOP, called a blind ram, which deforms or crimps the pipe and closes the hole.

An alternative form of the third preventer is a shear ram, which shears off the drill pipe completely and allows it to drop into the hole.

Another alternative, recently developed and not often used as yet, is an internal preventer to close off flow through the drill pipe.

Although technological developments could contribute to more effective identification and control kicks or mud loss, the industry identifies human error as the major problem. Specifically the problem is identified as inexperience, poorly trained personnel, or inadequate procedures (Kash et al. 1973).

Based on the analysis of OCS accidents presented by Kash et al., an average of nearly two major drilling blowouts may be expected to occur on the OCS each year. This figure is based on a drilling accident rate of 0.19% and an average of 900 new wells being started each year. In addition, two major production accidents can be expected on the basis of a production accident rate of 0.034% and a total of 6,000 producing wells on the OCS.

4.2.5 Desirable Changes to Drilling

Kash et al. (1973) listed 8 possible changes or improvements in blowout and drilling technology which could help reduce the possibility of these accidents:

1. Longer-lasting drill bits would reduce the number of trips and thus the risk involved in this most hazardous part of the operation.
2. Improved downhole instrumentation could contribute to earlier identification of potential blowouts. Specifically, to measure pressure at the face of the bit would permit drilling personnel to react more quickly to potential blowouts.

3. Separation of wellheads and fail-safe design of multi-well platforms could reduce the likelihood of massive accidents as a result of single failure.
4. The installation of distant and protected control consoles for all BOP stacks would make it possible to actuate the BOP's after well control has been lost.
5. Requiring the use of a mud monitoring system that can measure the sudden gain or loss of quantities on the order of one barrel of mud could facilitate earlier detection of potential blowouts.
6. Improved training procedures using the latest simulation techniques and more follow-up would insure a high level of performance on the part of all operating personnel.
7. Continued development of automatic drilling technology could help to eliminate human error.
8. Developing survivable event recorders, similar in function to the crash recorders required for commercial aircraft, could provide a record of equipment malfunctions causing or contributing to an accident.

4.3 COMPLETION

If commercial quantities of petroleum are found during exploratory drilling, the well is completed. Completion is the term used to describe the activities required to convert a well into a production facility. Completion may include setting and cementing casing; perforating casing, permitting oil and gas to enter the well from the surrounding formation; fracturing the formation to increase permeability; acidizing to open up parts of the formation; consolidating sand and installing downhole safety devices such as BOP's.

It is estimated that an average of 45% of the known OCS oil will be recovered. Current Louisiana values are about 46.5% while California is only expecting to recover about 24% of the known oil in place. The overall U.S. domestic production, both onshore and offshore is only 31% (National Petroleum Council n.d.d.).

4.4 PRODUCTION

From the wellhead, the product flows through a group of valves and fittings (the Christmas tree) on its way to treatment facilities. The Christmas tree directs the fluids to treatment facilities, closes off the well in the event of a malfunction or emergency, limits the well flow rate by the use of chokes and permits testing and workover or servicing operations to be performed on the well.

The nature of the treatment facility depends upon the composition of the product. Discarded fluids, produced water, brines, etc. must average not greater than 50 ppm oil after passing through the oil-water separator. This is equivalent to a loss of about 6 barrels per million barrels of oil produced (NAS 1975). After all major contaminants (gas, water and sand) have been removed, the gas or oil passes through Lease Automatic Custody Transfer (LACT) hardware where it is measured and its quality verified before entering the pipeline to shore.

Oil is lost to the environment through minor offshore operating spills. The National Academy of Sciences (1975) developed a loss factor of 2.6×10^{-6} barrels per barrel of oil produced which should be representative of U.S. offshore operations. This loss factor is 22 times lower than the one inferred by the USDI (1976). The NAS predicts about 1500 barrels of oil per year are lost due to minor spills from routine U.S. offshore operations. The losses due to minor offshore spills outside the United States are estimated to be about 62,000 barrels per year. This loss is about a factor of 10 lower than the 700,000 barrel figure Kash et al. (1973) reported for the year 1969-1970.

4.4.1 Subsea Production System Trends

As the potential for onshore oil and gas discoveries diminishes, oil operations are moving offshore. This trend is worldwide as shown by the rapid use in total offshore acreage under lease. The Gulf of Mexico sale in October, 1974 offered more than 500,000 acres. In this sale, 89 tracts were in water depths ranging from 400 to 2000 feet. This seaward progress demands more sophisticated technology be developed and implemented. Drilling contractors who are responsible for the design of most new rigs, have continually increased the depth capabilities of new rig designs.

In 1973, 10 million barrels/day were being produced from offshore operations. It has been estimated that by 1985, the production output from offshore will reach 25 million barrels/day (ETA Offshore Seminars 1976).

4.4.2 Systems

The SEAL Systems - an international consortium has developed two subsea production systems--the SEAL single-well completion and the multiple-well manifold/production station.

The single-well system is designed for individual wells drilled vertically with production rates ranging to 10,000 barrels/day.

The multiple-well system is intended for use where directional drilling is possible. A number of wells are drilled around the periphery of the manifold/production station through a base template. Wells are connected to the enclosure by a special wellhead connector assembly. The manifold/production station may also be used strictly as a manifold station for fields developed by widely spaced, vertically drilled wells.

4.4.3 Desirable Changes in Production

Kash et al. (1973) lists 7 possible long-term improvements in offshore operations. There are production technology modifications and developments which could benefit the oil industry immensely:

1. Development and use of subsea production systems
2. Increased attention to human-factors criteria during the design stage
3. Increased emphasis on automatic and fail-safe features in the design of production components
4. An overall review of platform systems design with particular attention given to safety and environmental criteria, including gas and flame detectors, fire containment, fire control equipment and personnel escape systems.

5. Incorporation of methods for identifying which wells on a multiwell platform are out of control during a fire.
6. Development and installation of survivable event recorders.
7. Development of a reliable surface actuated subsurface safety valve which could be used to replace storm chokes in existing wells.

4.5 STORAGE

When bulk carriers are used to transport product from OCS areas, it is necessary to maintain storage facilities at or near the production site as a buffer between continuous production of the wells and the discontinuous operations of tankers.

Offshore storage has not been used very much in the OCS areas of the U.S. because of the great dominance of installed pipelines serving the production sites.

Platform storage has been used successfully in the Gulf of Mexico. Unfortunately, storage tanks are large (usually rated at about 10,000 barrels or less) and require additional structural requirements of and space on a platform, therefore this type of storage is used only on low production wells. In the few cases where offshore storage has been used on the U.S. OCS, they are of the fixed-root type where emissions are greater than those of the floating-roof type. Underwater storage facilities are generally used as piling supports as well as for crude storage. They are attractive in areas where currents and tidal movements are mild (USDI 1977). U.S. companies have used subsea or bottom-standing storage systems in their overseas operations. Continental's Dubai installation in the Persian Gulf consists of three 500,000 barrel capacity tanks resembling inverted champagne glasses (Kash et al. 1973). These tanks are bottom mounted with only a small portion extending above the surface of the water. This design allows easy access from the surface yet is less susceptible to either weather or collision damage than surface tanks.

Floating storage has also increased in recent years. The barge Pazargad, for example, has a nominal one-million barrel capacity and is serving in the Persian Gulf as a storage, desalting, and loading facility. It uses a single point mooring system which allows the barge to head into the weather at all times (Kash et al. 1973). One of the advantages of this system is that a storage vessel can be readily obtained by utilizing an existing surplus tanker with certain modifications.

It seems unlikely that storage facilities will be used on the U.S. OCS in the near future. But, if refinery or distribution facilities cannot be located immediately onshore from the production field, tanker transport may be required to carry petroleum to distant ports for processing. In such cases, the use of OCS storage facilities may be necessary.

4.6 TRANSPORTATION

Oil and gas may be transported from the OCS either by pipeline or by bulk carriers, such as tankers or barges. In 1973, all production from offshore California and 98 percent of all OCS production in the Gulf of Mexico was transported to shore by pipeline. In general, bulk carriers have been used to transport oil from oil fields of low production rates or during field development.

In bulk transport operations, oil spillage generally is associated with transfer operations or as a result of collision.

4.6.1 Pipelines

Pipelines are accepted as the most versatile and reliable means available for moving large volumes of hydrocarbon products. Pipelines serve two main functions on the OCS, gathering gas and produced fluids, and transmitting them to land. The gathering lines terminate at the final metering point under USGS jurisdiction. Pipelines which then move the product beyond this point are termed transmission lines. These pipelines are either single custody or common carrier. Oil transported in these lines is generally metered onshore and, therefore, the lines are likely to be considered as gathering lines falling under USGS jurisdiction. Even when final metering is conducted offshore,

however, it appears that the USGS continues to exercise authority over single custody oil transmission lines. From the regulatory standpoint, it appears that most lines transporting gas to shore are treated as common carriers.

4.6.2 Pipelaying

There are three techniques for laying offshore pipelines. The most widely used technique is the lay barge in which pipe sections are welded together on the barge and released into the water as the barge moves forward. Lay barges can economically lay pipe of diameters between 4 inches and 52 inches (Kash et al. 1973).

A second technique for installing pipe in the offshore environment is the reel barge. Long sections of pipe are fabricated on land, wound onto large reels on the barge and then laid directly from the reel. This technique is limited to pipe diameters of 12 inches or less (Kash et al. 1973). For pipe diameters of 4 to 10 inches, the reel barge is more economic than the lay barge.

The third technique involves onshore fabrication of pipe followed by pulling the pipe into the water. This technique is limited to pipe lengths of 2 to 4 miles due to frictional drag created by the bottom. A related technique also involves onshore fabrication with long lengths of pipe being floated into position, sunk and welded into place.

Most of the more recent pipelaying projects are completed by burying the pipe. This method lessens possible damage to the pipeline from currents, storm waves, anchors and other marine equipment. A burial barge is used to sink the pipe beneath the surface, usually by displacing soil with a high-pressure water jet.

The environmental effects of pipelines are generally related to spills, shoreline modification and ocean floor disturbances. These impacts are discussed in more detail in Section 7 of this report.

4.6.3 Desirable Changes in Pipelines

Technology developments which would help reduce the chronic oil pollution problem from subsurface pipelines include:

1. Development of a method for detecting weak points and flaws in long pipelines for the purpose of preventive maintenance
2. Wider use of accurate mass flow monitoring systems which would automatically alert an operator or take remedial action when a major break occurs
3. Develop efficient multi-phase pumps and pipelines
4. Develop ways to bring pipelines ashore with minimum environmental impact.

5.0 ROUTINE RELEASES TO THE ENVIRONMENT

Insufficient data are reported in the literature to differentiate between levels of biogenic and petroleum hydrocarbons in most of the citations or to identify or quantify the various components making up the general class termed petroleum hydrocarbons. Estimated oil losses into the world ocean from routine offshore oil and gas operations during 1969-1970 was about 700,000 barrels. This is about 2% of the total oil losses to the environment (Kash et al. 1973).

The long-term effect of this type of pollution is not well understood. It is also clear that it is well within the state-of-the-art to reduce existing chronic releases by improvement in technology and in routine housekeeping procedures. Drip gutters, settling tanks, etc. will be necessary to meet new OCS dumping and wastewater discharge permits (Kash et al. 1973).

Produced water is the largest single source of discharges to offshore waters. Other effluents to the marine environment are free oil, organics and metals in drilling muds, borehole cuttings, well treatment fluids, produced sand, and chlorine from sanitary effluents. Offshore exploration, drilling and production also give rise to small but significant discharges to the atmosphere. Even though the effluent sources are diverse, the contents of the discharges are very similar. Sources of these discharges are internal combustion engines, gas in drilling muds, venting of gas during testing and production, flaring (burning of the natural gas) and vapors from storage tanks. Technologies for limiting these sources are available to or being practiced in offshore operations as shown in Table 5.1. Emissions will be discussed as a function of each technology. Within each technology discharges to the oceans will be followed by emissions to the atmosphere.

5.1 EXPLORATION - SEISMIC SURVEYS

Discharges to the environment from seismic surveys are from the routine operation of ocean-going ships.

5.1.1 Discharges to the Oceans from Seismic Surveys

During exploration activities, debris, bilge, domestic and sanitary wastes are released to the environment from survey ships. The use of

TABLE 5.1. Control Technologies for Offshore Oil and Gas Operations
(Stephens, Braxton and Stephens 1977)

Source	Control Technology	Pollutants Controlled
Power Generation - Drilling	Waste Heat Utilization, Combined-Cycle Operations (Developmental)	NO _x , SO ₂ , HC, CO, Part.
Mud Degassing	Combustion Flares	HC
Mud Tanks (Oil-Based Muds)	Covers, Dilution Flares	HC
Fuel Storage	Vapor Recovery	HC
Power Generation - Production	Waste Heat Utilization Combined - Cycle Operation (Developmental)	NO _x , SO ₂ , HC, CO, Part., H ₂ S NO _x , SO ₂ , HC, CO, Part., H ₂ S
Gas Drying	Waste Heat Utilization	NO _x , SO ₂ , CO, Part.
Compressor Seals	Maintenance	HC
Gas Processing Vents	Operating Practice	HC
Valve Seals (Gas Service)	Maintenance	HC
Oil Treaters	Waste Heat Utilization	NO _x , SO ₂ , CO, Part.
Pump Seals	Maintenance	HC
Valve Seals (Oil Service)	Maintenance	HC
Oil Storage/Surge	Vapor Recovery, Dilution Flares, Combustion Flares	HC
Water Treating	Maintenance, Design, Vapor Recovery	HC

high-energy sparkers, propane-oxygen guns or oscillators to generate sound waves during seismic surveys does not appear to adversely affect the environment. Bottom sampling and coring have minor physical impacts on the environment. The degree and extent of disturbance is expected to be low and only in the immediate vicinity of the core hole or bottom grab-sampling point.

On-board domestic waste sources include laundries, galleys, showers, and body wastes. Such sources are becoming tightly regulated in harbors, bays and near shore waters where they are known to be capable of degrading water quality. These wastes are not regulated on the open ocean (outside the territorial seas, the 3-mile limit).

5.1.2 Discharges to Atmosphere from Seismic Surveys

Exhausts from internal combustion engines powering survey ships is the major source of atmospheric emissions during oil and gas exploration. However, this source has not caused undue environmental concern judging from the literature reviewed by Frazier, Maase and Clark (1977). Generally, these surveys are conducted well offshore and the ships tracks are a considerable distance apart. Because emission data for exploration ships is not readily available, Frazier, Maase and Clark offer data from motorships (Table 5.2).

TABLE 5.2. Stack Emissions from Motorships
(Frazier, Maase and Clark 1977)

<u>Parameters</u>	<u>g/Mile (Underway)</u>
Particulates	900
SO _x (a)	680
Carbon Monoxide	540
Hydrocarbons	410
Nitrogen Oxides (NO ₂)	640
Aldehydes (HCHO)	<u>32</u>

(a)0.5 weight percent sulfur in fuel assumed.

5.2 EXPLORATORY AND DEVELOPMENT DRILLING

If geophysical and geological data indicate a possibility of finding oil or natural gas under the ocean floor, the next step is to drill an exploratory well. To do this, the industry uses mobile rigs, of which there are three types used in exploratory drilling. One is a jackup rig which can be towed to the site. Once in position, the legs are lowered to the seabed and the platform is jacked up to a safe level above the sea. The maximum water depth that will allow the use of jackup rigs is about 350 feet.

A second type of rig is known as a semi-submersible. As the name implies, the semi-submersible is partially submerged and moored by anchors, much like a ship. Mooring lines may extend more than a mile. About 100 of these rigs are in operation. Several semi-submersibles have drilled wells in water 1000 feet deep and a few rigs have been built to drill in water depths of 2000 to 3500 feet.

Finally, there is the drill ship. This is a ship with a hole through the hull for drilling. It is usually moored in the same manner as a semi-submersible; however, drill ships and semi-submersibles designed for use in deep water usually replace the conventional mooring system with a dynamic positioning system. The dynamic positioning system consists of series of propellers or thrusters coupled to sensors which detect and compensate for the ships movements. Drill ships have been used in waters deeper than 4000 feet.

The discharges to the environment from exploratory and development drilling result from the activities onboard these platforms.

5.2.1 Discharges to the Ocean from Drilling

Produced water is the largest single source of discharge to the offshore environment from drilling activities. Drilling muds, borehole cuttings, well treatment fluids, produced sand and chlorine are also released to the environment.

Injection of produced water is utilized where feasible as a secondary recovery technique. Although any estimate of the amount of produced water which is brought up with the crude oil is difficult, many assume that one

barrel of water will be produced for every barrel of oil produced. According to the USGS, produced water varies from 20% to 150% of oil production volume, with maximum production of water occurring at the end of a given reservoir's life (USDI 1977). The USGS estimated a peak oil production for the North Atlantic OCS which would translate to a release of 73 to 204 gallons of oil daily to the marine environment. The total oil dispersed to the North Atlantic from the OCS Sale No. 42 during the 20-year production period has been estimated to be between 4,500 to 15,900 barrels (USDI 1977).

5.2.1.1 Produced Water

Produced water is discharged to the oceans during normal drilling and production operations. A summary figure (Figure 5.1) generated at the trace metal and hydrocarbon seminars sponsored by BLM (USDI 1976a) depicts clearly the expected drilling platform releases to the oceans. Specific examples of the Gulf of Mexico produced formation water (Table 5.3) that from offshore California and Texas (Table 5.4) and offshore Alaska (Table 5.5) are given for comparison. A review of detailed data on the composition of produced water and the significance of hydrocarbons, organics and inorganic ions leads to the conclusion that toxic components are present in very low concentrations in produced waters if at all. Each component of produced water is briefly discussed.

- Hydrocarbons

Water coproduced with oil and gas and separated for discharge retains up to 50 ppm of separate-phase oil as small droplets. The water also may contain up to 35 ppm of dissolved hydrocarbons.

Upon discharge, the oil immediately undergoes a number of changes that result in changes in concentration and composition. The mechanisms are dilution, evaporation, spreading, emulsification, air-sea interchange, sedimentation, biological degradation and chemical and photo-oxidation (Weiss, Koons and McAuliffe 1977; NAS 1975). These natural processes quickly lower the actual measured concentration of hydrocarbons.

FIGURE 5.1. A Summary of Drilling Platform Environmental Releases (USDI 1976a) (reproduced with permission)

TABLE 5.3. Produced Formation Water Composition from the Gulf of Mexico^(a) (EPA 1974a)

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

(a) Twenty-five discharges analyzed in 1974 EPA survey, Gulf of Mexico.

Emulsified oil concentrations in salt water showed an evaporative loss of hydrocarbons from 25 to 30% in the first 24 hours (Koons et al. 1977). Most toxic compounds are present in this evaporative loss fraction and thereby oil toxicity is quickly reduced.

Laboratory experiments involving contacting crude oils with seawater were carried out by Anderson et al. (1974). The hydrocarbon composition of water-soluble fractions from Kuwait and South Louisiana crudes were measured and are listed in Table 5.6. These compositions are probably a little higher than would be found in actual produced water, because of the higher salinity values encountered in produced waters. An important extrapolation of the data in Table 5.6 was made by Weiss et al. (1977) regarding concentrations of polynuclear aromatic hydrocarbons in the water-soluble fractions. A review of the data from aromatic compounds having one, two and three rings is summarized in Table 5.7. Weiss et al. plotted the data from Table 5.7 and concluded that a five-ring polynuclear aromatic such as benzo(a)pyrene would be present in the water soluble fraction at a concentration much less

TABLE 5.4. Range of Constituents in Offshore Produced Formation Water from California and Texas (BCL 1976)

Parameter	California ^(a) Range mg/l	Texas ^(a) Range, mg/l
Arsenic	0.001-0.08	0.01-0.02
Cadmium	0.02-0.18	0.02-0.193
Total Chromium	0.02-0.04	0.1-0.23
Copper	0.05-0.116	0.1-0.38
Lead	0.0-0.28	0.01-0.22
Mercury	0.0005-0.002	0.001-0.13
Nickel	0.1-0.29	0.1-0.44
Silver	0.03	0.01-0.1
Zinc	0.05-3.2	0.1-0.27
Cyanide	0.0-0.004	(b)
Phenolic Compounds	0.35-2.1	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.

than 0.01 ppb. All direct evidence is that the content of benzo(a)pyrene or any other of the similar multiring polynuclear aromatics in produced water is below any level of detection, even with the most sensitive analytical measurements.

• Organics

Organics components found in produced waters during a 1971 Army Corps of Engineers permit program include phenols which ranged from 0.05 to 15 ppm and cyanide which was always in the low ppb range (Weiss et al. 1977).

TABLE 5.5. Comparison of Seawater and Oilfield Brine from the Gulf of Alaska (USDI 1975).

	<u>Seawater</u> (mg/l)	<u>Oilfield Brine</u> (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

Measurements of the organic carbon content in the waters around producing platforms indicated that there was no significant build-up of organic compounds in the vicinity of these producing platforms.

- Metals

There have been several extensive surveys to gather data on the composition of oilfield-produced waters. The results of these surveys show that the predominant cations are sodium (Na), calcium (Ca) and magnesium (Mg) along with a host of trace elements in the typical concentrations shown in Table 5.8. Other possible sources of trace metals are drill cuttings and contamination from structural materials or sacrificial electrodes associated with the platforms (Wheeler et al. 1978).

Although the Buccaneer platforms, offshore from Galveston, Texas have been characterized as a very clean and uncontaminated area (Middleditch 1978), Wheeler et al. (1978) did report that concentrations of Ba, Cd, Ni and Pb in Buccaneer sediment samples were higher than control stations.

TABLE 5.6. Hydrocarbons in the Water-Soluble Fractions from
the Experimental Contact of Crude Oil with Seawater
(Anderson et al. 1974)

Compound	S. Louisiana Crude Oil (ppm)	Kuwait Crude Oil (ppm)
Alkanes		
Ethane	0.54	0.23
Propane	3.01	3.30
Butane	2.36	3.66
Isobutane	1.69	0.90
Pentane	0.49	1.31
Isopentane	0.70	0.98
Cyclopentane + 2-Methylpentane	0.38	0.59
Methylcyclopentane	0.23	0.19
Hexane	0.09	0.29
Methylcyclohexane	0.22	0.08
Heptane	0.06	0.09
C ₁₆ n-Paraffin	0.012	0.006
C ₁₇ n-Paraffin	0.009	0.008
Total C ₁₂ -C ₂₄ n-Paraffins	0.089	0.004
Aromatics		
Benzene	6.75	3.36
Toluene	4.13	3.62
Ethylbenzene + m-, p-Xylenes	1.56	1.58
o-Xylene	0.40	0.67
Trimethylbenzenes	0.76	0.73
Naphthalene	0.12	0.02
1-Methylnaphthalene	0.06	0.02
2-Methylnaphthalene	0.05	0.008
Dimethylnaphthalenes	0.06	0.02
Trimethylnaphthalenes	0.008	0.003
Biphenyl	0.001	0.001
Methylbiphenyls	0.001	0.001
Dimethylbiphenyls	0.001	0.001
Fluorene	0.001	0.001
Methylfluorenes	0.001	0.001
Dimethylfluorenes	0.001	0.001
Dibenzothiophene	0.001	0.001
Phenanthrene	0.001	0.001
Methylphenanthrenes	0.002	0.001
Dimethylphenanthrenes	0.001	0.001
Total Saturates	9.86	11.63
Total Aromatics	13.90	10.03
Total Dissolved Hydrocarbons Measured	23.76	21.65

TABLE 5.7. Concentrations of PAH in Water-Soluble Fractions
(Weiss et al. 1977)

	<u>No. Rings in Compound</u>	<u>South Louisiana Crude Oil (ppm)</u>	<u>Kuwait Crude Oil (ppm)</u>
Benzene	1	6.75	3.36
Napthalene	2	0.12	0.02
Phenanthrene	3	0.001	0.001

TABLE 5.8. Concentrations of Inorganic Components of Produced
Water (mg/l)

<u>Component</u>	<u>USDI 1976a</u>	<u>Collins 1975</u>	<u>Rittenhouse et al. 1969</u>	<u>Weiss, Koons & McAuliffe 1977</u>
Ag	0.03	--	--	<0.01-0.1
Al	2.2	--	1-50	--
As	0.001	--	--	<0.1
B	--	--	1-50	--
Ba	--	--	1-50	--
Be	--	--	ppb	--
Ca	--	--	>300	--
Cd	0.03	--	--	<0.01-0.08
Cl	--	--	--	--
Co	--	<0.005	ppb	--
Cr	0.02	<0.001-0.01	ppb	<0.001-0.4
Cu	0.116	<0.001-0.15	ppb	0-0.9
Fe	1.35	--	1-50	--
Ga	--	--	ppb	--
Ge	--	--	ppb	--
Hg	0.0005	--	--	<0.0001
K	--	45-800	>50	--
Li	--	10-35	1-50	--
Mg	50.0	30-6000	>300	--
Mn	0.062	0.002-0.95	ppb	--
Na	--	--	--	--
Ni	0.29	<0.001-0.015	ppb	0.003-2.2
Pb	0.28	--	ppb	0.003-1.0
SO ₄	--	--	>300	--
Sn	--	<0.001-0.012	ppb	--
Sr	--	10-450	>50	--
Ti	--	<0.01	ppb	--
V	--	<0.001	ppb	--
W	--	--	ppb	--
Zn	0.18	--	ppb	<0.003-1.0
Zr	--	<0.01	ppb	--

The most abundant metal ions present in produced waters are common to seawater, many terrestrial deposits, or to subsurface brines continuously discharged into marine waters at sites of subsea oil seepages and are not considered hazardous. Metals considered to be hazardous are either undetectable or present in very low concentrations. Hazards from discharging produced waters containing trace concentrations of toxic metals into the marine environment may be placed into perspective by comparing the concentrations of the metals in produced water (Table 5.8) with the concentrations of these metals in normal seawater (Table 5.9).

TABLE 5.9. Partial List of Elements Present in Seawater (NAS 1971)

<u>Element</u>	<u>mg/l</u>
Li	0.17
Be	6×10^{-7}
B	4.5
Mg	1,300
Al	1×10^{-3}
K	390
Ti	1×10^{-3}
V	2×10^{-3}
Cr	5×10^{-4}
Mn	2×10^{-3}
Fe	3×10^{-3}
Co	4×10^{-4}
Ni	7×10^{-3}
Cu	3×10^{-3}
Zn	1×10^{-2}
Ga	3×10^{-5}
Ge	7×10^{-5}
As	2.6×10^{-3}
Se	9×10^{-5}
Sr	8
Zr	3×10^{-5}
Ag	3×10^{-4}
Cd	1×10^{-4}
Sn	8×10^{-4}
Ba	2×10^{-2}
W	1×10^{-4}
Hg	2×10^{-5}
Pb	3×10^{-5}

With the exceptions of Cu, Cr, Mn and Sr, the concentrations of trace metals in produced waters are not much different from those in normal seawater which leads to the conclusion that nature contributes more of these metals to the environment than does man.

Myers et al. (1975) determined amounts of Hg and Cd in effluents from a number of crude-oil offshore production units. Almost all values were below the minimal levels of detection (<0.5 ppb for Hg and <50 ppb for Cd).

- Other Pollutants

Other components of produced water are salinity, dissolved oxygen, organic compounds other than hydrocarbons and temperature.

Salinity. Generally offshore-produced waters contain more dissolved solids than the surrounding waters, sometimes as high as 110%. In the OCS environment these salinities would be lowered immediately upon discharge from dilution with the surrounding seawater.

Dissolved Oxygen. Produced water appears to be qualitatively lower in dissolved oxygen than the surrounding seawater. Koons et al. (1977) concluded that the insignificant depletion of oxygen observed at platform sites could be caused by the generally rich assemblage of biota living on the platform legs.

Organic Compounds Other Than Hydrocarbons. Other organics in platform production waters usually are in even lower concentration than those derived from petroleum.

Temperature. Production water tends to be somewhat warmer than the water surrounding the platforms, but as with dissolved species, instantaneous dilution makes any temperature gradient undetectable.

5.2.1.2 Drilling Muds

Cuttings from the down-hole face are removed by the drilling mud and carried to the surface for processing as described in Section 4. These muds can create small turbidity plumes downstream from the point of discharge (Ray 1978).

Drilling muds are often organized into two categories--water-based and the more expensive oil-based fluids. Water-based muds are composed of barite and a variety of additives to control pH, corrosion, emulsification, lubrication and viscosity of the fluid. Examples of water-based muds could number in the hundreds. Probably the most widely used system is a freshwater mud treated with lignite and lignosulfonate, such as in Table 5.10. The amount of barite required will depend upon the formation pressure encountered and would be on the order of 500 pounds of barite for one barrel of drilling fluid having a density of 18 lb/gal. (Simpson 1975).

A polymer mud, also shown in Table 5.10, would be very similar to the dispersive type clay-base water mud. The salt concentration would be about 100 lb/bbl when sodium chloride is used. If potassium chloride is used, only 10 to 20 lb/bbl might have to be used. The alkaline material (hydroxide) is added for pH control, because drilling with acidic mud tends to cause corrosion problems.

Oil muds are customarily prepared from diesel oil using some type of surfactant to emulsify water (Table 5.10). Oil-based muds also contain a mixture of organic acids and asphaltic stabilizing agents. Typical drilling mud additives are discussed in detail by Moore (1974). The U.S. Department of Interior data presented in Table 5.11 gives quantitative values for alternative drilling mud additives.

For a typical well of 10,000 feet, about 7,000 barrels of drilling mud containing about 260 tons of commercial mud components are required (USDI n.d.b.). Another estimate of the drilling mud needs by component for typical wells is shown in Table 5.12.

TABLE 5.10. Drilling Mud Types (Simpson 1975)

Water Muds	
Component	Concentration, lb/bbl
Water	200-340
Bentonite	15-30
Lignite	1-6
Lignosulfonate	2-10
Sodium Hydroxide	0.5-1.5
Barite	0-500
Polymer Mud	
Water	300-345
Bentonite	0-10
Salt	10-100
Sodium or Potassium Hydroxide	0.1-0.3
Polymer (Starch, Polyacrylamide	0.5-5
Bactericide (Paraformaldehyde)	0.1-0.5
Barite	0-300
Oil Mud	
Diesel Oil	150-230
Water	35-50
Calcium Chloride	15-25
Emulsifier (Soap, polyamide)	5-20
Filtrate Reducer (Amine Lignite)	0-10
Gellant (Amine Clay)	2-4
Barite	0-500

TABLE 5.11. Drilling Mud Alternative Additives Quantified
(Frazier et al. 1977; Moore 1974 and USDI 1977)

Function	Substance	Amount (lb/bbl)
Alkalinity and 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 ₂ O) _x	0.5-1.0
	2. Sodium Chloride NaCl	5.0-10.0
	3. Sodium Chromate Na ₂ CrO ₄	0.1-4.0
	4. Pentachlorophenol	NA(a)
Calcium Removers	1. Sodium Bicarbonate NaHCO ₃	0.1-1.5
	2. Sodium Carbonate Na ₂ CO 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 ₂ CrO ₄	0.1-4.0
	3. Film Forming Amine	2.0
Defoamers	1. Aluminum Stearate /CH ₃ (CH ₂) ₁₈ 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
Flocculants	1. Acrylamide Polymeric Hydrolite	0.0-0.01
	2. Bentonite	1.0-5.0
	3. Lignosulfonate	1.0-5.0
	4. Potassium Chloride KCl	NA(a)
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
	3. Oil	NA
	4. Detergents	NA
	5. Surfactants	NA
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	0.2-3.0
Thinners and Dispersants	1. Sodium Tetraphosphate Na ₄ P ₄ O ₁₃	0.1-0.2
	2. Calcium Lignosulfonate	1.0-4.0
	3. Ferrochrome Lignosulfonate	NA
	4. Lignite	NA
	5. Sodium Chromate Na ₂ CrO ₄	0.5-3.0
	6. Sodium Acid Pyrophosphate	NA
	7. Quebracho	1.0-10.0
Viscosifiers	1. Baronite	NA
	2. Bentonite	1.0-5.0
	3. Asbestos	2.0-6.0
	4. Sodium Carboxymethyl Cellulose	0.1-1.5
	5. Polymers	NA

(a)Not available

TABLE 5.12. Mud Components Used in Seawater - Lignosulfonate Systems to 15,000 Feet (weight in pounds)(a) (Frazier et al. 1977)

Component	Interval		Sub-Total	Interval		Sub-Total	Interval	Total
	0-900	900-3500	3500	3500-10,000	10,000	10-15,000	15,000	
	Feet	Feet	Feet	Feet	Feet	Feet	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	
Attapulgate 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	

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

During exploratory drilling, 50 to 75% of the water-based drilling mud is lost either to the formation, retained in the wellbore, adherence to cuttings or intentionally discharged to the marine environment (USDI 1977). Drilling muds may also leak from the marine riser system (Ray 1978) during operation or upon disconnection, and be released while drilling the upper portion of the hole prior to establishing circulation to the drilling platform (USDI 1976). As standard operating procedure, water-based drilling muds are discharged to the oceans after exploration as mud dumps, following EPA NPDES permit guidelines which limit the rig discharge rate to an average of about 5.2 gal/min.

Therefore for a typical well of 10,000 feet, between 3,500 and 5,200 barrels of commercial mud components are lost to the environment. If it is assumed that all of this material was released directly to the oceans, the resulting concentrations at the discharge pipe would resemble those presented in Table 5.13. Typically 10 to 30 holes are drilled from a single offshore platform. This large number of holes would not necessarily increase the concentration of materials entering the oceans, but would probably increase the effluent time to several years. It has been estimated that between 63,000 and 126,000 tons of commercial mud will be discharged to the North Atlantic during the exploratory phase of OCS Sale No. 42.

TABLE 5.13. Discharge Concentrations of Drilling Mud Components to the Oceans

	<u>mg/l</u>
Bentonite	57,000
Lignite	9,400
Lignosulfonate	16,300
Sodium Hydroxide	2,900
Barite	713,400

Paleontological information from development wells is not as critical as that from exploratory wells. As a consequence, drilling muds are recycled from one well to another (USDI 1977).

Barium compounds make up a large portion of commercial drilling muds. The presence of barium in southern California coastal waters has been suggested as a way to monitor marine contamination during offshore oil and gas exploration (Chow 1975).

Oil-based muds are generally barged ashore for final disposition (EPA 1974a). However, recent field tests using a field burner to incinerate oil-based muds appear to be a possible economic and environmentally preferable alternative to onshore disposal (World Oil 1976).

5.2.1.3 Cuttings

Drilling muds pick up cuttings from the bottom of the borehole as well as washing them off the drill face. As the drilling mud/drill cuttings mixture is circulated to the surface, the cuttings (pulverized rock and sediment) are separated from the mud by shale shakers, desilters, and desanders and then discharged overboard. Sediment containing free oil is washed to remove the hydrocarbons, the hydrocarbons are removed from the wash water, the wash water is shipped to shore, and the cuttings discharged to the oceans.

The amount of cuttings generated by drilling an exploratory well are highly dependent on well diameter and depth. A typical 10,000 ft Gulf of Mexico well will produce about 2,100 barrels of cuttings weighing about 920 tons. Cuttings have gathered under Gulf of Mexico drill rigs to the depth of several feet and cover about 0.5 acre. Each major storm acts to disperse some of the material. No cuttings were found beneath producing platforms in 60 ft of water where drilling ceased about 10 years ago (Shinn 1974). No cuttings were found to accumulate during a test boring on Tanner Bank offshore from southern California due to ocean currents (Ray 1978).

The Bureau of Land Management reportedly expects 1,760 barrels of drill cuttings from a hypothetical 15,000-foot deep exploratory well. This value can be adjusted to about 1,170 barrels for a 10,000 ft well, or about half the value reported by Shinn (1974).

Drilling muds and cuttings which are projected for release from developmental wells in the North Atlantic are shown in Table 5.14. The footnote for this table indicates that 75% of the mud used will be lost to the environment.

TABLE 5.14. Materials Released to the Oceans During Developmental Drilling (USDI 1977)

	<u>Volume (barrels)</u>	<u>Weight (tons/well)</u>
Drilling Muds & Components ^(a)		
Components		
Barite		220
Clay		27
Caustic		9
Ferrochrome lignosulfonate		11
Other ^(b)		3
Drill Cuttings	2456	995

(a) Assumptions: 10,000 ft well; 328 tons used/well; 246 tons lost/well; one complete jettison of drilling mud/platform.

(b) Such as aromatic detergents, organic polymers, and sodium chromate.

The BLM predicts that an average of over 1500 barrels of cuttings will be released to the Western Gulf of Alaska adjacent to the offshore platforms from each of the 468 planned exploratory and production wells (USDI n.d.d.).

5.2.1.4 Deck Drainage

During drilling and/or workover operations, the potential for accumulation of materials which can contribute to deck drainage is greatest. All machinery that might be subjected to an oil leak or spill is underlaid by a drip pan and these drip pans are connected by drain systems to a central collection tank (USDI 1977). Well completion and valve failures can result in spillage of drilling fluids. Acids (hydrochloric, hydrofluoric and various organic acids) used during workover operations can also contribute to deck drainage. Brines and other deck drainage constituents generally neutralize the acids prior to disposal. Oil is considered the primary contaminant in deck drainage.

5.2.1.5 Sanitary Wastes and Refuse

The magnitude of sanitary wastes and refuse is directly related to the population housed on the platform. The largest platform-based work force is

required during well completion. It has been estimated that 60 gallons of water per day per person with a biological oxygen demand (BOD) of about 0.2 pounds is a realistic waste generation rate (Lintfield and Hunter 1973). BLM reports a value of 6000 gallon/day/rig (USDI 1977). All human body wastes are either incinerated or rendered harmless by a combination of extended aeration/chlorination treatments prior to discharge overboard. EPA regulations and OCS orders require that the effluent have a minimum chlorine residual of 1.0 mg/l after a minimum retention time of 15 minutes. The Draft NPDES permits for the Mid-Atlantic currently limit the rig discharges to daily maximums of 1.5 mg/l of mercury, 3.0 mg/l of cadmium, 10#/100 ml of total fecal coliform, and 45 ppm (30 ppm daily average) of BOD (USDI 1977).

Garbage and trash will be required to be collected and sent to shore in metal containers for disposal from OCS rigs off the eastern U.S. (USDI 1977).

5.2.2 Discharges to the Atmosphere from Drilling

Atmospheric discharges may result from the generations of power and flaring of well testing gas.

5.2.2.1 Power Generation

The only continuous source of atmospheric discharge during drilling operations is from the generation of power. The two major load requirements on a drilling platform are the mud pumps and the rig draw works. The average for all U.S. platforms during 1975 was slightly over 2100 hp for mud pumps and 1600 hp for rig draw works (Stephens, Braxton, and Stephens 1977).

Minor power requirements (400 hp to 800 hp) are for the rotary table, and 500 hp for accessories and housekeeping. The rotary table is a heavy, circular casting mounted on a platform just above the derrick floor with an opening in the center through which the drill pipe and casing must pass. The table is rotated by power transmitted from the draw works and the drilling engines. As the table rotates, the kelly is turned, rotating the drill column and the drill bit.

The power sources for most drill rigs is either natural gas or diesel fueled internal combustion engines. The exhaust from diesel fueled engines can be properly adjusted so that smoke is not emitted in violation of air

pollution control regulations. Table 5.15 shows average emission rates from industrial-type diesel engines. Stephens, Braxton and Stephens (1977) have estimated the 1985 gaseous emissions to the atmosphere from offshore rigs off California, Texas, Louisiana and the Gulf of Mexico.

TABLE 5.15. Air Pollutant Emissions for Diesel Powered Industrial Equipment (Frazier, Maase and Clark 1977)

<u>Pollutants</u>	<u>g/hour</u>	<u>kg/10³ gal</u>
Particulates	64.9	15.2
Oxides of Sulfur	60.4	14.2
Aldehydes	13.6	3.2
Oxides of Nitrogen	912.0	213.0
Carbon Monoxide	197.0	46.3
Exhaust Hydrocarbons	72.6	17.0

5.2.2.2 Product Testing

Various tests are conducted on potential oil and gas wells. The duration of these tests may range from a few hours to a few days depending upon the nature of the well.

The oil and gas produced during testing is passed through separators, tanks and vent lines, then disposed of. Well testing gas is generally burned thus releasing combustion products to the atmosphere (Table 5.16). Exploratory well gas flow rates may range from a few thousand cubic feet per day to millions of cubic feet per day.

5.2.2.3 Mud Degassing

Another source of atmospheric discharge is the gas released from drilling mud. As the drill bit passes through a producing formation, gas may seep into the well bore and become dissolved or entrained in the drilling mud. The gases are separated from the mud in a mud separator and finally a degasser vessel which operates under a vacuum.

The gases that are removed from the mud are usually vented to the atmosphere without flaring (Stephens, Braxton, Stephens 1977). These workers

TABLE 5.16. Estimate of Quantity of Emissions from Burning of Well Testing Gas (Frazier, Maase, Clark 1977)

<u>Pollutant</u>	<u>kg/million cubic feet</u>
Particulate	8.6
Sulfur dioxide (SO ₂) ^(a)	0.27
Carbon monoxide	9.1
Hydrocarbons (CH ₄)	3.6
Nitrogen oxides NO ₂	54.5

(a)Based on average sulfur content of natural gas of 2000 grains/10⁶ ft³.

were unable to uncover sources of data that would indicate the rate at which gases are released. They did, however, calculate a rough value of as much as 20,000 cubic feet of gas could be released during a 24-hour period.

Some waste gases contain H₂S. In this situation the waste stream will have to be treated chemically to remove the H₂S prior to its release to the atmosphere (Bettge 1975).

5.3 PRODUCTION AND STORAGE

During the production phase of an offshore well, coproduced brine constitutes the major source of discharge to the ocean. Deck drainage and sanitary wastes are considered to be minor sources of concern. Major air emission sources include separator associated vents and flares, diesel engine emissions and storage tank losses.

5.3.1 Discharges to the Oceans from Production and Storage

The major waste stream from offshore production is the coproduced brine or production water discussed extensively in Section 5.2.1.1. Frazier, Masse and Clark (1977) reported that coproduced formation water can range from 2 to 98% of oil production. The age of the well is a major factor influencing the quantities of coproduced water. The Interstate Oil Compact Commission states

that 72% of a U.S. total of 25 million barrels/day of coproduced water is injected for either secondary recovery or disposal (Frazier, Maase and Clark 1977). Total OCS coproduction of brine water in the Gulf is reported to be about 605,000 barrels (from several hundred separate discharge points) with just over one-half being transported to shore (USDI n.d.b.). All brine production off California is piped ashore for treatment and disposal. In Alaska's Cook Inlet, 14 multiple well platforms pump their brine ashore for separation prior to disposal to the Inlet's surface waters (Frazier, Maase and Clark 1977).

The range of constituents in Gulf of Mexico, California and Texas offshore produced formation water is presented in Tables 5.3 and 5.4. Table 5.5 shows the averages of selected components of an oil field brine from the Gulf of Alaska compared with those of seawater. At 50 ppm effluent oil concentrations, the loss of oil to the oceans has been estimated at nine barrels for each million barrels of oil produced (Kash et al. 1973).

Sacrificial anodes mounted on the drill rigs below the water surface are thought to release metals such as aluminum, lead and mercury to the oceans.

The flushing of old heat exchangers could be a mechanism for the release of PCBs to the oceans.

5.3.2 Discharges to the Atmosphere from Production and Storage

The normal operation on a production platform consists mainly of handling production from oil and/or gas wells and separation of oil, gas, and water phases. Most air emissions from production operations are associated with oil-water-gas-separators and are generally flared, diesel engines (see Section 5.2.2), and petroleum storage tanks.

The major source of total hydrocarbon emissions on a platform is from oil storage or surge tanks. Storage tanks are used to store crude oil and distillage oil on offshore platforms. Crude oil storage tanks are usually rated at about 10,000 barrels or less due to the space available on platforms. Storage tanks are usually the fixed-roof type whose emissions are greater than those of a floating-roof type (Frazier, Maase and Clark 1977). Tables 5.17 and 5.18 show emission rates from floating-roof and fixed-roof

TABLE 5.17. Hydrocarbon Emissions from Storage of Crude Oil
(Burklin and Honerkamp 1976)

<u>Type of Tank</u>	<u>Breathing/Standing Loss (g/day per bbl capacity)</u>	<u>Working Loss (g per bbl throughput)</u>
Floating Roof		
Under 70,000 bbl	0.38	Neg.
Over 70,000 bbl	0.24	Neg.
Fixed Roof		
Under 70,000 bbl	1.3	34 ^(a)
Over 70,000 bbl	0.94	34 ^(a)

(a) This value is for Dos Cuadras crude with TVP 4.6 psia. The value for Wilmington Crude (TVP 1.8 psia) is 13. Breathing/standing losses are so small compared to working losses that separate values for the two crudes were not necessary.

TABLE 5.18. Evaporative Emissions from Fixed-Roof Storage Tanks
(Frazier, Maase and Clark 1977)

<u>Product</u>	<u>Breathing/Standing Loss (g/day per bbl capacity)</u>		<u>Working Loss (g per bbl throughput)</u>
	<u>New Tank Condition</u>	<u>Old Tank Condition</u>	
Crude Oil	2.86	3.24	139
Distillate Oil (Diesel fuel)	0.68	0.78	19

storage tanks for crude and distillate oils, respectively. Emissions also occur during the loading and unloading of storage tanks. These sources contribute about 1.4×10^5 Mg/yr. Vents which discharge intermittently during gas processing as required by process upsets and maintenance contribute about 9.3×10^4 Mg/yr to the environment. These two sources account for over 70% of the total nonmethane hydrocarbons emitted offshore (Stephens, Braxton and Stephens 1977). By comparison, this is only 2% of the non-methane emissions for all petroleum storage or less than 0.2% of the total non-methane emissions from all stationary combustion (EPA 1975).

Power generation during production operations for the year 1985 is estimated to be the largest continuous source of atmospheric pollutants (see Table 2) (Stephens, Braxton and Stephens 1977).

5.4 TRANSPORTATION

Crude oil is transported from OCS production wells by either submerged pipeline or by tanker and barges. The choice is generally made on economic grounds. If wells are low producers, crude may be accumulated in platform mounted storage tanks which are relieved by intermittent visits by surface vessels. High production wells require constant methods of crude oil transportation which can be more economically handled by pipelines.

5.4.1 Discharges to the Oceans from Transportation

Any time crude oil is routinely transported, small losses to the environment will occur. The magnitude of these losses depends upon how carefully transfer operations are handled, house-cleaning activities are conducted, and how carefully routine monitoring of the transportation system is carried out.

5.4.1.1 Pipelines

In the offshore field, pipelines have remarkable safety and service records, when compared with barging and other surface transportation, and offer advantages in the area of environmental protection. Rarely do pipelines experience significant leakage. Pipelines seldom totally rupture and release large quantities of product. According to USGS records, there have been only four pipeline incidents on the OCS resulting in injury, property or environmental damage during the period 1953-1971 (Kash et al. 1973).

However, pipelines do appear to be a major source of chronic pollution, although it is almost impossible to identify the specific amounts of oil released by them. Coast Guard data indicate that 1267 "line leaks" released 9062 barrels and 376 "pipe ruptures or leaks" released another 4247 barrels of oil into U.S. waters in 1971 (Kash et al. 1973). This represents 84% of all oil introduced into U.S. waters from routine offshore facilities operations.

Environmental factors to be considered in pipeline design are the depth or water, sea conditions during the installation and operational life of the pipelines, soil conditions and seismic activity. Sea conditions considered in pipeline design include height and period, current, and tide. The pipeline is designed to operate safely under the maximum conditions hypothesized for the 100-year storm (USDI 1977).

In regions of shifting, on-bottom sand waves a combination of weight-coating and trenching has proven most efficient. Most of the more recent pipe-laying projects are completed by burying the pipeline beneath the sea floor. It has been estimated that generically, pipeline burial would disturb 4000 to 8000 cubic yards of sediment per mile (USDI 1977).

Another concern is at the shoreline where pipelines are brought ashore. Extensive dredging and canal building may take place which could substantially alter coastal lands.

5.4.1.2 Tanker or Barge Ballast Water

Tankers and barges that transport crude oil to shore, return to the OCS in ballast (about 30% of the cargo capacity is required for vessel stability). Similarly tankers used to transport intermediate and final products generally arrive at the refinery in ballast (EPA 1974b).

Ballast waters were previously discharged at sea from tankers visiting OCS production facilities and tankers steaming to shore-based facilities. This practice, for incoming tankers, is no longer a practical alternative to the controlled disposal of ballast waters to either onshore ballast water tanks or holding ponds at the refinery. In many cases ballast water is discharged directly to the refinery waste water treatment system.

Product tanker ballast water is contaminated with the product material ranging from water soluble alcohol to residual fuels. In addition to the oil products contamination, brackish water and sediments are present, contributing to high chemical oxygen demand (COD) and dissolved solids to the refinery waste water system.

5.4.2 Discharges to the Atmosphere from Transportation

In the transportation and handling of crude oils, evaporation and entrainment losses occur in both the loading and unloading operations.

The losses which might be incurred in unloading of crude oil shipments at a refinery may not appear as a hydrocarbon emission during the operation. The losses to the atmosphere and/or water occur when the compartment is being refilled or when it is being cleaned or ballasted. Ballasting may occur at the refinery. This loss has been estimated as approximately the same at the analogous shore tank withdrawal loss or $0.007\%/\text{psia}$ true vapor pressure (TVP) (API 1973).

Loading emissions can be separated into the arrival component and the generated component. The arrival component consists of hydrocarbon vapors left in the empty cargo tanks from the previous cargo. The generated component consists of hydrocarbon vapors generated in the cargo tanks as hydrocarbon liquids are being loaded.

The arrival component of loading emissions is directly dependent on the true vapor pressure (TVP) of the previous cargo, the unloading rate of the previous cargo, and the cruise history of a cargo tank that may include heel washing, ballasting, vapor freezing, or no action at all.

The generated component of loading emissions is produced by the evaporation of hydrocarbons from liquids being loaded into the vessel tank. The quantity of hydrocarbons evaporated is dependent on both the true vapor pressure of the hydrocarbons and the loading practices. The greatest impact from loading practice is the loading rate.

The initial oil-fill encounters a compartment containing no vapors, and in the initial fill, the rate of saturation of the air space above the liquid is rapid. When the bottom of the oil inlet pipe is covered, turbulence decreases markedly and filling proceeds smoothly. The layer highest in hydrocarbon vapors is directly above the surface and dispersion throughout the balance of the compartment proceeds slowly. The gas leaving the top initially is relatively low in hydrocarbon vapors but becomes richer rapidly as the oil

surface approaches the top of the compartment, at which point the expelled gas may contain 30 to 50% of hydrocarbon vapors. The total loss of hydrocarbons is the average of the hydrocarbon concentration during the entire period of fill.

The total emission of hydrocarbon vapors during filling of a tanker initially vapor-free, is present in Table 5.19 (API 1973).

It should be noted that the total hydrocarbon mass lost ranges from about 2 tons for a 40,000 dwt tanker up to about 8 tons for a 300,000 dwt tanker. The advantages of larger tankers are clear.

Figure 5.2 presents a correlation curve for hydrocarbon loss derived from the equation:

$$\text{Loading loss \% by volume} = 0.008 \times \text{TVP}$$

This equation represents a loss appreciably higher than that given by the above table, and does not differentiate between size of tankers. However, if some saturation of the tank air space is assumed prior to loading, the discrepancies in loss of hydrocarbon vapors or hydrocarbon emissions to the atmosphere are not great (API 1973).

Burklin et al. (1977) only estimated the hydrocarbon emissions resulting from gasoline loading from marine transfer operations. He concluded from the gasoline data (Table 5.20) that there is good potential for using modifications in operating procedures to control hydrocarbon emissions from marine terminal loading operations.

The loss from loading tankers and barges is generally lower than that from loading tank trucks or tank cars.

Emissions to the atmosphere attributed to marine transportation also include emissions associated with combustion of fuel to power tankers and tugboats and also for pumps used to unload the crude oil. Tankers use the same engines for unloading and maneuvering, and barges are equipped with pumps for unloading but otherwise not powered. Tankers use #6 fuel oil, and

TABLE 5.19. Estimates of Total Vented Hydrocarbons from Tankers (API 1973)

Capacity of Tanker (dwt)	Tank Depth (ft)	Final Oil Depth (ft)	Mass of Oil per sq ft of Surface in Full Tanks (ton)	Gas Vented per sq ft of Oil Surface (ft ³)	Hydrocarbon Gas Vented per Ton of Oil (ft ³ /ton)	Total Volume Hydrocarbon Gas Vented (ft ³)	Mass of Hydrocarbon Gas Vented (ton)
40,000	50	49	1.17	1.25	1.07	42,800	2.05
100,000	70	68.6	1.62	1.25	0.772	77,200	3.70
200,000	80	78.4	1.87	1.25	0.667	133,400	6.38
300,000	95	93.1	2.22	1.25	0.563	168,900	8.10

FIGURE 5.2. Losses from Loading Tankers and Barges (API 1973)

TABLE 5.20. Summary of the Impact of Operational Control Techniques on Gasoline Loading Emissions (Burklin, Micheletti and Sherman 1977).

Tank Condition	Tankers		Ocean Barges	
	Emissions (lb/10 ³ gal)	Control Efficiency Over Dirty Tank	Emissions (lb/10 ³ gal)	Control Efficiency Over Dirty Tank
Dirty	2.4	0%	3.3	0%
Ballasted	1.6	33%	2.1	36%
Typical ^(a)	1.2	50%	2.7	18%
Cleaned	1.0	58%	1.3	61%
Cleaned w/slow Loading	0.4	83%	0.5	85%
Cleaned w/slow Loading and Short Loading	<0.2	>92%	<0.2	>94%
Dirty w/slow Loading	1.9	21%	2.5	24%
Dirty w/slow Loading and Short Loading	1.5	37%	2.0	39%

(a)The term typical refers to the national average emissions from vessels in 1975.

tugboats and barges use diesel fuel. Tanker emissions at sea are negligible when compared to emissions from vessels in port or loading at an OCS production and/or storage facility.

Atmospheric emissions from tankers, tugboats and barge pumps are given in Table 5.21. These data were generated by many workers and reported by AeroVironment, Inc. 1977.

5.4 REFINERY OPERATIONS

Crude oils contain principally hydrocarbons, with sulfur, nitrogen, oxygen and metals as minor components. Types of hydrocarbons and the composition of the minor elements depend upon the origin of crude oils. Elemental compositions are generally in the following ranges: carbon, 83 to 87%; hydrogen, 11 to 14%; sulfur, <3%; oxygen, <0.5%; nitrogen, <0.2% and metals, <0.1% (Hishiki 1973).

TABLE 5.21. Atmospheric Emissions from Marine Transport of Crude Oil
(AeroVironment 1977)

Pollutant	Tanker Engines (g/bbl fuel)	Tugboat Engines		Barge Pumps (kg/10 ³ gal fuel)
		Idle (kg/10 ³ gal fuel)	Under Load (kg/10 ³ gal fuel)	
Hydrocarbons	59	1.4	1.4	17
NO _x	920	10	20	213
CO	36	1.8	1.8	46
SO ₂	3,040 S ^(a)	12.7	12.7	12.7
TSP	440	6.8	6.8	15.2

(a)S indicates percent sulfur content of fuel by weight - 0.5 or 1.0
for a tanker coming into port in Southern California; otherwise 2.5.

Although the proportion of nitrogen, oxygen, metals and other minor components is very low, they exert large effects on the quality of petroleum products; e.g., the resulting amount of sulfur in the product. Purification steps are therefore required in the refining of crude oil. The biproducts of the purification steps are often marketable. For example, elemental sulfur, gypsum, ammonium sulfate, or asphalt are produced by the process.

Refinery discharges include used catalysts, acids, alkali, and clays. Sludge accumulating in processing equipment for oil, water, and dust removal from smoke are also included in the discharge (Hishiki 1973).

Refinery wastes are extensively treated and recycled whenever possible resulting in a very clear liquid discharge to the environment. Treatment steps include oil-water separation, active carbon treatment or activated sludge treatment.

Effluent treatment technology available today does not call for major innovations in refining processes. The waste water treatment technology recommended for the best available demonstrated technology (BADT) effluent limitations is the same as called for by best practical control technology currently available (BPT) and does not include physical-chemical treatment, because that technology has not been sufficiently demonstrated by the petroleum refining industry.

The effluent limitations proposed for BADT technology are based on the concentrations considered achievable by BPT and the flows from best available technology economically achievable (BAT) (EPA 1974b). The effluent guidelines (Table 5.22) became law on July 1, 1977. They were determined using effluent data from refineries or attainable effluent concentrations and the 50% probability of occurrence flow from the refineries with 3% or less of the heat removed by once-through cooling water.

A typical petroleum refinery is a complex combination of interdependent operations engaged in the separation of crude molecular constituents; molecular cracking, molecular rebuilding and solvent finishing to produce the major refinery products shown in Table 5.23.

The refining operations may be divided into several process categories listed in Table 5.24.

TABLE 5.22. Refinery Effluent Limitations Using BPT
(EPA 1974b)

<u>Parameter</u>	<u>Concentration mg/l</u>
BOD ₅	15
COD	(a)
TOC	2.2 x BOD ₅
TSS	10
Oil & Grease	5
Phenol	0.1
NH ₃ -N	80% Removal
Sulfide	0.1
Cr ^{III}	0.25
Cr ^{VI}	0.005

(a) The COD effluent concentrations determined from refinery effluent data are: topping - 80 mg/l; cracking - 115 mg/l; petrochemical - 96 mg/l; lube - 110 mg/l; and integrated - 110 mg/l.

TABLE 5.23. Intermediates and Finished Products
Frequently Found in the Petroleum
Refining Industry (Standard Industrial
Classification 2911)(EPA 1974b)

Acid Oil
 Alkylates
 Aromatic Chemicals
 Asphalt and Asphaltic Materials
 Benzene
 Benzol
 Butadiene
 Coke (petroleum)
 Fuel Oils
 Gas, Refinery
 Gas (LPG)
 Gasoline
 Greases: Petroleum, Mineral Jelly, Lubricative
 Jet Fuels
 Kerosene
 Mineral Oils, Natural
 Mineral Waxes, Natural
 Naphtha
 Naphtenic Acids
 Oils, Partly Refined
 Paraffin Wax
 Petroleums, Non-medicinal
 Road Oils
 Solvents
 Tar or Residuum

TABLE 5.24. Major Refinery Process Categories

Storage and Transportation
Crude Processes
Coking Processes
Cracking and Thermal Processes
Hydrocarbon Processing
Petrochemical Operations
Lube Manufacturing Processes
Treating and Finishing
Asphalt Production

The characteristics of the waste water differ considerably for different processes. Considerable knowledge is available that can be used to make meaningful qualitative interpretations of pollutant loadings from refinery processes. Table 5.25 is a qualitative presentation of the major sources of pollutants within a refinery.

A short description is presented of the major refinery process waste water components and the EPA discharge limitations.

Essentially all of the available data on refinery waste waters apply to total API separator effluents, rather than to effluents from specific processes (EPA 1974b).

Refineries frequently combine specific waste water streams from several processes for treatment and/or reuse. Thus, the size, sequence, and combination of contributing processes are so involved that a breakdown by units would be extremely difficult to achieve.

The evaluation of refinery waste loads are based on total refinery effluents discharged through the API oil separator to final waste water treatment.

Information on raw waste loading was compiled by the EPA (1974b) from the 1972 National Petroleum Refining Waste Water Characterization Studies and plant visits. The data were derived from field sampling and operating records.

TABLE 5.25. Qualitative Evaluation of Wastewater Flow and Characteristics by Fundamental Refinery Processes (EPA 1974b)

Production Processes	Flow	BOD	COD	Phenol	Sulfide	Oil	Emulsified Oil	pH	Temp.	Ammonia	Chloride	Acidity	Alkalinity	Susp. Solids
Crude Oil and Product Storage	XX	X	XXX	X		XXX	XX	0	0	0		0		XX
Crude Desalting	XX	XX	XX	X	XXX	X	XXX	X	XXX	XX	XXX	0	X	XXX
Crude Distillation	XXX	X	X	XX	XXX	XX	XXX	X	XX	XXX	X	0	X	X
Thermal Cracking	X	X	X	X	X	X		XX	XX	X	X	0	XX	X
Catalytic Cracking	XXX	XX	XX	XXX	XXX	X	X	XXX	XX	XXX	X	0	XXX	X
Hydrocracking	X			XX	XX				XX	XX				
Polymerization	X	X	X	0	X	X	0	X	X	X	X	X	0	X
Alkylation	XX	X	X	0	XX	X	0	XX	X	X	XX	XX	0	XX
Isomerization	X													
Reforming	X	0	0	X	X	X	0	0	X	X	0	0	0	0
Solvent Refining	X		X	X	0		X	X	0			0	X	
Asphalt Blowing	XXX	XXX	XXX	X		XXX								
Dewaxing	X	XXX	XXX	X	0	X	0							
Hydrotreating	X	X	X		XX		0	XX		XX	0	0	X	0
Drying and Sweetening	XXX	XXX	X	XX	0	0	X	XX	0	X	0	X	X	XX

XXX - Major Contribution
 XX - Moderate Contribution
 X - Minor Contribution
 0 - No Problem
 -- - No Data

Since the inter-refinery data suggest that pollutant loading expected from a refinery is relatively constant in concentration, an examination of water use practices was made. The results of the above data indicate that the following parameters are significant in describing the physical, chemical and biological characteristics of waste waters discharged by the petroleum refining industry (EPA 1974b).

5.5.1 Discharges to the Oceans from Refineries

Most liquid discharges to the environment from refineries are treated prior to being released into bays, harbors or estuaries.

5.5.1.1 BOD₅

Almost without exception, waste waters from individual petroleum refinery processes, prior to entering the refinery waste-water treatment system, exert a significant and sometimes major oxygen demand. The primary sources are soluble biodegradable hydrocarbons and inorganic sulfur compounds. Crude distillation, catalytic cracking and the product finishing operations are the major contributors of the 5-day biological oxygen demand (BOD₅). In addition, the combination of small leaks and inadvertent losses that occur almost continuously throughout a complex refinery can become principal BOD₅ pollution sources (see Table 5.26) (EPA 1974b). The BOD₅ effluent limitation to the environment is 15 mg/ℓ.

5.5.1.2 COD

Chemical oxygen demand (COD) effluent concentrations for various refinery processes are given in Table 5.25. The effluent limitations to the environment were determined to be: topping - 80 mg/ℓ; cracking - 115 mg/ℓ; petrochemical - 96 mg/ℓ; lub - 110 mg/ℓ; and integrated - 110 mg/ℓ (EPA 1974b).

5.5.1.3 TSS

In refineries, major sources of total suspended solids (TSS) are contributed by crude storage, alkylation, crude desalting and finishing operations. Suspended matter includes both organic and inorganic materials. The inorganic components include sand, silt, and clay. The organic fractions include grease, oil, tar, animal and vegetable fats, sawdust, hair, etc. Typical levels of

TABLE 5.26. Typical In-plant Raw Waste Load Concentrations for Each Subcategory of a Petroleum Refinery (EPA 1974b)

<u>Subcategory</u>	<u>BOD₅</u> <u>(mg/l)</u>	<u>COD</u> <u>(mg/l)</u>	<u>TOC</u> <u>(mg/l)</u>	<u>TSS</u> <u>(mg/l)</u>	<u>Oil and</u> <u>Grease (mg/l)</u>	<u>NH₃ - N</u> <u>(mg/l)</u>	<u>Phenol</u> <u>(mg/l)</u>	<u>Sulfide</u> <u>(mg/l)</u>	<u>Cr</u> <u>(mg/l)</u>
Topping	10-50	50-150	10-50	10-40	10-50	0.05-20	0-200	0-5	0-3
Cracking	30-600	150-400	50-500	10-100	15-300	0.5-200	0-100	0-400	0-6
Petrochemical	50-800	300-600	100-250	50-200	20-250	4-300	0.5-50	0-200	0-5
Lub	100-700	400-700	100-400	80-300	40-400	1-120	0.1-25	0-40	0-2
Integrated	100-800	300-600	50-500	20-200	20-500	1-250	0.5-50	0-60	0-2
Raw Municipal Waste	100-300	200-400	50-250	100-300					

suspended solids encountered in refinery process wastes are shown in Table 5.25. Effluent limitations to the environment employing BPT are 10 mg/ℓ.

5.5.1.4 Ammonia

Ammonia is commonly found in overhead condensates from distillation and cracking and from desalting. It is usually found combined with sulfide as an ammonium sulfide salt. Ammonia-nitrogen must be removed by a factor of 80% prior to its release to the environment.

5.5.1.5 Phenols

Phenolic compounds are found in catalytic cracking, crude distillation, and product finishing and treating waste waters. Catalytic cracking produces phenols by the decomposition of multicyclic aromatics, such as anthracene and phenanthrene. Some solvent refining processes use phenol as a solvent and although it is salvaged by recovery processes, losses are inevitable. Phenol releases to the environment are limited to 0.1 mg/ℓ.

5.5.1.6 Sulfide

In the refining industry major sources of sulfide wastes are crude desalting, crude distillation and cracking processes. Most of the recovered sulfide from waste water treatment is burned to produce sulfuric acid or elemental sulfur. Sulfide releases to the environment are limited to 0.1 mg/ℓ.

5.5.1.7 Chromium

Chromium salts are extensively used in industrial processes and chromate compounds are frequently added to cooling water for corrosion control. Chromium III must not exceed 0.25 mg/ℓ in the refinery discharge and Cr-VI must be held to 0.005 mg/ℓ release to the environment.

5.5.1.8 Other Pollutants

Other pollutants examined by the EPA (1974b) included total dissolved solids, cyanide, zinc, temperature, various metallic ions, chloride, fluoride and phosphates. It was determined that these parameters are generally found in refineries in too small a concentration to warrant broad treatment.

5.5.1.9 Storm Water Runoff

Refineries have an additional source of waste water due to rainfall runoff. Size and age of refinery, housekeeping practices, drainage areas, and frequency and intensity of rainfall are several factors which compound the containment problem.

A separate storm water sewer and holding system should be designed to withstand local maximum rainfall values. From this system, the water can be diverted to the oil-water separator facility at a constant feed rate.

5.5.2 Discharges to the Atmosphere from Refineries

Many releases to the atmosphere from refinery operations do not lend themselves to pretreatment.

5.5.2.1 Storage Tanks

The largest potential source of hydrocarbon emissions to the atmosphere from a refinery is evaporation loss from tankage (API 1973). This is particularly true if cone roof tanks are used for the storage of volatile products, such as gasoline and crude oils. Volatile products are defined as those having a true vapor pressure (TVP) of 1.5 pounds or above at ambient temperature to be consistent with EPA guidelines. Products having a TVP of 11.0 pounds or above at ambient storage temperature are not included because they require pressure storage facilities.

Refineries generally store a variety of products all of which must be included for purposes of calculating emissions. Crude oil, intermediate, and finished products are stored in tanks of varying size to provide adequate supplies of crude oils for primary fractionation runs of economic duration; to equalize process flows and provide feedstocks for intermediate processing units; and to store final products prior to shipment. Generally, operating schedules allow settling time for water and suspended solids.

Modern refineries impose strict Bottom Sediment and Water (BS&W) specifications on crude oil supplies and through the utilization of mixed-crude storage tanks should release little or no waste water. Waste waters associated with the storage of crude oil and products are mainly free and emulsified

oil and suspended solids. During storage, water and suspended solids separate and are drawn off the bottom of the tank. The emulsified water from the oil-water interface is often lost to the sewers (EPA 1974b). This waste is high in COD and contains a lesser amount of BOD₅. Additional quantities of waste result from leaks, spills, salt "filters," and tank cleaning.

Intermediate storage may be the source of polysulfide bearing waste waters and iron sulfide suspended solids. Finished product storage can produce high BOD₅, alkaline waste waters as well as tetraethyl lead. Tank cleaning can contribute large amounts of oil, COD, suspended solids, and a minor amount of BOD₅.

A model refinery has been chosen for analysis. The throughput of this refinery is 100,000 barrels/day, it handles two crude oils and produces a regular and a premium gasoline. Regular gasoline is produced at a rate of 30,000 bbl/day and premium at a rate of 15,000 bbl/day. The assumed storage capacity for unfinished gasolines is 50% of the finished gasoline storage. Therefore, about 2,334,000 barrels of crude oil is stored in tankage and almost 600,000 barrels of gasoline.

5.5.2.2 Storage Tank Losses

Storage losses are of two types: 1) breathing/standing losses and 2) working losses that are associated with loading the tank. No significant losses occur during emptying of storage tanks (see Section 5.3.2).

Breathing/standing losses depend upon the capacity of the storage tank while working losses are independent of the capacity and are dependent on the throughput of oil.

Evaporation is the mode of loss of hydrocarbons from storage tanks. Where a vapor space exists, as in a fixed-roof tank, this space tends to become saturated with hydrocarbon vapors, depending upon the volatility and temperature of the liquid. The mechanism of evaporative loss is accentuated by daily thermal expansion and contraction of the vapor-space exceeding the vent pressure setting.

The floating roof tank also loses vapors by these mechanisms, but to a much lesser degree. The API (1973) presents calculational methodology for obtaining hydrocarbon losses from tank breathing, filling, standing storage and from withdrawal of hydrocarbons from storage.

Tables 5.17 and 5.18 show the hydrocarbon emission factors for the storage of crude oil for both floating-roof and fixed-roof tanks (Burkline and Honerkamp 1976 and Frazier, Maase and Clark 1977, respectively).

Many refineries now have storage tanks equipped to minimize the release of hydrocarbons to the atmosphere. Refineries trying to reduce hydrocarbon emissions to the atmosphere will first generally attempt to convert their fixed-roof tanks to floating-roof tanks. Floating-roof covers do, however, add to the waste water flow from the tank. If the age of the storage tank is such that it is not structurally able to be converted, a vapor recovery system has been used. However, these systems have been somewhat limited due to safety and corrosion considerations (API 1973).

It is estimated that 184 tons of crude oil is saved from being released to the atmosphere annually from a comparison of a new floater versus a new cone roof on a storage tank with a 1,250,000 barrel annual throughput (API 1973). Similarly, 455 tons of gasoline is saved per year from a floating roof tank with a rated throughput of 1,833,000 barrels gasoline/year.

5.5.2.3 Gravity Sedimentation Facilities

Refinery liquid effluents may be directed to a primary gravity sedimentation facility. These facilities may include ponds, lagoons or stilling tanks. The recovery of oil by these devices vary from 80-95% of the total oil.

During this process, oil rises to the top of the basins and if the area is uncovered, evaporation occurs and hydrocarbon vapors are released to the atmosphere.

Many factors contribute to the magnitude of hydrocarbon loss (API 1973); they include:

- True vapor pressure of the slop oil
- Influent temperature.
- Distillation point (% distilled at 300°F)
- Sedimentation area.
- Time of exposure
- Film thickness
- Average wind velocity.

Figure 5.3 gives a series of curves showing volume % loss as a function of ambient temperature for differing inlet water temperatures.

The effect of separator influent temperature is shown in Figure 5.4. By varying the inlet water temperature from 90° to 160°F, the volume % loss increases from 5% to 20%.

An API separator of 5000 ft² surface area would loose 31 bbl/day or 4 g/bbl/day of refinery throughput.

Under the same conditions as above, an open pond or lagoon generally would lose more hydrocarbon vapors (possibly by a factor of two or three) due to their increased surface area (API 1973).

Stilling tanks are usually covered and have areas about the same as an API separator. Vapors caused by evaporation are collected in a gas-blanketed atmosphere (for safety) and are disposed of by burning in a firebox or flare. In this case, hydrocarbon emissions to the atmosphere are insignificant.

There are two basic methods of control. The first involves design changes and maintenance of the waste water collection system upstream of the separator. The goal of these changes would be a reduction in the total amount of oil. This may also reduce the volatility of the oil. The second method involves covering the separator, utilizing either a floating roof or a fixed roof. (API-928 [1973] discusses the cost-effectiveness of these alternatives.)

5.5.2.4 Post-Gravity (Intermediate) Sedimentation Devices

The basic mechanism for hydrocarbon losses from post-gravity separation devices is similar to that of primary gravity separation devices. However, the degree of loss is considerably less mainly because only 10 to 15% of the

FIGURE 5.3. Correlation of Evaporation of Hydrocarbons as a Function of Water Temperature in Gravity Sedimentation Facilities (API 1973)

FIGURE 5.4. Correlation of Evaporization of Hydrocarbons as a Function of Influent Temperature into Gravity Sedimentation Facilities (API 1973)

original oil remains for further evaporation. Accordingly, hydrocarbon emissions are considered negligible for most post-gravity sedimentation devices and especially for secondary ponds and lagoons in which there are no aeration devices (API 1973).

5.5.2.5 Pressure Relief Systems

Pressure relief systems for both liquids and gases are utilized in refineries. A 100,000 bbl/day refinery may have 1,000 to 2,000 relief valves. These valves discharge during periods of overpressurization and, in addition, usually have a slight continual leakage rate, resulting in hydrocarbon emissions to the atmosphere or into a flare system.

Hydrocarbon vapors are discharged to the atmosphere from relief vents. The most common discharge is flammable vapors heavier than air but of relatively low molecular weight. This type of discharge is limited to a velocity of 500 ft/sec (API 1973).

For overpressurizing, this release term cannot be predicted easily for quantification.

Emissions from valve leakage are the result of poor valve seatings caused by slight, initial manufacturing defects, corrosion products or dirt, or by improper seating after a valve releases. Two sources, referenced in API publication No. 928 (1973) indicate leakage rates to range from 0-4 kg/day/valve, with an average of 1.1 to 1.3 kg/day/valve. This leakage has also been estimated at the higher figure of 5 g/day/bbl of refinery capacity or 5.0 Mg/day for a 100,000 barrel refinery.

These discharges can be controlled by routing to a flare, establishing more frequent inspection and maintenance and/or fitting each relief valve with a rupture disc to minimize leakage.

5.5.2.6 Vacuum Devices and Hydrocarbon Emissions

It is desirable to conduct many refinery processes under vacuum conditions to avoid excessive temperature and steam consumption. Two common methods of producing this vacuum are by barometric condensers in conjunction with steam-actuated vacuum jets (singly or in series) and by surface condensers

which also require auxiliary vacuum jets. Vacuum compressors are seldom used except for clean gas removal and moderate vacuum (API 1973).

Barometric condensers and steam-actuated vacuum jets serve to remove condensed steam and condensable hydrocarbons when used together.

The losses to the atmosphere from vacuum devices are noncondensable gases. In vacuum distillation, noncondensables will include lighter gases, propane, butanes and pentanes. In general the normal concentration of vapors will be in the range of 6.8 to 23 kg/hr/1000 barrels of crude charged to the vacuum furnace and design rates are usually closer to the higher figure (API 1973).

These emissions may be minimized by the installation of an absorption system between vacuum tower and first stage vacuum jet or to incinerate non-condensables, or discharge to a vapor recovery system.

Incineration eliminates hydrocarbon emissions barring any leaks in the necessary piping and compressor system.

5.5.2.7 Regeneration of Catalyst in Catalytic Cracking

The used catalysts accelerate the splitting of large molecules to form gasolines. The catalysts absorb impurities such as metals, carbon, and oxide hydrocarbons and must be regenerated to maintain their reactivity. During regeneration carbon is burned to CO.

Catalytic reformers, hydrocrackers, and desulfurizers are also contributory to hydrocarbon emissions to some degree but there is considerably less carbon formed and regeneration may occur only once or twice a year. If necessary, the resultant gases can be conducted through a heater firebox to reduce hydrocarbon emissions.

In the control of particulate emissions, centrifugal collectors, alone or in combination with electrostatic precipitators, have found extensive application. This equipment has little or no effect on carbon monoxide or on hydrocarbons.

The loss to the atmosphere during catalyst regeneration is largely CO. Typical losses in percent by weight are CO, 96%; SO₂, 2%; hydrocarbons, 1%; and all others including aldehydes 1% (API 1973).

A typical fluid catalytic cracking unit with a capacity of 30,000-40,000 bbl/day, loses an average of 11.3 to 13.6 Mg/hr. Losses of hydrocarbons from thermal catalytic cracking units are only about 30% of this figure (API 1973).

One method of control results in essentially complete elimination of the hydrocarbon content by conversion to CO₂, CO and water. The first method is a CO waste heat boiler which converts CO to CO₂, thereby utilizing the heat of combustion and the sensible heat of the gases and also thereby eliminating the hydrocarbons.

5.5.2.8 Pump Losses and Mechanical Seals

Centrifugal pumps and positive displacement pumps leak from packed seals or mechanical seals where the drive shaft passes through the pump casting. Leakage losses include volatile as well as nonvolatile products.

The average losses from maintained pumps are low, averaging about 8.6 and 3.6 kg/day for packed and mechanical seals, respectively (API 1973). The mechanical seal is recommended to reduce hydrocarbon emissions for more or less continuous pumping of products. For some applications the seals vent directly to a vapor recovery system.

5.5.2.9 Miscellaneous Sources of Hydrocarbon Losses

- Equipment Leakage - This includes pipeline valves, pump seals and compressor seals and is probably the largest source of loss of the items listed under miscellaneous sources. Equipment leakage accounts for about 15 kg/day/100 barrel of refinery throughput, exclusive of pump seals, which were discussed earlier. This value is probably high and can be reduced considerably by adequate inspection and maintenance (API 1973).

- Burners or Furnaces - Even though modern boiler equipment, whether in refinery heaters or steam boilers, is usually quite efficient in operation, the presence of relatively small amounts of unburned hydrocarbons, including also aldehydes and organic acids have been verified (API 1973). Under normal conditions the concentration of hydrocarbons, aldehydes, and organic acids in the gaseous emission products do not usually exceed 20 ppm when burning No.6 fuel oil (API 1973).

- Tank Cleaning - Tank cleaning does present a problem for fixed roof tanks. The degree of saturation of the air space may vary from 10% to 100% depending upon the absolute vapor pressure of the material being stored.

This source could be reduced considerably in magnitude if only materials having a Reid vapor pressure of less than 2 lb were stored in fixed roofed storage tanks.

- Cooling Towers - Cooling towers are used extensively in the refinery operations to cool process water. The water which passes through the tower is not meant to come into contact with process water and, therefore, should not be contaminated with process type materials. Some degree of contamination is, however, unavoidable. The degree of contamination should not exceed 50-100 ppm. The total hydrocarbon emission is a function to the degree of water contamination, its circulation rate and the volatility of the hydrocarbons present. Some refineries utilize an "average" emission rate of 3.6 to 4.5 kg/1000 gpm of cooling water flow (API 1973).

The major release of contaminants from cooling towers is the high salt content and the anti-biological fouling chemicals released in the drift from the tower.

- Gas-Fired Engines - Gas-fired engines are used for various purposes in some refineries, especially where this fuel is readily available. The fuel is usually natural gas although refinery gas may also be used. These engines usually operate under constant loads, but some fuel remains unburned and is discharged through the exhaust.

Results of one survey, where natural gas was used, indicate that the exhaust may contain 1250 ppm of hydrocarbons, over 90% of which was methane (API 1973). Engines operating on refinery gas would exhaust fewer hydrocarbons, but the hydrocarbons would be of higher molecular weight.

6.0 WATER AND AIR QUALITY REGULATIONS FOR PETROLEUM RELATED ACTIVITIES ON THE OUTER CONTINENTAL SHELF

The impacts of liquid and atmospheric releases on the OCS are so negligible as not to historically be of concern. The great potential marine and atmospheric dilution and dispersion and the obvious lack of a resident human population have combined to make this area a non-issue in the past. However, if the OCS is extensively developed in a limited geographical area, the combined impact could be measured on land. These impacts need not be measured in pollutant concentration but possibly in public concern.

6.1 WATER QUALITY REGULATIONS APPLYING TO OCS OIL AND GAS DEVELOPMENT

The Federal Water Pollution Control Act Amendments of 1972 (PL 92-500), as amended by the Clean Water Act of 1977 (PL95-217), Sections 301 and 304 contain provisions relating to the regulation of effluents from extraction of offshore petroleum and natural gas. EPA had developed two sets of uniform effluent guidelines. The first set, for best practicable control technology currently available (BPT), was to have been applied by 1977 (EPA 1975c). As published in 1976, the second set, best available technology economically achievable (BAT), is to be applied by 1984. Under the Clean Water Act, some changes in timing are likely. The guidelines were developed for two offshore areas: the near-offshore (state waters usually within three miles) and the far-offshore (federal waters generally beyond the three mile limit) also termed outer continental shelf (OCS).

The present guidelines recommended by EPA are 72 ppm of oil for BPT and 48 ppm for BAT are proposed. The zero-discharge alternative goal initially considered for 1983 has been abandoned by EPA for far-offshore because it was judged excessively restrictive and economically impractical (NAS 1977).

Present U.S. Geological Survey (USGS) regulations governing offshore waters permit discharges averaging up to 50 ppm of oil in discharged water or an oil discharge of 9 barrels of oil per million barrels produced (ERDA 1977).

6.2 AIR QUALITY REGULATIONS APPLYING TO OCS OIL AND GAS DEVELOPMENT

Offshore facilities do not fall within the jurisdiction of local air pollution control agencies. Federal authority is primarily derived from the Clean Air Act of 1970. This act required the EPA to set national air quality standards which would protect the public health and welfare from any known or anticipated adverse effects resulting from air pollutants. These standards are presented in Table 6.1. The Clean Air Act does not deal specifically with air quality in the federally controlled outer continental shelf. The Clean Air Act Amendments-1977 do not speak to this either. AeroVironment (1977) references a legal memorandum from the Office of the General Counsel, USEPA

TABLE 6.1. National Ambient Air Quality Standards

Pollutant	Averaging Time	National Standards ^(a)	
		Primary	Secondary
Photochemical Oxidant (Ozone)	1 Hour	160 $\mu\text{g}/\text{m}^3$ (0.08 ppm)	160 $\mu\text{g}/\text{m}^3$ (0.08 ppm)
Carbon Monoxide	8 Hour	10 mg/m^3 (9 ppm)	10 mg/m^3 (9 ppm)
	1 Hour	40 mg/m^3 (35 ppm)	40 mg/m^3 (35 ppm)
Nitrogen Dioxide	Annual Average	100 $\mu\text{g}/\text{m}^3$ (0.05 ppm)	100 $\mu\text{g}/\text{m}^3$ (0.05 ppm)
Sulfur Dioxide	Annual Average	80 $\mu\text{g}/\text{m}^3$ (0.03 ppm)	---
	24 Hour	365 $\mu\text{g}/\text{m}^3$ (0.14 ppm)	---
	3 Hour	---	1.3 mg/m^3 (0.5 ppm)
Particulates	Annual Geometric Mean	75 $\mu\text{g}/\text{m}^3$	60 $\mu\text{g}/\text{m}^3$
	24 Hour	260 $\mu\text{g}/\text{m}^3$	150 $\mu\text{g}/\text{m}^3$
Hydrocarbons (corrected for methane)	3 Hour (6 to 9 a.m.)	160 $\mu\text{g}/\text{m}^3$ (0.24 ppm)	160 $\mu\text{g}/\text{m}^3$ (0.24 ppm)

(a) National Standards, other than those based on annual averages or annual geometric means, are not to be exceeded more than once per year.

(September 8, 1977) to the USEPA Regional Counsel that essentially states that the OCS Lands Act provides the authority for the Clean Air Act to be applied to fixed structures built on the OCS.

6.2.1 Offshore Impact

In the process of recovery and transporting resources from offshore, various types of air emissions will occur. The two major sources accounting for over 70% of the total non-methane hydrocarbon emissions are oil storage or storage tanks onboard the platform and vents which discharge intermittently during gas processing. Power generation during production operations is the largest source of essentially continuous emissions of oxides of nitrogen, sulfur oxides, carbon monoxide and particulates, but accounts for only about 10% of the total non-methane hydrocarbon emissions. Hydrocarbon emissions to the atmosphere was the subject of a report dealing with marine terminal operations (Burklin, Micheletti and Sherman 1977). Combustion product emissions from platform mounted power units, flares, work boats and tankers have been reviewed in Section 5. Storage tank emissions and releases from platforms and tankers during loading activities have also been reported in Section 5. Because of the distance from shore, the moisture content of the air, and the existing wind patterns, the air around specific offshore locations will be insignificantly impacted by minor amounts of air pollutants for short durations of time (USDI 1976). Air quality impact assessments of oil and gas development activities on the OCS have been reported for the southern California Bight (AeroVironment 1977) and the United States OCS in general (Braxton, Stephens and Stephens 1977). All atmospheric pollutant maximums for platforms off southern California have been reported to be well under applicable standards (AeroVironment 1977).

6.2.2 Nearshore and Onshore Impacts

Ships entering coastal waters leave federal jurisdiction and enter state jurisdiction. In the Pacific Northwest, Washington State has delegated regulatory and enforcement authority for its interior waters to a number of local air pollution control authorities. A listing of ambient air quality standards applicable to the Pacific Northwest and Alaska are presented in Table 6.2.

TABLE 6.2. Applicable Nearshore and Onshore Air Quality Standards for the Pacific Northwest and Alaska

Substance	$\mu\text{g}/\text{m}^3$					
	Oregon State	Washington State	Olympic APCA	Northwest APCA	Puget Sound APCA	Alaska State
SO_2						
Annual Average (a)	60	60	60	53	(b)	
24-Hour Maximum (c)	260	260	260	260	(b)	
3-Hour Maximum (c)	1,300				(b)	1,300
1-Hour Maximum (c)		1,048	1,048	1,048	(b)	
(twice per week)		655	655	655	(b)	
5-Minute Maximum (c)				2,096	(b)	
Total Suspended Particulates						
Annual Geometric Mean (a)	60	60		60	60	60
24-Hour Maximum (c)	150	150		150	150	150
(15% per month)	100					
Carbon Monoxide (d)						
8-Hour Maximum (c)	10	10		10	10	10
1-Hour Maximum (c)	40	40		40	40	40
Photochemical Oxidant						
1-Hour Maximum (c)	160	160		160	160	160
Hydrocarbons						
3-Hour Maximum (c)	160	160		160	160	160
(6 a.m. to 9 a.m.)						
Nitrogen Dioxide						
Annual Average (a)	100	100		100	100	100
H_2S Reduced Sulfur (d)						
0.5-Hour Maximum (c)						100

(a) Never to be exceeded

(b) See Table 6.3

(c) Not to be exceeded more than once per year

(d) mg/m^3

The Puget Sound Air Pollution Control Agency has, in addition to ambient air quality standards, published two emission standards (Regulation I 1977). These standards are applied to SO₂ and particulates when fuel is burned. The SO₂ emission standard is really an air concentration. Section 9.07 of the Regulation I states, "It shall be unlawful for any person to cause or permit the emission of sulfur dioxide from any premises which will result in concentrations and frequencies at a primary air mass station, ..." or a special station that exceed those shown in the following table, Table 6.3. Therefore,

TABLE 6.3. Maximum Allowable Sulfur Dioxide Concentrations
(Puget Sound - APCA 1977)

<u>Concentration</u>	<u>Averaging Time</u>	<u>Frequency of Occurrence</u>
1.0 ppm	5 min	Once in any 8 Consecutive Hours
0.4 ppm	60 min	Never to be Exceeded
0.25 ppm	60 min	Twice in any 7 Consecutive Days
0.10 ppm	24 hours	Never to be Exceeded
0.04 ppm	30 days	Never to be Exceeded
0.02 ppm	365 days	Never to be Exceeded

tankers entering Puget Sound to deliver petroleum to shore-based facilities would come under these regulations. Enforcement would be quite a different matter. Emission standards do not exist for any other air pollutant in Regulation I (1977).

The Region X office of the EPA was asked to evaluate the air quality impact associated with siting a marine oil transfer terminal for Alaskan oil in the Pacific Northwest (Bray 1977). Bray (1977) looked at emissions from storage tanks, pump seals, valves and routine spills. Tanker emissions resulting from the combustion of residual oil, fueling, ballasting and purging were also examined in the EPA study.

This study examined nine sites in Oregon and Washington. The report (Bray 1977) gives a geographical description of each site (Cherry Point, March Point, Burrows Bay, Port Angeles, Copalis Beach, Offshore Copalis, Grays Harbor, Offshore Clatsop County and Astoria) and a description of the existing air quality situation.

The proposed emissions were calculated for several scenarios. Oil transfer terminals in excess of 1 million bbl/day throughput were most interesting. When these emissions were added to the existing air quality situation for each site, a potential significant impact on air quality developed in some site areas. There appears, however, to be several mitigating measures which have the potential to substantially reduce the air quality impact of terminal facility when site-specific data, e.g., meteorology, terrain, existing emissions, become available for analysis.

7.0 ECOLOGICAL EFFECTS OF OCEAN DISCHARGES RELATED TO PETROLEUM ACTIVITIES

This section gives a brief account of literature on the effects of effluents routinely discharged from OCS petroleum activities and an assessment of the likely utility of available information in defining the relationship between activities proposed for the Alaskan OCS and effects on biological populations residing there. The specific technologies described in the preceding sections result in effluents primarily in four classes: 1) metals; 2) chemicals, other than petroleum hydrocarbons; 3) turbidity, a product of many of the development technologies; and 4) petroleum hydrocarbons. In marine waters, the ambient concentrations of the first three of these classes result primarily from activities other than OCS petroleum development. Thus, relatively greater attention is given the potential effects from petroleum hydrocarbon effluents.

The final section deals with the current state-of-the-art in ecological field studies as it relates to the primary question posed in this assessment; i.e., what are the projected actual, as distinct from potential, biological effects from OCS development at specific sites in Alaska? There is a scarcity of information that is suitable for answering this question. The section reviews approaches which have been used and proposes implementation of approaches which seem to have the most promise.

7.2 METALS

The most abundant metal ions present in produced water, sodium, calcium and magnesium are the major constituents of seawater. Metals considered to be hazardous are either undetectable or present in very low concentrations. The environmental impact of released metals depends upon the effluent concentration of the metals (Table 5.8), the concentration of these metals in normal seawater (Table 5.9) and the toxicity levels of the metals (Table 7.1).

Table 7.1 lists toxic elements considered to be of critical importance to marine pollution (Ketchum 1973). The "toxicities" assigned to the metals

TABLE 7.1. Metal Toxicity and Relationship to Input
(Ketchum 1973)

Element	"Toxicity" ($\mu\text{gm/liter}$)	Relative Critical Index (a) (10^{12} liters per year)		Sea Water ($\mu\text{gm/liter}$)	Produced Waters ($\mu\text{gm/liter}$)
		Man	Nature		
Mercury	0.1	16,000	25,000	0.2	<0.5 ^(b)
Cadmium	0.2	1,750	13,250	0.1	<50 ^(b)
Silver	1	70	11,000	0.3	ND ^(c)
Nickel	2	1,350	80,000	7	3
Selenium	5	90	1,440	0.09	ND ^(c)
Lead	10	360	11,000	0.03	ppb level
Copper	10	210	25,000	3	18
Chromium	10	150	20,000	0.5	2
Arsenic	10	70	7,200	2.6	---
Zinc	20	330	36,000	10	---
Manganese	20	350	12,500	2	2 to 950

(a) Input divided by toxicity

(b) Detection limit

(c) ND - not detected

in the table are really "levels assumed to be safe". Each "toxicity" concentration is at least 100 times smaller than the concentration acutely toxic to man or to individual marine organisms. A number of important points can be made from this table; for example, produced waters do not normally contain concentrations of the six most toxic elements listed greater than those found in seawater.

Myers et al. (1975) determined amounts of Hg and Cd in effluents from a number of crude-oil offshore production units. Almost all values were below the minimal levels of detection (<0.5 ppm for Hg and <50 ppm for Cd).

The concept of relative critical index in Table 7.1 is derived by Ketchum (1973) by dividing the annual amount of a substance mobilized by either human or natural activities by the assumed toxicities (100 times higher

than acute toxic levels). This index helps to identify elements as pollutants and assists in establishing the relative contributions of trace elements from nature and from man-made sources. For instance, this table shows that nature contributes more of each metal to the environment than does man.

7.2 CHEMICALS

A number of chemicals may be released to the marine environment from petroleum activities on the OCS. Perhaps the widest usage of chemicals is associated with drilling muds (Section 5.2.1.2). The EPA (1975a) held a symposium on the environmental aspects of chemical use in well-drilling operations. The typical ingredients of these muds include such materials as barium sulphate, bentonite clay, sodium chromate, ferrochrome lignosulfonate, and even bacteriocides such as paraformaldehyde and pentachlorophenol. The precise effect of these different drilling mud components on the survival or physiology of the marine ecosystem has not been critically examined either in long-term laboratory experiments or in the natural environment (George 1975).

Short-term acute exposure laboratory experiments indicate that critical concentrations of composite drilling muds exceed 1000 ppm for marine biota (George 1975).

The extreme dilution reported by Ray et al. (1978) for Tanner Bank study area reduced mud and mud/cuttings plume concentrations of TSS, chromium, barium and lead to background levels within 200 meters. Other natural forces which act to reduce discharge concentrations of organic chemicals are evaporation, photo-oxidation and biological reactions. Inorganic components are reduced in toxicity by chelation and sedimentation processes.

7.3 TURBIDITY

The concern about effects of the inert mud components on the marine ecosystem should be examined in perspective that mud is not an alien material to the ocean. For example, it has been estimated that the Mississippi River dumps over 1 million tons of sediment into the Gulf of Mexico each day and secondly, over 70% of the world ocean floor is made up of a mud-type substrate (George 1975).

Turbid waters are encountered in a number of offshore petroleum-related activities. Drilling mud discharges have produced down-current plumes of varying magnitude depending upon the oceanographic conditions of the site. Mud and cuttings have been found together in some areas of the Gulf of Mexico and not in others. Ray et al. (1978) did not observe any accumulation of mud or cuttings of the Tanner Bank drill site, southern California. Turbid plumes could affect planktonic organisms through interference of photosyntheses in phytoplankton and respiration of zooplankton and pelagic fish species.

Where drill cuttings do accumulate, mortality will occur to many of the sessile organisms in the immediate area due to simple burial. However, the cuttings piles have been observed to be quickly repopulated by mobile organisms and larval stages of sessile organisms.

Therefore, it is concluded that the effects of deposited drill cuttings are short-lived and minor in nature.

Perhaps the greatest local impact of turbidity could arise from the jet trenching activities associated with pipeline burial. Large quantities of bottom sediments are resuspended by this activity. Impacts of this practice would be local in nature and cause sessile organism disturbance, displacement and some burial. The benthic community should very quickly repopulate the disturbed area with no long-term effects.

7.4 PETROLEUM HYDROCARBONS

As described above, there are numerous sources of hydrocarbons from petroleum activities ranging from exploration through production, transport, and refining. The inputs include heavy metals, inorganic and organic compounds, and a wide range of petroleum hydrocarbons. The rates of introduction and volumes released can perhaps be classified as either short-term large inputs (spills from blowouts or accidents) or long-term chronic inputs from production and refining operations. In some cases, spills may produce chronic effects by slowing leaching of hydrocarbons from oil trapped in sediments, so sharp distinctions may not always be possible. Spill incidents generally cause dramatic effects initially, but areas recover at a rate dependent upon

the specific chemical and physical nature of the site. Considerable mortality is observed in the early stages of the spill, but it is often difficult to ascertain the relationships between hydrocarbon levels in the environment and animal tissues and the damage to the biota from the hydrocarbons. The total effect of the spill depends upon the specific physical environment impacted and the corresponding populations of organisms. Laboratory studies that have been conducted over the past 40 years or more confirm the difficulties in defining the cause and effect relationships between spills and organisms contamination, with associated mortality. This information will hopefully provide an estimate of oil toxicity and allow estimation of spill impacts. Until the mid-1970s the data produced were confusing, since quantitative chemical data were not coupled with biological effects. The impact of spills cannot be accurately predicted; but much of the laboratory data provide a basis for estimating the toxicity of various oil extracts, the extent of hydrocarbon contamination and the retention of contamination in water, tissue and sediment. These factors will be reviewed as they relate to inputs from all sources, and the findings will be compared to known levels of input from petroleum operations.

During the production of oil on offshore platforms, oil mixed with formation water (brine) is brought to a separator system on the rig. While the design and efficiency of the separator may vary, the basic step is the flotation of oil and the removal of the more dense water from beneath. This water or brine, mixed with ambient water, is drawn off and released to the surrounding marine environment. Mackin (1971 and 1973) prepared two reports on the effects of oil field brines and the latter included his interpretation of the effects of spills on biota. The oil fields examined by Mackin were in the shallow inshore waters of the Gulf of Mexico where dilution water would be expected to be relatively low and sediment load high.

Once hydrocarbons are released to the surrounding water at acceptable levels (50 ppm permitted by USGS) by either production or refining activity they begin to partition into various compartments of the environment. The physical-chemical characteristics of the specific petroleum hydrocarbons and the given environment regulate this partitioning. Low molecular weight

saturate (12 carbons or less) and aromatic (one benzene ring) hydrocarbons are very soluble in water and are also quite volatile. Solubilization would take place even in a cold water environment, but the rate of release via volatilization will be dependent upon water and air temperatures. Little data are available on the possible sorption of low molecular weight compounds on suspended particles (organic or inorganic) or bottom deposits. From laboratory tests, only one report of tissue accumulation of low molecular weight hydrocarbons may be found (Rossi, Anderson and Ward 1976). Trimethylbenzene from an extract of crude oil in seawater was accumulated by a factor of about five times its concentration in the water (magnification factor) by the tissue of a marine polychaete worm. These results were produced by very short exposures and other data indicate that concentrations of these and other low molecular weight aromatics disappear from exposure water rapidly and no long-term tissue contamination exists.

Tests conducted in the Alaskan environment indicate that light aromatics remain in the water for a longer period and compounds such as toluene may be responsible for a significant portion of the toxicity produced from extracts of Alaskan crude oil in cold seawater (Thomas and Rice 1978; Korn, Moles and Rice 1978). The Sequim Marine Research Laboratory (PNL) analyses of the flowing exposure system, which extracts hydrocarbons from Prudhoe Bay crude oil, show that low molecular weight compounds represent the majority of the petroleum hydrocarbons in the exposure seawater. Temperatures at the laboratory range from 8 to 13°C, which is representative of seawater temperatures from northern California to southern Alaska.

Summarizing this information on the inputs and fates of low molecular weight hydrocarbons from separator operations on OCS platforms and refineries, it can be concluded that solubility and volatility generally reduce the levels to the non-toxic range, but if the conditions of cold water and low dilution existed these components could be toxic (6 to 17 ppm is the 96-hour LC50 concentration for toluene). Bioaccumulation would probably not occur and it is unlikely that these components would build up significantly in marine sediments. Armstrong et al. (1977) have found very small amounts of low molecular weight saturates (C₁₀-C₁₂) and aromatic (C₃ and C₄ - benzenes) in fine mud

three meters below a separator platform, but this is the "worst case" possible in the marine and estuarine environments. This study was conducted in an oil field identified by Mackin (1971) as one of those where some effects on the benthic organisms were apparent. The fact that the effluent discharges into only a 3-meter water column, heavily loaded with suspended particles, would indicate that both the water and the sediment would likely be contaminated. In offshore environments, water dilution factors are much greater and the load of suspended particulates much less.

One major gap in our knowledge, which precludes evaluation of impacts from refining operations in various environments, is the lack of any specific chemical data from analyses of refinery effluents, the receiving waters or sediments. Judging from the high contribution of these low molecular weight compounds in laboratory prepared extracts of crude oils, chemical expertise should be applied to the determination of effluent characteristics of both produced waters and refineries. Until data are available on the proportion of these compounds remaining in the environment for significant periods of time, it is not possible to accurately estimate the extent of contamination in coastal regions nor the effects on the biota.

While not much more is known about the levels of higher molecular weight hydrocarbons in effluents and nearby sediment, there has been a large amount of research conducted on the fate and effects of these compounds in the marine environment. The majority of this research concerns the diaromatic compounds collectively called naphthalenes, but recently data have been compiled on 3-, 4- and 5-ring aromatics. Although it is venturesome to draw broad conclusions from insufficient data, a general pattern may be observed in respect to the toxicity, tissue accumulation, sediment retention, and degradation rates of hydrocarbons ranging between 2 and 5 aromatic rings. The mass of data compiled on naphthalenes indicates that both toxicity and tissue and sediment retention times increase as the number of methyl groups increase (alkylation) on the double ring structure. Little information is available for the tri- and tetramethyl-naphthalenes nor the alkylated phenanthrenes (3 rings). However, data on a marine worm indicate that toxicity continues

to increase from naphthalene through methylphenanthrene (Neff et al. 1976). Tests with 4- and 5-ring compounds indicated low toxicity which is likely the result of the very low water solubilities of these compounds.

Regarding tissue accumulation and release rates, there appears to be a maximum rate of uptake and a minimum rate of release at about phenanthrene. This pattern is not yet entirely consistent as lower molecular weight aromatics often are taken up as rapidly and release rates are sometimes slower for 4- and 5-ring compounds. Some confusion is no doubt introduced by differences in the volatilities and solubilities of the compounds during animal exposures and variations in the pathways for releasing the compounds from the tissues.

Two routes of hydrocarbon release from organismic tissues are possible and they are essentially the same as the pathways acting to depurate hydrocarbons from oiled sediment. The first of these considers the breakdown of the compounds to more water-soluble components by enzymatic systems. Fish, crabs, and some marine worms (polychaetes) possess the necessary metabolic pathways for hydrocarbon degradation and excretion. Other species are being studied, but one group that to date has not demonstrated this capability is the bivalve mollusks (clams and oysters). These organisms have been shown to contain metabolites of hydrocarbons, but these were apparently taken up from experimental solutions after microbial activity in the system produced them from the original compounds. Microbial activity in water and even to a greater extent in sediments is responsible for converting major amounts of petroleum hydrocarbons to water-soluble derivatives. The final disposition of degradation products produced by metabolism, photo-oxidation and chemical oxidation is unknown and there is some concern that these may also be hazardous to marine life and man.

While the above processes may be very important in reducing oil contamination levels in sediments over time, the process of solubilization or leaching is also a dominant factor in sediments and bivalves. As water flows past both tissues (filter-feeders) and sediments, there is a tendency for specific hydrocarbons to partition from oily particles and cells to the water, which is

governed by relative partitioning coefficient in oil or lipids versus water. More water-soluble compounds like the monoaromatics and naphthalene are readily released from tissue back to the water, but the alkylated naphthalenes, phenanthrenes, and 4- and 5-ring aromatics partition at slower rates. The release rates from both tissues and sediment appear to decrease with increasing molecular weight. In the natural environment, the process of oil depuration from sediment is aided by microbial activity as well as chemical and physical factors, one of which is the wave and tidal energy of the particular environment. Anoxic sediment layers tend to recover more slowly as oxygen, nutrients, light and microbial populations are not present to the extent they are in surface layers.

Considering the patterns, relationships, and firm biological uptake and effects data available, it is now time to turn to evaluation of probable impacts from hydrocarbon releases from petroleum operations. It is apparent that both large and small spills of crude oil and refined products (fuel oils) have an initial dramatic effect on biota. The coating action of the material kills birds, intertidal animals and algae, and covers the intertidal substrates. Birds suffer even when the slicks have not impacted the beach, but mortalities of aquatic plants, algae and animals increase markedly when oil either reaches the shore or is mixed with sediments in very shallow water. Other than these mechanical smothering or clogging effects, there are the effects from dissolved and dispersed oil in water. Concentrations of oil under slicks offshore have been reported to be between 0.2 and 0.4 ppm, but surely in high energy areas (surf zones or storm-blown shallow areas) concentrations increase. Spills significantly impact the biota and beaches and, therefore, represent a loss to local citizens. The likelihood of spills and their frequency are factors which must be considered in restricting and regulating offshore production, onshore facilities and transport operations. However, the probability for spillage is generally so small that it alone cannot be used to assess the hazards of OCS oil and gas production.

There is quite widespread agreement that long-term chronic effects from various aspects of oil production, transport and refining are more significant for marine biota and the general condition of the marine environment. Whether

the chronic conditions result from multiple small spills (harbors, loading docks, etc.) or effluents from platforms or refineries, the concern should be for characteristics and concentrations of the contaminants. The sections above have described the effects on organisms of specific concentrations of specific petroleum hydrocarbons, and their retention in water, tissues, and sediment. The impact of these operations could be accurately assessed if data were available on any of these hydrocarbons in any of the physical or biological compartments around platforms or refineries. Unfortunately, these data are not available and as noted above, this is the largest single gap in our knowledge associated with the impact of OCS operations. It is perhaps fortunate that such concentrations have not been reported from the few studies conducted, since this is very likely due to the fact that analytical techniques have not been developed or at least utilized which have the necessary sensitivity. While it is likely that water, tissue, and sediment around platforms in relatively deep water do not contain significant amounts of petroleum hydrocarbons, certainly undiluted effluents from both platforms and refineries and sediments near the latter (in shallow areas) do contain reasonably high levels of hydrocarbons. There has been no systematic attempt to obtain accurate and sensitive analyses of these compartments of the environment so that assessments could be made. The expertise and methodology is available for both biological and chemical studies; however, it appears that these have only been utilized in recent spill studies which have more localized and short-term effects.

To assess the impact of OCS operations a best and worst case situation should be examined. The best case is offshore platforms in water of 20 meters or more. Several reports have been prepared from studies in the Gulf of Mexico (Gallaway et al. 1978) and off Southern California (Wolfson et al. 1978), which indicate no adverse effects from these structures and state that the biota is enriched as a result of additional surface area for attachment. Neither sediments nor water in the vicinity of these operating platforms has been shown to contain detectable contamination from hydrocarbons or heavy metals. Similar studies of refineries to quantitatively assess the best or worst case have not been conducted.

An example of the worst case for a production platform which is separating oil from water and releasing an effluent containing hydrocarbon contaminants may be found in an API Publication (Armstrong et al. 1977). This describes the results of an investigation which was conducted over a period of approximately 2 1/2 years in Galveston Bay, Texas by Armstrong et al. (1977). The objectives were to determine the concentrations of diaromatic compounds (naphthalenes) in the sediments surrounding a separator platform in the bay at various distances from the platform. In addition, the abundance of benthic organisms in both numbers of species and individuals were measured at each of these locations. The relationship between the content of naphthalenes in the sediments and the populations of benthic organisms were then described. In addition to these objectives, detailed hydrocarbon analyses were conducted on the oil from the platform, the full-strength effluent, and the bay water very near the outfall from the platform. This appears to be the only case in which the original oil, the effluent, the sediment, and the water in a given locale have been described for detailed hydrocarbon composition.

Figure 7.1 is a representation of the data gathered during the study. Not only are there data available on the types of hydrocarbons present in the effluent, but a basic level of input of 2.5×10^4 grams of oil per day is given as an estimate of the total oil input. In this figure, data are summarized relative to benzenes and naphthalenes present in the water, sediments and effluents, since these two classes of compounds are implicated in most toxicity studies as being the important components of crude oils. They are also among the most soluble components from oil and would be most likely to be present in the water column from spills and during refinery and platform operations.

The events described in Figure 7.1 can be traced starting from the oil on the platform, which is being skimmed or separated from the brine pumped from the wellhead. This operation generates the oil and at the same time produces an effluent which has been equilibrated with oil for some period. The effluent is, therefore, enriched with the soluble components of oil to the extent that benzenes and naphthalenes represent 96% of the aromatics in the

EFFLUENT:
 MEAN VOLUME = 2.5×10^4 g OIL/DAY
 REPRESENTATIVE DATA:
 11.3 ppm BENZENES AND NAPHTHALENES,
 WHICH IS 96% OF AROMATICS AND 45%
 OF THE HYDROCARBONS MEASURED.

SEDIMENT CHARACTERISTICS:

1. FINE CLAY WITH REDUCED POPULATIONS OF BENTHIC SPECIES IN A 150 m RADIUS.
2. ABOUT 100 ppm CONCENTRATION OF HYDROCARBONS, WITH 13.4 ppm BENZENES AND NAPHTHALENES, REPRESENTING 39% OF AROMATICS AND 14% OF TOTAL MEASURED HYDROCARBONS.
3. IN 300 m DIAMETER AND TOP 5 cm THERE WOULD BE 5.2×10^5 g OF OIL OR ABOUT 20 TIMES THE AMOUNT OF DAILY OIL INPUT (2.5×10^4 g OIL/DAYS).

FIGURE 7.1. Inputs of Oil and Toxic Aromatic Hydrocarbons (Benzenes and Naphthalenes) from an Oil Separator Platform

effluents and 45% of the total hydrocarbons measured. The total aromatics only represented 27% of the total hydrocarbons in the oil, but now represent approximately 50% of the hydrocarbons in the effluent. Benzenes and naphthalenes represent only about 13% of the hydrocarbons in the oil while, as noted, they represent 45% of the hydrocarbons in the effluent. As the effluent containing 11 ppm benzene and naphthalenes is discharged to a 3-meter water column, dilution occurs such that the amount measured near this outfall only represents about 10 ppb. Other than the mere dilution, which occurs as the effluent contacts the water column, there is probably also adsorption of compounds onto suspended particles, which eventually make their way to the bottom, and volatilization, particularly for the benzenes and the parent compound naphthalene.

The fact that a total of approximately 100 ppm is in the sediment and 13 ppm represents benzenes and naphthalenes indicates that a portion of the compounds do reach the sediment. These concentrations in the sediments near the effluents (150 meter radius) indicate that either the soluble components are sticking to surface sediments or the components, plus dispersed particles, are adhering to suspended sediment particles and these eventually make their way to the bottom. In this particular estuarine environment, the water column is very shallow and there is a high sediment load in the water. Both of these factors would tend to make this situation the "worst case" type of area for affecting organisms and retaining hydrocarbons.

The amount of oil and specific components present in this water column if there was no dilution can be calculated from the inputs of hydrocarbons. Considering the volume of 2×10^8 liters in this 300-m diameter water column, there would be approximately 1×10^{-4} ppb of oil in the water, and 1×10^{-5} ppb benzenes and naphthalenes. This, of course, is assuming no additive effect from each day of discharge and merely considers a one time discharge in a static system. It is extremely difficult to approximate the flushing rate of this water, and anticipate what the constant stream of effluent might produce in the water column. An indication of the highest concentration produced is the 10.5 ppb benzenes and naphthalenes found at the effluent discharge site. This again would appear to be the highest concentration ever present in a platform area.

Using this concentration of 10 ppb naphthalenes in the water column, the content of organisms exposed to this concentration over a period of 1 to a few hours can be approximated. Figure 7.2 gives an estimate of what might be expected in the tissues of various types of organisms exposed to 10 ppb naphthalenes. The fish and shrimp would tend to magnify these compounds by approximately 100 times and would, therefore, contain on the order of 1 ppm. These data again assume a constant source of hydrocarbons at the 10 ppb level. Filtering clams would tend to magnify the concentration of naphthalenes by about 30 times, polychaetes by about 40 times, and the only data available on the magnification of benzenes indicate that this magnification would be about 5 times in polychaetes.

The data available on uptake from contaminated sediment are quite different. Filter feeding clams living in contaminated sediment apparently pick up no substantial contamination and this is also true of polychaetes ingesting and living in contaminated sediment. Experiments were conducted with a deposit feeding clam and a sipunculid worm, which indicated that contamination might be on the order of two or perhaps three times. It is not clear, however, if this contamination is merely associated with the gut contents as it is released relatively rapidly when the organisms are placed in clear water. Figure 7.2, again, illustrates the "worst case" type of exposure where naphthalenes and benzenes are made available constantly to the organisms at the 10 ppb level. All related studies indicate that the tissues depurate the contamination when organisms move to clean sites or the level in the immediate environment decreases. Fish, crabs, and polychaetes are capable of faster turnover rates since they possess enzyme systems for the detoxification and excretion of petroleum hydrocarbons. Thus far, data indicate that bivalves including both the filter feeding and deposit feeding clams do not have these metabolic capabilities. They, however, have been shown to release contamination over periods of two weeks to two months when placed in clean water. This release appears to be a matter of the hydrocarbons partitioning from the lipid phase of the bodies to the water phases, and subsequently to the water column.

The information illustrated in Figures 7.1 and 7.2 is good data, since the necessary measurements have been taken. It is clear, however, that the

FIGURE 7.2. Approximate Magnification Factors for Organisms Exposed to Naphthalenes in Water or Associated with Sediment

data shown in Figure 7.1 are rare, and a more comprehensive investigation of effluent characteristics and volumes must be obtained before evaluating the impact of offshore production operations. The results of the investigation by Armstrong et al. (1977) indicate that the benthic organisms were less abundant and less diverse in an area of approximately 150-meter radius around the outfall pipe. Other data indicated that beyond this point there were indications of contaminated sediment but the benthic populations returned to control levels relatively rapidly. The water column in this area was only three meters in depth and, therefore, both the sediment dwelling organisms and those in the water column were likely subjected to much higher levels than would be normal for outer continental shelf operations. There were no data available regarding the impact of this effluent on water column organisms, so it is difficult to evaluate what the low levels of contamination might have produced in terms of effects on fish and zooplankton. Approximately 5×10^5 grams of oil was present in the top 5 cm of the bottom which is about 20 times the amount of daily oil input in this area. This may represent a level of saturation and/or equilibrium in the surface sediments. The differences in the seasonal variations in the sediment content were not correlated with effluent input nor river flow from a nearby region of the estuary. The effects on sediment dwelling organisms exhibited in this study would seem to be nonexistent in areas where platforms are placed in water of 20 meters or greater. A considerable load of suspended particulate matter present in the shallow environment probably explains the rather high concentrations of hydrocarbons on the bottom sediments. Many of these particles apparently adsorb hydrocarbons while falling through the water column and contribute to the concentrations on the sediment surface.

Coastal regions of the Pacific Northwest and Alaska in general are strikingly different from this particular estuarine environment studies by Armstrong et al. (1977). The lower suspended particulate load and the increased depth of water would tend to have a great sparing effect on the concentrations found either in the water column or on the bottom. If an effluent of 11 ppm is diluted to 10 ppb in the near vicinity of the outfall, this is a factor of 1000 within a very short distance. The dilution in a 20-to 100-meter water column would be much greater and these levels, which

are likely below the limit of detection, would not appear to be harmful to the biota. It should be noted that not even concentrations of 10 ppb have been shown to be harmful to organisms in static or flowing exposure systems. The lowest levels that appear to be a problem for marine organisms tend to be 100 to 300 ppb over periods of a few weeks to a few months. It is, therefore, quite unlikely that inputs from separator platforms in production fields would ever reach a concentration that produces an abnormal response in the biota within the sediment or in the water column. Data on refineries is insufficient to make such a conclusion, particularly when these generally release effluents into more shallow waters. Quantitative data are needed on refinery effluents and the environment into which they discharge. The normal data reported in terms of "oil and grease" give very little information on which to assess damage.

7.5 ASSESSMENT OF FIELD STUDIES AS TO THEIR VALUE IN PREDICTING EFFECTS FROM OFFSHORE PETROLEUM DEVELOPMENT

In spite of the background of information regarding experimentally obtained effects from oil and other specific activities of the offshore exploration, development, and production processes on individual organisms, not much is known about the actual effects of these activities on marine populations and communities. Exertion of force on a population by killing even large numbers of individuals may have no appreciable effects on the persistence and well-being of the population. The presence or absence of some species seems to have little effect on the structure of the rest of the community. Others, because of important roles as predators, or primary competitors for food or space, may have immediate and far-reaching effects on the community structure. For guilds, or subunits of local populations, some key species have been identified and have been aptly called cornerstone species (Dayton 1972), or key species (Louis 1977).

A growing number of field studies relating to the generic problem of effects on marine populations and communities from activities associated with offshore petroleum are being reported. In contrast to the experimental

studies discussed in Section 7.4, attempts at assessment of damages from these activities generally fail to define the problem under study. From many case histories, it is possible in retrospect to recognize where the experimental design failed; from the majority of these studies even this consolation is not attainable. In quantitative terms, the bottom line status of a population or community can be expressed in terms of the density or standing crop of the population at the point in time of interest. The myriad other factors are contributory to the determination of this measure. Although there may be marked seasonal changes in density for a species, to attain status quo, the year to year average population density must be stable. Natural populations, unaltered by man's activities, or natural catastrophes of weather or geology, may approach this stable state. Adequate measurement of this phenomena has only been approached in species of high economic or pest value to men.

In the foregoing framework, hypotheses relevant to effects on populations have not been tested. When hypotheses are tested at all, the usual procedure is to test a hypothesis that the community composition, community structure, or population density is the same in the contaminated situation as in some version of a "control". From studies of effects of environmental alteration a central characteristic emerges. Factors relating to the specific site and season almost invariably explain the greatest portion of the differences observed. With respect to field studies with the goal of defining effects on marine biota, we have not seen a single study in which the sensitivity of the analysis methods, or the magnitude of hypotheses alternative to the null have been specified.

Satisfaction of basic elements of the scientific method requires that specific alternative hypotheses be formulated *a priori*. This requires two types of information not usually available to the investigator: 1) a background of information on the magnitude of changes expected in response to specific activities and/or contaminants--to date this information is limited to individual responses; and 2) site specific information on the changes expected in population or community parameters due to "natural" phenomena.

Status of information of the first type has been presented in the preceding section. This section will draw on information from field studies, which because control of "extraneous" variables is not possible, provide site specific information.

The preponderance of studies relating to petroleum development and production activities involve assessments of the effects of accidental oil spillage. At the outset, the need for haste in these studies might appear to be a good reason why experimental designs adequate for testing appropriate hypotheses have not been employed. In fact, although specific sites of oil spillage cannot be predicted, thus providing the investigator with an easy excuse for a poor experimental design, studies of chronic activities, e.g., continuous routine discharges, sustained construction, or dredging have not fared much better in design.

The scientists charged with designing appropriate experiments to objectively evaluate the effects from the outlined activities cannot be entirely at fault since obtaining an adequate estimate of the necessary variances (subsampling effects, biological interactions, weather patterns, occurrence of rare events) for any one species' density requires measurements taken over a number of years at a specific site. Data from a given year constitute a single point estimate falling within the natural variation. Funding agencies seldom have the mandate and/or resources available to follow even a few critical processes for the period of time necessary to obtain the estimate of variance needed to objectively apply the scientific method. More generally, the emphasis has been to cover all possible parameters for a short period of time. The inevitable result of this approach is that the data will "suggest" a number of possible effects from the activity, and fail to: 1) assign a probability that the observation is different from "control"; 2) irrefutably tie the observed "effect" to the activity via physics and chemistry; or 3) place the effect, if real, into perspective as to biological meaning. As an example, many marine species only recruit new population members in fairly improbable circumstances arising at intervals of several years. A closely defined and real total mortality of eggs and larvae for such a species may have from no effect to extinction on the local population.

The variety of approaches to the dilemma forced on investigators asking questions about the effects of petroleum-related activities on natural populations and communities is almost as great as the number of investigators. Since, as a group, the investigators have not specified the limits of sensitivity of their methods in quantitative terms, almost none of the approaches can be either qualified or disqualified in terms of relevance to the basic question.

7.5.1 Assessment Techniques

Certain concepts have from time to time gained in popularity and for this reason are worthy of mention in this assessment.

7.5.1.1 Species Diversity

Species diversity, as an index of community health, enjoyed a prolonged period of popularity in assessment of effects from petroleum related activities on communities and is still reported in many studies. The lure of the approach lies in an assumed and/or postulated relationship between species diversity and community stability. Lewis (1977) presents important data which raises questions about this relationship in the rocky littoral. Thus high diversity reputedly would be indicative of stable conditions and low diversity would indicate interference with the underlying processes. Theoretical grounds for the relationship have been pursued by many ecologists working primarily with birds (MacArthur 1961) and forests (Whittaker 1951, 1956, 1965). The then extensive literature on the subject was reviewed by Woodwell and Smith (1969). A renewed interest in species diversity resulted from the work of Wilhm and Dorris (1966) who inversely correlated species diversity with the site of a refinery discharge in a fresh water stream. Following many inconsistent observations on the relationship between computed diversities and pollutant stress, the use of species diversity as an indicator of pollutant effect has now gained widespread disfavor. Much of this disfavor relates to the fact that information on composition of the community is lost when data are indexed. Numerous criticisms have been given the indices based on a lack of knowledge about the underlying statistical distributions (Eberhardt 1969; Hurlburt 1971).

In the use of virtually all of the indices for purposes of assessment of oil pollutant effects, there is a gap, or assumption that sample values of the index are indicative of population values. One of the components of diversity in recently used indices is species density. Estimation of density in a context meaningful to evaluation of effects from offshore oil developments has not been done. Studies by McAuliffe et al. (1975), who reported increased diversity with increased measured sediment hydrocarbon content after the Chevron Main Pass Block 41 oil spill, and by Michael et al. (1975), who failed to find a significant correlation between species diversity and oil contaminated stations after the much studied West Falmouth oil spill, are typical findings. We suggest that these contradictions in findings may result as much from sampling sensitivity as from real differences in diversity.

7.5.1.2 Similarity Indices and Classifications

In an attempt to identify effects from petroleum-related activities in at least qualitative fashion, a number of investigators have used indices of similarity. These indices are based on the presence or absence--occurrence--of species in samples which have been classified for attributes of location, season, year, contaminant concentration, and other physical and chemical descriptions. The indices themselves suffer many of the same statistical difficulties as do the species diversity indices cited above. Recent evaluation of 25 different similarity indices has been performed by Johnston (1976) who concluded that the value of the indices is limited to qualitative description. Since the indices do refer to specific entities--species or higher taxa--they contain more descriptive information than do the indices of diversity.

The power of the approach is that a great number of sites or stations can be compared for the occurrence of species in samples and sites can be classified using dendrograms to provide a ranking of the mutual occurrence of groups of species. As index values approach unity, sites are considered to be more nearly the same. Thus, given two sites, half of each contaminated by oil, a great similarity between the two halves (one half oil; the other unoiled) leads to the conclusion that the effect of oiling was less important than site.

Assessments of the effects of oiling on the similarity of communities have usually found that site and/or seasonal effects give greater similarity in composition--co-occurrence of species--than does the oiling (Cimberg et al. 1973; Straughan 1978; Soule 1978; Addy et al. 1978). Although these studies are qualitative in the sense that hypotheses have not been tested using specified probability, they do point out that the magnitude of effect due to oiling is small relative to the background or "noise" due to natural variables. Since this is so, such studies make a good case for using quantitative site-specific approaches which will allow the legitimate partitioning of the variances associated with important natural factors.

7.5.1.3 Opportunistic Species

The presence and/or abundance of opportunistic species has been used as a tool for assessing the impact of petroleum-related activities--primarily following the 1969 spill of No. 2 fuel oil into Buzzards Bay, Massachusetts. In studies of this spill reported by Sanders, Grassle, and Harpson (1972) a large increase in numbers of species of polychaetes as well as numbers of individuals of certain species, was observed. Grassle and Sanders (1973) noted the importance of life history strategy in recolonization following impact. Grassle and Grassle (1974) outlined the characteristics of opportunistic life history strategies, pointing out that opportunistic species were characterized by many reproductions per year and rapid development. An increase in the percentage of these species and/or individuals within a species classified as opportunistic is taken as an indication of effects or disturbance. In follow-on studies at Buzzards Bay, Michael et al. (1975) observed a slightly higher percentage of opportunistic species at stations contaminated by the 1969 spill than at uncontaminated stations. In the Pacific Northwest (Washington State), the classification of species as opportunistic has been extended for use in evaluation of dredge spoil deposition--an activity necessary to construction of onshore refineries, platform construction and pipe-laying associated with off-shore production of oil. These studies, conducted by Harmon and Servold (1978), illustrate a central problem with the use of opportunistic species in that classification of a species as opportunistic was

based primarily on its reappearance at the impacted site, i.e., opportunistic species indicate the effect; and species are opportunistic if they appear first at the site of suspected impact. This seems circular to us.

Each of the above authors recognizes in greater or lesser detail that the classification of a species as opportunistic may relate to the site in question, i.e., a species may be opportunistic at one site and less so at another. As with the foregoing indices--diversity and similarity--quantitative studies which specify a level of probability that changes in either numbers of species or individuals within an opportunistic species have not been conducted. Quite obviously a considerable amount of work at a specific location will be needed before meaningful hypotheses can be formulated and tested. As with diversity indices these hypotheses will rest on estimation of species density and an estimate of the between-year variances for density will be needed.

7.5.1.4 Habitats

It is pertinent that the best information available regarding effects of oil and related activities comes from bottom habitats or the benthic communities residing therein. The studies cited above were studies of benthos. Population and community indices can, of course, be applied to the communities of other habitats as well. While many laboratory studies or potential effects from oil have centered on organisms from the water column--plankton and fishes--the generally greater mobility of these organisms even further confuses the issue when one wishes to test hypotheses about actual effects. Not only is the sampling problem for measurement of population density magnified because of mobility, but the construction of realistic descriptions of exposure intensities for these organisms is at this state of the art, a questionable undertaking. Virtually no information is available which can be utilized in interpreting effects from petroleum activities on water column organisms at the population or community levels of organization.

7.5.1.5 Survey Data

In the Pacific Northwest and Alaskan regions the vast majority of research effort has gone to "baseline" or "benchmark" studies under the auspices of

the Bureau of Land Management, Department of Interior. The data may serve some useful purpose in describing the general composition of communities; their value for assessment of the effects of petroleum-related activities is quite limited. The entire Department of Interior Environmental Studies Program aimed at OCS oil and gas has been recently critiqued by the National Research Council (National Academy of Sciences 1978). This critique recognizes the limitations of survey type data both in terms of the technical problem of measuring future impacts and the relevance of findings to policy decisions. They arrive, with respect to technical problems, at a conclusion based on studies of the Bureau of Land Management program that does not differ substantially from our own conclusion from the general literature, i.e.:

"The current long-term benchmark studies program of BLM should be terminated, and the needs of federal and state officials in meeting NEPA requirements for prediction should be the primary focus. A new format should be designed, based on stating and testing hypotheses, (our emphasis) that would produce work more relevant to the management of specific environmental effects of OCS activity."

The elements of a program more realistically suited to the needs of decision makers are stated by the National Research Council as:

1. "BLM should continue pre-leasing short-term reconnaissance studies.
2. Concerted effort by scientifically trained personnel is required to synthesize the data from reconnaissance studies and put it in a form useful to decision makers.
3. Appropriate interpretation of the social impacts of OCS oil and gas development on nearshore and onshore areas should be initiated using existing data.
4. For OCS development and production, more studies of the specific effects of low-level chronic inputs on aquatic communities should be undertaken by experienced scientists.
5. DOI should support immediate and continued studies of major spills whenever they occur on the U.S. outer continental shelf."

The primary generation of new data recommended by the National Research Council, elements 4 and 5, above, drives home the need for field experimental studies. It can be expected, based on background from the literature alluded to in the preceding discussion, that the results of these studies will have

site-specific, not generic, applicability. The choice of critical sites for experiments may be arrived at by pursuing the first three program elements outlined by the National Research Council.

7.5.2 Field Experiments

Two key technical problems facing the designer of experiments to measure the effects of petroleum activities in the field are: 1) ensuring that the experimental approach has sufficient sensitivity to detect and quantify changes in the population or community parameters of a magnitude expected by the impact; and 2) ensuring sufficient discriminating power to attribute the measured changes to the petroleum related activity. In two habitats characterized by relatively nonmobile adult populations--the rock littoral and the benthic--preliminary experiments have been conducted to help assess experimental design problems.

Because of its visual accessibility and gross similarity to terrestrial seres, the rocky littoral has received quite a lot of attention from classical ecologists. It is pertinent that the zone, because of its vulnerability to surface-carried oil, is also one for which a considerable amount of survey data--following catastrophic oil spillage--also exist. Classical ecologists (Connel 1970, 1972; Dayton 1971, 1975; Lewis 1970, 1977; Lewis and Bowman 1975; and Paine 1966) have for a number of years used manipulative experiments to assess the importance of biological interactions--predation and competition--in the determination of community structure. The experiments have generally been of two types: 1) the total removal or "clearing" of rock or organisms with follow-on observations of "cleared" and uncleared areas for community development; and 2) the selective removal of predators and/or competitors with follow-on observation of developing community structure. The experiments have two very positive attributes: 1) since evaluations have been made over a number of years, some data are available for estimation of the critical between-year variance for parameters of interest; and 2) it appears that the importance of predation and competition as determinants of community structure may operate independent of population density. On the negative side, as an assessment tool, the experiments conducted to date have not centered on evaluation of the removal of species particularly sensitive to

petroleum or activities associated therewith. Nonetheless, using estimates of variance obtained from these studies, Moore and McLaughlin (1977) have provided an elegant analysis of the sensitivity of the manipulative approach in quantitative terms using a variety of experimental designs. They concluded that detection of changes of a magnitude important to the determination of community structure using sample sizes routinely applied by the classical ecologists cited above had high probability. Thus, the first key technical problem in design, i.e., "ensuring that the experimental approach has sufficient sensitivity..." would seem to be partially resolved. In the rocky littoral, however, the second key problem in design--ensuring discriminating power--is a substantial one. Acceptable standardized methods for quantitative measurement of petroleum on solid substrates are not yet developed. If one uses water-borne petroleum as the measure of contaminant, or treatment intensity, the mobility of the water phase makes estimation of this factor a substantial sampling problem in its own right. Although measurements of water-borne petroleum has been employed following oil spillages (McAuliffe et al. 1975) data have not been evaluated in a framework suitable for testing hypotheses concerning effects.

In the case of bottom habitats, the classical experiments involving manipulations of key species have not been performed. These habitats have an overwhelming advantage over the rocky littoral in petroleum discriminating function since standard analytical chemistry methods (Warner 1976; MacLeod 1977) can be routinely applied to sediments and the fauna of interest live in the sediments. Although technically the route of petroleum hydrocarbon contamination of organisms living in sediments may be via overlying, or interstitial waters (Roesjadi et al. 1978), the sediments have in some cases been identified as a sink and source for contamination of infauna. Thus the possibility of gaining discrimination by directly applying petroleum to sediments in experiments is open.

A preliminary study, reported by Anderson et al. (1978) involved the experimental contamination of sediments placed in trays. Sediments, initially purged of all organisms, were treated with Prudhoe Bay crude oil and placed

in trays. Trays with oil-treated sediments and others with untreated sediments were buried on the bottom at the site of original collection of sediments. The dynamics of petroleum composition and concentration were followed for a period in excess of a year. The composition and numbers of organisms settling in trays were evaluated by subsampling. The biological data from this experiment were evaluated in a framework suitable for testing hypotheses about the effects of oil on natural settlement patterns (Vanderhorst et al. 1978). While sensitivity in the experiment was quite low because of sample size, the numbers of trays and subsamples required to detect differences in density due to oil treatment have been estimated. The indicated intensity falls well within the range of feasibility (for many species, about 5 trays and 7 subsamples give a sensitivity of 50 percent with 90 percent probability), for each treatment mean. Similar experiments using adequate sample sizes will be required to evaluate the general applicability of this tool.

From the foregoing discussion it is essential that tests of hypotheses, and ultimately, predictions about actual effects from the OCS development for petroleum, be made for specific sites in the Alaskan OCS. The overall charge in this assessment is for useful generalities about "Alaskan" and "Pacific Northwest" regions. The Alaskan OCS alone represents at least as great a diversity in habitat and marine populations as does the entire contiguous United States. Available information is limited to surveys, as discussed in a preceding subsection. Subregions of the large Alaskan OCS have been identified as areas for lease and development. Although the specification of subregions mitigates the assessment problem as compared to the Alaskan OCS as a whole, the subregions are still far too large for testing valid hypotheses about effects on marine populations with the present state of the art.

Scientifically valid assessment of the effects from routine releases from Alaskan OCS developments will only be possible after a specific well, or gathering net with associated wells, is in place and operational. It is recommended that interim predictions can best be made after a specific development site is identified. At that time judiciously planned field experiments involving amendment of segments of the development site could provide information useful to the development plan and possible alterations of development technologies.

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