

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 435

[FRL-5648-4]

RIN 2040-AB72

Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This Clean Water Act (CWA) regulation limits the discharge of pollutants into waters of the United States and the introduction of pollutants into publicly-owned treatment works by existing and new facilities in the coastal subcategory of the oil and gas extraction point source category.

This regulation establishes effluent limitations guidelines and new source performance standards (NSPS) for direct dischargers based on "best practicable control technology currently available" (BPT), "best conventional pollutant control technology" (BCT), "best available technology economically achievable" (BAT), and "best available demonstrated control technology" (BADCT) for new sources. The regulation also establishes "pretreatment standards for new sources" (PSNS) and "pretreatment standards for existing sources" (PSES) discharging their wastewaters to publicly-owned-treatment works (POTWs). In essence, this final rule codifies the current permit requirements for coastal oil and gas dischargers—except that it also requires zero discharge of offshore produced water for discharges to the main passes of the Mississippi River, applies to discharges not currently authorized by permits, and establishes limitations in Cook Inlet, Alaska which are equal to those previously established for the offshore subcategory. The major wastestreams being limited are produced water, drilling fluids, and drill cuttings. These limitations are expected to reduce discharges of conventional pollutants by 2,780,000 pounds per year, nonconventional pollutants by 1,490,000,000 pounds per year, and toxic pollutants by 228,000 pounds per year, assuming a baseline of current permit requirements. The statutory term "toxic pollutant" refers to a substance identified as belonging to one of the 65 families of chemicals listed in the CWA as toxic.

DATES: The regulation shall become effective January 15, 1997, except for § 435.45 NSPS which become effective December 16, 1996.

The compliance dates for the guidelines and standards established with this rule are different. The compliance date for PSES is January 15, 1997. The compliance date for NSPS and PSNS is the date the new source begins operation. Deadlines for compliance with BPT, BCT, and BAT are established in NPDES permits.

In accordance with 40 CFR part 23, this regulation shall be considered issued for the purposes of judicial review at 1 pm Eastern time on January 15, 1997. Under section 509(b)(1) of the CWA, judicial review of this regulation can be had only by filing a petition for review in the United States Court of Appeals within 120 days after the regulation is considered issued for purposes of judicial review. Under section 509(b)(2) of the CWA, the requirements in this regulation may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of January 15, 1997.

ADDRESSES: For additional engineering information contact Mr. Ronald P. Jordan, Office of Water, Engineering and Analysis Division (4303), U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460, (202) 260-7115. For additional information on the economic impact analyses contact Dr. Matthew Clark, Office of Water, Engineering and Analysis Division (4303), U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460, (202) 260-7192.

The complete public record for this rulemaking, including EPA's responses to comments received during rulemaking, is available for review at EPA's Water Docket; Room M2616, 401 M Street SW, Washington, DC 20460. For access to Docket materials call (202) 260-3027. The Docket staff requests that interested parties call, between 9 am and 3:30 pm, for an appointment before visiting the docket. The EPA regulations at 40 CFR part 2 provide that a reasonable fee may be charged for copying.

EPA notes that many documents in the record supporting these final rules have been claimed as confidential business information (CBI) and, therefore, are not included in the record that is available to the public in the

Water Docket. To support the rulemaking, EPA is presenting certain information in aggregated form or is masking facility identities to preserve confidentiality claims. Further, the Agency has withheld from disclosure some data not claimed as confidential business information because release of this information could indirectly reveal information claimed to be confidential.

FOR FURTHER INFORMATION CONTACT: Charles E. White, Office of Water, Engineering and Analysis Division (4303), U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460, (202) 260-5411.

SUPPLEMENTARY INFORMATION:

Regulated Entities

As described in the proposed rule (60 FR 9428, February 17, 1995), EPA has clarified the definition of the Coastal Subcategory in the Coastal Guidelines. This definition is used to describe the regulated entities. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Facilities engaged in field exploration, drilling, production, and well treatment in the oil and gas industry that are in areas defined as "coastal" or that discharge into areas defined as "coastal."

The term "coastal" refers to a location in or on a water of the United States landward of the inner boundary of the territorial seas. Note that all inland bays and wetlands are included in this definition. In addition, any location in Texas or Louisiana between the Chapman Line and the inner boundary of the territorial seas is defined as "coastal." The Chapman Line is defined by points of latitude and longitude within the states of Texas and Louisiana which are stated in the rule.

The preceding table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria § 435.10 and § 435.40 in the Regulatory Text section of the rule. If you have questions regarding the applicability of this action to a particular entity, consult the person

listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Alternative Baseline for Impact and Benefits Analyses

Subsequent to the issuance of general permits requiring zero discharge for coastal facilities along the Gulf of Mexico, EPA received individual permit applications from Texas dischargers seeking to discharge produced water. Additionally, the U.S. Department of Energy has provided the State of Louisiana with comments and analyses suggesting a change to the Louisiana state law requiring zero discharge of produced water to open bays by January 1997. Promulgation of this rule requiring zero discharge in these areas would generally preclude issuance of permits allowing discharge. Therefore, in addition to calculating the costs, economic impacts, and pollutant removals incremental to current permit limits, EPA has calculated an alternative estimate of these factors using an "alternative baseline." This "alternative baseline" assumes that zero discharge would no longer apply to Texas dischargers seeking individual permits and Louisiana open bay dischargers. Under this alternative baseline, this rule would reduce discharges of conventional pollutants by 11,300,000 pounds per year, nonconventional pollutants by 4,590,000,000 pounds per year, and toxic pollutants by 880,000 pounds per year.

Overview

The preamble describes the legal authority, background, technical and economic basis, and other aspects of the final regulation. The definitions, acronyms, and abbreviations used in this notice are defined in appendix A to the preamble. The regulatory text for amendments to 40 CFR part 435, that implements this rulemaking, follows the preamble.

Organization of This Document

Preamble

- I. Legal Authority
- II. Purpose and Summary of this Rulemaking
 - A. Purpose of this Rulemaking
 - B. Summary of the Final Coastal Guidelines
- III. Background
 - A. Definitions of Guidelines and Standards
 - B. Requirements for Promulgating, Reviewing, and Revising Guidelines and Standards
 - C. History of the Rulemaking
- IV. Description of the Industry
- V. Major Changes to the Database for the Final Regulation
 - A. Drilling Fluids and Drill Cuttings

- B. Produced Water
 - VI. Summary of the Most Significant Regulatory Changes From Proposal
 - VII. Basis for the Final Regulation
 - A. Drilling Fluids, Drill Cuttings, and Dewatering Effluent
 - B. Produced Water and Treatment, Workover, and Completion Fluids
 - C. Produced Sand
 - D. Deck Drainage
 - E. Domestic Wastes
 - F. Sanitary Wastes
 - VIII. Economic Analysis
 - A. Introduction
 - B. Economic Impact Methodology
 - C. Summary of Costs and Economic Impacts
 - D. Cost-Effectiveness Analysis
 - IX. Non-Water Quality Environmental Impacts
 - A. Drilling Fluids and Cuttings
 - B. Produced Water and Treatment, Workover and Completion Fluids
 - X. Environmental Benefits Analysis
 - A. Introduction
 - B. Quantitative Estimate of Benefits
 - C. Description of Non-Quantified Benefits
 - XI. Related Acts of Congress, Executive Orders, and Agency Initiatives
 - A. Pollution Prevention Act
 - B. Paperwork Reduction Act
 - C. Regulatory Flexibility Act
 - D. Small Business Regulatory Enforcement Fairness Act of 1996 (Submission to Congress and the General Accounting Office)
 - E. Unfunded Mandates Reform Act
 - F. Executive Order 12866 (OMB Review)
 - G. Common Sense Initiative
 - XII. Related Rulemakings
 - A. National Emission Standards for Hazardous Air Pollutants
 - B. Requirements for Injection Wells
 - C. Spill Prevention, Control, and Countermeasure
 - D. Shore Protection Act Regulations
 - XIII. Summary of Public Participation
 - XIV. Regulatory Implementation
 - A. Toxicity Limitation for Drilling Fluids and Drill Cuttings
 - B. Diesel Prohibition for Drilling Fluids and Drill Cuttings
 - C. Upset and Bypass Provisions
 - D. Variances and Modifications
 - E. Synthetic Drilling Fluids
 - F. Removal Credits for Indirect Dischargers
 - G. Implementation for NPDES Permit Writers
 - XV. Background Documents
- Appendix A to the Preamble—Abbreviations, Acronyms, and Other Terms Used in This Document

I. Legal Authority

This final regulation establishes effluent limitations guidelines and standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category under sections 301, 304, 306, 307, 308, and 501 of the Clean Water Act (CWA), 33 U.S.C. sections 1311, 1314, 1316, 1317, 1318, and 1361. The regulation is also being promulgated pursuant to a Consent Decree entered in *NRDC et al. v. Reilly*, (D D.C. No. 89–

2980, January 31, 1992) and is consistent with EPA's latest Effluent Guidelines Plan under section 304(m) of the CWA. (See 61 FR 52582, October 7, 1996).

II. Purpose and Summary of This Rulemaking

A. Purpose of This Rulemaking

This final rule establishes effluent limitations guidelines and standards for the control of the discharge of pollutants for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. The discharge limitations promulgated today apply to discharges from the coastal oil and gas industry. The processes and operations which comprise the coastal oil and gas subcategory (Standard Industrial Classification (SIC) Major Group 13) are currently regulated under 40 CFR part 435, subpart D. These regulations apply to those facilities engaged in field exploration, development drilling, production, and well treatment in the oil and gas industry that are in areas defined as "coastal." The term "coastal" refers to a location in or on a water of the United States landward of the inner boundary of the territorial seas. In addition, any location in Texas or Louisiana between the Chapman Line and the inner boundary of the territorial seas is defined as "coastal." The Chapman Line is defined by points of latitude and longitude within the states of Texas and Louisiana which are stated in the rule. The final rule promulgated today is referred to as the Coastal Guidelines throughout this preamble.

This preamble highlights key aspects of the Coastal Guidelines. The technology descriptions and economic analyses discussed later in this notice are presented in abbreviated form. More detailed descriptions are included in the *Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*, referred to hereafter as the "Coastal Development Document." EPA's economic impact assessment is presented in detail in the *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category* (hereinafter, "EIA"), included in the rulemaking record. EPA's complete environmental benefits analysis is presented in the *Water Quality Benefits Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory*

of the Oil and Gas Extraction Point Source Category (hereinafter, WQBA), included in the rulemaking record.

B. Summary of the Final Coastal Guidelines

This rule establishes regulations based on "best practicable control technology currently available" (BPT) for one wastestream where BPT did not previously exist, "best conventional pollutant control technology" (BCT), "new source performance standards" (NSPS), "best available technology economically achievable" (BAT), "pretreatment standards for existing sources" (PSES), and "pretreatment standards for new sources" (PSNS).

Drilling fluids, drill cuttings, and dewatering effluent are limited under BCT, BAT, NSPS, PSES, and PSNS. BCT limitations are zero discharge, except for Cook Inlet, Alaska. In Cook Inlet, BCT limitations prohibit discharge of free oil. For both BAT and NSPS, EPA is establishing zero discharge limitations for drilling fluids, drill cuttings, and dewatering effluent except for Cook Inlet. In Cook Inlet, discharge limitations include no discharge of free oil, no discharge of diesel oil, 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation of 30,000 ppm SPP. For both PSES and PSNS, EPA is establishing zero discharge limitations in all coastal subcategory locations.

Produced water and treatment, workover, and completion fluids are limited under BCT, BAT, NSPS, PSES, and PSNS. For BCT, EPA is establishing limitations on the concentration of oil and grease in produced water and treatment, workover, and completion fluids equal to current BPT limits. The Daily Maximum limitation for oil and grease is 72 mg/l and the Monthly Average limitation is 48 mg/l. For BAT and NSPS, EPA is establishing zero discharge limitations, except for Cook Inlet, Alaska. In Cook Inlet, the Daily Maximum limitation for oil and grease is 42 mg/l and the Monthly Average limitation is 29 mg/l. For both PSES and PSNS, EPA is establishing zero discharge limitations.

For produced sand, EPA is establishing zero discharge limitations under BPT, BCT, BAT, NSPS, PSNS, and PSES.

Deck drainage is limited under BCT, BAT, NSPS, PSES, and PSNS. For BCT, BAT, and NSPS, EPA is establishing discharge limitations of no free oil. For PSES and PSNS, EPA is establishing zero discharge limitations.

Domestic waste is limited under BCT, BAT, and NSPS. For BCT, EPA is establishing no discharge of floating

solids or garbage as limitations. For BAT, EPA is establishing no discharge of foam as the limitation. For NSPS, EPA is establishing no discharge of floating solids, foam, or garbage as limitations. There are no PSES and PSNS for domestic waste under the Coastal Guidelines.

Sanitary waste is limited under BCT and NSPS. For BCT and NSPS, sanitary waste effluents from facilities continuously manned by ten or more persons would contain a minimum residual chlorine content of 1 mg/l, with the chlorine level maintained as close to this concentration as possible. Facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons must not discharge floating solids. EPA is establishing no BAT, PSES, or PSNS regulations for sanitary waste under the Coastal Guidelines.

III. Background

The objective of the Clean Water Act is to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters". To that end, it is the national goal that the discharge of pollutants to the nation's waters be eliminated. CWA section 101.

A. Definitions of Guidelines and Standards

To assist in achieving the objective of the CWA, EPA issues effluent limitations guidelines, pretreatment standards, and new source performance standards for industrial dischargers. These guidelines and standards are summarized below:

1. Best Practicable Control Technology Currently Available (BPT)—Sec. 304(b)(1) of the CWA

BPT effluent limitations guidelines apply to discharges of conventional, toxic, and nonconventional pollutants from existing sources. BPT guidelines are generally based on the average of the best existing performance by plants in a category or subcategory. In establishing BPT, EPA considers the cost of achieving effluent reductions in relation to the effluent reduction benefits, the age of equipment and facilities, the processes employed, process changes required, engineering aspects of the control technologies, non-water quality environmental impacts (including energy requirements), and other factors as the Administrator deems appropriate. CWA section 304(b)(1)(B). Where existing performance is uniformly inadequate, BPT may be transferred from a different subcategory or category.

2. Best Conventional Pollutant Control Technology (BCT)—Sec. 304(b)(4) of the CWA

The 1977 amendments to the CWA established BCT as an additional level of control for discharges of conventional pollutants from existing industrial point sources. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that BCT limitations be established in light of a two part "cost-reasonableness" test. EPA published a methodology for the development of BCT limitations which became effective August 22, 1986 (51 FR 24974, July 9, 1986).

Section 304(a)(4) designates the following as conventional pollutants: biochemical oxygen demanding pollutants (measured as BOD₅), total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 FR 44501).

3. Best Available Technology Economically Achievable (BAT)—Sec. 304(b)(2) of the CWA

In general, BAT effluent limitations guidelines represent the best existing economically achievable performance of facilities in the industrial subcategory or category. The CWA establishes BAT as a principal national means of controlling the direct discharge of toxic and nonconventional pollutants. The factors considered in assessing BAT include the age of equipment and facilities involved, the process employed, potential process changes, non-water quality environmental impacts, including energy requirements, and such factors as the Administrator deems appropriate. The Agency retains considerable discretion in assigning the weight to be accorded these factors. An additional statutory factor considered in setting BAT is economic achievability across the subcategory. Generally, the achievability is determined on the basis of total costs to the industrial subcategory and their effect on the overall industry financial health. As with BPT, BAT may be transferred from a different subcategory or category. BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice.

4. Best Available Demonstrated Control Technology For New Sources (BADCT)—Sec. 306 of the CWA

NSPS are based on the best available demonstrated treatment technology and

apply to all pollutants (conventional, nonconventional, and toxic). New facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. Under NSPS, EPA is 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. In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.

5. Pretreatment Standards for Existing Sources (PSES)—Sec. 307(b) of the CWA

PSES are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of publicly-owned treatment works (POTW). The CWA authorizes EPA to establish pretreatment standards for pollutants that pass through POTWs or interfere with treatment processes or sludge disposal methods at POTWs. Pretreatment standards are technology-based and analogous to BAT effluent limitations guidelines.

The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR part 403. Those regulations contain a definition of pass-through that addresses localized rather than national instances of pass-through and establish pretreatment standards that apply to all non-domestic dischargers. See 52 FR 1586, January 14, 1987.

6. Pretreatment Standards for New Sources (PSNS)—Sec. 307(b) of the CWA

Like PSES, PSNS are designed to prevent the discharges of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. PSNS are to be issued at the same time as NSPS. New indirect dischargers have the opportunity to incorporate into their facilities the best available demonstrated technologies. EPA considers the same factors in promulgating PSNS as it considers in promulgating NSPS.

B. Requirements for Promulgating, Reviewing, and Revising Guidelines and Standards

Section 304(m) of the CWA requires EPA to establish schedules for (i) reviewing and revising existing effluent limitations guidelines and standards and (ii) promulgating new effluent guidelines. On January 2, 1990, EPA published an Effluent Guidelines Plan (55 FR 80), in which schedules were established for developing new and revised guidelines for several industry categories, including the coastal oil and gas industry. Natural Resources Defense Council, Inc., challenged the Effluent Guidelines Plan in a suit filed in the U.S. District Court for the District of Columbia, (NRDC *et al.* v. Reilly, Civ. No. 89-2980). On January 31, 1992, the Court entered a consent decree (the "304(m) Decree"), which establishes schedules for, among other things, EPA's proposal and promulgation of effluent guidelines for a number of point source categories, including the Coastal

Oil and Gas Industry. The most recent proposed Effluent Guidelines Plan was published in the Federal Register on October 7, 1996 (61 FR 52582).

C. History of the Rulemaking

EPA promulgated BPT effluent limitations guidelines for all subcategories under the oil and gas point source category on April 13, 1979 (44 FR 22069). Since then, EPA published a notice of information and request for comments on the coastal subcategory on November 8, 1989 (54 FR 46919) and published the proposed Coastal Guidelines on February 17, 1995 (60 FR 9428).

IV. Description of the Industry

Coastal oil and gas activities include field exploration, drilling, production, and well treatment. Coastal activities are located on waters of the United States inland of the inner boundary of the territorial seas. These water bodies include inland lakes, bays and sounds, as well as saline, brackish, and freshwater wetland areas. Although the definition includes waters of the U.S. even in all inland states, EPA knows of no existing operations other than those in certain states bordering the coast. The definition also includes certain wells in Texas and Louisiana between the "Chapman Line" and the inner boundary of the territorial seas as coastal. Thus, at this time, the coastal oil and gas operations are located only in coastal states. Table 1 summarizes the number of producing wells and annual drilling activities for the coastal subcategory.

TABLE 1.—PROFILE OF COASTAL OIL AND GAS INDUSTRY

Coastal location	Region	Number of producing wells (1992)	Number of production facilities (1992)	Annual drilling activity (wells)
Gulf of Mexico	Texas and Louisiana	4675	853	686
	Alabama and Florida	56	¹ ND	7
Alaska	Cook Inlet	237	8	9
	North Slope	2085	12	161
California	Long Beach Harbor	586	4	7
Total	7639	877	870

¹ Not determined.

The primary wastewater sources from the exploration and development phases of the coastal oil and gas extraction industry include the following:

- Drilling fluids
- Drill cuttings
- Sanitary wastes
- Deck drainage
- Domestic wastes

The primary wastewater sources from the production phase of the industry include the following:

- Produced water
- Produced sand
- Well treatment, workover, and completion fluids
- Deck drainage
- Domestic wastes
- Sanitary wastes

Drilling fluids and drill cuttings are the most significant waste streams from exploratory and development operations in terms of volume and pollutants. Produced water is the largest waste stream from production activities in terms of volumes discharged and quantity of pollutants.

Discharges from coastal oil and gas operations in states along the Gulf of

Mexico, California, and Alaska are regulated by general and individual NPDES permits based on BPT, State Water Quality Standards, and on Best Professional Judgment (BPJ) of BCT and BAT levels of control.

A more detailed description of the industry is included in the Coastal Development Document, contained in the record for this rule.

V. Major Changes to the Database for the Final Regulation

This section describes several of the most significant changes which have occurred since proposal to the methodology and data base used to calculate compliance costs, pollutant reductions, and non-water quality environmental impacts. Other changes and issues are discussed in other sections of the preamble, the Development Document, the Economic Impact Analysis, the environmental benefits analysis documents, and the record for this rule.

A. Drilling Fluids and Drill Cuttings

The compliance costs and pollutant removals presented in the Development Document for the proposed rule have been revised to reflect information received from coastal industry operators in response to the proposal. As in the analysis for the proposal, drilling waste compliance cost and pollutant reductions calculations apply only to operations in Cook Inlet, Alaska because the rest of the coastal subcategory is already attaining zero discharge. Since proposal, the industry profile in Cook Inlet has changed, increasing the total waste volume on which costs and removals are based by about 15 percent. In addition, industry-supplied information resulted in changes to particular cost items within the zero discharge analysis.

1. Drilling Projections

EPA's profile of future drilling activity in Cook Inlet is based on information submitted by Cook Inlet operators. In the Development Document for the proposal, EPA identified one operator in the analysis which had recently canceled plans to drill six new wells. This information about the cancellation was received too late to allow for revision of the analysis prior to proposal. EPA has since proposal confirmed that the operator does not intend to drill these wells and they are not included in the revised cost and pollutant reductions analyses for the final rule. EPA received other information in comments on the proposal updating the drilling plans for other operators in Cook Inlet. Compared

to the profile used for the proposal, the total number of new wells at existing platforms anticipated during the seven years following promulgation increased by four and the total number of platforms with drilling schedules decreased by two.

2. Engineering Costs

As was done for the proposal, EPA evaluated two disposal technologies for complying with a zero discharge limitation for drilling fluids and drill cuttings: 1) transport to shore for land disposal; and 2) grinding of the drilling wastes followed by injection in a dedicated disposal well. At proposal, compliance costs were based on an assumption that both land disposal and downhole injection were available technologies for all drilling locations in Cook Inlet. Costs for both compliance technologies were developed for each operator and the lowest cost compliance scenario was selected as the likely cost of the proposed rule. As a result, costs for two operators were based on disposal by injection. In response to comments disputing the feasibility of injecting drilling wastes into the geologic formations present in Cook Inlet, EPA reviewed information in the record and sought additional information on this issue from industry and State and Federal authorities. Based on the limited data available to date, EPA believes that the information in the record indicates that certain sites in Cook Inlet may not be able to inject sufficient volumes of drilling wastes to enable compliance with zero discharge as EPA has defined the technology. See the Development Document and section VII of the preamble for additional information. For the final rule, EPA has based zero discharge compliance costs for all operators on disposal of the drilling wastes at landfills. This is because EPA is unable at this time, with the limited data available, to estimate the degree to which injection would be available in Cook Inlet.

The costing methodologies for the landfill and injection scenarios in the final rule are based, in general, on the costing methodologies presented in the proposal. However, EPA improved the database and sought additional confirmatory data in response to comments on the proposal. Engineering costs have been adjusted from 1992 dollars to 1995 dollars to better reflect the current cost of compliance with zero discharge. Certain changes resulting from EPA's reevaluation of costing assumptions have led to a revision in the cost of landfilling drilling wastes.

In response to comments, EPA reevaluated certain assumptions related

to the use of supply boats and barges in transporting drilling wastes to shore for disposal at landfills. These comments led to a reassessment of platform storage space and boat capacities and resulted in an increase in the number of boat trips required to haul the drilling wastes.

As discussed at proposal, the sole land disposal site for drilling wastes in Cook Inlet (referred herein as the Kustatan landfill) is a private facility owned by two of the operators. While no regulatory obstacles would prohibit disposing of the wastes from other operators at the Kustatan landfill, since it is a private facility its availability for use by third parties cannot be assured. As a result, EPA's analysis considers the Kustatan landfill to be available for use by only two of the operators in the region. Since no other land disposal facilities in Alaska are believed available to the remaining Cook Inlet operators, the analysis for the proposal based land disposal costs for these operators on transporting the drilling wastes to a disposal facility in Idaho. In the preamble for the proposed rule, EPA discussed the availability of another disposal facility located in Oregon and stated that costs using this facility were expected to be "close to or less than the costs of using the Idaho facility." (See 60 FR 9442) Further review of these facilities has shown that savings would in fact be realized using the Oregon facility and it is the disposal site used in the final cost analysis. EPA also revised costing estimates to address industry comments regarding specific fees associated with disposal at the Kustatan landfill.

B. Produced Water

1. Industry Profile

a. Gulf of Mexico. For the analyses performed for the proposed rule, EPA used information provided by industry sources and state regulatory authorities to construct a profile of production facilities currently discharging in coastal areas of the Gulf of Mexico. Under regulations issued by the State of Louisiana, many facilities are required to cease discharges of produced water. Based on the data available to EPA at proposal, EPA estimated that there would be 216 production facilities discharging in the Gulf of Mexico by July 1996 (the original date scheduled for promulgating final Coastal Guidelines). Shortly before the proposal was published, EPA's Region 6 published final NPDES General Permits regulating produced water and produced sand discharges to coastal waters in Louisiana and Texas (60 FR

2387; January 9, 1995). These permits prohibited the discharge of any produced water derived from coastal waters of Louisiana and Texas. Because much of the industry covered by the proposed Coastal Guidelines is also covered by these General Permits, the industry profile used in the cost and economic analyses for the proposed rule overstates the number of facilities that would be incrementally affected by the final Coastal Guidelines. This discrepancy was noted at proposal. In the preamble for the proposed Coastal Guidelines, EPA stated that due to the close proximity (one month) of the timing of the publication of the Region 6 General Permits and the proposed guidelines, the costs and impacts of the proposed Coastal Guidelines was being presented in the preamble as if the General Permits were not final. EPA presented preliminary results of how the costs and impacts of the Coastal Guidelines would be reduced when the General Permits became effective and stated that the regulatory effects of the General Permits would be incorporated in the analysis conducted for the final guidelines. See 60 FR 9430.

The main difference between the general permits and the Coastal Guidelines is that the permits cover wastes generated by onshore Stripper Subcategory wells that are not covered under the Coastal Guidelines and the Louisiana permit does not cover produced water derived from Offshore Subcategory wells that is discharged into a major deltaic pass of the Mississippi River, or to the Atchafalaya River below Morgan City including Wax Lake Outlet. Since proposal, EPA has worked with industry sources and State regulatory authorities to identify those facilities whose discharges are covered by the Coastal Guidelines, but are not covered by General Permits. No facilities discharging Offshore Subcategory produced water into the Atchafalaya River were identified. Six production facilities with a total of eight outfalls were identified as discharging produced water derived from Offshore Subcategory wells into the major deltaic passes of the Mississippi River.

As discussed in the Supplementary Information section of this preamble, subsequent to the issuance of the general permits requiring zero discharge in the Gulf of Mexico region, EPA received individual permit applications from Texas dischargers seeking to discharge produced water. Additionally, the U.S. Department of Energy (DOE) has provided the State of Louisiana with comments and analyses suggesting a change in the Louisiana state law

requiring zero discharge of produced water to open bays by January 1997.

Because promulgation of this rule requiring zero discharge in these areas would preclude issuance of permits allowing discharge, EPA also calculated an alternative estimate of the costs, economic impacts, and pollutant removals under an "alternative baseline." This "alternative baseline" assumes that zero discharge under the general permits would no longer apply to Texas dischargers seeking individual permits and Louisiana open bay dischargers. To do this, EPA reviewed the list of facilities requesting an individual permit in Texas, 82 as of the date of this writing, and identified the number of facilities discharging to open bays using information developed by the State of Louisiana for the DOE study of open bays. EPA obtained all available information about these facilities from the states and EPA's Coastal Questionnaire and used this information to develop estimates of the technological availability, costs and economic achievability, non-water quality environmental impacts, and pollutant removals achieved by zero discharge.

b. Cook Inlet. EPA updated the profile of Cook Inlet production facilities with current hydrocarbon and water production rates to address information submitted by industry in comments. The profile was also updated with current waterflood rates for use in estimating compliance costs under the produced water zero discharge option. The most notable changes to the Cook Inlet production profile include one platform which resumed oil production and ceased waterflooding; two platforms that resumed waterflooding; and one platform substantially reduced its waterflood rate. Production and waterflood levels for the remaining Cook Inlet facilities have not changed significantly since 1993. These profile changes are discussed in detail in the Development Document and the record for the final rule.

2. Engineering Costs

a. Gulf of Mexico. Engineering costs have been adjusted from 1992 dollars to 1995 dollars to better reflect the current cost of compliance with zero discharge. Other than the adjustment to 1995 dollars, no significant changes were made to compliance cost estimates for the improved gas flotation option. The more significant changes to the cost estimates for the zero discharge option are discussed below.

Total labor costs in the final analysis are nearly double the labor costs estimated at proposal. The labor burden

associated with operating additional BAT/NSPS control technologies is unchanged from the analysis for the proposed rule, but the labor rate has been revised upward based on data from Bureau of Labor Statistics. Additional O&M costs were added to reflect the costs of replacing the filter cartridges used to remove solids from the produced water prior to injection.

O&M costs for injection pretreatment chemicals were revised based on new data provided by the industry, in combination with the data used at proposal. Chemicals are already added to the produced water at treatment facilities and source water in waterflooding operations at existing production locations. The treatment chemical costs included in EPA's analysis are costs added incremental to current chemical expenditures. In response to comments about the potential for solids buildup causing downhole problems in injection wells, EPA reviewed the workover data in the record. For the final rule, the frequency of backwashing injection wells was doubled—from biennial to once annually.

Pipeline costs have also been increased since proposal. While reviewing comments regarding pipeline costs, EPA detected a scale up error in the proposal analysis which led to underestimating costs.

In estimating costs, EPA also took into account facility-specific data and comments where it showed discharges were currently capable of meeting limits based on operation of improved gas flotation.

b. Cook Inlet. Other than to adjust costs to 1995 dollars, no significant changes were made to Cook Inlet compliance cost estimates for the limitations based on gas flotation. As at proposal, compliance with zero discharge for the Cook inlet facilities is based on the injection of produced water into production zones as part of the ongoing waterflood operations or into dedicated disposal wells where waterflooding operations do not exist.

In response to concerns raised in industry comments, capital costs for installation of a centrifuge to dewater filtration backwash solids were added to platforms assumed to inject produced water under the zero discharge scenario. Centrifuges would be used to concentrate the solids removed from the filtered produced water, thus allowing the liquid portion of the backwash to be injected. The dewatered solids would then be disposed of by transport to a landfill (as costed by EPA) or injected into a disposal well. This disposal cost

is included as a new O&M cost in the analysis for the final Coastal Guidelines.

O&M costs for treatment chemicals (e.g., scale inhibitors, corrosion inhibitors, biocides) were revised based on industry data. All locations that treat produced water prior to injection under the zero discharge scenario are assumed to incur costs for treatment chemicals. It should be noted that all facilities currently treating produced water for discharge already add some chemicals to enhance separation and provide protection of treatment equipment. Further, all facilities currently waterflooding seawater also add treatment chemicals prior to injection. The treatment chemical costs included in EPA's estimated compliance costs are incremental to current treatment facility and waterflooding chemical expenditures and therefore are considered to adequately address industry concerns about chemical addition costs resulting from injecting produced water into producing formations.

Information in the record indicates that injection well workover costs were underestimated at proposal. Workover costs for the final analysis were increased based on comments from Cook Inlet operators and a comparison to cost data for workovers in the Gulf of Mexico.

3. Pollutant Reduction Estimates

Similar to the February 1995 proposal, pollutant removals for the different produced water regulatory options of the final rule were determined by comparing the estimated effluent levels of pollutants after treatment by the BAT/NSPS treatment system (improved performance of gas flotation or reinjection) versus the effluent levels of pollutants associated with a typical BPT treatment (gravity separation or gas flotation).

In the proposal, EPA characterized BPT treatment in the Gulf of Mexico using data collected from ten coastal oil and gas facilities located in Louisiana and Texas. Comments received subsequent to the proposal stated that the facilities included in the database do not adequately represent the quality of produced water which has undergone BPT-level treatment and, as a result, overestimate the pollutant reductions associated with the BAT/NSPS control options. Several comments also disputed the presence of certain pollutants included in EPA's BPT characterization.

In response to these comments, EPA reassessed the characterization of BPT-level effluent quality. Certain pollutants

were dropped for the final analysis because they are believed to have been measured as a result of laboratory contamination or are otherwise not expected to be present in produced water. In comparison to the total mass of pollutants removed by the technologies evaluated in the BAT/NSPS options, excluding these pollutants had negligible effect on the reductions estimates. The pollutants excluded from the final analysis and the reasons for the exclusion are discussed in the Development Document, the Response to Comments Document, and the record.

Upon review of the data used at proposal, EPA determined that three of the facilities making up the Ten Facility dataset should be excluded from the BPT characterization for the final rule. These facilities had high levels of oil and grease, in excess of that allowed to be discharged under the BPT effluent limitations guidelines, and therefore the pollutant levels at these facilities are not considered representative of produced water which has been treated to a level which would allow discharge to surface waters. (Produced water from these facilities is disposed of through downhole injection.) EPA believes it is appropriate to continue using the effluent data collected from the remaining seven facilities to represent BPT-level pollutant concentrations, even though not all of these facilities actually discharge their produced water, since the treatment technology at these facilities is typical of that used at the majority of coastal facilities and the oil and grease content of the effluent for these facilities was lower than that required to meet the existing BPT effluent limitations. Total oil and grease measurements at these seven facilities range from 8 mg/l to 43 mg/l. When averaged together, the average oil and grease concentration for the seven facilities is 26.6 mg/l, in contrast to an average of 53 mg/l when using data from all ten facilities. EPA notes that this revised calculation of the oil and grease concentration in BPT-level effluent for the coastal subcategory (26.6 mg/l) compares favorably to the BPT-level effluent data (25 mg/l) collected previously for the offshore subcategory. (See Section IX of the *Development Document for Effluent Limitations Guidelines and Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category*, EPA 821-R-93-003, January 1993.) The technology basis used to develop BPT limitations for the coastal subcategory is identical to the basis used to develop the offshore subcategory BPT

limitations. (See the *Development Document for Interim Final Effluent Limitations Guidelines and Proposed New Source Performance Standards for the Oil and Gas Extraction Point Source Category*, EPA 440/1-76/055a, September 1976.)

EPA also took into account facility-specific data and comments where it showed discharges were currently capable of meeting limits based on operation of improved gas flotation in assessing pollutant reductions estimates.

VI. Summary of the Most Significant Regulatory Changes From Proposal

This section briefly identifies the most significant changes from proposal. More detailed discussion of these changes, and identification and discussion of other issues are included in other sections of this notice, the Coastal Development Document, the Economic Impact Analysis, and the record for this rule. The most significant changes from proposal occurred with regards to: (1) Drilling fluids, drill cuttings, and dewatering effluent and (2) produced water and treatment, workover, and completion fluids.

For drilling fluids, drill cuttings, and dewatering effluent, EPA proposed three options for both BAT and NSPS limitations. The three options were: (1) Zero discharge of drilling fluids, drill cuttings, and dewatering effluent except for Cook Inlet, where discharge limitations include no discharge of free oil, no discharge of diesel oil, 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation of 30,000 ppm SPP; (2) Zero discharge of drilling fluids, drill cuttings, and dewatering effluent except for Cook Inlet, where discharge limitations include no discharge of free oil, no discharge of diesel oil, both 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation more stringent than 30,000 ppm SPP; and (3) Zero discharge everywhere. For both BAT and NSPS, option (1) has been selected for the final rule.

For produced water and treatment, workover, and completion fluids, EPA proposed zero discharge everywhere for NSPS. For the final rule, NSPS limitations are zero discharge except for Cook Inlet, Alaska. In Cook Inlet, the Daily Maximum limitation for oil and grease is 42 mg/l and the Monthly Average limitation is 29 mg/l.

VII. Basis for the Final Regulation

A. Drilling Fluids, Drill Cuttings, and Dewatering Effluent

1. Waste Characterization

Drilling fluids and drill cuttings are typically discharged in bulk during episodes that occur intermittently during well drilling and at the end of the drilling phase.

There are currently no drilling fluid or drill cuttings discharges in any coastal area except for Alaska's Cook Inlet. Zero discharge is generally met by a combination of landfilling and injection. On Alaska's North Slope, while all drilling fluids and most drill cuttings are injected, some cuttings are cleaned and used as fill material in the construction of drill pads and roads. These fill materials require a fill permit issued pursuant to section 404 of the CWA.

In Cook Inlet, operators do not currently practice zero discharge, except for a small volume of drilling fluids and cuttings wastes (approximately one percent) which are not discharged because they do not meet current permit limits. Generally, drilling fluids and cuttings volumes average approximately 14,000 barrels (bbl) per new well drilled in Cook Inlet. (NOTE: The barrel is a standard oil and gas measurement and is equal in volume to 42 gallons). Based on industry projections given to EPA, an average of 89,000 bbls drilling fluids and cuttings are generated each year (bpy) in the Inlet. Pollutants present in these wastes include chromium, copper, lead, nickel, selenium, silver, beryllium and arsenic among the toxic metals. Toxic organics present include naphthalene, fluorene, and phenanthrene. Total Suspended Solids (TSS) make up the bulk of the pollutant loadings, part of which is comprised of the above mentioned toxic pollutants. TSS concentrations are very high due to the nature of the wastes.

Operators use solids control equipment to remove drill cuttings from the drilling fluid systems which allows drilling fluids to be recycled and reduces the total amount of drilling wastes generated. Depending on the solids control system and the method of waste storage and disposal onsite, a small wastestream, termed "dewatering effluent" may be segregated from the drilling fluids and cuttings. Dewatering effluent may be discharged from reserve pits or tanks which store drilling wastes for reuse or disposal. Dewatering effluent may also be generated in enhanced solids control systems. Enhanced solids control systems, also known as closed-loop solids control

operations, remove solids from the drilling fluid at greater efficiencies than conventional solids removal systems. Increased solids removal efficiency minimizes the buildup of drilled solids in the drilling fluid system, and allows a greater percentage of drilling fluid to be recycled. Smaller volumes of new or freshly made fluids are required as a result. An added benefit of the closed-loop technology is that the amount of waste drilling fluids can be significantly reduced. The installation of reserve pits is unnecessary in closed-loop systems for this reason.

EPA's general permits for drilling operations in Texas and Louisiana (58 FR 49126, September 21, 1993) have limitations for the discharge of dewatering effluent, while other parts of the nation generally treat dewatering effluent as part of the drilling fluids wastestream. However, results from the 1993 Coastal Oil and Gas Questionnaire show that few operators discharge dewatering effluent as a separate wastestream. Additionally, contacts with industry indicate that the volume of dewatering effluent from reserve pits is small and growing smaller since the use of pits is phasing out due to state permit conditions, environmental or land owner concern, and the expanding use of closed-loop systems. EPA site visits to drilling operations, where these closed-loop systems were in place, showed that none of the dewatering effluent is discharged. Instead, it is either recycled, or sent with other drilling wastes to commercial disposal. Operators at these facilities explained that it is less expensive to send this wastestream along with drilling fluids and drill cuttings for onshore disposal rather than to treat for discharge.

2. Selection of Pollutant Parameters

a. Pollutants Regulated. EPA is establishing BAT, BCT, NSPS, PSES, and PSNS limitations that would require zero discharge of drilling fluids, drill cuttings, and dewatering effluent, except for BAT, BCT, and NSPS in Cook Inlet, Alaska. Where zero discharge is required, EPA would be controlling all pollutants in the wastestream.

For BAT and NSPS in Cook Inlet, discharge limitations for drilling fluids, drill cuttings, and dewatering effluent include no discharge of free oil, no discharge of diesel oil, 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation of 30,000 ppm SPP.

As presented in the Coastal Development Document, the prohibitions on the discharge of free oil and diesel oil would effectively remove toxic, nonconventional, and

conventional pollutants. Diesel oil and free oil are considered, under BAT and NSPS, to be "indicators" for the control of specific toxic pollutants present in the complex hydrocarbon mixtures used in drilling fluid systems. Free oil is also an indicator for toxic pollutants present in crude oil. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. Additionally, diesel oil may contain from 20 to 60 percent by volume polynuclear aromatic hydrocarbons (PAHs) which constitute the more toxic components of petroleum products. Control of diesel oil would also result in the control of nonconventional pollutants under BAT and NSPS. Diesel oil contains a number of nonconventional pollutants, including PAHs such as methylnaphthalene, methylphenanthrene, and other alkylated forms of the listed organic toxic pollutants.

EPA is establishing BCT limitations for drilling fluids, drill cuttings, and dewatering effluent that prohibit the discharge of free oil (using the static sheen test) for Cook Inlet. The prohibition on the discharge of free oil would effectively reduce or eliminate the oil and grease in these discharges. EPA is limiting free oil under BCT as a surrogate for oil and grease in recognition of the complex nature of the oils present in drilling fluids, including crude oil from the formation being drilled.

For Cook Inlet, prohibiting the discharge of diesel oil and free oil eliminates discharges of the above listed constituents, to the extent that these constituents are present in either of these two parameters, and reduces the level of oil and grease present in the discharged drilling fluids and cuttings. Also, limitations on cadmium and mercury content in barite will control toxic and nonconventional pollutants in drilling waste discharges. This limitation directly controls the levels of cadmium and mercury, and indirectly controls the levels of other toxic pollutant metals. Control of other toxic pollutant metals occurs because cleaner barite that meets the mercury and cadmium limits has been shown to have reduced concentrations of other metals. Evaluation of the relationship between cadmium and mercury and the trace metals in barite shows a correlation between the concentration of mercury with the concentration of arsenic, chromium, copper, lead, molybdenum, sodium, tin, titanium and zinc; and the concentration of cadmium with the concentration of arsenic, boron, calcium, sodium, tin, titanium, and

zinc. (See the Coastal Development Document).

Toxicity of drilling fluids, drill cuttings, and dewatering effluent is being regulated as a nonconventional pollutant that controls certain toxic and nonconventional pollutants. It was shown, during EPA's development of the Offshore Guidelines, that control of toxicity encourages the use of less toxic, water-based drilling fluids, and where absolutely necessary, the use of less mineral oil added to a drilling fluid (and the pollutants, such as the PAH's, identified as constituents of mineral oil). A toxicity limitation thus encourages the use of low-toxicity drilling fluids and the use of low-toxicity drilling fluid additives.

b. Pollutants Not Regulated. Where zero discharge is required, all pollutants are controlled. In Cook Inlet, EPA has determined that it is not technically feasible to specifically control each of the toxic constituents of drilling fluids and cuttings that are controlled by the limits on the pollutants established in this regulation.

EPA has determined that certain of the toxic and nonconventional pollutants are not controlled by the limitations on diesel oil, free oil, toxicity, and mercury and cadmium in stock barite. EPA exercised its discretion not to regulate these pollutants because EPA did not detect these pollutants in more than a very few of the samples from EPA's field sampling program and does not believe them to be found throughout the industry; the pollutants when found are present in trace amounts not likely to cause toxic effects; and due to the large number and variation in additives or specialty chemicals that are only used intermittently and at a variety of drilling locations, it is not feasible to set limitations on specific compounds contained in additives or specialty chemicals. See the Coastal Development Document for further discussion.

3. Control and Treatment Technologies

a. Current Practice. BPT effluent limitations guidelines for coastal drilling fluids and drill cuttings prohibit the discharge of free oil (using the visual sheen test). However, because of either EPA general and individual permits, state requirements, or operational preference, no drilling fluids and cuttings discharges are occurring in the coastal waters of the Gulf coast states or California. The only coastal operators disposing of drilling fluids and drill cuttings by discharge are located in Cook Inlet. In Cook Inlet, neither diesel nor mineral-oil-based drilling fluids or resultant cuttings may be discharged to

surface waters. Compliance with the BPT limitations may be achieved either by product substitution (substituting a water-based fluid for an oil-based fluid), recycle and/or reuse of the drilling fluid, onshore disposal of the drilling fluids and cuttings at an approved facility, or disposal by injection where feasible. On Alaska's North Slope, all drilling fluids and most drill cuttings are injected, though some cuttings are cleaned for use as fill material for the construction of drilling pads and roads. This fill activity is regulated under section 404 of the CWA.

NPDES permits issued by EPA for Cook Inlet drilling operations have also included BAT limitations based on "best professional judgement" (BPJ). The permit requirements allow discharges of drilling fluids and drill cuttings provided certain limitations are met including a prohibition on the discharges of free oil and diesel oil, as well as limitations on mercury, cadmium, toxicity and oil content. Operators in Cook Inlet typically employ the following waste management practices to meet those permit limitations:

- * Product substitution—to meet prohibitions on free oil and diesel oil discharges, as well as the toxicity and/or clean barite limitations,

- * Onshore treatment and/or disposal of drilling fluids and drill cuttings that do not meet the toxicity limitations,

- * Waste minimization—enhanced solids control to reduce the overall volume of drilling fluids and drill cuttings, and

- * Conservation and recycling/reuse of drilling fluids.

Refer to the Coastal Development Document for a detailed discussion of each of these waste management techniques.

b. Additional Technologies Considered. EPA has evaluated an additional method for drilling fluid, drill cuttings, and dewatering effluent control and treatment in order to achieve zero discharge: namely, grinding and injection of drilling wastes. This process involves the grinding of the drilling fluids, drill cuttings, and dewatering effluent into a slurry that can be injected into a dedicated disposal well. The grinding system consists of a vibrating or rotating ball mill which pulverizes the cuttings and creates an injectable slurry. This comparatively contemporary technology has been successfully demonstrated on the North Slope, and has been used to a limited degree on the Gulf Coast. While injection has been demonstrated in other parts of the U.S., injection has

not been demonstrated in Cook Inlet. EPA believes that the ability to inject is related to the subsurface conditions of the receiving formations. While the geology of the formations in areas other than Cook Inlet have been favorable to injection of drilling fluids and drill cuttings, the record indicates that geology amenable to grinding and injection does not appear to occur throughout Cook Inlet.

In addition to grinding and injection, EPA has investigated the feasibility of onshore disposal for this wastestream. For the coastal subcategory drilling activities, in areas other than Cook Inlet, current permits require zero discharge of drilling fluids and cuttings or, in the case of the North Slope, zero discharge of drilling fluids, and drill cuttings except where drill cuttings are reused as a fill material. The fill activity is regulated under section 404 of the CWA. On-land disposal or downhole injection sites are available in these areas and are being utilized to comply with the zero discharge requirement.

With respect to onshore disposal capacity, on-land disposal sites are available to two of the Cook Inlet operators. These two operators jointly own an oil and gas landfill disposal site on the west side of the Inlet. Unfortunately, no on-land oil and gas waste disposal facilities are available in Alaska to the other Cook Inlet operators who plan to drill after promulgation of this rule. Therefore, EPA has estimated the costs for disposing of drilling wastes at an on-land oil and gas waste disposal site in Oregon.

Also with regard to zero discharge, EPA received information from operators concerned that compliance with zero discharge could significantly interfere with drilling operations. EPA has investigated the significant logistical difficulties and operational problems presented by storing and transporting drilling wastes in the Cook Inlet, due to the space constraints, combined with the extensive tidal fluctuations, strong currents, and ice formation during winter months. Also, EPA has taken into consideration supplementary costs incurred by additional winter transportation and storage of drilling wastes in its cost evaluation of the zero discharge option as described below.

In addition to zero discharge, EPA considered allowing the discharge of the drilling fluids, drill cuttings, and dewatering effluent in Cook Inlet providing the discharge met certain limitations. These limitations would prohibit the discharge of diesel oil and free oil using the static sheen test, limit cadmium and mercury in the stock barite used in fluid compositions, and

limit toxicity at either 30,000 ppm (SPP) or a more stringent toxicity in range of 100,000 ppm (SPP) to 1 million ppm (SPP). (The measure of toxicity is a 96 hour test that estimates the concentration of suspended particulate phase (SPP) from a drilling fluid that is lethal to 50 percent of the tested organisms. See 40 CFR part 435, subpart A, appendix 2). Drilling fluids and drill cuttings not meeting these limitations would not be allowed to be discharged, and therefore, would have to be injected or sent to shore for disposal.

As discussed above, one option at proposal would have retained the offshore limitations but required a more stringent toxicity limit. At proposal, EPA based the more stringent toxicity limitations, in part, on the volume of drilling wastes that could be injected or disposed of onshore without interfering with ongoing drilling operations. The more stringent toxicity limit would have been based on (1) the volume of drilling wastes that could be subjected to zero discharge without interfering with ongoing drilling operations and (2) a specified level of toxicity selected such that no more than this volume of waste, determined in the previous step, would exceed the specified level of toxicity. However, as pointed out in comments on the proposal and confirmed with further investigation, there are a number of problems with the database that would be used to establish a more stringent toxicity limitation. Many of the records in the database do not have either a waste volume identified or indicate whether the drilling fluids were discharged. Where waste volumes are reported, the methods used to determine these volumes are not consistent and they are not documented. It is also unclear whether the volumes and fluid systems reported for any given well represent a complete record of the drilling activity associated with the well. For these reasons, EPA rejected the option of developing a more stringent toxicity limitation for the final rule.

4. BAT and NSPS Options

For final consideration, EPA developed two options for the BAT and NSPS level of control for drilling fluids and drill cuttings. Limitations for the dewatering effluent are the same as those for drilling fluids and drill cuttings.

Option 1 would require zero discharge of drilling fluids, drill cuttings, and dewatering effluent for all coastal drilling operations except those located in Cook Inlet. Allowable discharge limitations for drilling fluids and cuttings in Cook Inlet would require compliance with a toxicity value of no

less than 30,000 ppm (SPP); no discharge of free oil (as determined by the static sheen test); no discharge of diesel oil and 1 mg/kg of mercury and 3 mg/kg of cadmium in the stock barite. Limitations for Cook Inlet are identical to the limitations applicable to offshore discharges in Alaska. Option 1 was developed taking into consideration that Cook Inlet operations are unique to the industry due to a combination of geology available for grinding and injection, climate, transportation logistics, and structural and space limitations that interfere with drilling operations.

Option 2 would prohibit the discharge of drilling fluids, drill cuttings, and dewatering effluent from all coastal oil and gas drilling operations. In Cook Inlet, this option uses onshore disposal as a basis for complying with zero discharge of drilling fluids and drill cuttings. Outside of Cook Inlet, this option uses a combination of grinding and injection and onshore disposal as a basis for complying with zero discharge of drilling fluids and drill cuttings.

a. Costs. Operators would not incur any costs under Option 1 because the requirements reflect current practice.

Costs to comply with Option 2 (zero discharge all) are attributed only to Cook Inlet operators (North Slope operators are beneficially reusing a portion of their drill cuttings and all other coastal operators are already practicing zero discharge). Costs to comply with this option are estimated to be approximately \$8,200,000 annually for the Cook Inlet operators. The basis for this cost analysis is that drilling fluids and drill cuttings generated in Cook Inlet would be hauled to shore for disposal. Costs for land disposal include water vessel transportation, storage prior to transport to the disposal facility, truck transportation to the disposal facility, and landfill disposal costs. While it was evaluated, grinding and injection is not used in the cost basis for Cook Inlet because, as mentioned earlier, geology amenable to grinding and injection does not appear to occur throughout Cook Inlet.

To determine the volume of drilling wastes requiring disposal, EPA obtained the projected drilling schedules for the Cook Inlet operators using information from the 1993 Coastal Oil and Gas Questionnaire and contacts with industry. Using information about the volume of drilling fluids and drill cuttings generated per well, and the projected amount of drilling over the seven years following scheduled promulgation, EPA estimates that the total amount of drilling fluids and drill cuttings annually generated from these

drilling operations will be approximately 89,000 barrels.

EPA also considered the logistical difficulties of transporting drilling wastes in Cook Inlet as part of EPA's costing analysis of the options. To achieve zero discharge, platforms would transport drilling wastes to the eastern side of Cook Inlet by supply boat, then: (1) Transfer the wastes to barges for transport to an existing landfill facility on the west side of the Inlet or (2) load these wastes onto trucks for transport to landfill disposal in Oregon. During periods of extensive ice floes, the drilling wastes are stored on the east side of the Inlet for extended periods of time.

For new sources, EPA expects that the costs of complying with NSPS would be equal to or less than those for existing sources. Note that, due to the high cost of installing new sources and the low expectation of return, EPA does not expect new sources to be installed in Cook Inlet independent of any new environmental regulations.

EPA also analyzed non-water quality environmental impacts for BAT and NSPS. These impacts are discussed in Section IX of the preamble.

b. BAT and NSPS Option Selection. For both BAT and NSPS control of drilling fluids, drill cuttings and dewatering effluent, EPA is establishing zero discharge limitations, except for Cook Inlet. In Cook Inlet, discharge limitations include no discharge of free oil, no discharge of diesel oil, both 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation of 30,000 ppm SPP. BAT limitations for dewatering effluent are applicable prospectively. BAT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

With regard to coastal facilities outside of Cook Inlet, zero discharge is technically and economically achievable and has acceptable non-water quality environmental impacts because it reflects current industry practices under existing permit requirements.

With regard to coastal facilities in Cook Inlet, EPA rejected zero discharge in large part because the technology of grinding and injection has not been demonstrated to be available throughout Cook Inlet. Drilling fluids and drill cuttings cannot be injected into producing formations, as is sometimes the case for produced water, because

they would interfere with hydrocarbon recovery. Thus, operators must have available different formation zones with appropriate characteristics (e.g., porosity and permeability) for injection of drilling fluids and drill cuttings. See the Coastal Development Document for discussion of geologic characteristics for the injection of these drilling wastes. Unlike the coastal region along the Gulf of Mexico or the North Slope of Alaska, where the subsurface geology is relatively porous and formations for injection are readily available, the geology in Cook Inlet is highly fragmented and information in the record indicates that formations for injection may be not available throughout Cook Inlet. EPA reviewed information where attempts to grind and inject drilling fluids and drill cuttings failed in the Cook Inlet area. For example, one operator attempted to operate a grinding and injection well in the Kenai gas field failed due to downhole mechanical failure of the injection well (1992/1993). There, the well experienced abnormal pressure on the well annulus, necessitating shutdown of the disposal operation. The operator also attempted annular pumping of drilling fluids and drill cuttings in two production wells in the Ivan River Field (onshore on the west side of Cook Inlet) where the annuli of both wells plugged during injection. Another operator, attempting to pump drilling waste into the annuli of exploration wells, lost the integrity of the well.

Because not all of the drilling fluids and drill cuttings can be injected, much of the waste would have to be land disposed. All but two of the operators would likely have to transport their drilling fluids and drill cuttings to a disposal facility out of state; the two other operators privately own the only drilling waste land disposal facility near Cook Inlet. (EPA is unaware of any other onshore disposal facilities coming into existence, as Cook Inlet is a fairly mature field nearing the end of its useful life. All but one of the existing platforms were installed in the 1960s. The newest platform began production in 1987, but production from the facility has remained well below expectations.) Land disposal is a problem for Cook Inlet operators, analogous to those faced by offshore operators in Alaska, because the climate and safety conditions that exist during parts of the year in Cook Inlet make transportation of drilling fluids and drill cuttings particularly difficult and hazardous. The harsh climate, snow, ice, and poor visibility from fog and snow often restrict land

and sea transportation. Also, the extensive tidal fluctuations (frequently in excess of 30 feet), strong currents, and ice formation during winter months in the Inlet impose severe logistical difficulties for storing and transporting the drilling wastes. Moreover, the limited storage space on platforms and transportation-related difficulties and delays associated with a zero discharge limitation for all drilling wastes would impose severe operational constraints on drilling activities. Thus, for purposes for BAT and NSPS, EPA does not believe that land disposal of all drilling wastes is generally available for Cook Inlet operators.

There are non-water quality environmental impacts associated with such transportation and land disposal. For BAT, EPA estimates that zero discharge would result in 5,200 Barrel of Oil Equivalents (BOE) of fuel being used annually, resulting in 36 tons or 72,000 pounds of air emissions to move the waste from Cook Inlet to Oregon and sites near Cook Inlet. While EPA believes the non-water quality environmental impacts—in and of themselves—are not unacceptable, by comparison with the operational constraints discussed above and pollutants removed by zero discharge, 4,300 pounds of toxic pollutants annually, these non-water quality environmental impacts weigh against requiring zero discharge in Cook Inlet.

Again, for NSPS control of drilling fluids, drill cuttings, and dewatering effluent, EPA is establishing zero discharge limitations, except for Cook Inlet. In Cook Inlet, discharge limitations include no discharge of free oil, no discharge of diesel oil, both 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation of 30,000 ppm SPP. Both inside and outside of Cook Inlet, these NSPS limitations are technically and economically achievable and has acceptable non-water quality environmental impacts because they reflect current practice. With regard to the potential for a barrier to entry, NSPS are equal to BAT limitations. BAT limitations have been demonstrated to be economically achievable for existing structures. Design and construction of pollution control equipment on new production facilities is generally less expensive than retrofitting existing facilities. Therefore, while the NSPS are equal to BAT limitations, it is less costly for new structures to meet these requirements and these costs would not inhibit development of new sources.

5. BCT

a. BCT Cost Test Methodology. EPA establishes BCT limitations based on a methodology which became effective August 22, 1986 (51 FR 24974, July 9, 1986). This methodology compares the costs of conventional pollutant removal under BCT with the cost of conventional pollutant removal at a publicly owned treatment works (POTW). A description of this methodology is contained in the preamble to the proposed rule (60 FR 9428, 9444) and the Coastal Development Document. If all options fail either of the two tests, then BCT limitations must be set at a level equal to BPT limitations.

b. BCT Costs Test Calculations and Options Selection. (i) Coastal Subcategory Except for Cook Inlet. Because all operators throughout the coastal subcategory, except in Cook Inlet, are currently practicing zero discharge of drilling fluids and drill cuttings and dewatering effluent, zero discharge was the only option considered. There is zero cost for this limitation. Thus, EPA determined that zero discharge passes the BCT cost tests and is the appropriate BCT limitation for this wastestream. BCT limitations for dewatering effluent are applicable prospectively. BCT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

(ii) Cook Inlet. EPA considered two BCT options for Cook Inlet: BPT limitations (no free oil) or zero discharge. BCT limits in the final rule are established equal to BPT. Although zero discharge was determined to be not available in Cook Inlet, the BCT cost test was calculated to show whether such a limitation would have passed the cost test. EPA determined that zero discharge limitations would not have passed the BCT cost test. Costs, pollutant reductions, and the results of the BCT cost test are presented in detail in the Coastal Development Document. BCT limitations for dewatering effluent are applicable prospectively. BCT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

6. PSES and PSNS

Section 307 of the CWA authorizes EPA to develop pretreatment standards for existing sources (PSES) and new sources (PSNS). Pretreatment standards are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. The pretreatment standards for existing sources are to be technology based and analogous to the best available technology economically achievable (BAT) for direct dischargers. The pretreatment standards for new sources are to be technology-based and analogous to the best available demonstrated control technology used to determine NSPS for direct dischargers. New indirect discharging facilities, like new direct discharging facilities, have the opportunity to incorporate the best available demonstrated technologies, including process changes, and in-plant controls, and end-of-pipe treatment technologies. EPA determines which pollutants to regulate in PSES and PSNS on the basis of whether or not they pass through, interfere with, or are incompatible with the operation of POTWs.

Based on comments, the 1993 Coastal Oil and Gas Questionnaire, and other information reviewed as part of this rulemaking, EPA has not identified any existing coastal oil and gas facilities which discharge drilling fluids, drill cuttings, or dewatering effluent to POTW's, nor are any new facilities projected to direct these wastes in such manner. However, due to the high solids content of drilling fluids and drill cuttings, EPA is establishing pretreatment standards for existing and new sources equal to zero discharge because these wastes would interfere with POTW operations. For further discussion, see the Coastal Development Document. For PSNS, zero discharge would not cause a barrier to entry, as further discussed in the Economic Impact Analysis.

B. Produced Water and Treatment, Workover, and Completion Fluids

At proposal, produced water was discussed and analyzed separately from treatment, workover, and completion fluids (TWC). However, EPA also proposed that discharge limitations for TWC be set equal to discharge limitations for produced water. As stated at that time, based on responses to the 1993 Coastal Oil and Gas Questionnaire and EPA's Region 10 Discharge Monitoring Reports, the typical industry practice is to combine produced water with treatment,

workover, and completion fluids for purposes of wastewater treatment. Because the treatment technologies for these wastestreams are linked, EPA has combined these wastestreams in the final rule for purposes of discussion.

1. Waste Characterization

Produced water is brought to the surface during the oil and gas extraction process and can include: formation water extracted along with oil and gas; injection water used for secondary oil recovery that has broken through the formation and mixed with the extracted hydrocarbons; and various well treatment chemicals added during the production and oil/water separation processes. Produced water is the highest volume waste in the coastal oil and gas industry. Depending on the age of a well and site-specific formation characteristics, the produced water can constitute between 2 percent and 98 percent of the gross fluid production at a particular well. Generally, in the early production phase of a well the produced water volume is relatively small and the hydrocarbon production makes up the bulk of the fluid. Over time, the formation approaches hydrocarbon depletion and the produced water volume usually exceeds the hydrocarbon production. Based on information received in the 1993 Coastal Oil and Gas Questionnaire, the average produced water rate from a well is approximately 1180 barrels per day (bpd) in Cook Inlet and 270 bpd in the Gulf Coast. EPA estimates under current permit requirements that 119 million barrels per year (bpy) of produced water are discharged to surface waters by the coastal oil and gas industry.

As part of this rulemaking, EPA has embarked upon a systematic effluent sampling program to identify and quantify the pollutants present in produced water, with an emphasis toward the identification of listed toxic pollutants. Details of EPA's data collection activities are presented in the Coastal Development Document. The information collected has confirmed the presence of a number of organic and metal toxic pollutants in produced water.

Pollutants contained in produced water discharges from facilities in the coastal oil and gas industry with treatment systems able to meet BPT permit limits were identified as part of EPA's sampling effort. A summary of the data from these sampling activities is contained in the Coastal Development Document. EPA's sampling data and the industry-supplied Cook Inlet Study identified many organic toxic pollutants and 12 of the 13 metal toxic pollutants

as being present in BPT treated discharges of produced water following some treatment for oil and grease (oil) removal. The toxic organics most often present in significant amounts were benzene, naphthalene, phenol, toluene, and ethylbenzene. In addition to the toxic pollutants, EPA identified total suspended solids, oil and grease, and a number of nonconventional pollutants including barium, chlorides, ammonia, magnesium, strontium and iron present in produced water.

TWC fluids are primarily generated during production. Well treatment and workover fluids are inserted downhole in a producing well to increase a well's productivity or to allow safe maintenance of the well. Completion fluids are inserted downhole after a well has been drilled, and serve to clean the wellbore and maintain pressure prior to production. In most operations, these fluids resurface with the production fluids once production is initiated and can be reused, discharged, or injected in a disposal well.

According to results obtained in the 1993 Coastal Oil and Gas Questionnaire, EPA estimates that approximately 275,000 bbls (205,000 and 70,000 bpy of treatment/workover and completion fluids respectively) of TWC fluids are discharged annually from coastal oil and gas operations in Texas and Louisiana under current permit requirements.

The composition of the discharges is highly dependent on the fluid's purpose, but they generally consist of acids (in the case of treatment) or weighted brines (for workover or completion). The principal pollutant in these fluids is oil and grease ranging in concentration from 15 to 722 mg/l. Total suspended solids, another major constituent in these fluids, is present in concentrations ranging from 65 to 1600 mg/l. Prominent toxic metals that exist in these wastes include chromium, copper, lead, and zinc. Priority organics are also present including acetone, benzene, ethylbenzene, xylene, toluene, and naphthalene.

Under current permit requirements, EPA estimates that approximately 314,000 pounds of priority pollutants and 3,700,000 pounds of conventional pollutants are being discharged annually into the coastal subcategory. In addition, approximately 2.55 million pounds of nonconventionals are being discharged including boron, calcium, cobalt, iron, manganese, molybdenum, tin, vanadium, and yttrium.

2. Selection of Pollutant Parameters

a. Pollutants Regulated. Where zero discharge is required, all pollutants

found in produced water and treatment, workover, and completion fluid discharges are controlled. Where discharges are allowed, *i.e.*, Cook Inlet, EPA is regulating oil and grease under BAT as an indicator pollutant controlling the discharge of toxic and nonconventional pollutants. Operationally, oil and grease is measured by EPA's method for Total Oil and Grease. Oil and grease is limited for produced water under BCT as a conventional pollutant. BCT limits for treatment, workover, and completion fluids prohibit the discharge of "free oil" as a surrogate for control over the conventional pollutant "oil and grease." No discharge of "free oil" is determined by the static sheen test. EPA is prohibiting discharge of "free oil" as a surrogate for control over the conventional pollutant "oil and grease" in recognition of the complex nature of the oils present in drilling fluids, including crude oil from the formation being drilled. Oil and grease is limited under NSPS as both a conventional pollutant and as an indicator pollutant controlling the discharge of toxic and nonconventional pollutants.

It has been shown (see the Coastal Development Document) that oil and grease serves as an indicator for toxic pollutants in the produced water wastestream, including phenol, naphthalene, ethylbenzene, and toluene. During its development of the Offshore Guidelines, EPA showed that gas flotation technology (the technology basis for the oil and grease limitations) removes both metals and organic compounds, resulting in lower concentration levels in the discharge for the above toxic pollutants (see Section IX of the Offshore Development Document).

b. **Pollutants Not Regulated.** For Cook Inlet, EPA evaluated the feasibility of regulating separately each of the constituents present in produced water and treatment, workover, and completion fluids during the development of the Offshore Guidelines. Based on that analysis, EPA determined for the Coastal Guidelines that it is not feasible to regulate each pollutant individually for reasons that include the following: (1) The variable nature of the number of constituents in the produced water and treatment, workover, and completion fluids, (2) the impracticality of measuring a large number of analytes, many of them at or just above trace levels, (3) use of technologies for removal of oil which are effective in removing many of the specific pollutants, and (4) many of the organic pollutants are directly associated with oil and grease because they are

constituents of oil, and thus, are directly controlled by the oil and grease limitation. See the Coastal Development Document for more details.

3. Control and Treatment Technologies

a. **Current Practice.** With regards to produced water, information collected by EPA through the 1993 Coastal Oil and Gas Questionnaire as well as industry contacts indicate that no coastal oil and gas facilities are discharging in Alabama, Alaska's North Slope, California, Florida, or Mississippi. This is due to a combination of factors including operational preference, waterflooding, and/or state and federal requirements. The Louisiana Department of Environmental Quality issued regulations in 1992 (LAC:33, IX, 7.708) which prohibit discharges of produced water to fresh water areas characterized as "upland" after July 1, 1992. The Louisiana regulation defines "upland" as "any land not normally inundated with water and that would not, under normal circumstances, be characterized as swamp of fresh, intermediate, brackish or saline marsh". The regulation does, however, allow discharges of produced water to a major deltaic pass of the Mississippi River or to the Atchafalaya River below Morgan City. The same regulation also requires that discharges inland of the inner boundary of the Territorial Seas into intermediate, brackish or saline waters must either cease discharges or comply with a specific set of effluent limitations. These requirements must be met within a certain time frame, as required in the regulations, but, no later than January 1997.

In addition, EPA issued general NPDES permits (60 FR 2387, January 9, 1995) for production wastes that prohibit discharges of produced water in coastal areas of Texas and Louisiana. The permits do not, however, apply to produced water derived from the offshore subcategory which is discharged into a main pass of the Mississippi River or Atchafalaya River below Morgan City. Along with the general permits, EPA issued an Administrative Order allowing until January 1997 to comply with the zero discharge requirement. Thus, although many coastal oil and gas operators are currently discharging produced water, current permit requirements and administrative orders indicate that the only facilities projected to be discharging by January 1997 would be those in Cook Inlet, Alaska, and six facilities discharging to a major deltaic pass of the Mississippi River.

Subsequent to EPA's issuance of the final coastal production permits, 82 facilities (as of the date of this writing) in Texas have applied to EPA Region 6 for individual NPDES permits authorizing discharge of produced water. Additionally, the U.S. Department of Energy has provided the State of Louisiana with comments and analyses suggesting a change in the Louisiana state law requiring zero discharge of produced water to open bays by January 1997.

The current BPT regulations established for the coastal subcategory limit the oil and grease content in the discharged produced water. Existing technologies for the removal of oil and grease include gravity separation, gas flotation, heat and/or chemical addition to assist oil-water separation, and filtration. Methods for the discharge or disposal of produced water from facilities in the coastal subcategory include free fall discharge to surface waters, discharge below the water surface, use of channels to convey the discharge to water bodies, and injection via regulated Class II Underground Injection Control (UIC) wells into underground formations. As an alternative, a number of production sites transport produced water by pipeline, truck or barge to shore facilities for disposal in UIC Class II wells. At times, this transport consists of the gross fluid produced and the oil-water separation takes place at the off-site facility.

While sampling data has indicated quantifiable reductions of naphthalene, lead, and ethylbenzene by BPT treatment (*i.e.*, by oil-water separation technology), this data also demonstrates the presence of significant levels of toxic pollutants remaining in the treated effluent.

With regard to treatment, workover, and completion fluids, current requirements for the control of discharges from these fluids include BPT limitations prohibiting free oil. EPA's final general permits applicable to discharges from coastal oil and gas drilling operations in Texas and Louisiana further prohibit discharges of treatment, workover and completion fluids to freshwater areas. Methods for treatment and discharge or disposal include:

- * Treatment and disposal along with the produced water
- * Neutralization for pH control and discharge to surface waters
- * Onshore disposal and/or treatment and discharge in coastal or offshore areas.

In addition, these fluids may in some cases be reused.

b. Additional Technologies.

In developing the regulation, EPA evaluated several treatment technologies for application to the produced water and treatment, workover, and completion fluid wastestreams. These technologies were considered for implementation at the coastal production sites and at the shore facilities where much of the produced water is currently treated for subsequent discharge to coastal subcategory waters.

(1) Improved Gas Flotation.

Gas flotation is a treatment process that separates low-density solids and/or liquid particles (e.g., oil and grease) from liquid (e.g., water) by introducing small gas (usually air) bubbles into wastewater. As minute gas bubbles are released into the wastewater, suspended solids or liquid particles are captured by these bubbles, causing them to rise to the surface where they are skimmed off.

EPA considered as an option using gas flotation technology with chemical addition as a basis for improving BPT-level performance. This option would require all coastal discharges of produced water to comply with oil and grease limitations of 29 mg/l monthly average and a daily maximum of 42 mg/l. The technology basis for these limitations is improved operating performance of gas flotation technology. EPA has determined that gas flotation systems could be improved to increase removal efficiencies—i.e., the amount of pollutants removed. Specific mechanisms include proper sizing of the gas flotation unit to improve hydraulic loading (water flow rate through the equipment), adjustment and closer monitoring of engineering parameters such as recycle rate and shear forces that can affect oil droplet size (the smaller the oil droplet, the more difficult the removal), additional maintenance of process equipment, and the addition of chemicals to the gas flotation unit. (See Offshore Development Document Section IX.)

The addition of chemicals can be a particularly effective means of increasing the amount of pollutants removed. Because the performance of gas flotation is highly dependent on "bubble-particle interaction," chemicals that enhance that interaction will increase pollutant removal.

Gas flotation is a technology which has been used for many years in treating produced water. This technology formed the basis for the BPT regulations EPA promulgated in 1979. In developing final effluent limitations guidelines and standards for the offshore subcategory (58 FR 12454; March 4, 1993), EPA evaluated comments and data submitted by the industry which strongly urged EPA to

select improved gas flotation technology as the basis for BAT limits and NSPS, based on data presented by the Offshore Operators Committee's (OOC's) 83 Platform Composite Study. Industry further noted that chemical additives would improve the amount of oil and grease in produced water that could be removed. EPA thoroughly reviewed these comments and additional data, and agreed with industry that improved gas flotation was the appropriate technology for setting BAT limits and NSPS in the offshore subcategory.

In establishing BAT limits and NSPS for produced water in the Offshore Subcategory, EPA evaluated the effluent data from the platforms in the 83 Platform Composite Study identified as using improved gas flotation (e.g., use of gravity separators and chemical additives). First, EPA modeled the offshore platform with "median" oil and grease effluent values—i.e., 50 percent of the platforms in the database had oil and grease effluent values above (and 50 percent below) the median of the effluent values measured at the median platform. Based on the oil and grease measured at the median platform after improved gas flotation treatment, and allowing for average "within-platform" variability, EPA set a daily maximum limit on oil and grease at 42 mg/l, and a 30-day average of 29 mg/l as the BAT limits and NSPS. (See 58 FR 12462, March 4, 1993.)

Since there are fewer operational constraints for coastal facilities than there are for offshore facilities, the BAT and NSPS limitations developed for the offshore subcategory, based on improved gas flotation technology, are technologically achievable in the coastal subcategory.

(2) Injection. EPA also considered using injection technology as a basis for setting a zero discharge requirement under this rule. With the exception of Cook Inlet, injection of produced water is widely practiced by facilities in the coastal subcategory. Independent of this rule, all coastal facilities in Alabama, California, Florida, and the North Slope of Alaska are currently practicing zero discharge and, as of January 1, 1997, EPA estimates that at least 80% to 99.9% of all coastal facilities in Louisiana and Texas will be practicing zero discharge. The 80% estimate is based on subtracting the sum of the 6 facilities discharging into a major deltaic pass of the Mississippi, the 82 facilities discharging to Louisiana open bays, and the 82 facilities associated with individual permit applicants in Texas from the 853 total coastal facilities estimated to exist along the Gulf of Mexico. The 99.9% estimate is based on

subtracting the number of facilities discharging into a major deltaic pass of the Mississippi from the total number of coastal facilities along the Gulf of Mexico. Additionally, using a combination of Coastal Survey information and counts of facilities known to be discharging, EPA estimated that 62% of coastal facilities along the Gulf of Mexico were practicing zero discharge in 1994. For the onshore subcategory, injection is the predominant technology used to comply with the zero discharge 1979 BPT limitation. Injection technology for produced water consists of injecting produced water, under pressure, into Class II UIC wells into underground formations. This option results in no discharge of produced water to surface waters.

4. Other Technologies

Other technologies considered but rejected are discussed in the Coastal Development Document.

5. Options Considered

EPA considered several options in developing BCT, BAT, NSPS, PSES and PSNS limitations for discharges of produced water and treatment, workover, and completion fluids by coastal facilities or in coastal locations. The bases for these options were gas flotation, improved gas flotation, injection, or a combination of injection and improved gas flotation. As proposed, implementation of limitations on discharges of offshore wastes into the coastal subcategory is accomplished by the addition of language describing the applicability of subcategory limitations when crossing subcategory boundaries and modification of the applicability language for the offshore subcategory. Limitations for the Agricultural and Wildlife Water Use Subcategory and the reserved status of the Stripper Subcategory are not affected by changes in the applicability language.

The three options selected for final consideration in developing BAT and NSPS for control of produced water are listed below with limitations associated with the options allowing discharges:

Option 1—(Zero Discharge; Except Major Deltaic Pass and Cook Inlet Based On Improved Gas Flotation): With the exception of facilities in Cook Inlet and facilities discharging offshore produced water into the coastal subcategory waters of a major deltaic pass of the Mississippi River or the Atchafalaya River below Morgan City, all coastal oil and gas facilities and all facilities discharging offshore produced water into coastal locations would be prohibited from discharging produced water and treatment, workover, and completion fluids. Coastal facilities in Cook Inlet and facilities

discharging offshore produced water into a major deltaic pass would be required to comply with oil and grease limitations of 29 mg/l monthly average and 42 mg/l daily maximum based on improved performance of gas flotation.

Option 2—(Zero Discharge; Except Cook Inlet Based On Improved Gas Flotation): With the exception of coastal facilities in Cook Inlet, all coastal oil and gas facilities would be prohibited from discharging produced water and treatment, workover, and completion fluids. Discharges of offshore produced water and treatment, workover, and completion fluids would be prohibited when the wastes are disposed in coastal locations. Coastal facilities in Cook Inlet would be required to comply with oil and grease limitations of 29 mg/l monthly average and 42 mg/l daily maximum based on improved performance of gas flotation.

Option 3—(Zero Discharge All): For all coastal facilities, this option would prohibit discharges of produced water and treatment, workover, and completion fluids based on injection. Further, discharges of offshore produced water and treatment, workover, and completion fluids would be prohibited in coastal locations.

For BCT, BPT and currently applicable permit limitations were considered in addition to the three previously mentioned options for BAT and NSPS. For produced water, BPT limitations include limitations on oil and grease of 48 mg/l for Monthly Average and 72 mg/l for Daily Maximum. For treatment, workover, and completion fluids, BPT limitations include no discharge of free oil and current permits, where applicable, prohibit the discharge of these fluids into fresh waters of Texas and Louisiana.

For PSES and PSNS, the only option considered is zero discharge.

With regard to options presented at proposal: (1) Options for treatment, workover, and completion fluids have been incorporated into the options for produced water and (2) one option was added. The option that considers allowing the discharge of offshore produced water into a major deltaic pass of the Mississippi River was included in response to comments. In response to comments, specific alternatives have been developed and examined carefully for facilities currently discharging offshore produced water into a major deltaic pass of the Mississippi River or the Atchafalaya River below Morgan City. EPA has identified six facilities with eight outfalls discharging offshore produced water into a major deltaic pass of the Mississippi River and no facilities discharging offshore produced water into the Atchafalaya River below Morgan City.

The specific alternatives discussed above have been developed for Cook

Inlet to account for the different operational practices, geological situations, and economic considerations that exist in Cook Inlet.

4. BAT and NSPS Options

EPA is selecting "Option 2—Zero discharge; Except Cook Inlet Based On Improved Gas Flotation" for the BAT and NSPS level of control for produced water.

a. Rationale for Selection of BAT

(1) Coastal Subcategory (except Cook Inlet)

EPA is establishing zero discharge as BAT for the coastal subcategory (except for Cook Inlet) because it is technically available, economically achievable and reflects the appropriate level of BAT control.

Zero discharge of produced water is technically available. Zero Discharge of produced water has been required of onshore facilities since EPA promulgated BPT regulations for the onshore subcategory of the oil and gas industry in 1979. 40 CFR part 435, subpart C (44 FR 22069; April 13, 1979). With the exception of Cook Inlet, injection of produced water is widely practiced by facilities in the coastal subcategory. Independent of this rule, all coastal facilities in Alabama, California, Florida, and the North Slope of Alaska are currently practicing zero discharge and, as of January 1, 1997, EPA estimates that at least 80% to 99.9% of all coastal facilities in Louisiana and Texas will be practicing zero discharge. The 80% estimate is based on subtracting the sum of the 6 facilities discharging into a major deltaic pass of the Mississippi, the 82 facilities discharging to Louisiana open bays, and the 82 facilities associated with individual permit applicants in Texas from the 853 total coastal facilities estimated to exist along the Gulf of Mexico. The 99.9% estimate is based on subtracting the number of facilities discharging into a major deltaic pass of the Mississippi from the total number of coastal facilities along the Gulf of Mexico. Additionally, using a combination of Coastal Survey information and counts of facilities known to be discharging, EPA estimated that 62% of coastal facilities along the Gulf of Mexico were practicing zero discharge in 1994. Some coastal operators have voluntarily upgraded to zero discharge technologies while other coastal operators have been subject to consent decrees requiring zero discharge in citizen suits filed by environmental groups. Zero discharge is available to coastal facilities in the Gulf of Mexico region because formations appropriate for injection are available.

In response to comments that operators discharging offshore produced water into a major deltaic pass of the Mississippi should not be subject to zero discharge, EPA closely examined these facilities. However, EPA has identified no basis for providing these facilities with limitations other than those established for the coastal subcategory outside of Cook Inlet. Injection has been widely demonstrated in practice as available to coastal facilities in states along the Gulf Coast, including facilities discharging coastal produced water that are near these facilities discharging offshore produced water.

Zero discharge for the coastal subcategory, except Cook Inlet, is economically achievable. As discussed below, EPA conducted the economic analysis under two baselines, the current regulatory requirements baseline and an alternative baseline. Under the current requirements baseline, the only facilities outside of Cook Inlet that are incurring costs as a result of this rule are those discharging wastes from the offshore subcategory into a "major deltaic pass." Under the alternative baseline, facilities outside of Cook Inlet that are incurring costs as a result of this rule includes those discharging wastes from the offshore subcategory into a "major deltaic pass," individual permit applicants in Texas, and Louisiana open bay dischargers.

No closures are projected for the six facilities discharging to a major deltaic pass. Major pass facilities incur costs and impacts under both the current requirements and the alternative baselines. For major pass operations, the lifetime production loss is expected to be up to 3.4 million total BOE, which is 0.6 percent of estimated lifetime production from these facilities. While these losses may be significant for these dischargers, in context of the coastal subcategory as a whole, this production loss represents 0.3 percent of the coastal production along the Gulf of Mexico. Employment losses in both Cook Inlet and along the Gulf Coast are acceptable, see section VIII. Considering this small percentage loss of BOE and profitability, coupled with the determination of no closures, EPA believes that zero discharge is economically achievable under the CWA.

For individual permit applicants in Texas and Louisiana open bay dischargers, a total of up to 94 wells may be first year shut-ins under zero discharge. Individual permit applicants in Texas and Louisiana open bay dischargers are considered to have financial impacts only under the alternative baseline. These wells are

approximately 2 percent of all Gulf of Mexico coastal wells. EPA estimates related production losses would be approximately 12.8 million BOE. This represents less than one percent of all Gulf coastal production, most of which is in compliance with zero discharge requirements. A maximum of 1 firm among the Louisiana open bay dischargers and 3 firms among the individual permit applicants from Texas could fail as a result of the proposed regulatory options. However, EPA's modeling tends to overestimate economic impacts and firm failures, since these models project that some currently operating firms have already failed. These potential failures represent less than one percent of all Gulf of Mexico coastal firms. EPA also did a facility level analysis, conducted in response to facility-level information received from Texas very late in the rulemaking, that shows fewer wells are baseline failures and fewer wells fail due to the costs of this rule because wells combine efforts for treatment and production. EPA views the small percentage loss of BOE and profitability, coupled with the determination of a small number of firm closures, to meet the definition of economic achievability under the CWA.

The non-water quality environmental impacts of zero discharge, discussed in section IX, are acceptable.

(2) Cook Inlet

EPA is establishing BAT limitations based on improved gas flotation, rather than zero discharge. EPA rejects zero discharge of produced water because zero discharge is not economically achievable in Cook Inlet.

EPA considered Cook Inlet separately from other areas in the coastal subcategory because Cook Inlet is geographically isolated from other areas in the coastal subcategory, zero discharge of produced water would have disproportionately adverse economic impact in Cook Inlet.

Unlike states along the Gulf Coast, only the production formation is generally available for injection of produced water. Because of this, zero discharge would require the additional costs associated with piping produced water from existing production facilities to existing waterflood injection sites.

EPA's economic analysis shows a disproportionate impact of zero discharge on Cook Inlet as compared with the rest of the coastal subcategory. EPA projects that zero discharge requirements for Cook Inlet would close 1 of the 13 existing production platforms and result in the loss of 108 jobs in the oil and gas industry in Cook Inlet. In addition, there are severe

economic impacts on two additional platforms that were projected to fail at proposal. These disproportionate impacts are demonstrated by a loss in net present value in Cook Inlet of 18.5 percent as compared to only 1.4 percent in the Gulf coast under the current requirements baseline. In addition, there are disproportionate impacts in Cook Inlet with regard to employment, where Cook Inlet already suffers from unemployment higher than the national average and higher than the rest of the coastal subcategory. The most recently reported (1991) unemployment rate in Cook Inlet is 12.7 percent, as compared with the unemployment rate in the Gulf coast of 6.2 to 6.4 percent and the national unemployment rate of about 5.2 percent). The loss of 108 jobs that would occur in Cook Inlet from zero discharge would raise the unemployment level in Cook Inlet 0.5 percent, to 13.2 percent. Thus, zero discharge would worsen the serious unemployment situation that exists in Cook Inlet. Because Cook Inlet is economically and geographically isolated and the economic effects of zero discharge in Cook Inlet are significant and disproportionately worse than they are in the rest of the subcategory, EPA rejects zero discharge in Cook Inlet as not economically achievable.

Limitations based on improved gas flotation are technically and economically achievable for Cook Inlet facilities. These limitations are a Daily Maximum of 42 mg/l and a Monthly Average of 29 mg/l for oil and grease. Improved gas flotation technology has been demonstrated in the offshore subcategory where the wastestreams and physical constraints are similar. No platform closures are expected as a result of establishing these limitations. EPA expects the production loss over the productive lifetime of these platforms to be approximately 2.4 million BOE, which is 0.5 percent of the estimated lifetime production for the Inlet.

The non-water quality environmental impacts of these limitations, discussed in section IX, are acceptable.

(3) Pollutant Reductions for the Selected Option

Assuming the current regulatory requirements baseline, the selected BAT option for produced water and treatment, workover, and completion fluids is expected to reduce discharges of conventional pollutants by 2,780,000 lbs. per year, nonconventional pollutants by 1,490,000,000 lbs. per year, and toxic pollutants by 228,000 lbs. per year.

Assuming the alternative baseline, the selected BAT option for produced water

and treatment, workover, and completion fluids is expected to reduce discharges of conventional pollutants by 11,300,000 lbs. per year, nonconventional pollutants by 4,590,000,000 lbs. per year, and toxic pollutants by 880,000 lbs. per year.

b. Rationale for Selection of NSPS
For NSPS control of produced water and treatment, workover, and completion fluid discharges from new sources, EPA is establishing the limitations associated with "Option 2—Zero Discharge; Except Cook Inlet Based On Improved Gas Flotation." Option 2 is economically achievable for the reasons discussed in the economic impact analysis and in Section VIII, below. The selected option for NSPS is equal to the selected BAT option for produced water and treatment, workover, and completion fluids. The BAT option has been demonstrated to be technologically available and economically achievable for existing structures. Design and construction of pollution control equipment on new production facilities is generally less expensive than retrofitting existing facilities. Therefore, while the NSPS requirements are equal to the BAT requirement, it is less costly for new structures to meet these requirements and these costs would not inhibit development of new sources.

In addition, as discussed in Section IX, EPA has determined the non-water quality environmental impacts to be acceptable for the selected NSPS option for produced water and treatment, workover, and completion fluids.

Zero discharge for Cook Inlet is rejected because of uncertainties regarding the availability of geologic formations suitable for receiving injected produced water. Information in the record indicates that a potential new source in Cook Inlet could be unable to inject adequate produced water volumes near the new source. As a result, the new source would be faced with piping the produced water to a location where suitable geology would be available. Based on information available in the record, EPA projects that no new sources will be developed in Cook Inlet. Nevertheless, EPA assessed the costs and economic impacts incurred by a model new source facility under the zero discharge scenario should conditions and future information lead to development of new sources in Cook Inlet. For the modeled scenario, EPA based costs on injecting produced water near the new source facility. However, because of the uncertainties regarding availability of formations suitable for injection, it is possible that a new source structure would incur some

unknown cost for piping the produced water to a suitable injection location. Since the location and availability of formations for any new source in Cook Inlet are unknown, the maximum cost associated with piping produced water from the wellhead to the nearest injection well cannot be estimated.

5. BCT Methodology and Options Selection

The methodology to determine the appropriate technology option for BCT limitations is previously described in the proposal and the Coastal Development Document.

EPA evaluated the options listed in section VII.B.5 according to the BCT cost reasonableness tests. The pollutant parameters used in this analysis were total suspended solids and oil and grease. All options fail the BCT cost reasonableness test. Thus, EPA establishes BCT limitations for produced water equal to BPT. Limitations for treatment, workover, and completion fluids are established as zero discharge for fresh water in Texas and Louisiana and no free oil everywhere else. This option reflects current permit requirements. Costs for this option are zero, thus this option passes the BCT cost test. A more detailed description of the BCT cost test for produced water and treatment, workover, and completion fluids is described in the Coastal Development Document. There are no non-water quality environmental impacts associated with the BCT limitations because it is equal to existing BPT requirements.

6. PSES and PSNS Options Selection

Based on the 1993 Coastal Oil and Gas Questionnaire and other information reviewed as part of this rulemaking, EPA has not identified any existing coastal oil and gas facilities which discharge produced water or treatment, workover, and completion fluids to POTWs, nor are any new facilities projected to direct their produced water discharge in such manner. However, because EPA is establishing a limitation requiring zero discharge for existing facilities, there is the potential that some facilities may consider discharging to POTWs in order to circumvent the BAT and/or NSPS limitations. Pretreatment standards for produced water and treatment, workover, and completion fluids are appropriate because EPA has identified the presence of a number of toxic and nonconventional pollutants, many of which are incompatible with the biological removal processes at POTWs and would result in pass through or

interference. Large concentrations of dissolved solids in the form of various salts in the produced water cause the discharge to POTWs to be incompatible with the biological treatment processes because these "brines" can be lethal to the organisms present in the POTW biological treatment systems. (See the Coastal Development Document for detailed information on produced water characterization.)

EPA is establishing pretreatment standards for existing and new sources (PSES and PSNS, respectively) that prohibit the discharge of produced water and treatment, workover, and completion fluids. Since zero discharge to POTWs is the current practice in the coastal oil and gas extraction industry, zero discharge is economically and technologically achievable for PSES, and has no non-water quality environmental impacts. The cost projections for both PSES and PSNS are considered to be zero since no existing sources discharge to POTWs and there are no known plans for new sources to be installed in locations amenable to sewer hookup. Design and construction of pollution control equipment on new production facilities is generally less expensive than retrofitting existing facilities. Therefore, while the PSNS requirements are equal to the PSES requirement, it is less costly for new structures to meet these requirements and these costs would not inhibit development of new sources. Non-water quality environmental impacts would be similar to those for new sources, which EPA has found to be acceptable. Thus, EPA has determined that pretreatment standards for new sources that are equal to NSPS are economically achievable and technologically available for PSNS and that the non-water quality environmental impacts are acceptable.

C. Produced Sand

1. Waste Characterization

Produced sand consists primarily of the slurried particles that surface from hydraulic fracturing and the accumulated formation sands and other particles (including scale) generated during production. Produced sand is generated during oil and gas production by the movement of sand particles in producing reservoirs into the wellbore. The generation of produced sand usually occurs in reservoirs comprised of geologically young, unconsolidated sand formations. The produced sand wastestream is considered a solid and consists primarily of sand and clay with varying amounts of mineral scale and corrosion products. This waste stream may also include sludges generated in

the produced water treatment system, such as tank bottoms from oil/water separators and solids removed in filtration.

Produced sand is carried from the reservoir to the surface by the fluids produced from the well. The well fluids stream consists of hydrocarbons (oil or gas), water, and sand. At the surface, the production fluids are processed to segregate the specific components. The produced sand drops out of the fluids stream during the separation process and accumulates at low points in equipment. Produced sand is removed primarily during tank cleanouts. Because of its association with the hydrocarbon stream during extraction, produced sand is generally contaminated with crude oil or gas condensate.

Additional discussion of produced sand is presented in the Coastal Development Document.

2. Selection of Pollutant Parameters

As proposed, EPA is establishing control of all pollutants present in produced sand by prohibiting discharge of this wastestream.

3. Control and Treatment Technologies

No effluent limitations guidelines have been promulgated for discharges of produced sand in the coastal subcategory. The final NPDES permits for Texas, Louisiana, and the existing state NPDES permits for Alabama contain a zero discharge limit for produced sand.

Data from the 1993 Coastal Oil and Gas Questionnaire indicate that the predominant disposal method for produced sand is landfarming, with underground injection, landfilling, and onsite storage also taking place to some degree. Because of the cost of sand cleaning, in conjunction with the difficulties associated with cleaning some sand sufficiently to meet existing permit discharge limitations, operators use onshore (onsite or offsite) or downhole disposal. In fact, only one operator was identified in the 1993 Coastal Oil and Gas Questionnaire as discharging produced sand in the Gulf of Mexico, but this operator also stated that it planned to cease its discharge in the near future. Cook Inlet operators submitted information stating that no produced sand discharges are occurring in this area. No comments on the proposed guidelines contained contrary information.

4. Options Considered and Rationale for Options Selection

EPA has selected zero discharge for control of produced sand. Because

current practice for the coastal subcategory is zero discharge, allowing the discharge of produced sand would not represent BAT level control. As stated above, EPA's Coastal Oil and Gas Questionnaire identified only one discharger of produced sand in the coastal subcategory and that discharger reported an intent to cease discharging. As stated above, the Region 6 NPDES permits published January 9, 1995 prohibit all discharges of produced sand in coastal waters of Louisiana and Texas. Because the industry practice is zero discharge, the zero discharge limitation will result in no increased cost to the industry.

EPA is establishing BPT, BCT, BAT and NSPS equal to zero discharge for produced sand. Zero discharge is established as BPT because it reflects the average of the best existing performance by facilities in the coastal subcategory. Since BCT is established as equal to BPT, there is no cost of BCT incremental to BPT. Therefore, this option passes the BCT cost reasonableness tests. EPA has determined that zero discharge reflects the BAT level of control because, as it is widely practiced throughout the industry, it is both economically achievable and technologically available. The selected option for NSPS is equal to the selected BAT option for produced sand. Design and construction of pollution control equipment on new production facilities is generally less expensive than retrofitting existing facilities. Therefore, while the NSPS requirements are equal to the BAT requirement, it is less costly for new structures to meet these requirements and these costs would not inhibit development of new sources. Zero discharge will have no economic impacts on the industry. As zero discharge reflects current practice, there are no incremental non-water quality environmental impacts from this option.

The technology basis for compliance with PSES and PSNS is the same as that for BAT and NSPS. EPA is establishing pretreatment standards for produced sands equal to zero discharge because, like drilling fluids and drill cuttings, their high solids content would interfere with POTW operations. Because EPA is not aware of any coastal operators discharging produced sand to POTWs, this requirement is not expected to result in operators incurring costs. Zero discharge for PSNS would not cause a barrier to entry for the same reasons as discussed above for NSPS. There are no additional non-water quality environmental impacts associated with this requirement because it reflects current practice.

D. Deck Drainage

1. Waste Characterization

Deck drainage consists of contaminated site and equipment runoff due to storm events and wastewater resulting from spills, drip pans, or washdown/cleaning operations, including washwater used to clean working areas. Deck drainage is generated during both the drilling and production phases of oil and gas operations. Currently, approximately 11.5 million barrels per year of deck drainage are discharged by facilities in the coastal subcategory. EPA estimates that 112,000 pounds of oil and grease are discharged in this wastestream annually. In addition to oil, various other chemicals used in drilling and production operations may be present in deck drainage. Limited treated effluent data are available for this wastestream, however, EPA has identified the presence of organic and metal toxic pollutants in deck drainage. EPA's analytical data for deck drainage comes from the data acquired during the development of the Offshore Guidelines. EPA conducted a three facility sampling program (described in Section V of the Offshore Development Document) during which samples were taken of untreated deck drainage. Eight of the toxic metals were detected, most notably lead (ranging in concentration from 25—352 ug/l) and zinc (ranging in concentration from 2970—6980 ug/l). Priority organics were also present including benzene, xylene, naphthalene and toluene. Other nonconventional pollutants found in deck drainage include aluminum, barium, iron, manganese, magnesium and titanium.

The content and concentrations of pollutants in deck drainage can also depend on chemicals used and stored at the oil and gas facility. An additional study on deck drainage from Cook Inlet platforms, reviewed during development of the Offshore Guidelines and this rule, showed that discharges from this wastestream may also include paraffins, sodium hydroxide, ethylene glycol, methanol and isopropyl alcohol.

2. Selection of Pollutant Parameters

EPA has selected free oil as the pollutant parameter for control of deck drainage. The specific conventional, toxic and nonconventional pollutants found to be present in deck drainage are those primarily associated with oil, with the conventional pollutant oil and grease being the primary constituent. In addition, other chemicals used in the drilling and production activities and stored on the structures have the potential to be found in deck drainage.

EPA believes that an oil and grease limitation together with incorporation of site specific Best Management Practices, as required under the stormwater program and as discussed below, will control the pollutants in this wastestream.

The specific conventional, toxic, and nonconventional pollutants controlled by the prohibition on the discharges of free oil are the conventional pollutant oil and grease and the constituents of oil that are toxic and nonconventional. Free oil is also an indicator for toxic pollutants present in crude oil. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitation on free oil in deck drainage reflects control of these toxic pollutants at the BAT and BADCT (NSPS) levels.

3. Control and Treatment Technologies

a. Current Practice. BPT limitations for deck drainage prohibit the discharge of free oil. All equipment and deck space exposed to stormwater or washwater are surrounded with berms or collars. These berms capture the deck drainage where it flows through a drainage system leading to a sump tank. Initial oil/water separation takes place in the sump tank which is generally located beneath the deck floor or underground at land-based operations. Effluent from the sump tank may be directed to a skim pile, where additional oil/water separation occurs. (The skim pile is essentially a vertical bottomless pipe with internal baffles to collect the separated oil.)

The deck drainage treatment system is a gravity flow process, and the treatment tanks generally do not require a power source for operation. Thus, deck drainage generated at operations located in powerless, remote situations, (such as satellite wellheads) can be effectively treated.

It is sometimes difficult to obtain an appropriate sample of deck drainage effluent, due to a submerged location. This precludes the use of the static sheen test for this wastestream. Thus, free oil is measured by the visual sheen test. Deck drainage treatment is discussed in more detail in the Coastal Development Document.

b. Additional Technologies Considered. At proposal, EPA considered commingling deck drainage with produced water or drilling fluids and requiring best management practices. Deck drainage could in some circumstances be commingled with either produced water or drill fluids and

thus, could become subject to the limitations imposed on these major wastestreams. EPA also considered requiring best management practices (BMPs) on either a site-specific basis or as part of the Coastal Guidelines. However, for the final rule, both of these proposed options have been rejected. The commingling of deck drainage with produced water or drilling fluids is not a demonstrated technology, as discussed below. Promulgating BMPs in this rule would be redundant to the requirements of the "Final National Pollutant Discharge Elimination System Storm Water Multi-Sector General Permit for Industrial Activities" (60 FR 50804, September 29, 1995).

With regard to commingling with produced water, the 1993 Coastal Oil and Gas Questionnaire as well as the industry site visits reveal that deck drainage is sometimes commingled with produced waters prior to discharge or injection. Because of this practice, EPA investigated an option requiring capture of the "first flush", or most contaminated portion of, deck drainage. Depending on whether the deck drainage is generated from drilling or production (actual hydrocarbon extraction) operations, this first flush would be subject to the same limitations as would be imposed on either produced water or drilling fluids and drill cuttings based on the assumption that these two wastestreams could be commingled.

EPA has rejected the first flush option for control of deck drainage for several reasons primarily relating to whether this option is technically available to operators throughout the coastal subcategory. Deck drainage is currently captured by drains and flows via gravity to separation tanks below the deck floor. However, the problems associated with capture and treatment beyond gravity feed, power independent systems, are compounded by the possibilities of back-to-back storms which may cause first flush overflows from an already full 500 bbl tank. In addition, tanks the size of 500 barrels are too large to be placed under deck floors. Installation of a 500 bbl tank would require construction of additional platform space, and the installation of large pumps capable of pumping sudden and sometimes large flows from a drainage collection system up into the tank. The additional deck space would add significantly, especially for water-based facilities, to the cost of this option. Further, many coastal facilities are unmanned and have no power source available to them. Deck drainage can be channeled and treated without power under the BPT limitations.

Capturing deck drainage at drilling operations poses additional technical difficulties. Drilling operations on land may involve an area of approximately 350 square feet. A ring levee is typically excavated around the entire perimeter of a drilling operation to contain contaminated runoff. This ring levee may have a volume of 6,000 bbls, sufficient to contain 500 bbls of the first flush. However, collection of these 500 bbls when 6,000 bbls may be present in the ring levee would not effectively capture the first flush. Costs to install a separate collection system including pumps and tanks, would add significantly to the cost of this option.

While costs are significant, the technological difficulties involved with adequately capturing deck drainage at coastal facilities are the principal reason why this option was not selected for the final rule.

EPA's final rule does not include best management practices (BMPs) for this wastestream. EPA believes that current industry practices, in conjunction with the requirements included in the previously mentioned general permit for stormwater, are sufficient to minimize the introduction of contaminants from this wastestream to the extent possible. These stormwater requirements require an oil and gas operator to develop and implement a site-specific storm water pollution prevention plan consisting of a set of BMPs depending on specific sources of pollutants at each site.

4. Options Selection

For BAT and NSPS, EPA is establishing a limitation of no free oil. Since free oil discharges are already prohibited under BPT, there are no incremental compliance costs, pollutant removals, or non-water quality environmental impacts associated with this control option. Since this preferred option limits free oil equal to existing BPT standards, it is technologically available and economically achievable.

EPA is establishing BCT limitations as no free oil. Since "no free oil" is the BPT limitation, there is no incremental cost and this option passes the BCT Cost Tests.

EPA is establishing PSES and PSNS limits for deck drainage as zero discharge. EPA believes that zero discharge for PSES and PSNS is appropriate because slugs of deck drainage would be expected to interfere with biological treatment processes at POTWs. This is discussed further in the Coastal Development Document.

E. Domestic Wastes

Domestic wastes result from laundries, galleys, showers, and other

similar activities. Detergents are often part of this wastestream. Waste flows may vary from zero for intermittently manned facilities to several thousand gallons per day for large facilities.

The conventional pollutant of concern in domestic waste is floating solids. The BPT limitations for domestic wastes prohibit discharges of floating solids. To comply with this limit, operators grind the waste prior to discharge. As proposed, EPA is establishing BCT and NSPS limitations as no floating solids. In addition, EPA is establishing BAT and NSPS limitations to prohibit discharges of foam. Foam is a nonconventional pollutant and its limitation is intended to control discharges that include detergents.

As proposed, EPA is establishing discharges limitations for garbage as included in U.S. Coast Guard regulations at 33 CFR part 151. These regulations implement Annex V of the International Treaty to Prevent Pollution from Ships (MARPOL) and the Act to Prevent Pollution from Ships, 33 U.S.C. 1901 et seq. (The definition of "garbage" is included in 33 CFR 151.05).

The pollutant limitations described above for domestic wastes are all technologically available and economically achievable and reflect the BCT, BAT and NSPS levels of control.

These limitations are technologically available because, under the Coast Guard regulations, discharges of garbage, including plastics, from vessels and fixed and floating platforms engaged in the exploration, exploitation and associated offshore processing of seabed mineral resources are prohibited with one exception. Victual waste (not including plastics) may be discharged from fixed or floating platforms located beyond 12 nautical miles from nearest land, if such waste is passed through a screen with openings no greater than 25 millimeters (approximately one inch) in diameter. Because vessels and fixed and floating platforms must comply with these limits, EPA believes that all coastal facilities are able to comply with this limit. While not all coastal facilities are located on platforms, compliance with a no garbage standard should be as achievable, if not more so, for shallow water or land based facilities that have access to garbage collection services. Further, the final drilling permits issued by Region 6 for coastal Texas and Louisiana incorporates these Coast Guard regulations.

No discharge of visible foam is required by the NPDES permit for Cook Inlet drilling. No discharge of floating solids is included in the Region 10 BPT general permit for Cook Inlet, the Region

10 drilling permit, and the Region 6 general permits for coastal operators.

These limitations are economically achievable because these BCT, BAT and NSPS limitations for domestic waste are already included in either existing NPDES permits or Coast Guard regulations, and therefore these limitations will not result in any additional compliance cost. Also, these limits and standards will have no additional non-water quality environmental impacts. There are no incremental costs associated with the BCT limitations; therefore, they pass the BCT cost reasonableness tests.

Pretreatment standards are not being developed for domestic wastes because domestic wastes are compatible with POTWs.

F. Sanitary Wastes

Sanitary wastes from coastal oil and gas facilities are comprised of human body wastes from toilets and urinals. The volume of these wastes vary widely with time, occupancy, and site characteristics. A larger facility, such as an offshore platform, typically discharges about 35 gallons of sanitary waste daily. Sanitary discharges from coastal facilities would be expected to be less than this value since the manning levels at most coastal facilities is less than that at offshore locations.

The existing BPT limitation for facilities continuously manned by 10 or more people requires sanitary effluent to have a minimum residual chlorine content of 1 mg/l, with the chlorine concentration to remain as close to this level as possible. Facilities intermittently manned or continuously manned by fewer than 10 people must comply with a BPT prohibition on the discharge of floating solids. EPA Regions 6 and 4 general permits for coastal facilities also limit the discharge of TSS, fecal coliform count, BOD and floating solids. The EPA Region 10 general permit for Cook Inlet also requires limitations for these same parameters in addition to requirements for foam and free oil.

EPA considered zero discharge of sanitary wastes based on off-site disposal to municipal treatment facilities or injection with other oil and gas wastes. Off-site disposal would require pump out operations that, while available to certain land facilities, are not easily available to remote or water-based operations. Because sanitary wastes are not accepted for injection into Class II wells, zero discharge based on Class II injection was rejected for sanitary wastes.

EPA is establishing BCT and NSPS as equal to BPT limits for sanitary waste

discharges. Sanitary waste effluents from facilities continuously manned by ten (10) or more persons must contain a minimum residual chlorine content of 1 mg/l, with the chlorine level maintained as close to this concentration as possible. Coastal facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons must comply with a prohibition on the discharge of floating solids.

Since there are no increased control requirements beyond those already required by BPT effluent guidelines, there are no incremental compliance costs or non-water quality environmental impacts associated with BCT and NSPS limitations for sanitary wastes. Since there are no incremental costs associated with the BCT limit, it passes the BCT cost tests.

EPA is not establishing BAT effluent limitations for the sanitary waste stream because no toxic or nonconventional pollutants of concern have been identified in these wastes.

Pretreatment standards are not being developed for sanitary wastes because they are compatible with POTWs.

VIII. Economic Analysis

A. Introduction

This section describes the capital investment and annualized costs of compliance with the Coastal Guidelines, and the potential impacts of these compliance costs on current and future operators of coastal oil and gas facilities. EPA's economic impact assessment is presented in detail in the *Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Oil and Gas Subcategory of the Oil and Gas Extraction Point Source Category* (hereinafter, "EIA"), included in the rulemaking record. The EIA estimates the economic effect of compliance costs on federal and state revenues, balance of trade considerations, and inflation. In addition, EPA has conducted a Regulatory Flexibility Analysis, which estimates effects on small entities, and a cost-effectiveness analysis of all evaluated options for (1) produced water and treatment, workover, and completion fluids and (2) drilling fluids, drill cuttings and dewatering effluent. Except where otherwise noted, only the results for selected options are presented here. For all other wastestreams, EPA selected options that would generate no costs to industry.

B. Economic Impact Methodology

This section (and, in more detail, the EIA) evaluates several measures of

economic impacts that result from compliance costs. The economic analysis in the EIA has six major components: (1) An assessment of the number of facilities that could be affected by this rule; (2) an estimate of the annual aggregate (pre-tax) cost for these facilities to comply with the rule using facility-level capital and O&M costs; (3) use of an economic model to evaluate impacts on the production and economic life of coastal facilities; (4) an evaluation of impacts on firms' financial health, future oil and gas production, Federal and State revenues, balance of trade, employment and other secondary effects; (5) an analysis of compliance cost impacts on new sources; and (6) an analysis of the effects on small entities.

Some of the economic impacts reported in this section are provided in terms of present value (PV) or net present value (NPV). The NPV of project worth is the total stream of production revenues minus all costs and taxes over a period of years discounted back to present value at the firm or industry borrowing rate, here 7 percent or 8 percent, depending on the region under consideration.

All costs are reported in 1995 dollars, with the exception of cost-effectiveness results, which, by convention, are reported in 1981 dollars. Any costs not originally in 1995 dollars have been inflated or deflated using the Engineering News Record Construction Cost Index, unless otherwise noted in the EIA (see EIA for details). Oil and gas prices reported by individual operators are used where available. The impacts reported in this analysis are based on the assumption that these oil prices will remain constant in real terms over the time frame of the analysis. This assumption may overestimate economic impacts, at least over the next several years, given industry and government forecasts showing small real price increases. Price increases would tend to alleviate the economic impacts caused by increased compliance costs.

The economic methodology is nearly identical to the methodology used at proposal. Changes include adjustments to costs (noted in Section V above), minor refinements to the financial models to more precisely reflect tax code and accounting practices, and a change in the baseline to which the costs of the rule are compared. The revision to the analytical baseline represents a significant departure from the 1995 proposal analysis, although it is consistent with EPA's stated intent at proposal to more fully incorporate the effects of recent permit requirements in the analyses for the final rule (see 60 FR 9430). At proposal, the Region 6 General

Permits requiring zero discharge of produced water in Texas and Louisiana were not yet issued. These permits apply to all coastal oil and gas operations in Louisiana and Texas with the exception of certain operations discharging offshore produced water into coastal waters of the Mississippi major deltaic passes (Major Pass dischargers). Therefore, at proposal, EPA counted compliance costs for facilities currently covered by these permits as costs of the Coastal Guidelines.

For the final rule cost analysis, EPA has based costs on the Region 6 General Permits. As a result, EPA considers facilities' Region 6 permit compliance costs to be part of the current regulatory requirements baseline against which the incremental costs attributable to the Coastal Guidelines are measured. Only those facilities not covered by the permits are considered to incur costs as a result of this rule. The current regulatory requirements baseline analysis also considers the effects of the revised guidelines on Cook Inlet operators, for whom information on drilling plans and production has been updated.

In response to comments, the Agency also has considered the effects of the Coastal Guidelines relative to an alternative baseline, which is based on the assumption that Louisiana Open Bay dischargers and dischargers who have applied for individual permits in Texas might continue to discharge under individual permits in the absence of this rule. This alternative baseline analysis estimates effects on these dischargers as well as the Major Pass and Cook Inlet operators. Specific effects on the Louisiana Open Bay dischargers and Texas Individual Permit applicants are also described as a separate part of this alternative analysis. Data for many of these dischargers were gathered for 1992 in the 1993 Coastal Oil and Gas Questionnaire. To EPA's knowledge, responses to the questionnaire provide the most recent and complete set of cost, revenue, and production data available to date for Louisiana Open Bay and Texas Individual Permit operations. The Texas Railroad Commission submitted data to EPA less than one week before the date of this rule, which, because of insufficient time remaining, could not be fully analyzed.

To model Cook Inlet and Major Pass operations, EPA used a financial model similar to the one used to model Cook Inlet in the EIA for the proposed rule. This model uses platforms and/or facilities (rather than wells) as the relevant analytical units. Information for the model was provided by the affected

operators, vendors, and publicly available documents, including information from the SEC, the Bureau of the Census, and the Bureau of Labor Statistics. In this model, the capital and operating costs for pollution control are added to (pre-compliance) baseline capital and operating costs to create a post-compliance financial scenario that evaluates the incremental effects of compliance costs for various options. When operating costs exceed revenues, EPA assumes that the well or facility ceases operation. EPA's model then calculates lifetime production in barrels of oil equivalent (BOE) and associated lifetime revenue (comprised of net income, taxes, and royalties). The net impacts of the rule are the changes in production and revenue from baseline to post-compliance estimates. These changes are the primary impacts of the rule; these in turn affect employment, firm financial health and balance of trade.

C. Summary of Costs and Economic Impacts

1. Overview of Economic Impact Analysis

The EIA focuses first on the costs and economic impacts of the rule, assuming current permit requirements to be the baseline to which the rule is compared. The analysis addresses costs and economic impacts of the BAT and NSPS requirements for drilling fluids, drill cuttings and dewatering effluent (Cook Inlet only), and for produced water and treatment, workover and completion (TWC) wastes combined (Cook Inlet and Major Passes). EPA's analyses are restricted to specific areas of the Louisiana Gulf of Mexico coast and Cook Inlet, Alaska; current permit requirements are for zero discharge in all other coastal areas. As noted in Section VII, no significant costs will be incurred for BAT and NSPS for other wastestreams, for which EPA is setting limits equal to current practice. Similarly, BPT requirements established by this rule are based on current practice and thus are expected to impose negligible additional costs. All options for BCT requirements other than BPT failed the BCT cost test. As a result, BCT is established equal to BPT, with no incremental costs. PSES and PSNS requirements, as noted in Section VII, are expected to have negligible impacts for coastal oil and gas producers, who do not discharge to POTWs.

2. Total Costs and Impacts of the Regulation

This section presents the total costs and impacts of the BAT limitations and

NSPS established by this rule under the current regulatory requirements baseline. Results for the alternative baseline are presented below in Section VIII(C)(4).

EPA estimates that there are six facilities (permits), associated with eight outfalls, that are not covered by the Region 6 permit and that are discharging offshore produced water into one of the major passes of the Mississippi River. There are also 13 platforms that discharge produced water and may discharge drilling wastes into Cook Inlet. Additionally, up to 684 existing wells and 45 new wells per year generating TWC wastes (which are not covered by the General Permits for produced water) would be affected by BAT and NSPS requirements, respectively.

The six Major Pass facilities discharge some combination of coastal and offshore produced water. EPA's evaluation of the costs and impacts of BAT options addresses only the offshore portion of these costs, because zero discharge of coastal waters is required by the Region 6 produced water permit.

Under the current regulatory requirements baseline, BAT limitations for drilling fluids, drill cuttings and dewatering effluent (zero discharge-Gulf; offshore limits-Cook Inlet) are current practice, and thus have no incremental cost. BAT limits for produced water and TWC fluids (zero discharge, except for Cook Inlet, where operators would have to meet oil and grease limits based on improved gas flotation) affect Major Pass dischargers and Cook Inlet dischargers and have total annual compliance costs of \$15.6 million (Table 2). The only NSPS costs incurred under this rule are \$600,000 annually for TWC fluids for new wells drilled in the Gulf of Mexico.

TABLE 2.—COSTS OF SELECTED BAT AND NSPS OPTIONS: CURRENT REGULATIONS BASELINE (1995)

Wastestream	Annualized compliance costs (\$ million/yr)	
	BAT	NSPS
Produced Water/TWC Option 2 (BAT only) ..	15.6
Drilling Fluids and Cuttings (BAT only) ...	0.00	0.00
Treatment, Workover & Completion Fluids (NSPS only)	0.00	0.6

a. Impacts from Best Available Technology (BAT). No firms are expected to fail as a result of this rule under the Current Regulatory

Requirements baseline. Implementation of this rule is expected to cause a reduction in national employment of 127 jobs annually, which result from delays and reduction in oil production. EPA estimates that these BAT limitations could reduce the NPV of affected projects' worth by up to \$63.7 million (\$51.8 million from Major Pass facilities and \$11.9 million from Cook Inlet), equivalent to annual impacts of \$9.1 million per year, or 1.4 percent of all coastal production's net worth. A change in project NPV considers the effects of both compliance costs and foregone oil and gas revenues on an oil and gas production project's, and ultimately, on a producing company's net worth. As a firm's net worth declines, its financial position becomes more tenuous and the risk of failure increases (see EIA for detailed description). Also, the BAT limitations result in \$6.1 million in lost state taxes, \$8.4 million in lost royalties and \$20.3 million in lost federal tax revenues (all in present value). This represents 0.3 percent (taxes) and 0.2 percent (royalties) of the present value of all coastal oil and gas revenues received by states (and individuals) and 0.9 percent of federal tax revenues from all coastal facilities.

Table 3 summarizes the BAT impacts discussed above for produced water/TWC (the BAT impacts for drilling fluid and drill cuttings are negligible).

TABLE 3.—SUMMARY OF PRESENT VALUE IMPACTS OF SELECTED BAT OPTIONS

Impact	PV impacts (\$ million)	Percent of coastal industry (percent)
Project NPV lost	63.7	1.4
Federal tax losses	20.3	0.9
State tax losses	6.1	0.3
Lost royalties	8.4	0.2
Total losses	98.5

Production losses under the selected BAT options are expected to total at most 5.8 million barrels of oil equivalent (BOE) over the lifetime of the wells and platforms (average post-compliance lifetime is 10 years in Major Pass and 12 years in Cook Inlet operations). In Cook Inlet, EPA expects the production loss over the productive lifetimes of the platforms to be approximately 2.4 million BOE, which is 0.5 percent of the estimated lifetime production for Cook Inlet. For Major Pass operations, the lifetime production loss is expected to be up to 3.4 million

total BOE, which is 0.6 percent of estimated lifetime production from these facilities. For the two regions combined, the loss in production is 0.5 percent of total nondiscounted lifetime production in Cook Inlet and the Major Passes, or 0.2 percent of all Coastal oil and gas production. These losses result only from shortened economic lifetimes; no platforms or treatment facilities are expected to shut-in immediately due to the selected options.

The rule is not likely to have a significant affect on energy prices, international trade, or inflation, and it would have a minimal and indeterminate impact on national-level employment. On average, the Major Pass facilities shut in 0.4 years earlier than they would without the rule (in 9.9 years instead of 10.3 years). In Cook Inlet, platforms shut in an average of 0.4 years earlier (in 12.3 years instead of 12.7 years). These impacts would have a minor effect on regional employment because ample time is still available for workers to find alternative employment, an effort they would need to undertake within a similar time frame without the rule. Based on the predicted economic impacts, EPA finds that the costs of the BAT limitations are economically achievable for the coastal oil and gas industry.

b. Impacts from NSPS. EPA does not expect compliance with any of the selected NSPS options to have a measurable impact on oil and gas income, royalties or taxes. EPA estimates no costs for the NSPS requirement for produced water in the Gulf of Mexico, because NSPS are the same as BAT and therefore are economically achievable and pose no barrier to entry. EPA also estimates no cost for the NSPS requirement for drilling wastes in the Gulf, because zero discharge represents the current BAT requirements. Therefore, NSPS is economically achievable and poses no barrier to entry. In the major passes, EPA estimates zero cost for NSPS also because EPA has determined that no new sources are planned that will discharge produced water. Costs of NSPS for TWC are associated only with 45 new source wells per year projected in the Gulf coastal region. Total annual NSPS compliance costs for TWC limits are \$0.6 million.

In Cook Inlet, NSPS requirements for produced water/TWC are equivalent to BAT requirements, and are therefore economically achievable and pose no barriers to entry. Costs for designing in compliance equipment to new structures are typically less than those for retrofitting the same equipment to existing operations. Based on

discussions with industry and on EPA's assessment of economic conditions given present oil prices and production trends from Cook Inlet's aging fields, the Agency expects no new facility (platform) construction in Cook Inlet. Therefore, EPA estimates NSPS costs at zero for Cook Inlet for all wastestreams. However, if potential revenue did support the construction of a new facility in Cook Inlet, NSPS produced water compliance costs would increase total capital costs by an estimated 2.3 percent. This would not influence a decision to build, as profits in Cook Inlet have a "hurdle rate" of somewhere around 20 to 25 percent. The hurdle rate is the estimated rate of return needed to interest an investor in undertaking an investment. It is particularly high in high-risk ventures such as Cook Inlet oil production. A 2.3 percent increase in capital costs would not alter the profit margin sufficiently to discourage construction of a facility. NSPS requirements for drilling waste are also the same as BAT requirements and, further, add no costs and thus are economically achievable and pose no barriers to entry. As noted above, EPA rejected zero discharge of drilling fluids, drill cuttings and dewatering effluent for BAT in Cook Inlet primarily for technological reasons; these reasons also apply to NSPS.

3. Economic Impacts of Rejected Options

EPA has determined that zero discharge of all wastestreams is both economically achievable and technically feasible in the coastal Gulf of Mexico. As stated in Section VII, EPA rejected BAT and NSPS limitations requiring zero discharge of produced water in Cook Inlet on the basis that this option was not economically achievable, nor was the combination of zero discharge of produced water and zero discharge of drilling wastes. The economic analysis related to these decisions for Cook Inlet is presented in the following section.

a. Produced Water. EPA rejected zero discharge of produced water in Cook Inlet base on a finding that it was not economically achievable, as discussed in Section VII(B)(4)(a)(2) above.

b. Drilling Fluids and Drill Cuttings. In establishing BAT limitations and NSPS for drilling fluids, drill cuttings and dewatering effluent in Cook Inlet, EPA rejected zero discharge primarily due to uncertainty regarding the technical feasibility of reinjection of drilling fluids, drill cuttings and dewatering effluent throughout the Inlet, as well as the operational problems and non-water quality

environmental impacts resulting from land disposal in the area. Zero discharge of these wastes may be particularly costly in Cook Inlet because of the lack of suitable geological formations for injecting drilling wastes (see Section VII). EPA estimated the annualized costs of zero discharge of drilling fluids, drill cuttings and dewatering effluent to be \$9.2 million, based on transporting some of these wastes to out-of-state landfills. EPA further determined that the combined impact of zero discharge of drilling fluids, drill cuttings and dewatering effluent and zero discharge of produced water in Cook Inlet would result in 4 of 13 platforms closing, which EPA considers to indicate economically unachievability.

4. Alternative Analytical Baseline

In response to comments from the Railroad Commission of Texas (RRC), on behalf of certain Texas dischargers who have applied for individual permits, and from the U.S. Department of Energy (DOE), on behalf of dischargers to open bays in Louisiana, EPA considered what the impacts of the Coastal Guidelines would be if EPA Region 6 (Texas) or the State of Louisiana were to grant individual permits to these dischargers allowing discharge of produced water. The RRC identified dischargers in Texas who have applied for individual permits (74 applicants for 82 facilities at the time of this analysis) and DOE identified 82 discharging facilities (outfalls) in Louisiana open bays operating under 37 permits.

EPA estimated effects on Texas Individual Permit applicants and Louisiana Open Bay operators at both the well level and at the facility level (unlike Cook Inlet and Major Pass operators, who were analyzed only at the facility or platform level). The well-level analysis tends to overestimate impacts, as each well is assumed to bear costs that are often shared by several wells served by a facility. Cost-sharing allows lower costs per well and allows more productive wells to support less productive ones as long as net present value is maximized. Many of the facilities identified by RRC and DOE were already included in EPA's Coastal Oil and Gas Questionnaire database. Costs and impacts to the remaining facilities were modeled based on operators' reported discharges and oil and gas production.

EPA addressed the effects of zero discharge for combined discharges of produced water and TWC in this analysis of Texas Individual Permit applicants and Louisiana Open Bay operators. BAT for other wastestreams is addressed by Region 6 permits. Section

VIII(C)(4)(a) addresses the effects of zero discharge only on the Texas Individual Permit applicants and Louisiana Open Bay facilities. Section VIII(C)(4)(b) assesses the combined effects on these Texas and Louisiana facilities together with costs and impacts to Major Pass and Cook Inlet dischargers. The impacts on Major Pass dischargers under the alternative baseline includes estimated compliance costs for zero discharge of produced water from coastal wells. Including coastal produced water increases Major Pass dischargers' costs by approximately 20 percent.

a. Produced Water BAT Impacts: Texas Individual Permits and Louisiana Open Bays. Relative to the alternative baseline, EPA estimates total annualized compliance costs for the Texas Individual Permit and Louisiana Open Bay dischargers to attain zero discharge of produced water to be \$34.2 million. EPA estimates related production losses would be approximately 12.8 million non-discounted BOE compared to the baseline. This represents less than one percent of all Gulf coastal production, most of which is already in compliance with zero discharge requirements. These losses are associated with declines in project NPV of up to \$126.7 million, or 3.4 percent of Gulf Coastal projects' NPV.

Production losses result from both first-year shut-ins and shortened economic lifetimes. In the well-level analysis, a range of 284 to 400 baseline shut-ins are estimated to take place before compliance costs are incurred, and up to 94 to 119 wells may be first year post-compliance shut-ins under the selected options. These baseline and first-year shut-ins are likely to be overestimates that result from EPA's well-level modeling approach, which EPA addresses in sensitivity analyses below and in Chapter 10 of the EIA. The 94 to 119 first year shut-in wells constitute approximately 1 to 2 percent of all Gulf coastal wells. Based on a screening analysis, EPA identified up to four potential firm failures, which represent less than one percent of all Gulf of Mexico coastal firms. These results are derived from an analysis based on well-level impacts, a conservative approach that exaggerates both baseline and post-compliance well shut-ins.

The BAT requirements could result in a present value loss of up to \$36.7 million in federal tax revenues, or up to \$5.2 million, on average, annually (1.9 percent of federal revenues from Gulf coastal production). Losses to state income and severance tax revenues could total \$19.8 million, or \$2.8 million annually (0.9 percent of

revenues from Gulf coastal production). The states (and individuals) could also lose royalties with an estimated present value of \$25.1 million, or \$3.6 million annually (0.5 percent of revenues from Gulf coastal production). These impacts of the Coastal Guidelines are acceptable when compared to total federal and state tax revenues and royalties collected from all Gulf coastal operators.

The impacts of the rule on Louisiana Open Bay dischargers and Texas Individual Permit applicants are not expected to affect energy prices, international trade or inflation, and would have a minimal impact on national-level employment. Total national employment losses would be expected to be 231 full-time equivalents (FTEs), which is approximately 2 percent of total Gulf of Mexico coastal oil and gas employment. EPA finds that, under the assumptions of the alternative baseline, while the economic impacts of the Coastal rule are significant to some individual operators, they are economically achievable when compared to the Coastal industry as a whole.

In response to late comments from the state of Texas, EPA has also conducted a sensitivity analysis at the facility level for each and every well identified as a baseline or first year shut-in among the Texas individual permit applicants group, based on actual facility level production and costs as reported by the operators of these wells. EPA's alternative analysis shows that, in fact, when these wells are treated as components of an entire facility, that is, where total facility production revenues must exceed facility operating costs in order to keep operating, most of these wells do remain open in the baseline and do not shut in as a result of compliance. Many of the wells do not produce much produced water (which generates compliance costs). The production from those wells that do shut-in simply cannot support, on a facility basis, the annual operations and maintenance costs reported by the operators. In this alternative analysis, the one (first year) post-compliance well shut-in that was identified in EPA's original well-level analysis does not shut-in during the first year.

The facility level analysis shows 8 baseline shut-in wells (all in Texas) with the Coastal rule causing 16 first year shut-ins only among Louisiana Open Bay producers (compared to a total of 94 first year shut-ins for both states in the well level analysis). The firm failure analysis does not change. EPA concludes that its facility level analysis indicates that the effect on Texas and Louisiana operators of the

coastal rule will be even less significant than reported in the well-level analysis (see Chapter 10 of EIA).

TABLE 4.—ECONOMIC IMPACTS OF PRODUCED WATER/TWC ZERO DISCHARGE BAT OPTIONS ON TEXAS INDIVIDUAL PERMIT APPLICANTS AND LOUISIANA OPEN BAY DISCHARGERS

Impact	Present value (\$ million)	Percent of Gulf Coastal subcategory (percent)
Project NPV lost	126.7	3.4
Federal tax losses	36.7	1.9
State taxes	19.8	0.9
Lost Royalties ...	25.1	0.5
Total losses	208.4	1.6

b. BAT and NSPS Impacts: Alternative Baseline Analysis. The analysis of the alternative baseline includes all of the financial impacts from the current regulatory requirements baseline and adds the impacts of compliance costs on Louisiana Open Bay dischargers, Texas Individual Permit applicants and the coastal portion of the Major Pass dischargers. For all of these facilities—Major Passes, Cook Inlet, Texas Individual Permit applicants and Louisiana Open Bay dischargers—the total annual BAT and NSPS compliance costs, including produced water, TWC, and drilling fluids, drill cuttings and dewatering effluent options are \$52.9 million relative to the alternative baseline (Table 5). Under the alternative baseline, produced water compliance costs for Major Pass facilities increase by approximately 20 percent, compared to the current regulatory requirements baseline, to account for the costs of zero discharge of their coastal share of produced water.

TABLE 5.—TOTAL COSTS OF BAT AND NSPS OPTIONS (\$1995)—ALTERNATIVE BASELINE

Wastestream	Annualized compliance costs (\$ million/yr)	
	BAT	NSPS
Produced Water/TWC Option 2 (BAT)	52.3	0.00
Drilling fluids, drill cuttings and dewatering effluent ..	0.00	0.00
Treatment Workover and Completion fluids (NSPS)	0.00	0.6

Relative to the alternative baseline, production losses associated with the selected BAT options are expected to be approximately 18.6 million barrels of oil equivalent (BOE) over the lifetime of the affected wells, facilities, and platforms. This is approximately 0.6 percent of total lifetime nondiscounted production in the coastal Gulf and Cook Inlet regions combined. Only 3 firms in Texas and one in Louisiana would be potential failures, and a maximum of 94 wells (2% of total coastal wells) would shut in. Most of these wells would shut in only a few years without the rule. Declines in the net present value of project worth would be approximately \$200 million or \$28 million annually discounted over 10 years (4.4 percent of total coastal NPV). BAT requirements could result in a present value loss of \$60 million in federal tax revenues, or \$8.5 million annually (2.5 percent of federal tax revenue from coastal operations). State income and severance tax revenues losses associated with BAT requirements would be approximately \$26.6 million or \$3.8 million annually (1.1 percent of all state tax revenue from coastal operations). The states and other individuals could also lose royalties totaling an estimated present value of \$33.6 million, or \$4.8 million annually (0.6 percent of coastal royalties).

The Coastal rule is not expected to affect energy prices, international trade or inflation, and would have a minimal impact on national-level employment. National level employment losses would be expected to be approximately 375 full-time equivalents (FTEs, or annual jobs) Table 6 summarizes the impacts discussed above.

NSPS compliance costs are the same as under the current regulatory requirements baseline, for reasons explained above. Based on the impacts predicted, EPA finds that the costs of the BAT limitations and NSPS are economically achievable relative to the alternative baseline for the Coastal Oil and Gas Industry.

TABLE 6.—SUMMARY OF IMPACTS OF SELECTED BAT OPTIONS: ALTERNATIVE BASELINE

Impact	Present value (\$million)	Percent of coastal subcategory (percent)
Project NPV lost	200	4.4
Federal tax losses	60	2.5
State taxes	26.6	1.1
Lost Royalties ...	33.6	0.6
Total losses	319.5	2.1

D. Cost-Effectiveness Analysis

In addition to the foregoing analyses, EPA has conducted cost-effectiveness analyses for all options considered by the Agency. Results of these analyses are presented in *Cost-Effectiveness Analysis for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*, which is included in the rulemaking record. Cost-effectiveness evaluates the relative efficiency of options in removing toxic pollutants. Costs evaluated include direct compliance costs, such as capital expenditures and operations and maintenance costs.

Cost-effectiveness results are expressed in terms of the incremental and average costs per “pound-equivalent” removed. A pound-equivalent is a measure that addresses differences in the toxicity of pollutants removed. Total pound-equivalents are derived by taking the number of pounds of a pollutant removed and multiplying this number by a toxic weighting factor. EPA calculates the toxic weighting factor using ambient water quality criteria and toxicity values. The toxic weighting factors are then standardized by relating them to a particular pollutant, in this case copper. EPA’s standard procedure is to rank the options considered for each waste stream in order of increasing pounds-equivalent (PE) removed. The Agency calculates incremental cost-effectiveness as the ratio of the incremental annual costs to the incremental pounds-equivalent removed under each option, compared to the previous (less effective) option. Average cost-effectiveness is calculated for each option as a ratio of total costs to total pounds-equivalent removed. EPA reports annual costs for all cost-effectiveness analyses in 1981 dollars, to enable limited comparisons of the cost-effectiveness among regulated industries.

At proposal, EPA solicited comment regarding the inclusion of indirect costs (e.g., oil and gas production-related losses) in its analysis of cost-effectiveness. With previous effluent guidelines, EPA has not included indirect costs associated with control technology options in cost-effectiveness analyses. While the primary purpose of the cost-effectiveness analysis is to compare the removal efficiencies of technology options for a given rule, a secondary use has been to benchmark the removal efficiency of a rule’s selected option in comparison to other effluent guidelines. Including additional costs that were not considered in other rules makes such comparisons less

meaningful. In response to comment, however, in this rule, EPA addresses cost-effectiveness in two separate analyses: first, EPA conducts the conventional analysis, considering only direct capital and operations and maintenance costs; and, second, EPA evaluates the cost of lost oil/gas production in addition to direct

compliance costs. The two approaches are compared in Tables 9 and 10. Table 7 presents the cost-effectiveness of different options considered for produced water/TWC and drilling wastes, for the current regulatory requirements baseline. Table 8 provides the produced water/TWC cost-effectiveness results for the alternative

baseline (the cost-effectiveness of drilling waste options is the same in both baselines). Table 7 shows that all considered options for produced water/TWC wastes, including zero discharge (with an incremental cost-effectiveness ratio of \$42 per pound-equivalent) are cost-effective.

TABLE 7.—COST-EFFECTIVENESS OF ALL OPTIONS: CURRENT REGULATORY BASELINE

Option	Total annual		Incremental		Average C-E (\$/Lb-Eq)	Incremental C-E (\$/Lb-Eq)
	Lb-Eq removed	Cost (\$1981)	Lb-Eq removed	Cost (\$1981)		
Produced Water/TWC:						
Option 1: Zero Discharge, Gulf/Discharge Limits, Major Pass & Cook Inlet	489,305	2,386,206	489,305	2,386,206	5	5
Option 2: Zero Discharge, Gulf/Discharge Limits, Cook Inlet	712,335	10,081,484	223,030	7,695,278	14	35
Option 3: Zero Discharge, All	1,213,725	30,935,664	501,390	20,854,180	25	42
Drilling fluid/cuttings:						
Option 1: Current limits	0	0	0	0	0	0
Option 2: Zero Discharge All	8,536	5,969,728	8,536	5,969,728	699	699

Table 8 shows that the cost-effectiveness analysis for produced water using the alternative baseline versus the current regulatory requirements baseline does not significantly change the outcome. Significant additional pounds of toxics are removed to offset the increased costs associated with using the alternative baseline.

TABLE 8.—COST-EFFECTIVENESS OF PRODUCED WATER/TWC OPTIONS: ALTERNATIVE BASELINE

Produced water/TWC option	Total annual		Incremental		Average C-E (\$/Lb-Eq)	Incremental C-E (\$/Lb-Eq)
	Lb-Eq removed	Cost (\$1981)	Lb-Eq removed	Cost (\$1981)		
Option 1: Zero Discharge, Gulf/Discharge Limits, Major Pass & Cook Inlet	1,091,754	24,502,620	1,091,754	24,502,620	22	22
Option 2: Zero Discharge, Gulf/Discharge Limits, Cook Inlet	1,314,784	33,781,413	223,030	9,278,983	26	42
Option 3: Zero Discharge, All	1,816,174	54,635,592	501,390	20,854,180	30	42

Tables 9 and 10 present the cost-effectiveness of selected produced water options, under both baselines, with and without the inclusion of production losses, respectively. Incremental and average cost-effectiveness for zero discharge of produced water under both baselines, not including production loss costs (i.e., EPA's standard analysis) are shown in Table 9; cost-effectiveness

results for zero discharge, including the value of production losses are shown in Table 10. The inclusion of production losses has a relatively minor effect on the selected options' cost-effectiveness. In fact, the costs shown, including production losses (Table 10), are somewhat less than those in Table 9. This is because, in order to avoid double counting, EPA assumed no compliance

costs associated with baseline and first year shut-ins and dry wells. These facilities would not incur compliance costs if they immediately shut in. Eliminating these facilities from the database used for compliance cost analysis results in lower total compliance costs, even though the value of their lost production is factored in.

TABLE 9.—COST-EFFECTIVENESS OF SELECTED OPTIONS—DIRECT COMPLIANCE COSTS ONLY

Wastestream	Lb-Eq removed	Cost (\$1981)	Average cost-effectiveness (\$/Lb-Eq)	Incremental cost-effectiveness (\$/Lb-Eq)
Produced Water/TWC:				
Current Requirements Baseline	712,335	10,081,484	14	35
Alternative Baseline	1,314,784	33,781,413	26	42

TABLE 10.—COST-EFFECTIVENESS OF SELECTED OPTIONS—COMPLIANCE COSTS AND PRODUCTION LOSSES

Wastestream	Lb-Eq removed	Cost (\$1981)	Average cost-effectiveness (\$/Lb-Eq)	Incremental cost-effectiveness (\$/Lb-Eq)
Produced Water/TWC:				
Current Requirements Baseline	712,335	9,494,585	13	31
Alternative Baseline	1,314,784	29,817,756	23	37

Based on the cost-effectiveness results shown in Tables 7 through 10, EPA has determined that the selected options are cost-effective.

IX. Non-Water Quality Environmental Impacts

The elimination or reduction of one form of pollution has the potential to aggravate other environmental problems. Under sections 304(b) and 306 of the CWA, EPA is required to consider these non-water quality environmental impacts (including energy requirements) in developing effluent limitations guidelines and NSPS. In compliance with these provisions, EPA has evaluated the effect of these regulations on air pollution, solid waste generation and management, consumptive water use, and energy consumption. Because the technology basis for the limitation on drilling fluids and drill cuttings requires transporting the wastes to shore for treatment and/or disposal, adequate onshore disposal capacity for this waste is critical in assessing the options. Safety, impacts of marine traffic on coastal waterways, and other factors related to implementation were also considered. EPA evaluated the non-water quality environmental impacts on a regional basis. Although not specifically detailed in the discussion below, the non-water quality environmental impacts that would be associated with requirements on future drilling and production activities in regions other than the Gulf of Mexico, California, and Alaska are considered acceptable because they would be considered to be similar to the impacts determined to be acceptable in the Gulf of Mexico, California, and Alaska. The non-water quality environmental impacts associated with requirements for drilling wastes and produced water are discussed below. The limitations and standards being promulgated for the remaining wastestreams covered by this rule will result in no significant increases in non-water quality environmental impacts.

A. Drilling Fluids, and Cuttings

The non-water quality environmental impacts quantified for the drilling

fluids, drill cuttings, and dewatering effluent control options are limited to the wastes generated in Cook Inlet. All other coastal areas are currently achieving zero discharge of these wastes and thus the control options cause no additional impacts. The control technology basis for compliance with the drilling waste options considered is a combination of product substitution and transportation of drilling wastes to shore for treatment and/or disposal. It is possible that in certain areas compliance with a zero discharge limitation for a portion of the drilling wastes would be achieved of by grinding followed by injection in disposal wells. However, EPA is unable to determine the degree to which this may be possible. The non-water quality environmental impacts associated with the treatment and control of these wastes from new wells at existing sources are summarized in Table 10. No new sources are expected to be developed in Cook inlet. Therefore, no non-water quality environmental impacts are expected to result from the NSPS requirements for drilling wastes.

EPA's methodology for calculating non-water quality environmental impacts is generally unchanged from the proposal. (See the preamble for the proposed rule at 60 FR 9467.) Certain assumptions related to waste handling and disposal which affect fuel use and air emissions have been updated. These changes are summarized in Section V of the preamble and presented in more detail in the Coastal Development Document and the record for the final rule.

TABLE 10.—NON-WATER QUALITY ENVIRONMENTAL IMPACTS FOR DRILLING WASTE CONTROL OPTIONS

Options	Energy consumption (BOE/year)	Air emissions (tons/year)
Option 1: Zero discharge all except Cook Inlet	0	0

TABLE 10.—NON-WATER QUALITY ENVIRONMENTAL IMPACTS FOR DRILLING WASTE CONTROL OPTIONS—Continued

Options	Energy consumption (BOE/year)	Air emissions (tons/year)
Option 2: Zero discharge all	5,200	36

B. Produced Water and Treatment, Workover and Completion Fluids

The energy requirements and air emissions calculated for produced water control options considered for existing sources are presented in Table 11. These non-water quality environmental impacts have been updated since proposal to address changes in the industry profile which have affected the volume of produced water requiring treatment and/or disposal. The technology bases used to quantify these impacts are improved gas flotation and subsurface injection. Detailed discussions of the additional equipment required to comply with the control options are included in the Coastal Development Document and the record for the final rule. EPA's estimates of the non-water quality environmental impacts calculated using the alternative baseline are presented in the Coastal Development Document.

Non-water quality environmental impacts from produced water and treatment, workover, and completion fluids NSPS accrue only from injection of TWC fluids. This is because for produced water, NSPS reflects current requirements, except for main pass dischargers. Thus, in the absence of NSPS, dischargers would have to meet BAT, which is zero discharge. There are no non-water quality environmental impacts for produced water and TWC fluids NSPS in Cook Inlet. There are no non-water quality environmental impacts for produced water in the main passes of the Mississippi River or Atchafalaya River, because no new sources are projected in these locations. Elsewhere in the Gulf, where new

sources are projected, existing general permits allow discharge of TWC fluids. Thus, EPA estimated the non-water quality environmental impacts resulting from injection of TWC fluids at new sources. These impacts are an increase in total air emissions by two tons per year and approximately 190 BOE per year in additional fuel use. These air emissions represent a small portion of the total emissions from coastal oil and gas activities along the Gulf Coast.

TABLE 11.—NON-WATER QUALITY ENVIRONMENTAL IMPACTS FOR PRODUCED WATER AND TWC FLUIDS CONTROL OPTIONS FOR EXISTING SOURCES

Options	Energy consumption (BOE/year)	Air emissions (tons/year)
Option 1: Zero Discharge; Except Major Deltaic Pass and Cook Inlet Based On Improved Gas Flotation	4,800	43
Option 2: Zero Discharge; Except Cook Inlet Based On Improved Gas Flotation	93,700	1,110
Option 3: Zero Discharge All	188,000	1,260

X. Environmental Benefits Analysis

A. Introduction

This section describes results of EPA's environmental benefits analysis. EPA's complete environmental benefits analysis is presented in the *Water Quality Benefits Analysis of Final Effluent Limitation Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category* EPA-821-R-96-024 (hereinafter, WQBA), included in the rulemaking record. The WQBA evaluates the effect of current discharges on the coastal environment and the benefits of the Coastal Guidelines. Two baselines, the current requirements baseline and the alternative baseline that are discussed in the preamble above, are used in this analysis. In addition, this analysis parallels the option selection discussion by distinguishing between Cook Inlet and all other coastal locations. For purposes of the WQBA, only the two main wastestreams (i.e., produced water and drilling fluids and drill cuttings) are evaluated. The analysis was limited to these wastestreams because: (1) Treatment, workover, and completion

fluids are conservatively considered to be a component of the produced water wastestream and (2) regulatory options considered for the other wastestreams reflect current permit requirements where applicable or current practice.

The WQBA examines potential impacts from current produced water discharges in both geographic areas, and from drilling fluids and drill cuttings discharges in Cook Inlet. The effects of produced water for other coastal areas (i.e., Florida, Alabama, Mississippi, California and North Slope, Alaska), and drilling fluids and drill cutting discharges in addition to the above coastal areas in Louisiana and Texas are not evaluated because they are prohibited by state authorities and existing NPDES permits, and EPA has issued no individual permits allowing these discharges.

Under the current requirements baseline, this rule will require major deltaic pass dischargers of offshore wastes (Major Pass facilities) to meet zero discharge of produced water, and Cook Inlet dischargers to meet new oil and grease limits for the discharge of produced water and current limits for the discharge of drilling fluids and drill cuttings. Under the alternative baseline, EPA investigated the impacts of produced water discharges by Texas individual permit applicants and Louisiana Open Bay dischargers on the coastal environment, and the benefits of zero discharge. Two types of benefits are analyzed: quantified (including non-monetized and monetized benefits), and non-quantified benefits.

Coastal waters have diverse ecosystems which: act as spawning grounds, nurseries and habitats for important estuarine and marine species (finfish and shellfish); support highly valuable commercial and recreational fisheries; and provide vital habitat for seabirds, shore birds and terrestrial wildlife. A majority of commercial and recreational shellfish (oysters, shrimps, and crabs) and many finfishes spend significant portion of their life in bays and estuaries. Total 1994 value of commercial fisheries (including both finfish and shellfish) \$336 million for Louisiana and \$207 million for Texas, for total of \$543 million. The 1995 value of Cook Inlet commercial fisheries (finfish, and shellfish) was \$51 million. The estimated Cook Inlet recreational fishery is valued at \$28 million per year (in 1995 dollars). In addition, personal use and subsistence fisheries provide a food source to the Gulf of Mexico coastal residents and a food source and cultural values to Alaskan residents and Alaskan native populations. Coastal areas also serve as vital habitats for

numerous federally designated endangered and threatened species (including 32 in coastal areas of Louisiana and Texas), and migrating waterfowl.

The coastal waters along the Gulf of Mexico are generally shallow, where tidal action has limited effect, and dilution and dispersion are more limited than offshore waters. Additionally, pollutants can migrate much more readily into sediments, where they may have long residence times. Consequently, these receiving environments are highly sensitive to pollutant discharges compared to open offshore areas. Many of the pollutants in coastal oil and gas discharges are either conventional pollutants, aquatic toxicants, human carcinogens, or human systemic toxicants. The aquatic impact of these pollutants on biota include acute toxicity; chronic toxicity; effects on reproductive functions; physical destruction of spawning and feeding habitats; and loss of prey organisms. In addition, many of these pollutants are persistent, resistant to biodegradation and accumulate in sediments and aquatic organisms. Chemical contamination of coastal water, sediment and biota may also directly or indirectly impact local aquatic and terrestrial wildlife and humans consuming exposed biota.

The five major passes of the Mississippi River receiving produced water from offshore operations differ physically in depth, river flows and sediment types. Compared to the narrower, more energetic passes with hard packed sand, flows in shallower, wider passes are of slower velocity, resulting in more organic bottom deposits and thus supporting more organic life. All these passes are important nursery grounds for both saltwater and freshwater organisms and support recreational and commercial fishery. The deltaic region of the Mississippi River ranks in the top 10% for productivity of all United States wetland estuaries. This region also includes the Delta National Wildlife Refuge (NWR) and the Pass a Loutre State Fish and Game Preserve (SFGP), which in turn support one of the largest wading bird rookeries in the United States and hundreds of thousands of wintering waterfowl. Three major passes receiving offshore produced water are connected to this region. Raphael Pass winds directly through Delta NWR, while Emeline Pass establishes the northern border of this refuge. North Pass is included as part of the northern border of Pass a Loutre SFGP.

Compared to the Gulf of Mexico region, Cook Inlet is an extremely

dynamic tidal estuarine system and its physical characteristics influence the fate and transport of contaminants in its waters. Water movement in Cook Inlet is dominated by the tidal cycle and strongly influenced by the freshwater inputs from rivers and precipitation.

Benefits of Coastal Guidelines include elimination or reduction of toxic, conventional, and nonconventional pollutants, and elimination or reduction of impacts on human health and aquatic life. Potential benefits may ultimately

include reduction of discharge-related aquatic habitat degradation; improved recreational fisheries; improved subsistence and personal use fisheries (potentially important to low-income anglers and Alaska's Native anglers, etc.); improved commercial fisheries; improved aesthetic quality of waters; improved recreational opportunities; and decreased harm to threatened or endangered species in the Gulf of Mexico and Cook Inlet.

Under the current requirements baseline, the Coastal Guidelines would eliminate total of about 1.5 billion pounds of pollutants to the coastal receiving waters of states adjacent to the Gulf of Mexico and to Alaskan waters. Under the alternative baseline, the Coastal Guidelines would eliminate total of 4.6 billion pounds of conventional, toxic and nonconventional pollutants (including Gulf of Mexico and Cook Inlet) (see Table 12).

TABLE 12.—POLLUTANTS REMOVED BY CURRENT PERMIT REQUIREMENTS AND ALTERNATIVE BASELINES

Pollutants removed by coastal guidelines (lbs/year)	Removals under the current requirements baseline ¹				Additional removals under the alternative baseline		
	Produced water		Drilling fluids and cuttings	Total (lbs/year)	Produced water		Total (lbs/year) ²
	Major deltaic passes	Cook Inlet			Cook Inlet	Louisiana open bay dischargers	
Conventional	1,855,319	855,054	0	2,710,373	7,072,298	1,453,081	11,235,752
Toxic Organics	108,018	70,367	0	178,385	450,458	92,551	721,394
Toxic Metals	33,877	14,755	0	48,632	90,535	18,602	157,769
Nonconventional	1,490,602,961	560,011	0	1,491,162,972	2,571,382,167	528,318,780	4,590,863,919
Total Pollutants (lbs/year)	1,492,600,175	1,500,187	0	1,494,100,362	2,578,995,458	529,883,014	4,602,978,834

¹ Under the current permit requirements baseline, removals (excluding TWC effluent) would result from: zero discharge for Major Pass facilities, discharge limits for Cook Inlet produced water, and current limits for Cook Inlet drilling fluids and drill cuttings.

² Under the alternative baseline, removals (Excluding TWC effluent) would result from zero discharge of produced water for Louisiana open bay and Texas individual permit applicants, in addition to those removals already presented under the baseline for current permit requirements.

B. Quantitative Estimate of Benefits.

(1) Current Requirements Baseline

(a) Quantified Non-Monetized Benefits—Gulf of Mexico. The benefits associated with zero discharge of produced water under the current requirements baseline include only non-monetized benefits (i.e., (i) review of case studies of environmental impacts of produced water that document adverse chemical and biological impacts resulting from current discharges into the Gulf of Mexico coastal area; (ii) modeled water quality benefits expressed as elimination in exceedances of human health or aquatic life state water quality standards for major deltaic pass facilities; and (iii) projected individual cancer risk reduction from consumption of seafood contaminated with Ra²²⁶ and Ra²²⁸ based on modeled levels for major deltaic pass dischargers. EPA could not estimate the potential number of cancer cases avoided and monetize benefits for these facilities, however, because the exposed angler population could not be determined for major pass facilities alone.

(i) Documented Case Studies. A comprehensive review of available data identified 25 study sites (12 in Louisiana and 13 in Texas) that

examined impacts of produced water discharges on the coastal environment. The detailed description and complete references for these studies are presented in the WQBA included in the rulemaking record. The majority of evaluated study sites are in water depths less than 3 meters, and include variable environments (i.e., wetlands, salt marshes, and fresh or brackish marshes), and both relatively low and high energy areas. The documented impacts show elevated hydrocarbons and metals in water column and sediments, and reveal impacts on biota (i.e., depressed community structure such as abundance or diversity) from the produced water discharge between 800 to 1000 meters in dead-end canals and effluent dominated creeks or bayous. The salinity effects are typically detected up to 300 meters from the discharge, and up to 800 meters in dead-end canals. A benthic dead zone (no benthic fauna) is documented up to 15 meters and severely depressed benthic communities are noted to 150 to 400 meters from produced water outfalls.

(ii) Projected Water Quality Benefits—Major Deltaic Pass Facilities. EPA evaluated the effects of toxic pollutants in current produced water discharges on receiving water quality. Of the 49 toxic

and nonconventional produced water pollutants (representing subcategory-wide produced water discharge), plume dispersion modeling was performed to project in-stream concentrations of 11 toxic pollutants with specified water quality standards in Louisiana. (There are no specified water quality standards for the other 38 pollutants). Pollutant concentrations were projected at the edge of state-prescribed mixing zones for acute and chronic aquatic, and human health standards for Louisiana. Site-specific cases (including ambient water depth and operational data) were developed for five (of six) major deltaic pass facilities/dischargers. (The effects of current discharges for one discharger was not evaluated because of the lack of site-specific ambient data.)

Of the six major deltaic pass dischargers, all five that were evaluated are projected to have discharges that exceed applicable human health or aquatic life water quality standards. Five dischargers are modeled to exceed the human health standard for benzene and the acute standard for copper. One discharger is modeled to exceed the acute aquatic life standard for toluene, and another to exceed the chronic aquatic life standards for copper and nickel. The final guideline's zero

discharge requirement would eliminate all projected exceedances.

EPA recognizes that in the absence of this rule, the permit issuing authority (the State of Louisiana or EPA in Texas) would be required to develop water quality-based effluent limits at the permitting stage. This rule would eliminate the need to develop such limits at the permitting stage for the pollutants of concern. It may also lessen the possibility that the state will in the future have to develop a Total Maximum Daily Load for the pollutants under § 303(d) of the CWA.

EPA recognizes that in the absence of this rule, the permit issuing authority (the State of Louisiana or EPA in Texas) would be required to develop water quality-based effluent limits at the permitting stage. This rule would eliminate the need to develop such limits at the permitting stage for the pollutants of concern. It may also lessen the possibility that the state will in the future have to develop a Total Maximum Daily Load for the pollutants under section 303(d) of the CWA.

In response to late comments, EPA reevaluated its use of the water quality model CORMIX to assess discharges to Major Deltaic Passes. In these areas, LADEQ regulations allow the use of other appropriate models in addition to the Complete Mix Balance Model (CMBM) specified in regulations. EPA used CORMIX because it is technically superior to the CMBM as discussed in the record. Nevertheless a sensitivity analysis was conducted using the CMBM. Use of CMBM still resulted in two of the outfalls exceeding criteria. One of these outfalls was the largest Major Deltaic Pass discharger with exceedances for benzene.

(iii) Projected Individual Cancer Risk Reduction Benefits—Major Deltaic Pass Dischargers. Upper bound individual cancer risks from consuming fish contaminated with Ra^{226} and Ra^{228} from current produced water discharges are estimated for recreational and subsistence anglers. To estimate Ra^{226} and Ra^{228} levels in seafood, EPA uses modeled effluent data, *i.e.*, current subcategory-wide produced water concentrations of Ra^{226} and Ra^{228} , plume dispersion modeling at site-specific discharge rates and water depths for five (of six) major deltaic pass facilities/dischargers with site-specific ambient data to support modeling. [Using the estimated Ra^{226} and Ra^{228} concentrations in seafood, EPA estimates individual cancer risks assuming two different consumption rates of 147.3 g/day for subsistence anglers and 15 g/day for recreational anglers]. In addition, all individual

cancer risks are adjusted by factors of 0.2 and 0.75 to account for ingestion of seafood from locations which are not contaminated with the Ra^{226} and Ra^{228} in coastal produced water discharges].

Projected individual cancer risks for 5 evaluated major deltaic pass facilities range from 2.4×10^{-5} to 6.3×10^{-4} for subsistence anglers and from 1.0×10^{-6} to 2.8×10^{-5} for recreational anglers. The Coastal Guidelines' zero discharge requirement for produced water will eliminate these estimated cancer risks over time.

EPA could not estimate the potential number of cancer cases avoided and monetize benefits for these facilities, however, because the exposed angler population could not be determined for major pass facilities alone.

(b) Quantitative Non-Monetized Benefits—Cook Inlet.

EPA analyzed non-monetized quantitative benefits associated with the Coastal Guidelines for produced water in Cook Inlet. These benefits include modeled water quality benefits expressed as reduction of mixing zone needed for produced water discharges to meet Alaska state water quality standards. (Effects of current drilling fluids and drill cuttings discharge are also evaluated, however, because this rule does not require a change in current practice no benefits are projected.)

Produced Water

EPA evaluated the effects of toxic pollutants in current produced water discharges on receiving water quality and the benefits of the final Coastal Guidelines. Site-specific plume dispersion modeling is performed to project in-stream concentration of 16 toxic and nonconventional pollutants at the edge of mixing zones from eight facilities constituting all of Cook Inlet produced water dischargers. The in-stream concentrations are then compared to the Alaska's state limitations. Unlike the Gulf of Mexico, Alaska state requirements do not have spatially-defined mixing zones. (Alaska determines the extent of mixing zone needed to achieve compliance with water quality standards and evaluates the reasonableness of this calculated mixing zone). The water quality assessment for Cook Inlet therefore determines the spatial extent of mixing zones needed for each evaluated outfall to meet all state standards at current discharge and at the final BAT. For the eight outfalls modeled, the distance from each facility where all standards are met ranges from within 100 meters to 3,500 meters at current level, and from within 100 meters to 1,000 meters for the final BAT.

2. Alternative Baseline

Under the alternative baseline, EPA investigated the impacts that Louisiana Open Bay dischargers and Texas individual permit applicants have on the coastal environment and projected the benefits associated with zero discharge of produced water for these dischargers. The projected quantified benefits include both: (a) Non-monetized benefits (*i.e.*, (i) reviewed a case study of environmental effects of Louisiana open bay produced water dischargers; (ii) modeled water quality benefits expressed as elimination in exceedances of human health or aquatic life state water quality standards; and (iii) projected individual cancer risk reduction from consumption of seafood contaminated with Ra^{226} and Ra^{228} based on modeled levels; and (b) monetized benefits (*i.e.*, (i) estimated avoidance of projected cancer cases (from consumption of seafood contaminated with Ra^{226} and Ra^{228} based on modeled levels) from Louisiana open bay and Texas permit applicant dischargers); and (ii) estimated ecological benefits of a zero discharge requirement for produced water open bay dischargers in Louisiana and permit applicants in Texas.

(a) Quantified Non-Monetized Benefits for Louisiana Open Bay and Texas Individual Permit Dischargers.

(i) The United States Department of Energy (DOE) conducted a study entitled *Risk Assessment for Produced Water Discharges to Louisiana Open Bays*, March, 1996 (hereafter, "DOE study"), included in the rulemaking record. This study evaluated potential human health and environmental risks from discharges of produced water to Louisiana open bays. The DOE study concluded that: "human health risks from radium in produced water appear to be small", and "ecological risks from radium and other radio nuclides in produced water also appear to be small". The DOE study also concluded that: "intakes of chemical contaminants in fish caught near open bay produced water discharges are expected to pose a negligible toxic hazard or carcinogenic risk", that a "potential impacts to benthic biota and fish and crustaceans in the water column are possible within the 200 ft mixing zone", but a "permanent damage to populations of organisms and ecosystems are not expected because mixing zones represent relatively small volumes and animals are not expected to remain continuously in the plume".

EPA believes that the study shows that there are impacts from coastal discharges, particularly regarding the

whole effluent toxicity and sediment contamination. Whole effluent toxicity risk assessment of Louisiana open bay dischargers conducted by the DOE study indicate that at 50 and 200 feet mixing zones 23 percent and 18 percent of modeled effluents exceed their respective LC50 values for mysids and sheep head minnows, and 57 percent and 56 percent of modeled effluents exceed their survival and growth-inhibition NOEL values, respectively, for mysids and sheep head minnow at 200 feet mixing zone. A sediment toxicity in excess of sediment quality "Effect Range Low" (ERL) and "Effect Range Medium" (ERM) criteria for heavy metals and total and individual PAH's is also documented by the study. (The measured values above ERL value, but less than ERM value "represent a possible-effects range within which effects would occasionally occur". Concentrations at or above the ERM value "represent a probable effect range within which effect would frequently occur" (Long, E.R., D.D. Macdonald, S.L. Smith, F.D. Calder, 1995, "Incidence of Adverse Biological Effects Within Ranges of Chemical Concentrations in Marine and Estuarine Sediments", Environmental Management 19:81-97).) Metals, arsenic and nickel are measured in excess of ERL value up to 500 m and 1000 m from discharge, respectively. The total and individual PAH's in excess of ERL are measured up to 500 m from discharge. The total PAH's, high molecular weight PAH's, and individual PAHs are also measured near discharge.

(ii) Projected Water Quality Benefits. The effects of toxic pollutants in current produced water discharges on receiving water quality and benefits associated with the Coastal Guidelines are evaluated. Of the 49 produced water pollutants (representing subcategory-wide produced water discharge), plume dispersion modeling is performed to project in-stream concentrations of 11 toxic pollutants with specified state water quality standards in Louisiana and in Texas. (There are no specified water quality standards for the other 38 pollutants in Louisiana and in Texas). Pollutant concentrations are projected at the edge of state-prescribed mixing zones for acute and chronic aquatic water quality standards, and human health water quality standards for Louisiana and Texas.

Estimated flow-weighted average ambient water depth characteristic and operational data are used for 69 Louisiana's open bay outfalls, and 82 Texas individual permit applicants. A mean discharge rate of 4,780 bpd and flow-weighted mean depth of 1.73

meters are used for Louisiana open bay dischargers, and mean discharge rate of 827 bpd and flow-weighted mean water depth of 1.66 meters for Texas permit applicants.

Eighteen of the 69 evaluated Louisiana's open bay outfalls are projected to exceed: acute aquatic life standards for two pollutants (copper and toluene); chronic aquatic life standards for four pollutants (copper, nickel, lead, and toluene); and human health standards for one pollutant (benzene). These 18 outfalls represent 79 percent of Louisiana's open bay total daily discharge flow. In Texas, eighteen of the 82 evaluated individual permit applicants are projected to exceed the acute and chronic aquatic life standards for silver. These 18 applicants represent 84 percent of the total produced water flow for the 82 applicants. The final guideline's zero discharge requirement would eliminate all projected exceedances.

EPA recognizes that in the absence of this rule, the permit issuing authority (State of Louisiana or EPA in Texas) would be required to develop water quality-based effluent limits at the permitting stage. This rule would eliminate need to develop such limits at the permitting stage for the pollutants of concern. It may also lessen the possibility the state will in the future have to develop a Total Maximum Daily Load for the pollutants under section 303(d) of the CWA.

(iii) Projected Individual Cancer Risk Reduction Benefits. Upper bound individual cancer risks from consuming fish contaminated with Ra²²⁶ and Ra²²⁸ from current produced water discharges are estimated for recreational and subsistence anglers. To estimate Ra²²⁶ and Ra²²⁸ levels in seafood, EPA uses: modeled effluent data, *i.e.*, current subcategory-wide produced water concentrations of Ra²²⁶ and Ra²²⁸; plume dispersion modeling at average outfall discharge rates and flow-weighted ambient average depths for 69 Louisiana open bay outfalls and 82 Texas individual permit applicant dischargers; and consumption rates as described in the section XII.B.1.(a)(iii) of this preamble.

Projected individual cancer risks from Louisiana open bay dischargers range from 2.9×10^{-4} to 1.1×10^{-3} for subsistence anglers and from 1.3×10^{-5} to 4.8×10^{-6} for recreational anglers. For Texas individual permit applicants, the projected individual cancer risks range from 3.7×10^{-5} to 1.4×10^{-4} for subsistence anglers and from 1.6×10^{-6} to 6.1×10^{-6} for recreational anglers. The Coastal Guidelines' zero discharge requirements for produced water will

eliminate these estimated cancer risks over time, resulting in projected elimination of 0.43 to 1.66 cancer cases per year for anglers consuming fish from the Louisiana open bay dischargers and Texas individual permit applicant dischargers (*i.e.*, 0.35 to 1.34 and 0.08 to 0.32 annual cancer cases in Louisiana and Texas, respectively)

(b) Quantified Monetized Benefits for Louisiana Open Bay and Texas Permit Applicant Dischargers.

(i) Projected Cancer Risk Reduction Benefits by Reducing Exposure to Radium in Produced Water. The projected avoidance of 0.43 to 1.66 cancer cases per year for anglers consuming fish from Louisiana open bay dischargers and Texas individual permit applicant dischargers will result in combined monetized benefits in \$1.1 to \$22.3 million per year (\$1995) range (including \$0.9 to \$18 million per year (\$1995) for Louisiana open bay dischargers and \$0.2 to \$4.3 million per year (\$1995) for Texas individual permit applicants).

The temporal dynamics of both impacts and benefits assessments is relevant to the human health risk assessment. For the assessments of cancer reduction benefits, the methodology is consistent with estimating costs for the rule, using a one-year "snap-shot" approach. Allocating the full value of annual benefits within one year following cessation of produced water discharges may appear to over-estimate potential annual benefits in cases where incomplete recovery has occurred. However, in such cases where impacts are incompletely recovered, a consideration of total impact would need to include any impacts expected to occur beyond that year. This analysis does not attempt to identify or allocate benefits on a yearly basis, but merely averages total benefits so that monetized benefits may be compared to costs that are developed using the same approach.

In response to late comments, EPA revised the population estimate of exposed individuals to reflect only coastal counties within 65 miles of the coast. The number of resident recreational anglers who only fish in state waters was adjusted by the proportion of state residents in coastal counties. EPA also received late comments to the effect that it should have used the monitoring data from the DOE study rather than EPA's modeled data. As is discussed further in the record, EPA continued to use the modeled effluent data rather than limited monitoring data to estimate risk. Although EPA modeling predicts radium concentrations significantly

higher than those measured in the DOE study, EPA believes it is not appropriate to use migratory fish species to represent tissue levels of all fish around platforms because EPA has information indicating that some resident species in coastal areas spend a significant amount of time in coastal waters.

(ii) Projected Ecological Benefits. A potential ecological benefit of zero discharge of produced water in Louisiana open bays and Texas individual permit applicants dischargers is projected from a Trinity Bay case study. Extrapolating from this case study is only applicable to shallow bay ecosystems contiguous with the Gulf of Mexico open bay discharge sites that are represented by the Louisiana open bay dischargers and the great majority of Texas individual permit applicant dischargers. This Trinity Bay study shows that sediment near the outfall (within 15 meters) were devoid of biota and that depressions in benthic abundance and species richness were not recovered until distances between 1.7 and 4 kilometers from the point of discharge. (Data on abundance of other species, such as waterfowl were not collected). Taking into account an integration of the severity of these impacts at different distances, the equivalent acreage affected in this case study ranges from 200 to 2,817 acres.

The analysis of this study is based on naphthalene concentration in sediment and extremely tight correlation between sediment naphthalene levels and benthic community structure parameters. In response to comments, EPA has adjusted the basis for projecting these effects because of the pre-BPT effluent quality of this study site and adjusted the acreage affected by the proportion between the Trinity Bay effluent naphthalene level (300 ppb) and current effluent naphthalene levels (184 ppb) to a 123 to 1,727 acres range.

EPA estimates that the total Louisiana and Texas open bay acreage affected by coastal oil and gas produced water discharges ranges from 6,918 acres to 97,438 acres (*i.e.*, 5,739 to 80,828 acres in Louisiana and 1,179 to 16,610 acres in Texas). EPA identifies numerous values for an acre of wetland but none are marginal estimates for Texas or Louisiana, and some did not subtract the cost of recreational use. There may be concern that the value of wetland recovery diminishes as the amount of recovered acreage increases and therefore these average values would overstate the relevant marginal values by an unknown amount. A literature review for wetland value estimates conducted for the Mineral Management Service (MMS), Department of Interior

in 1991, reports that different studies have estimated recreational and commercial wetland values for coastal Louisiana ranging from \$57 to \$940 per acre per year (with a median value of \$410 per acre per year) in 1990 dollars.

Using this range of values inflated to 1995 dollars, the estimated increase of Louisiana and Texas Bay recreational values from zero discharge of produced water ranges from \$0.48 million to \$106.8 million per year (*i.e.*, \$0.4 to \$88.6 million/year in Louisiana and \$0.08 to \$18.2 million/year in Texas).

These per acre estimates are consistent with the estimated average recreational value of the acreage of Galveston Bay, which ranges from \$336 to \$730 per acre. (\$1990) (The Galveston Bay estimates do not subtract the cost to recreational users of using the resource.) These estimates may not be marginal values as they are calculated from the total recreational value of Galveston Bay and total acreage of the Bay. As these studies use different estimation methods, cover different types of wetlands, marshes and coastal waters which may differ from those affected by this rule, and generally reflect average values rather than the social valuation of small (marginal) changes in acreage, EPA at proposal requested data on marginal values of wetlands, in particular in Louisiana and Texas. However, EPA did not receive any data on wetland values or any comments related to the values used in benefit analysis for the proposed rule.

In response to late comment, EPA performed a sensitivity analysis to assess the acreage affected based on the results of Trinity Bay study. EPA's approach uses a maximum observed species abundance and richness at 1677 and 3963 meters from the platform as a measure of background. This range is based on collecting species using two different sieve sizes. EPA believes that this is appropriate because a true measure of background cannot be determined since oil and gas facilities discharges have occurred in this water body for over 40 years. In late comments, some suggested that EPA instead use the average abundance of species richness beyond 686 meters as a background. Using this suggested approach substantially reduces the impacted area. More details are provided in the record.

The authors of the Trinity Bay study state that stations beyond 457 meters or further are unaffected by the platform. Based on the authors estimated impact area of 457 meters rather than EPA's estimated range of 1677–3963 meters, the estimated average impacted acreage would be 51 acres. Using this

methodology, the total monetized benefits are \$0.12—\$1.9 million (\$1995) based on wetland values of \$66—\$1087 (\$1995). EPA does not believe this is an appropriate impacted area because maximum species abundance and richness occurs between 1677 and 3963 meters. Furthermore sediment naphthalene levels, which can adversely effect aquatic species, are the lowest at 4,000 meters. Both stations beyond 4,000 meters have lower species abundance and richness. Both these stations are contaminated with naphthalene at levels that exceed Effect Range Median (ERM) for naphthalene. The ERM represents the concentrations at which adverse effects are frequently associated.

(iii) Total Monetized Benefits. EPA estimates that total monetized benefits (*i.e.* combining cancer risk reduction and ecological benefits) resulting from zero discharge of produced water for Louisiana open bay dischargers and Texas individual permit applicants dischargers range from approximately \$1.6 million to \$129.1 million per year (\$1995) (*i.e.*, \$1.3 to \$106.6 million/year in Louisiana and \$0.3 to \$22.5 million/year for Texas individual permit operators).

C. Description of Non-Quantified Benefits

The WQBA attempts to quantify the environmental effects, and whenever appropriate, to monetize specific environmental benefits that may result from the Coastal Guidelines. However, some of the potential benefits could not be quantified or monetized because of the lack of data, or because sufficient information to define the causal relationship between dischargers covered by the Coastal Guidelines and environmental effects is not available. This analysis includes: (1) An assessment of potential health risks to the Alaska's Native Populations from consumption of Cook Inlet's fish and shellfish and potential link between coastal oil and gas discharges and fish consumed by native populations; (2) effects on threatened or endangered species and migratory waterfowl, and potential benefits of the Coastal Guidelines on ecosystem health primarily for coastal areas of Gulf of Mexico and to a limited degree for Cook Inlet.

(1) An Assessment of Health Risks to Cook Inlet's Native Populations. EPA received comments from Native Americans concerned about coastal oil and gas discharges in Cook Inlet. The Chugachmuit Environmental Protection Consortium (CEPC) of Anchorage, Alaska raised concerns about the

impacts that oil and gas exploration and development activities in Cook Inlet and Kachemak Bay, Alaska have on the subsistence lifestyle of the Native Tribes of Port Graham and Nanwalek, and provided fish consumption data. EPA evaluated this data and all other data about the environmental impacts of coastal oil and gas discharges in Cook Inlet. EPA attempted to assess the potential health risks posed from the high subsistence use of Cook Inlet by native populations related to the discharges from coastal oil and gas facilities. Although sufficient information on the Cook Inlet's native population subsistence patterns exists, there is little fish tissue data with which to assess the risks from consumption of fish and shellfish from Cook Inlet. Two available studies provide some mussels tissue data, but no data on fish or other shellfish. One study investigated the occurrence of petroleum hydrocarbons, naturally occurring radioactive materials, and trace metals in water, sediments, and biota (mussels) in lower Cook Inlet. Very low levels of PAHs (including naphthalene) were found in mussel samples but the source of the PAHs could not be identified. The authors also found no anomalous trends evident from the mussels metals concentrations. Another Cook Inlet study, using caged mussels, found low levels of hydrocarbons in mussel tissue that were within a range of concentrations observed in organisms from unpolluted offshore environments. The study was conducted as part of environmental monitoring program to determine impacts of oil industry operations in Cook Inlet.

The mussel data may provide an upper bound of contaminant concentrations likely to be found in other shellfish. However, the data is insufficient to assess risk from consumption of fish. EPA cannot predict finfish contaminant concentrations based on mussel data because mussels have much higher bioaccumulation rates. Finfish tend to more rapidly metabolize and excrete contaminants (e.g., PAHs). In addition, mussels and shellfish in general represent only small portion (i.e., two to eight percent) of the fish and shellfish subsistence harvest for three Cook Inlet's native villages (i.e., Tyonek, Nanwalek and Port Graham). Finfish represent 74 to 80 percent of the harvest, (with salmon representing 57 to 97 percent of the finfish harvest). The finfish harvest data indicate consumption levels could be as high as 211 g/day, 238 g/day and 298 g/day (with salmon consumption levels of 121

gpd, 232 gpd, and 180 gpd) in Port Graham, Tyonek and Nanwalek, respectively. The shellfish harvest data indicate consumption levels of 6 g/day, 20 g/day, and 29 g/day in Tyonek, Port Graham, and Nanwalek, respectively. These consumption levels are higher than the subsistence consumption levels used in this WQBA for the Gulf of Mexico region. However, lacking the data on the concentration of pollutants in fish tissue, which represent up to 80 percent of the Cook Inlet's native population fish and shellfish intake rates, it is difficult to assess the human health risks from fish consumption, and to reasonably establish the link between coastal oil and gas discharges and human health effects from the discharges in Cook Inlet. EPA is, however, concerned about the potential for human health effects. Therefore, EPA will continue to monitor ongoing sediment, water quality and biological studies in Cook Inlet for applicability to future permit actions.

(2) Effects on Threatened and Endangered Species. The zero discharge of produced water may also have beneficial effects on 32 threatened and endangered species in coastal areas of Texas and Louisiana, including open bays and the major deltaic passes of the Mississippi River. Such threatened and endangered species include the Brown Pelican, Hawksbill Sea Turtle, Leatherback Sea Turtle, Ocelot, and others that use these areas as part of their habitat.

The control of produced water discharges by the Coastal Guidelines may also have beneficial effects on Cook Inlet biological resources. The Upper Cook Inlet serves as an important pathway for spawning fish and non-endangered mammals, provides critical habitat for seabirds, shorebirds, and migrating waterfowl, and at least four endangered cetacean species and endangered avian species which may occur as migrants in or near Cook Inlet.

XI. Related Acts of Congress, Executive Orders, and Agency Initiatives

A. Pollution Prevention Act

In the Pollution Prevention Act of 1990 (PPA) (42 U.S.C. 13101 *et seq.*, Pub. L. 101-508, November 5, 1990), Congress declared pollution prevention the national policy of the United States. The PPA declares that pollution should be prevented or reduced whenever feasible; pollution that cannot be prevented or reduced should be recycled or reused in an environmentally safe manner wherever feasible; pollution that cannot be recycled should be treated in an

environmentally safe manner wherever feasible; and disposal or release into the environment should be chosen only as a last resort.

Today's rules are consistent with the PPA. EPA developed these rules while focused on pollution-preventing technologies. The closed-loop recycle systems for drilling fluids and the achievement of zero discharge for produced water by injection form a substantial basis for this rule.

B. Paperwork Reduction Act

The Coastal Guidelines place no additional information collection or record-keeping burden on respondents. Therefore, an information collection request has not been prepared for submission to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*

C. Regulatory Flexibility Act

Pursuant to section 605(b) of the Regulatory Flexibility Act, 5 U.S.C. 605(b), the Administrator certifies that this rule will not have a significant economic impact on a substantial number of small entities. EPA analyzed the potential impact of the rule on small entities under several scenarios. Under the most conservative scenario (i.e. the scenario that assumes the largest number of small entities potentially affected by the rule), EPA's analysis shows that most small entities are already in compliance or are already covered by permit requirements equivalent to the rule's discharge requirements. Thus, the rule will not have any adverse economic impact on them. Under this same scenario, approximately 58 out of 372 small entities might have to take some action to achieve compliance. Even a smaller number of entities (34) may experience costs greater than one percent of revenues. Based on this analysis, EPA believes that the economic impact of the rule will not be significant for a substantial number of small entities.

Under the Regulatory Flexibility Act, an agency is not required to prepare a regulatory flexibility analysis for a rule that the agency head certifies will not have a significant economic impact on a substantial number of small entities. While the Administrator has so certified today's rule, the Agency nonetheless prepared a regulatory flexibility assessment equivalent to that required by the Regulatory Flexibility Act as modified by the Small Business Regulatory Enforcement Fairness Act of 1996. The assessment for this rule is detailed in the Economic Impact Analysis. Although not required by the Regulatory Flexibility Act, EPA also

analyzed the indirect economic impact of the Coastal rule on small communities. Indirect impacts are those impacts felt by entities not subject to the rule. Some of the royalty losses caused by the rule may be felt at the local level. To determine the significance of this indirect impact, EPA assumes that 50 percent of the total royalty losses would be borne by local county and parish revenues. In the offshore rule, local governments were estimated to receive approximately 3 percent of royalties. As a result, EPA considers the 50 percent assumption a significant overestimation that nonetheless serves to underscore the limits of the rule's indirect impact on local communities. EPA determined that spreading royalty losses over the population of counties and parishes adjacent to affected coastal waters would result in a per capita cost of \$0.12, or 0.002 percent of per capita income in Texas counties, and a per capita cost of \$0.44 to \$1.30 in Louisiana, which represents 0.004 to 0.012 percent of per capita income in affected parishes under the regulatory requirements and alternative baselines, respectively. EPA thus concludes that the indirect impacts of the rule are not significant.

D. Small Business Regulatory Enforcement Fairness Act of 1996 (Submission to Congress and the General Accounting Office)

Under 5 U.S.C. 801(a)(1)(A) as added by the Small Business Regulatory Enforcement Fairness Act of 1996, EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the General Accounting Office prior to publication of the rule in today's Federal Register. This rule is not a "major rule" as defined by 5 U.S.C. 804(2).

E. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), P.L. 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of \$100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to

identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. While EPA does not believe the rule imposes significant or unique effects on small governments, under section 203 and 205 of the UMRA, EPA has consulted with state governments as described in Section XIII. The estimated annual cost of the Coastal Guidelines, presented in Section VIII of this preamble, is \$16.4 million when estimated using the current requirements baseline and \$50.6 million when estimated using the alternative baseline. Thus, today's rule is not subject to the requirements of sections 202 and 205 of the UMRA.

F. Executive Order 12866 (OMB Review)

Under Executive Order 12866, (58 FR 51735, October 4, 1993) EPA must determine whether the regulatory action is "significant" and therefore subject to OMB review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a regulation that may:

(1) Have an annual effect on the economy of \$100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities,

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency,

(3) Materially alter the budgetary impact of entitlements, grants user fees, or loan programs or the rights and obligations of recipients thereof, or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a "significant regulatory action" because of novel policy issues raised by the Department of Energy. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

G. Common Sense Initiative

On August 19, 1994, the Administrator established the Common Sense Initiative (CSI) Council in accordance with the Federal Advisory Committee Act (5 U.S.C. Appendix 2, Section 9 (c)) requirements. A principal goal of the CSI includes developing recommendations for optimal approaches to multimedia controls for industrial sectors including Petroleum Refining, Metal Plating and Finishing, Printing, Electronics and Computers, Auto Manufacturing, and Iron and Steel Manufacturing.

The Coastal Guidelines were not among the rulemaking efforts included in the Common Sense Initiative. However, many oil and gas producers (mostly large companies) involved in coastal oil and gas extraction activities also have refineries. These companies are projected to incur costs associated with the requirements contained in this proposal, though these costs are not projected to have an economic impact at the firm level. The CSI objectives, described at proposal, have been incorporated into the Coastal Guidelines and the Agency intends to continue to pursue these objectives. The Agency particularly will focus on avenues for giving state and local authorities flexibility in implementing this rule, and giving the industry flexibility to develop innovative and cost effective compliance strategies. In developing this rule, EPA took advantage of several opportunities to gain the involvement of various stakeholders. Section XIII of this preamble references consultations with state and local governments and other parties including the industry. EPA has also coordinated among relevant program offices in developing this rule. Section XII describes related rulemakings that are being developed by

EPA's Office of Air Quality, Planning and Standards, Underground Injection Control Program, and Spill Prevention, Control and Countermeasure Program. EPA will be monitoring these related rulemakings to assess their collective costs to the industry. Section IX of the preamble describes the non-water quality environmental impacts this proposed rule would have on other media including air emissions and solid waste disposal.

XII. Related Rulemakings

In addition to these Coastal Guidelines, EPA is in the process of developing other regulations that specifically affect the oil and gas industry. These other rulemakings are summarized below. EPA's offices are coordinating their efforts with the intent to monitor these related rulemakings to assess their collective costs to industry.

A. National Emission Standards for Hazardous Air Pollutants

National emission standards for hazardous air pollutants are being developed for the oil and gas production industry by EPA's Office of Air Quality, Planning and Standards (OAQPS), under authority of section 112 (d) of the Clean Air Act as amended in 1990. Section 112 (d) of the Clean Air Act directs the EPA to promulgate regulations establishing hazardous air pollutant (HAP) emissions standards for each category of major and area sources that has been listed by EPA for regulation under section 112 (c). The 189 pollutants that are designated as HAP are listed in section 112 (d). For major sources, or facilities which emit 10 or more tons per year (TPY) of an individual HAP pollutant or 25 or more TPY of multiple HAPs, the air emission standards are based on "maximum achievable control technology" or MACT.

Major sources within the coastal oil and gas subcategory have been identified by OAQPS as stand alone glycol dehydrators, tank batteries, gas plants, and offshore production platforms. In most cases, OAQPS believes that, in order to be a major source, a coastal production facility must have glycol dehydrators located on-site. A production facility alone may not produce enough emissions to be classified as a major source.

EPA plans to propose MACT standards for the oil and gas industry by March 1997. OAQPS estimates that the total annual cost of these standards is \$16.5 million.

B. Requirements for Injection Wells

The Safe Drinking Water Act (SDWA) charges EPA with protecting underground sources of drinking water (USDW). As part of this mandate, EPA developed the Underground Injection Control (UIC) program to regulate the underground injection of all fluids, including produced water. EPA first promulgated regulations concerning the construction, operation, and closure of Class II injection wells for the disposal of oil and gas industry wastes in 1980 (45 FR 42500, June, 24, 1980).

C. Spill Prevention, Control, and Countermeasure

EPA's Oil Pollution Prevention regulation at 40 CFR part 112, which requires Spill Prevention, Control, and Countermeasure (SPCC) plans, was promulgated in 1973 under section 311 (j) of the CWA. The SPCC planning requirement applies to all oil extraction and production facilities that have an oil storage capacity above certain thresholds (*i.e.* an overall aboveground oil storage capacity greater than 1,320 gallons or greater than 660 in a single container, or an underground oil storage capacity of greater than 42,000 gallons) and are located such that a discharge could reasonably be expected to reach U.S. waters. EPA estimates that there are approximately 450,000 SPCC-regulated facilities. A preliminary estimate indicates that approximately 3,000 of these facilities may be either coastal or offshore facilities.

Under part 112, facility owners or operators are required to prepare and implement written SPCC plans that discuss conformance with procedures, methods, and equipment and other requirements to prevent discharges of oil and to contain such discharges.

On July 1, 1994, (59 FR 34070, July 1, 1994) EPA issued a final rule amending part 112 to require certain onshore facilities to prepare, submit to EPA, and implement plans to respond to a worst case discharge of oil to meet section 4202(a) of the Oil Pollution Act (OPA). EPA also intends to develop requirements in 1997 under section 4202(a) of OPA specifically for coastal facilities. (Note: Coastal and offshore facilities in the part 112 program are collectively referred to as "offshore". However, the intended OPA rulemaking specifically applies to facilities landward of the inner boundary of the territorial seas, and that are not onshore.) These regulations would, among other things, require that owners or operators of coastal facilities prepare and submit to the Federal government a

plan for responding to a worst case discharge of oil.

D. Shore Protection Act Regulations

EPA, in conjunction with the Department of Transportation, has developed proposed regulations that would establish waste handling practices for vessels and waste transfer stations for the hauling and handling of municipal and commercial wastes. This rule would assure that wastes will not be deposited into coastal waters during loading, off loading, and transport. The proposal was signed by the Administrator on August 19, 1994 and published in the Federal Register on August 30 (59 FR 44798). Promulgation is planned for March 1997. While this regulation will apply to operators of supply vessels used by coastal oil and gas extraction facilities, it will not directly impact the ability of coastal oil and gas extraction facilities to comply with effluent limitations guidelines and standards.

XIII. Summary of Public Participation

EPA encouraged full public participation in the development of the final Coastal Guidelines. Written comments were received on the 1989 Notice of Information and Request for Comments (54 FR 46919; November 8, 1989), industry trade associations and the Natural Resources Defense Council, Inc. participated in the development of EPA's questionnaire for the coastal oil and gas extraction industry, written comments were received on the proposed rule (60 FR 9428; February 17, 1995), and public meetings were held.

On July 19, 1994, EPA held a public meeting in New Orleans, Louisiana about the content and the status of the proposed regulation. The meeting was announced in the Federal Register (59 FR 31186; June 17, 1994), and information packages were distributed at the meeting. The public meeting also gave interested parties an opportunity to provide information, data, and ideas to EPA on key issues.

Additional public meetings were held on March 7, 1995 and March 21, 1995. The first of these meetings was held in New Orleans, Louisiana and the second in Seattle, Washington.

Meetings have been held with representatives from industry and environmental groups, as well as state and other federal agencies. These meetings are documented in the record.

EPA has formally assessed all comments and data received: at the July 19, 1994 public meeting, during the public comment period for the proposed rule, and as a result of the 1989 Notice of Information. Responses to these

comments are provided in the Comment Response Document for Final Effluent Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Category, which is in the record. In addition, as time allowed, EPA considered late comments.

XIV. Regulatory Implementation

A. Toxicity Limitation for Drilling Fluids and Drill Cuttings

EPA is establishing a toxicity limitation for drilling fluids and drill cuttings. The toxicity limitation would apply to any periodic blowdown of drilling fluid as well as to bulk discharges of drilling fluids and drill cuttings systems. The reader is referred to the Offshore Guidelines at 58 FR 12454, 12502 (March 4, 1993) for an explanation of the regulatory implementation for the toxicity limit.

B. Diesel Prohibition for Drilling Fluids and Drill Cuttings

Cook Inlet's oil and gas extraction platforms are prohibited from discharging diesel oil and drilling fluids and drill cuttings contaminated with diesel oil. The reader is referred to the Offshore Guidelines (58 FR 12502) for a discussion on the implementation of this requirement.

C. 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 "upsets" or "bypasses". The reader is referred to the Offshore Guidelines (58 FR 12501) for a discussion on upset and bypass provisions.

D. Variances and Modifications

Once this regulation is in effect, the effluent limitations must be applied in all NPDES permits thereafter issued to discharges covered under this effluent limitations guideline subcategory. Under the CWA certain variances from BAT and BCT limitations are provided for. A section 301(n) (Fundamentally Different Factors) variance is applicable to the BAT and BCT and pretreatment limits in this rule. The reader is referred to the Offshore Guidelines (58 FR 12502) for a discussion on the applicability of variances.

E. Synthetic Drilling Fluids

During the Offshore Guidelines rulemaking and again after the Coastal Guidelines proposed rule, several industry commenters noted recent developments in formulating synthetic-based drilling fluids as substitutes for the traditional water-based and oil-

based drilling fluids. Synthetic-based drilling fluids or synthetic-based muds (SBM) represent a new technology which was developed in response to the oil-based drilling fluids discharge ban in the North Sea. They were first used in the North Sea in 1990, and the first well drilled in the Gulf of Mexico using SBM was completed in June 1992. Operators have claimed that compared to the discharge of water-based muds (WBM) and cuttings and barging/hauling of cuttings from oil-based muds (OBM), the use of the synthetics and on-site discharge of associated cuttings presents a pollution prevention opportunity.

In the proposed Coastal Guidelines, the EPA requested additional information on the use of synthetic fluids including well logs, toxicity, analytical methods testing and in-situ seabed and water column physical, chemical and biological testing. EPA received numerous comments documenting and supporting environmental and operational benefits achieved by SBMs. The commenters contended that in the absence of definitions for SBM, NPDES permit restrictions on discharges of oil-based drilling fluids and inverse emulsions were unintentionally providing barriers to the discharge of drill cuttings generated with SBM even though such cuttings generally pass the sheen and toxicity tests. Based on a review of these comments EPA has identified certain environmentally beneficial aspects of using SBM. Improved drilling operations allow for smaller diameter holes resulting in less drill wastes being generated. Increased solids removal in the closed loop solids systems leads to less discharge of drilling fluids. Lower toxicity of the drilling fluids, at least in the aqueous or suspended particulate phase, leads to a decrease in water column toxicity effects, and possibly a decrease in overall toxicity effects.

In considering use of these drilling fluids EPA is examining the use of the current sheen and toxicity tests applied to the discharge of cuttings associated with SBM. Although the existence and limited use of SBM were known at the start of the Coastal and completion of the Offshore rulemakings, sufficient information was not available to propose any limitations different from those contained in the Offshore rule at this final Coastal rule. Nevertheless, EPA will address the concerns related to the sheen and toxicity tests by additional data gathering in order to provide guidance to NPDES permit writers about the use of alternative tests where the discharge of drilling wastes is allowed. The alternative tests are a gas chromatography (GC) test and a benthic

toxicity test to verify the results of the static sheen and the suspended particulate phase (SPP) toxicity testing currently required. Other tests for bioaccumulation potential and biodegradation may be appropriate for use in evaluating site specific (water quality) effects and rates of recovery for sea floor areas covered by cuttings piles. Such tests are already applied to SBM cuttings discharges in the North Sea.

EPA recognizes the potential pollution prevention opportunities presented by this new technology. Until guidelines can be written for this wastestream, EPA is encouraging their further development by including definitions in this rule for "synthetic-based drilling fluid" and the "synthetic material" which comprises the SBM. Furthermore, one commenter claimed to achieve the environmental and performance benefits of a synthetic based drilling fluid with an enhanced mineral oil (EMO). Since the EMOs are not synthetic based materials and were stated to be different from previously used mineral oils, EPA is also providing a definition for EMOs. The definitions are as follows:

The term *drilling fluid* refers to the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. The four classes of drilling fluids are:

(a) A water-based drilling fluid has water as its continuous phase and the suspending medium for solids, whether or not oil is present.

(b) An oil-based drilling fluid has diesel oil, mineral oil, or some other oil, but neither a synthetic material nor enhanced mineral oil, as its continuous phase with water as the dispersed phase.

(c) An enhanced mineral oil-based drilling fluid has an enhanced mineral oil as its continuous phase with water as the dispersed phase.

(d) A synthetic-based drilling fluid has a synthetic material as its continuous phase with water as the dispersed phase.

EPA is also introducing definitions for the "synthetic material" and "enhanced mineral oil" which comprise the respective drilling fluids as follows:

The term *enhanced mineral oil* as applied to enhanced mineral oil-based drilling fluid means a petroleum distillate which has been highly purified and is distinguished from diesel oil and conventional mineral oil in having a lower polycyclic aromatic hydrocarbon (PAH) content. Typically, conventional mineral oils have a PAH content on the order of 0.35 weight percent expressed as phenanthrene, whereas enhanced mineral oils typically have a PAH content of 0.001 or lower weight percent PAH expressed as phenanthrene.

The term *synthetic material* as applied to synthetic-based drilling fluid means material

produced by the reaction of specific purified chemical feedstock, as opposed to the traditional base fluids such as diesel and mineral oil which are derived from crude oil solely through physical separation processes. Physical separation processes include fractionation and distillation and/or minor chemical reactions such as cracking and hydro processing. Since they are synthesized by the reaction of purified compounds, synthetic materials suitable for use in drilling fluids are typically free of polycyclic aromatic hydrocarbons (PAHs) but test sometimes report levels of PAH up to 0.001 weight percent PAH expressed as phenanthrene. Poly(alpha olefins) and vegetable esters are two examples of synthetic materials used by the oil and gas extraction industry in formulating drilling fluids. Poly(alpha olefins) are synthesized from the polymerization (dimerization, trimerization, tetramerization, and higher oligomerization) of purified straight-chain hydrocarbons such as C₆-C₁₄ alpha olefins. Vegetable esters are synthesized from the acid-catalyzed esterification of vegetable fatty acids with various alcohols. The mention of these two synthetic fluid base materials is to provide examples, and is not meant to exclude other synthetic materials that are either in current use or may be used in the future. A synthetic-based drilling fluid may include a combination of synthetic materials.

Since the publication of the Offshore Guidelines in 1993, and publication of the proposed Coastal Guidelines in February 1995, data have been submitted to document the enhanced operational and environmental performance of synthetic fluids. The data for SBMs included: well logs, toxicity, analytical methods testing and in-situ seabed and water column physical, chemical and biological testing.

Impacts due to the discharge of drilling fluids and associated drill cuttings fall into two main categories: water column and sea floor. As detailed in the Coastal Development Document, these data and evidence presented in the literature show that use of SBM in place of WBM may reduce the adverse environmental impact in the water column because of (a) reduction in volume of muds discharged, (b) less dispersion of the muds and cuttings in the water, and (c) lower toxicity. In addition, the reduction in volume of wastes discharged may reduce the effects to the sea floor. Due to decreased washout (erosion), drilling of narrower gage holes, and lack of dispersion of the cuttings in the SBM, compared to WBM the quantities of muds and cuttings waste generated is reduced, reportedly in some cases by as much as 70 percent. The greatest reduction seen is for the drilling fluids. The SBM offer the opportunity for high recycle rates because unlike the WBM the cuttings do not disperse in the fluid and so less

dilution and additives are required to keep the necessary drilling fluid characteristics. In general the only SBM discharged is the amount adhered to the cuttings, which ranges from 7 to 12 percent based on dry cuttings weight. When WBM is used, the amount of drilling fluid discharged is often 5 or 6 times greater than discharged when drilling a similar hole with SBM. If the engineering aspects of the effectiveness of a drilling fluid are considered as a technology to reduce the levels of pollution, then SBM may be viewed as a control technology for conventional pollutants.

Sea floor effects can be separated into two types: Short-term burial effects and long-term toxic effects. The adverse impact caused by burial can be assumed to be directly proportional to the quantity of solids discharged, and will also depend on the dispersion of the settling solids. As discussed earlier the synthetics have been shown to create a lower volume of drilling wastes. Also, the cuttings which are coated with 7-12 percent synthetic material, tend to sink without drifting in the water column unlike the particulate matter of the WBM which tends to disperse and stay suspended longer. Therefore as compared to WBM one would expect the burial footprint from SBM cuttings discharge to be smaller and have less solids. The diminished dispersion of the SBM has been shown by relating barium concentrations on the sea floor.

In terms of the long-term toxic effects, studies have shown that changing the toxicity, biodegradation, and bioaccumulation of the oily or hydrophobic constituent of the cuttings has a large effect on the recovery of the benthic community. Most germane is a comparison of the recolonization of WBM cuttings piles compared to that of SBM cuttings piles. While WBM cuttings piles are said to recover "quickly" in the literature, data have not been found in any source which defines just how quickly. Thus, a comparison with the SBM recovery rates is not possible without additional study. The recovery of synthetics contaminated cuttings piles has been detailed in two instances known to EPA, one contaminated with a poly(alpha olefin) (PAO) and one contaminated with a vegetable ester. In both cases the PAO or vegetable ester organic contamination was found to either biodegrade or otherwise disperse to low concentrations at the eight month to one year evaluation times. At the one year to 16 months evaluation times, the cuttings piles were found to be in a natural state with a normal diversity and number of benthic organisms,

except at a few stations where there was either a dominant population of one organism or slightly elevated organic contamination. This is contrasted with the relatively large zone of impact and much slower rate of recovery of cuttings piles contaminated with oil from OBM.

While EPA recognizes the potential environmental benefits with the use of SBM over WBM, EPA has some concerns about the appropriateness of both the static sheen test used to determine compliance with the no free oil limitation and the toxicity test associated with the suspended particulate phase to determine compliance with the toxicity limitation. The sheen and toxicity tests were developed for use on WBM, which readily disperse in water, allowing components of the drilling fluid or contaminants to rise to the surface to give a sheen or partition to the suspended particulate phase (aqueous phase) and show toxicity. Conversely, the cuttings from SBM sink to the sea floor with little or no dispersion in the water. This is demonstrated in the laboratory toxicity test. When WBM drill associated cuttings are stirred in sea water as prescribed, the suspended particulate phase (SPP) becomes cloudy immediately and typically remains cloudy during the one-hour settling period. When stirring SBM or associated cuttings in sea water, the aqueous phase typically remains clear indicating little or no dispersion of drilling fluid, cuttings, or other components in the aqueous phase. For this reason, EPA believes it may be inappropriate to measure only the aquatic toxicity as part of the discharge requirement to judge the environmental effect of the discharge of these cuttings. The measurement of benthic toxicity may be appropriate for use in conjunction with the aquatic phase testing as a discharge requirement. Additional tests on bioaccumulation and biodegradation rates may be more useful for the evaluation of the synthetic material or SBM cuttings wastes with respect to environmental impact determinations.

In addition, previous commenters had identified the sheen test as giving false positive results due to discoloration which may occur when cuttings containing small amounts of some of the synthetic materials are discharged. Recently, these same commenters have endorsed the sheen test as viable when using the synthetic-based drilling fluids. In general, to pass the sheen test, the sample must be covered until below the surface of the water, at which point it can be released. Samples of synthetic-based drilling fluids may fail if stirred according to the test method.

Conversely, samples have been shown to pass the static sheen test following the addition of various levels of oil, crude oil, diesel oil, and mineral oil in a laboratory controlled evaluation. Results of this evaluation also showed that the sheen test appears to be more subjective and difficult to judge for the synthetics than for the water-based drilling fluids, due to the lack of dispersion of the synthetics in the aqueous phase which leads to the question of adequate stirring, and due to the formation of sheens (or discoloration) which are not iridescent.

There is also concern with the ability of the static sheen test to detect formation (crude) oil contamination on the cuttings when SBM is used. Since these compounds consist of lipophilic matrices, any oily (sheen producing) contaminants could dissolve in these matrices and be brought to the sea floor with no observed sheen surface effect. Thus the sheen test, which was developed to test for free oil contamination in the oil or water-based drilling wastes, which readily disperse in water, may not be appropriate. Formation oil contamination in certain synthetic fluids has been shown to be clearly identifiable by using gas chromatography (GC). Commenters have indicated that GC analysis with flame ionization detection (GC/FID) can be practically performed at a reasonable cost, and has in some instances been performed on offshore platforms. GC/FID as described in method 1663 in document EPA 821-R-92-008, "Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges," can be used to identify the presence or increase of n-alkane groups from crude oil contamination. Also contained in this document is high performance liquid chromatography (HPLC) method 1654A, and the combination of methods 1654A and 1663 can be used to differentiate diesel oil, mineral oil, crude oil, and synthetic material. Gas chromatography followed in series with mass spectroscopy (GC/MS) gives higher resolution and can also be used to identify the presence of PAHs, but is also more complicated and several times more expensive. Nonetheless, it may be beneficial to perform GC/MS analysis to identify the PAHs. Free oil is an indicator pollutant for PAHs. Several of the PAHs commonly found in crude oil are priority pollutants.

In the United Kingdom and Norway, discharge requirements of SBM drill cuttings follow the Oslo and Paris Commission (PARCOM) guidelines for a harmonized chemical notification

procedure. These guidelines require drilling fluids to undergo marine toxicity, bioaccumulation and biodegradation testing, and allow the regulatory authorities to calculate the maximum amount of the fluid which can be expected not to cause serious adverse environmental effects if lost or discharged to the sea. The marine toxicity test evaluates both water-borne and benthic organisms such as algae (*Skeletonema costatum*), zooplankton (*Acartia tonsa*), and amphipod crustacean sediment reworker (*Corophium volutator*). EPA believes that tests such as these (or some combination of these tests) may be more appropriate as the basis for both the environmental assessment and for discharge limitations for the cuttings associated with synthetic-based and EMO-based drilling fluids. Other static sediment toxicity tests, such as the ASTM E1367-92, may also be appropriate. Just recently detailed monitoring at several sites in the North Sea has begun to evaluate seven different mud systems and to compare the actual sea floor determinations with the laboratory determinations. While evaluations in the Gulf of Mexico may prove to be different from those in the North Sea due to the differences in physical parameters and sea life, EPA intends to follow these sea floor evaluations for early indications of appropriate laboratory and field evaluation methods.

The final rule incorporates clarifying definitions of drilling fluids for both the offshore and coastal subcategories to better differentiate between the types of drilling fluids. At this time, EPA's guidance to permit writers needing to write limits for SBMs on a best professional judgement (BPJ) basis is to use GC as a confirmation tool to assure the absence of free oil in addition to meeting the current no free oil (static sheen), toxicity, and barite limits on mercury and cadmium. Method 1663 as described in EPA 821-R-92-008 is recommended as a GC/FID method to identify an increase in n-alkanes due to crude oil contamination of the synthetic materials coating the cuttings to be discharged. Additional tests such as benthic toxicity conducted on the synthetic material prior to use or whole SBM prior to discharge, may be useful in controlling the discharge of cuttings contaminated with drilling fluid. One possible level of control is the use of the PARCOM protocol for 1000 ppm acute benthic toxicity for *Corophium volutator*, or similar protocol assessing a more appropriate local species as the indicator.

EPA intends to further evaluate the test methods for benthic toxicity and may determine an appropriate limitation if this additional test is warranted. In addition, test methods and results for bioaccumulation and biodegradation, as indications of the rate of recovery of the cuttings piles on the sea floor, will be evaluated. It is recognized that evaluations of such new testing protocols may be beyond the technical expertise of individual permit writers. Thus this effort will be coordinated as a continuing effluent guidelines effort. Results of this effort may lead to revision of the current effluent guidelines discharge limitations or may be useful in the revision or reissuance of permits only.

One commenter claimed the same environmental advantages over WBM as SBM with the use of enhanced mineral oil-based drilling fluids. EMO-based drilling fluids are similar to the SBMs with respect to dispersion in water and concerns with applicability of the current sheen and toxicity tests. However, while the mysid shrimp water column toxicity test may give comparable results for the EMOs and some synthetics, several research papers indicate that recovery of cuttings piles contaminated with low toxicity mineral oils may not be much better than those contaminated with diesel, whereas those contaminated by synthetic materials recover significantly faster. In the absence of data on EMO contaminated cuttings and data indicating the differences between low toxicity mineral oil and EMO, the application of limits on the discharge of SBM cuttings according to the mysid shrimp toxicity test and the static sheen test confirmed by GC test for no free oil, is not applicable to the discharge of EMO cuttings. If the tests of benthic toxicity, bioaccumulation, and biodegradation, which are indicative of rate of recovery of the cuttings pile, show that the performance of EMOs are acceptable, then they may be considered for discharge of associated drilling fluids and cuttings. Another complication with the use of EMO is that, since EMOs are not a specific product as the synthetics are, but an assortment of molecules conforming to the distillation cut, their gas chromatograph (GC) fingerprint is in certain cases less distinct than that of the synthetics. Contamination by formation oil, crude, or diesel, may be more difficult to detect in these EMOs.

G. Implementation for NPDES Permit Writers

EPA received numerous comments from operators in the Gulf of Mexico

coastal region claiming that they would need additional time to comply with the rule's zero discharge requirement for produced water. EPA recognizes that it may take some time for operators to determine the best and most cost effective mechanism of compliance and to implement that mechanism. EPA also recognizes that the NPDES permit issuing authority has discretion to use administrative orders to provide the requisite additional time to meet zero discharge.

In making the determination regarding the additional time that may be appropriate and interim requirements that will be placed on facilities until compliance is achieved, the permit issuing authority should consider several factors, including, but not limited to, the following. First, operators may wish to do engineering and structural analysis of existing pipes and wells in order to make use of existing infra-structure. Second, there are several options available to facilities on a per-well or per-facility basis to comply with the zero discharge requirement, including injection, sending produced water offsite to a centralized waste treatment facility, or shutting in individual wells. Third, the facility's preferred approach may take into consideration the projected productive life of individual wells and their relative effect on the overall facility costs and impacts in determining the most cost-effective mix of options. Fourth, the permit issuing authority has the discretion to consider the relative impact of the available options when determining an appropriate compliance schedule. Finally, in establishing any interim limitations on discharges, the permit issuing authority should consider water quality impacts.

XV. Background Documents

Major support for this regulation is detailed in two documents, each of which is supplemented by additional information and analyses in the rulemaking record. EPA's engineering foundation for the regulation is detailed in the "Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category" EPA-821-R-96-023. EPA's economic analysis is presented in the "Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category" EPA-821-R-96-022. Additionally, detailed responses to the public comments received on the proposed regulation and notices of data

availability are presented in the document entitled "Response to Public Comments on Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category," which is available in the public record. The public record for this rulemaking is available for review at EPA's Water Docket: 401 M Street, SW; Washington, DC. The room number is M2616 and the phone number is (202) 260-3027.

List of Subjects in 40 CFR Part 435

Environmental protection, Incorporation by reference, Oil and gas extraction, Pollution prevention, Waste treatment and disposal, Water pollution control.

Dated: October 31, 1996.

Carol M. Browner,
Administrator.

Appendix A to the Preamble— Abbreviations, Acronyms, and Other Terms Used in This Document

Agency—U.S. Environmental Protection Agency

BADCT—The best available demonstrated control technology, for new sources under section 306 of the CWA.

BAT—The best available technology economically achievable, under section 304(b)(2)(B) of the CWA.

bbl—barrel, 42 U.S. gallons

bpd—barrels per day

bph—barrels per hour

bpy—barrels per year

BCT—Best conventional pollutant control technology under section 304(b)(4)(B).

BMPs—Best management practices under section 304(e) of the CWA.

BOD—Biochemical oxygen demand.

BOE—Barrels of oil equivalent

BPT—Best practicable control technology currently available, under section 304(b)(1) of the Clean Water Act.

CFR—Code of Federal Regulations

Clean Water Act—Federal Water Pollution Control Act (33 U.S.C. 1251 *et seq.*).

Coastal Development Document—Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Coastal Subcategory Of the Oil and Gas Extraction Point Source Category.

Conventional pollutants—Constituents of wastewater as determined by section 304(a)(4) of the Act, including, but not limited to, pollutants classified as biochemical oxygen demanding, suspended solids, oil and grease, fecal coliform, and pH.

CWA—Clean Water Act

Direct discharger—A facility that discharges or may discharge pollutants to waters of the United States.

DOE—U.S. Department of Energy

EIA—*Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category*

EPA—U.S. Environmental Protection Agency
Indirect discharger—A facility that introduces wastewater into a publicly owned treatment works.

LC50—The estimated concentration of a test material lethal to 50 percent of test organisms used in a specified type of toxicity test.

mg/l—milligrams per liter

Nonconventional pollutants—Pollutants that have not been designated as either conventional pollutants or toxic pollutants.

NORM—Naturally Occurring Radioactive Materials

NPDES—The National Pollutant Discharge Elimination System under section 402 of the CWA.

NPV—Net Present Value

NSPS—New source performance standards under section 306 of the CWA.

Offshore Guidelines—Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category

Offshore Development Document—Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category

OMB—Office of Management and Budget

PAH—polynuclear aromatic hydrocarbons

POTW—Publicly Owned Treatment Works

ppm—parts per million

PSES—Pretreatment standards for existing sources of indirect discharges, under section 307(b) of the CWA.

PSNS—Pretreatment standards for new sources of indirect discharges, under sections 307 (b) and (c) of the CWA.

RRC—Railroad Commission of Texas

SIC—Standard Industrial Classification

SPP—Suspended particulate phase.

Toxic pollutants—A statutory term for the 65 pollutants and classes of pollutants designated under section 307(a) of the CWA.

TSS—Total Suspended Solids

UIC—Underground Injection Control program

U.S.C.—United States Code

For the reasons set forth in the preamble, 40 CFR part 435 is amended as follows:

PART 435—OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

1. The authority citation for part 435 continues to read as follows:

Authority: (33 U.S.C. 1311, 1314, 1316, 1317, 1318 and 1361).

Subpart A [Amended]

2. Section 435.10 is revised to read as follows:

§ 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 industry which are located in waters that are seaward of the inner boundary of the territorial seas ("offshore") as defined in section 502(g) of the Clean Water Act.

3. Section 435.11 is revised to read as follows:

§ 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 *average of daily values for 30 consecutive days* shall be the average of the daily values obtained during any 30 consecutive day period.

(c) The term *daily values* as applied to produced water effluent limitations and NSPS shall refer to the daily measurements used to assess compliance with the maximum for any one day.

(d) 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. Within the definition of deck drainage for the purpose of this subpart, the term rainwater for those facilities located on land is limited to that precipitation runoff that reasonably has the potential to come into contact with process wastewater. Runoff not included in the deck drainage definition would be subject to control as storm water under 40 CFR 122.26. For structures located over water, all runoff is included in the deck drainage definition.

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

(f) 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 for Diesel Fuel Oils D975-91, that is typically used as the continuous phase in conventional oil-based drilling fluids. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103. Copies may be inspected at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. A copy may also be inspected at EPA's Water Docket; Room M2616, 401 M Street SW, Washington, DC 20460.

(g) The term *domestic waste* shall refer to materials discharged from sinks, showers, laundries, safety showers, eye-wash stations, hand-wash stations, fish cleaning stations, and galleys located within facilities subject to this subpart.

(h) 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.

(i) The term *drilling fluid* refers to the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. The four classes of drilling fluids are:

(1) A water-based drilling fluid has water as the continuous phase and the suspending medium for solids, whether or not oil is present.

(2) An oil-based drilling fluid has diesel oil, mineral oil, or some other oil, but neither a synthetic material nor enhanced mineral oil, as its continuous phase with water as the dispersed phase.

(3) An enhanced mineral oil-based drilling fluid has an enhanced mineral oil as its continuous phase with water as the dispersed phase.

(4) A synthetic-based drilling fluid has a synthetic material as its continuous phase with water as the dispersed phase.

(j) The term *enhanced mineral oil* as applied to enhanced mineral oil-based drilling fluid means a petroleum distillate which has been highly purified and is distinguished from diesel oil and conventional mineral oil in having a lower polycyclic aromatic hydrocarbon (PAH) content. Typically, conventional mineral oils have a PAH content on the order of 0.35 weight percent expressed as phenanthrene, whereas enhanced mineral oils typically have a PAH content of 0.001 or lower weight percent PAH expressed as phenanthrene.

(k) The term *exploratory 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.

(l) The term *maximum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the maximum concentration allowed as measured in any single sample of the barite.

(m) The term *maximum for any one day* as applied to BPT, BCT and BAT effluent limitations and NSPS 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. Alternatively, for BAT and NSPS the maximum concentration allowed may be determined on the basis of physical composition of the four grab samples prior to a single analysis.

(n) The term *minimum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the minimum 96-hour LC50 value allowed as measured in any single sample of the discharged waste stream. The term minimum as applied to BPT and BCT effluent limitations and NSPS for sanitary wastes shall mean the minimum concentration value allowed as measured in any single sample of the discharged waste stream.

(o) 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.

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

(q) The term *new source* means any facility or activity of this subcategory 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 consistently with all of the following definitions:

(1) The term *water area* as used in the term "site" in 40 CFR 122.29 and 122.2 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* as used in 40 CFR 122.29 shall mean the process of surveying, clearing or preparing an area of the ocean floor for the purpose of constructing or placing a development or production facility on or over the site. "New Source" does *not* include facilities covered by an existing NPDES permit immediately prior to the effective date of these guidelines pending EPA issuance of a new source NPDES permit.

(r) 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 or fail the static sheen test defined in Appendix 1 to 40 CFR part 435, subpart A.

(s) The term *produced sand* shall refer to slurried particles used in hydraulic fracturing, the accumulated formation sands and scales particles generated during production.

Produced sand also includes desander discharge from the produced water waste stream, and blowdown of the water phase from the produced water treating system.

(t) 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.

(u) The term *production facility* shall mean any fixed or mobile structure subject to this subpart that is either engaged in well completion or used for active recovery of hydrocarbons from producing formations.

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

(w) 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 to 40 CFR part 435, subpart A.

(x) The term *synthetic material* as applied to synthetic-based drilling fluid means material produced by the reaction of specific purified chemical feedstock, as opposed to the traditional base fluids such as diesel and mineral oil which are derived from crude oil solely through physical separation processes. Physical separation processes include fractionation and distillation and/or minor chemical reactions such as cracking and hydro processing. Since they are synthesized by the reaction of purified compounds, synthetic materials suitable for use in drilling fluids are typically free of polycyclic aromatic hydrocarbons (PAH's) but are sometimes found to contain levels of PAH up to 0.001 weight percent PAH expressed as phenanthrene. Poly(alpha olefins) and vegetable esters are two examples of synthetic materials used by the oil and gas extraction industry in formulating drilling fluids. Poly(alpha olefins) are synthesized from the polymerization (dimerization, trimerization, tetramerization, and higher oligomerization) of purified straight-chain hydrocarbons such as C₆-C₁₄ alpha olefins. Vegetable esters are synthesized from the acid-catalyzed esterification of vegetable fatty acids with various alcohols. The mention of these two branches of synthetic fluid base materials is to provide examples, and is not meant to exclude other

synthetic materials that are either in current use or may be used in the future. A synthetic-based drilling fluid may include a combination of synthetic materials.

(y) The term *toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall refer to the bioassay test procedure presented in Appendix 2 of 40 CFR part 435, subpart A.

(z) The term *well completion fluids* shall refer to salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production.

(aa) The term *well treatment fluids* shall refer to any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

(bb) The term *workover fluids* shall refer to salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures.

(cc) The term *96-hour LC50* shall refer to the concentration (parts per million) or percent of the suspended particulate phase (SPP) from a sample that is lethal to 50 percent of the test organisms exposed to that concentration of the SPP after 96 hours of constant exposure.

4. Subpart D is revised to read as follows:

Subpart D—Coastal Subcategory

Sec.

435.40 Applicability; description of the coastal subcategory.

435.41 Specialized definitions.

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

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

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

435.45 Standards of performance for new sources (NSPS).

435.46 Pretreatment Standards of performance for existing sources (PSES).

435.47 Pretreatment Standards of performance for new sources (PSNS).

Subpart D—Coastal Subcategory

§ 435.40 Applicability; description of the coastal 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 industry in areas defined as "coastal." The term "coastal" shall mean:

(a) Any location in or on a water of the United States landward of the inner boundary of the territorial seas; or

(b) (1) Any location landward from the inner boundary of the territorial seas and bounded on the inland side by the line defined by the inner boundary of the territorial seas eastward of the point defined by 89°45' West Longitude and 29°46' North Latitude and continuing as follows west of that point:

Direction to west longitude	Direction to north latitude
West, 89°48'	North, 29°50'.
West, 90°12'	North, 30°06'.
West, 90°20'	South, 29°35'.
West, 90°35'	South, 29°30'.
West, 90°43'	South, 29°25'.
West, 90°57'	North, 29°32'.
West, 91°02'	North, 29°40'.
West, 91°14'	South, 29°32'.
West, 91°27'	North, 29°37'.
West, 91°33'	North, 29°46'.
West, 91°46'	North, 29°50'.
West, 91°50'	North, 29°55'.
West, 91°56'	South, 29°50'.
West, 92°10'	South, 29°44'.
West, 92°55'	North, 29°46'.
West, 93°15'	North, 30°14'.
West, 93°49'	South, 30°07'.
West, 94°03'	South, 30°03'.
West, 94°10'	South, 30°00'.
West, 94°20'	South, 29°53'.
West, 95°00'	South, 29°35'.
West, 95°13'	South, 29°28'.
East, 95°08'	South, 29°15'.
West, 95°11'	South, 29°08'.
West, 95°22'	South, 28°56'.
West, 95°30'	South, 28°55'.
West, 95°33'	South, 28°49'.
West, 95°40'	South, 28°47'.
West, 96°42'	South, 28°41'.
East, 96°40'	South, 28°28'.
West, 96°54'	South, 28°20'.
West, 97°03'	South, 28°13'.
West, 97°15'	South, 27°58'.
West, 97°40'	South, 27°45'.
West, 97°46'	South, 27°28'.
West, 97°51'	South, 27°22'.
East, 97°46'	South, 27°14'.
East, 97°30'	South, 26°30'.
East, 97°26'	South, 26°11'.

(2) East to 97°19' West Longitude and Southward to the U.S.-Mexican border.

§ 435.41 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 *average of daily values for 30 consecutive days* shall be the average of the daily values obtained during any 30 consecutive day period.

(c) The term "Cook Inlet" refers to coastal locations north of the line between Cape Douglas on the West and Port Chatham on the east.

(d) The term *daily values* as applied to produced water effluent limitations and NSPS shall refer to the daily measurements used to assess compliance with the maximum for any one day.

(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 *development facility* shall mean any fixed or mobile structure subject to this subpart that is engaged in the drilling of productive wells.

(g) The term *dewatering effluent* means wastewater from drilling fluids and drill cuttings dewatering activities (including but not limited to reserve pits or other tanks or vessels, and chemical or mechanical treatment occurring during the drilling solids separation/recycle/disposal process).

(h) 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 for Diesel Fuel Oils D975-91, that is typically used as the continuous phase in conventional oil-based drilling fluids. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103. Copies may be inspected at the Office of the Federal Register, 800 North Capitol Street, NW., Suite 700, Washington, DC. A copy may also be inspected at EPA's Water Docket; Room M2616, 401 M Street SW., Washington, DC 20460.

(i) The term *domestic waste* shall refer to materials discharged from sinks, showers, laundries, safety showers, eye-wash stations, hand-wash stations, fish cleaning stations, and galleys located within facilities subject to this subpart.

(j) 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.

(k) The term *drilling fluid* refers to the circulating fluid (mud) used in the rotary drilling of wells to clean and

condition the hole and to counterbalance formation pressure. The four classes of drilling fluids are:

(1) A water-based drilling fluid has water as the continuous phase and the suspending medium for solids, whether or not oil is present.

(2) An oil-based drilling fluid has diesel oil, mineral oil, or some other oil, but neither a synthetic material nor enhanced mineral oil, as its continuous phase with water as the dispersed phase.

(3) An enhanced mineral oil-based drilling fluid has an enhanced mineral oil as its continuous phase with water as the dispersed phase.

(4) A synthetic-based drilling fluid has a synthetic material as its continuous phase with water as the dispersed phase.

(l) The term *enhanced mineral oil* as applied to enhanced mineral oil-based drilling fluid means a petroleum distillate which has been highly purified and is distinguished from diesel oil and conventional mineral oil in having a lower polycyclic aromatic hydrocarbon (PAH) content. Typically, conventional mineral oils have a PAH content on the order of 0.35 weight percent expressed as phenanthrene, whereas enhanced mineral oils typically have a PAH content of 0.001 or lower weight percent PAH expressed as phenanthrene.

(m) The term *exploratory 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.

(n) The term *garbage* means all kinds of victual, domestic, and operational waste, excluding fresh fish and parts thereof, generated during the normal operation of coastal oil and gas facility and liable to be disposed of continuously or periodically, except dishwater, graywater, and those substances that are defined or listed in other Annexes to MARPOL 73/78. A copy of MARPOL may be inspected at EPA's Water Docket; Room M2616, 401 M Street SW, Washington, DC 20460.

(o) The term *maximum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the maximum concentration allowed as measured in any single sample of the barite.

(p) The term *maximum for any one day* as applied to BPT, BCT and BAT effluent limitations and NSPS 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. Alternatively, for BAT and NSPS, the maximum concentration allowed may be determined on the basis of physical composition of the four grab samples prior to a single analysis.

(q) The term *minimum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall mean the minimum 96-hour LC50 value allowed as measured in any single sample of the discharged waste stream. The term *minimum* as applied to BPT and BCT effluent limitations and NSPS for sanitary wastes shall mean the minimum concentration value allowed as measured in any single sample of the discharged waste stream.

(r) The term *M9IM* shall mean those coastal facilities continuously manned by nine (9) or fewer persons or only intermittently manned by any number of persons.

(s) The term *M10* shall mean those coastal facilities continuously manned by ten (10) or more persons.

(t) (1) The term *new source* means any facility or activity of this subcategory 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 consistently with all of the following definitions:

(i) The term *water area* as used in the term "site" in 40 CFR 122.29 and 122.2 shall mean the water area and water body floor beneath any exploratory, development, or production facility where such facility is conducting its exploratory, development or production activities.

(ii) The term *significant site preparation work* as used in 40 CFR 122.29 shall mean the process of surveying, clearing or preparing an area of the water body floor for the purpose of constructing or placing a development or production facility on or over the site.

(2) "New Source" does not include facilities covered by an existing NPDES permit immediately prior to the effective date of these guidelines pending EPA issuance of a new source NPDES permit.

(u) 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 or fail the static sheen test defined in appendix 1 to 40 CFR part 435, subpart A.

(v) The term *produced sand* shall refer to slurried particles used in hydraulic fracturing, the accumulated formation sands and scales particles generated during production. Produced sand also includes desander discharge from the produced water waste stream,

and blowdown of the water phase from the produced water treating system.

(w) 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.

(x) The term *production facility* shall mean any fixed or mobile structure subject to this subpart that is either engaged in well completion or used for active recovery of hydrocarbons from producing formations. It includes facilities that are engaged in hydrocarbon fluids separation even if located separately from wellheads.

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

(y) 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 to 40 CFR part 435, subpart A.

(z) The term *synthetic material* as applied to synthetic-based drilling fluid means material produced by the reaction of specific purified chemical feedstock, as opposed to the traditional base fluids such as diesel and mineral oil which are derived from crude oil

solely through physical separation processes. Physical separation processes include fractionation and distillation and/or minor chemical reactions such as cracking and hydro processing. Since they are synthesized by the reaction of purified compounds, synthetic materials suitable for use in drilling fluids are typically free of polycyclic aromatic hydrocarbons (PAH's) but are sometimes found to contain levels of PAH up to 0.001 weight percent PAH expressed as phenanthrene. Poly(alpha olefins) and vegetable esters are two examples of synthetic used by the oil and gas extraction industry in formulating drilling fluids. Poly(alpha olefins) are synthesized from the polymerization (dimerization, trimerization, tetramerization, and higher oligomerization) of purified straight-chain hydrocarbons such as C₆-C₁₄ alpha olefins. Vegetable esters are synthesized from the acid-catalyzed esterification of vegetable fatty acids with various alcohols. The mention of these two branches of synthetic fluid base materials is to provide examples, and is not meant to exclude other synthetic materials that are either in current use or may be used in the future. A synthetic-based drilling fluid may include a combination of synthetic materials.

(aa) The term *toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings shall refer to the bioassay test procedure presented in appendix 2 of 40 CFR part 435, subpart A.

(bb) The term *well completion fluids* shall refer to salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production.

(cc) The term *well treatment fluids* shall refer to any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

(dd) The term *workover fluids* shall refer to salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures.

(ee) The term *96-hour LC50* shall refer to the concentration (parts per million) or percent of the suspended particulate phase (SPP) from a sample that is lethal to 50 percent of the test organisms exposed to that concentration of the SPP after 96 hours of constant exposure.

§ 435.42 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 125.30-125.32, 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.

BPT EFFLUENT LIMITATIONS—OIL AND GREASE

[In milligrams per liter]

Pollutant parameter waste source	Maximum for any 1 day	Average of values for 30 consecutive days shall not exceed	Residual chlorine minimum for any 1 day
Produced water	72	48	NA
Deck drainage	(¹)	(¹)	NA
Drilling fluid	(¹)	(¹)	NA
Drill cuttings	(¹)	(¹)	NA
Well treatment, workover, and completion fluids	(¹)	(¹)	NA
Sanitary:			
M10	NA	NA	≥ 1
M9IM ³	NA	NA	NA
Domestic ³	NA	NA	NA
Produced sand	Zero discharge ...	Zero discharge ...	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.

§ 435.43 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 125.30-125.32, 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):

BAT EFFLUENT LIMITATIONS

Stream	Pollutant parameter	BAT effluent limitations
Produced Water:		
(A) All coastal areas except Cook Inlet	No discharge.
(B) Cook Inlet	Oil & Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l.
Drilling Fluids, Drill Cuttings, and Dewatering Effluent: ¹		
(A) All coastal areas except Cook Inlet	No discharge.
	Free Oil ²	No discharge.
	Diesel Oil	No discharge.
(B) Cook Inlet	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3 percent by volume ⁴ .
Well Treatment, Workover and Completion Fluids:		
(A) All coastal areas except Cook Inlet	No discharge.
(B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l.
Produced Sand	No discharge.
Deck Drainage	Free Oil ³	No discharge.
Domestic Waste	Foam	No discharge.

¹ BCT limitations for dewatering effluent are applicable prospectively. BCT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

² As determined by the static sheen test (see appendix 1 to 40 CFR part 435, subpart A).

³ As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).

⁴ As determined by the toxicity test (see appendix 2 of 40 CFR part 435, subpart A).

§ 435.44 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 125.30–125.32, 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

Stream	Pollutant parameter	BCT effluent limitations
Produced Water (all facilities)	Oil & Grease	The maximum for any one day shall not exceed 72 mg/l and the 30-day average shall not exceed 48 mg/l.
Drilling Fluids and Drill Cuttings and Dewatering Effluent: ¹		
All facilities except Cook Inlet	No discharge.
Cook Inlet	Free Oil	No discharge. ²
Well Treatment, Workover and Completion Fluids.	Free Oil	No discharge. ²
Produced Sand	No discharge.
Deck Drainage	Free Oil	No discharge. ³
Sanitary Waste:		
Sanitary M10	Residual Chlorine	Minimum of 1 mg/l maintained as close to this concentration as possible.
Sanitary M91M	Floating Solids	No discharge.
Domestic Waste	Floating Solids and garbage	No discharge of Floating Solids or garbage. ⁴

¹ BCT limitations for dewatering effluent are applicable prospectively. BCT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

² As determined by the static sheen test (see appendix 1 to 40 CFR part 435, subpart A).

³ As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).

⁴ As determined by the toxicity test (see appendix 2 of 40 CFR part 435, subpart A).

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

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

NSPS EFFLUENT LIMITATIONS

Stream	Pollutant parameter	NSPS effluent limitations
Produced Water (all facilities)	No discharge.
Drilling Fluids and Drill Cuttings and Dewatering Effluent: ¹		
(A) All coastal areas except Cook Inlet	No discharge.
(B) Cook Inlet	Free Oil ¹	No discharge.
	Diesel Oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite; 3 mg/kg dry weight maximum in the stock barite.
	Cadmium	Minimum 96-hour LC50 of the SPP shall be 3 percent by volume. ³
	Toxicity.	
Well Treatment, Workover and Completion Fluids:		
(A) All coastal areas except Cook Inlet	No discharge.
(B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l.
Produced Sand	No discharge.
Deck Drainage	Free Oil ²	No discharge.
Sanitary Waste:		
Sanitary M10	Residual Chlorine	Minimum of 1 mg/l and maintained as close to this concentration as possible.
Sanitary M91M	Floating Solids	No discharge.
Domestic Waste	Floating Solids, Garbage ⁴ and Foam	No discharge of floating solids or garbage or foam.

¹ BAT limitations for dewatering effluent are applicable prospectively. BAT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of this rule no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority.

² As determined by the static sheen test (see Appendix 1 to 40 CFR part 435, subpart A).

³ As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).

⁴ As determined by the toxicity test (see Appendix 2 of 40 CFR part 435, subpart A).

⁵ As defined in 40 CFR 435.41(1).

§ 435.46 Pretreatment Standards of Performance for Existing Sources (PSES)

Except as provided in 40 CFR 403.7 and 403.13, any existing source with discharges subject to this subpart that introduces pollutants into a publicly owned treatment works must comply with 40 CFR part 403 and achieve the following pretreatment standards for existing sources (PSES).

PSES EFFLUENT LIMITATIONS

Stream	Pollutant parameter	PSES effluent limitations
Produced Water	No discharge.
Drilling Fluids and Drill Cuttings Well Treatment.	No discharge.
Workover and Completion Fluids.	No discharge.
Produced Sand	No discharge.
Deck Drainage	No discharge.

§ 435.47 Pretreatment Standards of performance for new sources (PSNS)

Except as provided in 40 CFR 403.7 and 403.13, any new source with discharges subject to this subpart that introduces pollutants into a publicly

owned treatment works must comply with 40 CFR part 403 and achieve the following pretreatment standards for new sources (PSNS).

PSNS EFFLUENT LIMITATIONS

Stream	Pollutant parameter	PSNS effluent limitations
Produced Water (all facilities).	No discharge.
Drilling fluids and Drill Cuttings.	No discharge.
Well Treatment, Workover and Completion Fluids.	No discharge.
Produced Sand.	No discharge.
Deck Drainage.	No discharge.

5. Subpart G consisting of § 435.10 is added to read as follows:

Subpart G—General Provisions

§ 435.10 Applicability.

(a) *Purpose.* This subpart is intended to prevent oil and gas facilities, for which effluent limitations guidelines

and standards, new source performance standards, or pretreatment standards have been promulgated under this part, from circumventing the effluent limitations guidelines and standards applicable to those facilities by moving effluent produced in one subcategory to another subcategory for disposal under less stringent requirements than intended by this part.

(b) *Applicability.* The effluent limitations and standards applicable to an oil and gas facility shall be determined as follows:

(1) An Oil and Gas facility, operator, or its agent or contractor may move its wastewaters from a facility located in one subcategory to another subcategory for treatment and return it to a location covered by the original subcategory for disposal. In such case, the effluent limitations guidelines, new source performance standards, or pretreatment standards for the original subcategory apply.

(2) An Oil and Gas facility, operator, or its agent or contractor may move its wastewaters from a facility located in one subcategory to another subcategory for disposal or treatment and disposal, provided:

(i) If an Oil and Gas facility, operator or its agent or contractor moves

wastewaters from a wellhead located in one subcategory to another subcategory where oil and gas facilities are governed by less stringent effluent limitations guidelines, new source performance standards, or pretreatment standards, the more stringent effluent limitations guidelines, new source performance

standards, or pretreatment standards applicable to the subcategory where the wellhead is located shall apply.

(ii) If an Oil and Gas facility, operator or its agent moves effluent from a wellhead located in one subcategory to another subcategory where oil and gas facilities are governed by more stringent effluent limitations guidelines, new

source performance standards, or pretreatment standards, the more stringent effluent limitations guidelines, new source performance standards, or pretreatment standards applicable at the point of discharge shall apply.

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