

**ENVIRONMENTAL PROTECTION
AGENCY**
40 CFR Part 435
[FRL-2719-1]
**Oil and Gas Extraction Point Source
Category, Offshore Subcategory;
Effluent Limitations Guidelines and
New Source Performance Standards**
AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed regulation and request for comments.

SUMMARY: EPA is proposing regulations under the Clean Water Act to limit effluent discharges to waters of the United States from offshore oil and gas extraction facilities. The purpose of this proposal is to establish new source performance standards (NSPS), best available technology economically achievable (BAT) and best conventional pollutant control technology (BCT) effluent limitations guidelines for the offshore segment of this industry. After considering comments received in response to this proposal, EPA will promulgate a final rule. This proposal would also amend the current definition of "free oil" and the analytical method of compliance, both of which will apply to BPT as well as BAT, BCT and NSPS.

The Agency has scheduled two technical workshops for State and EPA permit writers. EPA will present and explain the proposed regulation at these workshops. The Agency believes the workshop information will also be of interest to industry representatives and members of environmental and public interest groups.

DATES: The comment period for this proposed rule will begin on September 16, 1985 and end on December 16, 1985. The development documents and rulemaking record for this proposed rule will be available beginning September 16, 1985.

The general public is invited to attend the workshops on September 24-25 in New Orleans, Louisiana, and October 29-30 in Santa Barbara, California. For locations and time please see the ADDRESSES section of this document.

ADDRESSES: Comments should be sent to Mr. Dennis Ruddy, Industrial Technology Division (WH-522), Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460.

The supporting information and all comments on this proposal will be available for inspection and copying at the EPA Public Information Reference Unit, Room 2402 (Rear of EPA Library). The EPA public information regulation

(40 CFR Part 2) provides that a reasonable fee may be charged for copying. Technical information and copies of technical documents may be obtained from Mr. Dennis Ruddy at the above address. The economic analysis report may be obtained from Ms. Kathleen Ehrensberger, Economic Analysis Staff (WH-586), Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460, or call (202) 382-5397. The environmental assessment report may be obtained from Ms. Eleanor Zimmerman, Industrial Technology Division (WH-552), at the above address, or call (202) 382-7126.

The workshops will be conducted at the following locations:

September 24-25, 1985, Sheraton New Orleans Hotel, 500 Canal Street, New Orleans, Louisiana

October 29-30, 1985, Sheraton Santa Barbara Hotel, 1111 East Cabrillo Boulevard, Santa Barbara, California

There will be no pre-registration. On-site registration will begin at 8:30 a.m. The workshops will be conducted from 9:00 a.m. to 4:00 p.m. local time.

FOR FURTHER INFORMATION CONTACT: Mr. Dennis Ruddy at the above address, or call (202) 382-7131.

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Introduction

The Supplementary Information section of this preamble describes the legal authority and background, the technical and economic bases, and other aspects of the proposed regulations. That section also solicits comments on specific areas of interest. Abbreviations, and other terms used in this preamble, generic drilling fluids, priority pollutants, and certain technical, economic and environmental documents used in regulation development are listed in Appendices A through D to this preamble.

These proposed regulations are supported by documents available from EPA. Technical conclusions are detailed in the *Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category* (EPA 440/1-85/0556). The Agency's economic analysis is found in *Economic Impact Analysis of Proposed Effluent Limitations and Standards for the Offshore Oil and Gas Industry* (EPA 440/2-85/003). An environmental analysis is presented in *Assessment of Environmental Fate and Effects of Discharges from Offshore Oil and Gas Operations* (EPA 440/4-85/002).

I. Legal Authority

The regulations described in this notice are proposed under the authority of Sections 301, 304, 306, 307, and 501 of the Clean Water Act (the Federal Water Pollution Control Act Amendments of 1972, 33 U.S.C. 1251 et seq., as amended by the Clean Water Act of 1977, Pub. L. 95-217), also called the "Act." These regulations are also proposed in response to the Court Order in *Natural Resources Defense Council, Inc. v. Costle*, C.A. No. 79-3442 (D.D.C.) July 7, 1980.

II. Scope of This Rulemaking

The purpose of this rulemaking is to propose standards of performance for new sources and effluent limitations guidelines for existing sources under sections 301, 304, 306, 307 and 501 of the Clean Water Act.

These proposed regulations would apply to discharges from offshore oil and gas extraction facilities, including exploration, development and production operations. These processes and operations comprise the offshore oil and gas extraction segment (Standard Industrial Classification (SIC) Major Group 13).

EPA's 1973 to 1976 rulemaking efforts emphasized the achievement of best practicable control technology currently available (BPT) by July 1, 1977. In general, BPT represents the average of the best existing performances of well known technologies for control of traditional (i.e., "classic") pollutants. BPT for this industrial subcategory limits the discharge of oil and grease in produced water to a daily maximum of 72 mg/l and a thirty day average of 48 mg/l; prohibits the discharge of free oil in deck drainage, drilling fluids, drill cuttings, and well treatment fluids; requires a minimum residual chlorine content of 1 mg/l in sanitary discharges; and prohibits the discharge of floating solids in sanitary and domestic wastes.

This rulemaking aims for the achievement of the best available technology economically achievable (BAT) that will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants. At a minimum, BAT represents the best economically achievable performance in the industrial category or subcategory. Moreover, as a result of the Clean Water Act of 1977, the emphasis of EPA's program has shifted from "classical" pollutants to the control of listed toxic pollutants. The BAT effluent limitations guidelines being proposed today would prohibit the discharge of free oil in drilling fluids, deck drainage, drill cuttings, produced

sand and well treatment fluids; prohibit the discharge of drilling fluids that are oil-based or that contain diesel oil; prohibit the discharge of drill cuttings that are contaminated with diesel oil or that are generated with the use of drilling fluids that are oil-based; limit the acute toxicity of drilling fluid discharges to a minimum 96-hr LC-50 (lethal concentration to 50 percent of the test organisms) of 3 percent (30,000 ppm) as measured in the diluted suspended particulate phase (SPP); and limit the discharge of cadmium and mercury in drilling fluids to a maximum of 1 mg/kg, each (whole fluid basis). BAT effluent limitations guidelines for produced water, and for deck drainage, produced sand and well treatment fluids for pollutants other than free oil are being reserved for future rulemaking.

EPA is proposing BCT equal to the previously promulgated BPT effluent limitations guidelines. EPA is, however, reserving BCT effluent limitations guidelines for additional conventional pollutant parameters in deck drainage, drilling fluids, drill cuttings, produced sand, and well treatment fluids for future rulemaking.

New source performance standards are also being proposed today. These proposed standards are the same as the Agency's proposed BAT/BCT effluent limitations guidelines with one exception. EPA is proposing a prohibition on the discharge of produced water from all offshore oil production facilities that are located in or would discharge to shallow water areas as defined in the proposed regulation. Produced water discharges from all other new source offshore facilities engaged in exploration, development, and production activities would be limited to a maximum oil and grease concentration of 59 mg/l (i.e., no single sample to exceed).

III. Summary of Legal Background

The Federal Water Pollution Control Act Amendments of 1972 established a comprehensive program to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters," Section 101(a). To implement the Act, EPA is to issue effluent limitations guidelines, new source performance standards, and pretreatment standards for industry dischargers. These are discussed in detail in the Development Document supporting these proposed regulations. The following is a brief summary:

1. Best Practicable Control Technology Currently Available (BPT). BPT limitations are generally based on the average of the best existing performance by plants of various sizes,

ages, and unit processes within the industry or subcategory.

In establishing BPT limitations, EPA considers the total cost of applying the technology in relation to the effluent reduction derived, the age of equipment and facilities involved, the process employed, the engineering aspects of control technologies, process changes, and nonwater quality environmental impacts (including energy requirements) and other factors the Administrator considers appropriate. The total cost of applying the technology is balanced against the effluent reduction. EPA promulgated BPT for the offshore segment of the oil and gas extraction point source category on April 13, 1979 (44 FR 22069). The only portion of the BPT regulation being opened for comment today is the proposed change in definition of "no discharge of free oil" and the method for determining compliance with this limitation. Otherwise, BPT is printed in this proposed rule only for sake of completeness to the reader.

2. Best Available Technology Economically Achievable (BAT). BAT limitations, in general, represent the best existing performance of technology in the industrial category of subcategory. The Act establishes BAT as the principal national means of controlling the direct discharge of toxic and nonconventional pollutants to navigable waters.

The factors considered in assessing best available technology economically achievable (BAT) include the age of equipment and facilities involved, the process employed, process changes, nonwater quality environmental impacts (including energy requirements) and the costs of applying such technology (section 304(b)(2)(B) of the Clean Water Act). At a minimum, the BAT technology level represents the best economically achievable performance of plants of various ages, sizes, processes or other shared characteristics. As with BPT, where the Agency has found the existing performance to be uniformly inadequate, BAT may be transferred from a different subcategory or category. BAT may include feasible process changes or internal controls, even when not in common industry practice.

The required assessment of BAT "considers" costs, but does not require a balancing of costs against pollutant removal benefits (see *Weyerhaeuser v. Costle, supra*). In developing the proposed BAT, however, EPA has given substantial weight to the reasonableness of cost. The Agency has considered the volume and nature of discharges expected after application of BAT, the

general environmental effects of the pollutants, and the costs and economic impacts of the required pollution control levels.

Despite this expanded consideration of costs, the primary determinant of BAT is still pollutant removal capability. As a result of the Clean Water Act of 1977, the achievement of BAT has become the principal national means of controlling toxic water pollution.

3. Best Conventional Pollutant Control Technology (BCT). The 1977 Amendment added Section 301(b)(2)(E) to the Act establishing "best conventional pollutant control technology" (BCT) for discharge of conventional pollutants from existing industrial point sources. Conventional pollutants are those defined in Section 304(a)(4) [biochemical oxygen demand (BOD₅), total suspended solids (TSS), fecal coliform and pH], and any additional pollutants defined by the Administrator as "conventional" (oil and grease, 44 FR 44501, July 30, 1979).

BCT is not an additional limitation but replaces BAT for the control of conventional pollutants. In addition to other factors specified in section 304(b)(4)(B), the Act requires the BCT limitations be assessed in light of a two part "cost-reasonableness" test, *American Paper Institute v. EPA*, 660 F.2d 954 (4th Cir. 1981). The first test compares the cost for private industry to reduce its conventional pollutants with the costs to publicly owned treatment works for similar levels of reduction in their discharge of these pollutants. The second test examines the cost-effectiveness of additional industrial treatment beyond BPT. EPA must find that limitations are "reasonable" under both tests before establishing them as BCT. In no case may BCT be less stringent than BPT.

EPA published its methodology for carrying out the BCT analysis on August 29, 1979 (44 FR 50372). In the case mentioned above, the Court of Appeals ordered EPA to correct data errors underlying EPA's calculation of the first test, and to apply the second cost test. (EPA had argued that the second cost test was not required.)

On October 29, 1982, the Agency proposed a revised BCT methodology. On September 20, 1984, EPA noticed the availability of new data and analyses that it was considering for the development of BCT limitations (49 FR 37046). EPA is today proposing BCT limitations for produced water, deck drainage, drilling fluids, drill cuttings, well treatment fluids, sanitary, domestic and produced sand waste streams. The Agency is reserving BCT coverage of all pollutants except free oil for deck drainage, drilling fluids, drill cuttings,

well treatment fluids, and produced sand waste streams pending additional data collection and promulgation of the final methodology for BCT.

4. Pretreatment Standards. No pretreatment standards have been promulgated for the offshore segment of this industry and EPA does not intend to propose pretreatment standards for the offshore segment. This is because the Agency is not aware of any existing or planned indirect dischargers in the offshore segment.

5. New Source Performance Standards (NSPS). The basis for NSPS under Section 306 of the Act is the best available demonstrated technology. New facilities have the opportunity to design the best and most efficient wastewater treatment technologies. Therefore, Congress directed EPA to consider the best demonstrated process changes and end-of-pipe treatment technologies that reduce pollution to the maximum extent feasible.

IV. Prior EPA Regulations

On September 15, 1975, EPA promulgated effluent limitations guidelines for interim final BPT (40 FR 42543) and proposed regulations for BAT and NSPS (40 FR 42572) for the offshore segment of the oil and gas extraction point source category. The Agency promulgated final BPT regulations for the offshore segment on April 13, 1979 (44 FR 22069), but deferred action on the BAT and NSPS regulations.

The Natural Resources Defense Council filed suit on December 29, 1979 seeking an order to compel the Administrator to promulgate final NSPS for the offshore subcategory. In settlement of *NRDC v. Costle*, C.A. No. 79-3442 (D.D.C.), the Agency acknowledged the statutory requirement and agreed to take steps to issue such standards. However, because of the length of time that had passed since proposal, EPA believed that examination of additional data and reproposal were necessary. Consequently, the Agency withdrew the proposed NSPS on August 22, 1980 (45 FR 56115). The proposed BAT regulations were withdrawn on March 19, 1981 (46 FR 17567).

This notice serves to propose NSPS, BAT, BCT, and certain amendments to BPT. For convenience to the reader, today's proposed regulation also contains all of the existing BPT limitations applicable to the offshore oil and gas extraction subcategory. With the exception of one proposed amendment to BPT, the existing BPT limitations are not being subjected to comment. The one proposed amendment

concerns the prohibition on discharges of free oil, which is discussed below.

Ocean discharge criteria also applicable to this industry segment were promulgated on October 3, 1980 (45 FR 65942) under Section 403(c) of the Act. These guidelines are to be used in making site specific assessments of the impacts of discharges; Section 403 limitations are imposed through Section 402 NPDES permits. Section 403 is intended to prevent unreasonable degradation of the marine environment and to authorize imposition of effluent limitations, including a prohibition of discharge, if necessary, to ensure this goal.

Offshore oil and gas facilities may also be required to prepare and implement spill prevention control and countermeasure (SPCC) plans under Section 311(j) of the Act. These requirements are set forth at 40 CFR Part 112.

V. Overview of the Industry

A. Industry Profile

The offshore segment of the oil and gas extraction point source category covers those facilities located off the coast of the United States that are engaged in the production of crude petroleum and natural gas, the drilling of oil and gas wells, and oil and gas field exploration services. These facilities, such as exploratory rigs, drilling platforms, and production platforms, are considered offshore if they are located in waters that are seaward of the inner boundary of the territorial seas, as defined in Section 502 of the Act.

There are currently about 3900 platforms producing oil and gas in U.S. offshore waters. This estimate covers all federal and state leased tracts in the Gulf of Mexico and along the coasts of California and Alaska. In 1982 over 405 million barrels of oil and 4.7 trillion cubic feet of gas with a market value of almost \$23 billion were produced offshore. These quantities represent 15 percent and 25 percent, respectively, of the total oil and gas produced in the United States. The combined bonus payments and royalties paid to the Federal government for offshore leases totaled almost \$10 billion in 1981.

The majority (98 percent) of existing U.S. operations are located in the Gulf of Mexico. However, exploration and development activities are expected to expand in the California, Alaska, and Atlantic Coast regions. For example, large potential petroleum reserves have been discovered at Point Arguello, California and in the Beaufort Sea, Alaska. Results of exploration drilling to

date for the Atlantic outer continental shelf (OCS) areas and the Gulf of Alaska have not demonstrated significant petroleum reserves. The lack of geologic data to confirm the presence of economically recoverable oil or gas make development projections for these areas less certain.

Offshore drilling activity varies from year to year depending on such factors as hydrocarbon market conditions, state and federal leasing programs, reservoir discoveries, and the strategic planning decisions and financial health of companies within the industry. In 1981 there were almost 1500 wells drilled offshore, culminating a steady upward trend throughout the 1970's. The average number for the period 1972-82 is approximately 1100 wells per year. Drilling rig utilization declined in 1982, and activity is not expected to improve significantly for some time, especially with the current downturn in crude oil prices.

EPA estimates that approximately 833 new source oil and gas platforms will be constructed between 1986 and the year 2000 in offshore U.S. waters. Today's proposed regulation distinguishes between oil facilities and gas facilities in the following manner. A gas facility consists of only gas wells. An oil facility consists of one or more oil wells, but could also have gas wells. Definitions in Section 435.11 in today's proposed regulations present these distinctions.

B. Exploration, Development, and Production

Exploration, development, and production activities generate waste discharges that include produced water, deck drainage, drilling fluids, drill cuttings, well treatment fluids, produced sand, and sanitary and domestic wastes.

Exploration activities are those operations involving the drilling of wells to determine the nature of potential hydrocarbon reservoirs. These operations are usually of short duration at a given site, involve a small number of wells and are generally conducted from mobile drilling units. Discharges are composed principally of drilling fluids and drill cuttings.

Development activities involve the drilling and completion of production wells once a hydrocarbon reserve has been identified. These operations usually involve a large number of wells and are typically conducted from a fixed platform. Discharges are composed principally of drilling fluids and drill cuttings.

Production activities begin as each well is completed during the development phase. The production phase involves active recovery of

hydrocarbons from producing formations. Development and production activities may occur simultaneously until all wells are completed and reworked. During production, discharges are composed principally of produced water and also drilling fluids and drill cuttings while concurrent development is in progress. The discharge of drilling fluids and drill cutting stops when development and well reworking operations end.

C. Waste Streams

Produced water (brine) is brought up from the hydrocarbon-bearing strata along with produced oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Drilling fluids (muds) are those materials used to maintain hydrostatic pressure control in the well, lubricate the drill bit, remove drill cuttings from the well, and stabilize the walls of the well during drilling or workover operations.

Drill cuttings are the solids resulting from drilling into subsurface geologic formations, and are brought to the surface of the well in the drilling fluid system.

Deck drainage includes all waste resulting from platform washings, deck washings, rainwater, and runoff from curbs, gutters, and drains including drip pans and work areas.

Well treatment wastes are spent fluids that result from acidizing and hydraulic fracturing operations to improve oil recovery. Workover fluids and completion fluids are also considered to be well treatment wastes.

Produced sand consists of the slurried particles used in hydraulic fracturing and the accumulated formation sands generated during production.

Sanitary wastes originate from toilets and domestic wastes originate from sinks, showers, laundries, and galleys located on drilling and production facilities.

VI. Summary of Methodology

In developing effluent regulations for this industry segment, EPA first studied the industry to determine whether differences in factors such as production methodology, location and type of operation, size and age of facility, and waste constituents require separate limitations and standards for different segments of the category. This study involved an evaluation of how these factors affect raw waste loads, and the identification of raw waste and treated effluent characteristics, including sources and volumes of waste streams.

The Agency then determined the waste constituents, including toxic pollutants, which should be considered for effluent limitations guidelines and standards of performance.

EPA also identified both actual and potential control and treatment technologies that can be applied within each industry segment. The Agency compiled and evaluated both historical and newly generated data on the performance and operational limitations of these technologies. In addition, EPA considered the impacts of these technologies on air quality, solid waste generation, and energy requirements.

The Agency also estimated capital and annual costs associated with each control and treatment alternative. In general, unit process costs were derived by applying data on production and waste characteristics for model facilities to unit costs developed for each control and treatment process. These unit process costs were added together to yield a total cost for each treatment level. The Agency was then able to determine total industry costs, evaluate the costs of applying alternative technologies, and assess the economic impacts of compliance for each regulatory option considered.

Consideration of these factors enabled EPA to classify the various control and treatment technologies as a basis for NSPS, BAT, and BCT regulations. The proposed regulations, however, do not require the application of any particular technology. Rather, they require compliance with effluent limitations and standards representative of the proper operation of these or equivalent technologies.

VII. Data Gathering Efforts

A. Existing Information

After the proposed NSPS were withdrawn in 1980 in accordance with the Court Order in *NRDC v. Costle*, the Agency conducted an assessment of existing information related to point source discharges from the offshore segment of the industry. This included profiles of current and projected offshore drilling and production activities, regulatory history and enforcement status, waste characterization, existing and potential control and treatment technologies, and the cost, energy and non-water quality impacts of pollution control. Existing data were assembled through contacts with EPA regional offices, other Federal and State government agencies, industry associations, industry representatives, third party oil transmission pipeline companies, solid waste dump site

operators, drill cuttings washer suppliers, equipment manufacturers, and various technical publications.

B. Additional Data Collection

Several areas were identified that required further study to support the reproposal of effluent limitations guidelines and standards. These included an evaluation of priority pollutant levels in produced water discharges, an evaluation of alternative control and treatment technologies for reducing the discharge of priority pollutants, a characterization of drilling fluids and additives presently in use, an investigation of alternative disposal practices for drilling fluids and drill cuttings, an assessment of the impacts of discharging drilling and production wastes to the marine environment in general, and updated projections on the location, size and configuration of new sources.

C. Sampling and Analytical Programs

The sampling and analysis programs conducted for this rulemaking have focused on produced water and drilling fluids and cuttings, and on the toxic pollutants designated in the Clean Water Act. However, EPA sampled and analyzed wastes in the offshore subcategory for certain conventional and nonconventional pollutants as well as inorganic and organic toxic pollutants. Analyses for priority pollutants were based on a number of the proposed analytical methods (44 FR 69464 (December 3, 1979); 44 FR 75028 (December 18, 1979)). The final analytical methods were published on October 26, 1984 (49 FR 43234).

1. Produced Water

The Agency's initial effort to investigate priority pollutants in produced water consisted of a preliminary screening survey conducted at six production platforms in the Gulf of Mexico during 1980. Results obtained by using the standard procedures proposed by EPA at that time indicated the presence of toxic organics and metals. However, produced waters are brines containing significant concentrations of dissolved salts. The briny nature of this waste stream required the Agency to develop modified or unique analytical methods. Representatives of the Offshore Operators Committee (OOC), the American Petroleum Institute, and EPA cooperated in a joint effort in 1981 to develop analytical protocols to measure toxic pollutants in produced water.

During the first of a two-phase analytical program, produced water samples were collected at two

production platforms in the Gulf of Mexico and sent to several Agency and industry laboratories for comparative testing. Final analytical protocols were established employing standards purged from ten percent sodium chloride brines, isotope dilution gas chromatography/mass spectrometry (GCMS) for analysis of volatile organic pollutants, continuous and/or acid/neutral extraction and fused silica capillary column isotope dilution GCMS for analysis of semivolatile organic pollutants, and standard addition flame atomic absorption for metals analysis.

The second phase of the analytical program was conducted with the use of established protocols to confirm the presence and further quantify the concentrations of toxic pollutants in produced water discharges at 30 production facilities in the Gulf of Mexico. Selected conventional and non-conventional parameters were also investigated. Samples were taken of influents to and effluents from produced water treatment systems during visits that ranged from one to three days at individual sites. Strict adherence to specified collection and quality assurance procedures was maintained throughout the program. Additional samples were collected for independent analyses sponsored by the OOC.

Priority pollutant sampling efforts have also been conducted at Alaska and California sites. Produced water samples were collected from both offshore and onshore treatment facilities at Cook Inlet and Prudhoe Bay in Alaska and from three offshore production platforms in California's Santa Barbara Channel.

2. Drilling Fluids

Another program was initiated by the Agency for this rulemaking to evaluate the characteristics of water-based drilling fluids. Such fluids, or muds, include a variety of compositions used as aids in drilling and stabilizing a borehole in the earth.

One objective of this on-going program is to examine the test procedures that are being proposed today as analytical methods applicable to this industrial subcategory for measuring acute toxicity and for detecting the presence of diesel oil in mud discharges. A second objective is to evaluate test results derived from these and other Agency approved analytical procedures in the development of effluent limitations guidelines and standards.

The first phase of this program involved the selection and specification of test muds. The Agency's intent was to select a group of the more commonly

used water-based mud formulations for testing purposes. In doing so, the Agency relied upon information gathered during the development of NPDES permits issued in 1978 to operators drilling on leases in the Atlantic Ocean. Eight basic mud types were defined during the Mid-Atlantic Bioassay Program conducted by the Atlantic Ocean permittees in cooperation with EPA Region II and the Offshore Operators Committee (OOC). These eight generic mud types were selected to encompass virtually all water-based muds, exclusive of specialty additives, used on the outer continental shelf. The components of each mud type were identified, and allowable concentration ranges for each component were specified, as presented in Appendix B to this preamble. Bioassay tests were conducted as a permit condition, and results of the Mid-Atlantic Program indicated that all eight generic muds demonstrated relatively low toxicity. Under their NPDES permits, operators were allowed to discharge muds that complied with these specifications. This generic fluid concept has been employed by other EPA regional offices in the permitting process.

Since these eight generic mud types were considered to be operationally satisfactory for the majority of offshore drilling situations, the Agency selected the same mud compositions for investigation under the BAT and NSPS regulation development program. However, it was determined that, for regulation development, tests would be more appropriately conducted on mud mixtures with components at the upper limits of the allowable concentrations. Laboratory-prepared muds, based on the eight generic fluid formulations with most components present at the upper limits of allowable concentration, were obtained from the Petroleum Equipment Suppliers Association (PESA) in mid-1983. Samples of these formulations were sent to EPA laboratories for chemical, physical, and biological testing. Bioassay data collected over the past five years by both government and industry sponsored studies on the acute toxicity of drilling fluids were considered unsatisfactory as a basis for establishing effluent limitations because of non-standard testing procedures and a high degree of variability among testing laboratories. The Agency therefore developed a standard method for measuring acute toxicity of drilling fluids for this industrial subcategory (see Appendix 3 of the proposed regulation). Toxicity tests were then conducted at EPA's Environmental

Research Laboratories in Gulf Breeze, FL, and Narragansett, RI using the standard bioassay procedure being proposed in today's rulemaking. Analyses for oil content, biochemical oxygen demand, chemical oxygen demand, total organic carbon, and priority pollutants excluding pesticides were also performed at EPA contract laboratories, along with the static sheen test being proposed today (Appendix 1 of the proposed regulation).

To examine the characteristics of oil contaminated muds, the Agency also obtained, through PESA and OOC, samples of two of the generic mud formulations spiked with various amounts of mineral and diesel oils. The two mud types selected were those that are most often used in drilling situations that require oil additives. The same analytical procedures were used to test both the spiked and unspiked formulations.

One drilling fluid constituent that is a focus of concern is diesel oil, which is typically used as the primary component in conventional oil-based drilling fluids, and is a fuel oil readily available offshore for use as a spotting fluid and lubricating agent in water-based muds. Research sponsored by both industry and government agencies has shown that diesel oil contributes significantly to the acute toxicity of such fluids. To add to the information already available in the literature on the chemical makeup of diesel oil, the Agency gathered and tested samples of commercially available diesel fuels and a diesel mud additive from an offshore drilling operation in the Gulf of Mexico. Samples were analyzed for the organic priority pollutant compounds using gas chromatography/mass spectrometry. Gas chromatography methods are also being used to determine the presence of diesel oil in drilling fluids.

The Offshore Operators Committee is also conducting a program to collect data on the organic constituents of diesel and mineral oils used as drilling fluid additives. The Agency is participating in this program which will examine the differences in chemical composition and toxicity between diesel and mineral oil, and evaluate methods for measuring the diesel content of drilling fluids.

Another major constituent of drilling fluid systems is barium sulfate, commonly called barite, a mineral used primarily as a weighting agent to control downhole pressures. Commercial forms of barite can contain various impurities, including toxic metals. To investigate the presence of these contaminants, the Agency obtained samples of barite from four different sources and analyzed

them for priority pollutant metals. The Agency intends to continue its survey of the quality and availability of commercial barite stocks.

EPA will continue to evaluate the proposed Drilling Fluids Toxicity Test, Static Sheen Test and the gas chromatography method for detecting the presence of diesel oil. The Agency plans to conduct interlaboratory validation programs before the promulgation of final regulations to determine the precision and accuracy of these methods.

3. Drill Cuttings

The discharge of oil and other mud constituents that adhere to or are mixed with waste cuttings is the primary concern in the drill cuttings waste stream. The data gathered on the quality of mud compositions were used to assess the expected effects of the discharge of contaminated drill cuttings to the ocean. In addition, information was obtained from suppliers of various types of cuttings washer systems on projected washer performance and treatment costs. Selected samples of oil contaminated drill cuttings before and after washing were obtained for screening purposes and tested for the same conventional, nonconventional, and some priority pollutant parameters that were investigated during the drilling fluids program.

4. Other Waste Streams

The Agency did not perform any new sampling or analytical programs for deck drainage, sanitary, domestic, produced sand, and well treatment fluids waste streams. Today's NSPS, BAT, and BCT proposed regulations for these waste streams are based upon information collected during the development of the existing BPT regulations. Effluent limitations and standards for certain toxic, conventional, and nonconventional pollutants are being reserved for certain of these waste streams, as described below, pending additional data collection by the Agency.

D. Environmental Effects Information Collection

The Agency has obtained information from numerous sources regarding the general environmental effects of discharges from offshore oil and gas platforms. In November of 1982, EPA issued a draft report entitled, *Interim Final Assessment of Environmental Fate and Effects of Discharges from Offshore Oil and Gas Operations* which summarized recent literature on the effects of produced water, drilling fluids, drill cuttings, deck drainage and

sanitary wastes. The Agency distributed the report for comment to some environmental organizations and industry groups. On April 19, 1983, the Agency met with the Offshore Operators Committee (OOC) in Houston, Texas to discuss their comments on this report.

Subsequent to the issuance of this report, the Agency investigated other data sources on produced water including an API report titled *Effects of Oilfield Brine Effluent on Benthic Organisms in Trinity Bay, Texas* (API Publication No. 4291) and a more recent draft report titled *Ecological Effects of Produced Water Discharges from Offshore Oil and Gas Production Platforms* (API Project No. 248). Other reports on drilling fluids and cuttings were also reviewed which include, *Drilling Discharges in the Marine Environment* by the National Research Council and *Results of the Drilling Fluids Research Program Sponsored by the Gulf Breeze Environmental Research Laboratory, 1976-1984 and Their Application to Hazard Assessment* (EPA Publication 600/4-84-055).

In response to comments on the draft environmental assessment, the Agency has also summarized findings from other field studies pertinent to this regulation in the final environmental assessment. This assessment, titled *Assessment of Environmental Fate and Effects of Discharges From Offshore Oil and Gas Operations*, is included as supporting documentation for today's proposed regulations and supersedes the draft assessment of November 1982. In addition to the discussion of the field studies and other reports, this final assessment discusses the results from the PLUME model which was developed by EPA's Corvallis Environmental Research Laboratory. This model predicts dilution, trap depth and depth of maximum penetration of the produced water discharges.

The Agency has also investigated the following: (1) biocides in use on platforms and rigs; (2) commercial landings of fish and invertebrates and level of effort statistics for the Gulf of Mexico; (3) marine species distributions for the United States; and (4) potential impacts from barite discharges. An EPA report on biocides titled *Biocides in Use on Offshore Oil and Gas Platforms and Rigs* is included in the rulemaking record and referenced in the environmental assessment. The other analyses are also summarized in the final environmental assessment supporting the proposed regulations.

E. Economic Information Collection

The Agency obtained most of the economic data from a variety of secondary sources. Department of the Interior publications provided information on offshore leasing, platform development, production and income. Department of Energy publications were used for information on energy development, production and price. Annual and 10-K reports and industry trade publications were used to construct financial profiles of energy development companies. In addition to the above sources, a number of industry specialists in both the public and private sector provided data and opinions on technical and economic issues.

VIII. Waste Characterization

The major sources of waste generated from offshore exploration, development, and production activities are summarized in Section V. Pollutant parameters of concern include oil content (oil and grease, free oil, oil-based drilling fluids, diesel oil), organic and inorganic priority pollutants, acute toxicity, residual chlorine, and floating solids. The Agency's effort to develop effluent limitations and standards for this rulemaking focused on produced water, drilling fluids, and drill cuttings.

A. Produced Water

Water brought up from hydrocarbon-bearing strata with petroleum liquids and natural gas includes brine trapped with oil and gas in the formation and water injected into the reservoir to increase productivity. Such produced water is the major source of wastewater from offshore production operations. Data from a recent survey by the Offshore Operators Committee indicate that more than 1.5 million barrels per day of produced water were discharged to state and federal waters of the Gulf of Mexico in 1983. The percentage of water in the total fluid production from a reservoir ranges considerably, but generally increases with the age of a well. Although produced water discharge rates vary widely, it has been found that, on the average, gas wells generate considerably less water than do oil wells. Data gathered by the Offshore Operators Committee show that, for the Gulf of Mexico OCS in 1983, the average produced water discharge from a gas production well is about ten percent of that discharged by an oil production well.

Produced water contains an abundance of chlorides and dissolved solids in concentrations several times greater than in seawater. Significant concentrations of oil and grease,

suspended and settleable solids, and dissolved hydrocarbons are also present.

The analytical data obtained on the presence and concentration of priority pollutants in produced water confirms the presence of several of these pollutants in both untreated and BPT-treated effluents. The results of EPA's survey of produced water discharges from 30 production platforms in the Gulf of Mexico described above show that, of 88 organic priority pollutants analyzed for, benzene, ethylbenzene, naphthalene, phenol, toluene, and 2,4-dimethylphenol were detected in most if not all of the 79 samples tested. Bis(2-ethylhexyl) phthalate, anthracene, and phenanthrene were found somewhat less frequently, but in more than half of the samples analyzed. Twenty-one of the organic priority pollutants were detected at significantly lower frequencies (less than 30 percent), and 58 of the organic priority pollutants were never detected.

Of the seven priority pollutant metals analyzed in the same study, zinc was the only metal detected at quantifiable levels in the majority of samples (more than 80 percent). Copper, nickel, lead, cadmium, and silver were detected at trace levels at significantly lower frequencies. Chromium was not detected in quantifiable amounts.

During a 1980 survey of 10 production platforms in the Gulf of Mexico sponsored by the Agency's Office of Research and Development, and summarized in a report titled *Oil Content in Produced Brine on Ten Louisiana Production Platforms* (the "Crest" report), several other chemicals were found in produced water. These chemicals include biocides, coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers and scale inhibitors. EPA has determined that most of the biocides registered for use in this industry are not priority pollutants. The priority pollutants identified as active ingredients in biocides registered for use in this industry were acrolein and pentachlorophenol. At the present time no halogenated phenol compounds, such as polychlorinated biphenyls and pentachlorophenol, may be used in any operational activity. This is based on an operating order published by U.S. Geological Survey (see 44 FR 39031).

Analytical results also confirm the findings of the study supporting BPT that significant levels of oil and grease are found in untreated produced water. In the 30-platform study, the median oil and grease removal from produced

water by existing treatment systems was estimated at 63 percent. In fact, the Agency determined that, with improved operation and maintenance practices, BPT treatment facilities can achieve measurable additional reductions in oil and grease (see Section X). The effects of BPT treatment on the other chemicals (non-priority pollutants) found in produced water are incidental because the BPT equipment is not designed to remove these chemicals, which are added directly to the production or treatment systems in many instances (biocides, corrosion inhibitors, coagulants, etc). Generally, no measurable reduction in the levels of such chemicals is expected from existing BPT-type treatment systems.

Analytical results were compared to those reported by the Offshore Operators Committee (OOC) from duplicate samples taken at 6 of the 30 offshore platforms sampled by EPA. The quantitative concentrations measured by the industry differed somewhat from those reported by EPA contract laboratories. However, the industry data does confirm the presence of priority pollutants in produced water; that BPT treatment reduces the level of some of these priority pollutants; and that priority pollutants are still being discharged to waters of the United States after existing treatment.

For purposes of determining appropriate limitations and standards, the Agency categorized the pollutants present in produced water waste streams as follows. First, the priority pollutants, organics and metals are "toxic" pollutants being designated as such pursuant to Section 307(a)(1) of the Act. It would be appropriate to set BAT limitations for these pollutants as well as for NSPS. Then the other chemicals, such as those contained in biocides, coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers and scale inhibitors which have not been identified as containing designated "toxic" pollutants, would be considered nonconventional pollutants subject to BAT limitations and NSPS. Any pollutants in these products which have been designated "toxic pollutants" would be subject to BAT and NSPS toxic limitations and standards. Finally, the oil and grease present in produced water would be considered a conventional pollutant subject to BCT limitations and NSPS.

B. Drilling Fluids

Drilling fluids, or muds, are suspensions of solids and dissolved

materials in a base of water or oil that are used in rotary drilling operations to lubricate and cool the drill bit, carry cuttings from the hole to the surface, and maintain hydrostatic pressure downhole. Oil-based drilling fluids are those in which oil, typically diesel, serves as the continuous phase with water as the dispersed phase. Such fluids contain blown asphalt and usually one to five percent water emulsified into the system with caustic soda or quicklime and an organic acid. Silicate, salt, and phosphate may also be present. Oil-based muds are more costly and more toxic than water-based muds, and are normally used only for particularly demanding drilling conditions. In water-based muds, water is the suspending medium for solids and is the continuous phase, whether or not oil is present. Water-based muds are more commonly for use offshore and were focused upon in the development of today's rulemaking.

Drilling fluids are specifically formulated to meet the physical and chemical requirements of a particular well. Mud composition is affected by geographic location, well depth, and rock type, and is altered as well depth, rock formations, and other conditions change. The number and nature of mud components varies by well, and several products may be used at any given time to control the properties of a mud system.

A survey was conducted by the Agency of drilling muds used in recently completed wells in the Gulf of Mexico. Its purpose was to obtain an accurate estimate of the types and quantities of mud components used in current practice. Chemical inventories of base components and specialty additives used downhole were collected for 74 exploratory and development wells drilled offshore since 1981. These wells were representative of drilling activities in 55 lease areas throughout Louisiana state waters, Texas state waters, and federal OCS waters.

Survey findings indicate that four kinds of material, excluding water, account for about 90 percent by weight of all components used, namely barite, clays, lignosulfonates, and lignites. Other components, including lime, caustic soda, soda ash, and a multitude of specialty additives, are used as dictated by well requirements. The quantities of components used were found to vary considerably from well to well, but certain trends were observed. Wells in federal outer continental shelf waters required, on average, more drilling muds and specialty additives than did wells in state waters. Also,

exploratory wells required more drilling mud and specialty additives than did development wells. Average total mud consumption for the surveyed wells amounted to 3.1 million pounds per exploratory well and 0.8 million pounds per development well.

Direct discharges of drilling fluids are generally in bulk form and occur intermittently during well drilling. Low volume discharges are made to maintain proper solids levels in mud systems. High volume discharges occur during changes in mud types, for dilution purposes, and when mud tanks are emptied at the end of drilling operations if fluids are not being reused. Such discharges can occur several times while drilling a well, and can total 2,000 barrels or more for each drilling fluid system changeover.

As discussed in Section VII, the Agency selected eight generic, water-based mud types for investigation during the development of today's proposed rulemaking. Chemical, physical, and biological analyses were conducted on laboratory-prepared samples of these eight formulations, both with and without oil additives. Samples were hot-rolled prior to testing to simulate the downhole pressures and temperatures to which spent muds would be subjected.

Analytical results indicate that none of the organic priority pollutants were detected in any of the base generic drilling fluid formulations. However, 10 of the 13 metals on the priority pollutant list were found in detectable quantities in the generic formulations. Cadmium and mercury, in particular, were present in all muds tested, but at levels below 1 mg/kg each.

Bioassay results indicate that the acute toxicity of the generic muds range considerably. No median effects (50 percent mortality) were observed for three of the eight mud types, whereas the most toxic was found to be the potassium/polymer mud. Its suspended particulate phase showed a 96-hr LC-50 of 3 percent by volume (30,000 ppm), as measured by the proposed bioassay test method (Appendix 3 of today's proposed regulation).

Drilling fluid toxicity was found to increase with the addition of mineral oil, and even more so with diesel oil additions. These findings are consistent with results of other research activities conducted at EPA's Environmental Research Laboratory in Gulf Breeze, Florida. The Agency will continue to investigate the toxicity of various mineral oil additives to determine which formulations are operationally adequate substitutes for the more toxic diesel oil

and result in the least overall toxicity in generic drilling fluid formulations.

GC/MS analyses of diesel additives to date show the presence of organic priority pollutants, including benzene, toluene, ethylbenzene, naphthalene, and phenanthrene. Limited analyses of mineral oils to date also show the presence of organics, including benzene, naphthalene, phenanthrene, and fluorene.

Static sheen tests were conducted on the generic muds using the proposed methodology. Free oil was not detected in any of the eight base formulations that did not contain oil additives. Sheen tests were also conducted on water-based muds that contained various amounts of mineral and diesel oil. The two generic mud types selected for testing were those that are most often used in drilling situations that require oil additives. Both mineral and diesel oil additions were found to cause sheens on test waters. However, water-based muds with diesel spikes produced sheens at lower spiking concentrations, as low as one percent by volume.

The Agency categorized the pollutants present in drilling fluids waste streams for purposes of determining appropriate limitations and standards. First, the priority pollutants, organics and metals, are "toxic pollutants" being designated as such pursuant to Section 307(a)(1) of the Act. These toxic pollutants include the mercury and cadmium in barite and the organic pollutants listed above which are present in the diesel and mineral oils which may be added to drilling fluids. Also, the large number of specialty additives which may be used can contain priority pollutants or nonconventional pollutants. It would be appropriate to establish BAT limitations as well as NSPS for the toxic and nonconventional pollutants. As discussed in greater detail in Section XI.A.2, the Agency has proposed specific numeric limitations on mercury and cadmium, and a prohibition on the discharge of free oil, oil-based drilling fluids, and diesel oil, which are all considered as "indicators" of toxic pollutants. Second, the oil and grease present in drilling fluids would be considered a conventional pollutant subject to BCT limitations as well as NSPS.

C. Drill Cuttings

When circulating drilling fluid returns to the platform from the well being drilled, it contains drill cuttings that have been cut from the well bore by the bit. These cuttings range from micron-sized to coarse, sand- to pebble-like particles. The cuttings are coated with

drilling fluid. Drilling fluid additives may absorb onto or be absorbed by the cuttings.

The drilling fluid from the well discharges to a rig shale shaker where the cuttings are separated from the drilling fluid. This separation step does not completely remove drilling fluid from the cuttings. Some drilling fluid and additives remain on the drill cuttings. Therefore, the composition of the cuttings will be similar to the drilling fluid except for the downhole formation particles, particle size distribution, and the relative amounts of the various drilling fluid constituents.

Results of recent analyses by EPA contract laboratories on drill cuttings derived from the use of oil-based drilling fluids show oil and grease levels of up to 136,000 mg/kg, chemical oxygen demand (COD) running as high as 270,000 mg/kg, and biochemical oxygen demand (BOD) as high as 8,000 mg/kg. The BOD values are artificially low as a result of the inhibition by oil. In addition, several toxic organic compounds, including naphthalene, acenaphthene, phenanthrene, 4-nitrophenol, N-nitrosodiphenylamine, pyrene, and bis (2-ethylhexyl) phthalate, and 10 of the 13 priority pollutant metals were found in measurable quantities. These data indicate the presence of toxic pollutants in oil-contaminated cuttings, and that organic loadings due to the discharge of such waste streams can be significant.

The Agency's approach to determining the appropriate limitations and standards for drill cuttings is the same as that used for drilling fluids since the drilling fluids that adhere to the drill cuttings are the major concern. The priority pollutants present in the drilling fluids would be controlled by BAT limitations and NSPS that prohibit the discharge of free oil and cuttings from oil-based fluid systems. These limitations serve as indicators of the toxic pollutants that could be present in the drilling fluids adhering to the drill cuttings.

The conventional pollutant "oil and grease" will be subject to a BCT limitation and NSPS prohibiting the discharge of free oil.

D. Deck Drainage

Deck drainage results primarily from precipitation runoff miscellaneous leakage and spills, and washdown of platform or drill ship decks and floors. It often contains petroleum-based oils from miscellaneous spills and leakage of oils and other production chemicals used by the facility. It may also contain detergents from washdown operations and discarded or spilled drilling fluid components. For the reasons described

above, the Agency has identified priority pollutant constituents of oil as pollutants of concern and has proposed a no discharge of free oil limitation as both a BAT limitation serving as an indicator toxic pollutants and as a BCT limitation for conventional pollutants.

E. Sanitary Wastes

The volume and concentration of sanitary wastes vary widely with time, facility occupancy, and operational situation. The wastewater primarily contains body waste but, depending upon the sanitary system for the particular facility, other waste may be contained in the waste stream. Usually the toilets are flushed with fresh water but, in some cases brackish or sea water is used.

The concentrations of waste are significantly different from those for municipal domestic discharges, since the offshore operations require regimented work cycles which impact waste concentrations and cause fluctuation in flows. Waste flows have been found to fluctuate up to 300 percent of the daily average, and BOD concentrations have varied up to 400 percent.

Waste flows may vary from zero for intermittently manned facilities to several thousand gallons per day for large facilities. Pollutants of concern are the conventional pollutants fecal coliform and floating solids and are proposed to be regulated for the BCT level of control. Fecal coliform would be controlled by a residual chlorine limitation.

F. Domestic Wastes

Domestic wastes result from laundries, galleys, showers, etc. Waste flows may vary from zero for intermittently manned facilities to several thousand gallons per day for large facilities. Since these wastes do not contain fecal coliform, which must be chlorinated, they must only be ground up so as not to cause floating solids on discharge. Thus, the conventional pollutant of concern is floating solids which is proposed to be regulated for the BCT level of control.

G. Produced Sand

The fluids produced with oil and gas may contain varying amounts of sand and other particles such as scale, which must be removed from lines and vessels. This may be accomplished by opening a series of valves in the vessel manifolds that create high fluid velocity around the valve. The sand is then flushed through a drain valve into a collector vessel or drum. Produced sand may also be removed in cyclone separators when it occurs in appreciable amounts.

Produced sand has been reported to be generated at the rate of one barrel per 2,000 barrels of oil.

The sand that is removed from the produced fluids typically has a high oil content. The primary pollutant of concern in produced sand wastes is oil. Therefore, for the reasons discussed above, the Agency has proposed no discharge of free oil as a BAT limitation serving as an indicator of toxic pollutants. The no discharge of free oil is also proposed as a BCT limitation on conventional pollutants.

H. Well Treatment Fluids

Well treatment fluids include chemicals used in acidizing and fracturing operations performed as part of remedial service work on old or new wells. Additionally, the fluids used to "kill" a well so that it can be serviced may create wastes for disposal.

Spent acid and fracturing fluids usually move through the normal production system and through the waste water treatment systems. Therefore, the fluids do not appear as a discrete waste source. However, their presence in the waste treatment system can cause upsets and a higher oil content in the discharged water. Liquids used to kill wells are normally drilling mud, water, or an oil.

Coverage of well treatment fluids for all pollutants except free oil is reserved in this proposed rulemaking pending collection and analysis of sufficient analytical data and information by EPA. However, to the extent any particular offshore facility passes such wastes through the produced water treatment system or commingles it with other regulated wastes streams for discharge, the commingled well treatment fluids would also be subject to the same effluent limitations as for the regulated waste stream(s).

IX. Industry Subcategorization

In many industries, factors which affect the ability of facilities to achieve technology-based limitations vary among groups of facilities. In such cases, EPA will establish different effluent limitations guidelines or standards for the various groups of facilities (i.e., subcategories). Essentially, subcategorization allows the Agency to more precisely tailor the requirements of technology-based limitations to the capacity of a diverse industry.

The oil and gas extraction point source category currently includes five subcategories: offshore, onshore, coastal, agricultural and wildlife water use, and stripper (40 CFR Part 435). Today's proposal covers only the

offshore subcategory. This subcategory is applicable to those facilities engaged in field exploration, drilling, well production, and well treatment in the oil and gas extraction industry which are located in waters that are seaward of the inner boundary of the territorial seas as defined in section 502 of the Act.

The studies in support of previously proposed NSPS and BAT and final BPT regulations for the oil and gas extraction industry concluded that three major factors—geographic location, type of facility, and waste water disposition—are the bases for subcategorization of this industry. (41 FR 44945, 44 FR 22069).

In developing today's proposed NSPS, BAT, and BCT regulations for the offshore segment of this industry, EPA evaluated characteristics of wells, platform waste effluents, available treatment technologies, and platform operations to determine if it was appropriate to modify the BPT subcategorization scheme. EPA found no basis upon which to change the existing subcategorization for the offshore segment. The Agency concluded that the existing single subcategory for the offshore segment was also appropriate for today's proposed NSPS, BAT and BCT regulations. It should be noted that while the Agency determined that it was not necessary to change the existing offshore subcategorization, the proposed NSPS includes different produced water standards based on the type of operation and location of the facility. (See § 435.15 of today's proposed regulations.)

X. Control and Treatment Technologies

A. Current Practice

BPT regulations established for the offshore segment of the industry are focused primarily on the control of the oil content of waste streams that are discharged to the ocean.

1. Produced Water

Existing technologies for the on-site removal of oil and grease from produced water discharges include gas flotation, parallel plate coalescers, loose or fibrous media filtration, gravity separation, and chemical addition to assist oil-water separation. On-site disposal methods from offshore production platforms include free fall discharge to the ocean, discharge below the water surface, and reinjection into a subsurface formation. As an alternative, some production sites transport produced fluids by pipeline to shore facilities for oil-water separation and disposal.

The removal of priority pollutants in BPT treatment systems is a complex

phenomenon that has not been fully explored. While the sampling data indicated quantifiable reductions of naphthalene, lead, and ethylbenzene after BPT treatment (i.e., by oil water separator technology), the presence of significant levels of priority pollutants (e.g., naphthalene and ethylbenzene) in all effluent samples demonstrates the limitations of such treatment technologies.

Reinjection is a disposal technique for injection of produced water into a subsurface formation. When reinjection is used for disposal purposes only, the receiving formation may not be the same formation from which produced fluids were extracted. Secondary recovery or pressure maintenance is when produced water (or other fluids) is injected into a producing formation to enhance recovery of hydrocarbons. Reinjection of produced water into a producing formation may serve both purposes, i.e., disposal of produced water and enhanced recovery of hydrocarbons.

Treatment of produced water prior to injection may be necessary and may include oil-water separation and/or filtration to minimize plugging of the receiving formation. (Oil-water separation also serves for recovery of oil as a commercial product.) Also, biocides, corrosion inhibitors and sequestering agents may be added to the water to reduce or prevent scaling and corrosion of the injection equipment. The type and amount of treatment depends primarily on the properties of the receiving formation and wastewater characteristics.

2. Drilling Fluids

Disposal of drilling fluids, as currently regulated by BPT, prohibits the discharge of free oil that would cause a film or sheen upon or a discoloration of the surface of the receiving water. The discharge of drilling fluids is regulated by NPDES permits under section 402 of the Clean Water Act and by Department of the Interior lease sale stipulations under the Outer Continental Shelf Lands Act. Water-based drilling fluids are discharged directly to the oceans unless the fluid has been contaminated with oil. Water-based fluids are discharged at the surface, into the water column, or shunted to the ocean bottom through a pipe. Where water-based drilling fluids are contaminated with oil to the extent that they would cause a sheen upon discharge, current BPT regulations prohibit their discharge; compliance with the prohibition is by transportation of the spent fluids to shore for recovery or land disposal. When oil-based drilling fluids are used offshore, the fluids are

not discharged, but are returned to shore for reconditioning and reuse or disposal.

3. Drill Cuttings

Existing practices for the handling of drill cuttings include: (1) on-site disposal of drill cuttings with an oil content that does not cause a sheen on the receiving water; (2) washing of drill cuttings that contain oil at a level that would cause a sheen so that they may be discharged to a receiving water; and (3) transportation to shore for land disposal. Some cases of disposal of muds and cuttings contaminated by oil have been reported in the Gulf of Mexico by the Minerals Management Service (MMS). MMS's District supervisors have issued at least 13 letters since 1980 that list items of non-compliance (INC) involving oil in discharged muds and cuttings. MMS required the responsible operators to clean up the disposal sites where oil was seeping to the ocean surface and causing a sheen.

The cuttings are segregated from the drilling fluid with a shale shaker and associated separation equipment. If the cuttings contain no oil or levels of oil that will not cause a sheen upon discharge, the cuttings are sluiced with sea water to the receiving water. However, if the levels of oil in the cuttings are such that a sheen would occur if the cuttings were discharged to the receiving water, the cuttings are either washed prior to discharge or transported to shore for land disposal.

Various types of cuttings washers are available. The basic process for the washing of cuttings is similar for all cuttings washer systems that were investigated. The process consists of first exposing the cuttings to a washing liquid (water, water plus cleaning chemicals, or solvents). The "washed" cuttings are then processed to remove the working liquid and discharged to the receiving water or transported to shore for land disposal. The washing liquid is then processed to recover the oil washed from the cuttings and reused. Separated oil is directed to the oil-water separation system serving the production wells. Oil-contaminated wash fluids are either reused in the drill cuttings wash process, burned, or transported to shore for disposal.

The greater the sophistication and cost of the cuttings washer system, the more efficient the oil removal. All washer systems investigated were reported to reduce oil content of drill cuttings to less than 10 percent, by weight. The more sophisticated systems using solvents are reported to reduce oil to less than 0.5 percent, by weight. Quantitative information on cuttings

washer performance was not well documented in the information obtained from suppliers.

4. Deck Drainage.

Deck drainage is either collected and treated separately for oil removal by gravity separation or is handled by the produced water treatment system before discharge.

A commonly used treatment technology for removal of free oils from deck drainage is oil-water separation. This is typically a gravity separation process, whereby the waste stream is collected and diverted to a tank, pit, sump pile, or other vessel. Adequate volume is provided in the vessel to provide sufficient detention time for the free oil and water to separate. The oil layer is then removed by decanting or skimming and returned to the production process, and the water layer drawn off for discharge. The majority of platforms in the Gulf of Mexico and offshore California use gravity separation technology on the platform for treatment of deck drainage. Some California platforms pipe deck drainage along with produced water to shore for treatment. Alaska operations typically treat deck drainage wastes on the platform.

Deck drainage treatment systems and systems that handle both produced water and deck drainage operate much more efficiently when good housekeeping and maintenance practices are employed. These include separation of crank case oils from the deck drainage collection system, minimization of spills, discriminate use of detergents, and preventing drilling fluids from entering the deck drainage collection system.

5. Produced Sand

Produced sand wastes are either transported to shore for disposal or are treated by water and/or solvent washes for oil removal to prevent the discharge of free oil.

6. Sanitary Wastes

Sanitary wastes from offshore facilities are usually treated at the source by physical/chemical systems. Facilities that are manned continuously by ten or more people are required to maintain a residual chlorine concentration in the sanitary waste discharge as close to 1 mg/l as possible for disinfection purposes. This chlorine residual is achieved by introducing chlorine in flow dependent amounts. Chlorine is either supplied from commercial sources or may be electrocatalytically generated from seawater. This chlorine requirement is based upon the use of U.S. Coast Guard

approved marine sanitation devices (40 CFR Part 140) and is required by the BPT regulations.

7. Domestic Wastes

Domestic wastes at all facilities and sanitary discharges from facilities that are manned intermittently by nine or fewer people must be free of floating solids which is required by the BPT regulations. This is accomplished with the use of shredders or screening devices.

B. Additional Technologies Considered

The Agency considered the following additional control and treatment technologies in the formulation of today's proposed regulations.

1. Produced Water

EPA evaluated each of the following treatment technologies for NSPS. These technologies were considered for implementation at offshore facilities, and onshore where produced water is piped to shore for treatment.

(a) *Improved Performance of BPT Technology.* EPA evaluated the costs and feasibility of improved performance of existing BPT treatment technologies to determine whether more stringent effluent limitations for oil and grease would be appropriate. This technology would consist of improved operation and maintenance of existing BPT treatment equipment (e.g., gas flotation, coalescers, gravity oil separation), more operator attention to treatment system operation, and possibly resizing of certain treatment system components for better treatment efficiency.

Based upon statistical analysis of effluent data from facilities sampled during the Agency's 30-platform survey, EPA determined that an oil and grease effluent limitation of 59 mg/l maximum (i.e., no single sample to exceed) can be achieved through improved performance of BPT technology. This limitation would supersede the existing 72 mg/l BPT daily maximum (average of four samples in one day). This limitation is supported by information presented in the report titled *Potential Impact of Proposed EPA BAT/NSPS Standards for Produced Water Discharges From Offshore Oil and Gas Extraction Industry*, (January 1984), sponsored by the Offshore Operator's Committee for the Gulf of Mexico. The Agency's analysis of information from this study concluded that at least 75 percent of existing offshore operations in the Gulf of Mexico were already achieving oil and grease levels of 59 mg/l (maximum) or less in produced water. In addition, the Agency analyzed produced water effluent data from available discharge

monitoring reports (DMR's) submitted by operators of offshore production facilities in the Gulf of Mexico. The results indicate that at least 60 percent of these facilities are presently achieving an oil and grease concentration of 59 mg/l or less (daily maximum) in produced water discharges. Thus, the Agency concluded that improved BPT performance to achieve greater reduction in oil and grease warranted further consideration in the development of NSPS and BCT for produced water.

(b) *Filtration.* EPA considered filtration as an add-on technology to BPT. The purpose of filtration is to remove suspended matter, including insoluble oils, from produced water. The filtration process is physical in nature and normally will not remove soluble materials. Because the majority of the priority pollutants in produced water are in solution or in a soluble form, no quantifiable reductions in priority pollutants are effected by filtration technology alone. However, reductions in conventional pollutants such as total suspended solids and oil and grease are expected. These conclusions are supported by analytical results obtained by EPA from sampling filtration systems that treat produced water.

While the Agency determined that filtration is technologically feasible to implement on an industry-wide basis, EPA rejected filtration from further consideration as a BAT treatment alternative because it is not effective in reducing priority pollutant levels. However, because filtration is a feasible technology for controlling conventional pollutants (i.e., oil and grease), the Agency concluded that filtration warranted further consideration in developing NSPS and BCT.

(c) *Reinjection.* Reinjection technology for produced water typically consists of injecting it under pressure to subsurface strata or formations. Treatment of the waters prior to injection is usually necessary. Such treatment may include removal of free oils and suspended matter by oil-water separation and filtration technologies. The removal of suspended matter prior to injection is usually performed to prevent pressure buildup and plugging of the receiving formation or strata. Biocides and corrosion inhibitors are typically added to the waters to minimize corrosion and scaling of the injection equipment. Reinjection technology results in no discharge to surface waters, i.e., zero discharge.

EPA evaluated this technology for implementation by both existing and new platforms. While EPA found that

reinjection is technologically feasible and economically achievable for implementation by new sources, the Agency currently lacks sufficient information on the technological feasibility and costs of retrofitting this model technology on a national basis for existing facilities. This is due to uncertainty of retrofit requirements for existing platforms, which can include either construction of additions to existing platforms or construction of auxiliary platforms to accommodate injection well slots and other injection equipment.

(d) *Carbon Adsorption.* EPA considered carbon adsorption as an add-on technology to BPT. The purpose of carbon adsorption would be to reduce the levels of priority organic pollutants in produced water. EPA determined that carbon adsorption is presently technologically infeasible to implement in this industry segment. This is because of the unknown effects that the brine-like nature of produced waters has on the adsorption process, the lack of performance information in either the literature or on a pilot or full-scale basis, and the disproportionately high costs to even attempt to implement this technology on a national basis for this industry segment. Therefore, EPA rejected carbon adsorption from further consideration for NSPS and BAT.

(e) *Biological Treatment.* Biological treatment of produced water was considered as an add-on technology to BPT. The purpose of biological treatment would be to reduce the levels of priority organic pollutants and oil in produced water. The available literature on the treatment of wastewater containing high dissolved solids levels (such as produced water) indicates severe problems with acclimating and maintaining biological cultures to treat such briny wastes. The dissolved solids (measure of brine content) levels in produced water are significantly higher than levels at which any biologically activated treatment system has been used or even tested. Therefore, EPA rejected biological treatment from further consideration for NSPS and BAT because it is, at present, technologically infeasible to implement on a national basis for this industry segment.

(f) *Chemical Precipitation.* EPA evaluated chemical precipitation as an add-on technology to BPT for the reduction of priority pollutant levels in produced water. Chemical precipitation technology can be effective in removing soluble metallic ions by their conversion to an insoluble form with subsequent removal by sedimentation (settling) or filtration. The Agency evaluated the

efficacy of hydroxide (lime) and sulfide precipitation, the two most likely types of chemical treatment for this type of wastewater. The Agency's analytical data on produced water prior to treatment indicated that zinc is the only priority pollutant metal found in the majority of samples of produced water discharges. Hydroxide and sulfide precipitation were determined to effect virtually no removal of zinc from BPT-treated produced water because of the low concentrations of zinc in the BPT effluent. Sulfide precipitation was also found to cause potentially serious problems with its use, including generation of sulfide gases and toxicity of the treatment chemicals. In addition, with the use of chemical precipitation, large settling facilities would be required to effect proper treatment and then the large quantities of sludge generated would have to be disposed. Thus, EPA rejected chemical precipitation from further consideration for NSPS and BAT on a national basis for this industry segment because of operational problems with implementing the technology and nonquantifiable reductions of priority pollutant metals levels in BPT-treated produced water.

2. Drilling Fluids.

EPA evaluated each of the following practices with respect to offshore drilling operations.

(a) *Clearinghouse/Toxicity Approach.* The concept of generic muds is that operationally satisfactory mud systems can be formulated with constituents that are less environmentally harmful than many currently used drilling mud components. This concept is based on the stipulation of general, water-based mud types, classified by major components, which are considered acceptable for discharge.

One such approach to the control of drilling fluid discharges during drilling activities was developed cooperatively in the late 1970's by EPA Region II and the Offshore Operators' Committee. Operators working on leases in the Baltimore Canyon had applied to Region II for NPDES permits to discharge drilling wastes. At the time, the Agency grouped all drilling muds into two broad categories, oil-based and water-based, and did not recognize differences among water-based systems. Region II prohibited the discharge of all oil-based drilling fluids, but needed a means of classifying and controlling the discharge of water-based systems which could contain numerous possible combinations of constituents.

As an alternative to requiring each mid-Atlantic permittee to perform bioassay and chemical tests every time

a mud discharge occurred, Region II allowed a joint testing program to cover all muds selected for use. Eight generic mud types were identified which encompassed virtually all water-based mud compositions used on the Outer Continental Shelf. (See Appendix B of this preamble). Concentration ranges of various base constituents were specified to allow sufficient flexibility in performance characteristics and operational needs. A bioassay procedure was developed and tests were conducted on samples of field muds representing each of the eight basic mud types. Results of the Mid-Atlantic Bioassay Program indicated that the eight selected mud types demonstrated relatively low toxicity. Operators were then allowed to discharge drilling fluids of the eight types, including certain approved specialty additives, without conducting additional tests. This generic mud concept has since been incorporated into permits issued by other EPA regional offices.

(b) *Product Substitution/Toxicity Approach.* This option involves a series of product substitutions to reduce or eliminate the discharge of priority pollutants and minimize the toxicity of discharged drilling fluids and additives. Product substitutions include: use of generic (water-based drilling fluid base formulations instead of oil-based drilling fluids (as discussed in option (a) above), use of mineral oil instead of diesel oil for lubricity and spotting purposes to reduce the toxic organics content of discharged fluids, use of barite with low to non-existent toxic metals content, and use of low-toxicity specialty additives. This option would also include a toxicity limitation (LC-50) to be achieved when the drilling fluid system is discharged. The toxicity limitation would be based upon the use of water-based drilling fluids to encourage their use.

(c) *Zero Discharge.* This option is based upon the transport of spent drilling fluids to shore for recovery, reconditioning for reuse, or land disposal. This option would result in no discharge of pollutants to surface waters.

3. Drill Cuttings

EPA evaluated the following treatment technologies with respect to implementation at the facility.

(a) *Mechanical Processes.* Drill cuttings are typically separated from the drilling fluid in a shale shaker or other similar device. However, quantities of drilling fluid, and oil and additives if used, remain with the separated drill

cuttings. The drilling mud is first loosened from the cuttings either by a pressure spray or by immersion in a tank containing a wash solution and equipped with an agitator. The wash solution may be seawater, a water-based wash solution, or a closed-solvent wash system. Sometimes a detergent is used to facilitate washing of the cuttings. A mechanical separation step usually follows which separates the solids, oils and additives from the wash solution. The separated oil and additives may be returned to the drilling mud system. Wash solutions are recycled, and the washed cuttings are typically discharged overboard.

The performance of cuttings washer systems is measured in terms of residual oil remaining on the cuttings. Most of the washer suppliers claim that the residual oil after washing will be less than 10 percent by weight and no sheen will result from their discharge. One washer supplier provides a system that dries the cuttings after washing to a powder-like form with claimed oil residuals of 0.5 percent or less, by weight.

The mechanical washing process is the most prevalent system in operation in the Gulf of Mexico, off the California Coast and in the North Sea.

(b) *Solvent Extraction System.* In this process, oil from the cuttings is extracted by a solvent, the cuttings are separated from the solvent wash solution, and discharged to the sea. Oil is separated from the solvent by a proprietary process and the solvent reused.

One supplier of solvent type washer systems claims that residual oil on the cuttings would not exceed 1 percent by weight and it may be possible to reduce the oil content to a maximum of 0.2 percent by weight. No solvent extraction unit is known, as yet, to be in full-scale field operation. Therefore, this technology was not given further consideration at this time.

(c) *Vacuum Distillation.* Vacuum distillation of cuttings is basically a "mini-refinery" process where the cuttings are ground to a fine powder and fed to a vacuum retort. The retort is heated and a two-stage vacuum pump removes the evaporated water, oil and chemicals. The mixed vapor first flows through a cyclone for solids separation and then to a vapor condenser. The condensed liquid (oil, water and some chemicals) is recycled in the mud system and the cuttings, in the form of solid residues, are discharged overboard.

The washer supplier claims that the amount of oil remaining on the cuttings

will be in the range of 100 to 500 ppm, by weight (i.e., less than 0.05 percent).

Three units have been manufactured and sold for use in the United Kingdom. The operational history of this type of unit has not been reported thus far. Therefore, this technology was not given further consideration at this time.

4. Deck Drainage, Sanitary Wastes, Domestic Wastes, Produced Sand

The Agency did not identify any control and treatment technologies other than the current practices discussed above.

5. Well Treatment Fluids

The Agency is reserving coverage of NSPS, BAT and BCT for all pollutants except free oil for this waste stream pending additional data collection and analysis.

XI. Selection of Control and Treatment Options

A. New Source Performance Standards

The basis for new source performance standards under Section 306 of the Act is the best available demonstrated technology. New facilities have the opportunity to design and implement the best and most efficient processes and waste treatment technologies. Therefore, Congress directed EPA to consider the best demonstrated process changes, in-plant controls, and end-of-process control and treatment technologies that reduce pollution to the maximum extent feasible.

The Agency has investigated several control and treatment options as a basis for NSPS to reduce the discharge of pollutants in waste streams generated by the offshore segment of this industry. These options and the rationale for selecting NSPS are presented below for the major waste streams.

1. Produced Water

(a) *Control and Treatment Options Considered.* EPA evaluated the following three control and treatment options for establishing NSPS for produced water.

OPTION 1

Option 1 would base performance standards on the improved performance of BPT technology. A discharge standard of 59 mg/l (maximum) for oil and grease would result from this option. For the 833 projected new source platforms in the year 2000, this level of technology would result in an annual reduction of 700,000 pounds of oil and grease beyond the allowable BPT discharge level. This option would not result in quantifiable reductions of priority pollutants beyond

those achieved by existing BPT-type treatment technologies.

The Agency was unable to develop incremental cost estimates for imposing Option 1 on all new source platforms. This is because the elements of improved operation and maintenance of BPT treatment equipment are very site specific. However, the Agency does believe that, for any particular new source platform, such costs are minimal compared to the installed costs of the BPT equipment and the cost of operation and maintenance to achieve the BPT effluent limitations. Also, new source operators have the opportunity to design for and install the latest equipment as an integrated part of the platform superstructure; therefore they would not be subject to any retrofit expenditures that were incurred by existing platforms to comply with the BPT regulations. Furthermore, the Offshore Operator's Committee report titled *Potential Impact of Proposed EPA BAT/NSPS Standards for Produced Water Discharge From Offshore Oil and Gas Extraction Industry* (January 1984), projects that at least 75 percent of the existing offshore platforms in the Gulf of Mexico are already achieving the 59 mg/l oil and grease limitation with treatment technology designed to achieve compliance with BPT limitations.

OPTION 2

Option 2 would base performance standards on granular media filtration as an add-on technology to BPT. This level of technology would result in additional reductions of conventional pollutants beyond the BPT level of control. Effluent limitations of 20 mg/l monthly average and 30 mg/l daily maximum for both oil and grease and total suspended solids would result from this option. For the 833 projected new source platforms, this option would result in an annualized cost of \$275.7 million in the year 2000 (1983 dollars). Investment costs for the 62 platforms expected to be installed in the year 2000 are estimated to be \$185.4 million (1983 dollars). These compliance costs are incremental to BPT technology, i.e., they do not include the costs for BPT technology.

This option would result in an annual reduction of 4.2 million pounds of oil and grease beyond the levels allowed under the BPT level of control. Significant reductions of total suspended solids levels are also achieved by granular media filtration. No quantifiable reductions in priority pollutants found in BPT-treated discharges would be achieved by this option.

OPTION 3

Option 3 would require zero discharge, based upon reinjection technology. This level of technology would result in no discharge of pollutants to surface waters.

For the projected 833 new platforms, this option would result in an annualized cost of \$487.1 million in the year 2000 (1983 dollars). Investment costs for the 62 platforms expected to be installed in the year 2000 are estimated to be \$442.0 million (1983 dollars). These compliance costs are incremental to BPT technology, which may be required ahead of the reinjection system required by this option.

This option would result in an annual reduction of 3.9 million pounds of priority pollutants beyond the discharge levels observed for existing platforms using BPT technology. This option would also result in an annual reduction of 7.0 million pounds of conventional pollutants (oil and grease) beyond the levels allowed under the BPT level of control. Significant reductions of total suspended solids levels are also achieved by this option.

(b) *Selected Option and Basis for Selection:* The option which the Agency is proposing for NSPS is a combination of Options 1 and 3. Option 3, or zero discharge, would be required for all oil production facilities that are located in or would discharge to shallow water areas, i.e., platforms in 20 meters of water or less in the Gulf of Mexico, the Atlantic Coast, and the Norton Basin; in 50 meters of water or less for the California Coast, Cook Inlet/Shelikof Strait, Bristol Bay, and Gulf of Alaska; and in 10 meters of water or less in the Beaufort Sea. The regulatory boundaries for each of these areas are defined in Appendix 4 of today's proposed regulation. The Agency has selected Option 1, improved BPT-treatment technology, which requires compliance with a 59 mg/l limitation for oil and grease (maximum for any single sample), for all oil facilities that are neither located in nor discharge to these shallow water areas, for all gas facilities regardless of location or water depth, and for all exploratory facilities regardless of location or water depth.

This selected option would require an estimated 132 new oil production facilities to meet the zero discharge standard. The other 701 new production facilities would be required to meet an oil and grease standard of 59 mg/l (maximum) based upon improved performance of BPT technology.

In selecting NSPS for produced water, the Agency considered the technical feasibility and industry compliance

costs of imposing each of the above three NSPS options. In addition, EPA calculated aggregate industry compliance costs with various combinations of these options based upon platform type and location. The record supporting today's proposal presents the details of these other options.

Because Option 3, which is based on reinjection, is the only treatment technology that EPA found to be both technologically feasible to implement and capable of achieving reductions of all pollutants, including priority pollutants, the Agency focused its evaluation on reinjection. The Agency recognized that, while reinjection is an available and demonstrated technology for controlling the discharge of pollutants in produced water from offshore oil and gas facilities, the Agency also had to consider the costs of implementing such a control option. The estimated total annualized cost for all 833 projected new facilities to implement reinjection of produced water is \$487.1 million in the year 2000 (1983 dollars). In light of the statutory mandate to consider cost in establishing NSPS, EPA decided to reject the imposition of this option on all new facilities in the offshore subcategory because of its very high aggregate cost. This prompted the Agency to evaluate limiting the scope of a zero discharge requirement (i.e., reinjection) in order to reduce the total cost.

To analyze possible ways to reduce the total aggregate cost of Option 3, the Agency then developed costs for reinjection based upon the type of facility, i.e., oil platforms or gas platforms. Not imposing a zero discharge requirement on the estimated 537 new source gas platforms would reduce the annualized cost of NSPS Option 3 by \$217.8 million in the year 2000 (1983 dollars). The Agency decided to exclude all gas platforms from coverage by Option 3 to reduce total aggregate costs.

To confirm this decision, EPA evaluated the characteristics of produced water from oil platforms versus gas platforms. The Agency determined that, while produced water from gas wells exhibits higher concentrations of the priority pollutants than produced water from oil wells (approximately fourfold higher), the typical flow volume of produced water from gas wells is significantly less (approximately 1/5) than that for oil wells. Thus, on a mass basis, discharges of priority pollutants from gas wells are approximately 25 percent of those from oil wells. The higher quantity of priority pollutants discharged from oil platforms

compared to gas platforms supports the Agency's decision that deleting gas platforms from a zero discharge requirement to reduce aggregate annualized costs was appropriate. This reduced total annualized costs to \$269.3 million (1983 dollars) while continuing to target attention on the discharges of greatest concern.

While total projected annualized costs were reduced, the Agency believed that \$269.3 million was still too high and evaluated reducing costs further by limiting the zero discharge option to shallower waters where compliance costs would be less. Facilities in shallow waters generally have the alternative of onshore reinjection which is less costly than reinjection offshore.

The Agency has found that in shallower waters a high percentage of the existing production platforms pipe to shore for treatment rather than treating the produced waters on the platform. The Agency has also determined that the costs of drilling and equipping reinjection wells on land is less costly than drilling reinjection wells at the platform.

The Agency has selected variable depth limits for different offshore areas which represent the shallower waters and which generally allow for the alternative of onshore reinjection by the facility.

Industry data for the Gulf of Mexico indicate that 82 percent of the projected new sources in state waters and 25 percent of the projected new sources in federal waters would pipe produced water to shore for treatment. The data also indicate that about 52 percent of all new sources in 15 meters or less of offshore waters would pipe produced water to shore. The Agency believes this same percentage of platforms in water depths of 20 meters or less could pipe to shore and reinject.

The 20 meter water depth was also selected for the Atlantic Coast. There is no historic trend for production platforms in this area. Therefore, the Gulf of Mexico statistics on the probable practice of onshore reinjection were assumed to be applicable for production facilities in the Atlantic Ocean.

In California, statistics indicate that 60 percent of the active production platforms located in water depths of 50 meters or less pipe to shore for treatment and only eight percent of the facilities in water depths greater than 50 meters pipe to shore for treatment. Based on this data, a depth of 50 meters or less was selected for the California Coast.

The Agency does not have historic data on production platforms for some

parts of Alaska since no offshore production platforms have been constructed to date in those areas. All of the 14 existing production platforms in Cook Inlet are classified in the coastal subcategory. The Agency believes that the Southern Alaskan bathymetry is somewhat similar to California's bathymetry and therefore, a water depth of 50 meters or less is proposed for Southern Alaska since platforms locating in this water depth may choose to pipe produced water to shore for treatment. The Southern Alaska region includes the Bristol Bay/Aleutian Island Chain, Cook Inlet and the Gulf of Alaska. The Agency realizes that some of these areas may not be amenable to piping to shore for reinjection because of seasonal ice formations, glaciers, or unsuitable terrain. However, the Agency believes that piping to shore in shallow waters will occur in areas that are suitable.

For other parts of Alaska, the Agency believes the platforms which locate in the Norton Basin in water depths of 20 meters or less and in the Beaufort Sea in 10 meters or less will have the option of piping to shore for treatment. The water depths are less than the 50 meters selected for Southern Alaska because the harsher climates in these more northern regions would result in a lesser probability of piping to shore for treatment.

The Agency developed a zero discharge option for facilities in 20 meters of water or less in the Gulf of Mexico, the Atlantic Coast and the Norton Basin; for 50 meters of water or less for the California Coast and Southern Alaska including the Aleutian Island Chain; and for 10 meters of water or less in the Beaufort Sea.

EPA then calculated the total costs of this zero discharge option in shallower waters. In the Gulf of Mexico, the agency projects that 124 new platforms will be built in 20 meters of water or less by the year 2000. The Agency estimates annualized costs of a zero discharge standard to be \$50.0 million in the year 2000 (1983 dollars). For the California Coast, the Agency projects two new platforms that will be built in 50 meters or less of water and estimates the annualized cost to be \$5.5 million (1983 dollars). While six platforms are projected to be built in the shallow waters of the Beaufort Sea, the Agency is not attributing incremental compliance costs to this regulation because existing Department of the Interior and State of Alaska lease stipulations already require zero discharge of produced water. However, these costs are included in the Agency's

baseline economic analysis for these proposed regulations. Similarly, no costs are attributed to Atlantic Coast operations because no facilities are projected to be built in 20 meters of water or less by the year 2000. Nonetheless, EPA realizes that development is possible in the Atlantic and has found that reinjection technology is feasible for meeting a zero discharge standard for platforms located in 20 meters of water or less for the Atlantic Coast.

The proposed regulatory option, developed from the variable depth considerations presented above, results in an annualized cost of \$55.6 million in the year 2000 (1983 dollars). The annualized costs apply to 126 of the 132 new oil facilities expected to be built between 1986 and the year 2000 which would be subject to this zero discharge requirement. The other six facilities are projected to be located in Alaskan waters and subject to reinjection, but the cost of reinjection is not attributed to this regulation, as described above. The Agency found these costs to be economically achievable. This cost represents the total annualized cost of NSPS. This is because the Agency's selection of improved BPT performance (i.e., 59 mg/l maximum oil and grease) for all facilities not subject to the zero discharge standard would result in negligible costs incremental to BPT.

As explained above, the agency assumes only minimal incremental costs for new sources to meet 59 mg/l oil and grease for produced water. The Agency selected Option 1 (improved BPT) over option 2 (filtration) because the aggregate annualized cost of \$275.7 million (1983 dollars) to implement Option 2 is believed to be too high.

The proposed regulatory option would result in an estimated annual reduction of 700,000 pounds of priority pollutants based on discharge levels observed for existing facilities using BPT technology. This option would also result in an annual reduction of 1.3 million pounds of conventional pollutants beyond the discharge levels allowed under the BPT level of control. No decline in energy production is projected to occur from this option.

Both reinjection and improved BPT technology represent the application of the best available demonstrated control technology in the respective areas where they will need to be used to meet the proposed standards. The Agency has thoroughly considered the cost of achieving the proposed standards and concludes that the costs will not be a barrier to future entry into offshore oil and gas exploration, development or

production operations. No adverse non-water quality environmental impacts or substantial increases in energy requirements will occur as a result of these proposed regulations.

This proposed option would require produced water from all new exploration facilities regardless of location or water depth to comply with a 59 mg/l maximum oil and grease standard, based upon improved operation of BPT. Because of the short duration of exploratory operations, the small amount of water which is generated during exploratory operations, and the fact that each exploratory well could require the drilling of a reinjection well, the Agency concluded that the cost of a zero discharge requirement for any exploratory operation is too high.

EPA is proposing that development/production facilities that would have to implement zero discharge under this option would have up to 300 days from the commencement of well drilling operations to begin complying with the zero discharge standard. For this purpose, commencement of well drilling operations means the start of borehole drilling for the first development well at an offshore oil facility.

During this 300-day period, any discharges of produced water would have to comply with a 59 mg/l (maximum) oil and grease standard, which is based upon improved performance of BPT technology. This 300-day period is being proposed in order to allow for the use of any dry (non-producing) wells which are suitable for reinjection. It is based upon the time required for the average number of development wells to be drilled before encountering a dry well that could be reworked and equipped for use as an injection well, and the average time to rework and equip the dry well for injection of produced water. If no dry wells become available and are ready for use as injection wells within this period, then compliance with the zero discharge standard would be achieved by drilling and equipping an injection well(s) for use by the 301st day from the commencement of development drilling operations.

The Agency estimates that, typically, less than two percent by volume of the produced water generated over the life of a facility would be discharged during the initial 300-day period. The Agency estimates that the difference in cost between the use of a new injection well and use of a reworked dry well for reinjection is a minimum of \$400,000 per facility. The Agency believes that it is reasonable to delay the requirement for

meeting zero discharge by new offshore oil facilities for 300 days from commencement of development drilling in order to minimize the expenditure of these substantial costs.

The reasonableness of the Agency's decision to require zero discharge in the shallow waters is confirmed by the Agency's analyses which show that it would provide protection to the most environmentally sensitive marine environments. In reviewing the environmental documents referenced in Section VII.D, the Agency determined that the highest probability of direct environmental effects of produced water discharges is most prevalent in shallower waters. In the Gulf of Mexico, for example, species distribution data provided by the National Oceanic and Atmospheric Administration (NOAA) indicate that water depths of 20 meters or less encompass approximately 88 percent of the nursery areas for selected fish and invertebrates. The Agency projected that 124 new platforms would be built in 20 meters or less of water in the Gulf of Mexico.

The Agency also evaluated the Beaufort Sea, Norton Basin, Cook Inlet, Bristol Bay, and the Gulf of Alaska in Alaska. EPA analyses indicate that a 10-meter isobath (i.e., water depth of 10 meters or less) in the Beaufort Sea; a 20-meter isobath in the Norton Basin; and a 50-meter isobath in Cook Inlet/Shelikof Strait, Bristol Bay, and the Gulf of Alaska would provide substantial protection of valuable life stages for the commercial and subsistence species in each region.

For the California Coast, EPA's analyses indicate that the 50-meter isobath will protect the majority of the designated areas of biological significance. It will also protect most of the known nursery areas.

Along the Atlantic Coast, species distribution data were obtained from NOAA that indicate approximately 83 percent of the nursery areas for the selected fish and invertebrates are encompassed by water depths of 20 meters or less.

A zero discharge requirement for produced water would also achieve control of many nonconventional, toxic pollutants in addition to the 128 listed priority pollutants (See Appendix C of this preamble). An EPA survey of 10 production platforms in Louisiana (the "Crest" report) identified chemicals containing toxic or nonconventional, toxic pollutants in use on the platforms that were either present or likely to be present in produced water. These chemicals include biocides, coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin

control agents, reverse emulsion breakers, and scale inhibitors. Detergents used to clean the platforms were also found in produced water. The Agency is currently collecting additional information on the use and effects of biocides and other chemicals in this industry for consideration in development of the final regulations.

The regulatory boundaries for each geographic area covered by today's proposed regulations are based on some of the Minerals Management Service (MMS) proposed planning areas for the new 5-year Outer Continental Shelf (OCS) oil and gas leasing program (49 FR 28332, July 11, 1984) which encompass all federal oil and gas lease activities. For the purpose of today's proposed regulations, the regulatory boundaries include the area from the state water boundary that adjoins the MMS planning area boundary landward to the inner boundary of the territorial seas. In addition, the outer (seaward) boundary of each regulatory area is proposed to coincide with the 200-mile Fishery Conservation Zone boundary.

The regulatory areas include the Gulf of Mexico, the Atlantic Coast, the California Coast and portions of Alaskan waters, as presented in Appendix 4 of today's proposed regulations.

2. Drilling Fluids

(a) *Control and Treatment Options Considered.* This section presents the regulatory options considered for NSPS drilling fluids. Because these options are the same as the options considered for BAT, the discussion of costs is presented in the BAT section for drilling fluids. Thus there are no NSPS costs or impact incremental to BAT for drilling fluids.

OPTION 1—TOXICITY LIMITATION

This option would result in the regulation of free oil, oil-based fluids, diesel oil, cadmium, mercury and the toxicity of the discharged drilling fluid. Most of these limitations are achieved by product substitution—specifically, through the use of water-based drilling fluids (i.e., generic muds), low toxicity specialty additives, the use of mineral oil instead of diesel oil for lubricity and spotting purposes, and use of barite with low toxic metals content.

Under this option the discharge of free oil would be prohibited, as in the existing BPT regulation. The discharge of oil-based fluids would also be prohibited. Oil-based fluids typically contain 50 or more volume percent of oil. One method of compliance is substitution with less toxic water-based fluids. Water-based, or generic, drilling

fluids, as explained under Option 2 below, can be used in virtually all offshore drilling situations.

The prohibition on the discharge of free oil for BPT effectively prohibits the discharge of oil-based drilling fluids. Therefore, any differential costs incurred to implement substitution of water-based for oil-based fluids is a cost attributable to compliance with BPT requirements. Moreover, in contrast to the BPT regulation, this NSPS option contains an explicit prohibition on the discharge of oil-based fluids in addition to the prohibition on discharges of free oil. The alternative to product substitution, i.e., use of water based mud systems, is to transport the spent mud system to shore for reconditioning, recovery or land disposal.

The prohibition on the discharge of oil-based fluids is included in this option as an "indicator" of the toxic pollutants present in oil-based fluids. The free oil discharge prohibition in BPT originally was imposed to prevent the discharge of oils in amounts that would cause a sheen on receiving waters and this limitation will continue.

The discharge of diesel oil, either as a component in an oil-based drilling fluid or as an additive to a water-based drilling fluid, would be prohibited under this option. Diesel oil would be regulated as a toxic pollutant because it contains such toxic organic pollutants as benzene, toluene, ethylbenzene, naphthalene, and phenanthrene. The method of compliance with this prohibition is to use mineral oil instead of diesel oil for lubricity and spotting purposes. Mineral oil is a less toxic alternative to diesel oil and is available to serve the same operational requirements. Low toxicity mineral oils are also available as substitutes for diesel oil and continue to be developed for use in drilling fluids.

The purpose of the toxicity limitation for any drilling fluids which are to be discharged is to encourage the use of generic or water-based drilling fluids and the use of low-toxicity drilling fluid additives (i.e., product substitution). The basis for the toxicity (LC-50) limitation is the toxicity of the most toxic of the generic fluids discussed in Option 2 below. The most toxic generic fluid is potassium/polymer mud (see Appendix B of this preamble). The imposition of an LC-50 toxicity limitation for all drilling fluids which are to be discharged would allow for use of at least any of the eight generic drilling fluids. Seven of the generic drilling fluids (i.e., all but potassium/polymer mud) could be supplemented with low-toxicity specialty additives and lubricity agents

to meet operational requirements, and should still be able to comply with the LC-50 toxicity limitation prior to discharge. The potassium/polymer drilling fluid probably could not be supplemented with additives that exhibit a toxicity greater than the proposed LC-50 limitation because the LC-50 toxicity limitation is based upon the base formulation of this drilling fluid. However, industry operators and drilling fluid suppliers have indicated that potassium/polymer drilling fluid is seldom used. In drilling situations where there is no substitute for potassium/polymer drilling fluid for operational reasons, such a spent mud system would comply with the proposed LC-50 toxicity limitation (3 percent, diluted suspended particulate phase) only if any required lubricity agents (oils) or specialty additives are no more toxic than the base mud formulation. Such additives are available. However, where the toxicity of the spent mud system exceeds the LC-50 toxicity limitation, the method of compliance with this option would be to transport the spent fluid system to shore for either reconditioning for reuse or land disposal.

The toxicity limitation would apply to any periodic blowdown of drilling fluid as well as to bulk discharges of drilling fluid systems. The term drilling fluid systems refers to the major types of muds used during the drilling of a single well. As an example, the drilling of a particular well may use a spud mud for the first 200 feet, a seawater gel mud to a depth of 1,000 feet, a lightly treated lignosulfonate mud to 5,000 feet, and finally a freshwater lignosulfonate mud system to a bottom hole depth of 15,000 feet. Typically, bulk discharges of 1,000 to 2,000 barrels of spent drilling fluids occur when such mud systems are changed during the drilling of a well or at the completion of a well.

For the purpose of self monitoring and reporting requirements in NPDES permits, it is intended that only samples of the spent drilling fluid system discharges be analyzed in accordance with the proposed bioassay method. These bulk discharges are the highest volume mud discharges and will contain all the specialty additives included in each mud system. Thus, spent drilling fluid system discharges are the most appropriate discharges for which compliance with the toxicity limitation should be demonstrated. In the above example, four such determinations would be necessary.

For determining the toxicity of the bulk discharge of mud used at maximum well depth, samples may be obtained at

any time after 80 percent of actual well footage (not total vertical depth) has been drilled and up to and including the time of discharge. This would allow time for a sample to be collected and analyzed by bioassay and for the operator to evaluate the bioassay results so that the operator will have adequate time to plan for the final disposition of the spent drilling fluid system, e.g., if the bioassay test is failed, the operator could then anticipate and plan for transport of the spent drilling fluid system to shore in order to comply with the effluent limitation. However, the operator is not precluded from discharging a spent mud system prior to receiving analytical results. Nonetheless, the operator would be subject to compliance with the effluent limitations regardless of when self monitoring analyses are performed. The prohibition on discharges of free oil, oil-based drilling fluids, and diesel oil would apply to all discharges of drilling fluid at any time.

Cadmium and mercury would be regulated at a level of 1 mg/kg, each, as a maximum value ("not to exceed") on a dry weight basis in any spent drilling fluid system discharge. These two toxic metals would be regulated to control the metals content of the barite component of any drilling fluid discharges. The method of compliance with these limitations is product substitution. This involves use of barite from sources that either do not contain these metals or contain the metals at low enough levels such that resultant levels in discharges of the drilling fluid do not exceed the limitations.

The causes for noncompliance with the specific requirements of this option could include: inability to use a drilling fluid that can meet the proposed toxicity limitation, such as the need for an oil-based mud or a potassium/polymer mud with oil additives because of operational reasons, the need to add lubricity agents or other specialty additives to a mud system to meet particular operational requirements, or the unavailability of barite containing low toxic metals levels. However, as previously noted, BPT effectively prohibits the discharge of oil-based drilling fluids, and less toxic water-based fluids are available substitutes. Although the potassium/polymer mud represents the most toxic water-based fluid allowed for discharge, it is seldom used for offshore drilling purposes. It is also recognized that the availability of barite stocks containing low levels of trace metals could be limited at any given time due to market conditions. For the purposes of today's proposal, the Agency assumed that

sufficient sources of such barite do exist and can be directed to offshore drilling use in those cases where an operator intends to discharge drilling fluids. Mineral oil is an available alternative to diesel oil for use as a lubricant or spotting fluid. Although there are specialty additives for which less toxic substitutes have not been identified, the toxicity limitation is applied to the discharge of the entire drilling fluid system, and not to individual components. Thus, the Agency believes that only a limited number of offshore drilling operations would not be allowed to discharge spent drilling fluids due to violation of one or more of the requirements of this option. A conservative estimate is that, at most, ten percent of all spent drilling fluid systems would violate the proposed limitations and would have to be transported to shore to comply with this NSPS option.

OPTION 2—CLEARINGHOUSE APPROACH

Option 2 would provide for the establishment of a national clearinghouse administered by EPA which would serve as a repository for all toxicity and related physical and chemical characteristics of base drilling fluid formulations and additives. This information would be available to operators (as well as the general public) for use in selecting drilling fluid formulations that would likely comply with the established toxicity limitation. The initial list would include the eight generic fluids discussed in Section VIII and presented in Appendix B of this preamble. These fluids are of known composition and toxicity and have been evaluated and listed as acceptable for discharge in NPDES permit actions.

Chemical and toxicity information on new additives and mud formulations would be included in the clearinghouse data base as adequate testing data become available.

OPTION 3—ZERO DISCHARGE

This option would require zero discharge for all drilling fluids, based upon transport of spent drilling fluids to shore for recovery, reconditioning for reuse, or land disposal, or transport to an approved ocean disposal site. This level of technology would result in no discharge of pollutants to surface waters except at approved ocean disposal sites.

(b) Selected Option and Basis for Selection. EPA has selected Option 1 as the basis for proposed new source performance standards for drilling fluids. The proposed standards include the following limitations:

- A prohibition on the discharge of free oil, oil-based drilling fluids, and diesel oil, all considered as "indicators" of priority pollutants.

- A 96-hour LC-50 toxicity limitation on the discharged drilling fluids of no less than 3.0 percent by volume of the diluted suspended particulate phase.

- A maximum limitation (i.e., no single sample to exceed) on the amount of cadmium and mercury in discharged drilling fluids of 1 mg/kg each.

The prohibitions on the discharge of free oil, oil-based drilling fluids, and diesel oil are all intended to limit the oil content in drilling fluid waste streams and thereby control the priority as well as conventional and nonconventional pollutants present in those oils. The pollutants "free oil," "oil-based drilling fluids," and "diesel oil" are each considered to be "indicators" of the priority pollutants present in these complex hydrocarbon mixtures used in drilling fluid systems. These pollutants include benzene, toluene, ethylbenzene, naphthalene and phenanthrene. The Agency's primary concern is controlling the priority pollutants in the oils although these prohibitions also will serve to control nonconventional and conventional pollutants. The Agency selected the "indicator" approach as an alternative to establishing limitations on each of the specific toxic and nontoxic pollutants present in these oil-contaminated wastestreams. The sampling and analysis data demonstrate that when the amount of oil, especially diesel, is reduced in drilling fluid, the concentrations of priority pollutants and the overall toxicity of the fluid generally are reduced. The Agency has determined that control of the amount or type of oil present in drilling fluids with limitations on the three "indicators" (free oil, oil-based drilling fluids and diesel oil) will provide a good level of control of the priority pollutants present in drilling fluids. This method of toxic regulation obviates the difficulties and costs of monitoring and analysis if limitations were established for each of the organic priority pollutants present in the drilling fluids. The Agency requests comment on its decision to use these three limitations as "indicators" of priority pollutants. The Agency also requests comment on whether limitations should be established for each of the specific organic priority pollutants present in drilling fluids.

The purpose for the LC-50 toxicity limitation on the discharge of drilling fluids is to reduce the toxic constituents in drilling fluid discharges. While the three indicator limitations on the amount or type of oil present in drilling fluids should significantly reduce the

toxic pollutants present in drilling fluids, other additives such as mineral oil or some of the numerous specialty additives may greatly increase the toxicity of the drilling fluid. The toxicity is, in part, caused by the presence and concentration of priority pollutants. By establishing a toxicity limitation, the Agency believes that operators will consider toxicity in selecting additives and select the less toxic alternative. For instance, there can be a broad spectrum in the toxicity of mineral oils. The Agency believes that the Clean Water Act authorizes the Agency to establish a toxicity limitation as an effluent limitation designed to control the chemical or toxic constituents of the discharge. The availability of a wide selection of additives makes product substitution the best available demonstrated technology for complying with the toxicity limitation. The Agency has considered the costs of product substitution and finds them to be acceptable for this industry, resulting in no barrier to future entry. These standards are not expected to have any adverse non-water quality environmental impacts or increase energy requirements. The generic drilling fluids list is a primary basis for both the prohibitions on the discharge of free oil and oil-based drilling fluids and the LC-50 limitation. As discussed in section VIII; EPA has determined, through the NPDES permit process, that the eight generic water-based drilling fluids, whose formulations are presented in Appendix B of this preamble, are adequate for virtually all drilling situations and are less toxic than oil-based drilling fluids. In order for a drilling fluid to be discharged, it must be no more toxic than the proposed LC-50 standard as determined with the Drilling Fluids Toxicity Test presented in Appendix 3 of today's proposed regulation.

Under this option, a drilling fluid can be discharged only if it does not contain additives that would cause its toxicity to exceed the toxicity of the most toxic generic mud. Further, EPA has determined that refined mineral oil is an adequate substitute for diesel oil and is a less toxic alternative to diesel oil. Accordingly, diesel oil would not be an allowable additive, either as a lubricity agent or spotting fluid, to a drilling fluid intended to be discharged. Mineral oil would be allowed as a lubricity agent and spotting agent in the drilling fluid provided that its addition would not cause the toxicity of the discharged drilling fluid, including all other additives, to exceed the proposed LC-50 standard.

The limitations on cadmium and mercury for discharged drilling fluids are intended to control the concentrations of toxic metals in barite, a major component of drilling fluids. As discussed above, these limitations would be met by product substitution, the best available demonstrated technology which is economically achievable.

In addition, the Agency is proposing a different definition of the term "no discharge of free oil" from that promulgated for the BPT regulation (44 FR 22075, April 13, 1979). Also, the test procedure for determining compliance with this prohibition on free oil discharges is proposed to be changed from that used for BPT. This revised test procedure is called the "Static Sheen Test", and is presented in Appendix 1 of today's proposed regulation. The rationale for these proposed changes is the same as that discussed in Section XI.B.

This NSPS option is the same as the proposed BAT option for drilling fluids, as discussed below. Therefore, there are no NSPS compliance costs or impacts incremental to BAT for drilling fluids.

Option 2 was not selected as the basis for NSPS at this time because the Agency does not anticipate such a "clearinghouse" program to be established prior to promulgation of NSPS. Development of listing methodologies and criteria and compilation of an adequate toxicity data base, which is central to the "clearinghouse approach" of Option 2, is estimated to take from three to five years. Such methodologies, criteria and data are essential for full implementation on a nationwide basis. The Agency has begun to investigate the requirements for management of a clearinghouse approach. Upon completion of the investigation and if the Agency establishes such a program, the Agency may decide to propose to amend the approach to NSPS accordingly.

The Agency rejected Option 3, zero discharge, for implementation on a national basis for two major reasons. The Agency believes that the aggregate industry compliance costs of \$126.3 million annually (1983 dollars) for transport and land disposal of all spent drilling fluids is too high. In addition, the Agency believes that there may be problems with adequate land availability for disposal of spent drilling fluids under such a zero discharge option. In part, this may be due to existing or future restrictions on the land disposal of drilling fluids under the

requirements of hazardous waste disposal laws.

3. Drill Cuttings

(a) *Control and Treatment Options Considered.* Option 1 would result in the regulation of free oil, oil-based fluids, and diesel oil in discharged drill cuttings. These limitations, as for the selected option for drilling fluids, are achieved by product substitution. Water-based drilling fluids would be substituted for oil-based fluids and mineral oil would be substituted for diesel oil. These three pollutant parameters would be regulated in a manner identical to that for the same pollutant parameters for drilling fluids Option 1. The rationale for their regulation is also the same as for drilling fluids Option 1 because the constituent of concern in the drill cuttings waste stream is the residual drilling fluid that adheres to the drill cuttings.

Option 2 would be equivalent to Option 1 plus a limitation on the allowable oil content of the discharged cuttings. The oil content limitation of 10 percent maximum by weight would be based upon water/detergent washer technology, as discussed in Section X of this preamble. This "residual oil" limitation would be imposed as an indicator of toxic pollutants, specifically the priority organic pollutants in oils that are added to drilling fluid systems, and to control conventional pollutants in this waste stream.

Option 3 would require zero discharge of all drill cuttings, based upon transport of drill cuttings to shore for land disposal or to an approved ocean disposal site. This option would result in no discharge of pollutants to surface waters except at approved ocean disposal sites.

(b) *Selected Option and Basis for Selection.* The Agency selected Option 1 as the basis for proposed NSPS for drill cuttings. The requirements of Option 1 are comparable to those of the selected option for drilling fluids.

The Agency did not select Option 2 at this time because it believes that establishing an oil content limitation on drill cuttings may be redundant because the prohibition on the discharge of free oil appears to be a more stringent limitation. While presently demonstrated cuttings washer technology will reduce residual oil content to less than ten percent by weight, the Agency's data base indicates that visible sheen can be caused by as little as one percent oil. Thus, the free oil discharge prohibition may be more stringent than any residual oil limitation that can be presently established with cuttings washer technology that has

been demonstrated on a full-scale basis. The Agency will collect and evaluate additional cuttings washer performance data, especially with respect to the use of mineral oil for lubricity and spotting purposes, to establish whether an oil content limitation is more stringent than the prohibition on the discharge of free oil.

The Agency rejected Option 3, zero discharge, because of high aggregate compliance costs and land availability problems as discussed below for drilling fluids BAT Option 3.

4. Deck Drainage

As with BAT/BCT, the Agency is proposing to establish NSPS for deck drainage the same as the BPT level of control. This would result in a prohibition on the discharge of free oil. The technology basis is oil-water separation. The Agency is reserving coverage for all other pollutant parameters and characteristics for deck drainage pending additional data collection and analysis. This additional data will include toxic, nonconventional, and conventional pollutant information and control and treatment technology evaluation.

The method of determining compliance with the free oil prohibition is by the static sheen test discussed earlier and as presented in Appendix 1 of today's proposed regulation. Where deck drainage is collected and treated separately from produced water, the free oil prohibition would apply. However, where deck drainage is commingled and cotreated with produced water, only the effluent limitations for produced water would apply to these two combined waste streams.

Because this proposed standard is equal to BAT/BCT, there are no incremental compliance costs due to NSPS.

5. Sanitary Wastes

The Agency is proposing to establish NSPS for sanitary wastes equal to the BAT/BCT level of control. This would result in: (1) a prohibition on the discharge of floating solids for facilities manned by nine or fewer persons or intermittently manned by any number of persons; and (2) an effluent standard for residual chlorine of 1 mg/l minimum and to be maintained as close as possible to 1 mg/l, for facilities continuously manned by ten or more persons. Because these proposed standards are equal to BAT/BCT, there are no incremental compliance costs due to NSPS.

6. Domestic Wastes

The Agency is proposing to establish NSPS equal to the BCT level of control for domestic wastes. This would result in a prohibition on the discharge of floating solids. Since NSPS would equal BCT, no compliance costs incremental to BCT are associated with this standard.

7. Produced Sand

As with BAT/BCT, the Agency is proposing to establish a prohibition on the discharge of free oil for produced sand NSPS. The technology basis for this standard is water or solvent wash of produced sands prior to discharge, or transport of produced sand to shore for land disposal. The method of determining compliance with the free oil prohibition is by the static sheen test discussed earlier and as presented in Appendix 1 of today's proposed regulation. There are no NSPS compliance costs incremental to the proposed BAT/BCT limitations.

The Agency is reserving coverage for all other pollutant parameters and characteristics for produced sand pending additional data collection and analysis. This additional data will include toxic, nonconventional, and conventional pollutant information and control and treatment technology evaluation.

8. Well Treatment Fluids

The Agency is proposing to establish an NSPS prohibition on the discharge of free oil for well treatment fluids as an "indicator" to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. The method of determining compliance with the free oil prohibition is by the static sheen test discussed earlier and as presented in Appendix 1 of today's proposed regulation. This is equal to the proposed BAT level of control, as discussed below. Therefore, there are no NSPS compliance costs incremental to BAT.

The Agency is reserving NSPS coverage of all other pollutant parameters for well treatment fluids and characteristics pending additional data collection and evaluation. This additional data will include toxic, nonconventional and conventional pollutant information and control and treatment technology evaluation.

B. Best Available Technology

1. Produced Water

The Agency is not proposing BAT effluent limitations for produced water from existing sources at this time. The Agency lacks sufficient information on reinjection and control of biocides and

other chemical usage by existing facilities to properly evaluate the technological feasibility and economic achievability of these options.

The Agency is presently undertaking a data collection effort to obtain industry profile information, retrofit costing information for reinjection, information on the extent of biocide and other chemical use, and associated environmental impacts for existing facilities. Upon analysis of this information, the Agency may propose at a future date a BAT regulatory option of: (1) reinjection based upon water depth or use of biocides and other chemicals; (2) product substitution to require the use of less toxic or persistent biocides and chemicals; (3) establishment of effluent limitations to limit the quantities of biocides and chemicals discharged or an option based upon a combination of these three approaches.

Because BAT is intended to control toxic and nonconventional pollutants, the Agency will not further consider the improved BPT or filtration technologies of options 1 and 2 for existing sources because these technologies primarily control conventional pollutants, and do not effect quantifiable reductions of toxic pollutants.

2. Drilling Fluids

(a) Control and Treatment Options Considered.

OPTION 1—TOXICITY LIMITATION APPROACH

This option is the same as NSPS Option 1 for drilling fluids. It would regulate the discharge of free oil, oil-based fluids, diesel oil, cadmium, mercury and the toxicity of discharged drilling fluids. These limitations are achieved by product substitution through the use of water-based drilling fluids (i.e., generic muds), low toxicity specialty additives, the use of mineral oil instead of diesel oil for lubricity and spotting purposes, and use of barite with low toxic metals content. The purpose and rationale for these effluent standards is the same as that presented above for NSPS.

This option would result in an annual cost of \$26.3 million (1983 dollars) for an estimated 1166 wells. These costs are incremental to BPT requirements and are based upon the following: transport of ten percent of all spent drilling fluid systems either to shore for recovery, reuse or land disposal or to an approved ocean disposal site; a 15 percent increase in barite costs due to increased storage and handling costs and increased demand for barite with low toxic metals content; analytical costs associated with the toxicity limitation

and the mercury and cadmium effluent limitations; and monitoring costs based on the sampling frequencies presented in Section XII of this preamble. The differential cost of substituting mineral oil for diesel oil (approx. \$2.10 per gallon, including storage, for the Gulf of Mexico) is not attributable to the BAT option as an incremental cost to BPT. While BPT does not explicitly prohibit the discharge of diesel oil, the discharge of diesel oil in any significant amounts (i.e., one volume percent or more) would cause a sheen on receiving waters which would violate the BPT prohibition on the discharge of free oil. Therefore, the amount of mineral oil required to comply with a proposed prohibition on the discharge of diesel oil would be minimal, and the associated costs would be minimal.

OPTION 2—CLEARINGHOUSE APPROACH

This option is the same as NSPS Option 2 for drilling fluids. It is based upon the establishment by EPA of a toxicity and chemical data base of drilling fluid formulations and additives that would be used to determine whether drilling fluid systems would likely be acceptable for discharge.

OPTION 3—ZERO DISCHARGE

This option is the same as NSPS Option 3 for drilling fluids. It would require zero discharge for all drilling fluids, based upon transport of spent drilling fluids to shore for recovery, reconditioning for reuse, land disposal, or transport to an approved ocean disposal site. This level of technology would result in no discharge of pollutants to surface waters, except at approved ocean disposal sites.

For the estimated 1166 wells drilled annually, this option would cost \$126.3 million (1983 dollars). These compliance costs are incremental to BPT requirements, and reflect barging and monitoring costs.

This option would result in an annual reduction of 6.2 million barrels of drilling fluids to surface waters, except at approved ocean disposal sites.

(b) *Selected Option and Basis for Selection.* EPA has selected Option 1 as the basis for proposed BAT for drilling fluids. BAT would include the same limitations as NSPS:

- A prohibition on the discharge of free oil, oil-based drilling fluids, and diesel oil, all considered as "indicators" of toxic pollutants.
- A 96-hour LC-50 toxicity limitation on discharged drilling fluids of no less than 3.0 percent by volume of the diluted suspended particulate phase.

- A maximum limitation (i.e., no single sample to exceed) on the amount of cadmium and mercury in the discharged drilling fluids of 1 mg/kg each, dry weight basis.

Options 2 and 3 were rejected for the same reasons as discussed above for NSPS.

As with NSPS, the three discharge prohibitions on oil will serve as "indicators" of toxic pollutants. The Agency believes it is appropriate to establish these prohibitions as BAT toxic limitations. The primary purpose is to control the priority pollutants present in the oils. Control on the oil content of fluids could also be achieved through a numeric limitation on the conventional pollutant "oil and grease." In fact, the Agency has included the prohibition on the discharge of free oil as a BCT limitation in recognition of the complex nature of the oils present in drilling fluids. However, the Agency's decision to establish BAT limitations through the three oil prohibitions was based on the consideration that it would be less difficult and costly to comply with these three "indicator" limitations than numeric limitations on each of the organic priority pollutants present in the oils. This decision to establish limitations on oils as indicators of priority pollutants is consistent with the Agency's listing of "oil and grease" as a conventional pollutant. (44 FR 44501.) In that notice, the Agency explained that "where toxic substances are associated with oil and grease, the Agency may require control at BAT levels. This will be done either by identification of oil and grease as an indicator pollutant or by establishing BAT limitations for the specific toxic pollutant." *Id.* The Agency solicits comments on its decision to establish these indicator pollutant limitations as BAT rather than setting numeric limitations on the specific organic priority pollutants or conventional pollutants. Since the oils would be considered BAT toxic indicators, such limitations would not be subject to Section 301(c) or Section 301(g) modifications.

The LC-50 toxicity limitation and limitations on mercury and cadmium also are appropriate BAT limitations. Compliance with these limitations as well as the three oil prohibitions can be achieved through product substitution. Product substitution is both a technologically feasible and economically achievable means for compliance.

Related to this option, the Agency is proposing to amend the current definition of the term "no discharge of free oil." The current definition of "no

discharge of free oil" defines the term to mean "that a discharge does not cause a film or sheen upon or a discoloration on the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines." This limitation was originally intended to prohibit the discharge of drilling fluids (as well as drill cuttings and well treatment fluids) that, when discharged, would cause a sheen on the receiving water. The limitation was then extended for final BPT regulations to include deck drainage, and the current definition of the term "no discharge of free oil" was established to be consistent with the oil discharge provision of Section 311 of the Act. Technically, however, discharged drilling fluids could be considered "sludge." For this reason, the Agency is proposing to amend the current definition by excluding language that prohibits the deposition of sludge beneath the surface of the receiving water. This would allow the discharge of drilling fluids, provided that other effluent limitations are met.

The amended definition is accompanied by a test procedure for determining compliance with the prohibition on free oil discharges. This test is the "static sheen test" used in definition § 435.11(m) and presented in Appendix 1 of today's proposed regulations. This would apply to the same waste streams that are covered by the existing BPT prohibition, i.e., deck drainage, drilling fluids, drill cuttings, and well treatment fluids.

The compliance monitoring procedure previously required by permits was a visual inspection of the receiving water after discharge. However, since the intent of the limitations is to prohibit discharges containing free oil that will cause a sheen, the method of determining compliance should examine oil contamination prior to discharge. Also, concerns have been raised that the intent of the existing definition of "no discharge of free oil" may be violated too easily for the limitation to be effective. Violations which may result from intentional or unintentional actions include the use of emulsifiers or surfactants, discharges that occur under poor visibility conditions (i.e., at night or during stormy weather), and discharges into heavy seas, which are common on the outer continental shelf. Additionally, concerns have been expressed over the utility of the visual observation of the receiving water compliance monitoring procedure for certain discharges during ice conditions as in Alaskan operations. These include above-ice discharges where the receiving water would be

covered with broken or solid ice, and below-ice discharges where the effluent stream would be obscured.

To correct for these monitoring problems, the Agency developed an alternative compliance test, the Static Sheet Test, which is presented in Appendix 1 of today's proposed regulations. The alternative test continues the visual observation for sheen, but provides for inspection before discharge using laboratory procedures. The test is conducted by adding samples of the effluent stream into a container in which the sample is mechanically mixed with a specific proportion of seawater, allowed to stand for a designated period of time, and then viewed for a sheen.

Since the intent of a "no discharge of free oil" limitation is to prevent the occurrence of a sheen on the receiving water, the new test method will prevent the discharge of fluids that will cause such a sheen.

3. Drill Cuttings

(a) Control and Treatment Options Considered.

OPTION 1

Option 1 is the same as NSPS Option 1 for drill cuttings. It would result in the prohibited discharge of free oil, oil-based fluids, and diesel oil in discharged drill cuttings. These limitations, as for the selected option for drilling fluids, are achieved by product substitution. The rationale for these limitations is also the same as for drilling fluids Option 1 because the constituent of concern in the drill cuttings waste stream is the residual drilling fluid that mixes with and adheres to the drill cuttings.

For the estimated 1166 wells drilled annually, this option would result in an estimated annual cost of \$8.6 million (1983 dollars) for transport of drill cuttings to shore for land disposal and for effluent monitoring. No investment costs are expected to occur from this option. This option would result in an estimated annual reduction of at least 1.3 million pounds of oil otherwise discharged to surface waters.

OPTION 2

Option 2 is equivalent to Option 1 plus a limitation on the allowable oil content of the discharged cuttings. This option is the same as NSPS Option 2 for drill cuttings. The oil content limitation of 10 percent maximum by weight would be based upon drill cuttings water/detergent washer technology, as discussed in Section XI of this preamble.

OPTION 3

Option 3 would require zero discharge of all drill cuttings, based upon transport

of drill cuttings to shore for recovery and reuse or land disposal, or transport to an approved ocean disposal site. This option would result in no discharge of pollutants to surface waters, except at approved ocean disposal sites. This option is the same as NSPS Option 3 for drill cuttings.

For the estimated 1166 wells drilled annually, this option would result in annual effluent monitoring and transport costs of \$77.1 million (1983 dollars). This option would result in an annual reduction of 1.7 million barrels of drill cuttings discharged to surface waters.

(b) *Selected Option and Basis for Selection.* The Agency selected Option 1 as the basis for proposed BAT for drill cuttings. The requirements of Option 1 are comparable to those of the selected option for drilling fluids. This option is based on product substitution which is both a technologically feasible and economically achievable means for compliance by the industry.

The Agency is not selecting Option 2 at this time because it believes, as discussed above for NSPS, that establishing an oil content limitation on drill cuttings may be redundant because the prohibition on the discharge of free oil appears to be a more stringent limitation. The Agency will collect and evaluate additional cuttings washer performance data, especially with respect to the use of mineral oil for lubricity and spotting purposes, to establish whether an oil content limitation is more stringent than the free oil limitation.

The Agency rejected Option 3, zero discharge, because of high aggregate compliance costs and concern for adequate land availability for disposal as discussed above for NSPS.

4. Deck Drainage

The Agency is proposing to establish BAT for deck drainage equal to the BPT level of control. This would result in a prohibition on the discharge of free oil as an "indicator" to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. The technology basis is oil-water separation. BAT compliance costs incremental to BPT consist of additional compliance monitoring expenditures of \$1.09 million (1983 dollars) annually, reflecting use of the proposed static sheet test to determine compliance with the prohibition on the discharge of free oil.

The Agency is reserving coverage of all other toxic and nonconventional pollutant parameters and characteristics for deck drainage pending additional data collection and analysis. This additional data will include toxic

pollutant information and control and treatment technology evaluation.

5. Sanitary Wastes and Domestic Wastes

The Agency is not proposing to establish BAT effluent limitations for these waste streams because there have been no toxic or nonconventional pollutants of concern identified in sanitary or domestic wastes.

6. Produced Sand

The Agency is proposing to establish a BAT prohibition on the discharge of free oil for produced sand as an "indicator" to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. The technology basis for this limitation is water or solvent wash of produced sand prior to discharge, or transport of produced sand to shore for land disposal. Because this waste stream is of low volume and because most facilities currently practice either washing or land disposal, the Agency did not attribute any compliance costs to this proposed limitation, except for nominal compliance monitoring expenses to perform the static sheen test to determine the presence of free oil.

The Agency is reserving coverage of all other toxic and nonconventional pollutant parameters and characteristics for produced sand pending additional data collection and analysis. This additional data will include toxic pollutant information and control and treatment technology evaluation.

7. Well Treatment Fluids

The Agency is proposing to establish a BAT prohibition on the discharge of free oil for well treatment fluids as an "indicator" to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. This is equal to the BPT level of control. Therefore, there are no compliance costs incremental to BPT, except for nominal compliance monitoring expenses to perform the static sheen test to determine the presence of free oil.

The Agency is reserving BAT coverage of all other pollutants and characteristics for well treatment fluids pending additional data collection and evaluation. This additional data will include toxic and nonconventional pollutants information and control and treatment technology evaluation.

C. Best Conventional Technology

The 1977 amendments added section 301(b)(4)(E) to the Act, establishing "best conventional pollutant control technology" (BCT) for discharges of conventional pollutants from existing

industrial point sources. Conventional pollutants are those defined in section 304(b)(4)—BOD, TSS, fecal coliform and pH—and any additional pollutants defined by the Administrator as "conventional." On July 30, 1979, EPA designated "oil and grease" as a conventional pollutant (44 FR 44501).

BCT is not an additional limitation; rather it replaces BAT for the control of conventional pollutants. BCT requires that limitations for conventional pollutants be assessed in light of "cost-reasonableness." EPA published proposed rules for BCT on October 29, 1982 (47 FR 49176). These proposed rules set forth a revised procedure which includes two tests to determine the reasonableness of costs incurred to comply with candidate BCT technologies. These cost tests are the "POTW test" and the "industry cost test." On September 20, 1984, EPA published a "notice of data availability" concerning the proposed BCT regulations (49 FR 37046).

1. Produced Water

(a) *Control and Treatment Options Considered.* EPA examined three treatment options for removing conventional pollutants from produced water in relation to the proposed BCT methodology.

OPTION 1—IMPROVED PERFORMANCE OF BPT

This option would require effluent limitations based on the improved performance of BPT technology. As presented above for NSPS option 1, this level of technology would result in additional reductions of oil and grease beyond the BPT level of control. A discharge limitation of 59 mg/l maximum (no single sample to exceed) for oil and grease would result from this option.

OPTION 2—FILTRATION ON SITE

This option would require effluent limitations based on granular media filtration as an add-on technology to BPT. Filtration equipment would be installed on the platform with the treated effluent being discharged at the platform. This level of technology would result in additional reductions of conventional pollutants beyond the BPT level of control. Effluent limitations of 20 mg/l monthly average and 30 mg/l daily maximum for oil and grease would result from this option.

OPTION 3—FILTRATION ONSHORE

This option is the same as Option 2 except it is applicable to facilities which presently separate produced water from hydrocarbon product at the platform,

pipe the produced water to shore for treatment to meet BPT effluent limitations, and discharge the treated effluent to surface waters.

(b) *Selected Option and Basis for Selection.* The Agency rejected the options presented above and is proposing to establish BCT for produced water at the BPT level of control. This would result in effluent limitations of 48 mg/l monthly average and 72 mg/l daily maximum for oil and grease, based upon oil water separation technologies. The Agency rejected Options 1 through 3 because they all fail the first part of the Agency's proposed BCT cost test (the "POTW test").

For Option 1, the Agency was unable to directly perform the POTW test because the Agency lacks sufficient information to accurately estimate the incremental cost of improved BPT performance (see section XI.A.1(a) above); this cost is necessary in order to perform the POTW test. Therefore, the Agency analyzed this option by determining the maximum dollar expenditure per day that model platforms could incur to implement this option without exceeding the POTW test benchmark.

The maximum cost per pound of conventional pollutant removal whereby the "POTW test" will be passed is presented in the BCT "notice of data availability" referenced above. These maximum costs were used to calculate the total dollars that could be expended at each of the 32 model platforms to comply with this option and still pass the "POTW test." This was accomplished by multiplying the pounds of conventional pollutants that would be removed by BCT Option 1 technology for each of the 32 model platforms used for this study by the benchmark cost per pound presented in the "notice of data availability."

This total cost for each model platform ranged from \$0.79 per day for the smallest model platform to \$182 per day for the largest model platform. The Agency believes that the cost of implementing Option 1 is minimal, although not as low as the range of daily costs derived by the above procedure. Therefore, the Agency rejected Option 1 because it fails the POTW cost test.

For Options 2 and 3, the Agency calculated compliance costs (incremental to BPT) for each of 32 model platforms and then performed the POTW test for each model size platform. The range in costs per pound of conventional pollutant removed beyond BPT for Options 2 and 3 based on model platform size, is as follows:

	Lowest cost—dollars per pound removed (1980 dollars)	Highest cost—dollars per pound removed (1980 dollars)
Option 2.....	64	71
Option 3.....	54	63

These costs were compared with the fourth quarter, 1980 POTW proposed benchmark of \$1.04 per pound of conventional pollutant removed. The POTW test failed for Options 2 and 3 for all of the model platforms. Therefore, EPA rejected these options for the BCT level of control. The Agency intends to evaluate reinjection technology for BCT after collection of certain additional technology and cost information (see Section XX) prior to promulgation of the final regulations. The Agency may also re-evaluate the proposed BCT limitations for produced water when the final BCT methodology is promulgated.

2. Drilling Fluids, Drill Cuttings, Deck Drainage and Well Treatment Fluids

With one exception, the Agency is reserving BCT requirements for drilling fluids, drill cuttings, deck drainage and well treatment fluids until final promulgation of the general BCT methodology. The exception is a prohibition on the discharge of free oil. This limitation is equal to the BPT level of control for these waste streams. Therefore, no incremental costs are associated with this proposed BCT limitation. Because BCT is proposed to be equal to BPT, the free oil discharge prohibition will pass any BCT cost test. When the final BCT methodology is promulgated, the Agency may propose to establish BCT limitations for other conventional pollutants for these waste streams. At this time, the Agency is soliciting comment on what pollutants in drilling fluid and drill cuttings waste streams should be considered conventional pollutants. Specifically, the Agency solicits comments on whether the solids components of the fluids and cuttings should be considered total suspended solids.

3. Domestic and Sanitary Wastes

The Agency is proposing BCT coverage for sanitary and domestic wastes equal to the BPT level of control. The Agency is proposing a residual chlorine effluent limitation for facilities continuously manned by 10 or more persons of 1 mg/l maximum and maintained as close to this level as possible in sanitary discharges to control fecal coliform. Residual chlorine is being treated as a BCT parameter

because its purpose is to control the conventional pollutant fecal coliform.

The proposed BCT limitation for domestic wastes from all facilities and sanitary wastes from facilities continuously manned by 9 or fewer persons or manned intermittently by any number of persons is "no discharge of floating solids." No compliance costs incremental to BPT are associated with the proposed BCT limitations. Since no additional costs will be incurred these limitations pass the BCT cost tests.

4. Produced Sand

With one exception, the Agency is reserving BCT coverage for produced sand until the promulgation of the final BCT methodology. The Agency is proposing a BCT limitation that would prohibit the discharge of free oil for produced sand discharges. As discussed above for BAT, this limitation would result in negligible compliance costs.

The Agency solicits comment on other pollutants in the produced sand waste stream that should be considered for regulation at the BCT level of control.

D. Best Practicable Technology

As discussed above for NSPS and BAT, the Agency is proposing to amend the definition of the term "no discharge of free oil" and the test procedure for determining compliance with the prohibition of free oil discharges. For consistency, the Agency is proposing the same change to the existing BPT regulations. This change does not affect the conclusion that the current BPT limitation of no discharge of free oil may be met through use of the best practicable control technology currently available and that the costs of that technology are justified by the effluent reduction benefits.

XII. Cost and Economic Impact

A. Treatment Technology Costs

The costs of implementing the treatment options considered for today's proposed regulations were developed through compilation of cost data obtained from equipment manufacturers, the offshore oil and gas extraction industry, cost estimating manuals, and by the application of standard engineering data and cost estimation techniques.

Costs were determined for 32 model platform sizes. Treatment components were sized and costed for each model platform for all treatment options which were considered to be technologically feasible. In addition, a typical or model well depth was established so that cost estimates accounted for situations

where well depth affected pollution control costs.

Various assumptions were made on the area required for installation of equipment, cost of new platform space, cost of land used for onshore treatment, and piping and energy costs. The Agency estimated that from 17 to 84 percent of new offshore production facilities covered by this regulation would reinject onshore, depending upon geographic location, e.g., Gulf of Mexico, California, Alaska.

Energy costs were determined based on pumping requirements and treatment facility operation. Natural gas was assumed to be the source of energy to power either electrical generation or prime movers for waste treatment on platforms, with the cost of the natural gas at commercial value. Natural gas was the chosen fuel source because of its availability and because air emissions from natural gas combustion are cleaner than those from diesel fuel. For onshore treatment installations, use of locally generated electrical power was assumed, at commercial rates.

The costs of barging and land disposal were obtained from barge operators, oil industry contacts, and landfill operators. Dry wells were assumed to be available for use as injection wells for produced water. Exhausted production wells were assumed not to be available. However, additional cost savings could be realized by using exhausted production wells for injection of produced water. These assumptions were based on API drilling statistics for the Gulf of Mexico and discussions with state officials.

To determine the installed cost of equipment on platforms, multipliers of 3.5 times the equipment purchase cost were used for skid-mounted equipment and 4.0 times the equipment purchase cost for items shipped loose. These factors were supplied by an engineering consultant to OOC in a report titled *Determination of Best Practicable Control Technology Currently Available to Remove Oil from Water Produced with Oil and Gas*, Brown and Root, Inc., March 1974. EPA solicits comments on the reasonableness of these factors used to estimate installed costs.

Geographical factors were also used to translate the cost from the base location, the Gulf of Mexico (multiplier = 1), to Alaska, the California Coast and the Atlantic Coast. The following are the cost multipliers used:

Location	Capital cost multiplier	Applicable to—
Atlantic Coast.....	1.6	Equipment and wells.
California Coast.....	1.6	Do.

Location	Capital cost multiplier	Applicable to—
Alaska:		
Norton Basin	3.5	Do.
Beaufort Sea	3.5	Do.
Bristol Bay	3.5	Do.
Gulf of Alaska	3.5	Do.
Cook Inlet/Shelikof Strait.	2.0	Equipment.
Cook Inlet/Shelikof Strait.	2.5	Wells.

EPA also solicits comments on the reasonableness of these cost multipliers.

The Agency did not include potential costs for compliance with the underground injection control (UIC) program administered under the Safe Drinking Water Act (42 U.S.C. 300f *et seq.*). The Agency invites comments and supporting data on the impacts of UIC requirements for onshore reinjection including the costs of complying with these requirements.

None of the technologies studied in the development of these proposed regulations is considered to be innovative. All of the controls described in this preamble and in greater detail in the Development Document have either been used or investigated for use in this industry and do not represent major process changes.

B. Compliance Monitoring Frequencies and Costs

The Agency has estimated compliance monitoring costs for a facility where both development and production operations are being performed. As such, the total monitoring costs presented below are conservative. The BAT compliance monitoring costs for drilling fluids and all sheen tests are the monitoring costs that are incremental to existing BPT monitoring costs.

Waste stream	Analyses	Cost per sample for analysis and labor	Frequency	Cost per month
Produced water	Oil and grease	¹ \$40	1/week	\$640
Drilling fluids	Bioassay (LC-50)	\$1,000	1/month ²	1,000
	Mercury, total	\$50	1/month ³	50
	Cadmium, total	\$50	1/month ³	50
	Static sheen	\$25	3/week	300
Drilling cuttingsdo.....	\$25	daily	750
Deck drainagedo.....	\$25do.....	750
Produced sanddo.....	\$25do.....	750
Well treatment fluidsdo.....	\$25	1/month ³	25
Sanitary M91M and Domestic wastes	Floating solids	nil	daily	0
Sanitary M10	Residual chlorine	\$20	1/month	20

¹ Four samples per determination.
² Twice per well.
³ As needed.

C. Economic Impact

1. Introduction

The Agency's economic impact assessment is set forth in the *Economic Impact Analysis of Proposed Effluent Limitations and Standards of Performance for the Offshore Oil and Gas Industry*. (EPA 440/2-85/003). This report details the investment and annualized costs for the industry as a whole and for facilities covered by the offshore segment. The report also estimates the probable economic effect of compliance costs in terms of prices, Federal and State revenues, production levels, employment, and international trade effects and profitability.

EPA has also conducted an analysis of the cost-effectiveness of alternative treatment technologies that remove toxic pollutants from produced water. The results of this cost-effectiveness analysis are expressed in terms of the incremental removal cost per pound-equivalent, where differences in toxicity among the pollutants found are taken into account through the use of toxic weighting factors. In this analysis, a

pound-equivalent is calculated by multiplying the number of pounds of pollutant discharged by a weighting factor for that pollutant. The weighting factor is equal to the water quality criterion for a standard pollutant (copper), divided by the water quality criterion for the pollutant being evaluated. The cost per pound-equivalent removed would be lower when a highly toxic pollutant is removed. This analysis is included in the record of this rulemaking, and is titled *Cost Effectiveness Analysis of Proposed Regulations for the Offshore Oil and Gas Industry*. Copies of this report may be obtained from the economic analysis staff referenced in the Addresses section of this preamble.

2. Impacts

a. Basis of Analysis. The costs and economic impacts associated with today's proposed regulations differ depending on whether drilling or production operations are analyzed. Costs to control drilling related effluents are the same for existing source platforms and for new platforms.

Additional costs from production related effluents, however, arise from the zero discharge requirement for certain new source facilities.

Production related effluents at existing facilities would be regulated at the BPT level of control. Also, for existing source production facilities, the proposed regulations would prohibit the discharge of free oil for produced sand discharges. As explained in Section XI.B, no compliance costs are attributed to this proposed limitation, except for nominal compliance monitoring expenses.

The economic analysis of drilling operations is based on the total number of exploratory, delineation and development wells which the Agency expects to be drilled each year. Offshore drilling operations occur primarily in the Gulf of Mexico along the Texas and Louisiana coasts although increasing efforts are being made in offshore California and Alaska, and, to a lesser extent, in the Atlantic. The average number of wells drilled annually over the past ten years is 1166; the total annual footage drilled is 11 million feet. All of the wells drilled for exploratory, delineation, and development purposes are covered by the proposed regulation.

The analysis of production operations is based on the number of platforms projected to be built between 1986 and the year 2000. By the year 2000, new source oil and gas development should have stabilized such that the rate of growth of new facilities should equal the rate of obsolescence of facilities already covered by the regulation. EPA expects 833 new platforms to be built between 1986 and the year 2000. EPA based its estimates for platform and well development on Department of Energy projections of future energy production, Department of Interior historical data, and on industry estimates. Of the 833 new platforms, 132 are expected to be located in water depths that would be subject to the zero discharge requirement for produced water. The remaining platforms would be subject to the oil and grease standard of 59 mg/1 maximum for produced water discharges.

b. Aggregate Impacts and Costs. The combined annualized cost of today's proposed BCT, BAT and NSPS regulations is \$91.5 million (1983 dollars) in the year 2000. The capital investment for these proposed requirements is \$18.6 million (in 1983 dollars). No price changes will result due to this regulation. No curtailment of oil or gas production is expected. State and Federal lease revenues are expected to decline by \$49.1 million in the year 2000

(1983 dollars) if companies reduce their lease bid prices. The effect of reduced bid prices is not expected to exceed 0.1 percent of total revenues for States affected by the proposed option. No employment or international trade effects are projected.

Between 85 to 95 percent of new facility construction is likely to occur on new lease tracts. These operations cannot pass the additional cost of the regulation on to customers in the form of price increases, since the price is determined in a large international market. The operations are expected to pass the additional cost of the regulation on to the State and Federal government in the form of lower lease bids. The Agency's analysis projected the revenue effects on the States and Federal government.

Some new drilling and platform construction is likely to occur on existing lease tracts. These operations must absorb the costs of the regulation, since the costs cannot be passed on in the form of higher prices or lower lease bids.

c. Methodology. The Agency used a net present value analysis to calculate whether offshore development operations could remain profitable after regulatory costs were incurred. Costs and revenues were projected over the life of the model project first based on the existing BPT requirements. Then the regulatory costs were added to these baseline costs to determine if model platforms remained profitable. EPA used 32 model platforms representing operations in the Gulf of Mexico, California Coast, Alaska and the Atlantic Coast. Distinct technical and economic characteristics for facilities in these areas were developed. Costs included in the baseline condition were those associated with leasing, exploration, delineation, development and production operations.

To assess the impact on offshore oil and gas companies, the Agency developed two representative company financial profiles: one for major integrated companies and one for independents. Pre- and post-regulation balance sheets were developed and the effect of the regulatory costs on their financial condition was assessed.

3. Best Conventional Pollutant Control Technology

BCT is either proposed equal to existing BPT requirements or reserved for this proposed rulemaking. No costs or impacts are projected as a result of today's proposal of BCT.

4. Best Available Technology Economically Achievable

Because the Agency is reserving coverage of produced water for BAT, no costs or impacts are projected for the discharge of produced water by existing platforms.

Exploratory, delineation, and development operations will incur a combined cost of \$35.9 million annually to comply with the drilling fluids and cuttings limitations (1983 dollars). No capital investment will need to be made to meet these limitations. The costs are based on an estimated annual drilled footage of 11.2 million and include incremental costs of clean barite for drilling fluids as well as monitoring and barging costs. Monitoring and testing costs total \$5.0 million and are based on the sampling frequency presented in Part B of this section. Costs of transportation to shore and land disposal total \$20.2 million; these costs are expected to occur when drilling fluid discharges exceed either the LC-50 limitation or mercury or cadmium limitations, or when fluids or cuttings discharges would not pass the static sheen test. An estimated 10 percent of all drilling operations are expected to incur transport costs. Barite costs total \$10.7 million and are based on an assumed price increase of 15 percent to reflect the combined increased storage and handling costs as well as increases in price of blended barite.

To calculate the decline in the rate of return associated with the BAT limitation, the Agency used the net present value analysis described above but used the BPT requirements as a baseline. The decline in rate of return of the model platforms was approximately 0.1 percent. No curtailment in drilling activities is expected to occur from the proposed requirements. No effect on oil and gas prices, employment or international trade is projected. The Agency finds these costs to be economically achievable for the oil and gas industry.

5. New Source Performance Standards

Incremental costs of compliance with the proposed regulation will arise only from production operations. Control of effluents from drilling operations at new sources is no more stringent than that for existing sources; therefore, no incremental costs are assigned to new sources.

Of the 833 platforms projected to be built between 1986 and the year 2000, 701 would be subject to the proposed 59 mg/l oil and grease standard for produced water. Incremental costs for platforms complying with the 59 mg/l

standard are expected to be *de minimis* and, therefore, are considered to be economically achievable. This standard represents improved operation and maintenance of existing BPT treatment technology. An estimated 126 of the other 132 facilities are expected to incur an annualized cost of \$55.6 million (1983 dollars) to comply with the zero discharge requirement for produced water. This annualized cost reflects the cost for 124 new platforms operating in the year 2000 in water depths of 20 meters or less in the Gulf of Mexico and two platforms located in 50 meters or less of water for the California Coast. The six platforms projected in 10 meters or less of water in Alaska must comply with an existing zero discharge requirement and are not expected to incur additional costs associated with their produced water effluent. The investment cost for facilities in the year 2000 is \$18.6 million (1983 dollars). The investment cost applies to new facilities projected for the year 2000 in the depth coverage areas.

In calculating the costs associated with the zero discharge requirement, the Agency assumed that from 20 to 50 percent of all wells drilled are dry and between 7 and 25 percent of all dry wells are usable for injection. The Agency also assumed that between 17 and 84 percent of the platforms will reinject onshore depending upon distances from shore. The onshore reinjection costs include the drilling of all injection wells necessary to handle produced water volumes. EPA does not expect any of the facilities that are projected to be placed in the depth coverage areas to become unprofitable due to reinjection requirements.

The majority of new facilities will be built in new lease tracts. These operations cannot pass the additional costs of the regulation on to their customers as price increases because they represent only a very small segment of the international market in which prices are determined. However, they are not expected to experience significant declines in profits because they are expected to pass any additional costs of the regulation on to state and federal governments through lower lease prices. Thus, for the majority of new platforms, the impact of the regulations would be to reduce federal and state revenues. The reduction in revenues for the affected states is not expected to exceed 0.1 percent.

For the 5 to 15 percent of new platforms to be constructed on existing lease tracts, the cost of the regulation cannot be passed on as reduced lease bids. As a result, the rate of return for

these operations is expected to decline from 0.4 to 4.5 percent (with an average decline of 1.8 percent).

The Agency projects no net decline in energy production as a result of the zero discharge requirement because the majority of platforms are not expected to experience a change in production levels. Some platforms may shut down a year early and therefore produce less oil than they would have without the regulation. Approximately one-third of the model platforms are projected to shut down early due to an increase in the water/oil ratio in produced water, which will reduce profitability. Those that do are not expected to shut down more than a year early and the resultant decline in production is less than 0.1 percent of total model project production. Platforms able to use waterflooding may benefit from reinjection of produced water. As water is injected into a producing formation, increased pressure causes oil production increases. On balance, these production changes are expected to offset each other.

The Agency projects no employment or international trade effects as a result of this regulation.

XIII. Nonwater Quality Environmental Impact

The elimination or reduction of one form of pollution may aggravate other environmental problems. Therefore, Sections 304(b) and 306 of the Act require the Agency to consider the non-water quality environmental impacts (including energy requirements) of certain regulations. In compliance with these provisions, the Agency has considered the effect of these regulations on air pollution, solid waste generation, water scarcity, and energy consumption. This proposal was circulated to and reviewed by Agency personnel responsible for nonwater quality environmental programs. While it is difficult to balance pollution problems against each other and against energy use, the Agency is proposing regulations that it believes best serve often competing national goals.

The following are the nonwater quality environmental impacts associated with today's proposed regulations:

A. Energy Requirements

Additional energy requirements imposed by these regulations are due primarily to the filtration and pumping of produced water into injection wells for those new source facilities subject to the zero discharge standard. The energy requirements for the 132 new source platforms that would be required to

reinject produced water total approximately 170 million kilowatt-hours per year. This represents approximately 0.05 percent of the energy content of the produced hydrocarbons from these facilities. Therefore, the small incremental energy requirements for reinjection of produced water will not significantly affect the cost of pollution control, nor will they measurably affect energy supplies.

There are no measurable increases in energy requirements beyond BAT for those new sources that would be subject to improved performance of BPT technology for produced water.

Today's proposed NSPS regulations for waste streams other than produced water and the proposed BAT regulations are based primarily on product substitution techniques and practices that do not involve the expenditure of measureable amounts of energy.

B. Air Pollution

This Agency estimated air pollution from offshore oil and gas platforms in a report titled *Atmospheric Emissions from Offshore Oil and Gas Development and Production*, June 1977 (EPA 450/3-77-026). Emissions of hydrocarbons, hydrogen sulfide, nitrogen oxide and sulfur dioxides are estimated in this report. Presently there are no national standards that directly regulate emissions from offshore oil and gas facilities.

Sources of air pollution include leaks, oil water separators, dissolved air flotation units, painting apparatus, storage tanks and diesel or gas engines for generating power. The following discussion addresses air pollution aspects of the proposed regulations.

When additional pumping is required, due to the application of a particular pollution control technology for produced water, additional air emissions will be created due to the use of fuel to power either electric generators or prime movers. However, the use of gas turbine engines projected for the majority of sites offshore should result in the least emissions to the atmosphere. If treatment facilities are located onshore, power would be obtained from local electric power companies, with no air emissions from on-site power generation.

C. Solid Waste

Operators of offshore platforms could discharge drilling fluids and drill cuttings in accordance with today's proposed regulations and any additional 403(c) considerations. In the majority of situations, drilling fluids and additives can be selected such that they would achieve the effluent limitations. As such,

minimal solid waste generation for onshore disposal is expected to result from these regulations.

Section 3001 of the Resource Conservation and Recovery Act (RCRA) presently exempts offshore drilling wastes from compliance with solid waste disposal regulations. Section 3001 of RCRA states that "drilling fluids, produced water, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy shall be subject only to existing state or federal regulatory programs in lieu of Subtitle C [regulation of land disposed hazardous wastes] * * *"

Section 8002 of RCRA prescribes that these exempt waste streams be investigated by the EPA's Office of Solid Waste and that a final determination be made on their status of exemption from RCRA. The Agency is currently preparing a preliminary assessment of these wastes.

Minimal additional solid waste is associated with filtration when used to treat produced water prior to reinjection. The final disposition of the filtration wastes would be in approved land fills, except for platforms in offshore California waters where controlled ocean disposal of drilling wastes may be allowed.

D. Consumptive Water Loss

No consumptive water loss is expected as a result of these regulations.

XIV. New Source Definition

The exploration, development, and production of oil and gas in offshore waters involves operations sometimes unique from normal industrial operations performed on land. The definition section of this regulation includes a definition of "new source" appropriate for this subcategory of the oil and gas industry. While the provisions in the NPDES regulations that define new source (40 CFR 122.2) and establish criteria for a new source determination (40 CFR 122.29(b)) are applicable to this subcategory, two terms, "water area" and "significant site preparation work", are defined in this subcategory-specific new source definition in order to give the terms meanings relevant to offshore oil and gas operations. The special definitions in today's proposed regulations are consistent with § 122.29(b)(1) which provides that § 122.2 and 122.29(b) shall apply "Except as otherwise provided in an applicable new source performance standard." See 49 FR 38048 (September 26, 1984).

Before discussing the two special definitions, a brief discussion follows on the scope of the term "new source" for the offshore oil and gas industry. The term "new source" is applicable to all activities covered by the offshore subcategory. This includes mobile and/or fixed exploratory and development drilling operations as well as production operations. Coverage of all such offshore oil and gas operations is required by Section 306 of the Act.

Section 306(a)(2) defines a "new source" to mean "any source, the construction of which is commenced" after publication of the proposed NSPS if such standards are promulgated consistent with section 306. The Act defines "source" to mean any "facility . . . from which there is or may be the discharge of pollutants" and "construction" to mean "any placement, assembly, or installation of facilities or equipment . . . at the premises where such equipment will be used." The term "source" clearly would include all drilling rigs and platforms as well as production platforms. The breadth of the term "construction," which encompasses the concept of "placement" of "equipment" at the "premises," would include the location and commencement of drilling or production operations at an offshore site to be "construction" of a new source. This is a critical distinction. Drilling rigs obviously are moved from site to site for several years. Production platforms are built on shore and transported to an offshore site. The appropriate reading of section 306(a)(5) would not make the date of building the rig or platform determinative of whether the rig or platform was a new source, but rather when the rig or platform was placed at the offshore site where the drilling and production activity and discharge would occur. Therefore, drilling operations that commence after the NSPS are effective, even if performed by an existing mobile rig, would be new sources, coming within the definition of "constructed" by "placement" of "equipment" at the "premises."

Similarly, a mobile drilling rig which carries the drilling equipment would be considered "placed" at the location it anchors for drilling, which would be the "premises." The Agency considers the drilling rig to be the "facility . . . from which there is or may be the discharge of pollutants" within the meaning of Section 306(a)(3). The same reasoning applies to development drilling rigs and structures and production structures, platforms or equipment. The critical determination of whether a source is a "new source" is the date of placement

and commencement of operations, not the date the source originally was built.

The first special term that is defined in these proposed regulations is "water area" as used in the term "site" in § 122.29(b). The term "site" is defined in § 122.2 to include the "water area" where a facility is "physically located" or an activity is "conducted." For the purposes of determining the "site" of new source offshore oil and gas operations, the Agency is proposing to define "water area" to mean the specific geographical location where the exploration, development, or production activity is conducted, including the water column and ocean floor beneath such activities. Therefore, if a new platform is built at or moved from a different location, it will be considered a new source when placed at the new site where its oil and gas activities take place. Even if the platform is placed adjacent to an existing platform the new platform will still be considered a "new source," occupying a new "water area" and therefore a new site.

EPA considered defining "water area" as a larger body of water, such as a lease block area. This alternative was rejected because such an artificial distinction would allow the commencement of many additional oil and gas activities (not considered to be "new sources") in an area merely by virtue of the fact that an existing activity was currently operating in the lease block. This result is inconsistent with the definitions and purpose of Section 306 of the Act. Under Section 306 a "new source" means "any source" the construction of which begins after the Agency publishes a NSPS.

The second special term for which EPA is proposing a special definition is "significant site preparation work." As explained above, the date of "placement" of a rig or platform is determinative of when a source is considered to be "constructed." The date of "placement" (i.e., "construction") may be earlier under the provision of 40 CFR § 122.29(b)(4) which defines construction as being commenced when "significant site preparation work" has been done at a site. The effect of the proposed definition for "significant site preparation work" is important in determining what individual sources would be considered to have "commenced construction" or commenced "placement" prior to the publication of the NSPS and therefore would not be considered a new source. EPA is proposing to define this term to mean the processes of clearing and preparing an area of the ocean floor for purposes of constructing or placing a

development or production facility on or over the site. Therefore, if clearing or preparation of an area for development or production had occurred at a site prior to the publication of the NSPS, then subsequent development and production activities at that site would not be considered a new source. The significance of this definition is that exploration activities at a site prior to the effective date of the NSPS are not considered significant site preparation work. Therefore, if only exploratory drilling had been performed at a site, subsequent development and production activities would not be "grandfathered in" as existing sources at the site but rather would be considered "new sources." The Agency does not consider exploratory activities to be "significant site preparation work" because such activities are not necessarily followed by development or production activities at a site. Even when exploratory drilling ultimately leads to drilling and production activities, the latter may not be commenced for months or years after the exploratory drilling is completed. The purpose of this provision is to allow a future source to be considered an existing source if "significant site preparation work," thereby evidencing an intent to establish full-scale operations at a site, had been performed prior to NSPS becoming effective. While a development or production platform would not be built unless an exploratory well had been drilled, exploration wells are drilled at vastly more sites and can precede development by months or years.

Another provision of § 122.29(b)(4) regarding when construction of a new source has commenced, provides that construction has commenced if the owner or operator has "entered into a binding contractual obligation for the purchase of facilities or equipment which are intended to be used in its operation within a reasonable time." The Agency is not proposing a special definition of this provision believing it should appropriately be a decision for the permit writer. However, the Agency carefully has considered this provision and is providing the following general guidance concerning the proper application of the provision for the special circumstances of offshore oil and gas activities.

A common practice in the industry is for oil companies to enter into long-term contracts with independent drilling companies. These contracts may require that the drilling company will provide its services for a specified number of wells over a period of months or years. The exact site for the exploratory drilling

services may not be specified. The Agency believes such contracts would appropriately fall within the provision of § 122.29(b)(4)(ii) thereby making the drilling activities under those contracts existing sources, not new sources. Such contracts generally do not or cannot specify the exact site for future exploratory drilling.

The situation generally is not the same for development drilling or production activities. Contracts for these activities usually specify the site where activities are to be conducted or facilities placed. Therefore, a contract that meets the conditions of § 122.29(b)(4)(ii) for an exact site probably would not be considered a new source. However, a general contract for construction or use of a development or production platform with no indication of the location where it would be placed or used would not qualify to make a future selected site for its use an existing source. An opposite result would allow companies to move an existing platform or use old platforms at new sites in shallow water areas thereby avoiding the NSPS zero discharge requirement for produced water. Such a result would be contrary to the purpose of establishing NSPS.

An issue of continuing concern under the Clean Water Act has been whether NSPS must be applied after their proposal or only after their promulgation. Section 306(a)(1) of the Act provides that a "new source" is a source, the construction of which commences after proposal of NSPS if such NSPS are promulgated in accordance with section 306. Section 306(b)(1)(B) requires promulgation within 120 days of proposal. EPA's implementing regulations for direct dischargers provide that a new source means a source, the construction of which commenced either after proposal if the NSPS are promulgated within 120 days of after promulgation in all other cases. Section 122.2.

EPA does not intend that the NSPS for this subcategory shall be effective until they are promulgated unless they are promulgated within 120 days of proposal in which case the effective date would be the date of proposal. Therefore, no source will be considered a "new source" subject to NSPS until the Agency promulgates the NSPS. This decision is consistent with the Agency's definition of "new source" in 40 CFR § 122.2 since for the reasons discussed below the Agency will not be able to promulgate NSPS within 120 days of proposal. While the Agency continues to believe the definition of new source in § 122.2 is appropriate and consistent

with the Act, the Third Circuit Court of Appeals has twice in *NAMF v. EPA*, 719 F.2d 624, 641 (3rd Cir. 1983) and *Pennsylvania Department of Environmental Resources v. EPA*, 618 F.2d 991 (3rd Cir. 1980), held that as a general matter EPA's new source standards shall be applied as of their date of proposal. However, the Court in those cases also recognized that there may be circumstances, such as cases where "substantial changes" may occur between proposal and promulgation that would justify an NSPS effective date as the date of promulgation. See *NAMF v. EPA*, 719 F.2d at 643 n.20. The Agency believes that today's proposal is such a case, as discussed below.

First, one of the issues in this rulemaking is the definition of "new source." The Agency has solicited public comment on the proposed definition of new source. The agency's final decision on the definition of new source for this subcategory will be critical to knowing what facilities must comply with the NSPS. Because the proposed definition of NSPS may change upon promulgation, individual dischargers would be unable to determine their status for an extended period of time. This would hinder operational planning during the period.

Second, the proposed standards may change on promulgation. After proposal and prior to promulgation, the Agency will be collecting substantial additional data on the proposed standards and will be reconsidering its decisions. In light of this fact and the substantial number of expected comments, it seems inappropriate to require compliance with the proposed NSPS.

Finally, one of the primary effects of a decision to apply NSPS at the date of proposal would be that the National Environmental Policy Act (NEPA) would apply to the action of issuing the permit for the new source. For new lease areas, the Department of Interior ("DOI") already is preparing environmental impact statements (EIS) that consider the proposed oil and gas operations in the lease areas. EPA has entered into a memorandum of understanding with DOI providing for EPA participation in the EIS process. Therefore, for new federal lease areas, the provisions of NEPA are being applied.

XV. Best Management Practices

Section 304(e) of the Clean Water Act authorizes the Administrator to prescribe "best management practices" ("BMP") to control "plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage." Section 402(a)(1) and NPDES regulations (40 CFR 122) also

provide for best management practices to control or abate the discharge of pollutants when numeric effluent limitations are infeasible. However, the Administrator may prescribe BMP's only where he finds that they are needed to prevent "significant amounts" of toxic or hazardous pollutants from entering navigable waters.

In the offshore oil and gas industry there are various types of wastes that may be affected by the application of BMP's in NPDES permits. These include deck drainage and leaks and spills from various sources. The amount of contaminated deck drainage can be decreased considerably if proper segregation is practiced. "Clean" deck drainage should be segregated from sources of contamination. Many sources exist on an offshore platform where leaks or spillages could occur. The areas should be secured so that all leakages and/or spills are contained and not discharged overboard.

Good operation and maintenance practices reduce waste flows and improve treatment efficiencies, as well as reducing the frequency and magnitude of system upsets. Some examples of good offshore operation are:

1. Separation of waste crankcase oils from deck drainage collection systems.
2. Minimization of wastewater treatment system upsets by the controlled usage of deck washdown detergents.
3. Reduction of oil spillage through the use of good prevention techniques such as drip pans and other collection methods.
4. Elimination of oil drainage from pump bearings and/or seals by directing the drainage to the crude oil processing system.
5. If oil is used as a spotting fluid, careful attention to the operation of the drilling fluid system could result in the segregation from the main drilling fluid system of the spotting fluid and the drilling fluid that has been contaminated by the spotting oil. Once segregated, the contaminated drilling fluid can be disposed of in an environmentally acceptable manner.

Proper initial engineering of the various systems is essential to proper operation and ease of maintenance. The use of spare equipment is a requirement for continual operation when breakdowns occur. Selection of proper treatment chemicals, to insure optimum pollutant removals, is essential. Alarms should be provided to make the operator aware of off-normal conditions so corrective action can be taken.

Careful planning, good engineering and a commitment on the part of the operating, maintenance and management personnel are needed to ensure that the full benefits of all pollution reduction facilities are realized.

The Agency solicits comment on whether the final regulation should include best management practices and what substantive areas should be addressed.

XVI. Upset and Bypass Provisions

A recurring issue of concern has been whether industry guidelines should include provisions authorizing noncompliance with effluent limitations during periods of "upset" or "bypass." An upset, sometimes called an "excursion", is an unintentional noncompliance occurring for reasons beyond the reasonable control of the permittee. It has been argued that an upset provision is necessary in EPA's effluent limitations because such upsets will inevitably occur even in properly operated control equipment. Because technology based limitations require only what technology can achieve, it is claimed that liability for such situations is improper. When confronted with this issue, courts have disagreed on whether an explicit upset or excursion exemption is necessary, or whether upset or excursion incidents may be handled through EPA's exercise of enforcement discretion. Compare *Marathon Oil Co. v. EPA*, 564 F.2d 1253 (9th Cir. 1977) with *Weyerhaeuser v. Costle*, 590 F.2d 1011 (D.C. Cir. 1978), and *Corn Refiners Association, et al. v. Costle*, 594 F.2d 1223 (8th Cir., 1979). See also *American Petroleum Institute v. EPA*, 540 F.2d 1023 (10th Cir. 1976); *CPC International, Inc. v. Train*, 540 F.2d 1320 (8th Cir. 1976); and *FMC Corp. v. Train*, 539 F.2d 973 (4th Cir. 1976).

A bypass is an act of intentional noncompliance during which waste treatment facilities are circumvented because of an emergency situation. EPA has in the past included bypass provisions in NPDES permits.

The Agency has determined that both upset and bypass provisions should be included in NPDES permits. (See 40 CFR 122.41 (m) and (n), published at 48 FR 14168, April 1, 1983.) The upset provision establishes an upset as an affirmative defense to prosecution for violation of technology-based effluent limitations. The bypass provision authorizes bypassing to prevent loss of life, personal injury, or severe property damage. Consequently, permittees in the offshore segment of this industry will be entitled to upset and bypass provisions

in NPDES permits. Thus, these proposed regulations do not address these issues.

XVII. Variances and Modifications

Upon the promulgation of final regulations, the effluent limitations for the appropriate subcategory must be applied in all Federal and State NPDES permits thereafter issued to direct dischargers in the oil and gas extraction industry.

For the BPT effluent limitations, the only exception to the binding limitations is EPA's "fundamentally different factors" variance. See *E.I. duPont de Nemours and Co. v. Train*, 430 U.S. 112 (1977); *Weyerhaeuser Co. v. Costle*, supra; *EPA v. National Crushed Stone Association, et al.* 449 U.S. 64 (1980). This variance recognizes that there may be factors concerning a particular discharger that are fundamentally different from the factors considered in this rulemaking. This variance clause was originally set forth in EPA's 1973-1976 industry regulations. It is now included in the NPDES regulations and will not be included in specific industry regulations. See the NPDES regulation, 40 CFR 125, Subpart D, 44 FR 32854, 32893 (June 7, 1979), 45 FR 33512 (May 19, 1980), 46 FR 9460 (January 28, 1981), and 47 FR 52309 (November 19, 1982) for the text and explanation of the "fundamentally different factors" variance.

Dischargers subject to BAT and BCT limitations are also eligible for EPA's "fundamentally different factors" variance. In addition, BAT limitations for nonconventional pollutants may be modified under sections 301 (c) and (g) of the Act. Section 301(1) precludes the Administrator from modifying BAT requirements for any pollutants which are on the toxic pollutant list under section 307(a)(1) of the Act.

The economic modification section (301(c)) gives the Administrator authority to modify BAT requirements for nonconventional pollutants for dischargers who file a permit application after July 1, 1977, upon a showing that such modified requirements will: (1) represent the maximum use of technology within the economic capability of the owner or operator; and (2) result in reasonable further progress toward the elimination of the discharge of pollutants.

The environmental modification section (301(g)) allows the Administrator, with the concurrence of the State, to modify limitations for nonconventional pollutants from any point source upon a showing by the owner or operator of such point source satisfactory to the Administrator that:

(a) Such modified requirements will result at a minimum in compliance with BPT limitations or any more stringent limitations necessary to meet water quality standards;

(b) Such modification will not interfere with the attainment or maintenance of that water quality which shall assure protection of public water supplies, and the protection and propagation of a balanced population of shellfish, fish, and wildlife, and allow recreational activities, in and on the water and such modification will not result in the discharge of pollutants in quantities which may reasonably be anticipated to pose an unacceptable risk to human health or the environment because of bioaccumulation, persistency in the environment, acute toxicity, chronic toxicity (including carcinogenicity, mutagenicity or teratogenicity), or synergistic propensities.

Section 301(j)(1)(B) of the Act requires that application for modifications under section 301 (c) or (g) must be filed within 270 days after the promulgation of an applicable effluent guideline. For further details, see 43 FR 40859, September 13, 1978.

XVIII. Relationship to NPDES Permits

The effluent limitations in these regulations will be applied to individual dischargers through NPDES permits issued by EPA or approved State agencies under section 402 of the Act. The preceding section of this preamble discussed the binding effect of this regulation on NPDES permits, except to the extent that variances and modifications are expressly authorized. This section describes several other aspects of the interaction of these regulations with NPDES permits.

One matter that has been subject to different judicial views is the scope of NPDES permit proceedings in the absence of effluent limitations, guidelines, and standards. Under current EPA regulations, states and EPA regions that issue NPDES permits before regulations are promulgated do so on a case-by-case basis on consideration of the statutory factors. See *U.S. Steel Corp. v. Train*, 556 F.2d 844, 854 (7th Cir. 1977.) In these situations, EPA documents and draft documents (including these proposed regulations and supporting documents) are relevant evidence, but are not binding in NPDES permit proceedings. (See 44 FR 32854, June 7, 1979.)

Another noteworthy topic is the effect of this regulation on the powers of NPDES permit-issuing authorities. The promulgation of this regulation does not

restrict the power of any permit-issuing authority to act in any manner consistent with law or these or any other EPA regulations, guidelines, or policy. For example, to the extent that State water quality standards or other provisions of State or Federal law require limitation of pollutants not covered by this regulation (or require more stringent limitations on covered pollutants), such limitations must be applied by the permit-issuing authority.

One additional topic that warrants discussion is the operation of EPA's NPDES enforcement program, many aspects of which have been considered in developing this regulation. The Agency wishes to emphasize that, although the Clean Water Act is a strict liability statute, the limitation of enforcement proceedings by EPA is discretionary (*Sierra Club v. Train*, 527 F.2d 485, 5th Cir. 1977). EPA has exercised and intends to exercise that discretion in a manner that recognizes and promotes good faith compliance efforts and conserves enforcement resources for those who fail to make good faith efforts to comply with the Act.

XIX. Summary of Public Participation

The Agency has had contact with individual companies in the industry and with associations such as the Offshore Operators Committee, the Petroleum Equipment Suppliers Association, the Western Oil and Gas Association, the Alaska Oil and Gas Association, and the American Petroleum Institute during the collection of information and data basic to this proposal. Information supplied by these groups was used in the development of this proposal. The Agency has also met with or received comments from other organizations such as the Natural Resources Defense Council and the Sierra Club. The Agency held meetings on BAT permits based upon best professional judgement and to solicit input from the above groups, the general public, and the states in Denver, Colorado on June 11-12, 1984 and in Santa Barbara, California on July 27-29, 1984.

XX. Alternative Approaches to Regulation

A. Diesel Oil Recovery

During the drilling of a well, the addition of oil ("pill") may be required to free a stuck drill bit or string. The type of oil typically used is diesel oil. This oil, when added, would most likely cause the drilling fluid to exceed effluent limitations for free oil (sheen) and toxicity (LC-50), which would make it

unacceptable for discharge. If the portion of the drilling fluid that contains the diesel oil can be segregated from the rest of the drilling fluid system and removed ("pill" removal or recovery), then it could be disposed of in an environmentally acceptable manner. Then the remainder of the spent drilling fluid system has a higher likelihood of meeting the free oil and toxicity limitations and may be acceptable for discharge.

The volume of drilling wastes that must be removed from the drilling fluid system to assure recovery of all spotting fluids is yet to be determined. The Agency is currently developing an information collection program to resolve such technical issues. This information will be considered during development of the final regulations, which could result in the allowable discharge of drilling fluids to which diesel oil pills have been added, provided effective pill removal/recovery practices are implemented. The Agency solicits comments on this approach to the regulation of drilling fluids and drill cuttings.

B. Specific Pollutant Approach

The Agency is considering an alternate approach to the regulation of waste discharges for this industry segment whereby specific pollutants would be limited instead of formulations or compounds. For example, rather than regulating "diesel oil" as a pollutant parameter, one or more of its toxic pollutant constituents would be regulated. For diesel oil this could include benzene, toluene, ethylbenzene, and naphthalene. The Agency will consider this approach when reviewing the comments on the proposed limitations. Those commenters criticizing proposed toxicity limitations or a prohibition on the discharge of diesel oil should address the alternative of specific numeric limitations on the priority pollutant constituents of drilling fluids and additives.

C. Alternatives for Regulating Produced Water Discharges

The Agency is evaluating several alternative approaches to NSPS for produced water other than, or combined with, the water depth basis for reinjection selected for today's proposed regulations.

One alternative approach is to target zero discharge requirements to those platforms which use biocides or other chemicals in their produced water handling systems, regardless of facility type or location. In other words, those facilities that use biocides or other chemicals would be required to meet a

zero discharge standard for produced water. Another approach would be to regulate the types and discharge levels of any biocides used as well as other pollutants added to produced water wastestreams. This could be accomplished by meeting a toxicity-based effluent limitation through use of less toxic biocides, i.e., product substitution, or by limiting the quantities of biocides or other chemicals used.

The Agency will be performing an extensive survey on the use and discharge of biocides and other chemicals in produced water by existing offshore facilities in order to evaluate the appropriateness and feasibility of this type of approach. This information will be considered during development of the final regulations. Upon analysis of this information, the Agency may select a final regulatory option for produced water based upon reinjection for facilities that use biocides or other chemicals, product substitution to require the use of less toxic or persistent biocides and chemicals, establishing effluent limitations and standards to limit the quantities of biocides and chemicals, or an option based on a combination of these three approaches.

The Agency is also evaluating the appropriateness of imposing the zero discharge requirement for new source facilities located in the Gulf of Mexico in water depths of less than the 20 meter isobath appearing in today's proposed NSPS regulations. This includes estimating the number, size and type of facilities to be located in such waters, and analysis of differential costs, and amount of pollutants removed compared to the depth bases of today's NSPS proposal for produced water.

The Agency will be performing a tract-by-tract assessment of water depth to obtain NSPS profile and costing information in order to properly characterize this segment of NSPS offshore platforms. This information will be considered during development of the final regulations.

D. Oil Content Limitations

The Agency is considering the establishment of quantitative effluent limitations and standards on oil content, which would replace either the visible sheen or static sheen detection method for determining compliance with the prohibition on discharges of free oil. Such an alternative limitation could apply to deck drainage, drilling fluids, drill cuttings, well treatment fluids, and produced sand waste streams. The Agency solicits comment on this alternative.

XXI. Solicitation of Comments

The Agency invites and encourages comments on any aspect of these proposed regulations, but is particularly interested in receiving comments on the issues listed below, the alternative approaches to regulation discussed in Section XX, and on the "clearinghouse" approach to drilling fluids (NSPS and BAT Option 2). In order for the Agency to evaluate views expressed by commenters, the comments should contain specific data and information to support their views.

1. The Agency does not have adequate information on whether an operator can determine prior to the commencement of production operations whether biocides or other chemicals will be required during such production operations. The Agency is requesting additional information to determine whether an operator can determine in advance of development and production whether it will need biocides or other chemicals. This information will be used to determine whether an operator could plan during design and construction of a new facility for compliance with limitations and standards based upon biocide or other chemical usage.

2. The Agency's information on biocides is based on the registration of various pesticides with EPA's Office of Pesticides. The Agency's approach to determining which biocides are used and quantities of use is presented in the EPA report titled *Biocides in Use on Offshore Oil and Gas Platforms and Rigs*. The Agency is soliciting additional data on the actual use and application rates of biocides. In addition, the Agency invites comments and supporting data on alternatives to biocides for control of bacteria.

3. The Agency's evaluation of various treatment technologies shows that only reinjection of produced water effectively reduces priority pollutant discharges associated with produced water. In particular, EPA concluded that BPT technologies are not effective in reducing priority pollutant levels. The Agency invites comments on the use of other treatment technologies that reduce or eliminate priority pollutants in produced water discharges from offshore operations.

4. The Agency's estimate of new source compliance costs for zero discharge of produced water in the Gulf of Mexico is based on a projection of platforms in depths of 50 feet (approximately 15 meters) and extrapolated to 20 meters. The Agency will be performing tract-by-tract assessments to determine whether a zero discharge requirement for water

depths less than the 20 meter isobath would be more appropriate for the Gulf of Mexico. The Agency will also use this information to refine its cost estimates for today's proposed NSPS option for produced water. The Agency invites interested parties to suggest approaches and provide information to perform this assessment.

5. The Agency has limited information on the mercury and cadmium content in foreign and domestic sources of barite. The Agency also has limited data on the effect that blending of different barite sources has on barite metals content. For purposes of its economic analysis supporting today's proposal, the Agency assumed a fifteen percent increase in the price of barite to reflect the additional storage, maintenance, transportation, and monitoring costs associated with providing offshore operations with barite of low toxic metals content. The Agency invites comments and supporting data on the availability of barite with low metals content and the priority pollutant content of barite.

The Agency also has limited information on the heavy metals content of drilling mud clays and additives and seeks to determine whether their toxic metals content warrants regulation on a national basis. The Agency solicits additional information on the concentrations of mercury, cadmium, and other toxic metals in the basic drilling mud clays, such as bentonite, attapulgite and hematite.

6. The Agency intends to prepare cost estimates for the application of add-on technologies for the handling and treatment of produced water, drilling fluids, drill cuttings and deck drainage waste streams from existing offshore oil and gas facilities. In the performance of this work, an important element will be retrofit costs to install new equipment on existing platforms. These costs would include platform addition costs, auxiliary platform costs and equipment rearrangement costs. The Agency solicits such costs, including geographic cost multipliers for use in preparing the estimates. Comments received on the subject should be in a form usable for the intended purpose, with appropriate references to substantiate their bases.

7. The proposed NSPS regulation for produced water is, in part, based on improved operation of BPT treatment to achieve oil and grease levels in the produced water discharge which are lower than BPT levels. The Agency believes that incremental costs beyond BPT to achieve a 59 mg/l maximum oil and grease standard will be minimal but some costs will be realized. The Agency solicits comments on the cost

differential to meet the lower oil and grease level, realizing, however, that new sources will not incur retrofit expenses. These costs could include the cost of increased chemical use and more operator labor.

8. In the preparation of capital cost estimates, the Agency used various geographic and location cost multipliers to determine installed equipment costs and to adjust the base costs of facilities (which were prepared for the Gulf of Mexico) to other geographic locations. These other locations are: Atlantic Coast, California Coast, Cook Inlet/Shelikof Strait, Norton Basin, Gulf of Alaska, and the Beaufort Sea. The Agency solicits comments on the accuracy of the factors used, which are presented in Section XII A. of this preamble.

9. During the data gathering programs for the development of today's proposed regulations, the Agency was unable to obtain sufficient information on the oil content of drill cuttings before and after application of cuttings washer technology with which to establish national effluent limitations. While some information was available, the Agency does not believe that the data base is complete enough to be used for the formulation of national regulations. Therefore, the Agency solicits comments, including empirical data, on the oil content of drill cuttings before and after washing. This includes water wash, solvent cleaning and thermal processing technologies. This information is solicited for the use of both diesel oil and mineral oil as lubricity agents or spotting fluids for the drilling of offshore oil and gas wells. In addition, the Agency is considering and solicits comments on the appropriateness of establishing effluent limitations on oil content for drill cuttings in addition to the limitations on free oil, diesel oil and oil-based drilling fluids in the proposed options for NSPS and BAT.

10. The Agency is aware that at least two other processes exist for the treatment and disposal of drilling fluids, namely detoxification and solidification. These are relatively new technologies and, as such, were not considered by the Agency for this proposed rulemaking. The Agency solicits comments on the applicability of these two technologies for the offshore subcategory, and seeks information on cost, energy and nonwater quality aspects of using these techniques to process and dispose of drilling fluid waste streams.

11. The Agency requests comment on all aspects of the static sheen test as presented in Appendix 1 of today's

proposed regulations. The Agency particularly invites comment on the sample volumes, method of observation for sheen, and precision (reproducibility) of the proposed method.

12. The Agency requests comment on all aspects of the diesel oil analytical method as presented in Appendix 2 of today's proposed regulations for use on drilling fluids and drill cuttings waste streams.

13. The Agency requests comment on the appropriateness of establishing a limitation or standard on oil and grease for deck drainage in addition to, or instead of, a prohibition on the discharge of free oil.

XXII. Executive Order 12291

Executive Order 12291 requires EPA and other agencies to perform regulatory impact analyses of major regulations. The primary purpose of the Executive Order is to ensure that regulatory agencies carefully evaluate the need for taking the regulatory action. Major rules are those which impose a cost on the economy of \$100 million a year or more or have certain other economic impacts. This regulation is not a major regulation because its annualized cost of \$91.5 million (1983 dollars) is less than \$100 million and it meets none of the other criteria specified in paragraph (b) of Executive Order 12291.

XXIII. Regulatory Flexibility Analysis

Pub. L. 96-354 requires EPA to prepare an Initial Regulatory Flexibility Analysis for all proposed regulations that have a significant impact on a substantial number of small entities. This analysis may be done in conjunction with or as part of any other analysis conducted by the Agency. The economic impact analysis described above indicates that there will not be a significant impact on any segment of the regulated population. Additionally, the analysis has determined that none of the oil and gas development companies directly affected by the regulation are small businesses. Therefore, a formal regulatory flexibility analysis is not required.

XXIV. OMB Review

This regulation was submitted to the Office of Management and Budget for review as required by Executive Order 12291. Any written comments from OMB to EPA and any EPA responses to those comments are available for public inspection at Room M2404, U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460 from 9:00 a.m. to 4:00 p.m. Monday through Friday, excluding Federal holidays.

XXV. List of Subjects in 40 CFR Part 435

Oil and gas extraction, Waste treatment and disposal, Water pollution control.

XXVI. Appendices

Appendix A—Abbreviations, Acronyms, and Other Terms Used in this Notice

- Act—The Clean Water Act.
- Agency—The U.S. Environmental Protection Agency.
- API—American Petroleum Institute.
- BAT—The best available technology economically achievable, under Section 304(b)(2)(B) of the Act.
- BCT—The best conventional pollutant control technology.
- BDT—The best available demonstrated control technology processes, operating methods, or other alternatives, including where practicable, a standard permitting no discharge of pollutants under Section 306(a)(1) of the Act.
- BMP—Best management practices under Section 304(e) of the Act.
- BOD—Biochemical oxygen demand.
- BPT—The best practicable control technology currently available, under Section 304(b)(1) of the Act.
- Bypass—An act of intentional noncompliance during which waste treatment facilities are circumvented because of an emergency situation.
- Clean Water Act—The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 et seq.), as amended by the Clean Water Act of 1977 (Pub. L. 95-217).
- COD—Chemical oxygen demand.
- Direct discharger—A facility which discharges or may discharge pollutants to waters of the United States.
- LC-50—The concentration of a test material that is lethal to 50 percent of the test organisms in a bioassay.
- NPDES Permit—A National Pollutant Discharge Elimination System permit issued under Section 402 of the Act.
- NRDC—Natural Resources Defense Council.
- NSPS—New source performance standards under Section 306 of the Act.
- OOO—Offshore Operators Committee.
- PESA—Petroleum Equipment Suppliers Association.
- Priority Pollutants—The 65 pollutants and classes of pollutants declared toxic under Section 307(a) of the Act. Appendix C contains a listing of specific elements and compounds.
- RCRA—Resource Conservation and Recovery Act (Pub. L. 94-580) of 1976.
- Amendments to Solid Waste Disposal Act.
- SPCC—A spill prevention control and countermeasure plan required under Section 311(j) of the Act.
- Spot—The introduction of oil to a drilling fluid system for the purpose of freeing a stuck drill bit or string.
- TOC—Total organic carbon.
- Upset—An unintentional noncompliance occurring for reasons beyond the reasonable control of the permittee.
- WOGA—Western Oil and Gas Association.

Appendix B—Generic Drilling Fluids List

Type of fluid and base components	Typical concentration range (pound per barrel)
1. Potassium/Polymer Mud:	
Barite.....	0-450
Caustic soda.....	0.5-3
Cellulose polymer.....	0.25-5
Drilled solids.....	20-100
Potassium chloride.....	5-50
Seawater or fresh water.....	(¹)
Starch.....	2-12
Xanthan gum polymer.....	0.25-2
2. Seawater/Lignosulfonate Mud:	
Attapulgit or bentonite.....	10-50
Barite.....	25-450
Caustic soda.....	1-5
Cellulose polymer.....	0.25-5
Drilled solids.....	20-100
Lignite.....	1-10
Lignosulfonate.....	2-15
Seawater.....	(¹)
Soda ash/sodium bicarbonate.....	0-2
3. Lime Mud:	
Barite.....	25-180
Bentonite.....	10-50
Caustic soda.....	1-5
Drilled solids.....	20-100
Fresh water or seawater.....	(¹)
Lignite.....	0-10
Lignosulfonate.....	2-15
Lime.....	2-20
Soda ash/sodium bicarbonate.....	0-2
4. Nondispersed Mud:	
Acrylic polymer.....	0.5-2
Barite.....	25-180
Bentonite.....	5-15
Drilled solids.....	20-70
Fresh water or seawater.....	(¹)
5. Spud Mud (slugged intermittently with seawater):	
Attapulgit or bentonite.....	10-50
Barite.....	0-50
Caustic soda.....	0-2
Lime.....	0.5-1
Seawater.....	(¹)
Soda ash/sodium bicarbonate.....	0-2
6. Seawater/Fresh Water Gel Mud:	
Attapulgit or bentonite.....	10-50
Barite.....	0-50
Caustic soda.....	0.5-3
Cellulose polymer.....	0-2
Drilled solids.....	20-100
Lime.....	0-2
Seawater or fresh water.....	(¹)
Soda ash/sodium bicarbonate.....	0-2
7. Lightly Treated Lignosulfonate Freshwater/Seawater Mud:	
Barite.....	0-180
Bentonite.....	10-50
Caustic soda.....	1-3
Cellulose polymer.....	0-2
Drilled solids.....	20-100
Lignite.....	0-4
Lignosulfonate.....	2-6
Lime.....	0-2
Seawater-to-freshwater ratio.....	(²)
Soda ash/sodium bicarbonate.....	0-2
8. Lignosulfonate Freshwater Mud:	
Barite.....	0-450
Bentonite.....	10-50
Caustic soda.....	2-5
Cellulose polymer.....	0-2
Drilled solids.....	20-100
Fresh water.....	(¹)
Lignite.....	2-10
Lignosulfonate.....	4-15
Lime.....	0-2

¹ As needed.
² 1:1 approximately.

Appendix C—126 Priority Pollutants

- Acenaphthene
- Acrolein
- Acrylonitrile
- Benzene
- Benzidine

Carbon tetrachloride (tetrachloromethane)
 Chlorobenzene
 1,2,4-trichlorobenzene
 Hexachlorobenzene
 1,2-dichloroethane
 1,1,1-trichloroethane
 Hexachloroethane
 1,1-dichloroethane
 1,1,2-trichloroethane
 1,1,2,2-tetrachloroethane
 Chloroethane
 Bis(2-chloroethyl) ether
 2-chloroethyl vinyl ether (mixed)
 2-chloronaphthalene
 2,4,6-trichlorophenol
 Parachlorometa cresol
 Chloroform (trichloromethane)
 2-chlorophenol
 1,2-dichlorobenzene
 1,3-dichlorobenzene
 1,4-dichlorobenzene
 3,3-dichlorobenzidine
 1,1-dichloroethylene
 1,2-trans-dichloroethylene
 2,4-dichlorophenol
 1,2-dichloropropane
 1,2-dichloropropylene (1,3-dichloropropene)
 2,4-dimethylphenol
 2,4-dinitrotoluene
 2,6-dinitrotoluene
 1,2-diphenylhydrazine
 Ethylbenzene
 Fluoranthene
 4-chlorophenyl phenyl ether
 4-bromophenyl phenyl ether
 Bis(2-chloroisopropyl) ether
 Bis(2-chloroethoxy) methane
 Methylene chloride(dichloromethane)
 Methyl chloride (dichloromethane)
 Methyl bromide (bromomethane)
 Bromoform (tribromomethane)
 Dichlorobromomethane
 Chlorodibromomethane
 Hexachlorobutadiene
 Hexachlorocyclopentadiene
 Isophorone
 Naphthalene
 Nitrobenzene
 2-nitrophenol
 4-nitrophenol
 2,4-dinitrophenol
 4,6-dinitro-o-cresol
 N-nitrosodimethylamine
 N-nitrosodiphenylamine
 N-nitrosodi-n-propylamine
 Pentachlorophenol
 Phenol
 Bis(2-ethylhexyl)phthalate
 Butyl benzyl phthalate
 Di-N-Butyl Phthalate
 Di-n-Octyl phthalate
 Diethyl Phthalate
 Dimethyl phthalate
 1,2-benzanthracene (benzo(a)anthracene)
 Benzo(a)pyrene (3,4-benzo-pyrene)
 3,4-Benzofluoranthene(benzo(b)fluoranthene)
 11,12-benzofluoranthene(benzo(b)fluoranthene)
 Chrysene
 Acenaphthylene
 Anthracene
 1,12-benzoperylene(benzo(ghi)perylene)
 Fluorene
 Phenanthrene
 1,2,5,6-dibenzanthracene(dibenzo(h)anthracene)

Indeno(1,2,3-cd)pyrene(2,3-o-phenylene pyrene)
 Pyrene
 Tetrachloroethylene
 Toluene
 Trichloroethylene
 Vinyl chloride (chloroethylene)
 Aldrin
 Dieldrin
 Chlordane (technical mixture and metabolites)
 4,4-DDT
 4,4-DDE(p,p-DDX)
 4,4-DDD(p,p-TDE)
 Alpha-endosulfan
 Beta-endosulfan
 Endosulfan sulfate
 Endrin
 Endrin aldehyde
 Heptachlor
 Heptachlor epoxide (BHC-hexachlorocyclohexane)
 Alpha-BHC
 Beta-BHC
 Gamma-BHC(lindane)
 Delta-BHC(PCB-polychlorinated biphenyls)
 PCB-1242(Arochlor 1242)
 PCB-1254(Arochlor 1254)
 PCB-1221(Arochlor 1221)
 PCB-1232(Arochlor 1232)
 PCB-1248(Arochlor 1248)
 PCB-1260(Arochlor 1260)
 PCB-1016(Arochlor 1016)
 Toxaphene
 Antimony
 Arsenic
 Asbestos
 Beryllium
 Cadmium
 Chromium
 Copper
 Cyanide, Total
 Lead
 Mercury
 Nickel
 Selenium
 Silver
 Thallium
 Zinc
 2,3,7,8-tetrachloro-dibenzo-p-dioxin (TCDD)

Appendix D—Major Documents Supporting the Proposed Regulation

With the exception of the first document listed in each of the following subsections, all documents are available only for public inspection and copying at Room 2404, U.S. EPA, 401 M St., S.W., Washington, D.C. from 9:00 am to 4:00 pm Monday through Friday, excluding Federal holidays. The first document listed in each section may be obtained by contacting the individuals listed in the Addresses section of this preamble.

Technology and Cost Reports

1. Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category, EPA 440/1-85/0556.
2. Assessment of Existing Data for the Offshore Oil and Gas Extraction Industry, October 6, 1980.
3. Technical Feasibility of Brine Reinjection for the Offshore Oil and Gas Extraction Industry, May, 1981.

4. Sampling and Logistics Plan for EPA Priority Pollutant Sampling Program, Offshore Oil and Gas Extraction Industry, October 5, 1981.

5. Evaluation of Analytical Data Obtained from the Gulf of Mexico Sampling Program, Offshore Oil and Gas Extraction Industry, Volumes I and II, February 4, 1983.

6. Review of Drill Cuttings Washer Systems, Offshore Oil and Gas Extraction Industry, October 14, 1983.

7. Technologies for the Onshore Treatment of Produced Waters from Offshore Oil and Gas Platforms, December, 1983.

8. Results of Laboratory Analyses on Drilling Fluids and Cuttings, April 3, 1984.

9. Acute Toxicity of Eight Laboratory-Prepared Generic Drilling Fluids to Mysids, May, 1984.

10. Acute Toxicity of Suspended Particulate Phase of Drilling Fluids Containing Diesel Fuels, May, 1984.

11. Results of the Drilling Fluids Research Program Sponsored by EPA's Gulf Breeze Environmental Research Laboratory, 1976-1984, and Their Application to Hazard Assessment, EPA-600/4-84-055, June, 1984.

12. Summary of Cost Estimates for Systems to Treat Produced Water Discharges in the Offshore Oil and Gas Industry to Meet BAT and NSPS, June 28, 1984.

13. Application of the Proposed Best Conventional Pollutant Control Technology (BCT) Cost Tests on Produced Water—Offshore Oil and Gas Extraction Industry, June 28, 1984.

14. Cost of Offshore Cuttings Washer Systems, Offshore Oil and Gas Extraction Industry, September 12, 1983, revised June, 1984.

15. Technical Memorandum: Costs of Drill Cuttings Washing and Mud and Cuttings Transportation to Shore and Land Disposal for the Offshore Oil and Gas Industry—Gulf of Mexico, April 1984, revised July 5, 1984.

Environmental Reports

1. Assessment of Environmental Fate and Effects of Discharges From Offshore Oil and Gas Operations, 1984, EPA 440/4-85/002.

2. Analysis of Drilling Muds from 74 Offshore Oil and Gas Wells in the Gulf of Mexico, 1984.

3. Biocides in Use on Offshore Oil and Gas Platforms and Rigs, 1984.

4. 403(c) Determination for Lease Sale No. 52: Background Review, 1984.

Economic Reports

1. Economic Impact Analysis of Proposed Effluent Guidelines and Standards for the Offshore Oil and Gas Industry, EPA 440/2-85/003, 1984.

2. Cost Effectiveness Analysis of Proposed Effluent Guidelines and Regulations for the Offshore Oil and Gas Industry, 1984.

3. Economic Impacts Analysis of the Offshore Effluent Guideline Affecting the Barite Industry, 1984

Dated: August 2, 1985.

Lee M. Thomas,
Administrator.

For the reasons discussed above, EPA proposes to revise 40 CFR Part 435 as follows:

**PART 435—OIL AND GAS
EXTRACTION POINT SOURCE
CATEGORY**

Subpart A—Offshore Subcategory

Sec.

435.10 Applicability; description of the offshore subcategory.

435.11 Specialized definitions.

435.12 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).

435.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

435.14 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best conventional pollutant control technology (BCT).

435.15 Standards of performance for new sources (NSPS).

Appendix 1—Static Sheen Test

Appendix 2—Analysis of Diesel Oil in Drilling Fluids and Drill Cuttings

Appendix 3—Drilling Fluids Toxicity Test

Appendix 4—Regulatory Boundaries

Authority: Secs 301, 304 (b), (c), (e), and (g), 306 (b) and (c), 307 (b) and (c), and 501, Federal Water Pollution Control Act as amended (the Act); 33 U.S.C. 1251, 1311, 1314 (b), (c), (e), and (g), 1316 (b) and (c), 1317 (b) and (c), 1318 and 1361; 86 Stat. 816, Pub. L. 92-500; 91 Stat. 1567, Pub. L. 95-217.

Subpart A—Offshore Subcategory

§ 435.10 Applicability; description of the offshore subcategory.

The provisions of this subpart are applicable to those facilities engaged in field exploration, drilling, well production, and well treatment in the oil and gas extraction industry which are located in waters that are seaward of the inner boundary of the territorial seas ("offshore") as defined in section 502 of the Act. This includes offshore facilities that transport wastes to onshore locations for treatment or disposal.

§ 435.11 Specialized definitions.

For the purpose of this subpart:

(a) Except as provided below, the general definitions, abbreviations and methods of analysis set forth in 40 CFR Part 401 shall apply to this subpart.

(b) The term "drilling fluid" shall refer to the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to

counterbalance formation pressure. A water-base drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspending medium for solids, whether or not oil is present. An oil-base drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase.

(c) The term "spent drilling fluid system discharge" shall mean the bulk discharge of an entire drilling fluid system prior to a complete changeover to another drilling fluid system, or at the completion of the drilling of a well.

(d) The term "drill cuttings" shall refer to the particles generated by drilling into subsurface geologic formations and carried to the surface with the drilling fluid.

(e) The term "deck drainage" shall refer to any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas within facilities subject to this subpart.

(f) The term "produced water" shall refer to the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

(g) The term "produced sand" shall refer to slurrified particles used in hydraulic fracturing and the accumulated formation sands and scales particles generated during production.

(h) The term "well treatment fluids" shall refer to those fluids used in stimulating a hydrocarbon-bearing formation or in completing a well for oil and gas production, and drilling fluids used in reworking a well to increase or restore productivity.

(i) The term "sanitary waste" shall refer to human body waste discharged from toilets and urinals located within facilities subject to this subpart.

(j) The term "domestic waste" shall refer to materials discharged from sinks, showers, laundries, and galleys located within facilities subject to this subpart.

(k) The term "M10" shall mean those offshore facilities continuously manned by ten (10) or more persons.

(l) The term "M9IM" shall mean those offshore facilities continuously manned by nine (9) or fewer persons or only intermittently manned by any number of persons.

(m) The term "no discharge of free oil" shall mean that waste streams may not be discharged when they would cause a film or sheen upon or a discoloration of the surface of the receiving water, as determined by the Static Sheen Test.

(n) The term "Static Sheen Test" shall refer to the standard test procedure that has been developed for this industrial subcategory for the purpose of demonstrating compliance with the requirement of no discharge of free oil. The methodology for performing the Static Sheen Test is presented in Appendix 1 of this regulation.

(o) The term "Analysis of Diesel Oil in Drilling Fluids and Drill Cuttings" shall refer to the standard test procedure that has been developed for this industrial subcategory for the purpose of determining the presence of diesel oil in drilling fluids and drill cuttings. The methodology for performing this test is presented in Appendix 2 of this regulation.

(p) The term "diesel oil" shall refer to the grade of distillate fuel oil, as specified in the American Society for Testing and Materials' Standard Specification D975-81, that is typically used as the continuous phase in conventional oil-based drilling fluids.

(q) The term "Drilling Fluids Toxicity Test" shall refer to the standard bioassay test procedure that has been developed for this industrial subcategory for the purpose of measuring the toxicity of drilling fluids. The methodology for performing the Drilling Fluids Toxicity Test is presented in Appendix 3 of this regulation.

(r) The term "96-hr LC-50" shall mean the concentration of test material that is lethal to 50 percent of a the test organisms in a bioassay after 96 hours of constant exposure.

(s) The term "exploration facility" shall mean any fixed or mobile structure subject to this subpart that is engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs.

(t) The term "development facility" shall mean any fixed or mobile structure subject to this subpart that is engaged in the drilling and completion of productive wells.

(u) The term "production facility" shall mean any platform or fixed structure subject to this subpart that is used for active recovery of hydrocarbons from producing formations.

(v) The term "new source" means any exploratory, development or production facility or activity that meets the definition of "new source" under 40 CFR § 122.2 and meets the criteria for determination of new sources under 40 CFR § 122.29(b) applied consistent with the following definitions:

(1) The term "water area" as used in 40 CFR § 122.29(b)(1)(i) shall mean the water area and ocean floor beneath any

exploratory, development, or production facility where such facility is conducting its exploratory, development or production activities.

(2) The term "significant site preparation work" shall mean the process of surveying, clearing and preparing an area of the ocean floor for the purpose of constructing or placing a development or production facility on or over the site.

(w) The term "gas well" shall refer to any well that produces more than 15,000 cubic feet of natural gas for each barrel of produced petroleum liquids.

(x) The term "oil well" shall refer to any well that produces 15,000 cubic feet or less of natural gas for each barrel of produced petroleum liquids.

(y) The term "gas development and production facilities" shall mean those facilities subject to this subpart that are engaged in the development of or production from gas wells only.

(z) The term "oil development and production facilities" shall mean those facilities subject to this subpart that are engaged in the development of or production from oil wells or oil and gas wells.

(aa) The term "maximum for any one day" as applied to BPT and BCT effluent limitations for oil and grease in produced water shall mean the maximum concentration allowed as measured by the average of four grab samples collected over a 24 hour period that are analyzed separately.

(bb) The term "maximum" as applied to BAT effluent limitations for drilling fluids and to NSPS for produced water and drilling fluids shall mean the maximum concentration allowed as measured in any single sample of the discharged waste stream.

(cc) The term "minimum" as applied to BAT effluent limitations and NSPS for drilling fluids shall mean the minimum 96-hour LC-50 value allowed as measured in any single sample of the discharged waste stream.

§ 435.12 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available (BPT).

Except as provided in 40 CFR 125.30-32, any existing point source subject to this subpart must achieve the following effluent limitations representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available:

Pollutant parameter waste source	BPT Effluent Limitations		
	Oil and grease, mg/l		Residual chlorine, mg/l. Minimum for any 1 day
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed—	
Produced water	72	48	NA
Deck drainage	(¹)	(¹)	NA
Drilling fluids	(¹)	(¹)	NA
Drill cuttings	(¹)	(¹)	NA
Well treatment fluids	(¹)	(¹)	NA
Sanitary:			
M10	NA	NA	(²) 1
M9IM	NA	NA	NA
Domestic	NA	NA	NA

¹ No discharge of free oil.
² Minimum of 1 mg/l and maintained as close to this concentration as possible.
³ There shall be no floating solids as a result of the discharge of these wastes.
 NA—Not applicable.

§ 435.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

Except as provided in 40 CFR 125.30-32, any existing point source subject to this subpart must achieve the following effluent limitations representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT):

Waste source	Pollutant parameter or characteristic	BAT effluent limitations
Produced water.	[Reserved]	[Reserved]
Deck drainage.	Free oil	No discharge.
	[All other pollutant parameters reserved]	
Drilling fluids.	Free oil	No discharge.
	Oil-based fluid.	No discharge.
	Diesel oil	No discharge in detectable amounts.
	Toxicity	Minimum 96-hr LC-50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 30 percent by volume.
	Cadmium	1 mg/kg dry weight maximum in the whole drilling fluid.
	Mercury	1 mg/kg dry weight maximum in the whole drilling fluid.
Drill cuttings	Free oil	No discharge.
	Oil-based fluid.	No discharge.
	Diesel oil	No discharge in detectable amounts.
Sanitary M10.	None	
Sanitary M9IM.	None	
Domestic waste.	None	
Produced sand.	Free oil	No discharge.
	[All other pollutant parameters reserved].	
Well treatment fluids.	Free oil	No discharge.

BAT EFFLUENT LIMITATIONS—Continued

Waste source	Pollutant parameter or characteristic	BAT effluent limitations
[All other pollutant parameters reserved].		

§ 435.14 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best conventional pollutant control technology (BCT).

Except as provided in 40 CFR 125.30-32, any existing point source subject to this subpart must achieve the following effluent limitations representing the degree of effluent reduction attainable by the application of the best conventional pollutant control technology (BCT):

BCT EFFLUENT LIMITATIONS

Waste source	Pollutant parameter or characteristic	BCT effluent limitations	
		Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed—
Produced water.	Oil and grease	72 mg/l	48 mg/l
Deck drainage.	Free Oil	No discharge.	
	[All other pollutant parameters reserved].		
Drilling fluids.	Free oil	No discharge.	
	[All other pollutant parameters reserved].		
Drilling cuttings.	Free oil	No discharge.	
	[All other pollutant parameters reserved].		
Sanitary M10.	Residual Chlorine	Minimum of 1 mg/l and maintained as close to this concentration as possible.	
Sanitary M9IM.	Floating solids	No discharge.	
Domestic waste.	Floating solids	No discharge.	
Produced sand.	Free oil	No discharge.	
	[All other pollutant parameters reserved].		
Well treatment fluids.	Free oil	No discharge.	
	[All other pollutant parameters reserved].		

¹ For the control of fecal coliform.

§ 435.15 Standards of performance for new sources (NSPS).

Any new source subject to this subpart must achieve the following new source performance standards (NSPS):

(a) For all oil development and production facilities located in or discharging to water depth of 20 meters or less in the Gulf of Mexico, Atlantic Coast, and Norton Basin; water depth of 50 meters or less in the California Coast, Cook Inlet/Shelikof Strait, the Aleutian Island-Chain including Bristol Bay and Gulf of Alaska; and water dept of 10 meters or less in the Beaufort Sea as specified in Appendix 4 (Regulatory Boundaries):

NSPS EFFLUENT LIMITATIONS

Waste source	Pollutant parameter or characteristic	NSPS effluent limitations
Produced water. Deck drainage.	Free oil.....	No discharge.
	[All other pollutant parameters reserved]	
Drilling fluids..	Free oil.....	No discharge.
	Oil-based fluid.	No discharge.
	Diesel oil.....	No discharge in detectable amounts.
	Toxicity.....	Minimum 96-hr LC-50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 3.0 percent by volume.
Drill cuttings..	Free oil.....	No discharge.
	Oil-based fluid.	No discharge.
	Diesel oil.....	No discharge in detectable amounts.
Sanitary M10.	Residual chlorine.	Minimum of 1 mg/l and maintained as close to this concentration as possible.
	Floating solids.	No Discharge.
Sanitary M91M. Domestic waste.	Floating solids.	No discharge
	Free oil.....	No discharge.
Produced sand	[All other pollutant parameters reserved]	
	Free oil.....	No discharge.
Well treatment fluids.	[All other pollutant parameters reserved].	
	Free oil.....	No discharge.

¹ Facilities must be in compliance with the no discharge standard no later than 300 days after commencement of development drilling operations. Prior to that date, discharges shall comply with the oil and grease standard of 59 mg/l maximum in § 435.15(b).

(b) For all exploratory facilities and all gas development and production facilities regardless of location, and for all oil development and production facilities located in and discharging to water depth of more than 20 meters in the Gulf of Mexico, Atlantic Coast and Norton Basin; water depth of more than 50 meters in the California Coast, Cook Inlet/Shelikof Strait, the Aleutian Island Chain including Bristol Bay and Gulf of Alaska; and water depth of more than 10 meters in the Beaufort Sea as specified in Appendix 4 (Regulatory Boundaries):

NSPS EFFLUENT LIMITATIONS

Waste source	Pollutant parameter or characteristic	NSPS effluent limitations
Produced Water. Deck drainage.	Oil and grease.	59 mg/l maximum.
	Free oil.....	No discharge.
Drilling fluids..	[All other pollutants—Reserved].	
	Free oil.....	No discharge.
	Oil-based fluid.	No discharge.
	Diesel oil.....	No discharge in detectable amounts.
	Toxicity.....	Minimum 96-hr LC-50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 3.0 percent by volume.
	Cadmium.....	1 mg/kg dry weight maximum in the whole drilling fluid.
	Mercury.....	1 mg/kg dry weight maximum in the whole drilling fluid.
Drill cuttings..	Free oil.....	No discharge.
	Oil-based fluid.	No discharge.
	Diesel oil.....	No discharge in detectable amounts.
Sanitary M10.	Residual chlorine.	Minimum of 1 mg/l and maintained as close to this concentration as possible.
	Floating solids.	No Discharge.
Sanitary M91M. Domestic waste.	Floating solids.	No discharge.
	Free oil.....	No discharge.
Produced sand	[All other pollutant parameters reserved].	
	Free oil.....	No discharge.
Well treatment fluids.	[All other pollutant parameters reserved].	
	Free oil.....	No discharge.

Appendix 1—Static Sheen Test

1. Scope and Application

This method is to be used as a compliance test for the "no discharge of free oil" requirement for discharges of drilling fluids, drill cuttings, deck drainage, produced sand, and well treatment fluids. Free oil refers to any oil contained in a waste stream that when discharged will cause a film or sheen upon or a discoloration of the surface of the receiving water.

2. Summary of Method

Samples of drilling fluids, deck drainage or well treatment fluids (0.15 mL and 15 mL) and samples of drill cuttings or produced sand (1.5 g and 15 g, wet weight basis) are introduced into ambient seawater in a container having an air to liquid interface area of 1000 cm². Samples are dispersed within the container and observations made no more than 1 hour later to ascertain if these materials cause a sheen, iridescence, gloss, or increased reflectance on the surface of the test seawater. The occurrence of any of these visual observations will constitute a demonstration that the tested material contains "free oil", and therefore, results in a prohibition on its discharge into receiving waters.

3. Interferences

Residual "free oil" adhering to sampling containers, the magnetic stirring bar used to mix drilling fluids, and the stainless steel spatula used to mix drill cuttings will be the principal sources of contamination problems.

These problems should only occur if improperly washed and cleaned equipment are used for the test. The use of disposable equipment minimizes the potential for similar contamination from pipets and the test container.

4. Apparatus Materials and Reagents

- 4.1 Apparatus.
 - 4.1.1 Sampling containers—1 liter polyethylene beakers.
 - 4.1.2 Graduated cylinder—100 mL graduated cylinder required only for operations where predilution of mud discharges is required.
 - 4.1.3 Plastic disposable weighing boats.
 - 4.1.4 Triple beam scale.
 - 4.1.5 Disposable pipets—1 mL and 25 mL disposable pipets.
 - 4.1.6 Magnetic stirrer and stirring bar.
 - 4.1.7 Stainless steel spatula.
 - 4.1.8 Test container—open plastic container whose internal cross-section parallel to its opening has an area of 1000±50 cm², and a depth of no more than 30 cm.
- 4.2 Materials and Reagents.
 - 4.2.1 Plastic liners for the test container—Oil free, heavy duty plastic trash can liners that do not inhibit the spreading of an oil film. Liners must be of a sufficient size to completely cover the interior surface of the test container. Permittees must determine an appropriate local source of liners that do not inhibit the spreading of 0.05 mL diesel fuel added to the lined test container under the test conditions and protocol described below.
 - 4.2.2 Ambient receiving water.

5. Calibration

None currently specified.

6. Quality Control Procedures

None currently specified.

7. Sample Collection and Handling

- 7.1 Sampling containers must be thoroughly washed with detergent, rinsed a minimum of 3 times with fresh water, and allowed to air dry before samples are collected.
- 7.2 Samples of drilling fluid must be obtained once per day from the active mud pit; the sample volume should range between 200 mL and 500 mL.
- 7.3 Samples of drill cuttings or produced sand must be obtained from each type of solids control equipment from which discharges occur on any given day prior to addition of any washdown water; samples should range between 200 and 500 grams.
- 7.4 Samples of deck drainage or well treatment fluids must be obtained from holding facility prior to discharge; the sample volume should range between 200 mL and 500 mL.
- 7.5 Samples must be tested no later than 1 hour after collection.
- 7.6 Drilling fluid samples must be mixed in their sampling containers for 5 minutes prior to testing using a magnetic bar stirrer. If predilution is imposed as a permit condition, the sample must be mixed at the same ratio with the same prediluting water as the discharged muds and stirred for 5 minutes.
- 7.7 Drill cuttings must be stirred and well mixed by hand in their sampling containers

prior to testing, using a stainless steel spatula.

8. Procedure

8.1 Ambient receiving water must be used as the "receiving water" in the test. The test container must have an air to liquid interface area of $1000 \pm 50 \text{ cm}^2$. The surface of the water should be no more than 5 cm below the top of the test container.

8.2 Plastic liners shall be used, one per container per test, and discarded afterwards. Some liners may inhibit spreading of added oil; operators shall determine an appropriate local source of liners that do not inhibit the spreading of the oil film.

8.3 Drilling fluid materials, well treatment fluids, or deck drainage must be introduced into the test container 1 cm below the water surface, by pipet, at 0.15 mL and 15 mL. Pipets must be filled and discharged with test material prior to the transfer of test material and its introduction into test containers. The test water-test material mixture must be stirred using the pipet to distribute the test material homogeneously throughout the test water. The pipet must be used only once for a test and then discarded.

8.4 Drill cuttings or produced sand should be weighed on plastic weighing boats; 1.5 gram and 15 gram samples must be transferred by scraping test material into the test water with a stainless steel spatula. The weighing boat must be immersed in the test water and scraped with the spatula to transfer any residual material to the test container. The test material must be stirred with the spatula to an even distribution of solids on the bottom of the test container.

8.5 Observations must be made no later than 1 hour after the test material is transferred to the test container. Viewing points above the test container should be made from at least three sides of the test container, at viewing angles of approximately 60° and 30° from the horizontal. Illumination of the test container must be representative of adequate lighting for a working environment to conduct routine laboratory procedures.

8.6 Detection of a "silvery" or "metallic" sheen, gloss, or increased reflectivity; visual color; or iridescence on the water surface shall constitute a demonstration of "free oil." These visual observations include patches, sheets, or streaks of such altered surface characteristics.

Appendix 2—Analysis of Diesel Oil in Drilling Fluids and Drill Cuttings

1. Scope and Application

This method is to be used as a compliance test for detecting the presence of diesel oil in drilling fluids and drill cuttings waste streams. The method involves the separation of diesel fuel from drilling fluid or drill cuttings samples and subsequent qualitative and quantitative analysis by capillary column gas chromatography. The method makes no attempt to chemically identify the individual diesel components but uses a pattern recognition technique for data analysis.

2. Summary of Method

A weighed amount of drilling fluid or drill cuttings is placed in a retort apparatus and

distilled according to the retort manufacturer's instructions. The distillate is extracted with methylene chloride, an internal standard is added, and a GC analysis is conducted. Using low attenuation for high sensitivity, a detection of 1 mg/kg of diesel oil in the sample is possible with this method.

The analyst is cautioned that there is no standard diesel fuel oil. The components, as seen by gas chromatography, will differ depending upon the crude source, the date of the diesel production and the producer. In addition, there are three basic types of diesel fuel oils: ASTM Designations No. 1-D, No. 2-D, and No. 4-D. The No. 2-D is most commonly referred to in terms of "diesel fuel." However, No. 2-D is sometimes blended with No. 1-D which has a lower boiling range. Thus it is highly desirable that the sample chromatograms be matched with a reference standard made from the same diesel oil source suspected to be in the sample.

3. Apparatus, Reagents and Materials

3.1 Apparatus.

3.1.1 Gas Chromatograph (GC)—A temperature programmable GC equipped with a flame ionization detector.

3.1.2 Integrator—A recording integrator capable of resolving and integrating recorder response peaks.

3.1.3 Chromatographic Column—A borosilicate glass capillary column (WCOT), 30 meter x 0.25 mm ID, coated with Supelco SPB-1 (Bonded SE-30 methyl silicone) with 1.0 μm thickness (Supelco catalog number 2-4029). Other columns may be substituted if they can demonstrate similar and satisfactory results.

3.1.4 Distillation Apparatus—A 20 mL retort apparatus.

3.1.5 Kuderna—Danish Concentrator—A 500 mL flask, 3-ball Snyder column and a 10 mL (or 15 mL) receiving ampule graduated in 0.1 mL units at the bottom.

3.1.6 Separatory Funnel—A 60 mL separatory funnel with a Teflon stopcock and glass stopper.

3.1.7 Glass Filtering Funnel—A glass filtering crucible holder (Corning 9480 or equivalent).

3.1.8 Centrifuge Tubes—15 mL glass centrifuge tubes.

3.2 Materials and Reagents.

3.2.1 Glass Wool—Corning 3950 or equivalent.

3.2.2 Anhydrous Sodium Sulfate—Analytical grade.

3.2.3 Methylene Chloride—Nanograde or equivalent.

3.2.4 Trichlorobenzene (TCB) Internal Standard—Dissolve 1.0 gm of 1,3,5 Trichlorobenzene (Kodak 1801 or equivalent) in 100 mL of Methylene Chloride. Store in glass and tightly cap with Teflon lid liner to prevent solvent evaporation loss.

4. Procedure

4.1 Sample Preparation.

4.1.1 Preweigh or tare the retort sample cup and cap to the nearest 0.1 gm. Transfer a well homogenized and representative portion of the material to be tested into the sample cup, filling it to the top. Place the cap on the

cup, wipe off the excess material and reweigh. Record the weight of the sample to the nearest 0.1 gm.

4.1.2 Following the retort manufacturer's instructions, distill the sample. The presence of solids in the distillate will require that the distillation be rerun starting with a new portion of sample. Placing more steel wool in the retort expansion chamber, per instructions, will help prevent the solids from going over in the distillation.

4.2 Gas Chromatography.

4.2.1 Pour the retort distillate into a 60 mL separatory funnel. Rinse the distillate container with two full portions of methylene chloride into the separatory funnel. Stopper and shake for 1 minute and allow the layers to separate.

4.2.2 Prepare a crucible holder funnel by plugging the bottom with a piece of glass wool and pouring in 1-2 inches of anhydrous sodium sulfate. Wet the funnel with a small portion of methylene chloride and allow it to drain to a waste container.

4.2.3 Place the filter holder into the top of a Kuderna-Danish (K-D) flask equipped with a 10 mL separatory funnel containing the methylene chloride into the K-D flask passing it through the filter funnel.

4.2.4 Repeat the methylene chloride extraction twice more, rinsing the centrifuge tube with two through washings each time and draining each extraction into the K-D flask.

4.2.5 Place a Snyder column on the K-D flask and evaporate on a steam bath. Concentrate the sample to a 1.0 mL final volume or until the contents will not concentrate any further and note the final volume. The receiving ampule graduations should be laboratory calibrated for accuracy.

4.2.6 Using a micropipet, transfer equal portions of the sample from the K-D ampule and the TCB internal standard (a 100 μL portion of each is suggested) into a GC injection vial or other suitable container. Mix thoroughly.

4.2.7 Set up the gas chromatograph conditions as follows:

(a) GC—Injector Port and manifold temperature = 275°C .

(b) Column—A SPB-1, 30 meter column with a nitrogen carrier at 0.2 mL/min, a split ratio of 100:1 and nitrogen make-up (if needed) at 60 cc/min.

(c) Temperature Program— 90°C initial temperature with no hold, 5° per minute to a final temperature of 250°C ; final hold for at least 10 minutes.

(d) Detector—FID with 30 cc/min hydrogen and 240 cc/min air. Set the amplifier range at 10^{-11} amps full scale (X10 on most instruments)

(e) Recording Integrator—Set the chart speed at a minimum of 1 cm/min. Adjust the attenuation during the run as to exclude minor peaks.

4.2.8 Inject 1 μL of the sample containing the internal standard. The TCB will elute at approximately 8.5 minutes into the run and should be approximately 50 percent at full scale at 8×10 .

4.2.9 Prepare a reference standard using, if possible, the same diesel oil suspected to be in the sample. Using Table 1 as a guide,

weigh out the appropriate amount of oil into a tared 10 mL volumetric flask and dilute to volume with methylene chloride. Mix equal portions of the reference oil standard and the TCB as outlined in 4.2.6 and analyze using the same GC conditions used for the analysis of the sample.

5. Interpretation of Data

5.1 Compare the sample chromatogram to the chromatogram of the standard. If the sample contains No. 2 diesel oil, the major peaks present in the standard (e.g. those greater than 1 percent of the total integrated area) should also be present in the sample and in the same relative intensity and pattern (see Figure 1).

5.2 Some mineral oil lubricity additives have similar chromatographic patterns to that of diesel oil. The presence of early, smaller peaks from 1 minute (following the solvent peak) to approximately 4 minutes will differentiate between distillates containing only mineral oil and those with No. 2 diesel oil (See Figure 2).

5.3 The use of the TCB internal standard makes it possible to correlate peaks from sample to standard on the basis of Relative Retention Time (RTT). Approximate RRT's are presented in Table 2.

6. Calculation of Results

6.1 Choose those peaks that are applicable as outlined in Section 5; a minimum of 10 peaks should be used. Sum the integrated areas of the chosen peaks in the sample and divide by the integrated area of the Internal Standard in the sample:

$$\frac{\Sigma A_{ps}}{A_{is}} = R_{Fs}$$

where:

ΣA_{ps} = Summation of peak areas of interest in sample

A_{is} = Area of internal standard peak in sample

R_{Fs} = Response factor for sample

6.2 Repeat the above process (6.1) for the chosen peaks in the standard:

$$\frac{\Sigma A_{pr}}{A_{ir}} = R_{Fr}$$

where:

ΣA_{pr} = Summation of peak areas of interest in reference standard

$$\text{mg/kg Diesel Oil} =$$

where:

R_{Fs} = Response factor for sample

R_{Fr} = Response factor for reference standard

V_s = Final volume of sample from K-D in mL

C_r = Concentration of reference standard in mg/mL

G_s = Starting weight of sample in grams on a wet weight or whole mud basis.

Note.—This equation does not take into account attenuation changes if they affect the calculated peak areas as reported by the integration.

7. Quality Control

7.1 Each laboratory that uses this method is required to operate a formal quality control program. The minimum requirements of this program consist of an initial demonstration of laboratory capability, the analysis of a retorted No. 2 diesel oil standard as a continuing check on recovery, and duplicate samples for a precision check on performance. The laboratory is required to maintain performance records to define the quality of data that are generated. Ongoing performance checks must be compared with established performance criteria to determine if the results of analyses are within accuracy and precision limits expected of the method.

7.2 In order to demonstrate recovery, a No. 2 diesel oil standard must be subjected to the entire analytical procedure starting with section 4.1. Pipette 1.00 ml of the reference diesel oil into the preweighed or tared retort sample cup and weigh to the nearest 0.1 gram. Place a small plug of steel wool into the

A_{ir} = Area of internal standard peak in the reference standard

R_{Fr} = Response factor for reference standard

6.3 Calculate the mg/kg of diesel oil in the sample as follows:

$$\frac{R_{Fs} \times V_s \times C_r \times 1000}{R_{Fr} \times G_s}$$

cup, cap and proceed with the retort distillation. Calculate the percent recovery of the retorted reference standard to that of a reference standard prepared as specified in section 4.2.9. The percent recovery of the retorted reference standard must fall within 60 to 120 percent recovery. This should be performed on each retort unit utilized before attempting any sample analyses. Reference standards should be run at least once for each batch of samples processed or for every ten samples analyzed.

7.3 The laboratory must analyze duplicate samples for each sample type at a minimum of 20 percent. A duplicate sample shall consist of a well-mixed, representative aliquot of the sample and should be subjected to the entire analytical procedure starting with section 4.1. The relative percent differences (RPD) for duplicates are calculated as follows:

$$RPD = \frac{(D_1 - D_2)}{\frac{(D_1 + D_2)}{2}} \times 100$$

where:

RPD = relative percent difference

D_1 = percent of diesel oil in the first sample

D_2 = percent diesel oil in the second sample (duplicate)

A control limit of ± 20 percent for RPD shall be used.

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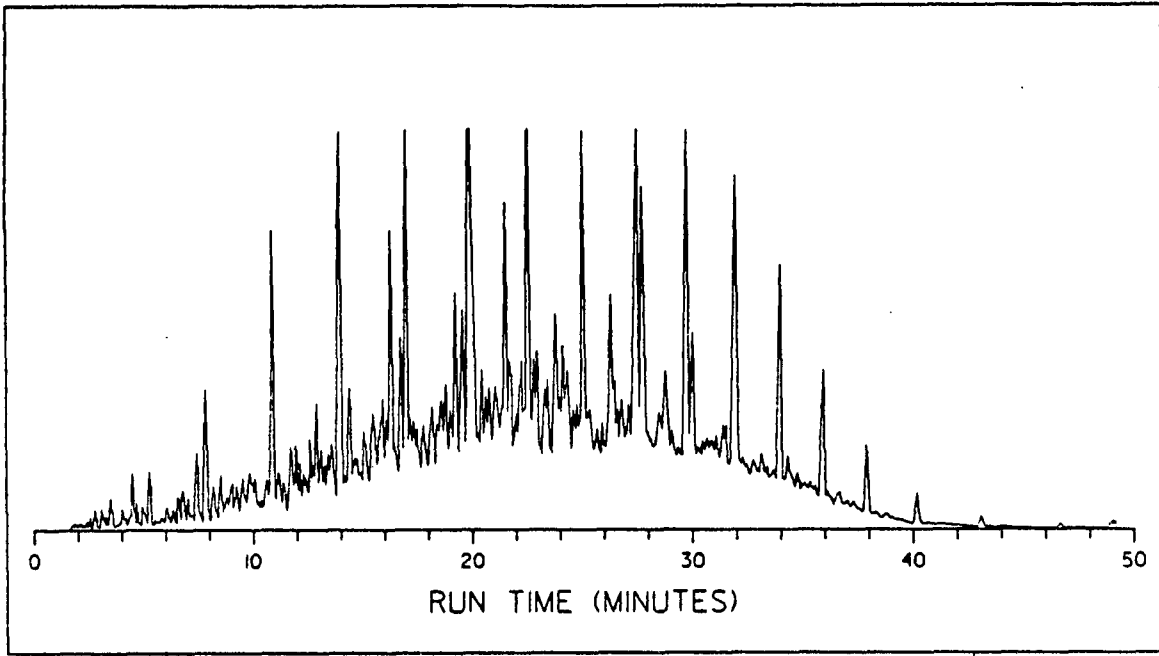


FIGURE 1
CHROMATOGRAM OF NO.2 DIESEL OIL SAMPLE
(NO SOLVENT OR INTERNAL STANDARD PEAKS PRESENT)

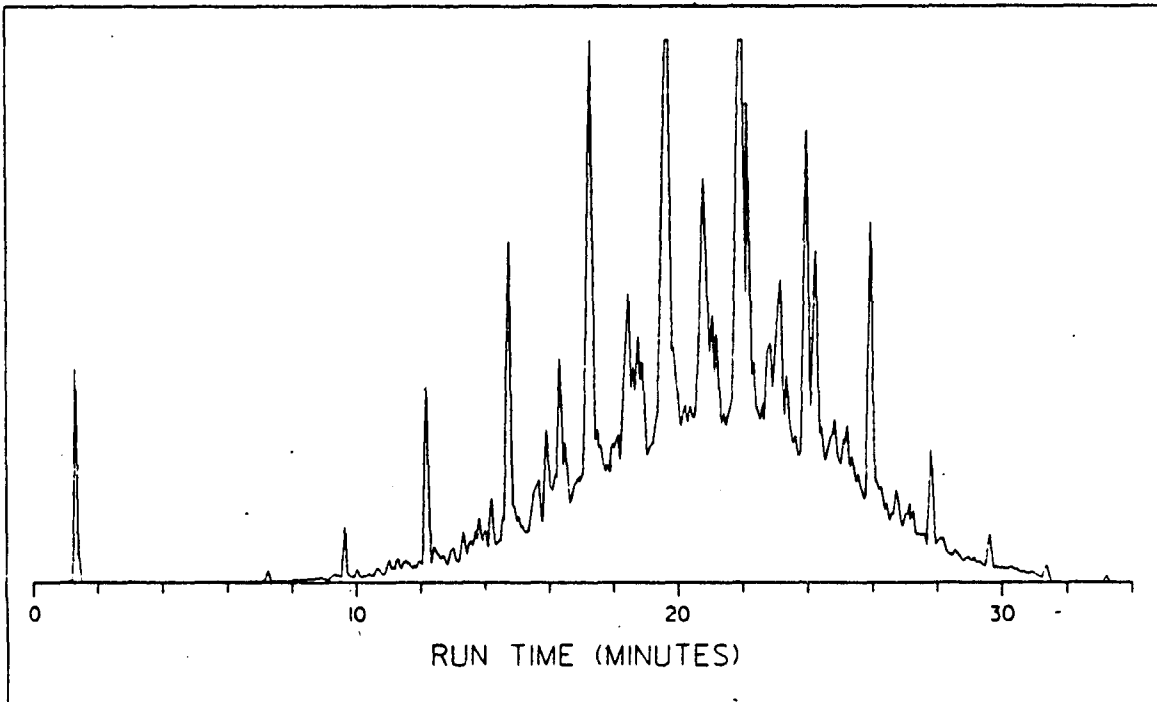


FIGURE 2
CHROMATOGRAM OF MINERAL OIL SAMPLE
250-A

TABLE 1.—PERCENT RANGES OF DIESEL AND STANDARDS

Expected percent diesel in sample	Wt of No. 2-D oil in 10 mL volumetric ¹ (g)
5.....	Use undiluted oil.
3.....	7.6.
1.....	3.0.
0.5.....	1.5.

¹ Weigh oil to the nearest 0.1 mg.

Table 2

Approximate Relative Retention Times for TCB IS and No. 2-D Diesel Fuel.

1,3,5 Trichlorobenzene Internal Standard=100

Expected RRT's for Predominate Peaks in No. 2-D Diesel:

124	231
155	245
179	260
183	273
186	276
188	299
193	324
207	348
216	370
220	

Appendix 3—Drilling Fluids Toxicity Test

I. Sample Collection

The collection and preservation methods for drilling fluids (muds) and water samples presented here are designed to minimize sample contamination and alteration of the physical or chemical properties of the samples due to freezing, air oxidation, or drying.

I-A. Apparatus

(1) The following items are required for water and drilling mud sampling and storage:

- Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminating drilling mud sampler.
- Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminating water sampler.
- Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminated vessels for water and mud samples.
- Ice chests for preservation and shipping of mud and water samples.

I-B. Water Sampling

(1) Collection of water samples shall be made with appropriate acid-rinsed linear-polyethylene bottles or other appropriate noncontaminating water sampling devices. Special care shall be taken to avoid the introduction of contaminants from the sampling devices and containers. Prior to use, the sampling devices and containers should be thoroughly cleaned with a detergent solution, rinsed with tap water, soaked in 10 percent hydrochloric acid (HCl) for 4 hours, and then thoroughly rinsed with glass-distilled water.

I-C. Drilling Mud Sampling

(1) Drilling mud formulations to be tested shall be collected from active field systems. Obtain a well-mixed sample from beneath the shale shaker after the mud has passed through the screens. Samples shall be stored in polyethylene containers or in other

appropriate uncontaminated vessels. Prior to sealing the sample containers on the platform, flush as much air out of the container by filling it with drilling fluid sample, leaving a one inch space at the top.

(2) Mud samples shall be immediately shipped to the testing facility on blue or wet ice (do not use dry ice) and continuously maintained at 4 °C until the time of testing.

(3) Bulk mud samples shall be thoroughly mixed in the laboratory by using a 1,000-rpm high-shear mixer and then subdivided into individual, small wide-mouthed (e.g., one- or two-liter non-contaminating containers for storage.

(4) The drilling muds stored in the laboratory shall have any excess air removed by flushing the storage containers with nitrogen any time the containers are opened. Moreover, the sample in any container opened for testing must be thoroughly stirred by using a 1,000-rpm high-shear mixer prior to use.

(5) Most drilling mud samples may be stored for periods of time longer than 2 weeks prior to toxicity testing, provided that proper containers are used and proper conditions are maintained.

II. Suspended Particulate Phase Sample Preparation

(1) Mud samples that have been stored under specified conditions in this protocol shall be prepared for tests within three months after collection. The SPP shall be prepared as detailed below.

II-A Apparatus

- The following items are required:
 - Magnetic stir plates and bars.
 - Several graduated cylinders, ranging in volume from 10 mL to 1L.
 - Large (15-cm) powder funnels.
 - Several 2-L graduated cylinders.
 - Several 2-L large mouth graduated Erlenmeyer flasks.

(2) Prior to use, all glassware shall be thoroughly cleaned. Wash all glassware with detergent, rinse five times with tap water, rinse once with acetone, rinse several times with distilled or deionized water, place in a clean 10-percent (or stronger) HCl acid bath for a minimum of 4 hours, rinse five times with tap water, and then rinse five times with distilled or deionized water. For test samples containing mineral oil or diesel oil, glassware should be washed with petroleum ether to assure removal of all residual oil.

Note.—If the glassware with nytex cups soaks in the acid solution longer than 24 hours, then an equally long deionized water soak should be performed.

II-B. Test Seawater Sample Preparation

(1) Diluent seawater and exposure seawater samples are prepared by filtration through a 1.0-micrometer filter prior to analysis.

(2) Artificial seawater may be used as long as the seawater has been prepared by standard methods or ASTM methods, has been properly "seasoned," filtered, and has been diluted with distilled water to the same specified 20±2ppt salinity and 20±2°C temperature as the natural seawater.

II-C. Sample Preparation

(1) The pH of the mud shall be measured before use. If the pH is less than 9, if black spots appear on the walls of the sample container, or if the mud sample has a foul odor, that sample shall be discarded. Subsample a manageable aliquot of drill mud from the well-mixed original sample. Mix the mud and filtered test seawater in a volumetric mud-to-water ratio of 1 to 9. This is best done by the method of volumetric displacement in a 2-L, large mouth, graduated Erlenmeyer flask. Place 1,000 mL of seawater into the graduated Erlenmeyer flask. The mud subsample is then carefully added funnel to obtain a total volume of 1,200 mL. (A 200-mL volume of mud will now be in the flask).

The 2-L, large mouth, graduated Erlenmeyer flask is then filled to the 2,000 mL mark with 800 mL of seawater, which produces a slurry with a final ratio of one volume drilling mud to nine volumes water. If the volume of SPP required for testing or analysis exceeds 1,500 to 1,600 mL, the initial volumes should be proportionately increased. Alternatively, several 2-L drill mud/water slurries may be prepared as outlined above and combined to provide sufficient SPP.

(2) Mix this mud/seawater slurry with magnetic stirrers for 5 minutes. Measure the pH and, if necessary, adjust (decrease) the pH of the slurry to within 0.2 units of the seawater by adding 6N HCl while stirring the slurry. Then, allow the slurry to settle for 1 hour. Record the amount of HCl added.

(3) At the end of the settling period, carefully decant (do not siphon) the Suspended Particulate Phase (SPP) into an appropriate container. Decanting the SPP is, one continuous action. In some cases, no clear interface will be present; that is, there will be no solid phase that has settled to the bottom. For those samples the entire SPP solution should be used when preparing test concentrations. However, in those cases when no clear interface is present, the sample must be remixed for five minutes. This insures the homogeneity of the mixture prior to the preparation of the test concentrations. In other cases, there will be samples with two or more phases, including a solid phase. For those samples, carefully and continuously decant the supernatant until the solid phase on the bottom of the flask is reached. The decanted solution is defined to be 100 percent SPP. Any other concentration of SPP refers to a percentage of SPP that is obtained by volumetrically mixing 100 percent SPP with seawater.

(4) SPP samples to be used in toxicity tests shall be mixed for 5 minutes and must not be preserved or stored.

(5) Measure the filterable and unfilterable residue of each SPP prepared for testing. Measure the dissolved oxygen (DO) and pH of the SPP. If the DO is less than 4.9 ppm, aerate the SPP to at least 4.9 ppm which is 65 percent of saturation. Maximum allowable aeration time is 5 minutes using a generic commercial air pump and air stone. Neutralize the pH of the SPP to a pH 7.8±.1 using a dilute HCl solution. If too much acid is added to lower the pH saturated NaOH may be used to raise the pH 7.8±.1 units. Record the amount of acid or NaOH needed

to adjust to the appropriate pH. Three repeated DO and pH measurements are needed to insure homogeneity and stability of the SPP. Preparation of test concentrations may begin after this step is complete.

(6) Add the appropriate volume of 100 percent SPP to the appropriate volume of seawater to obtain the desired SPP concentration. The control is seawater only. Mix all concentrations and the control for 5 minutes by using magnetic stirrers. Record the time; and, measure DO and pH for Day 0. Then, the animals shall be randomly selected and placed in the dishes in order to begin the 96-hour toxicity test.

III. Guidance for Performing Suspended Particulate Phase Toxicity Tests Using *Mysidopsis bahia*

III-A. Apparatus

(1) Items listed by Borthwick¹ are required for each test series, which consists of one set of control and test containers, with three replicates of each.

III-B. Sample Collection Preservation

(1) Drilling muds and water samples are collected and stored, and the suspended particulate phase prepared as described in Section 1-C.

3-C. Species Selection

(1) The suspended particulate phase (SPP) tests on drilling muds shall utilize the test species *Mysidopsis bahia*. Test animals shall be 3 to 6 days old on the first day of exposure. Whatever the source of the animals, collection and handling should be as gentle as possible. Transportation to the laboratory should be in well-aerated water from the animal culture site at the temperature and salinity in which they were cultured. Methods for handling, acclimating, and sizing test organisms given by Borthwick¹ and Nimmo² shall be followed in matters for which no guidance is given here.

III-D. Experimental Conditions

(1) Suspended particulate phase (SPP) tests should be conducted at a salinity of ± 2 ppt. Experimental temperature should be 20 ± 2 °C. Dissolved oxygen in the SPP shall be raised to or maintained above 65 percent of saturation prior to preparation of the test concentrations. Under these conditions of temperature and salinity, 65 percent of saturation is a DO of 5.3 ppm. Beginning at Day 0—before the animals are placed in the test containers DO, temperature, salinity, and pH shall be measured every 24-hours, DO should be reported in milligrams per liter.

(2) Aeration of test media is required during the entire test with a rate estimated to be 50-140 cubic centimeters/minute. This air flow to each test dish may be achieved through polyethylene tubing (0.045-inch inner

diameter and 0.062-inch outer diameter) by a small, generic aquarium pump. The delivery method, surface area of the aeration stone, and flow characteristics shall be documented. All treatments, including control, shall be the same.

(3) Light intensity shall be 1,200 microwatts/cm², using cool white fluorescent bulbs with a 14-hour light and 10-hr dark cycle. This light/dark cycle shall also be maintained during the acclimation period and the test.

III-E. Experimental Procedure

(1) Wash all glassware with detergent, rinse five times with tap water, rinse once with acetone, rinse several times with distilled or deionized water, place in a clean 10 percent HCl acid bath for a minimum of 4 hours, rinse five times with tap water, and then rinse five times with distilled water.

(2) Establish the definitive test concentrations based on the results of a range-finding test. A minimum of five test concentrations plus a control and positive control (reference toxicant) is required for the definitive test. To estimate the LC-50, two concentrations shall be chosen that should give (other than zero and 100 percent) mortality above and below 50 percent.

(3) Twenty organisms are exposed in each test dish. Nytex® cups shall be inserted into every test dish prior to adding the animals. These "nylon mesh screen" holding cups are fabricated by gluing a collar of 363-micrometer mesh nylon screen to a 15-centimeter wide Petri dish with silicone sealant. The nylon screen collar is approximately 5 centimeters high. The animals are placed into the test concentration within the confines of the Nytex® cups.

(4) Individual organisms shall be randomly selected and assigned to treatments. A randomization procedure is presented in Section V of this protocol. Make every attempt to expose animals of approximately equal size. The technique described by Borthwick,¹ or other suitable substitutes, should be used for transferring specimens. Throughout the test period, mysids shall be fed daily with approximately 50 *Artemia* (brine shrimp) nauplii per mysid. This will reduce stress and decrease cannibalism.

(5) Cover the dishes, aerate, and incubate the test containers in an appropriate test chamber. Positioning of the test containers holding various concentrations of test solution should be randomized if incubator arrangement indicates potential position difference. The test medium is not replaced during the 96-hour test.

(6) Observations may be attempted at 4, 6 and 8 hours. They must be attempted at 0, 24, 48, and 72 hours; and, must be made at 96 hours. Attempts at observations refers to placing a test dish on a light table and visually counting the animals. Do not lift the "nylon mesh screen" cup out of the test dish to make the observation. No unnecessary handling of the animals should occur during the 96-hour test period. DO and pH measurements must also be made at 0, 24, 48, 72, and 96 hours. Take and replace the test medium necessary for the DO and pH

measurements outside of the Nytex® cups to minimize stresses on the animals.

(7) At the end of 96 hours, all live animals must be counted. Death is the end point, so the number of living organisms is recorded. Death is determined by lack of spontaneous movement. All crustaceans molt at regular intervals, shedding a complete exoskeleton. Care should be taken not to count an exoskeleton. Dead animals might decompose or be eaten between observations. Therefore, always count living, not dead animals. If daily observations are made, remove dead organisms and molted exoskeletons with a pipette or forceps. Care must be taken not to disturb living organisms and to minimize the amount of liquid withdrawn.

IV. Methods for Positive Control Tests (Reference Toxicant)

(1) Sodium lauryl sulfate (dodecyl sodium sulfate) is used as a reference toxicant for the positive control. The chemical used should be approximately 95 percent pure. The source, lot number, and percent purity shall be reported.

(2) Test methods are those used for the drilling fluid tests, except that the test material was prepared by weighing one gram of sodium lauryl sulfate on an analytical balance, adding the chemical to a 100-milliliter volumetric flask, and bringing the flask to volume with deionized water. After mixing this stock solution, the test mixtures are prepared by adding 0.1 milliliter of the stock solution for each part per million desired to one liter of seawater.

(3) The mixtures are stirred briefly, water quality is measured, animals are added to holding cups, and the test begins. Incubation and monitoring procedures are the same as those for the drilling fluids.

V. Randomization Procedure

V-A. Purpose and Procedure

(1) The purpose of this procedure is to assure that mysids are impartially selected and randomly assigned to six test treatments (five drilling fluid or reference toxicant concentrations and a control) and impartially counted at the end of the 96-hour test. Thus, each test setup, as specified in the randomization procedure, consists of 3 replicates of 20 animals for each of the six treatments, i.e., 360 animals per test. Figure 1 is a flow diagram that depicts the procedure schematically and should be reviewed to understand the over-all operation. The following tasks shall be performed in the order listed.

(2) Mysids are cultured in the laboratory in appropriate units. If mysids are purchased, go to Task 3.

(3) Remove mysids from culture tanks (6, 5, 4, and 3 days before the test will begin, i.e. Tuesday, Wednesday, Thursday, and Friday if the test will begin on Monday) and place them in suitably large maintenance containers so that they can swim about freely and be fed.

Note.—Not every detail (the definition of suitably large containers, for example) is provided here. Training and experience in aquatic animal culture and testing will be required to successfully complete these tests.

¹Borthwick, Patrick W. 1978. Methods for acute static toxicity tests with mysid shrimp (*Mysidopsis bahia*). *Bioassay Procedures for the Ocean Disposal Permit Program*, EPA-600/9-78-010: March.

²Nimmo, D.R., T.L. Hamaker, and C.A. Somers. 1978. Culturing the mysid (*Mysidopsis bahia*) in flowing sea water or a static system. *Bioassay Procedures for the Ocean Disposal Permit Program*, EPA-600/9-78-010: March.

(4) Remove mysids from maintenance containers and place all animals in a single container. The intent is to have a homogeneous test population of mysids of a known age (3-6 days old).

(5) For each toxicity test, assign two suitable containers (500-milliliter (mL) beakers are recommended) for mysid separation/enumeration. Label each container (A1, A2, B1, B2, and C1, C2, for example, if two drilling fluid tests and a reference toxicant test are to be set up on one day). The purpose of this task is to allow the investigator to obtain a close estimate of the number of animals available for testing and to prevent unnecessary crowding of the mysids while they are being counted and assigned to test containers. Transfer the mysids from the large test population container to the labeled separation and enumeration containers but do not place

more than 200 mysids in a 500-mL beaker. Be impartial in transferring the mysids; place approximately equal numbers of animals (10-15 mysids is convenient) in each container in a cyclic manner rather than placing the maximum number in each container at one time.

Note.—It is important that the animals not be unduly stressed during this selection and assignment procedure. Therefore, it will probably be necessary to place all animals (except the batch immediately being assigned to test containers) in mesh cups with flowing seawater or in larger volume containers with aeration. The idea is to provide the animals with near optimal conditions to avoid additional stress.

(6) Place the mysids from the two labeled enumeration containers assigned to a specific test into one or more suitable containers to be used as counting dishes (2-liter Carolina

dishes are suggested). Because of the time required to separate, count, and assign mysids, two or more people may be involved in completing this task. If this is done, two or more counting dishes may be used, but the investigator must make sure that approximately equal numbers of mysids from each labeled container are placed in each counting dish.

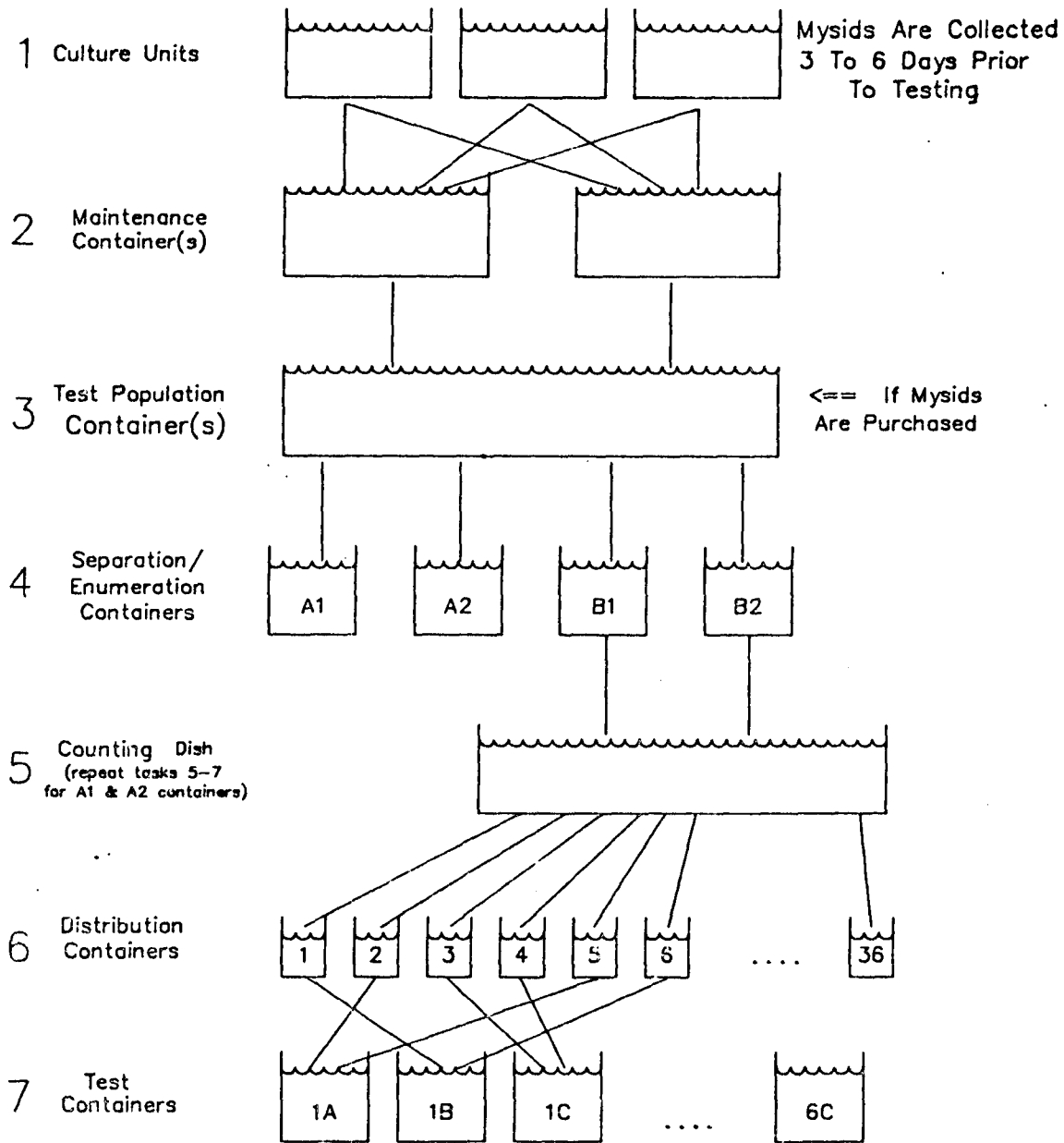
(7) By using a large-bore, smooth-tip glass pipette, select mysids from the counting dish(es) and place them in the 36 individually numbered distribution containers (10-ml beakers are suggested). The mysids are assigned two at a time to the 36 containers by using a randomization schedule similar to the one presented below. At the end of selection/assignment round 1, each container will contain two mysids; and so on until each contains ten mysids.

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Figure 1

Mysid Randomization Procedure

Task



EXAMPLE OF A RANDOMIZATION SCHEDULE

Selection/assignment round (2 mysids each)	Place mysid in the numbered distribution containers in the random order shown
1.....	8, 21, 6, 28, 33, 32, 1, 3, 10, 9, 4, 14, 23, 2, 34, 22, 36, 27, 5, 30, 35, 24, 12, 25, 11, 17, 19, 26, 31, 7, 20, 15, 18, 13, 16, 29
2.....	35, 18, 5, 12, 32, 34, 22, 3, 9, 16, 26, 13, 20, 28, 6, 21, 24, 30, 8, 31, 7, 23, 2, 15, 25, 17, 1, 11, 27, 4, 19, 36, 10, 33, 14, 29
3.....	7, 19, 14, 11, 34, 21, 25, 27, 17, 18, 6, 16, 29, 2, 32, 10, 4, 20, 3, 9, 1, 5, 28, 24, 31, 15, 22, 13, 33, 26, 36, 12, 8, 30, 35, 23
4.....	30, 2, 18, 5, 8, 27, 10, 25, 4, 20, 26, 15, 31, 36, 35, 23, 11, 29, 16, 17, 28, 1, 33, 14, 9, 34, 7, 3, 12, 22, 21, 6, 19, 24, 32, 13
5.....	34, 28, 16, 17, 10, 12, 1, 36, 20, 18, 15, 22, 2, 4, 19, 23, 27, 29, 25, 21, 30, 3, 9, 33, 32, 6, 14, 11, 35, 24, 26, 7, 31, 5, 13, 8

(8) Transfer mysids from the 36 distribution containers to 18 labeled test containers in random order. A label is assigned to each of the three replicates (A, B, C) of the six test concentrations. Count and record the 96 hour response in an impartial order.

(9) Repeat tasks 5-7 for each toxicity test. A new random schedule should be followed in Tasks 6 and 7 for each test.

Note.—If a partial toxicity test is conducted, the procedures described above are appropriate and should be used to prepare the single test concentration and control, along with the reference toxicant test.

V-B. Data Analysis and Interpretation

(1) Complete survival data in all test containers at each observation time shall be presented in tabular form. If greater than 10 percent mortality occurs in the control, the experiment shall be repeated. Unacceptably high control mortality indicates the presence of important stresses on the organisms other than the material being tested, such as injury or disease, stressful physical or chemical conditions in the containers, or improper handling, acclimation, or feeding. If 10 percent mortality or less occurs in the control, the data may be evaluated and reported.

(2) A definitive, full toxicity test conducted according to the EPA protocol is used to estimate the concentration that is lethal to 50 percent of the test organisms that do not die naturally. This toxicity measure is known as the median lethal concentration, or LC-50. The LC-50 is adjusted for natural mortality or natural responsiveness. The maximum likelihood estimation procedure with the adjustments for natural responsiveness as given by D.J. Finney, in *Probit Analysis* 3rd edition, 1971, Cambridge University Press, Chapter 7, can be used to obtain the probit model estimate of the LC-50 and the 95 percent fiducial (confidence) limits for the LC-50. These estimates are obtained by using the logarithmic transform of the concentration. The heterogeneity factor (Finney 1971, pages 70-72) is not used. For a test material to pass the toxicity test according to the requirements stated in the offshore oil and gas extraction industry BAT

regulation, the lower 95 percent limit for the LC-50 adjusted for natural responsiveness must be greater than 3 percent suspended particulate phase (SPP) concentration by volume unadjusted for the 1 to 9 dilution. Other toxicity test models may be used to obtain toxicity estimates provided the modeled mathematical expression for the lethality rate must increase continuously with concentration. The lethality rate is modeled to increase with concentration to reflect an assumed increase with concentration to reflect an assumed increase in toxicity with concentration even though the observed lethality may not increase uniformly because of unpredictable animal response fluctuations.

(3) The range-finding test is used to establish a reasonable set of test concentrations in order to run the definitive test. However, if the lethality rate changes rapidly over a narrow range of concentrations, the range-finding test may be too coarse to establish an adequate set of test concentrations for a definitive test.

(4) The EPA Environmental Research Laboratory in Gulf Breeze, Florida prepared a Research and Development Report titled *Acute Toxicity of Eight Drilling Fluids to Mysid Shrimp (Mysidopsis bahia)*, May 1984 EPA-600/3-84-067. The Gulf Breeze data for drilling fluid number 1 are displayed in Table 1 for purposes of an example of the probit analysis described above. The SAS Probit Procedure (SAS Institute, Statistical Analysis System, Cary, North Carolina, 1982) was used to analyze these data. The 96-hour LC-50 adjusted for the estimated spontaneous mortality rate is 3.3 percent SPP with 95 percent limits of 3.0 and 3.5 percent SPP with the 1 to 9 dilution. The estimated spontaneous mortality rate based on all of the data is 9.6 percent.

TABLE 1.—LISTING OF ACUTE TOXICITY TEST DATA (AUGUST 1983 TO SEPTEMBER 1983) WITH EIGHT GENERIC DRILLING FLUIDS AND MYSID SHRIMP—FLUID N2=1

Percent concentration	Number exposed	Number dead (96 hrs)	Number alive (96 hrs)
0.....	60	3	57
1.....	60	11	49
2.....	60	11	49
3.....	60	25	35
4.....	60	48	12
5.....	60	60	0

V-C. The Partial Toxicity Test for Evaluation of Test Material

(1) A partial test conducted according to EPA protocol can be used economically to demonstrate that a test material passes the toxicity test. The partial test cannot be used to estimate the LC-50 adjusted for natural response.

(2) To conduct a partial test, follow the test protocol for preparation of the test material and organisms. Prepare the control (zero concentration), one test concentration (3 percent suspended particulate phase) and the reference toxicant according to the methods of the full test. A range finding test is not used for the partial test.

(3) Sixty test organisms are used for each test concentration. Find the number of test organisms killed in the control (zero percent SPP) in the column labeled X₀ of Table 2. If the number of test organisms killed in the control (zero percent SPP) exceeds the table values, then the test is unacceptable and must be repeated. If the number of organisms killed in the 3 percent test concentration is less than or equal to corresponding number in the column labeled X₁, then the test material passes the partial toxicity test. Otherwise the test material fails the toxicity test.

TABLE 2.

	X ₀	X ₁
0.....		22
1.....		22
2.....		23
3.....		23
4.....		24
5.....		24
6.....		25

(4) Data shall be reported as percent suspended particulate phase.

6. References

- (1) Borthwick, Patrick W. 1978. Methods for acute static toxicity tests with mysid shrimp (*Mysidopsis bahia*). *Bioassay Procedures for the Ocean Disposal Permit Program*, EPA-600/9-78-010: March.
- (2) Nimmo, D.R., T.L. Hamaker, and C.A. Somers. 1978. Culturing the mysid (*Mysidopsis bahia*) in flowing sea water or a static system. *Bioassay Procedures for the Ocean Disposal Permit Program*, EPA-600/9-78-010: March.
- (3) American Public Health Association et al. 1980. *Standard Methods for the Examination of Water and Wastewater*. Washington, D.C. 15th Edition: 90-99.

Appendix 4—Regulatory Boundaries

New source offshore oil production facilities located in or discharging to the following areas are subject to the zero discharge standard for produced water, depending upon water depth at the location of the facility or discharge. Unless otherwise stated below, the outer boundary for each designated area is the 200-mile boundary of the Fishery Conservation Zone.

(A) Gulf of Mexico—Water Depth 20 Meters or Less

Extending from the inner boundary of the territorial seas of Eastern Texas, Louisiana, Mississippi, Alabama and Western Florida.

(B) Atlantic Coast—Water Depth 20 Meters or Less

Extending from the inner boundary of the territorial seas offshore of the contiguous states between and including Maine and Florida.

(C) California Coast—Water Depth 50 Meters or Less

2. Central and Northern California: Extending offshore of California and bounded on the north by approximately 42° N. latitude and bounded on the south by the U.S.-Mexico boundary.

(D) Alaska

1. Gulf of Alaska—Water Depth 50 meters or less: It is bounded approximately on the west by 151° 55' W. longitude; thence east along 59° N latitude to 148° W longitude; thence south to 58° N latitude; thence east along 58° N latitude to 147° W longitude, thence south.

2. Cook Inlet/Shelikof Strait—Water Depth 50 Meters or Less: Lies east of 156° W. longitude and north of 57° N latitude to the inner boundary of the territorial seas near Kalgin Island.

3. Bristol Bay/Aleutian Range—Water Depth 50 meters or less: (a) North Aleutian Basin: Lies in the eastern Bering Sea northwest of the Alaskan Peninsula and south of 59° N latitude. It is bounded on the

west by 165° W. longitude and on the east by the inner boundary of the territorial seas.

(b) St. George Basin—Water Depth 50 meters or less; Lies in the eastern Bering Sea northwest of the Aleutina Islands chain and is bounded on the north by 59° N latitude and on the west by 174° W longitude from 59° N. latitude to 56° N. latitude; thence east to 171° W. longitude, thence south. It is bounded on the east by 165° W. longitude.

4. Norton Basin—Water Depth 20 meters or less: Lies south and southwest of the Seward Peninsula. It is bounded on the south by 63° N. latitude, on the west by the U.S.-Russia Convention Line of 1867, on the north by 65° 34' N. latitude, and on the east by the inner boundary of the territorial seas.

5. Beaufort Sea—Water Depth 10 meters or less: Lies offshore of Alaska in the Beaufort Sea and the Arctic Ocean. It is bounded on

the west by the Mineral Management Service Chukchi Sea planning area, extends eastward to the limit of U.S. jurisdiction, and on the south by the inner boundary of the territorial seas.

To determine water depth at the facility location, reference the most recent nautical charts or bathymetric maps with the smallest scale (highest resolution) available from the National Oceanic and Atmospheric Administration for the area in question. Water depth is the mean lower low water depth indicated on the appropriate map for the location of the facility or discharge. Water depth at the facility is based upon the proposed location of the facility's well slot structure or produced water discharge point.

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