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Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category; OMB Approval Under the Paperwork Reduction Act: Technical Amendment; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 435

[FRL–6929–8]

RIN 2040–AD14

Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category; OMB Approval Under the Paperwork Reduction Act: Technical Amendment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final Rule; technical amendment.

SUMMARY: EPA is publishing final regulations establishing technology-based effluent limitations guidelines and standards for the discharge of synthetic-based drilling fluids (SBFs) and other non-aqueous drilling fluids from oil and gas drilling operations into waters of the United States. Oil and gas extraction facilities generate cuttings wastes from drilling operations. This regulation applies to existing and new sources that perform oil and natural gas extraction drilling in certain offshore and coastal waters. The final rule allows a controlled discharge of SBF-cuttings anywhere offshore of Alaska and offshore of the rest of the United States beyond three miles from shore. This regulation prohibits discharge of such fluids in coastal Cook Inlet, Alaska, unless certain findings are made by the permit authority. The final rule prohibits the discharge of SBFs not associated with drill cuttings into all waters of the United States.

Compliance with this rule is estimated to reduce the annual discharge of cuttings by 118 million pounds per year for new and existing sources. This rule will also lead to a decrease of 2,927 tons of air emissions and 200,817 barrels of oil equivalent (BOE) per year for new and existing sources. EPA estimates that the rule will result in annual savings of $48.9 million and no adverse economic impacts to the industry as a whole. EPA also incorporated Best Management Practices (BMPs) into the final rule to provide industry with additional flexibility in meeting today's final rule. In compliance with the Paperwork Reduction Act (PRA), this action also makes a technical amendment to the table in part 9 that lists the Office of Management and Budget (OMB) control numbers issued under the PRA for today's final rule. EPA is amending part 9 to include the OMB control number for the information collection requirements associated with the BMPs promulgated in today's final rule.

DATES: This regulation shall become effective February 21, 2001. For judicial review purposes, this final rule is promulgated as of 1 p.m. Eastern Time on February 5, 2001, as provided in 40 CFR 23.2. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Office of Federal Register as of February 21, 2001.

ADDRESSES: The public record is available for review in the EPA Water Docket, East Tower Basement, Room EB–57, 401 M St. SW., Washington, DC 20460. The public record for this rule has been established under docket number W–98–26, and includes supporting documentation, but does not include any information claimed as Confidential Business Information (CBI). The record is available for inspection from 9 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. For access to docket materials, please call (202) 260–3027 to schedule an appointment.

FOR FURTHER INFORMATION CONTACT: For additional technical information contact Mr. Carey A. Johnston at (202) 260–7186 or send E-mail to: johnston.carey@epa.gov. For additional economic information contact Mr. James Covington at (202) 260–5132 or send E-mail to: covington.james@epa.gov.

SUPPLEMENTARY INFORMATION:

Regulated Entities

Entities potentially regulated by this action include:

Category	Examples of regulated entities
Industry	Facilities engaged in the drilling of wells in the oil and gas industry in areas defined as "coastal" or "offshore" and discharging in geographic areas where drilling wastes are allowed for discharge (anywhere offshore of Alaska and offshore of the rest of the United States beyond three miles from shore, and the coastal waters of Cook Inlet, Alaska). Includes certain facilities covered under Standard Industrial Classification code 13 and North American Industrial Classification System codes 211111 and 213111.

This 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 in 40 CFR part 435 (*see* §§ 435.10 and 435.40). If you have questions regarding the applicability of this action to a particular entity, consult the person listed for technical information in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Compliance Dates

Deadlines for compliance with Best Practicable Control Technology Currently Available (BPT), Best Conventional Pollutant Control Technology (BCT), and Best Available Technology Economically Achievable (BAT) are established in National Pollutant Discharge Elimination System (NPDES) permits. A new source must comply with New Source Performance Standards (NSPS) on the date the new source commences discharging.

Technical Amendments to Part 9

EPA is amending the table of currently approved information collection request (ICR) control numbers issued by OMB for various regulations. The amendment updates the table to list those information collection requirements promulgated under today's final rule. The affected regulations are codified at 40 CFR part 9. EPA will continue to present OMB control numbers in a consolidated table format to be codified in 40 CFR part 9 of the Agency's regulations, and in each CFR volume containing EPA regulations. The table lists CFR citations with reporting, recordkeeping, or other information collection requirements, and the current OMB control numbers. This listing of the OMB control numbers and their subsequent codification in the CFR satisfies the requirements of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*) and OMB's implementing regulations at 5 CFR part 1320.

This ICR was previously subject to public notice and comment prior to OMB approval. Due to the technical

nature of the table, EPA finds that further notice and comment is unnecessary. As a result, EPA finds that there is ''good cause'' under section 553(b)(B) of the Administrative Procedure Act, 5 U.S.C. 553(b)(B), to amend this table without prior notice and comment. As a result of today's technical amendment pertaining to BMPs, EPA is now authorized under the Paperwork Reduction Act to conduct or sponsor the information collection requirements in 40 CFR 435.13, 435.15, 435.43, and 435.45.

Supporting Documentation

The rules promulgated today are supported by several major documents:

1. ''Economic Analysis of Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category'' (EPA–821–B–00–012). Hereafter referred to as the SBF Economic Analysis, this document presents the analysis of compliance costs and/or savings; facility closures; and changes in rate of return. In addition, impacts on employment and affected communities, foreign trade, specific demographic groups, and new sources also are considered.

2. ''Development Document for Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category'' (EPA–821–B–00–013). Hereafter referred to as the SBF Development Document, the document presents EPA's technical conclusions concerning the promulgated rules. This document describes, among other things, the data collection activities, the wastewater treatment technology options, effluent characterization, effluent reduction of the wastewater treatment technology options, estimate of costs to the industry, and estimate of effects on non-water quality environmental impacts.

3. ''Environmental Assessment of Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category'' (EPA–821–B–00–014). Hereafter referred to as the SBF Environmental Assessment, the document presents the analysis of water quality impacts for each regulatory option. EPA describes the environmental characteristics of SBF drilling wastes, types of anticipated impacts, and pollutant modeling results for water column concentrations, pore water concentrations, and human health effects via consumption of affected seafood.

4. ''Statistical Analyses Supporting Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category'' (EPA–821–B–00–015). Hereafter referred to as the SBF Statistical Support Document, this document presents analyses of retention on cuttings of SBF. EPA describes the performance characteristics of cuttings treatment technologies and calculates summary statistics for use as numerical limits.

How To Obtain Supporting Documents

All documents are available from the National Service Center for Environmental Publications, PO Box 42419, Cincinnati, OH 45242–2419, (800) 490–9198. The supporting technical documentation (*e.g.*, SBF Development Document) and previous technical documentation and Federal Register notices can also be obtained on the Internet, located at WWW.EPA.GOV/OST/GUIDE. This website also links to an electronic version of today's final rule.

Overview

This preamble includes a description of the legal authority for these final regulations; a summary of the final regulations; background information on the industry and its processes; a description of the technical and economic methodologies and data used by EPA to develop these regulations; and a summary of EPA responses to major comments received on the Proposal (February 3, 1999; 64 FR 5488) and Notice of Data Availability (April 21, 2000; 65 FR 21548). The definitions, acronyms, and abbreviations used in this preamble are defined in Appendix A.

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I. Legal Authority

EPA is promulgating these regulations under the authority of sections 301, 304, 306, 307, 308, 402, and 501 of the Clean Water Act, 33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342 and 1361. The technical amendment to part 9 is promulgated under the authority of 7 U.S.C. 135 *et seq.*, 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251 *et seq.*, 1311, 1313d, 1314, 1318, 1321, 1326, 1330, 1342, 1344, 1345 (d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857 *et seq.*, 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

II. Background

A. Clean Water Act

Congress adopted the Clean Water Act (CWA) to ''restore and maintain the chemical, physical, and biological integrity of the Nation's waters'' (Section 101(a), 33 U.S.C. 1251(a)). To achieve this goal, the CWA prohibits the discharge of pollutants into navigable waters except in compliance with the statute. The Clean Water Act confronts the problem of water pollution on a number of different fronts. Its primary reliance, however, is on establishing restrictions on the types and amounts of pollutants discharged from various industrial, commercial, and public sources of wastewater.

Direct dischargers must comply with effluent limitations in National Pollutant Discharge Elimination System (''NPDES'') permits; indirect dischargers must comply with pretreatment standards. These limitations and standards are established by regulation for categories of industrial dischargers and are based on the degree of control that can be achieved using various levels of pollution control technology.

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

Section 304(b)(1)(A) of the CWA requires EPA to identify effluent reductions attainable through the application of, ''best practicable control technology currently available for classes and categories of point sources.'' Generally, EPA determines BPT effluent levels based upon the average of the best existing performances by plants of various sizes, ages, and unit processes within each industrial category or subcategory. In industrial categories where present practices are uniformly inadequate, however, EPA may determine that BPT requires higher levels of control than any currently in place if the technology to achieve those levels can be practicably applied (*see* A Legislative History of the Federal Water Pollution Control Act Amendments of 1972, U.S. Senate Committee of Public Works, Serial No. 93–1, January 1973, p. 1468).

In addition, CWA Section 304(b)(1)(B) requires a cost assessment for BPT limitations. In determining the BPT limits, EPA must consider the total cost of treatment technologies in relation to the effluent reduction benefits achieved. This inquiry does not limit EPA's broad discretion to adopt BPT limitations that are achievable with available technology unless the required additional reductions are ''wholly out of proportion to the costs of achieving such marginal level of reduction.'' (*see* Legislative History, op. cit. p. 170). Moreover, the inquiry does not require the Agency to quantify benefits in monetary terms (*e.g.*, American Iron and Steel Institute v. EPA, 526 F. 2d 1027 (3rd Cir., 1975)).

In balancing costs against the benefits of effluent reduction, EPA considers the volume and nature of expected discharges after application of BPT, the general environmental effects of pollutants, and the cost and economic impacts of the required level of pollution control. In developing guidelines, the Act does not require consideration of water quality problems attributable to particular point sources, or water quality improvements in particular bodies of water.

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

The CWA establishes BAT as a principal means of controlling the discharge of toxic and non-conventional pollutants. In general, BAT effluent limitations guidelines represent the best existing economically achievable performance of direct discharging plants in the industrial subcategory or category. The factors considered in assessing BAT include the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the processes employed, engineering aspects of the control technology, 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 to these factors. An additional statutory factor considered in setting BAT is economic achievability. Generally, the achievability is determined on the basis of the total cost to the industrial subcategory and the overall effect of the rule on the industry's financial health. BAT limitations may be based upon effluent reductions attainable through changes in a facility's processes and operations. As with BPT, where existing performance is uniformly inadequate, BAT may be based upon technology transferred from a different subcategory within an industry or from another industrial category. BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice.

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

The 1977 amendments to the CWA required EPA to identify effluent reduction levels for conventional pollutants associated with BCT technology for discharges from existing industrial point sources. BCT is not an additional limitation, but replaces Best Available Technology (BAT) for control of conventional pollutants. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that EPA establish BCT limitations after consideration of a two part ''cost-reasonableness'' test. EPA explained its methodology for the development of BCT limitations in July 1986 (51 FR 24974).

Section 304(a)(4) designates the following as conventional pollutants: biochemical oxygen demand (BOD_5), 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).

4. New Source Performance Standards (NSPS)—Section 306 of the CWA

NSPS reflect effluent reductions that are achievable based on the best available demonstrated control technology. New facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS should represent the greatest degree of effluent reduction attainable through the application of the best available demonstrated control technology for all pollutants (*i.e.,* conventional, non-conventional, and priority pollutants). 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)—Section 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 (POTWs). 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 implementing 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)—Section 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 plants the best available demonstrated technologies. The Agency considers the same factors in promulgating PSNS as it considers in promulgating NSPS.

7. Best Management Practices (BMPs)

Sections 304(e), 308(a), 402(a), and 501(a) of the CWA authorize the Administrator to prescribe BMPs as part of effluent limitations guidelines and standards or as part of a permit. EPA's BMP regulations are found at 40 CFR 122.44(k). Section 304(e) of the CWA authorizes EPA to include BMPs in effluent limitations guidelines for certain toxic or hazardous pollutants for the purpose of controlling ''plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage.'' Section 402(a)(1) and NPDES regulations (40 CFR 122.44(k)) also provide for best management practices to control or abate the discharge of pollutants when numeric limitations and standards are infeasible. In addition, section 402(a)(2), read in concert with section 501(a), authorizes EPA to prescribe as wide a range of permit conditions as the Administrator deems appropriate in order to ensure compliance with applicable effluent limitations and standards and such other requirements as the Administrator deems appropriate.

8. CWA Section 304(m) Requirements

Section 304(m) of the CWA, added by the Water Quality Act of 1987, requires EPA to establish schedules for: (1) Reviewing and revising existing effluent limitations guidelines and standards; and (2) 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 effluent guidelines for several industry categories, including the oil and gas extraction 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. *Browner,* 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. The most recent Effluent Guidelines Plan was published in the **Federal Register** on August 31, 2000 (65 FR 53008). This plan requires, among other things, that EPA take final action regarding the Synthetic-Based Drilling Fluids Guidelines by December 2000.

B. Pollution Prevention Act

The Pollution Prevention Act of 1990 (PPA) (42 U.S.C. 13101 *et seq.*, Public Law 101–508, November 5, 1990) ''declares it to be the national policy of the United States that pollution should be prevented or reduced whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner whenever feasible; and disposal or release into the environment should be employed only as a last resort * * *'' (Sec. 6602; 42 U.S.C. 13101 (b)). In short, preventing pollution before it is created is preferable to trying to manage, treat or dispose of it after it is created. The PPA directs the Agency to, among other things, ''review regulations of the Agency prior and subsequent to their proposal to determine their effect on source reduction'' (Sec. 6604; 42 U.S.C. 13103(b)(2)). EPA reviewed this effluent guideline for its incorporation of pollution prevention.

According to the PPA, source reduction reduces the generation and release of hazardous substances, pollutants, wastes, contaminants, or residuals at the source, usually within a process. The term source reduction ''include(s) equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training or inventory control. The term ''source reduction'' does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a hazardous substance, pollutant, or contaminant through a process or activity which itself is not integral to or necessary for the production of a product or the providing of a service.'' 42 U.S.C. 13102(5). In effect, source reduction means reducing the amount of a pollutant that enters a waste stream or that is otherwise released into the environment prior to out-of-process recycling, treatment, or disposal.

In these final regulations, EPA supports pollution prevention technology by encouraging the appropriate use of synthetic-based drilling fluids (SBFs) based on the use of base fluid materials in place of traditional: (1) Water-based drilling fluids (WBFs); and (2) oil-based drilling fluids (OBFs) consisting of diesel oil/or and mineral oil. The appropriate use of SBFs in place of WBFs will generally lead to more efficient and faster drilling and a per well reduction in non-water quality environmental impacts (including energy requirements) and discharged pollutants. Use of SBFs may also lead to a reduced demand for new drilling rigs and platforms and development well drilling though the use directional and extended reach drilling. Discharges from SBF-drilling operations have lower aqueous and

sediment toxicities, lower bioaccumulation potentials, and faster biodegradation rates as compared to OBFs. In addition, polynuclear aromatic hydrocarbons (PAHs), including those which are priority pollutants, which are constituents in OBFs are not present in SBFs.

EPA considered a ''zero discharge'' requirement (*i.e.,* BAT/NSPS Option 3) for SBF-cuttings wastes and determined that under this requirement most operators would decrease the use of SBFs in favor of OBFs and WBFs due to lower OBF and WBF drilling fluid unit costs. EPA concluded that a zero discharge requirement for SBF-cuttings and the subsequent increased use of OBFs and WBFs would result in: (1) Unacceptable non-water quality environmental impacts (NWQIs); and (2) more pollutant loadings to the ocean due to operators switching from SBFs to less efficient WBFs.

The appropriate use of SBF in place of OBF will generally shorten the length of the drilling project and eliminate the need to barge to shore or re-inject OBF-waste cuttings, thereby reducing NWQI such as fuel use, air emissions, and land disposal of OBFs. The controlled discharge option also eliminates the risk of OBF and OBF-cuttings spills and cross-media contamination at land disposal operations. Operators would be increasing the toxicity of their drilling fluids and wastes by using OBFs in place of SBFs. As stated in April 2000 (65 FR 21557), EPA used SBF and OBF spill data in the final rule as a factor in supporting a controlled discharge option. U.S. Department of Interior, Minerals Management Service (MMS) spill data show that riser disconnects in deep water drilling can release approximately 2,400 barrels of neat SBF and these incidences occur in deep water on average two to three times per year due to riser failure (Docket No. W–98–26, Record No. IV.B.a.3). Riser disconnects in the deep water are a particular concern due to: (1) Increased riser tensioning; (2) deep water technical requirements (*e.g.,* riser verticality, increased use of top drive systems, multiple flex joints in riser, placement of well heads and upper casing sections in soft sea beds); and (3) deep water ocean environments (*e.g.,* uncharted eddy and loop currents) (Docket No. W–98–26, Record No. IV.B.a.4; Record No. IV.B.a.5). Use of WBFs in place of SBFs would also lead to: (1) An increase in NWQIs due to the increased length of the drilling project; and (2) a per well increase pollutants discharged due to poorer technical performance of WBFs. For these primary reasons, EPA rejected the zero discharge option.

In addition, the technology controls in the final regulation are based on a more efficient solids control technology to increase recycling of SBF in the drilling operation. Increased SBF recycling reduces the quantity of SBF required for drilling operations and the quantity of SBF discharged with drill cuttings. A discussion of this pollution prevention technology is contained in Section V.A of this preamble and in the SBF Development Document.

C. Profile of Industry

1. Well Drilling Process Description

The SBF Development Document presents a thorough description of the industry including drilling practices, solids control systems, and waste disposal operations. The following summary is excerpted from that technical document.

Drilling occurs in two phases: exploration and development. Exploration activities are those operations involving the drilling of wells to locate hydrocarbon bearing formations and to determine the size and production potential of hydrocarbon reserves. Development activities involve the drilling of production wells once a hydrocarbon reserve has been discovered and delineated.

Drilling for oil and gas is generally performed by rotary drilling methods which use a circularly rotating drill bit that grinds through the earth's crust as it descends. Drilling fluids are pumped down through the drill bit via a pipe that is connected to the bit, and serve to cool and lubricate the bit during drilling. The rock chips that are generated as the bit drills through the earth are termed ''drill cuttings'' or simply ''cuttings.'' The drilling fluid also serves to transport the drill cuttings back up to the surface through the space between the drill pipe and the well wall (this space is termed the annulus), in addition to controlling downhole pressure and stabilizing the well bore.

As drilling progresses, large pipes called ''casing'' are inserted into the well to line the well wall. Drilling continues until the hydrocarbon bearing formations are encountered. In areas where drilling fluids and drill cuttings are allowed to be discharged under the current regulations, well depths range from approximately 4,000 to 12,000 feet deep, and it takes approximately 20 to 60 days to complete drilling.

On the surface, the drilling fluid and drill cuttings undergo an extensive separation process to remove fluid from the cuttings. The fluid is then recycled into the system, and the cuttings become a waste product. The drill cuttings retain a certain amount of the drilling fluid that are discharged or disposed with the cuttings. Drill cuttings are discharged by the shale shakers and other solids separation equipment (*e.g.,* decanting centrifuges, mud cleaners, cuttings dryers). Drill cuttings are also cleaned out of the mud pits and from the solid separation equipment during displacement of the drilling fluid system (*i.e.,* accumulated solids). Intermittently during drilling, and at the end of the drilling process, drilling fluids may become wastes if they can no longer be reused or recycled.

In the relatively new area of ultra-deep water drilling (*i.e.,* water depths greater than 3,000 feet), new drilling methods are evolving which can significantly improve drilling efficiencies and thereby reduce NWQIs (*e.g.,* fuel, steel casing consumption, air emissions) and the per well amount of pollutants discharged. Subsea drilling fluid boosting, referred to as ''dual gradient drilling,'' is one such new drilling technology. Dual gradient drilling is similar to traditional rotary drilling methods as previously described with the exception that the drilling fluid is energized or boosted by use of a pump at or near the seafloor. By boosting the drilling fluid, the adverse effect on the wellbore caused by the drilling fluid pressure from the seafloor to the surface is eliminated, thereby allowing wells to be drilled with as much as a 50% reduction in the number of casing strings generally required to line the well wall. As a result of the reduced number of casing strings, dual gradient wells can be drilled almost one-third faster and with smaller hole sizes than conventional deep water drilling. Smaller hole sizes and faster drilling translate into fewer pollutants being discharged to the ocean and fewer NWQI. Dual gradient drilling technology can also potentially eliminate or reduce the amount of whole drilling fluid released to the environment during an inadvertent riser disconnect. Finally, dual gradient drilling technology can greatly reduce the potential release of drilling fluid when drilling through shallow sand intervals (*e.g.,* shallow water flow) (Docket No. W–98–26, Record No. IV.B.a.6).

Some dual gradient drilling systems require the separation of the largest cuttings (*e.g.,* larger than approximately ¼ inch) at the seafloor since these cuttings may interfere with the rotatory action of subsea pumps (*e.g.,* electrical

submersible pumps). The larger cuttings are routed at the seafloor to a venturi action pump (with no moving parts), mixed with seawater, and pumped to a cuttings discharge hose at the seafloor within a 300 foot radius of the well site. The hose is perforated on the last 50 ft of its length to maximize the spread of cuttings. The action of pumping cuttings with seawater can be expected to have some cleaning and dispersion effect. A remotely operated vehicle (ROV) can also be used to reposition the subsea discharge hose to maximize cuttings dispersal. Representative samples of drill cuttings discharged at the seafloor can be transported to the surface by a ROV for purposes of monitoring. The drilling fluid, which is boosted at the seafloor and transports most of the drill cuttings (*e.g.,* 95–98% of total cuttings generated) back to the surface, is processed as described in the general rotary drilling methods described above in this section.

A commercial potential determination is made at the completion of rotary drilling (*i.e.,* once the target oil or natural gas formations have been reached). The well is then made ready for production by a process termed ''completion.'' Completion involves cleaning the well to remove drilling fluids and debris, perforating the casing that lines the producing formation, inserting production tubing to transport the hydrocarbon fluids to the surface, and installing the surface wellhead. The well is then ready for production (*i.e.,* actual extraction of hydrocarbons).

2. Location and Activity

This rule establishes effluent limitations guidelines and standards that control discharges of SBF and SBF-cuttings throughout the Offshore subcategory beyond three miles from shore, except for Offshore Alaska where no three mile restriction applies. This rule prohibits discharge of SBF and SBF-cuttings in Upper (Coastal Subcategory) Cook Inlet, Alaska, unless operators meet criteria demonstrating that they are unable to: (1) Box and store their cuttings on-site for zero discharge cuttings transfer operations (*i.e.,* haul to shore for land disposal or re-injection at another rig or platform); or (2) re-inject their SBF-cuttings on-site. When Coastal Cook Inlet, AK, operators demonstrate to the NPDES controlling authority that they are unable to achieve zero discharge of their SBF-cuttings, they may discharge their SBF-cuttings under the same controls as exist for SBF-cuttings discharges in Offshore waters. Criteria for establishing when operators cannot achieve zero discharge are established in the final regulation. SBF-cuttings discharged in Offshore Cook Inlet, Alaska, are controlled in the same manner as other SBF-cuttings in other Offshore waters. This rule does not amend the requirements for zero discharge of drilling fluids and drill cuttings where they have already been prohibited from discharge.

Drilling is currently active in three regions: (1) The offshore waters beyond three miles from shore in the Gulf of Mexico (GOM); (2) offshore waters beyond three miles from shore in California; and (3) Cook Inlet, Alaska. Most drilling activity occurs in the GOM, where 1,302 wells were drilled in 1997, compared to 28 wells drilled in California and 7 wells drilled in Cook Inlet. In the GOM, over the last few years, there has been high growth in the number of wells drilled in deep water (*e.g.,* water depths greater than 1,000 feet). For example, in 1995, 84 wells were drilled in deep water, comprising 8.6% of all GOM wells drilled that year. By 1997, that number increased to 173 deep water wells drilled and comprised over 13% of all GOM wells drilled. Most recent 1999 data show that this trend is continuing as over 15% of all GOM wells drilled were in deep water. The increased activity in deep water increases the usefulness of SBFs. Operators drilling in deep water cite the following factors for selecting SBFs over WBFs and OBFs: (1) Potential for riser disconnect (*i.e.,* inadvertent releases of drilling fluid) in floating drill ships, which favors SBF over OBF; (2) higher daily drilling cost which more easily justifies use of more expensive SBFs over WBFs; and (3) greater distance to barge drilling wastes that may not be discharged (*i.e.,* OBFs, WBFs that fail the SPP Toxicity Test as currently required by EPA in Appendix 2 to Subpart A of 40 CFR part 435).

3. Drilling Wastestreams

Drilling fluids and drill cuttings are a major source of waste from exploratory and development well drilling operations. This final regulation establishes limitations for both the drilling fluid and the drill cuttings wastestream when SBFs are used. All other wastestreams and drilling fluids (*e.g.,* WBFs, OBFs) already have limitations; those limitations are outside the scope of this rule. The characteristics of both drilling fluids and drill cuttings wastestreams are summarized in Section V.A of this preamble. A more detailed discussion of the origins and characteristics of these wastes is also included in the SBF Development Document.

D. Proposed Rule

On February 3, 1999 (64 FR 5488), EPA published proposed effluent limitations guidelines for the discharge of SBF drilling fluids and drill cuttings into waters of the United States by existing and new facilities in the oil and gas extraction point source category.

EPA received comments on many aspects of the proposal. The majority of comments related to: (1) The proposed analytical test methods for stock and discharge limitations; (2) equipment used to set BAT and NSPS cuttings retention limitations; (3) Best Management Practices (BMPs) and their use to control small volume spills and releases of SBF; (4) the proposal's engineering and economic modeling parameters; and (5) procedural and definition issues. EPA evaluated all of these issues based on additional information collected by EPA or received during the comment period. EPA then discussed the results of these evaluations in a Notice of Data Availability which is discussed below.

E. Notice of Data Availability

On April 21, 2000 (65 FR 21548), EPA published a Notice of Data Availability (NODA) to present a summary of new data received in comments on the proposed rule or collected by EPA following publication of the proposal. In the April 2000 NODA, EPA discussed the major issues and presented several revised modeling and alternative approaches to address these issues. EPA solicited comment on the data collected since proposal and on the revised modeling and alternative approaches to manage SBF discharges.

III. Summary of Data and Information Received in Response to the Notice of Data Availability

The April 2000 NODA summarized the data and information received by EPA in response to the February 1999 proposal and information received before the April 2000 NODA. This section describes the data received by EPA in response to the April 2000 NODA.

A. Pollutant Loading and Numeric Limit Analyses

1. SBF Retention on Cuttings

SBF retention on cuttings (ROC) data quantify the amount of SBF retained on cuttings (mass of SBF/mass of wet cuttings, expressed as a percentage). Lower ROC values indicate less SBF retained on cuttings. EPA uses ROC data, along with other engineering factors (*e.g.,* installation requirements, fluid rheology) to evaluate the

performance of various solids control technologies.

In response to the February 1999 proposal, industry submitted data for SBF ROC from 36 wells. EPA determined that 16 files were complete and accurate, and these data were presented in the April 2000 NODA. EPA rejected six files due to incomplete reporting. EPA received 14 files too late for inclusion in the April 2000 NODA analyses.

In response to the April 2000 NODA, EPA received and evaluated ROC data from an additional 79 SBF wells: the 14 received after the February 1999 proposal comment period; 27 additional sets received during the April 2000 NODA comment period; and 38 received after the April 2000 NODA comment period. EPA determined that data from 49 of these 79 wells were complete for inclusion in the final rule analyses. Therefore, EPA used data from 65 wells to determine the ROC performance of the various solids control technologies. The collection, engineering review, and extraction of data from these files are described in the SBF Development Document.

EPA revised the average ROC values of various solids control technologies based on the final ROC data. These revised average ROC values were combined to yield the average ROC value for the following three SBF-cuttings technology options: (1) BAT/NSPS Option 1 is based on the use of shale shakes, cuttings dryer, fines removal unit, and discharges from the cuttings dryer and fines removal unit and has a long-term average ROC value of 4.03%; (2) BAT/NSPS Option 2 is based on the use of shale shakes, cuttings dryer, and fines removal unit, and one discharge from the cuttings dryer, and has a long-term average ROC value of 3.82%; and (3) BAT/NSPS Option 3 is based on the use of shale shakes, cuttings boxes, barges, and zero discharge land disposal and offshore re-injection and has a long-term average ROC value of 10.2%. In addition, using the ROC data, EPA developed a BAT limitation and standard controlling the base fluid retained on cuttings for drilling fluids with the environmental performance of esters (*e.g.,* biodegradation, sediment toxicity). EPA developed this option to provide operators an incentive to use ester-based SBFs and has a long-term average ROC value of 4.8%. EPA used the ROC data to establish a BAT limitation and a NSPS on base fluid retained on cuttings. The base fluid retained on cuttings limitation and standard both incorporate the variability of solids control efficiencies and are higher than the long term average.

2. Days to Drill

EPA uses the number of days to drill the SBF interval, for all four model wells, as an input parameter in the NWQI and cost analysis. EPA extracted relevant data from each of the 65 wells identified above to estimate the number of days to drill each of the four model well SBF intervals (Docket No. W–98–26, Record No. IV.B.a.7). The revised numbers of days required to drill the SBF model wells are based on a revised average rate of SBF-cuttings generation (*i.e.,* 108.7 bbls wet cuttings/day). The revised numbers of days required to drill the SBF model wells are: (1) 5.2 days for shallow-water development wells (SWD); (2) 10.9 days for shallow-water exploratory wells (SWE); (3) 7.9 days for deep-water development wells (DWD); and (4) 17.5 days for deep-water exploratory wells (DWE).

3. Well Count Projections Over Next Five Years

EPA revised well count projections for Offshore GOM, Offshore California, and Cook Inlet, AK, based on information submitted by industry (Docket No. W–98–26, Record No. IV.B.a.9; Record No. IV.B.a.10; Record No. IV.B.a.11). The revised annual well counts are 1,047 shallow water wells and 138 deep water wells in Offshore GOM; 7 shallow water wells and no deep water wells in Offshore California; and 6 shallow water wells and no deep water wells in Cook Inlet, AK. These revised well counts are not significantly different from the well counts used in the February 1999 proposal and April 2000 NODA (*i.e., see* SBF Proposal Development Document (EPA–821–B–98–021), Table IV–2: 1,022 shallow water wells and 139 deep water wells across the GOM, Offshore California, and Cook Inlet, AK).

Industry only provided the well counts in terms of shallow water versus deep water wells. EPA further divided the revised well counts into development and exploratory well category counts for estimating pollutant loadings, compliance costs, and NWQIs. EPA performed this allocation using prior well count data from the April 2000 NODA. EPA derived percentages of development versus exploratory wells for both shallow water well types and deep water well types. EPA then applied these percentages to the revised aggregated shallow water and deep water well counts provided by industry. EPA also collected additional washout rates for WBF and SBF drilling.

EPA also revised well count projections to reflect enhanced directional drilling capabilities when using SBF. EPA received information that SBF directional drilling can reduce the number of wells required to drill a development well project. Specifically, industry stated that SBF development drilling can generally reduce the drilled footage required for full development of a typical reservoir by one-third as compared with WBF drilling (Docket No. W–98–26, Record No. IV.B.a.9). EPA has included this consideration by reducing the footage drilled by one-third for WBF development wells projected to convert from WBF to SBF under the two controlled discharge options.

4. Current and Projected OBF, WBF, and SBF Use Ratios

For the February 1999 proposal and April 2000 NODA, EPA estimated that 80% of the average annual GOM wells are drilled using WBF exclusively; 10% are drilled with SBF; and 10% are drilled with OBF. EPA also included in well counts estimates of operators converting from OBF to SBF or SBF to OBF under each of the SBF-cuttings controlled discharge options.

For the final rule, EPA revised the relative frequency of use between WBF, OBF, and SBF under the two discharge options and the zero discharge option based on data submitted by industry (Docket No. W–98–26, Record No. IV.B.a.9; Record No. IV.B.a.10; Record No. IV.B.a.11). Industry supplied this information to EPA in several formats. EPA used the most reliable information (*e.g.,* the actual well count data for WBF, OBF, and SBF wells over a period of three years) to estimate drilling fluid use under each of the SBF-cuttings control options (*see* SBF Development Document).

EPA believes that some operators would switch from WBFs to SBFs for certain wells due to the increased efficiency of SBF drilling. While no good industry average statistics exist, it is generally considered that SBFs reduce overall drilling time by 50% (*e.g.,* if a well took 60 days to drill with WBF, the same well should be able to be drilled with SBF in 30 days) (Docket No. W–98–26, Record No. IV.B.a.9; Record No. IV.B.a.10; Record No. IV.B.a.11). Reducing drilling time generally reduces drilling costs. However, not all drilling operators will switch from WBFs to SBF due to a variety of other factors, (*e.g.,* WBFs are less expensive (per barrel) than SBFs, potential for lost circulation downhole).

Additionally, EPA believes that under the SBF-cuttings zero discharge option, not all operators would switch from

SBFs to OBFs but that some operators would switch to WBFs. Some drilling operations require the technical performance of non-aqueous drilling fluids and operators must select either an OBF or SBF. Therefore, for these drilling operations, operators would select OBFs in place of SBF under the SBF-cuttings zero discharge option as OBFs are less expensive (per barrel) than SBFs. However, some drilling operations could use either WBFs or oleaginous drilling fluids such as OBFs, enhanced mineral oil based drilling fluids, or SBFs. Depending on a variety of site specific factors (*e.g.,* formation characteristics, directional drilling requirements, torque and drag requirements), operators may select WBFs in lieu of SBFs or OBFs under the SBF-cuttings zero discharge option.

5. Waste Volumes and Characteristics

EPA collected additional data to identify the volumes and characteristics of WBF discharges. This additional data more adequately describes the total amount of pollutants loadings and NWQI under each of the three SBF-cuttings management options. For example, under the SBF zero discharge option (BAT/NSPS Option 3) operators would more likely choose WBF and OBF over SBF due primarily to the relatively higher unit cost of SBF.

Different pollutant loadings and NWQI are expected for WBF as compared with either OBF or SBF wells based on differences in washout and length of drilling time. EPA anticipates a reduction in cuttings waste volume when comparing SBF-drilling to WBF-drilling based on greater hole washout (*i.e.,* enlargement) in WBF drilling. Industry estimated that WBF washout percentages vary between 25% and 75%, with 45% being an acceptable average and confirmed EPA's SBF and OBF washout percentage of 7.5% as appropriate (Docket No. W–98–26, Record No. IV.B.a.9).

For the final rule, EPA also estimated that the barite used in SBF drilling is nearly pure barium sulfate (*i.e.,* $BaSO_4$) and, by gravimetric analysis, calculated the weight percentage of barium in barite as 58.8%.

B. Compliance Costs Analyses

1. Equipment Installation and Downtime

For the April 2000 NODA, projected compliance costs for all options included equipment installation and downtime for each SBF well drilled. After further review of ROC data wells (*see* Section III.A), EPA modified this parameter in the final analyses to reflect current practice of drilling multiple wells per year for any one equipment installation (Docket No. W–98–26, Record No. IV.B.a.9). EPA reviewed the ROC well data for the frequency of multiple wells on specified structures. EPA used the resulting well-per-structure analysis to adjust projected annual SBF compliance costs by including the consideration of drilling more than one SBF well per equipment installation per year. EPA estimated that 2.2 development wells per structure and 1.6 exploratory wells per structure are current industry practice, based on industry-submitted data (*see* SBF Development Document).

EPA received information on the ability of operators to install cuttings dryers (*e.g.,* vertical or horizontal centrifuges, squeeze press mud recovery units, High-G linear shakers) on existing GOM rigs (Docket No. W–98–26, Record No. IV.B.b.33). While some industry sources filed timely comments alleging that some rigs could not accommodate additional solids control equipment, in late comments, industry provided data concerning the number of GOM rigs in operation which are not capable of having a cuttings dryer system installed due to either rig space and/or rig design without prohibitive costs or rig modifications.

EPA also received information on a new cuttings containment, handling, and transfer equipment system. The new system is designed to eliminate the need to use cuttings boxes to handle cuttings. EPA received information from one operator that recently field tested the cuttings transfer system on one 12¼ inch well section in the North Sea. The operator contained 100% of the cuttings on a rig (Alba) with limited deck space. Cuttings were handled in bulk below deck and pumped directly onto a waiting vessel for eventual land disposal. The operator estimated that use of the new cuttings transfer system eliminated hundreds of crane lifts and manual handling issues and thereby improved worker safety.

2. Current Drilling Fluid Costs

In response to the April 2000 NODA, EPA revised unit costs of WBF, OBF, and SBF. Based on industry data, EPA used the WBF unit cost of $45 per barrel for the final rule. The February 1999 Proposal and April 2000 NODA used OBF and SBF unit costs of $75 and $200 per barrel of drilling fluid, respectively. Industry data indicates a range of OBF unit costs from $70–$90 per barrel and EPA used the OBF unit cost of $79 per barrel for the final rule. EPA estimates that SBF unit costs will remain between $160 to $300 per barrel of drilling fluid over the next few years. EPA used an SBF unit cost of $221 per barrel of drilling fluid for the final rule based on the most frequently used SBF in the offshore market.

3. Cost Savings of SBF Use as Compared With WBF Use

EPA revised its compliance costs to include the following factors: (1) The cost savings associated with increased rate of penetration when using SBF as compared to WBF; and (2) the cost of lost WBFs that are discharged while drilling. EPA also examined, but did not include in its final compliance cost impacts, the costs associated with projected failures of a fraction of WBF wells to meet sheen or toxicity limitations, including costs of meeting zero discharge from these wells. EPA used this data to examine compliance costs impacts if operators switch from SBF to WBF drilling, or vice versa.

EPA requested data from industry on rate of penetration (ROP) for WBF operations as compared to SBF operations. Industry stated that ROP values of 300 feet per hour for SBF (and OBF) operations and 150 feet per hour for WBF are reasonable averages. However, using these values over an entire well was not recommended ''due to the large number of variables'' (Docket No. W–98–26, Record No. IV.B.a.9). Industry's information further states that a generally-accepted estimate is that ''SBFs reduce overall drilling time by 50%'' (Docket No. W–98–26, Record No. IV.B.a.9).

4. Construction Cost Index

EPA used the Construction Cost Index (CCI) from the Engineering News and Record (*see* http://www.enr.com/cost/costcci.asp) to reflect costs in 1999 dollars rather than 1998 dollars as was used for the April 2000 NODA. EPA used a CCI factor of 1.108 to reflect 1999 dollars and a base year of 1995.

C. Economic Impacts Analyses

For the final rule, EPA obtained and used MMS data on drilling through 1999 to identify any new firms operating in the offshore GOM and determine which firms were involved in deep water drilling operations. EPA identified 17 additional firms newly drilling in the GOM, of which 2 were identified as drilling in deep water. Of the new firms, 7 were identified as or assumed to be (for lack of data) small entities. One of these seven small firms was identified as a small entity drilling in deep water. This latter firm drilled two wells in the deep water in 1999.

EPA collected 1999 financial information on number of employees,

assets, equity, revenues, net income, return on assets, return on equity, and profit margin for the publicly held, newly identified firms. EPA also updated financial information for the publicly held firms identified in February 1999 proposal SBF Economic Analysis (EPA–821–B–98–020).

EPA also collected information on 13 GOM onshore sites where offshore oil and gas drilling waste is handled or disposed. This information consists of precise geographical location, amount of waste handled annually, and site capacity. This information was provided to EPA Region 6 for use in its environmental justice (EJ) computer model to screen for sites (*i.e.,* Tier 1 analysis) where disposal of additional drilling wastes under a zero discharge option might have environmental justice implications. EPA Tier 1 analyses identified that five of the thirteen onshore facilities warranted additional review.

D. Water Quality Impact and Human Health Analyses

In response to April 2000 NODA comments and information, EPA revised the water quality and human health analyses for the final rule based on: (1) Information on seabed surveys; (2) revised fish consumption rates; (3) information on Alaska state water quality standards; and (4) revised ROC data which affect EPA modeling of water quality, sediment quality, and human health impacts.

1. Seabed Surveys

EPA received public comments regarding the impact of SBF discharges on the benthic environment. Several seabed surveys were submitted to EPA together with the public comments. Information from two comments contained specific seabed survey data on sediment SBF concentrations after discharge of SBF cuttings. EPA included additional data from six wells in the calculation of mean SBF sediment concentration (at 100 meters from the modeled discharge) used in the water quality analysis. The mean SBF sediment concentration changed from 14,741 mg/kg as published in the April 2000 NODA to 9,718 mg/kg for modeled Gulf of Mexico wells and from 8,655 mg/kg to 13,052 mg/kg for wells modeled in Offshore California and Cook Inlet, Alaska.

EPA also received information on the on-going joint Industry/MMS GOM seabed survey. The Industry/MMS workgroup completed the first two cruises of the four cruise study in time for EPA's consideration for this final rule. Cruise 1 was a physical survey of 10 GOM shelf locations, with the objective of detection and delineation of cuttings piles using physical techniques. Cruise 2 was to scout and screen the final 5 shelf and 3 deep water GOM wells chosen for the definitive study where SBF were used. The SBF-cuttings discharges included either internal olefins or LAO/ester blends. Both cruises did not detect any large mounds of cuttings under any of the rigs or platforms. Remotely operated vehicles (ROV) using video cameras and side-scanning sonar were used to conduct the physical investigations on the seabed. Video investigations only detected small cuttings clumps (<6″) around the base of some of the facilities and 1″ thick cuttings accumulations on facility horizontal cross members. Outside of a 50–100′ radius from the facility, no visible cuttings accumulations (large or small) were detected at any of the facility survey sites.

Finally, EPA received a report prepared for the MMS which provided a review of the scientific literature and seabed surveys to determine the environmental impacts of SBFs (Docket No. W–98–26, Record No. IV.F.1). The literature report confirms EPA's position that benthic communities will recover as SBF concentrations in sediments decrease and sediment oxygen concentrations increase. The report also confirms EPA's position that within three to five years of cessation of SBF-cuttings discharges, concentrations of SBFs in sediments will have fallen to low enough levels and oxygen concentrations will have increased enough throughout the previously affected area that complete recovery will be possible.

2. Fish Consumption Rates

EPA revised the fish consumption rates for use in environmental assessment analyses. The consumption rates vary depending on the fish habitat location (*i.e.,* freshwater, estuarine, and marine). EPA used the marine only fish consumption rate for the finfish consumption health risk analysis for the Gulf of Mexico and Offshore California. EPA used the estuarine/marine consumption rate for the Cook Inlet, Alaska analysis. EPA used the estuarine/marine consumption rate for all regions in the shrimp consumption health risk analysis.

EPA also conducted an investigation into the environmental factors affecting Native subsistence foods in Cook Inlet. EPA has incorporated relevant information from this investigation into the SBF Environmental Assessment.

3. State Water Quality Standards

EPA evaluated the potential decrease of water quality from the regulatory discharge options and compared the pollutant concentrations to recommended Federal water quality criteria. For discharges occurring in Cook Inlet, Alaska, EPA also compared the receiving water quality to Alaska state water quality standards. EPA used the updated Alaska state standards for the water quality analysis for Cook Inlet, Alaska.

E. Non-Water Quality Environmental Impact Analyses

EPA received additional data affecting the NWQI analyses in response to the April 2000 NODA. These data include additional information on retention on cuttings and information regarding offshore injection and onshore disposal practices for each of the three geographical areas: Gulf of Mexico, Offshore California, and Cook Inlet, Alaska.

EPA revised the average SBF retention on cuttings for the discharge options based on additional ROC data. Revisions in ROC data affect the volume of SBF-cuttings generated. Consequently, EPA revised the amount of SBF-cuttings that will need to be treated under the two SBF-cuttings controlled discharge options (*e.g.,* BAT/NSPS Options 1 and 2). EPA also revised: (1) The amount of SBF-fines that will need to be re-injected on-site or hauled to shore for disposal under one of the SBF-cuttings controlled discharge option (*e.g.,* BAT/NSPS Option 2); and (2) the amount of SBF-fines and SBF-cuttings re-injected on-site or hauled to shore for disposal under the zero discharge option (BAT/NSPS Option 3).

EPA received additional SBF well interval data which was used to re-calculate the number of days to drill the model SBF wells (*see* Section III.B.). For the NWQI analyses, the number of days to drill the model wells serves as the basis for estimating the length of time equipment will be used to either treat the cuttings before discharge or the hauling requirements under the zero discharge option. The EPA NWQI models estimate that air emissions and fuel use rates increase when the time required to complete a model well also increases.

EPA obtained information regarding the current practice of zero discharge disposal for each of three geographic areas, Gulf of Mexico, Offshore California, and Cook Inlet, Alaska (*see* Section IV.D). Current practice indicates that most of the waste generated in the Gulf of Mexico and Offshore California

and brought to shore is injected onshore, whereas all of the waste currently generated in Cook Inlet is injected offshore at the drilling site or at a near-by Class II Underground Injection Control (UIC) disposal well. EPA also received from an on-shore injection facility specific equipment information, including the cuttings injection rate and cuttings grinding and injection equipment power requirements and fuel rates (Docket No. W–98–26, Record No. IV.D.2).

Industry provided EPA with information regarding SBF use (*see* Section III.A). One operator (Unocal) stated that it is starting to use SBF to drill the entire well and not just intervals in which WBFs present problems because drilling time can be significantly reduced. EPA incorporated this information into the NWQI analyses by estimating the reduction of impacts when using SBFs instead of WBFs. EPA also received during the April 2000 NODA comment period information related to the average increase in drilling time (1.5 days) in order to comply with zero discharge (Docket No. W–98–26, Record No. IV.A.a.3).

F. Compliance Analytical Methods

EPA completed additional studies in response to the April 2000 NODA to support the development of analytical methods for determining sediment toxicity, biodegradation, and oil retention on cuttings. For sediment toxicity and biodegradation, EPA focused specifically on optimizing test conditions (*e.g.,* test duration, sediment composition), discriminatory power, reproducibility, reliability, and practicality. EPA's sediment toxicity study provided toxicity data for both pure base fluids and standard mud formulations of these base fluids. EPA's biodegradation study evaluated the degradation of pure base fluids as determined by the solid phase test. For oil retention on cuttings, EPA conducted studies to verify and document the sensitivity of the retort test method.

During this same time period, industry sponsored Synthetic Based Muds Research Consortium (SBMRC) conducted parallel studies on the same three parameters (*i.e.,* sediment toxicity, biodegradation, and base fluid retention on cuttings). For sediment toxicity, industry provided extensive data comparing a 4-day versus a 10-day test duration, natural versus synthetic sediments, as well as toxicity data on both pure base fluids and mud formulations of these base fluids. For biodegradation, industry submitted results from the closed bottle and respirometry tests for biodegradation in addition to the solid phase test. For oil retention on cuttings, Industry and EPA conducted rig-based method detection limit studies.

IV. Summary of Revisions Based on Notice of Data Availability Comments

A summary of significant revisions to the analyses made by EPA in response to the February 1999 proposal is provided in the April 2000 NODA (*see* 65 FR 21549, Sections III and IV). This section describes the revisions to the analyses since publication of the April 2000 NODA.

A. Pollutant Loading Analyses

1. Loadings for Water-Based Drilling Fluids and Cuttings

For the final rule, EPA included the pollutant reductions (or increases) of the technology options based on operators switching from OBFs or WBFs to SBFs (or vice versa) and used data contained in the Offshore Development Document (EPA–821–R–93–003). Waste volume and/or pollutant loading data, on use of OBFs and WBFs presented in the Offshore Development Document, were expressed on a ''per bbl,'' ''per well,'' or a ''per day'' basis. Data from the Offshore rule record included: (1) WBF composition; (2) waste volumes for WBFs, OBFs, and associated cuttings; (3) the frequency of mineral oil use in WBF operations; and (4) the expected permit limitation failure rates (primarily for toxicity) on mineral oil fluids resulting in the requirement to haul or inject these wastes). These data then were applied to the current, revised well count projections and/or projected waste volumes to estimate discharge option loadings and the amount of OBFs, WBFs, and associated cuttings that require zero discharge under existing regulations (*e.g.,* OBFs containing diesel oil, WBFs that fail the SPP Toxicity Test). The Offshore Development Document provided information relevant to the inclusion of WBFs in the final analyses including: (1) Frequency of WBFs that failed permit limitations (Tables XI–10 and XI–7); (2) the composition of WBFs (Tables XI–3 and XI–6); (3) mineral oil composition (Table XI–5); and (4) the composition of cuttings from WBF (Section XI.3.4).

Industry-wide, regional, and total loadings were calculated for the loadings analyses for this final rule from the revised well counts provided by industry (Docket No. W–98–26, Record No. IV.B.a.9; Record No. IV.B.a.10; Record No. IV.B.a.11) combined with composition and estimated discharge volumes for WBFs (Offshore Development Document, Table XI–2).

In the final loadings analyses, EPA also corrected an error in the loading model used for the April 2000 NODA analyses. The error related to how EPA estimated the volume of fines from the fines removal unit captured and not discharged under BAT/NSPS Option 2. The volume of fines is based on many factors including the hole size, washout, and the percentage of the total wet cuttings produced from the solids control system that are fines. EPA incorrectly used the volume of dry cuttings per model well in the April 2000 NODA loading model to estimate the volume of fines generated from the BAT/NSPS Option 2 solids control system. The final loadings model correctly uses the volume of wet cuttings per model well to estimate the volume of fines generated from the BAT/NSPS Option 2 solids control system. The correction of the error had the effect of increasing the amount of fines captured for zero discharge under BAT/NSPS Option 2.

2. Drilling Fluid and Cuttings Composition and Density

The density of drilling wastes hauled in California was revised from 704 to 716 pounds per barrel to reflect the current density derived from the weight and volume data in the revised loadings model. This results in a change in the unit cost to haul waste in California to $12.53 and $5.89 per barrel for disposal and handling costs, respectively.

3. Days to Drill

EPA revised the number of drilling days based on data submitted in response to the April 2000 NODA for each of the four model well types. The number of drilling days input parameter affects NWQI and compliance costs (*e.g.,* equipment rental costs).

4. Directional Drilling

EPA also received additional data concerning the performance of SBF versus WBF for directional drilling operations (Docket No. W–98–26, Record No. IV.B.a.9). EPA used this information, the reduced number of wells and total footage of SBF-drilled development wells, to estimate pollutant loading reductions resulting from WBF to SBF conversions. For each of the two SBF-cuttings controlled discharge options (*i.e.,* BAT/NSPS Option 1 and 2), this revision reduced the annual sum total of discharged WBF and WBF-cuttings.

B. Compliance Cost Analysis

1. Costs of WBF

As stated above, EPA modified the cost analysis for the final rule to include WBF cost factors. The WBF cost factors that EPA considered include: (1) The cost of discharged WBFs and WBF associated with cuttings discharged onsite; (2) the projected occurrence of mineral oil spots and/or lubrication and the projected failure rate of these mineral oil-amended fluids to meet permit limitations on toxicity and subsequent requirement to re-inject these materials down hole or haul them for onshore disposal; and (3) the rig costs associated with increases or decreases of drilling time related to WBF-to-SBF or SBF-to-WBF conversions over the projected interval of SBF use.

The volumes of discharged WBF and associated cuttings were estimated on a per well basis from data contained in the Offshore Development Document (EPA–821–R–93–003) for Gulf of Mexico, California, and Cook Inlet, AK wells. A weighted average discharge volume for each region, based on volumes projected for shallow wells and deep wells and the projected number of wells for each, was derived to estimate the volume of fluids and cuttings discharged onsite, per well, from WBF operations. (**Note:** In the Offshore Development Document ''shallow'' and ''deep'' refer to well depth, and are not the same as ''shallow'' water and ''deep'' water wells which refer to water depth in this final rule.) The volume of adhering WBF on discharged cuttings, as contained in the Offshore Development Document, was estimated at 5% of the total cuttings volume. The costs for these discharged WBFs were then calculated from a per barrel estimate of average WBF cost. These per well costs were then applied to the well count data in this final rule to derive aggregate regional and total costs. Also, to assess lost fluid costs over the projected SBF drilling interval, for the zero discharge option, the average discharge volumes per well were recalculated as average discharge volumes per day, based on the assumed number of days (*i.e.,* 20 days) used in the Offshore Development Document for drilling WBF wells.

The projected incidences of WBF with mineral oil spots, mineral oil lubrication, or both mineral oil spot and lubrication were based on the Offshore Development Document estimates of the percentages of projected wells in each region, projected shallow water versus deep water wells, and the projected incidence of spotting and lubrication. These percentages were then applied to current well count data for this final rule. EPA used the Offshore Development Document rates of failure (*i.e.,* exceeding permit toxicity limitations) to project the current number of wells that would require onsite injection or onshore disposal of mineral oil-amended WBF, and their disposal volumes were calculated from per well volume estimates for WBF wells.

The effect of WBF-to-SBF conversion (anticipated under the discharge options) and SBF-to-WBF conversion (anticipated under the zero discharge option) were derived from the estimated duration (in days) of the SBF-drilled interval. The projected number of drilling days was increased by a factor of 2 for each WBF model well to derive the projected number of drilling days that would be required if WBFs were used in place of SBFs. The incremental drilling time was used to estimate compliance costs (*e.g.,* increased rig costs) associated with SBF-to-WBF conversions.

2. Equipment Installation and Downtime

In the April 2000 NODA, EPA estimated that each SBF well incurred cuttings dryer installation and downtime costs. EPA revised the number of SBF wells drilled per cuttings dryer equipment installation per year based on industry-supplied ROC data (*see* Section III.B.1). EPA concluded that operators are drilling multiple wells per year with the same cuttings dryer equipment installation. Consequently, EPA reduced the number of cuttings dryer equipment installations required to drill the annual number of SBF wells. For development wells, the average number of SBF wells drilled per cuttings dryer equipment installation per year is 2.2. For exploration wells, the average number of SBF wells drilled per cuttings dryer equipment installation per year is 1.6. EPA incorporated these factors into the compliance costs estimates and these factors reduced the overall cuttings dryer equipment installation and downtime costs for the industry.

3. Proportion of Hauled Versus Injected Wastes

EPA estimated in the April 2000 NODA that 80% of drilling operations in the GOM, Offshore California, and Cook Inlet, Alaska, haul waste onshore with the remaining 20% re-injecting these wastes onsite. EPA used these proportions to weight the average cost of complying with zero discharge (*i.e.,* BAT/NSPS Option 3). EPA revised these proportions based on additional information received in response to the April 2000 NODA (*see* Section IV.E below) and updated the compliance cost and NWQI models.

4. OBF and WBF Conversion to SBF

EPA revised its compliance cost model to incorporate the effect of operators switching from one type of drilling fluid to another under each of the three SBF-cuttings technology options (*see* Section III.A.4). Generally, as compared with WBF and OBFs, SBFs led to a reduction in days required to drill a model well which leads to a decrease in drilling costs. Additionally, EPA revised the development drilling footage estimate due to additional information on the improved directional drilling capabilities of SBF over WBF.

C. Economic Impacts Analyses

In response to the April 2000 NODA, EPA identified that two projects used for economic modeling have shut in. Consequently, EPA removed these two projects from the economic analysis. A total of 18 projects remain for the economic modeling of existing projects and 13 remain for the economic modeling of new projects.

EPA added an environmental justice (EJ) analysis which investigates the potential for impacts on minorities and socioeconomically disadvantaged groups under the zero discharge option. EPA performed a Tier 1 screening analysis, which combines geographic location and U.S. Census Bureau data to determine the number of persons living within 1 mile and 50 miles of drilling waste handling and disposal sites, their race, and their socioeconomic status. A computer program developed by EPA Region 6 was used to rank and characterize sites on the basis of whether the populations near the site contain higher proportions of minority and socioeconomically disadvantaged persons than the state as a whole. Based on scores derived for the 13 GOM onshore drilling waste handling and disposal sites, EPA identified five facilities that could be potentially associated with disproportionate impacts on minorities or socioeconomically disadvantaged groups. EPA presents the results of the EJ analysis in Section IX.

D. Water Quality Impact and Human Health Analyses

EPA received comments regarding the heavy metal leach factors used in the water quality impact analyses but did not receive any specific data that could be used in the analyses (Docket No. W–98–26, Record No. IV.A.a.2). EPA

therefore did not change these factors. However, EPA reevaluated the modeling used in the proposal that metals for which there were no factors found in the literature were completely insoluble in the receiving water (*i.e.,* the leach factor would be zero). EPA estimated that these heavy metals would not be less soluble than iron which has the lowest leach percentage factor. Thus, the iron leach factor was transferred to the following metals for which a zero leach factor was previously used: aluminum, antimony, beryllium, selenium, silver, thallium, tin, and titanium.

E. Non-Water Quality Environmental Impact Analyses

As mentioned in Section III.E, EPA received additional information regarding waste disposal practices in each of the three geographic areas (*e.g.,* GOM, Offshore California, Cook Inlet, Alaska). As a result of this information, EPA revised the modeling for the fraction of waste either injected at the drill site, injected on-shore or land disposed (*see* SBF Development Document). Though the percentage of waste injected onsite versus hauled to shore (20% vs. 80%) in the GOM remains unchanged, the method of onshore disposal has been revised for the final rule. In the GOM, 80% of the waste hauled to shore is injected onshore and only 20% is landfarmed.

EPA estimates that all SBF wastes from Californian deep water exploratory wells are sent onshore (*i.e.,* 100% onshore disposal vs. 0% on-site injection). For all other wells (*i.e.,* shallow water development and exploratory and deep water development), EPA estimates that most of the offshore waste is disposed through offshore on-site cuttings re-injection (*i.e.,* 20% onshore disposal vs. 80% on-site injection) based on the fact that most of these wells are being drilled from fixed facilities. EPA estimates that most California offshore wastes sent onshore are disposed via onshore formation injection (*i.e.,* 20% of offshore wastes sent onshore disposed via landfarming vs. 80% of offshore wastes sent onshore disposed via onshore injection) based on the number of California land disposal operations.

At proposal, based on the record for the 1996 Coastal rule, EPA determined that onsite injection was not feasible throughout Cook Inlet, Alaska (*see* Coastal Development Document, EPA–821–R–96–023, Section 5.10.3). More recently, however, EPA identified in the April 2000 NODA (65 FR 21558) that the SBF rule record now demonstrates that many Cook Inlet operators in Coastal waters are using cuttings re-injection (*see* Docket No. W–98–26: Record No. III.B.a.11, Record No. III.B.a.23, Record No. III.B.a.53). EPA contacted Cook Inlet operators (*e.g.,* Phillips, Unocal, Marathon Oil) and the State regulatory agency, Alaska Oil and Gas Conservation Commission (AOGCC), for more information on the most recent re-injection practices of Coastal and Offshore Cook Inlet operators (65 FR 21558). AOGCC regulations provide Cook Inlet operators the opportunity to permit and operate Class II disposal wells and annular disposal activities. Information provided to EPA indicate that Cook Inlet operators in Coastal waters are availing themselves of on-site cuttings injection and are receiving AOGCC permits for this activity. Generally, Cook Inlet operators in Coastal waters agree that on-site injection is available for most operations.

AOGCC also agreed that there should be enough formation re-injection disposal capacity for the small number of wells (< 5–10 wells per year) being drilled in Cook Inlet Coastal waters. AOGCC stated, however, that case-specific limitations should be considered when evaluating disposal options. For instance, Unocal has experienced difficulty establishing formation injection in several wells that were initially considered for annular disposal. In addition, Cook Inlet operators have the burden of proving to AOGCC's satisfaction that the waste will be confined to the formation disposal interval. Approval of annular disposal includes a review of cementing and leak-off test records. In some instances the operator may also have to run a cement bond log. When an older well is converted for use as a disposal well, some of this information may not exist. In cases where there is insufficient information, disposal is not allowed. Annular disposal is also limited to the facility on which the waste is generated. Although Class II disposal regulations don't restrict waste transport, it has generally been the practice of the various fields' owners not to accept any waste generated by other operators. In addition, AOGCC stated that a zero discharge requirement poses serious technical hurdles with respect to the handling of drilling waste for exploration drilling with mobile rigs. Normally, there is neither capacity for storage or room for processing equipment on exploratory drilling rigs. Therefore, to be conservative for the NWQI analysis, EPA estimates that all of the cuttings from the Coastal Cook Inlet operations (*i.e.,* shallow water wells) are re-injected (*i.e.,* 0% onshore disposal vs. 100% on-site injection) based on the ability of industry to dispose of oil-based cuttings via on-site formation injection after gaining State regulatory approval.

In order to assess the SBF NWQIs relative to the total impacts from drilling operations, EPA included estimates of the daily drilling rig impacts to the NWQIs from SBF-related activities. The additional impacts consist of fuel use and air emissions resulting from the various drilling rig pumps and motors as well as impacts of a daily helicopter trip for transporting personnel and/or supplies. Impacts were assessed for the number of days that an SBF interval is drilled versus the number of days well intervals are drilled using WBFs and OBFs and for the number of wells drilled using each of the drilling fluids.

F. Numerical Limits for Retention of SBF Base Fluid on SBF-Cuttings

A series of potential numerical limits for retention of SBF base fluid on SBF-cuttings were developed based in part on combinations of data selection criteria suggested in comments on the April 2000 NODA. These data selection criteria include: (1) Existing record of retention calculations (*i.e.,* ''back-up'' retort sheet information for quality assurance/quality control purposes); and (2) foreign or domestic location of well drilling activity (*e.g.,* North Sea, Canada). Numerical limits promulgated in today's final rule were based on data with existing records of retention calculations, and they included data from well drilling activities in foreign countries. The inclusion of data from foreign countries is intended to include data representing drilling with cuttings dryers at a wider range of geological formations than just the ones for which data was received from current operations.

V. Development and Selection of Effluent Limitations Guidelines and Standards

A. Waste Generation and Characterization

Drill cuttings are produced continuously at the bottom of the hole at a rate dependent on a variety of factors including: (1) The advancement of the drill bit; (2) the size and design of drill bit used (*e.g.,* polycrystalline diamond compact (PDC)); and (3) the drilling fluid type used. Drill cuttings are carried to the surface by the drilling fluid, where the cuttings are separated from the drilling fluid by the solids control system. The drilling fluid is then

sent back to the active mud system (*e.g.,* mud pumps, down hole, trip tanks, etc.), provided it still has characteristics to meet technical requirements. Drilling fluids cool and lubricate the drill bit, stabilize the walls of the borehole, transport cuttings, and maintain equilibrium between the borehole and the formation pressures. Various sizes of drill cuttings are separated by the solids separations equipment, and it is necessary to remove the fines (*i.e.,* small sized cuttings or ''low gravity solids'') as well as the large cuttings from the drilling fluid to maintain the required rheological properties.

Increased recovery from the cuttings is more problematic for WBF than for SBF because the WBF water-wets the cuttings which encourages the cuttings to disperse and spoil the drilling fluid properties. Therefore, compared to WBF, more aggressive methods of recovering SBF from the cuttings wastestream are practical.

SBFs, used or unused, are a valuable commodity and not a waste. It is industry practice to continuously reuse the SBF while drilling a well interval, and at the end of the well, to ship the remaining SBF back to shore for refurbishment and reuse. One of the main incentives for operators to attempt to recover as much SBF as possible during drilling is the relatively high unit cost of SBF, approximately $160 to $300 per barrel, as compared to OBFs ($70 to 90 per barrel) and WBFs ($45 per barrel) (Docket No. W–98–26, Record No. IV.B.a.13). Operators involved in the first 1998 GOM field demonstrations of cuttings dryers (*i.e.,* advanced solids control technology) were attempting to obtain further reductions in drilling costs, beyond that obtained by shortening the overall drilling time for the well, by recovering more SBF. SBFs are relatively easy to separate from the drill cuttings because the drill cuttings do not disperse or hydrate in the drilling fluid to the same extent as compared to WBFs. Reducing cuttings hydration is particularly important in certain formations (*e.g.,* shale formations in GOM). With WBF, due to dispersion of the drill cuttings, drilling fluid components often need to be added to maintain the required drilling fluid properties. These additions are often in excess of what the drilling system can accommodate. The excess ''dilution volume'' of WBF is a resultant waste. This dilution volume waste does not occur with SBF. For these reasons, SBF is only discharged as a contaminant of the drill cuttings wastestream. It is not discharged on purpose as neat drilling fluid (*i.e.,* drilling fluid not associated with cuttings).

Current practice is that the top well section is normally drilled with a WBF. As the well becomes deeper, the performance requirements of the drilling fluid increase, and the operator may, at some point, decide that the drilling fluid system should be changed to either a traditional OBF, based on diesel oil or mineral oil, or an SBF. The system, including the drill string and the solids separation equipment, must be changed entirely from the WBF to the SBF (or OBF) system, and the two do not function as a blended system. The entire system is either: (1) A water dispersible (aqueous) drilling fluid such as a WBF; or (2) an oleaginous drilling fluid such as OBFs, enhanced mineral oil based drilling fluids, or SBFs. The decision to change the system from a WBF water dispersible system to an oleaginous drilling fluid depends on many factors including:

I. The operational considerations (*e.g.,* rig type, risk of riser disconnects, rig equipment, and distance from support facilities);

II. The relative drilling performance of one type fluid compared to another (*e.g.,* rate of penetration, well angle, hole size/casing program options, compatible drilling bit, and horizontal deviation);

III. The presence of geologic conditions that favor a particular fluid type or performance characteristic (*e.g.,* formation stability/sensitivity, formation pore pressure vs. fracture gradient, and potential for gas hydrate formation);

IV. Drilling fluid cost (*i.e.,* base cost plus daily operating cost);

V. drilling operation cost (*i.e.,* rig cost plus logistic and operation support); and

VI. Drilling waste disposal cost.

Industry has commented that while the right combination of factors that favor the use of SBF can occur in any area, they most frequently occur with ''deep water'' operations (*i.e.,* greater than or equal to 1,000 feet of water). This is due to the fact that these operations are higher cost and can therefore better justify the higher initial cost of SBF use. Industry has also commented that SBF may be increasingly used in shallow water wells due to the ability of SBF to increase average rates of penetration and shorten average times to complete drilling operations (Docket No. W–98–26, Record No. IV.A.a.3).

The volume of cuttings generated while drilling the SBF or OBF intervals of a well depends on the type of well (development or production) and the water depth (shallow or deep). EPA developed OBF and SBF model well characteristics from information provided by the American Petroleum Institute (API). API provided well size date for four types of wells currently drilling the GOM: development and exploratory wells in both deep water (*i.e.,* greater than or equal to 1,000 feet of water) and shallow water (*i.e.,* less than 1,000 feet of water). These model wells are referred to as: (1) Shallow-water development (SWD); (2) shallow-water exploratory (SWE); (3) deep-water development (DWD); and (4) deep-water exploratory (DWE). For the four model wells, EPA determined that the volumes of cuttings generated by these SBF or OBF well intervals are (in barrels): 565 for SWD; 1,184 for SWE; 855 for DWD; and 1,901 for DWE. These volumes represent only the rock, sand, and other formation solids drilled from the hole, and do not include drilling fluid that adheres to these formation cuttings. These values also include the additional formation cuttings volume of 7.5% washout. Washout is caving in or sloughing off of the well bore. Washout, therefore, increases hole volume and increases the amount of cuttings generated when drilling a well. The washout percentage EPA used in its analyses (*i.e.,* 7.5%) is based on the rule of thumb reported by industry representatives of 5 to 10% washout when drilling with SBF or OBF.

Drilling fluid returning from the well is laden with drill cuttings. The drill cuttings range in size from large particles which are on the order of a centimeter or more in size to small particles (*i.e.,* fines or ''low gravity solids'') which are fractions of a millimeter in size. Standard or current practice solids control systems employ primary and secondary shale shakers in series with a ''fines removal unit'' (*e.g.,* decanting centrifuge or mud cleaner). The drilling fluid and drill cuttings from the well are first passed through primary shale shakers. These shakers remove the largest cuttings which are approximately 1 to 5 millimeters in size. The drilling fluid recovered from the primary shakers is then passed over secondary shale shakers to remove smaller drill cuttings. Finally, a portion or all of the drilling fluid recovered from the primary and secondary shakers may be passed through the fines removal unit to remove fines from the drilling fluid. It is important to remove fines from the drilling fluid in order to maintain the desired rheological properties of the active drilling fluid system (*e.g.,* viscosity, density). Thus, the cuttings wastestream normally consists of discharged cuttings from the primary and secondary shale shakers and fines from the fines removal unit.

Operators using improved solids control technology process the cuttings discarded from the primary and secondary shale shakers through a ''cuttings dryer'' (*e.g.,* vertical or horizontal centrifuge, squeeze press mud recovery unit, High-G linear shaker). The cuttings from the cuttings dryer are discharged and the recovered SBF is sent to the fines removal unit. The advantage of the cuttings dryer is that more SBF is recovered for re-use and less SBF is discharged into the ocean. This, consequently, will reduce the pollutant loadings to the ocean and the potential of the waste to cause anoxia (lack of oxygen) in the receiving sediment.

As discussed in the April 2000 NODA (65 FR 21569), solids control equipment generally breaks larger particles into smaller particles. An undesirable increase in drilling fluid weight and viscosity can occur when drill solids degrade into fines and ultra-fines. Ultra-fines are generally classified as being less than 5 microns (10^{-6} meters) in length and solids control equipment generally cannot remove these ultra-fines. An unacceptable high fines content (*i.e.,* generally > 5% of total drilling fluid weight) may consequently lead to drilling problems (*e.g.,* undesirable rheological properties, stuck pipe). Therefore, it is possible that the increased recovery of SBF from cuttings for re-use in the active mud system, often achieved through use of the cuttings dryer in solids control systems, may lead to a build-up in fines for certain formation characteristics (*e.g.,* high reactivity of formation cuttings, limited loss of drilling fluid into the formation). In the April 2000 NODA, EPA solicited comments regarding whether EPA's proposed numeric cuttings retention value might cause operators (where there are unfavorable formation characteristics) to: (1) Dilute the fines in the active mud system through the addition of ''fresh'' SBF; and/or (2) capture a portion of the fines in a container and send the fines to shore for disposal.

Comments from API/NOIA identified only one instance in which the use of a cuttings dryer in combination with a fines removal unit in the United States may have lead to an increase in ''fines build-up'' and a loss of circulation event (Docket No. W–98–26, Record No. IV.A.a.13). Further communication with additional industry stakeholders identified that this well (Shell, Green Canyon 69, OCS–G–13159#3) was the first application of the cuttings dryer type (horizontal centrifuge cuttings dryer) in the GOM and inexperience with this type of technology may have contributed to the build-up of fines causing well problems. However, other commentors stated that fines build-up was not an issue for the well in question (Docket No. W–98–26, Record No. IV.A.b.1). Moreover, further industry comments revealed that the properties of formations are often the main culprit of loss circulation and that the same rig (Marianas) had a loss of circulation at another nearby well in the same formation when a cuttings dryer was not being used (Docket No. W–98–26, Record No. IV.A.b.1). Therefore, based on the record, which includes over three dozen successful cuttings dryer deployments, EPA concludes that fines build up is not an issue of concern when operators properly operate and maintain cuttings dryers and fines removal equipment.

Drill cuttings are typically discharged continuously as they are separated from the drilling fluid in the solids separation equipment. The drill cuttings will also carry a residual amount of adhered drilling fluid. Therefore, the two parameters that make up the bulk of the pollutant loadings are TSS and what is measured by the API Retort Method (Appendix 7) as Total Oil. TSS is comprised of two components: the drill cuttings themselves and the solids in the adhered drilling fluid. The drill cuttings are primarily small bits of stone, clay, shale, and sand. The source of the solids in the drilling fluid is primarily the barite weighting agent, and clays (*e.g.,* amine clays) which are added for filtration control and to modify the rheological properties. Benthic smothering and/or sediment grain size alteration resulting in potential damage to invertebrate populations and alterations in benthic community structure is a concern with uncontrolled SBF drilling discharges due to the quantity and characteristics of associated TSS discharges. In general, large cuttings particles with a high percentage of adhering SBF (*e.g.,* >12% (wt. SBF)/(wt. wet cuttings)) tend to conglomerate and quickly settle out to the benthic environment quickly near the well site.

Additionally, environmental impacts can be caused by toxic, conventional, and non-conventional pollutants adhering to the solids. The adhered SBF drilling fluid is mainly composed, on a volumetric basis, of the synthetic material (*i.e.,* ''base fluid''). Formation oil can also contaminate SBF-cuttings and contribute priority, conventional, and non-conventional pollutants. The oleaginous material (*i.e.,* SBF base fluid and formation oil) may be toxic and it may contain priority pollutants such as polynuclear aromatic hydrocarbons (PAHs). Depending on bottom currents, temperature, and rate of biodegradation this oleaginous material may cause hypoxia (*i.e.,* reduction in dissolved oxygen concentrations) or anoxia (*i.e.,* absence of dissolved oxygen) in the immediate sediment. Oleaginous materials which biodegrade quickly will reduce dissolved oxygen concentrations more rapidly than more slowly degrading oleaginous materials. EPA, however, thinks that fast biodegradation is environmentally preferable to slower biodegradation despite the increased risk of temporary hypoxia which accompanies fast biodegradation. EPA's position is supported by published seabed surveys which show that benthic re-colonization by infaunal individuals after the discharge of SBF-cuttings or OBF-cuttings can be correlated with the disappearance of the base fluid in the sediment. Large persistent cuttings piles may provide a source of environmental contamination for many years (Docket No. W–98–26, Record No. IV.F.2). Moreover, benthic re-colonization rates do not seem to be correlated with the severity of any hypoxic or anoxic effects that may result while the SBF base fluid is degrading or dispersing. Numerous studies show that SBF base fluids that biodegrade faster lead to a more rapid recovery of the pre-discharge benthic community.

As a component of the drilling fluid, the barite weighting agent is also discharged as a contaminant of the drill cuttings. Barite is a mineral principally composed of barium sulfate ($BaSO_4$), and it is known to generally have trace contaminants of several toxic heavy metals such as mercury, cadmium, arsenic, chromium, copper, lead, nickel, and zinc. SBF also contain non-conventional pollutants found in other drilling fluid components (*e.g.,* emulsifiers, oil wetting agents, filtration control agents, and viscosifiers).

As previously stated in the April 2000 NODA (65 FR 21560), EPA learned that SBF is controlled with zero discharge practices at the drill floor, in the form of vacuums and sumps to retrieve spilled fluid. EPA also learned that approximately 75 barrels of fine solids and barite, which have an approximate SBF content of 25%, can accumulate in the dead spaces of the mud pit, sand trap, and other equipment in the drilling fluid circulation system. Current practice is to either wash these solids out with water for overboard discharge, or to retain the waste solids for disposal. Several hundred barrels (approximately 200 to 400 barrels) of water are used to wash out the mud pits. Industry representatives also indicated to EPA that those oil and gas extraction

operations that discharge wash water and accumulated solids first recover free SBF.

B. Selection of Pollutant Parameters

1. Stock Limitations and Standards for Base Fluids

a. *General.* In the final rule, where SBF-cuttings may be discharged, except for Cook Inlet, Alaska, EPA is establishing BAT limitations and NSPS that require the synthetic materials which form the base fluid of the SBFs to meet limitations and standards on PAH content, sediment toxicity, and biodegradation. If these stock limitations are not met the technology basis for meeting these limitations and standards is: (1) Product substitution; or (2) zero discharge based on land disposal or cuttings re-injection. The regulated toxic, conventional, and non-conventional pollutant parameters are identified below. A large range of synthetic, oleaginous, and water miscible materials are available for use as base fluids. These stock limitations on the base fluid are intended to encourage product substitution reflecting best available technology and best available demonstrated technology wherein only those synthetic materials and other base fluids which minimize potential loadings and toxicity may be discharged. Additionally, EPA is retaining BPT and BCT requirements for SBFs and SBF-cuttings as no discharge of free oil as determined by the static sheen text (Appendix 1 of subpart A of 40 CFR Part 435).

As stated below in Section V.F, EPA is today promulgating BPT, BCT, BAT, and NSPS for SBFs and SBF-cuttings for Coastal Cook Inlet, Alaska as zero discharge except when Coastal Cook Inlet, Alaska, operators are unable to dispose of their SBF-cuttings using any of the following disposal options: (1) On-site re-injection (annular disposal or Class II UIC); (2) re-injection using a nearby Coastal or Offshore Class II UIC disposal well; or (3) onshore disposal using a nearby Class II UIC disposal well or land application. If an operator is able to make these showings, then the operator would be subject to the same requirements for SBF-cuttings that apply elsewhere. The regulated toxic, conventional, and non-conventional pollutant parameters are identified below.

b. *PAH Content.* EPA is regulating the PAH content of base fluids because PAHs are comprised of toxic priority pollutants. SBF base fluids typically do not contain PAHs, whereas the traditional OBF base fluids of diesel and mineral oil typically contain 5 to 10% PAH and 0.35% PAH respectively. The PAHs typically found in diesel and mineral oil include: (1) the toxic priority pollutants fluorene, naphthalene, phenanthrene, and others; and (2) non-conventional pollutants such as alkylated benzenes and biphenyls. Therefore, the PAH BAT limitation and NSPS are components of this final regulation to help discriminate between acceptable and non-acceptable base fluids.

c. *Sediment Toxicity.* EPA is also regulating the sediment toxicity in base fluids as a non-conventional pollutant parameter and as an indicator for toxic pollutants and non-conventional pollutants in base fluids (*e.g.,* enhanced mineral oils, internal olefins, linear alpha olefins, poly alpha olefins, paraffinic oils, C_{12}–C_{14} vegetable esters of 2-hexanol and palm kernel oil, ''low viscosity'' C_8 esters, and other oleaginous materials). It has been shown, during EPA's development of the Offshore Guidelines, that establishing limits on toxicity encourages the use of less toxic drilling fluids and additives. Many of the SBF base fluids have been shown to have lower toxicity than OBF base fluids, but among SBFs some are more toxic than others. Today's final discharge option (*i.e.,* BAT/NSPS Option 2) includes a base fluid sediment toxicity stock limitation, as measured by the 10-day sediment toxicity test (ASTM E1367–92) using a natural sediment or formulated sediment and *Leptocheirus plumulosus* as the test organism.

d. *Biodegradation.* EPA is also regulating the biodegradation in base fluids as an indicator of the extent, in level and duration, of the toxic effect of toxic pollutants and non-conventional pollutants present in the base fluids (*e.g.,* enhanced mineral oils, internal olefins, linear alpha olefins, poly alpha olefins, paraffinic oils, C_{12}–C_{14} vegetable esters of 2-hexanol and palm kernel oil, ''low viscosity'' C_8 esters, and other oleaginous materials). Based on results from seabed surveys at sites where various base fluids have been discharged with drill cuttings, EPA believes that the results from the three biodegradation tests used during the rulemaking (*i.e.,* solid phase test, anaerobic closed bottle biodegradation test, respirometry biodegradation test) are indicative of the relative rates of biodegradation in the marine environment. In addition, EPA thinks the biodegradation parameter correlates strongly with the rate of recovery of the seabed where OBF- and SBF-cuttings have been discharged. The various base fluids vary widely in biodegradation rates, as measured by the three biodegradation methods. However, the relative ranking of the base fluids remain relatively similar across all three biodegradation tests.

As originally proposed in February 1999 (64 FR 5504) and re-stated in the April 2000 NODA (65 FR 21550), EPA is today promulgating a BAT limitation and NSPS to control the minimum amount of biodegradation of base fluid. Today's final discharge option (*i.e.,* BAT/NSPS Option 2) includes a base fluid biodegradation stock limitation, as measured by the marine anaerobic closed bottle biodegradation test (*i.e.,* ISO 11734).

e. *Bioaccumulation.* EPA also considered establishing a BAT limitation and NSPS that would limit the base fluid bioaccumulation potential. The regulated parameters would be the non-conventional and toxic priority pollutants that bioaccumulate. EPA reviewed the current literature to identify the bioaccumulation potential of various base fluids. EPA determined that SBFs are not expected to significantly bioaccumulate because of their extremely low water solubility and consequent low bioavailability. Their propensity to biodegrade makes them further unlikely to significantly bioaccumulate in marine organisms.

EPA identified that hydrophobic chemicals (*e.g.,* ester base fluids) that have a log K_{ow} less than about 3 to 3.5 may bioaccumulate rapidly but not to high concentrations in tissues of marine organisms, particularly if they are readily biodegradable into non-toxic metabolites (Docket No. W–98–26, Record No. IV.F.1). (**Note:** The octanol/water partition coefficient (K_{ow}) is used as a surrogate for estimating lipid/water partitioning). Moreover, hydrophobic chemicals (*e.g.,* C_{16}–C_{18} internal olefins, various poly alpha olefins, and C_{18} n-paraffins) with a log K_{ow} greater than about 6.5 to 7 do not bioaccumulate effectively from the water, because their solubility in both the water and lipid phases is very low (Docket No. W–98–26, Record No. IV.F.1). Finally, the degradation by-products of SBF base fluids (*e.g.,* alcohols) are likely to be more polar (*i.e.,* more miscible with water) than the parent substances. The higher water solubility will result in these degradation by-products partitioning into the water column and being diluted to toxicologically insignificant concentrations.

2. Discharge Limitations

a. *Free Oil.* Under BPT and BCT limitations for SBF-cuttings, EPA retains the prohibition on the discharge of free oil as determined by the static sheen test

(*see* Appendix 1 of subpart A of 40 CFR part 435). Under this prohibition, drill cuttings may not be discharged when the associated drilling fluid would fail the static sheen test. The prohibition on the discharge of free oil is intended to minimize the formation of sheens on the surface of the receiving water. The regulated parameter of the no free oil limitation would be the conventional pollutant oil and grease which separates from the SBF and causes a sheen on the surface of the receiving water.

The free oil discharge prohibition does not control the discharge of oil and grease and crude oil contamination in SBFs as it would in WBFs. With WBFs, oils which may be present (*e.g.,* diesel oil, mineral oil, formation oil, or other oleaginous materials) are present as the discontinuous phase. As such these oils are free to rise to the surface of the receiving water where they may appear as a film or sheen upon or discoloration of the surface. By contrast, the oleaginous matrices of SBFs do not disperse in water. In addition they are weighted with barite, which causes them to sink as a mass without releasing either the oleaginous materials which comprise the SBF or any contaminant formation oil. Thus, the test would not identify these pollutants. However, a portion of the SBF may rise to the surface to cause a sheen. The components that rise to the surface fall under the general category of oil and grease and are considered conventional pollutants. Therefore, the purpose of the no free oil limitation of today's final regulation is to control the discharge of conventional pollutants which separate from the SBF and cause a sheen on the surface of the receiving water. The limitation is not intended to control formation oil contamination nor the total quantity of conventional pollutants discharged.

b. *Formation Oil Contamination.* As originally proposed in February 1999 (64 FR 5505) and re-stated in the April 2000 NODA (65 FR 21552), EPA is today promulgating a BAT limitation and NSPS of zero discharge to control formation oil contamination on SBF-cuttings. EPA is also today promulgating a screening method (Reverse Phase Extraction (RPE) method presented in Appendix 6 to subpart A of part 435) and a compliance assurance method (Gas Chromatograph/Mass Spectrometer (GC/MS) method presented in Appendix 5 to subpart A of part 435).

Formation oil is an ''indicator'' pollutant for the many toxic and priority pollutant pollutants present in formation (crude) oil (*e.g.,* aromatic and polynuclear aromatic hydrocarbons). These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. EPA is requiring that formation oil contamination be measured at two points. First, EPA is requiring that operators verify and document that a SBF is free of formation oil contamination before initial use of the SBF through use of the GC/MS compliance assurance method (Appendix 5 to subpart A of 40 CFR part 435). Second, EPA is requiring that operators use the RPE method (Appendix 6 to subpart A of 40 CFR part 435) for the SBF recovered by the solids control equipment to detect formation oil contamination. The RPE method is a fluorescence test and is appropriately ''weighted'' to better detect crude oils. These crude oils contain more toxic aromatic and PAH pollutants and show brighter fluorescence (*i.e.,* noncompliance) in the RPE method at lower levels of crude oil contamination. Since the RPE method is a relative brightness test, operators may also use the GC/MS compliance assurance method when the results from the RPE method are in doubt by either the operator or the enforcement authority. Results from the GC/MS compliance assurance method will supersede those of the RPE method.

c. *Retention of Drilling Fluid on Cuttings.* EPA is today promulgating a BAT limitation and NSPS to control the retention of drilling fluid on drill cuttings. The BAT limitation and NSPS are presented as the percentage of base fluid on wet cuttings (*i.e.,* mass base fluid (g)/mass wet cuttings (g)), averaged over the entire well sections drilled with SBF. The limitation and standard controls the quantity of drilling fluid discharged with the drill cuttings. Both toxic pollutants and non-conventional pollutants would be controlled by this limitation. Several pollutants are present in the barite weighting agent, including the toxic metal pollutants arsenic, chromium, copper, lead, mercury, nickel, and zinc, and the non-conventional metal pollutants aluminum and tin. A complete SBF formulation also includes non-conventional pollutants found in the SBF base fluids (*e.g.,* enhanced mineral oils, internal olefins, linear alpha olefins, poly alpha olefins, paraffinic oils, C_{12}–C_{14} vegetable esters of 2-hexanol and palm kernel oil, ''low viscosity'' C_8 esters, and other oleaginous materials) and in other drilling fluid components (*e.g.,* emulsifiers, oil wetting agents, filtration control agents, and viscosifiers). These pollutants would not be controlled by the sediment toxicity stock limitations. In response to the February 1999 proposal (64 FR 5501), EPA received comments that these non-conventional pollutants include fatty acids (Docket No. W–98–26, Record No. III.A.a.7). EPA also received further information that the non-conventional pollutants in these drilling fluid components include amine clays, amine lignites, and dimer/trimer fatty acids (Docket No. W–98–26, Record No. III.B.b.1).

This limitation would also control the toxic effect of the drilling fluid and the persistence or biodegradation of the base fluid. Specifically, as stated in the April 2000 NODA (65 FR 21553), lowering the percentage of residual drilling fluid retained on cuttings increases the recovery rate of the seabed receiving the cuttings (Docket No. W–98–26, Record No. I.D.b.30 and 31; Record No. III.B.a.15). Limiting the amount of SBF content in discharged cuttings controls: (1) The amount of toxic and non-conventional pollutants in SBF which are discharged to the ocean; (2) the biodegradation rate of discharged SBF; and (3) the potential for SBF-cuttings to develop cuttings piles and mats which are deleterious to the benthic environment.

As originally proposed in February 1999 (64 FR 5547) and re-stated in the April 2000 NODA (65 FR 21552), EPA is today promulgating a retort and sampling compliance method for the cuttings retention BAT limitation and NSPS (*see* Appendix 7 to subpart A of 40 CFR part 435; API Recommended Practice 13B–2).

d. *Sediment Toxicity.* EPA is also regulating the sediment toxicity in SBF discharged with cuttings as a non-conventional pollutant parameter and as an indicator for toxic pollutants in SBFs. As originally proposed in February 1999 (64 FR 5491) and re-stated in April 2000 (65 FR 21557), EPA is today promulgating a BAT limitation and NSPS to control the maximum sediment toxicity of the SBF discharged with cuttings at the point of discharge. The sediment toxicity of the SBF-cuttings at the point of discharge is measured by the modified sediment toxicity test (ASTM E1367–92) using a natural sediment or formulated sediment and *Leptocheirus plumulosus* as the test organism.

EPA finds that the sediment toxicity test at the point of discharge is practical as an indicator of the sediment toxicity of the drilling fluid at the point of discharge. The sediment toxicity test applied at the point of discharge will control non-conventional pollutants found in some drilling fluid components (*e.g.,* emulsifiers, oil wetting agents, filtration control agents,

and viscosifiers) which are added to the base fluid in order to build a complete SBF package. Other possible toxic pollutants in drilling fluids may include mercury, cadmium, arsenic, chromium, copper, lead, nickel, and zinc, and formation oil contaminants. As previously stated, establishing discharge limits on toxicity encourages the use of less toxic drilling fluids and additives. The modifications to the 10-day sediment toxicity test include shortening the test to 96-hours. Shortening the test will allow operators to continue drilling operations while the sediment toxicity test is being conducted on the discharged drilling fluid. Moreover, discriminatory power is substantially reduced for the 10-day test on drilling fluid as compared to the 96-hour test (*i.e.,* the 10-day test is of lower practical use in determining whether a SBF is substantially different from OBFs). Finally, operators discharging WBFs are already complying with a biological test at the point of discharge, the 96-hour SPP toxicity test, which tests whole WBF aquatic toxicity using the test organism *Mysidopsis bahia*.

3. Maintenance of Current Requirements

Today's rule does not modify the existing BAT and NSPS limitations on the stock barite of 1 mg/kg mercury and 3 mg/kg cadmium. These limitations control the levels of toxic pollutant metals because cleaner barite that meets the mercury and cadmium limits is also likely 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 (*see* Section VI, Offshore Development Document, EPA–821–R–93–003).

Today's rule does not modify the existing BAT and NSPS limitations prohibiting the discharge of drilling wastes containing diesel oil in any amount. Diesel oil is considered an ''indicator'' for the control of specific toxic pollutants. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. Diesel oil may contain from 3 to 10% by volume PAHs, which constitute the more toxic pollutants in petroleum products.

Today's rule does not modify the existing BAT limitation and NSPS for controlling the maximum aqueous phase toxicity of SBF-cuttings at point of discharge using the suspended particulate phase (SPP) test (*see* Appendix 2 of subpart A of Part 435). The BAT limitation and NSPS for controlling aqueous toxicity of discharged SBF-cuttings is retained as the minimum 96-hour LC_{50} of the SPP shall be 3% by volume. EPA is interested in controlling the toxicity of drilling fluids in the sediment and the water column and is requiring both a sediment toxicity test and an aqueous phase toxicity test to assess overall toxicity of the drilling fluid at the point of discharge. EPA finds that the SPP test at the point of discharge is practical as a measurement of the aquatic toxicity of the drilling fluid at the point of discharge. The discharge SPP test will control non-conventional pollutants found in drilling fluid components (*e.g.,* emulsifiers, oil wetting agents, filtration control agents, and viscosifiers) which are added to the base fluid in order to build a complete SBF package. Moreover, operators discharging WBFs are already complying with the SPP toxicity test on discharged WBFs.

C. Regulatory Options Considered and Selected for Drilling Fluid Not Associated With Drill Cuttings

In the February 1999 proposal, EPA proposed BPT, BCT, BAT, and NSPS as zero discharge for SBFs not associated with drill cuttings. In the April 2000 NODA, EPA published two options for the final rule for the BAT limitation and NSPS for controlling SBFs not associated with SBF drill cuttings: (1) Zero discharge; or (2) allowing operators to choose either zero discharge or an alternative set of BMPs with an accompanying compliance method. Industry supported the second option stating that the first option (zero discharge) would result in the costly and potentially dangerous collection, shipping, and disposal of large quantities of rig site wash water containing only a small quantity of SBF (Docket No. W–98–26, Record No. IV.A.a.13). Industry also stated that BMPs would be extremely effective at reducing the quantity of non-cuttings related SBF and would focus operators' attention on reducing these discharges.

EPA is today promulgating BPT, BCT, BAT, and NSPS of zero discharge for SBFs not associated with drill cuttings. This wastestream consists of neat SBFs that are intended for use in the downhole drilling operations (*e.g.,* drill bit lubrication and cooling, hole stability). This wastestream is transferred from supply boats to the drilling rig and can be released during these transfer operations. This wastestream is often spilled on the drill deck but contained through grated troughs, vacuums, or squeegee systems. This wastestream is also held in numerous tanks during all phases of the drilling operation (*e.g.,* trip tanks, storage tanks). EPA received information that rare occurrences of improper SBF transfer procedures (*e.g.,* no bunkering procedures in place for rig loading manifolds) and improper operation of active mud system equipment (*e.g.,* no lock-out, tag-out procedures in place for mud pit dump valves) has the potential for the discharge of tens to hundreds of barrels of neat SBF, or SBF not associated with cuttings, if containment is not practiced (Docket No. W–98–26, Record No. IV.A.a.26, QTECH LTD Reports for Ocean America and Discoverer 534).

Current practice for control of SBF not associated with drill cuttings is zero discharge (*e.g.,* drill deck containment, bunkering procedures), primarily due to the value of SBFs recovered and reused. Therefore, zero discharge for SBF not associated with drill cuttings is technologically available and economically achievable. Moreover, these controls generally allow the re-use of SBF in the drilling operation and has no unacceptable NWQIs.

EPA has also decided that solids accumulated at the end of the well (''accumulated solids'') and wash water used to clean out accumulated solids or on the drill floor are associated with drill cuttings and are therefore not controlled by the zero discharge requirement for SBFs not associated with drill cuttings (*see* Section V.F.2.b).

D. BPT Technology Options Considered and Selected for Drilling Fluid Associated With Drill Cuttings

EPA is today promulgating BPT effluent limitations for the cuttings contaminated with SBFs (''SBF-cuttings''). The BPT effluent limitations promulgated today for SBF-cuttings would control free oil as a conventional pollutant. The BPT limitation is no free oil as measured by the static sheen test, performed on SBF separated from the cuttings in U.S. Offshore waters and Coastal Cook Inlet, Alaska.

In setting the no free oil limitation in U.S. Offshore waters and Coastal Cook Inlet, Alaska, EPA considered the sheen characteristics of currently available SBFs. Since this requirement is currently met by dischargers in the GOM, EPA anticipates no additional costs to the industry to comply with this limitation. Therefore, EPA believes that this limitation represents the appropriate level of control for SBFs associated with drill cuttings.

E. BCT Technology Options Considered and Selected for Drilling Fluid Associated With Drill Cuttings

In July 1986, EPA promulgated a methodology for establishing BCT effluent limitations. EPA evaluates the reasonableness of BCT candidate technologies—those that are technologically feasible—by applying a two part cost test: (1) A POTW test; and (2) an industry cost-effectiveness test.

EPA first calculates the cost per pound of conventional pollutant removed by industrial dischargers in upgrading from BPT to a BCT candidate technology and then compares this cost to the cost per pound of conventional pollutants removed in upgrading POTWs from secondary treatment. The upgrade cost to industry must be less than the POTW benchmark of $0.25 per pound (in 1976 dollars). In the industry cost-effectiveness test, the ratio of the incremental BPT to BCT cost divided by the BPT cost for the industry must be less than 1.29 (i.e., the cost increase must be less than 29%).

The BCT effluent limitations promulgated today would control free oil as a conventional pollutant. EPA is today promulgating a BCT effluent limitation for SBF-cuttings of no free oil equivalent to the BPT limitation for SBF-cuttings of no free oil as determined by the static sheen test in U.S. Offshore waters and Coastal Cook Inlet, Alaska.

In developing BCT limits for the U.S. Offshore waters and Coastal Cook Inlet, Alaska, EPA considered whether there are technologies (including drilling fluid formulations) that achieve greater removals of conventional pollutants than promulgated for BPT, and whether those technologies are cost-reasonable according to the BCT Cost Test. EPA identified no technologies that can achieve greater removals of conventional pollutants as compared with the U.S. Offshore waters and Coastal Cook Inlet BPT requirements that are also cost-reasonable under the BCT Cost Test. Accordingly EPA is today promulgating BCT effluent limitations for SBF-cuttings equal to the promulgated BPT effluent limitations for SBF-cuttings in U.S. Offshore waters and Coastal Cook Inlet, Alaska.

F. BAT Technology Options Considered and Selected for Drilling Fluid Associated With Drill Cuttings

EPA is promulgating stock limitations and discharge limitations in a two part approach to control SBF-cuttings discharges under BAT. The first part is based on product substitution through use of stock limitations (*e.g.,* sediment toxicity, biodegradation, PAH content, metals content) and discharge limitations (*e.g.,* diesel oil prohibition, formation oil prohibition, sediment toxicity, aqueous toxicity). The second part is the control of the quantity of SBF discharged with SBF-cuttings. As previously stated in the April 2000 NODA, EPA finds that the second part is particularly important because limiting the amount of SBF content in discharged cuttings controls: (1) The amount of SBF discharged to the ocean; (2) the biodegradation rate of discharged SBF; and (3) the potential for SBF-cuttings to develop cuttings piles and mats which are detrimental to the benthic environment.

EPA is also today retaining the existing BAT limitations on: (1) The stock barite of 1 mg/kg mercury and 3 mg/kg cadmium; (2) the maximum aqueous toxicity of discharged SBF-cuttings as the minimum 96-hour LC_{50} of the Suspended Particulate Phase toxicity test (SPP) shall be 3% by volume; and (3) prohibiting the discharge of drilling wastes containing diesel oil in any amount. These limitations control the levels of toxic metal and aromatic pollutants respectively. EPA at this time thinks that all of these components are essential for appropriate control of SBF-cuttings discharges.

The BAT effluent limitations promulgated today for SBF-cuttings would control a variety of toxic and non-conventional pollutants in the stock base fluids by controlling their PAH content, sediment toxicity, and biodegradation. The BAT effluent limitations promulgated today for SBF-cuttings would also control a variety of toxic and non-conventional pollutants at the point of discharge by controlling formation oil contamination, sediment toxicity, and the quantity of SBF discharged. The BAT stock and discharge limitations are described below.

The BAT level of control in the U.S. Offshore waters has been developed taking into consideration among other things: (1) The availability, cost, and environmental performance of SBF base fluids in terms of PAH content, sediment toxicity, and biodegradation rate; (2) the availability, cost, and environmental performance of SBFs retained on the cuttings discharge in terms of sediment toxicity and biodegradation rate; (3) the frequency of formation oil contamination at the various control levels for the discharges; (4) the availability, cost, and environmental performance of equipment and methods to recover SBF from the drill cuttings being discharged; and (5) the NWQIs of each option. By environmental performance, EPA means both a reduction in the quantity of pollutants discharged to the ocean and a reduction in their environmental effects in terms of sediment toxicity, aquatic toxicity, and biodegradation rate. Issues related to the technical availability and economic achievability of today's promulgated BAT limitations are discussed below by regulated parameter. The NWQIs of each selected option is discussed in Section VIII below. EPA also considered NWQIs in selecting the controlled discharge option for SBF-cuttings (*i.e.,* BAT/NSPS Option 2) (*see* Section VIII).

EPA and industry sediment toxicity and biodegradation laboratory studies show that both vegetable esters and low viscosity esters have better environmental performance than all other SBF base fluids. EPA, however, rejected the option of basing BAT sediment toxicity and biodegradation stock limitations and NSPS solely on vegetable esters and low viscosity esters because the record does not indicate that these fluids can be used in drilling situations throughout the offshore subcategory nor could EPA predict the conditions and circumstances where these fluids would be able to be used (*see* Section V.F.1.a). EPA is sufficiently satisfied, however, that both esters provide better environmental performance (*e.g.,* sediment toxicity, biodegradation). Consequently, EPA is promulgating an alternative higher retention on cuttings (ROC) BAT discharge limitation to encourage the use of esters. The higher ROC discharge limitation for SBFs complying with the stock limitations based on esters is derived from data representing four cuttings dryer technologies (*e.g.,* vertical centrifuge, horizontal centrifuge, squeeze press mud recovery unit, and High-G linear shaker). The lower ROC BAT discharge limitation for the SBFs complying with the C_{16}–C_{18} internal olefin stock limitations is based on data from the two top performing cuttings dryer technologies (*e.g.,* vertical centrifuge and horizontal centrifuge). EPA data demonstrates that operators properly using these cuttings dryer technologies (*e.g.,* vertical centrifuge, horizontal centrifuge, squeeze press, High-G linear shaker) will be able to comply with the final higher ROC numerical limitation for ester-based SBFs. EPA believes that this balancing of the importance of retention values with environmental performance as reflected by sediment toxicity and biodegradation rates is justified because of the greater ability of esters to

biodegrade and of their lower sediment toxicity.

Therefore, EPA balanced the environmental performance of the base fluid (in terms of sediment toxicity and biodegradation) with the environmental performance of cuttings associated with drilling fluids (in terms of the retention on cuttings limit) to determine the appropriate best available technology. EPA determined that the improved toxicity and biodegradation of the ester based fluids justified increased flexibility in the ROC limitation as long as the limitation reflected the use of cuttings dryers technologies.

EPA, however, did not base the higher ROC BAT discharge limitation for esters on current shale shaker technology because this does not represent the best available technology (or best available demonstrated technology). EPA does not believe that the improved environmental performance of esters justifies the huge difference in pollutant loadings between existing shale shaker technology and newer cuttings dryer technology. Because the effluent limitations and standards promulgated in this rule account for variability, the effluent limitation and standards are higher than the long term average upon which the technology is based. Here, the LTA for the esters ROC limitation of 9.4% is 4.8%; while the LTA for the IOs ROC limitation of 6.9% is 3.82%. By contrast, the LTA for existing shale shaker technology is 10.2%. This difference translates to 118 million pounds per year of pollutants being discharged using the existing and new model well counts for the selected BAT option (*i.e.,* BAT/NSPS Option 2) (*see* SBF Development Document). Further, as previously stated in the April 2000 NODA (65 FR 21553), field results show that: (1) Cuttings are dispersed during transit to the seabed and no cuttings piles are formed when SBF concentrations on cuttings are held below 5%; and (2) cuttings discharged from cuttings dryers (with SBF retention values under 5%) in combination with a sea water flush, hydrate very quickly and disperse like water-based cuttings. Thus, while EPA is willing to provide additional flexibility to dischargers of ester-based fluids, EPA believes that the appropriate technology basis that reflects BAT is cuttings dryers technology.

EPA determined that zero discharge for BAT was technically feasible and economically achievable because prior to the use of SBFs, the industry was able to operate using only the traditional OBFs (based on diesel oil and mineral oil), which are prohibited from discharge. EPA concluded that a zero discharge BAT limitation for SBF-cuttings would decrease the use of SBFs in favor of OBFs and WBFs. This is because a zero discharge BAT limitation for SBF-cuttings would create an incentive for operators to use the least expensive drilling fluids (*i.e.,* OBFs, WBFs) in order to minimize overall compliance costs.

EPA rejected the BAT zero discharge option for SBF-cuttings wastes because it would result in unacceptable increases in NWQIs. Therefore, EPA rejected the zero discharge option for SBF-cuttings wastes in U.S. waters in the Offshore subcategory of 40 CFR part 435 (''U.S. Offshore waters''). As previously stated in Section II.B, use of OBFs in place of SBFs would lead to an increase in NWQIs including the toxicity of the drilling waste. Use of WBFs in place of SBFs would generally lead to a per well increase in pollutants discharged, an increase in NWQIs, and an increase in aquatic toxicity. WBF drilling operations lead to per well increases in pollutants discharged because WBFs generate six times more washout (*e.g.,* sloughing) of the well wall than SBFs. Also, WBF drilling operations lead to increases in NWQIs because WBF drilling operations generally take longer than SBF drilling operations which lead to more air emissions and fuel usage from drilling rigs and equipment. Aquatic toxicity generally increases when drilling fluid manufacturers add supplements (*e.g.,* glycols, shale inhibitors) to WBFs for the purpose of making WBFs have technical capabilities (*e.g.,* lubricity, shale suppression) similar to SBFs. EPA estimates that, under the zero discharge option, some operators would switch to WBF compositions with more non aqueous drilling fluid properties (*e.g.,* lubricity, shale suppression), and that these WBFs would exhibit greater aquatic toxicity.

EPA's analyses show that under the SBF-cuttings zero discharge option as compared to current practice, for U.S. Offshore waters existing sources, there would be an increase of 35 million pounds of cuttings annually shipped to shore for disposal in non-hazardous oilfield waste (NOW) sites and an increase of 166 million pounds of cuttings annually injected. In addition, under the SBF-cuttings zero discharge option, operators would use the more toxic OBFs. The zero discharge option for SBF-cuttings would lead to an increase in annual fuel usage of 358,664 BOE and an increase in annual air emissions of 5,602 tons. Finally, the SBF-cuttings zero discharge option in the U.S. Offshore waters would lead to an increase of 51 million pounds of WBF cuttings being discharged to U.S. Offshore waters. This pollutant loading increase is a result of GOM operators switching from efficient SBF drilling to less efficient WBF drilling.

EPA's analysis shows that the impacts of adequately controlled SBF discharges to the water column and benthic environment are of limited scope and duration. By contrast, the landfilling of OBF-cuttings is of a longer term duration and associated pollutants may affect ambient air, soil, and groundwater quality. EPA and DOE documented at least five CERCLA (or ''Superfund'') sites in Louisiana and California contaminated with oilfield wastes and more than a dozen other sites subject to Federal or State cleanup actions.

Nonetheless, while SBF-cuttings discharge with adequate controls is preferred over zero discharge in U.S. Offshore waters, SBF-cuttings discharge with inadequate controls is not preferred over zero discharge. EPA believes that to allow discharge of SBF-cuttings in U.S. Offshore waters, there must be appropriate controls to ensure that EPA's discharge limitations reflect the ''best available technology'' or other appropriate level of technology. EPA has worked with industry to address the appropriate determination of PAH content, sediment toxicity, biodegradation, quantity of SBF discharged, and formation oil contamination that are technically available, economically achievable, and have acceptable NWQIs. The final BAT limitations are a result of this effort and are discussed below.

EPA is today promulgating BAT of zero discharge for SBF-cuttings for Coastal Cook Inlet, Alaska except when Coastal Cook Inlet, Alaska, operators are unable to dispose of their SBF-cuttings using any of the following disposal options: (1) On-site re-injection (annular disposal or Class II UIC); (2) re-injection using a nearby Coastal or Offshore Class II UIC disposal well; or (3) onshore disposal using a nearby Class II UIC disposal well or land application. Coastal Cook Inlet, Alaska, operators are required to demonstrate to the NPDES permit controlling authority that none of the above three disposal options are technically feasible in order to qualify for the alternate BAT limitation. Coastal Cook Inlet, Alaska, operators that qualify for the alternate BAT limitation are allowed to discharge SBF-cuttings at the same level of BAT control as operators in Offshore waters. The NPDES permit controlling authority will use the procedure given in Appendix 1 to subpart D of 40 CFR part 435 to establish whether or not a Coastal Cook Inlet, Alaska, operator qualifies for the

SBF-cuttings zero discharge exemption. As stated in Appendix 1 to subpart D of 40 CFR part 435, the following factors are considered in the determination of whether or not Coastal Cook Inlet, Alaska, operators qualify for the SBF-cuttings zero discharge exemption: (1) Inability to establish formation injection in wells that were initially considered for annular or dedicated disposal; (2) inability to prove to UIC controlling authority that the waste will be confined to the formation disposal interval; (3) inability to transport drilling waste to an offshore Class II UIC disposal well or an onshore disposal site; and (4) whether or not there is no available land disposal facilities (*e.g.,* onshore re-injection, land disposal).

EPA finds that this option is technically available and economically achievable. Operators are currently barred from discharging OBFs, SBFs, and enhanced mineral oil based drilling fluids under the Cook Inlet NPDES general permit (64 FR 11889). As previously discussed in Section IV.E, EPA identified that many Cook Inlet operators in Coastal waters are using cuttings re-injection to comply with zero discharge disposal requirements for OBFs and OBF-cuttings. EPA contacted Cook Inlet operators (*e.g.,* Phillips, Unocal, Marathon Oil) and the State regulatory agency, AOGCC, for more information on the most recent re-injection practices of Coastal and Offshore Cook Inlet operators. AOGCC stated that there should be enough formation re-injection disposal capacity for the small number of non-aqueous drilling fluid wells (<5–10 wells per year) being drilled in Cook Inlet Coastal waters. Therefore, since Coastal Cook Inlet operators are already complying with zero discharge of OBF- and SBF-cuttings, this option is economically achievable as there are no incremental compliance costs.

AOGCC stated, however, that case specific limitations should be considered when evaluating disposal options (*see* Section IV.E). Cook Inlet, Alaska, operators may experience the following difficulties in attempting to comply with a zero discharge requirement for SBFs: (1) Inability to establish formation injection in wells that were initially considered for annular or dedicated Class II UIC disposal; (2) inability to prove to AOGCC's satisfaction that the waste will be confined to the formation disposal interval; and (3) inability to transport drilling waste to an offshore Class II UIC disposal well or an onshore disposal site. EPA believes that while these problems are currently not presented by drilling in Cook Inlet, they could be a problem in the future. Further, EPA believes this to be a greater problem in Cook Inlet where climate, tides, and its distance from commercial disposal sites make transportation to shore less feasible than in other offshore waters near the continental U.S. If EPA did not provide for some exceptions within the guideline itself, and these problems presented themselves beyond the time frame for requesting a Fundamentally Different Factors variance (under section 301(n)(2) of the CWA, 180 days) this would render zero discharge not achievable. Therefore, EPA believes it is reasonable to provide for some flexibility to the current practice of zero discharge in Cook Inlet.

EPA further finds the NWQIs of this option for Cook Inlet to be acceptable. As previously stated, few non-aqueous drilling fluid wells are drilled in Coastal Cook Inlet, Alaska (<5–10 wells per year). EPA finds that the small number of wells drilled per year (even if all of them are drilled using SBF) leads to very small increases in NWQIs. Tables 6 though 10 describe the annual air emissions and fuel usage for the three geographic regions including Cook Inlet, Alaska. In particular, a zero discharge requirement for SBFs and SBF-cuttings in Cook Inlet, Alaska, would lead to an annual increase of 94 tons of air emissions and 6,067 BOE fuel used for existing sources. EPA does not anticipate and new sources in Cook Inlet, Alaska. Consequently, EPA finds that the overall small increases in NWQIs from the zero discharge option, as compared to either of the two SBF-cuttings discharge options, in Coastal Cook Inlet, Alaska, are acceptable. The two SBF-cuttings discharge options show little change in NWQIs as compared to baseline (*see* Tables 6 though 9).

1. Stock Base Fluid Technical Availability and Economic Achievability

a. Introduction. As SBFs have developed over the past few years, the industry has come to use mainly a limited number of primary base fluids. These include the internal olefins, linear alpha olefins, poly alpha olefins, paraffinic oils, C_{12}–C_{14} vegetable esters of 2-hexanol and palm kernel oil, and ''low viscosity'' C_8 esters. These fluids represent virtually all the SBFs currently used in oil and gas extraction industry. EPA collected data on performance, environmental impact, and costs for these SBFs to develop the effluent limitations for today's final rule. The following definitions are used in this preamble to describe various SBFs: (1) Internal olefin (IO) refers to a series of isomeric forms of C_{16} and C_{18} alkenes; (2) linear alpha olefin (LAO) refers to a series of isomeric forms of C_{14} and C_{16} monoenes; (3) poly alpha olefin (PAO) refers to a mix mainly comprised of a hydrogenated decene dimer $C_{20}H_{62}$ (95%), with lesser amounts of $C_{30}H_{62}$ (4.8%) and $C_{10}H_{22}$ (0.2%); (4) vegetable ester refers to a monoester of 2-ethylhexanol and saturated fatty acids with chain lengths in the range C_8–C_{16}; and (5) ''low viscosity'' ester refers to an ester of natural or synthetic C_8 fatty acids and alcohols. EPA also has data on other SBF base fluids, such as enhanced mineral oil, paraffinic oils (*i.e.,* saturated hydrocarbons or ''alkanes''), and the traditional OBF base fluids: mineral oil and diesel oil.

The stock base fluid limitations in today's rule are based on the technology of product substitution. The promulgated limitations are technically available because they are based on currently available base fluids that can be used in the wide variety of drilling situations in U.S. offshore waters. EPA anticipates that the base fluids meeting all requirements would include vegetable esters, low viscosity esters, and internal olefins. In addition, based on current information, EPA believes that the stock base fluid controls on PAH content, sediment toxicity, and biodegradation rate being promulgated today are sufficient to only allow the discharge of only those base fluids (*e.g.,* esters, internal olefins) with lower bioaccumulation potentials (*i.e.,* log K_{ow} <3 to 3.5 and log K_{ow}> 6.5 to 7). Therefore, EPA found it was unnecessary to promulgate a separate limitation for bioaccumulation.

As previously stated in April 2000 (65 FR 21554), EPA considered basing the sediment toxicity and biodegradation stock limitations and standards solely on vegetable esters (*i.e.,* original esters) instead of the proposed C_{16}–C_{18} IO. EPA also considered subcategorizing the final rule to determine when vegetable esters are not practical and when C_{16}–C_{18} IOs could be used instead. EPA considered these options due to the potential for better environmental performance of vegetable ester-based drilling fluids. EPA and industry analytical testing show that esters have better sediment toxicity and biodegradation performance.

EPA rejected the option of basing sediment toxicity and biodegradation stock limitations and standards on vegetable esters due to several technical limitations. These technical limitations of vegetable esters preclude their use in all areas of the GOM, Offshore California, and Cook Inlet, Alaska. Vegetable ester technical limitations

include: (1) High viscosity compared with other IO SBFs at all temperatures, with an increasing difference as temperature decreases, leading to lower rates of penetration in wells and greater probability of losses due to higher equivalent circulating densities; (2) high gel strength in risers that develops when a vegetable ester-based SBF is not circulated; (3) a high temperature stability limit ranging from about 225 °F to perhaps 320 °F—the exact value depends on the detailed chemistry of the vegetable ester (*i.e.,* the acid, the alcohol) and the drilling fluid chemistry; (4) reduction of the thermal stability limit through hydrolysis when vegetable esters are in contact with highly basic materials (*e.g.,* lime, green cement) at elevated temperatures; and (5) less tolerance of the muds to contamination by seawater, cement, and drill solids than is observed for IO–SBFs (Docket No. W–98–26: Record No. IV.A.a.3, Attachment A2—''Limitations of Esters'; Record No. IV.A.a.13, Attachments Ester-51, 52, 53, 54, 56).

EPA also rejected the option of subcategorizing the use of esters to define drilling conditions when only esters could be allowed for a controlled discharge. EPA could not establish a ''bright line'' rationale to define the situation where only esters should be the benchmark fluid (*i.e.,* only esters would be allowed for a controlled discharge). EPA considered many of the engineering factors used for selection of a drilling fluid (*e.g.,* rig size and equipment; formation characteristics; water depth and environment; lubricity, rheological, and thixotropic requirements) and determined that this type of sub-categorization was not possible. EPA, however, is encouraging the use of esters by promulgating a higher ROC limitation and standard when esters are used.

EPA also considered basing sediment toxicity and biodegradation stock limitations and standards on low viscosity esters. Comments to the April 2000 NODA state that laboratory analyses, which were designed to simulate GOM conditions to which a fluid may be exposed, indicate that low viscosity esters have the following technical properties: (1) Similar or better viscosity than C_{16}–C_{18} IOs; (2) can be used to formulate stable low viscosity ester-based SBFs up to 300 °F; (3) can be used to formulate low viscosity ester-based SBFs to 16.0+ lbs/gal mud weight; (4) can reduce oil/water ratios to 70/30, thus reducing volumes of base fluid discharged; (5) high tolerance to drilled solids; (6) flat gels make it easier to break circulation, minimizing initial circulation pressures and subsequent risk of fracture; (7) high tolerance to seawater contamination; and (8) rheological properties can be adjusted by use of additives to suit specific conditions (Docket No. W–98–26, Record No. IV.A.a.7). EPA also received information on one well section drilled with low viscosity esters. Some of the results from this low viscosity ester well section were compared to the results from another well section in the same location where C_{16}–C_{18} IOs were used. These results show that the low viscosity ester had: (1) Comparable or better equivalent circulating densities (*i.e.,* acceptable fluid properties); and (2) faster ROP through better hole cleaning and higher lubricity (*i.e.,* fewer days required to drill to total depth which lead to less NWQI and overall drilling costs). The low viscosity esters are relatively new base fluids and have only recently been available to the market. Despite the results from the laboratory analyses and one well section, EPA does not believe that this is enough information to make the determination that low viscosity esters can be used in all or nearly all drilling conditions in the offshore U.S. waters (*e.g.,* differing formations, water depths, and temperatures). Therefore, EPA rejected the option of basing sediment toxicity and biodegradation stock limitations and standards on low viscosity esters. EPA is sufficiently satisfied, however, that low viscosity esters and vegetable esters provide better environmental performance (*e.g.,* sediment toxicity, biodegradation). Consequently, EPA is promulgating higher retention on cuttings discharge limitations where esters are used to encourage operators to use esters when possible.

b. PAH Content Technical Availability. Today's promulgated limitation of PAH content for U.S. Offshore waters is a weight ratio defined as the weight of PAH (as phenanthrene) per weight of the stock base fluid sample. The PAH weight ratio is 0.001%, or 10 parts per million (ppm). This limitation is based on the availability of base fluids that are free of PAHs and the detection of the PAHs by EPA Method 1654A, ''PAH Content of Oil by High Performance Liquid Chromatography with a UV Detector.'' Method 1654A was published in Methods for the Determination of Diesel, Mineral and Crude Oils in Offshore Oil and Gas Industry Discharges (EPA–821–R–92–008, incorporated by reference and available from National Technical Information Service at (703) 605–6000). As originally proposed in February 1999 (64 FR 5503), EPA is promulgating the use of the EPA Method 1654A for compliance with this PAH content BAT limitation.

EPA's promulgated PAH content limitation is technically available. Producers of several SBF base fluids have reported to EPA that their base fluids are free of PAHs. The base fluids which suppliers have reported are free of PAHs include IOs, LAOs, vegetable esters, low viscosity esters, certain enhanced mineral oils, synthetic paraffins, certain non-synthetic paraffins, and others. The use of these fluids can accommodate the broad varieties of drilling situations faced by industry in offshore U.S. waters (*see* SBF Development Document, Chapter IV). Compliance with the stock BAT limitation and NSPS on PAH content will be achieved by product substitution.

c. Sediment Toxicity Technical Availability. EPA is today promulgating a sediment toxicity stock base fluid limitation that would only allow the discharge of SBF-cuttings using SBF base fluids as toxic or less toxic, but not more toxic, than C_{16}–C_{18} IOs. Alternatively, this limitation could be expressed in terms of a ''sediment toxicity ratio'' which is defined as 10-day LC_{50} of C_{16}–C_{18} internal olefins divided by the 10-day LC_{50} of stock base fluid being tested. EPA is promulgating a sediment toxicity ratio of less than 1.0. Compliance with this limitation is determined by the 10-day *Leptocheirus plumulosus* sediment toxicity test (*i.e.,* ASTM E1367–92: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests With Marine and Estuarine Amphipods' (incorporated by reference and available from ASTM, 100 Bar Harbor Drive, West Conshohocken, PA 19428), supplemented with the preparation procedure specified in Appendix 3 of Subpart A of 40 CFR part 435). As originally proposed in February 1999 (64 FR 5503) and re-stated in April 2000 (65 FR 21549), EPA is promulgating the use of the ASTM E1367–92 method for compliance with this sediment toxicity BAT limitation.

Since the February 1999 proposal, EPA and other researchers conducted numerous 10-day *L. plumulosus* sediment toxicity tests on various SBF base fluids with natural and formulated sediments. Nearly all the SBF base fluids have lower sediment toxicity than diesel and mineral oil. Some SBF base fluids, however, show greater sediment toxicity than other SBF base fluids (*see* 65 FR 21550; Docket No. W–98–26, Record No. IV.A.a.13). The base fluids meeting this limitation include vegetable esters, low viscosity esters, internal olefins, and some PAOs (*see* 65

FR 21550; Docket No. W–98–26, Record No. IV.A.a.13).

EPA finds this limit to be technically available and economically achievable through product substitution because information in the rulemaking record supports the findings that vegetable esters, low viscosity esters, and internal olefins have performance characteristics enabling them to be used in the wide variety of drilling situations in offshore U.S. waters and meet today's promulgated limit.

EPA selected the C_{16}–C_{18} IO, which is the most popular drilling fluid in the GOM, as the basis for the sediment toxicity rate ratio limitation instead of the vegetable ester or low viscosity ester for several reasons: (1) EPA does not believe that vegetable esters can be used in all drilling situations; and (2) EPA does not have sufficient field testing information that low viscosity esters can be used in all drilling situations (*see* Section V.F.1.a). In addition, because of the uncertainty about ester performance, operators may not be encouraged to switch from OBFs or WBFs to SBF when properly installed and maintained. Specifically, vendor supplied data associated with these cuttings dryer deployments suggest that the overall cuttings dryer downtime (*i.e.,* time when cuttings dryer equipment is not operable) is approximately 1 to 2% (Docket No. W–98–26, Record No. IV.A.a.6). EPA finds this small downtime percentage as acceptable.

EPA discussed how it revised the BAT/NSPS-level solids control equipment configuration used in its analyses in the April 2000 NODA (65 FR 21559). EPA also discussed a range of management options regarding the BAT limitation for SBF retention on SBF-cuttings: (1) Two discharges from the BAT/NSPS-level solids control equipment configuration (*i.e.,* one discharge from the cuttings dryer and another discharge from the fines removal unit); (2) one discharge from the BAT/NSPS-level solids control equipment configuration (*i.e.,* one discharge from the cuttings dryer with the fines from the fines removal unit captured for zero discharge); and (3) zero discharge of SBF-cuttings. These three options are labeled as BAT/NSPS Option 1, BAT/NSPS Option 2, and BAT/NSPS Option 3, respectively. EPA estimates that 97% and 3% of the total cuttings are generated by cuttings dryer and fines removal unit, respectively.

EPA developed two numerical well averaged ROC limitations (*i.e.,* one for SBFs with the stock base fluid performance similar to esters and another for SBFs with the stock base fluid performance similar to C_{16}–C_{18} internal olefins) and based both of these ROC limitations on the technology of only one discharge from the cuttings dryer with the fines from the fines removal unit captured for zero discharge (*i.e.,* BAT/NSPS Option 2). The numerical well averaged ROC maximum limitation for SBFs (*i.e.,* 9.4%) with the environmental characteristics of esters is based on a combination of data from horizontal centrifuge, vertical centrifuge, squeeze press, and High–G linear shaker cuttings dryer technologies. The numerical well averaged ROC maximum limitation for SBFs (*i.e.,* 6.9%) with the environmental characteristics of C_{16}–C_{18} internal olefins is based on a combination of data from horizontal and vertical centrifuge cuttings dryer technologies. EPA estimates that operators, generally installing new equipment where none has been used in the past, will be able to choose from among the better technologies, designs, operating procedures, and maintenance procedures that EPA has considered to be among the best available technologies. EPA data demonstrates that operators properly using these cuttings dryer technologies will be able to comply with these final ROC numerical limitations. Data submitted to EPA show that operators using the vertical centrifuge and horizontal centrifuge are capable of achieving the lower ROC limitation (*i.e.,* 6.9%). Data submitted to EPA also show that operators using the vertical centrifuge, horizontal centrifuge, squeeze press, and High-G linear shaker are capable of achieving the higher ROC limitation (*i.e.,* 9.4%). More details on the observed performance of the individual technologies and details of calculation for the numerical limits are presented in the SBF Statistical Support Document and SBF Development Document.

EPA developed the two ROC limitations because EPA used a two part approach to control SBF-cuttings discharges. The first part is the control of which SBF are allowed for discharge through use of stock limitations (*e.g.,* sediment toxicity, biodegradation, PAH content, metals content) and discharge limitations (*e.g.,* diesel oil prohibition, formation oil prohibition, sediment toxicity, aqueous toxicity). The second part is the control of the quantity of SBF discharged with SBF-cuttings. As previously stated, EPA and industry sediment toxicity and biodegradation laboratory studies show that both vegetable esters and low viscosity esters have better environmental performance than all other SBF base fluids. However, because the technical availability of product substitution with esters was not demonstrated across the offshore subcategory, EPA rejected the option of basing sediment toxicity and biodegradation stock limitations and standards on vegetable esters and low viscosity esters (*see* V.F.1.a). EPA is sufficiently satisfied, however, that both esters provide better environmental performance (*e.g.,* sediment toxicity, biodegradation). Consequently, EPA is promulgating a higher retention on cuttings discharge limitation to encourage operators to use esters when possible. EPA estimates that a higher retention on cuttings discharge limitation for esters is equivalent to the same level of control as a lower retention on cuttings discharge limitation for all other SBFs that have poorer sediment toxicity and biodegradation performances.

In response to the April 2000 NODA, EPA received comments from an ester-based SBF manufacturer that EPA should create an incentive for operators to use ester-based SBFs by basing the ROC limitation for ester-based SBFs on baseline solids control equipment (*e.g.,* primary and secondary shale shakers, fines removal unit) (Docket No. W–98–26, Record No. IV.A.a.7). In late comments, this same commentor claimed that a ROC limitation based on any cuttings dryer technology would not provide any incentive for the use of ester-based SBFs (Docket No. W–98–26, Record No. IV.A.a.38). Further, they argued that the superior laboratory performance of these ester base fluids in terms of sediment toxicity and biodegradation justifies allowing them to be discharged with a ROC limitation based on baseline solids control equipment. EPA estimates that a ROC BAT limitation based on the baseline solids control equipment is above 15.3%.

While EPA is willing to expand the technology basis to allow the use of less effective cuttings dryers for ester-based SBFs (*e.g.,* squeeze press, High-G linear shakes), EPA is unwilling to entirely abandon the use of cuttings dryers for ester-based SBF drilling operations. EPA is unwilling to set a higher ROC limitation for SBFs with the environmental performance of ester-based SBFs based on baseline solids control technology because the environmental improvement resulting from the use of improved solids control technology (*i.e.,* cuttings dryers) outweighs the incremental ester laboratory sediment toxicity and biodegradation performance over internal olefins. Cuttings dryers promote pollution prevention through increased re-use of drilling fluids and prevent

significant amounts of pollutants from being discharged to the ocean.

EPA provides for variability from the long term average (LTA) of performance data from the candidate treatment technology or technologies. The LTA performance of the baseline solids control technology is 10.2%, as compared to the LTA of 4.8% based on data from all four cutting dryer technologies. This difference translates to 118 million pounds per year of pollutants being discharged using the existing and new model well counts for the selected BAT option (*i.e.,* BAT/NSPS Option 2) (*see* SBF Development Document). Further, as previously stated in the April 2000 NODA (65 FR 21553), field results show that: (1) Cuttings are dispersed during transit to the seabed and no cuttings piles are formed when SBF concentrations on cuttings are held below 5%; and (2) cuttings discharged from cuttings dryers (with SBF retention values under 5%) in combination with a sea water flush, hydrate very quickly and disperse like water-based cuttings. Thus, while EPA is willing to provide additional flexibility to dischargers of ester-based fluids, EPA believes that the appropriate technology basis that reflects BAT is cuttings dryers technology. In balancing the environmental effects of these additional ester-based SBFs discharges controlled with the use of baseline solids control technology against the environmental effects of lower internal olefin-based SBFs discharges controlled with the use of cuttings dryers, EPA has concluded that the improvement in solids control technology leading to lower values of ROC is a more significant factor than laboratory data for ester base fluids showing lower sediment toxicity and higher biodegradation.

EPA is also not convinced that the difference in ROC limitations provides no incentive to use ester-based SBFs, as the ester-based SBF manufacturer argues. EPA believes that the difference between 6.9% and 9.4% could provide an incentive for operators to use ester-based SBFs. As operators have increasingly installed cuttings dryers in the GOM (over three dozen successful deployments in the last two years), and as any SBF discharger installs new technology to comply with the lower ROC limitation (*i.e.,* 6.9%), operators may find that it is worthwhile to purchase ester-based SBFs in order to be able to operate with even a greater margin of flexibility under a limit of 9.4% as compared to 6.9%.

As this rule is performance based, EPA is not prohibiting the discharge of SBF-cuttings from the fines removal unit in order to comply with the base fluid retained on cuttings discharge BAT limitation. Operators are only required to show that the volume weighted average of all their SBF-cuttings discharges is below the discharge BAT limitation. EPA expects that most operators will be able to discharge cuttings from the cuttings dryer and fines removal unit and comply with this discharge BAT limitation. If, for example, the average retention of SBF on SBF-cuttings from a cuttings dryer is 6.00%, the average retention of SBF on SBF-cuttings from a fines removal unit is 12.00%, and the fines are observed to comprise 3% of the total cuttings discharged, then the well average is 6.18% (*i.e.,* (0.97) (6.00%) + (0.03)(12.00%) = 6.18%). If the well average for SBF retention from the cuttings dryer exceeds the discharge limit then in order to comply with this discharge BAT limitation all cuttings must be re-injected on-site or hauled to shore for land disposal. EPA finds that if this is the case, the limit is technologically available because operators have transported OBFs to shore since 1986 and have transported WBFs that do not meet the existing effluent limitations and standards since 1993.

EPA finds that both ROC limitations (*i.e.,* 6.9%, 9.4%) are technically available to the industry because they are based on product substitution and a statistical analysis of ROC performance from drilling conditions throughout offshore waters. The BAT limitations for controlling the amount of SBF discharged with SBF-cuttings are calculated such that nearly all well averages for retention are expected to meet these values using the selected technologies without any additional attention to design, operation, or maintenance. EPA data demonstrates that operators properly using these cuttings dryer technologies will be able to comply with these final ROC numerical limitations because: (1) These limits allow for variation in formation characteristics that may not exist in the United States; (2) operators, generally installing new equipment where none has been used in the past, will be able to choose from among the better technologies, designs, operating procedures, and maintenance procedures that EPA considers to be among the best available technologies; and (3) operators may elect to use SBFs with the stock base fluid performance of esters and horizontal or vertical centrifuge cuttings dryers to achieve a ROC well average well below the 9.4% ROC limitation.

Data used in the calculation of the numerical limits exclude retention results submitted without backup calculations (*i.e.,* without raw retort data) and include data from drilling operations in foreign waters (*e.g.,* Canada). EPA excluded ROC data without raw retort data (*e.g.,* masses and volumes of cuttings samples and recovered liquids taken during the retort method by the field technician) due to concerns over data quality (*e.g.,* no independent method to check data quality). EPA included ROC data from Canadian drilling operations to incorporate the variability of cuttings dryer performance in harder and less permeable formations that generally lead to higher ROC values. EPA estimates that the major factors leading to higher ROC values for all solids control equipment include: (1) Slower rates of penetration; (2) formations that are harder and less permeable; and (3) selection of certain drill bits. The Canadian ROC data come from formations that are generally much harder and less permeable than what is observed in the GOM. These harder formations generally lead to slower rates of penetration. The less permeable Canadian formations lead to fewer downhole losses of SBF. Downhole losses require the addition of fresh SBF to maintain volume requirements for the active mud system. These additions of fresh SBF to the active mud system help control the potential of build-up of fines. In addition, operators often use PDC drill bits in order to grind through the hard Canadian formations. This grinding action leads to smaller cuttings than is what is observed in the GOM. The smaller cuttings have more surface area for SBF than larger cuttings and generally have higher ROC values. Consequently, EPA's use of Canadian data in its analyses incorporate sufficient variability to model the formations in GOM, Offshore California, Cook Inlet, Alaska, and other offshore U.S waters where EPA does not have ROC data.

EPA finds that both well-average discharge BAT ROC limitations (*e.g.,* 6.9%, 9.4%) for base fluid on wet cuttings are economically achievable. According to EPA's analysis, in addition to reducing the discharge of SBFs associated with the cuttings, EPA estimates that this control will result in a net savings of $48.9 million ($1999) dollars per year. This savings results, in part, because the value of the SBF recovered is greater than the cost of installation of the improved solids control technology.

EPA concluded that a zero discharge requirement for SBF-cuttings from

existing sources and the subsequent increase use of OBFs and WBFs would result in: (1) Unacceptable NWQIs; and (2) more pollutant loadings to the ocean due to operators switching from SBFs to less efficient WBFs (*see* Sections II.B and V.F). For these reasons, EPA rejected the BAT zero discharge option for SBF-cuttings from existing sources.

EPA also requested comments in the April 2000 NODA (65 FR 21570) on the issue of rig compatibility with the installation of cuttings dryers (*e.g.,* vertical or horizontal centrifuges, squeeze press mud recovery units, High-G linear shakers). EPA received general information on the problems and issues related to cuttings dryer installations from API/NOIA stating that not all rigs are capable of installing cuttings dryers (Docket No. W–98–26, Record No. IV.A.a.13). In late comments, some industry commentors asserted that 48 of the 223 GOM drilling rigs are not capable of having a cuttings dryer system installed due to either rig space and/or rig design without prohibitive costs or rig modifications (Docket No. W–98–26, Record No. IV.B.b.33). Upon a further, more extensive review of GOM rigs, these same commentors asserted that 30 of 234 GOM drilling rigs are not capable of having a cuttings dryer system installed due to either rig space and/or rig design without prohibitive costs or rig modifications (Docket No. W–98–26, Record No. IV.B.b.34). EPA also received late comments from one operator, Unocal, stating that 36 of 122 Unocal wells drilled between late 1997 and mid-2000 were drilled with rigs that do not have 40 foot × 40 foot space available which they assert is necessary for a cuttings dryer installation (Docket No. W–98–26, Record No. IV.B.b.31). The API/NOIA rig survey and the Unocal rig survey identified most of the same rigs as unable to install cuttings dryers. However, two rigs (*i.e.,* Parker 22, Nabors 802) identified in the Unocal rig survey as having no space for a cuttings dryer installation were identified in the API/NOIA rig survey as each having a previous cuttings dryer installation. Unocal requested in late comments that EPA subcategorize certain rigs from being subject to the retention limit or that these rigs be able to discharge SBFs using performance that reflects current shale shaker technology (Docket No. W–98–26, Record No. IV.A.a.36).

Based on the record, EPA finds that current space limitations for cuttings dryers do not require a 40 foot × 40 foot space. Specifically, EPA has in the record information gathered during EPA's October 1999 site visit and information supplied by API/NOIA, MMS, and equipment vendors. EPA received information from a drilling fluid manufacturer and cuttings dryer equipment vendor, M-I Drilling Fluids, stating that they are not aware of any GOM rig not capable of installing a cuttings dryer (Docket No. W–98–26, Record No. IV.B.b.32). Another cuttings dryer equipment vendor, JB Equipment, asserted that there are at most only a few rigs that pose questionable installation problems and that they have yet to survey a rig that they could not install a cuttings dryer (Docket No. W–98–26, Record No. IV.B.b.48). JB Equipment also stated that inexperience with cuttings dryer installations may inhibit the ability of operators or rig owners to properly judge whether a cuttings dryer can be installed. JB Equipment cited an example where the operator concluded that a cuttings dryer could not be installed on a rig (Nabors 803) while JB Equipment surveying efforts identified the cuttings dryer installation for the same rig as one of the simplest installations JB Equipment performs. MMS also concluded that rigs do not need a 40 foot × 40 foot space to install a cuttings dryer and that, with the exception of a few jackup and platform rigs, there should not be any significant issues related to installing cuttings dryers on OCS drilling rigs (Docket No. W–98–26, Record No. IV.B.a.28). API/NOIA estimated that 150 square feet are required for a cuttings dryer installation in order to meet the ROC BAT limitation and NSPS (Docket No. W–98–26, Record No. IV.A.a.13). EPA also estimates that the minimum height clearance for a typical cuttings dryer installation is 6 feet (*see* SBF Development Document). The API/NOIA estimate is based on the installation of a horizontal centrifuge cuttings dryer (*i.e.,* MUD–6). The Unocal estimate is based on the vertical centrifuge cuttings dryer and is also characterized by other industry representatives and MMS as too high (Docket No. W–98–26, Record No. IV.B.b.34; Record No. IV.B.a.28). EPA's estimate of a typical vertical centrifuge installation is 15 feet × 15 feet (*i.e.,* 225 square feet) with a minimum height clearance of 11 feet (*see* SBF Development Document). EPA based the ROC BAT limitation and NSPS (*e.g.,* 6.9%) on the use of both these cuttings dryers for SBFs with the stock limitations of C_{16}–C_{18} IOs. Based on comments from operators, equipment vendors, and MMS, EPA believes that most of these shallow water rigs have the requisite 150–225 square feet available to install a cuttings dryer (*see* SBF Development Document). Therefore, EPA finds that operators are not required to have a 1,600 square foot space for a cuttings dryer installation in order to meet the ROC BAT limitation and NSPS. Proper spacing and placement of cuttings dryers in the solids control equipment system should prevent installation problems.

Because of the large discrepancy between EPA's record information and the space requirements asserted by the commenter (1,600 square feet versus EPA's 225 square feet + 11 feet in height for the vertical centrifuge or 150 square feet + 6 feet in height for the horizontal centrifuge—MUD–6), EPA does not necessarily believe that there are as many wells that cannot install cuttings dryers as the commentor (Unocal) claims. Further, based on scant detail supporting these assertions, and their lateness in the process, EPA has no basis upon which to assess them or verify them.

Moreover, EPA does not believe that it has enough information to reasonably subcategorize these facilities, nor did it have time to provide public notice of how it would define such a subcategory, given the court-ordered deadline for this rule. EPA does not believe that basing a subcategory by specifying a space requirement alone (*e.g.* operators that do not have a certain amount of deck space available on, below or adjacent to the deck would not be subject to this requirement) would be sufficient to prevent operators from configuring their other equipment in a manner that would enable them to fit into the subcategory. Such an exception might also lead to operators to make other assertions justifying that they should be included (*e.g.,* that while they have a certain amount of space available, safety reasons prevent placement of the technology on the rig). Without a solution to these issues, EPA is concerned that such a subcategorization would potentially be too broad and be unworkable.

For these reasons, EPA believes that the appropriate way to handle these concerns is through the fundamentally different factors (FDF) variance process. This process, provided for under CWA section 301(n), would allow operators to submit supporting data and information to EPA and would give the public the opportunity to comment on that data to determine whether an FDF is truly warranted for that drilling facility. EPA has authority over owners and operators, who are both dischargers, but the NPDES regulations require the operator to apply for the NPDES permit: ''When a facility or activity is owned by one person but is operated by another person, it is the operator's duty to obtain

a permit,'' (*see* 40 CFR 122.21(b)). Thus, mobile drill rig ''operators'' as dischargers can apply for FDFs (*see* 40 CFR 125.32; 122.21(b)).

EPA notes that the ROC limitations and standards do not preclude the use of SBFs if an operator cannot meet them if the operator can meet zero discharge through re-injection or shipment to shore. Historically, dischargers have used water-based fluids in shallow water wells and this may also be an option. EPA considers controlled WBF discharges preferable to uncontrolled SBF discharges. EPA examined the NWQIs associated with these zero discharge operations as acceptable (*see* SBF Development Document). The NWQIs of zero discharge for the shallow water wells are much smaller that those associated for the entire region covered by this rule. Further, while a SBF-cuttings discharge option with adequate controls is preferred over the zero discharge option for SBF-cuttings in U.S. Offshore waters, a SBF-cuttings discharge option with inadequate controls is not preferred over zero discharge. The retention limit is a very important control because it controls: (1) The amount of SBF discharged to the ocean; (2) the biodegradation rate of discharged SBF; and (3) the potential for SBF-cuttings to develop cuttings piles and mats which are detrimental to the benthic environment. In short, EPA does not view existing shale shaker technology (or performance of other technology equivalent to shale shaker technology) to constitute the appropriate level of control under BAT or BADT (NSPS).

EPA has also decided that solids accumulated at the end of the well (''accumulated solids'') and wash water used to clean out accumulated solids or on the drill floor are associated with drill cuttings and are therefore not controlled by the zero discharge requirement for SBFs not associated with drill cuttings (*see* Section V.C). EPA has decided to control accumulated solids and wash water under the discharge requirements for cuttings associated with SBFs. The amount of SBF base fluid discharged with discharged accumulated solids will be estimated using procedures in Appendix 7 to subpart A of 40 CFR part 435 and incorporated into the base fluid retained on cuttings numeric limitation or standard. The source of the pollutants in the accumulated solids and associated wash water are drill cuttings and drilling fluid solids (*e.g.,* barite). The drill cuttings and drilling fluid solids can be prevented from discharge with SBF-cuttings due to equipment design (*e.g.,* sand traps, sumps) or improper maintenance of the equipment (*e.g.,* failing to ensure the proper agitation of mud pits). EPA agrees with commentors that the discharge of SBF associated with accumulated solids in the SBF active mud system and the associated wash water is normally a one-time operation performed at the completion of the SBF well (*e.g.,* cleaning out mud pits and solids control equipment).

The quantity of SBF typically discharged with accumulated solids and wash water is relatively small. The SBF fraction in the 75 barrels of accumulated solids is approximately 25% and generally only very small quantities of SBF are contained in the 200 to 400 barrels of associated equipment wash water. Current practice is to retain accumulated solids for zero discharge or recover free oil from accumulated solids prior to discharge. Since current practice is to recover free oil and discharge accumulated solids, the controlled discharge option for SBF-cuttings represents current practice and is economically achievable. Moreover, recovering free oil from accumulated solids prior to discharge has no unacceptable NWQIs. EPA defines accumulated solids and wash water as associated with drill cuttings. Therefore, operators will control these SBF-cuttings wastes using the SBF stock limitations and cuttings discharge limitations. As compliance with EPA's SBF stock limitations and cuttings discharge limitations does not require the processing of all SBF-cuttings wastes through the solids control technologies (*e.g.,* shale shakers, cuttings dryers, fines removal units), operators may or may not elect to process accumulated solids or wash water through the solids control technologies.

EPA is also promulgating a set of BMPs for operators to use that demonstrates compliance with the numeric ROC limitation and therefore reduces the retort monitoring otherwise required to determine compliance with the numeric ROC limitation. This option combines the set of BMPs that represent current practice with BMPs that are associated with the use of improved solids control technology. This option is technologically available and economically achievable for the same reasons that apply to compliance with the ROC numerical limitations. Examples of BMPs that represent current practices are, for example, use of mud guns, proper mixing procedure, elimination of settling places for accumulated solids. Examples of BMPs associated with the use of the new solids control technology are, for example, operating cuttings dryers in accordance with the manufacturer's specifications and maintaining a certain mass flux. If operators elect to use this BMP option, they will be required to demonstrate compliance through limited retort monitoring of cuttings and additional BMP paperwork. Paperwork requirements are detailed in Appendix 7 of subpart A of 40 CFR part 435. Paperwork cost and burden estimates are detailed in Section IX.D of the preamble.

d. *Sediment Toxicity of SBF Discharged with Cuttings.* As originally proposed in February 1999 (64 FR 5491) and re-stated in April 2000 (65 FR 21557), EPA is today promulgating a BAT limitation to control the maximum sediment toxicity of the SBF discharged with cuttings. This BAT limitation controls the sediment toxicity of the SBF discharged with cuttings as a non-conventional pollutant parameter and as an indicator for other pollutants in the SBF discharged with cuttings. Some of the toxic, priority, and non-conventional pollutants in the SBF discharged with cuttings may include: (1) The base fluids such as enhanced mineral oils, internal olefins, linear alpha olefins, poly alpha olefins, paraffinic oils, C_{12}–C_{14} vegetable esters of 2-hexanol and palm kernel oil, ''low viscosity'' C_8 esters, and other oleaginous materials; (2) barite which is known to generally have trace contaminants of several toxic heavy metals such as mercury, cadmium, arsenic, chromium, copper, lead, nickel, and zinc; (3) formation oil which contains toxic and priority pollutants such as benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol; and (4) additives such as emulsifiers, oil wetting agents, filtration control agents, and viscosifiers.

The sediment toxicity of the SBF discharged with cuttings is measured by the modified sediment toxicity test (*i.e.,* ASTM E1367–92: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests With Marine and Estuarine Amphipods'' (incorporated by reference and available from ASTM, 100 Bar Harbor Drive, West Conshohocken, PA 19428), supplemented with the preparation procedure specified in Appendix 3 of subpart A of 40 CFR part 435) using a natural sediment or formulated sediment, 96-hour testing period, and *Leptocheirus plumulosus* as the test organism. EPA is today promulgating a sediment toxicity limitation for the SBF discharged with cuttings at the point of discharge that would only allow the discharge of SBF-cuttings using SBFs as toxic or less toxic, but not more toxic, than C_{16}–C_{18}

IOs SBFs. Alternatively, this limitation could be expressed in terms of a ''SBF sediment toxicity ratio'' which is defined as 96-hour LC_{50} of C_{16}–C_{18} internal olefins SBF divided by the 96-hour LC_{50} of the SBF being discharged with cuttings at the point of discharge. EPA is promulgating a SBF sediment toxicity ratio of less than 1.0.

EPA finds that the sediment toxicity test at the point of discharge is practical as an indicator of the sediment toxicity of the drilling fluid at the point of discharge. As previously stated, establishing discharge limits on toxicity encourages the use of less toxic drilling fluids and additives. The modifications to the sediment toxicity test include shortening the test to 96-hours. Shortening the test will allow operators to continue drilling operations while the sediment toxicity test is being conducted on the discharged drilling fluid. Moreover, discriminatory power is substantially reduced for the 10-day test on drilling fluid as compared to the 96-hour test (*i.e.,* the 10-day test is of lower practical use in determining whether a SBF is substantially different from OBFs). Finally, operators discharging WBFs are already complying with a biological test at the point of discharge, the 96-hour SPP toxicity test, which tests whole WBF aquatic toxicity using the test organism *Mysidopsis bahia.*

The promulgated sediment toxicity limitation would be achievable through product substitution. EPA anticipates that the base fluids meeting the sediment toxicity limitation would include vegetable esters, low viscosity esters, and internal olefins. The reference C_{16}–C_{18} IOs SBF will be formulated to meet the specifications in Table 1 and also contained in Appendix 8 of subpart A of 40 CFR part 435. The sediment toxicity discharge limitation is technically and economically achievable because it is based on currently available base fluids that can be used and are used across the wide variety of drilling situations found in U.S. offshore waters. EPA estimates minimal monitoring costs associated with this limitation. Additionally, the sediment toxicity discharge limitation will not lead to an increase of NWQIs.

TABLE 1.—PROPERTIES FOR REFERENCE C_{16}–C_{18} IOS SBF USED IN DISCHARGE SEDIMENT TOXICITY TESTING

Mud weight of SBF discharged with cuttings (pounds per gallon)	Reference C_{16}–C_{18} IOs SBF (pounds per gallon)	Reference C_{16}–C_{18} ISOs SBF synthetic to water ratio (%)
8.5–11	9.0	75/25
11–14	11.5	80/20
> 14	14.5	85/15
Plastic Viscosity (PV), centipoise (cP)		12–30
Yield Point (YP), pounds/100 sq. ft.		10–20
10-second gel, pounds/100 sq. ft.		8–15
10-minute gel, pounds/100 sq. ft.		12–30
Electrical stability, V		> 300

G. NSPS Technology Options Considered and Selected for Drilling Fluid Associated with Drill Cuttings

The general approach followed by EPA for developing NSPS options was to evaluate the best demonstrated SBFs and processes for control of priority toxic, non-conventional, and conventional pollutants. Specifically, EPA evaluated the technologies used as the basis for BPT, BCT and BAT. The Agency considered these options as a starting point when developing NSPS options because the technologies used to control pollutants at existing facilities are fully applicable to new facilities.

EPA has not identified any more stringent treatment technology option which it considered to represent NSPS level of control applicable to the SBF-cuttings wastestream. Further, EPA has made a finding of no barrier to entry based upon the establishment of this level of control for new sources. Therefore, EPA is promulgating that NSPS be established equivalent to BPT and BAT for conventional, priority, and non-conventional pollutants. EPA concluded that NSPS are technologically and economically achievable for the same reasons that BAT is available and BPT is practical. EPA also concluded that NWQIs are reduced under the selected NSPS for new wells due to the increased efficiency of SBF drilling.

EPA concluded that a zero discharge requirement for SBF-cuttings from new sources and the subsequent increased use of OBFs and WBFs would result in: (1) unacceptable NWQIs; and (2) more pollutant loadings to the ocean due to operators switching from SBFs to less efficient WBFs (*see* Sections II.B and V.F).

For the same reasons that the BAT limitations promulgated in today's rule are technologically and economically achievable, the promulgated NSPS are also technologically and economically achievable. EPA's analyses show that under the SBF zero discharge option for all areas as compared to current practice as a basis for new source standards there would be an increase of 3.4 million pounds of cuttings annually shipped to shore for disposal in NOW sites and an increase of 10.2 million pounds of cuttings annually injected. This zero discharge option would lead to an increase in annual fuel use of 18,067 BOE and an increase in annual air emissions of 528 tons. Finally, the SBF zero discharge option for the GOM would lead to an increase of 7.5 million pounds of WBF-cuttings being discharged to U.S. Offshore waters. This pollutant loading increase is a result of operators in U.S. Offshore waters (in the GOM) switching from efficient SBF drilling to less efficient WBF drilling. EPA found these levels of NWQIs unacceptable and rejected the NSPS zero discharge option for SBF-cuttings from new sources, except in Coastal Cook Inlet, Alaska.

H. PSES and PSNS Technology Options

EPA is not establishing pretreatment standards for the facilities covered by this rule. Based on information in the record, EPA has not identified any existing offshore or Cook Inlet coastal oil and gas extraction facilities that discharge SBF and SBF-cuttings to publicly owned treatment works (POTWs), nor are any new facilities projected to direct these wastes in such manner.

I. Best Management Practices (BMPs) to Demonstrate Compliance with Numeric BAT Limitations and NSPS for Drilling Fluid Associated with Drill Cuttings

Sections 304(e), 308(a), 402(a), and 501(a) of the CWA authorize the Administrator to prescribe BMPs as part of effluent limitations guidelines and standards or as part of a permit (*see* Section II.A.7). The BMP alternatives to numeric limitations and standards in this final rule are directed, among other things, at preventing or otherwise controlling leaks, spills, and discharges of toxic and hazardous pollutants in SBF cuttings wastes (*see* 65 FR 21569 for a list of the toxic and hazardous pollutants controlled by these BMPs).

As discussed in the April 2000 NODA (65 FR 21568), EPA considered three options for the final rule for the BAT limitation and NSPS controlling SBF retained on discharged cuttings: (1) A single numeric discharge limitation with an accompanying compliance test method; (2) allowing operators to choose either a single numeric discharge limitation with an accompanying compliance test method, or as an alternative, a set of BMPs that employs limited cuttings monitoring; or (3) allowing operators to choose either a single numeric discharge limitation with an accompanying compliance test method or an alternative set of BMPs that employ no cuttings monitoring. Under the third BMP option for SBF-cuttings (*i.e.,* cuttings discharged and not monitored), EPA also considered whether to require as part of the BMP option, the use of a cuttings dryer as representative of BAT/NSPS or to make the use of a cuttings dryer optional.

EPA selects the second BMP option (*i.e.,* allowing operators to choose either a single numeric discharge limitation with an accompanying compliance test method, or as an alternative, a set of BMPs that employs limited cuttings monitoring) in the final rule. EPA selects this option as it provides for a reasonable level of flexibility and is based on quantifiable performance measures. EPA analyses show that cuttings monitoring for the first third of the SBF footage drilled for a SBF well interval is a reliable indicator of the remaining two-thirds of the SBF-interval (*see* SBF Statistical Support Document; Docket No. W–98–26, Record No. III.B.a.18; Record No. III.B.b.15). Procedures for demonstrating compliance with the selected BMP option are given in Appendix 7 to subpart A of part 435.

For the final rule, EPA did not have enough data from across a wide variety of drilling conditions (*e.g.,* formation, water depth, rig size) to demonstrate that BMPs without cuttings monitoring are equivalent to a numeric ROC limitation or standard. EPA is also concerned that a set of BMPs without cuttings monitoring is not as objective to enforce. This is because with a numeric limitation or with the selected BMP option with reduced cuttings monitoring, operators will need to keep records demonstrating compliance with the numeric limitation. By contrast, under a BMP option with no numeric limit, there is no objective performance measure. This presents a particular problem offshore, where real-time inspections are not as practical as on land based industries. Therefore, EPA rejected the third BMP option and cuttings dryer sub-option for SBF-cuttings (*i.e.,* allowing operators to choose either a single numeric discharge limitation with an accompanying compliance test method or an alternative set of BMPs that employ no cuttings monitoring). EPA concluded that BMP option one and BMP option two demonstrate the same level of compliance with the well averaged ROC limitation and standard (*see* SBF Statistical Support Document). Therefore, EPA selected BMP option two over BMP option one to provide operators with greater flexibility to demonstrate compliance with the well averaged ROC limitation and standard.

The BMP option promulgated in this final rule includes information collection requirements that are intended to control the discharges of SBF in place of numeric effluent limitations and standards. These information collection requirements include, for example: (1) Training personnel; (2) analyzing spills that occur; (3) identifying equipment items that might need to be maintained, upgraded, or repaired; (4) identifying procedures for waste minimization; (4) performing monitoring (including the operation of monitoring systems) to establish equivalence with a numeric cuttings retention limitation and to detect leaks, spills, and intentional diversion; and (5) generally to periodically evaluate the effectiveness of the BMP alternatives.

BMP option two also requires operators to develop and, when appropriate, amend plans specifying how operators will implement BMP option two, and to certify to the permitting authority that they have done so in accordance with good engineering practices and the requirements of the final regulation. The purpose of those provisions is, respectively, to facilitate the implementation of BMP option two on a site-specific basis and to help the regulating authorities to ensure compliance without requiring the submission of actual BMP Plans. Finally, the recordkeeping provisions are intended to facilitate training, to signal the need for different or more vigorously implemented BMP alternatives, and to facilitate compliance assessment. Details on burden and cost estimates associated with these additional paperwork requirements are discussed in Section IX.D.

VI. Costs and Pollutant Reductions for Final Regulation

A. Compliance Costs

EPA has analyzed the compliance costs and incremental compliance costs or savings beyond current industry practices and requirements, as well as pollutant loadings and incremental loadings or reductions, EPA has performed these analyses for the Gulf of Mexico, offshore California, and coastal Cook Inlet, Alaska, for baseline (current) costs and three control option costs. (Compliance costs were not developed for other offshore regions in Alaska where oil and gas production activity exists because discharges of drill cuttings is not expected to occur in these areas.) The three technology-based options considered are: (1) BAT/NSPS Option 1 (controlled discharge option with discharges from the cuttings dryer and fines removal unit); (2) BAT/NSPS Option 2 (controlled discharge option with discharges from the cuttings dryer but not the fines removal unit); and (3) BAT/NSPS Option 3 (Zero Discharge Option). Compliance costs/savings and pollutant increases/reductions are based on: (1) Projected annual drilling activity in the three geographic regions; (2) model well volumes and waste characteristics; and (3) technology and monitoring costs.

The compliance cost analysis begins with the development of defined populations of wells on a regional and well-type basis, develops per-well estimates from an analysis of line-item costs, and then aggregates costs into total regional and well-type costs by applying per well costs to appropriate populations of wells. EPA estimates baseline compliance costs for current industry waste management practices and for compliance with each regulatory option. EPA then calculated incremental compliance costs, which reflect the difference between compliance costs for a regulatory option and baseline compliance costs and the net compliance costs or savings which incorporate the costs along with savings realized by recovering drilling fluids and more efficient drilling. Tables 2 and

3, for existing and new sources respectively, list the total annual baseline costs, compliance costs, incremental compliance costs, cost savings, and net incremental compliance costs, calculated for each geographic area and regulatory option.

1. Large Volume Discharges

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Table 2: Summary Annual Cost/Savings, Existing Sources (1999$/year)

Technology Basis	Cost (savings) in 1999$/year			
	Gulf of Mexico [wells/year]	Offshore California [wells/year]	Cook Inlet, Alaska [wells/year]	Total [wells/year]
Baseline/Current Practice Technology Costs:				
Discharge with 10.2% retention of SBF on cuttings	29,437,863 [201]	0 [0]	0 [0]	29,437,863 [201]
Zero Discharge via land disposal or onsite injection				
Current OBF-drilled wells	10,034,296 [67]	413,282 [2]	516,602 [2]	10,964,179 [71]
Current WBF-drilled wells	-- [857]	-- [5]	-- [4]	-- [866]
Total Baseline Costs per Area	**39,472,159** [1,125]	**413,282** [7]	**516,602** [6]	**40,402,042** [1,138]
WBF-Related Cost Savings:				Total per Technology:
BAT/NSPS 1: ROP-related rig cost savings	(33,280,000)	0	0	
Discharged WBF cost savings	(15,552,540)	0	0	**(48,832,540)**
BAT/NSPS 2: ROP-related rig cost savings	(33,280,000)	0	0	
Discharged WBF cost savings	(15,552,540)	0	0	**(48,832,540)**
BAT/NSPS 3: Zero Discharge				**0**
Technology Option Costs:				
BAT/NSPS 1: Discharge of SBF cuttings and fines	35,569,256 [264]	0 [0]	266,864 [1]	35,836,120 [265]
Zero Discharge via land disposal or onsite injection				
Projected OBF-drilled wells	5,992,961 [40]	413,282 [2]	349,706 [1]	6,755,969 [43]
Projected WBF-drilled wells	-- [803]	-- [5]	-- [4]	-- [812]
Total BAT/NSPS Option 1	**41,562,237** [1,107]	**413,282** [7]	**616,570** [6]	**42,592,088** [1,120]
BAT/NSPS 2: Discharge SBF cuttings/zero discharge fines	35,749,388 [264]	0 [0]	266,864 [1]	36,016,252 [265]
Zero Discharge via land disposal or onsite injection				
Projected OBF-drilled wells	5,992,981 [40]	413,282 [2]	349,706 [1]	6,755,969 [43]
Projected WBF-drilled wells	-- [803]	-- [5]	-- [4]	-- [812]
Total BAT/NSPS Option 2	**41,742,369** [1,107]	**413,282** [7]	**616,570** [6]	**42,772,221** [1,120]
BAT/NSPS Option 3: Zero Discharge of SBF	5,318,258 [11]	0 [0]	0 [0]	5,318,258 [12]
Zero Discharge via land disposal or onsite injection				
Projected OBF-drilled wells	62,886,162 [237]	413,282 [2]	516,602 [2]	63,816,045 [241]
Projected WBF-drilled wells	-- [877]	-- [5]	-- [4]	-- [886]
Total BAT/NSPS Option 3	**68,204,419** [1,125]	**413,282** [7]	**516,602** [6]	**69,134,303** [1,138]

Technology Basis	Cost (savings) in 1999$/year			
	Gulf of Mexico [wells/year]	Offshore California [wells/year]	Cook Inlet, Alaska [wells/year]	Total [wells/year]
Incremental Compliance Costs (total annual):				
BAT/NSPS 1: Discharge of SBF cuttings and fines	2,090,078	0	99,968	**2,190,046**
BAT/NSPS 2: Discharge SBF cuttings; zero discharge fines	2,270,210	0	99,968	**2,370,178**
BAT/NSPS 3: Zero Discharge	28,732,260	0	0	**28,732,260**
NET Incremental Annual Compliance Costs (Savings):				
BAT/NSPS 1: Discharge SBF cuttings and fines	(46,742,462)	0	99,968	**(46,642,494)**
BAT/NSPS 2: Discharge SBF cuttings/zero discharge fines	(46,562,330)	0	99,968	**(46,462,362)**
BAT/NSPS 3: Zero Discharge	28,732,260	0	0	**28,732,260**

Table 3: Summary Annual Cost/Savings, New Sources (1999$/year)

Technology Basis	Cost (savings) in 1999$/year
	Gulf of Mexico [wells/year-wpy]
Baseline/Current Practice Technology Costs:	
Discharge with 10.2% retention of SBF on cuttings	2,152,540 [20 wpy]
Zero Discharge via land disposal or onsite injection	
Current OBF-drilled wells	221,430 [2 wpy]
Current WBF-drilled wells	-- [38 wpy]
Total Baseline Costs	**2,373,970** [60 wpy]
WBF-Related Cost Savings:	
BAT/NSPS 1: ROP-related rig cost savings	(1,440,000)
Discharged WBF cost savings	(683,505)
Total WBF-Related Cost Savings	**(2,123,505)**
BAT/NSPS 2: ROP-related rig cost savings	(1,440,000)
Discharged WBF cost savings	(683,505)
Total WBF-Related Cost Savings	**(2,123,505)**
BAT/NSPS 3: Zero Discharge	**0**

Technology Basis	Cost (savings) in 1999$/year Gulf of Mexico [wells/year-wpy]
Technology Option Costs:	
BAT/NSPS 1: Discharge of SBF cuttings and fines	1,902,672 [24 wpy]
Zero Discharge via land disposal or onsite injection	
Projected OBF-drilled wells	110,715 [1 wpy]
Projected WBF-drilled wells	-- [35 wpy]
Total BAT/NSPS Option 1	**2,013,387** [60 wpy]
BAT/NSPS 2: Discharge SBF cuttings/zero discharge fines	1,906,776 [24 wpy]
Zero Discharge via land disposal or onsite injection	
Projected OBF-drilled wells	110,715 [1 wpy]
Projected WBF-drilled wells	-- [35 wpy]
Total BAT/NSPS Option 2	**2,017,491** [60 wpy]
BAT/NSPS 3: Zero Discharge of SBF	710,889 [3 wpy]
Zero Discharge via land disposal or onsite injection	
Projected OBF-drilled wells	2,039,092 [15 wpy]
Projected WBF-drilled wells	-- [42 wpy]
Total BAT/NSPS Option 3	**2,749,981** [60 wpy]
Incremental Compliance Costs (total annual):	
BAT/NSPS 1: Discharge of SBF cuttings and fines	**(360,583)**
BAT/NSPS 2: Discharge SBF cuttings; zero discharge fines	**(356,479)**
BAT/NSPS 3: Zero Discharge	**376,011**
NET Incremental Annual Compliance Costs (Savings):	
BAT/NSPS 1: Discharge SBF cuttings and fines	**(2,484,088)**
BAT/NSPS 2: Discharge SBF cuttings/zero discharge fines	**(2,479,984)**
BAT/NSPS 3: Zero Discharge	**376,011**

2. Small Volume Discharges

As previously stated, EPA learned that SBF is controlled with zero discharge at the drill floor, in the form of vacuums and sumps to retrieve spilled fluid and associated wash water. EPA also learned that approximately 75 barrels of fine solids and barite, which have an approximate SBF content of 25%, can accumulate in the dead spaces of the mud pit, sand trap, and other equipment in the drilling fluid circulation system. Current practice is to either wash these solids out with water for overboard discharge, or to retain the waste solids for disposal. Several hundred barrels (approximately 200 to 400 barrels) of water are used to wash out the mud pits. Industry representatives also indicated to EPA that those oil and gas extraction operations that discharge wash water and accumulated solids first recover free SBF.

No additional costs were considered for controlling the minor spills of SBF (*e.g.*, < 5 gallons spilled during each drill string connection or disconnection) at the drill floor as: (1) Zero discharge practices for recovering SBF at the drill floor during drilling are the current practice; and (2) current practice is also to recover free SBF from the wash water used at the drill floor. Additionally, since current practice is to first recover free SBF from accumulated solids and discharge the accumulated solids with wash water, no additional costs were

considered for controlling these discharges.

EPA did not select zero discharge for management of these accumulated solids and associated wash water. EPA is defining these wastes as being associated with SBF-cuttings and subject to the same requirements as other SBF discharges associated with SBF-cuttings. In particular, the final rule requires operators to first recover free oil from any accumulated solids or associated wash water prior to discharging the accumulated solids and associated wash water. These practices are related to the current BPT limitations (*i.e.,* no discharge of free oil) and current industry practice using solids control equipment in order to comply with the no free oil (sheen test) and SPP toxicity requirements. Accordingly, the requirement to recover free oil from accumulated solids and associated wash water prior to discharge is technologically and economically achievable with no additional NWQIs. Retort monitoring will also be performed on the accumulated solids and the retort monitoring results will be incorporated into the overall well-average SBF retained on cuttings value as described in Appendix 7 of Subpart A of 40 CFR 435.

B. Pollutant Reductions

The methodology for estimating pollutant loadings and incremental pollutant loadings (reductions) effectively parallels that of the compliance cost analysis. The pollutant loadings analysis uses data from EPA and industry sources that quantify the pollutant characteristics of drilling fluids and cuttings waste streams (typically in, or converted to, a per barrel basis). Waste volumes for the four model well types (DWD, DWE, SWD, SWE) are coupled with these per barrel pollutant quantities to obtain per well estimates of pollutant loadings. These per well estimates are then coupled with the same well count data as used in the cost analysis to derive well type and aggregate regional pollutant loadings for the baseline and all options. Similar to the cost analysis, incremental loadings (or removals) are obtained by difference between the estimated loadings of each option less baseline loadings, at both the BAT and NSPS level of control. This methodology is presented in more detail in the SBF Development Document.

The loadings and non-water quality impacts of wastes subject to zero discharge limitations by this rule are important factors in its development. Zero discharge wastes have two fates: they are injected into sub-seabed formations onsite or they are transported to shore for disposal via land farming or injection. The allocation of zero discharge wastes between onsite injection versus onshore disposal follow the same well type and regional assumptions as were used for the cost analysis. Zero discharge loadings (removals) are determined identically to discharge loadings; they are presented in detail in the Development Document and are summarized below.

Table 4 presents a summary of industry-wide results, by region, for BAT baseline loadings, both discharge options, and the zero discharge option, as well as their incremental loadings (removals). Table 5 presents this information for new sources.

The BCT cost test evaluates the reasonableness of BCT candidate technologies as measured from BPT level compliance costs and pollutant reductions. The proposed BCT level of regulatory control is equivalent to the BPT level of control for both the discharge options and the zero discharge option. If there is no incremental difference between BPT and BCT, there is no cost to BCT and thus the option passes both BCT cost tests.

Table 4: Summary Annual SBF Pollutant Loadings, Existing Sources (lbs/year)

Technology Basis	SBF Pollutant Loadings (reductions) in pounds/year [wells/year-wpy]			
	Gulf of Mexico	Offshore California	Cook Inlet, Alaska	Total
Baseline/Current Practice Technology Loadings:				
Discharge with LTA of 10.2% SBF ROC	237,890,828 [201 wpy]	NA	NA	237,890,828 [201 wpy]
Discharge of WBF and cuttings	2,093,084,293 [857 wpy]	9,617,040 [5 wpy]	8,407,772 [4 wpy]	2,111,109,104 [866 wpy]
Discharge of OBF	0 [67 wpy]	0 [2 wpy]	0 [2 wpy]	0 [71 wpy]
Total Baseline Loadings per Area	2,330,975,121 [1,125 wpy]	9,617,040 [7 wpy]	8,407,772 [6 wpy]	2,348,999,932 [1,138 wpy]
Technology Option Loadings:				
BAT/NSPS Option 1				
Discharge with LTA of 4.03% SBF ROC	259,628,314 [264 wpy]	0 [0 wpy]	552,796 [1 wpy]	260,181,110 [265 wpy]
Discharge of WBF and cuttings	1,963,501,883 [803 wpy]	9,617,040 [5 wpy]	8,407,772 [4 wpy]	1,981,526,694 [812 wpy]
Discharge of OBF	0 [40 wpy]	0 [2 wpy]	0 [1 wpy]	0 [43 wpy]
Total BAT/NSPS Option 1 Loadings per Area	2,223,130,197 [1,107 wpy]	9,617,040 [7 wpy]	8,960,568 [6 wpy]	2,241,707,804 [1,120 wpy]
BAT/NSPS Option 2				
Discharge with LTA of 3.82% SBF ROC	252,066,749 [264 wpy]	0 [0 wpy]	536,696 [1 wpy]	252,603,445 [265 wpy]
Discharge of WBF and cuttings	1,963,501,883 [803 wpy]	9,617,040 [5 wpy]	8,407,772 [4 wpy]	1,981,526,804 [812 wpy]
Discharge of OBF	0 [40 wpy]	0 [2 wpy]	0 [1 wpy]	0 [43 wpy]
Total BAT/NSPS Option 2 Loadings per Area	2,215,568,632 [1,107 wpy]	9,617,040 [7 wpy]	8,944,468 [6 wpy]	2,234,130,139 [1,120 wpy]
BAT/NSPS Option 3 - Zero Discharge				
Discharge of SBF on cuttings	0 [11 wpy]	0 [0 wpy]	0 [1 wpy]	0 [12 wpy]
Discharge of WBF and cuttings	2,144,121,984 [877 wpy]	9,617,040 [5 wpy]	8,407,772 [4 wpy]	2,162,146,796 [886 wpy]
Discharge of OBF	0 [237 wpy]	0 [2 wpy]	0 [1 wpy]	0 [240 wpy]
Total BAT/NSPS Option 3 Loadings per Area	2,144,121,984 [1,125 wpy]	9,617,040 [7 wpy]	8,407,772 [6 wpy]	2,162,146,796 [1,138 wpy]
Incremental Technology Option Loadings (Reductions):				
BAT/NSPS Option 1				(107,292,128)
BAT/NSPS Option 2				(114,869,793)
BAT/NSPS Option 3- Zero Discharge				(186,853,137)

Note: The following terms are used in this table: long-term average (LTA) and retention on cuttings (ROC)

TABLE 5.—SUMMARY ANNUAL SBF POLLUTANT LOADINGS, NEW SOURCES

[In pounds/year]

Technology basis	SBF pollutant loadings (reductions)—Gulf of Mexico
Baseline/Current Practice Technology Loadings:	
Discharge with LTA of 10.2% SBF ROC	17,405,127
Discharge of WBF and cuttings	92,903,606
Discharge of OBF	0
Total Baseline Loadings	110,308,733
Technology Option Loadings:	
BAT/NSPS Option 1.	
Discharge with LTA of 4.03% SBF ROC	20,241,106
Discharge of WBF and cuttings	87,462,923
Discharge of OBF	0
Total NSPS 1 Loadings	107,704,029
BAT/NSPS Option 2.	
Discharge with LTA of 3.82% SBF ROC	19,722,488
Discharge of WBF and cuttings	87,462,923
Discharge of OBF	0
Total NSPS 2 Loadings	107,185,411
BAT/NSPS Option 3—Zero Discharge.	
Discharge of SBF	0
Discharge of WBF and cuttings	100,387,607
Discharge of OBF	0
Total NSPS 3 Loadings	100,387,607
Incremental Technology Option Loadings (Reductions):	
BAT/NSPS Option 1: Discharge with 4.03% retention of SBF on cuttings	(2,604,704)
BAT/NSPS Option 2: Discharge with 3.82% retention of SBF on cuttings	(3,123,322)
BAT/NSPS Option 3: Zero Discharge of SBF-wastes via land disposal or onsite injection	(9,921,126)

NOTE: EPA estimates the following GOM WBF/OBF/SBF new sources: Baseline—38/2/20; BAT/NSPS Option 1 & 2—35/1/24; and BAT/NSPS Option 3—42/15/3. EPA estimates no new sources for Offshore California or Cook Inlet, AK.

NOTE: The following terms are used in this table: long-term average (LTA) and retention on cuttings (ROC).

VII. Economic Impacts of Final Regulation

EPA evaluated the economic effects of the options considered for today's regulation. The methodology and results are presented in detail in the SBF Economic Analysis (EPA–821–B–00–012). The following discussion presents a summary of that analysis and its conclusions. Small business impacts are summarized below and in Section IX.B. Environmental justice issues are summarized in Section IV.C.

A. Impacts Analysis

EPA examined the potential impacts of the rule several ways: effects on drilling well costs, changes to financial performance of drilling facilities and production, impacts on small firms, and secondary impacts. The economic methodology used to examine potential impacts on drilling well costs, firms, and secondary impacts is the same as that used for the February 1999 proposal (*see* 64 FR 5521–5527; February 1999 proposal Economic Analysis (EPA–821–B–98–020)).

In response to comments and new data, EPA developed a series of economic models for existing and new deep water projects in the Gulf of Mexico similar to those used for the Offshore and Coastal rules (*see* 58 FR 12454–12512 and 61 FR 66086–66130). This additional analysis is discussed in the April 2000 NODA (65 FR 21558). The models focus on the deep water Gulf because it is the region with the highest level of current drilling with and future interest in drilling with SBFs. The economic models are based on a cash flow approach. Revenues are based on an assumed price of oil, current and projected production of oil and gas, well production decline rates, and royalty rates. Operating costs are based on an assumed cost per BOE produced. The models are based on data from MMS and industry (*see* Summary of Data to be Used In Economic Modeling for more details on the methodology, data, and parameters on which the models are based and how the models were constructed (Docket No. W–98–26, Section III.G of the Rulemaking Record)) and SBF Economic Analysis, Appendix A. EPA received no comments on this NODA with respect to the economic methodology or the data.

The costs and revenues are compared yearly and the project is assumed to run for 30 years or to shut in when operating costs exceed revenues. That is, the economic models have differing lifetimes according to project characteristics and each model may have a shortened lifetime as a result of incremental costs. The model then calculates the lifetime of the project, total production, and the net present value of the operation (net income of the operation over the life of the project in terms of today's dollars), which includes the net operating earnings, taxes, expenditures on drilling, other capital expenditures, etc. A positive net present value means that the project is a good investment. In these cases, the return is greater than the discount rate,

which represents the opportunity cost of capital. If the net present value is negative, it means that money would have been better invested elsewhere. For existing projects, the model uses current operations; all expenditures in prior years, such as exploration, delineation, and infrastructure development costs are considered sunk costs and are not addressed. For new projects, the model uses data and parameters about timing of the various phases of exploration, delineation and development, along with cost estimates about costs incurred during these phases to compute a full lifetime financial model of these projects.

Each model is run twice—with and without the change due to pollution control. The models support changes in both directions—*i.e.,* costs or savings. If a model shows the net present value of a project to be positive in the baseline, but would have a negative net present value under any of the regulatory options, some or all of the wells would not be drilled. This difference between baseline and postcompliance would generate production impacts.

The likely outcome of today's rule is an overall savings associated with the ability to discharge SBF cuttings (*see* Section VI.A). The cost model (which provides the input to the economic models) projects that the savings exceed any incremental costs of compliance in the aggregate. EPA does not expect the alternate higher ROC limitation and standard for drilling fluids with the stock base fluid performance of esters to affect costs. EPA expects that operators will likely use ester-based SBFs for the increased flexibility and not for any economic benefits. The results of the economic models indicate no adverse impacts on drilling well costs (exploratory or developmental), project lifetime, or production for both BAT and NSPS projects. There are no adverse impacts on firms, employment, trade, or inflation.

B. Small Business Analysis

Although today's rule will not have a significant economic impact on a substantial number of small entities (*see* Section VII.A), EPA assessed the impacts of the rule on small businesses. The small business analysis is described more fully in Chapter 6 of the SBF Economic Analysis.

The small business definitions and the methodology were outlined in the April 2000 NODA and the February 1999 Proposal Economic Analysis and have not changed. Briefly, EPA relied on the Small Business Administration's size standards to determine whether a firm is a small business. If EPA could not find employment or revenue data to confirm a firm's size, it was classified as ''potentially'' small. EPA identified 40 small and potentially small firms. As noted in the previous paragraph, today's rule results in cost savings, and EPA projects no adverse impacts on small businesses.

VIII. Water Quality and Non-Water Quality Environmental Impacts of Final Regulation

A. Overview of Water Quality and Non-Water Quality Environmental Impacts

EPA conducted various analyses to assess the impact of the final regulation on water quality, sediment quality, and human health. In general, EPA has found that no adverse impacts are expected from controlled discharges of SBFs.

B. Water Quality Modeling

In order to assess the impacts of potential SBF discharges to the receiving waters, EPA conducted pore water, water column, and sediment guidelines analyses. EPA calculated pollutant concentrations for both the water column and pore water and compared them to the respective EPA recommended marine water quality criteria or to applicable state standards to determine the nature and magnitude of any projected water quality exceedances. Details of the analyses and results are presented in the final SBF Environmental Assessment.

EPA included the discharge of WBFs in the engineering analyses (*see* Section II.A). Environmental impacts such as water column, pore water, fish tissue and human health risk analyses were not estimated for the discharge of WBFs versus the use and discharge of SBF cuttings. However, industry has provided information that drilling is significantly more efficient using SBFs rather than WBFs because hole volumes with SBFs are approximately 1.8 times smaller. Therefore, the pollutant loadings of appropriately controlled SBF discharge are less than pollutant loadings associated with controlled WBF discharge.

1. Water Column Water Quality Analyses

There are no water quality criteria exceedances in the water column for any of the regulatory options being considered including the ROC option based on data from all four cuttings dryer technologies for drilling fluids with the sediment toxicity and biodegradation characteristics of ester-based SBFs which results in a slightly higher LTA. Also, no Alaska state water quality standards are exceeded under the discharge options in Cook Inlet, Alaska.

2. Pore Water Quality Analyses

As described above in Section III.D.1, the addition of several seabed survey data changed the estimated SBF sediment concentration at 100 meters (328 feet) as used in the pore water quality analyses. The revised analyses estimate that baseline (or BPT) pore water pollutant concentrations at 100 meters from the discharge exceed recommended water quality criteria for the heavy metal, chromium, for two model well types, shallow water exploratory and deep water exploratory. There are no pore water exceedances of any of the Alaska state water quality standards for potential Cook Inlet, Alaska discharges. Also, there are no pore water exceedances under the controlled SBF discharges (*i.e.,* BAT/NSPS Options 1 and 2) including the ROC option based on data from all four cuttings dryer technologies for drilling fluids with the sediment toxicity and biodegradation characteristics of ester-based SBFs which results in a slightly higher LTA.

3. Sediment Guidelines Analyses

The EPA proposed sediment guidelines for the protection of benthic organisms assesses potential benthic impacts of certain metals. The revised analyses, based on revised pore water concentrations, result in 2 exceedances only under the baseline (or BPT) conditions. There are no sediment guidelines exceedances under controlled SBF discharge conditions (*i.e.,* BAT/NSPS Options 1 and 2) including the ROC option based on data from all four cuttings dryer technologies for drilling fluids with the sediment toxicity and biodegradation characteristics of ester-based SBFs which results in a slightly higher LTA.

C. Human Health Effects Modeling

The human health risk analyses were revised to incorporate changes to the fish consumption rates (*see* Section III.D.b). The revised analyses show no risk to human health.

D. Seabed Surveys

EPA reviewed the seabed surveys submitted during public comment to the April 2000 NODA. As previously stated, EPA used data from two surveys drilling six wells with SBFs in the environmental assessment analyses. Additionally, EPA also received information on the on-going joint Industry/MMS GOM seabed survey. The Industry/MMS workgroup has

completed the first two cruises of the four cruise study (*see* Section III.D.1). Outside of a 50–100′ radius from the drilling facility, no visible cuttings accumulations (large or small) were detected at any of the drilling facility survey sites.

E. Energy Impacts

As described in Sections III.E and IV.E, EPA included additional data and revised several parameters in estimating energy impacts of the final SBF rule. EPA estimated the amount of fuel required, expressed as barrels of oil equivalents per year (BOE/yr), to operate the equipment associated with each of the regulatory options as well as the fuel consumed by daily rig operations. EPA also estimated the current energy requirements of WBF discharge in order to determine the relative decrease in impacts of SBF versus WBF use. EPA does not expect the alternate higher ROC limitation and standard for drilling fluids with the stock base fluid performance of esters to affect energy impacts because equipment used under the ester option (*e.g.,* shale shakers, cuttings dryer, fines removal unit) has the same or similar energy requirements. The results of the energy impact analysis are presented in Tables 6 and 7 for existing and new sources, respectively.

TABLE 6.—INCREMENTAL SUMMARY ANNUAL ENERGY IMPACTS, EXISTING SOURCES

Technology basis	Energy impacts: Reductions (Increases)[a] fuel use (BOE/yr)			
	Gulf of Mexico	Offshore California	Cook Inlet, AK	Total
BAT/NSPS Option 1: Discharge with LTA of 4.03% SBF ROC	202,146	0	19	202,165
BAT/NSPS Option 2: Discharge with LTA of 3.82% SBF ROC	195,124	0	0	195,124
BAT/NSPS Option 3: Zero Discharge of SBF-wastes via land disposal or onsite injection	(346,459)	(6,138)	(6,067)	(358,664)

[a] Annual fuel usage reductions or increases are incremental to baseline/current practice (*i.e.,* discharge of SBF-cuttings at 10.2% ROC in the GOM and zero discharge in Offshore California and Cook Inlet, AK).

Note: BOE = Barrels of Oil Equivalent.

Note: The following terms are used in this table: long-term average (LTA) and retention on cuttings (ROC).

TABLE 7.—INCREMENTAL SUMMARY ANNUAL ENERGY IMPACTS, NEW SOURCES

Technology basis	Energy impacts: Reductions (increases)[a] fuel use (BOE/yr)
BAT/NSPS Option 1: Discharge with LTA of 4.03% SBF ROC	6330
BAT/NSPS Option 2: Discharge with LTA of 3.82% SBF ROC	5693
BAT/NSPS Option 3: Zero Discharge of SBF-wastes via land disposal or onsite injection	(18,067)

[a] Annual fuel usage reductions or increases are incremental to baseline/current practice (*i.e.,* discharge of SBF-currings at 10.2% ROC in the GOM).

Note: BOE = Barrels of Oil Equivalent.

Note: The following terms are used in this table: long-term average (LTA) and retention on cuttings (ROC).

Note: EPA estimates no new sources for Offshore California or Cook Inlet, AK.

F. Air Emission Impacts

EPA calculated the air emissions, expressed as short tons per year, resulting from activities associated with each of the regulatory options. Air emissions are a function of the: (1) Type of fuel burned (*e.g.,* natural gas or diesel); and (2) amount of fuel consumed as determined from the length of equipment operation and the fuel consumption rate. The methodology and modeling parameters parallel that of the energy impact analysis as the amount of fuel consumed is the basis for the air emissions analysis. Therefore, the air emissions analysis includes the estimate of emissions of daily rig operations and an estimate of WBF drilling operation air emissions. EPA does not expect the alternate higher ROC limitation and standard for drilling fluids with the stock base fluid performance of esters to affect air emissions because equipment used under the ester option (*e.g.,* shale shakers, cuttings dryer, fines removal unit) has the same or similar air emissions. The results of the air emission analysis are presented in Tables 8 and 9 for existing and new sources, respectively.

TABLE 8.—INCREMENTAL SUMMARY ANNUAL AIR EMISSIONS, EXISTING SOURCES

Technology basis	Annual Air Emission Reductions (Increases)[a] (tons/yr)			
	Gulf of Mexico	Offshore California	Cook Inlet, AK	Total
BAT/NSPS Option 1: Discharge with LTA of 4.03% SBF ROC	3,172	0	0	3,172
BAT/NSPS Option 2: Discharge with LTA of 3.82% SBF ROC	3,074	0	(1)	3,073
BAT/NSPS Option 3: Zero Discharge of SBF-wastes via land disposal or onsite injection	(5,414)	(94)	(94)	(5,602)

[a] Annual air emissions reductions or increases are incremental to baseline/current practice (i.e., discharge of SBF-cuttings at 10.2% ROC in the GOM and zero discharge in Offshore California and Cook Inlet, AK).

Note: 1 ton = 2000 lbs.

Note: The following terms are used in this table: long-term average (LTA) and retention cuttings (ROC).

TABLE 9.—INCREMENTAL SUMMARY AIR EMISSIONS, NEW SOURCES—GULF OF MEXICO

Technology basis	Annual air emissions reduction (increases) [a] (tons/yr)
BAT/NSPS Option 1: Discharge with LTA of 4.03% SBF ROC	(136)
BAT/NSPS Option 2: Discharge with LTA of 3.82% SBF ROC	(145)
BAT/NSPS Option 3: Zero Discharge of SBF-wastes via land disposal or onsite injection	(528)

[a] Annual air emissions reductions or increases are incremental to baseline/current practice (i.e., discharge of SBF-cuttings at 10.2% ROC in the GOM).

Note: 1 ton = 2000 lbs.
Note: The following terms are used in this table: long-term average (LTA) and retention on cuttings (ROC).
Note: EPA estimates no new sources for Offshore California or Cook Inlet, AK.

G. Air Emissions Monetized Human Health Benefits

EPA estimated emissions associated with each of the regulatory options as part of the NWQI analyses. The pollutants considered in the NWQI analyses are nitrogen oxides (NO_X), volatile organic carbon (VOC), particulate matter (PM), sulfur dioxide (SO_2), and carbon monoxide (CO). Of these pollutants, EPA monetized the human health benefits or impacts associated with VOC, PM, and SO_2 emissions using the methodology presented in the Environmental Assessment of the Final Effluent Limitations Guidelines and Standards for the Pharmaceutical Manufacturing Industry (EPA–821–B–98–008). Each of these pollutants have human health impacts and reducing these emissions can reduce these impacts.

Several VOCs exhibit carcinogenic and systemic effects and VOCs, in general, are precursors to ground-level ozone, which negatively affects human health and the environment. PM impacts include aggravation of respiratory and cardiovascular disease and altered respiratory tract defense mechanisms. SO_2 impacts include nasal irritation and breathing difficulties in humans and acid deposition in aquatic and terrestrial ecosystems.

The unit values (in 1990 dollars) are $489 to $2,212 per megagram (Mg) of VOC; $10,823 per Mg of PM; and $3,516 to $4,194 per Mg of SO_2. Using the Engineering News Record Construction Cost Index (*see* www.enr.com/cost/costcci.asp) these conversion factors are scaled up using the ratio of 6060:4732 (1999$:1990$). EPA does not expect the alternate higher ROC limitation and standard for drilling fluids with the stock base fluid performance of esters to affect monetized benefits because equipment used under the ester option (*e.g.,* shale shakers, cuttings dryer, fines removal unit) has the same or similar air emissions. Following is a summary of the monetized benefits for each of the regulatory options for both existing and new sources.

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Table 10: Summary of Monetized Human Health Benefits or Impacts Associated with VOC, PM, and SO_2 Emissions, Existing Sources (1999$/yr)

	Criteria Air Pollutant		
	VOC	**PM**	**SO_2**
Baseline/Current Practice Air Emissions, Mg/yr:			
Discharge with 10.2% retention of SBF on cuttings	23,635	3,460	3,006
Zero Discharge (current OBF wells only)	847	126	109
Total Baseline Air Emissions, Mg/yr	24,482	3,586	3,115
Compliance Air Emissions, Mg/yr:			
(1) Discharge with 4.03% retention of SBF on cuttings	21,960	3,222	2,799
(2) Discharge with 3.82% retention of SBF on cuttings	21,980	3,226	2,803
(3) Zero Discharge [a]	24,919	3,654	3,175
Incremental Compliance Emission Reductions (Increases), Mg/yr:			
(1) Discharge with 4.03% retention of SBF on cuttings	2,522	364	316
(2) Discharge with 3.82% retention of SBF on cuttings	2,502	360	312
(3) Zero Discharge [a]	(437)	(68)	(59)
Unit Value of Poll. Reductions, 1990$/Mg: [b]	489 to 2,212	10,823	3,516 to 4,194
Unit Value of Poll. Reductions, 1999$/Mg: [c]	626 to 2,833	13,860	4,503 to 5,371
Incremental Compliance Benefits (Costs), 1998$/yr:			
(1) Discharge with 4.03% retention of SBF on cuttings	1,579,429 to 7,144,576	5,049,778	1,423,174 to 1,697,608
(2) Discharge with 3.82% retention of SBF on cuttings	1,566,817 to 7,087,524	4,991,937	1,406,834 to 1,678,118
(3) Zero Discharge [a]	(273,777) to (1,238,434)	(948,091)	(267,560) to (319,154)

[a] via land disposal or on-site offshore injection

[b] conversion factors from *Environmental Assessment of the Final Effluent Limitations Guidelines and Standards for the Pharmaceutical Manufacturing Industry* (EPA-821-B-98-008)

[c] scaled from 1990$ using the Engineering News Record Construction Cost Index

Table 11: Summary of Monetized Human Health Benefits or Impacts Associated with VOC, PM, and SO_2 Emissions, New Sources (1999$/yr)

	Criteria Air Pollutant		
	VOC	PM	SO_2
Baseline/Current Industry Practice Air Emissions, Mg/yr:			
Discharge with 10.2% retention of SBF on cuttings	589	86	75
Compliance Air Emissions, Mg/yr:			
(1) Discharge with 4.03% retention of SBF on cuttings	813	119	104
(2) Discharge with 3.82% retention of SBF on cuttings	913	134	117
(3) Zero Discharge [a]	998	146	127
Incremental Compliance Emission Reductions (Increases), Mg/yr:			
(1) Discharge with 4.03% retention of SBF on cuttings	(224)	(33)	(29)
(2) Discharge with 3.82% retention of SBF on cuttings	(323)	(48)	(41)
(3) Zero Discharge [a]	(409)	(60)	(52)
Unit Value of Poll. Reductions, 1990$/Mg: [b]	489 to 2,212	10,823	3,516 to 4,194
Unit Value of Poll. Reductions, 1999$/Mg: [c]	626 to 2,833	13,860	4,503 to 5,371
Incremental Compliance Benefits (Costs), 1998$/yr:			
(1) Discharge with 4.03% retention of SBF on cuttings	(140,269) to (634,508)	(453,927)	(128,265) to (152,999)
(2) Discharge with 3.82% retention of SBF on cuttings	(202,421) to (915,655)	(658,885)	(186,271) to (222,190)
(3) Zero Discharge [a]	(256,052) to (1,158,253)	(831,151)	(234,472) to (279,686)

[a] via land disposal or on-site offshore injection

[b] conversion factors from *Environmental Assessment of the Final Effluent Limitations Guidelines and Standards for the Pharmaceutical Manufacturing Industry* (EPA-821-B-98-008)

[c] scaled from 1990$ using the Engineering News Record Construction Cost Index

H. Solid Waste Impacts

EPA calculated the amount of waste cuttings that would be land disposed, injected onshore, and/or injected onsite in each regulatory scenario, and determined that there would be a considerable reduction in the amount of drill cuttings land disposed and injected with the implementation of a controlled discharge option for SBF-cuttings.

EPA's analyses show that under the SBF-cuttings zero discharge option as compared to current practice, for U.S. Offshore waters existing sources, there would be an annual increase of 35 million pounds of cuttings shipped to shore for disposal in non-hazardous oilfield waste (NOW) sites and an increase of 166 million pounds of cuttings injected. In addition, under the SBF-cuttings zero discharge option, operators would use the more toxic OBFs. The zero discharge option for SBF-cuttings would lead to an increase in annual fuel usage of 358,664 BOE and an increase in annual air emissions of 5,602 tons. Finally, the SBF-cuttings zero discharge option in the U.S. Offshore waters would lead to an increase of 51 million pounds of WBF cuttings being discharged to U.S. Offshore waters. This pollutant loading increase is a result of GOM operators switching from efficient SBF drilling to less efficient WBF drilling.

Additionally, EPA's analyses show that under the SBF-cuttings zero discharge option as compared to current practice, for GOM new sources, there would be an annual increase of 3.4 million pounds of drill cuttings shipped to shore for disposal in NOW sites and an increase of 10.2 million pounds of drill cuttings injected. These zero discharge options for SBF-cuttings would lead to an increase in annual fuel use of 18,067 BOE and an increase in annual air emissions of 528 tons. Finally, the SBF-cuttings zero discharge option in the GOM would lead to an increase of 7.5 million pounds of WBF-cuttings being discharged to U.S. Offshore waters. Again, this pollutant loading increase is a result of GOM operators switching from efficient SBF drilling to less efficient WBF drilling.

I. Other Factors

EPA also considered the impact of the effluent limitations guidelines and

standards on safety. EPA has identified two safety issues related to drilling fluids: (1) Deleterious vapors generated by organic materials in drilling fluids; and (2) waste hauling activities that increase the risk of injury to workers.

1. Vapors Generated by Organic Materials in Drilling Fluids

One of the key concerns in exploration and production projects is the exposure of wellsite personnel to vapors generated by organic materials in drilling fluids (Docket No. W–98–26, Record No. III.D.12). Areas on the drilling location with the highest exposure potentials are sites near solids control and open pits. These areas are often enclosed in rooms and ventilated to prevent unhealthy levels of vapors from accumulating. If the total volume of organic vapors can be reduced then any potential health effects will also be reduced regardless of the nature of the vapors.

Generally speaking the aromatic fraction of the vapors is the most toxic to the mammalian system. The high volatility and absorbability through the lungs combined with their high lipid solubility serve to increase their toxicity. OBFs have a high aromatic content and vapors generated from using these drilling fluids include aromatics (*e.g.,* alkybenzenes, naphthalenes, and alkyl-naphthalenes), alkanes (*e.g.,* C_7–C_{18} straight chained and branched), and alkenes. Some minerals oils also generate vapors that contain the same types of chemical compounds, but generally at lower concentrations, as those found in the diesel vapors (*e.g.,* aromatics, alkanes, cyclic alkanes, and alkenes). Because SBF are manufactured from compounds with specifically defined compositions, the subsequent compound can exclude toxic aromatics. Consequently, toxic aromatics can be excluded from the vapors generated by using SBFs.

In general, SBFs (*e.g.,* esters, LAOs, PAOs, IOs) generate much lower concentrations of vapors than do OBFs (Docket No. W–98–26, Record No. III.D.12). Moreover, the vapors generated by these SBFs are less toxic than traditional OBFs because they do not contain aromatics.

2. Waste Hauling Activities

Industry has commented in previous effluent guidelines, such as the Coastal Subcategory Oil and Gas Extraction and Development ELG, that a zero discharge requirement would increase the risk of injury to workers due to increased waste hauling activities. These activities include vessel trips to and from the drilling facility to haul waste, transfer of waste from the drilling facility onto a service vessel, and transfer in port onto a barge or dock.

EPA has identified and reviewed additional data sources to determine the likelihood that imposition of a zero discharge limitation on cuttings contaminated with SBF could increase risk of injury due to additional waste hauling demands. The sources of safety data are the U.S. Coast Guard (USCG), the Minerals Management Service (MMS), the American Petroleum Institute (API), and the Offshore Marine Service Association (OMSA). The following is a summary of the findings from this review.

The data indicate that there are reported incidents that are associated with the collection, hauling, and onshore disposal of wastes from offshore. However, the data do not distinguish whether any of these incidents can be attributed to specific waste management activities.

Most offshore incidents are due to human error or equipment failure. The rate at which these incidents occur will not be changed significantly by increased waste management activities. However, if the number of man hours and/or equipment hours are increased, there will be more reportable incidents given an unchanged incident rate. These potential increases may be offset by reduced incident rates through increased training or equipment maintenance and inspection; but these changes cannot be predicted. One indication that training and maintenance can reduce incident rates is a 1998 API report entitled ''1997 Summary of U.S. Occupational Injuries, Illnesses, and Fatalities in the Petroleum Industry,'' which established that injury incident rates have been decreasing over the last 14 years. If this decrease continues, there should be no increase in the number of safety incidents due to a requirement to haul SBF-contaminated cuttings to shore for disposal. The details of this analysis are available in a technical support document in the rule record for today's final rule.

IX. Regulatory Requirements

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735 (October 4, 1993)), the Agency 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 rule 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.'' As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations are documented in the public record.

B. Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 USC 601 et. seq.

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rule requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business with fewer than 500 employees for oil and gas production operators and less than $5 million per year in revenues for oil and gas services providers (*i.e.,* the definitions from SBA's size standards); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. After considering the economic impact of today's final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Today's rule affects small businesses only; there are no impacts on small governmental jurisdictions or small organizations.

In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant *adverse* economic impact on small entities. Since the primary purpose of the regulatory flexibility analysis is to identify and address regulatory alternatives ''which minimizes any significant economic impact of the proposed rule on small entities.'' 5 U.S.C. Sections 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

EPA projects that today's rule will result in operational savings and will have no adverse economic impacts. These conclusions apply to all firms, both large and small. EPA estimates that between five and 40 small businesses (between five and 40% of all firms) are covered by today's rule. If the small businesses are using SBF and continue to do so, or if they switch to SBF, they need to comply with today's effluent limitations. EPA estimates that the operational savings associated with an allowable SBF-cuttings discharge will result in an economic advantage, contrasted to other SBF-cuttings regulatory scenarios. EPA selected the controlled discharge option which will allow operators to use of SBF in place of OBF and WBFs. Using SBFs in place of OBFs will generally shorten the length of the drilling project and eliminate the need to barge to shore or re-inject OBF-waste cuttings, thereby reducing costs and NWQI such as fuel use, air emissions, and land disposal of OBFs. Use of SBFs in place of WBFs would also lead to: (1) a decrease in costs and NWQIs due to the decreased length of the drilling project; and (2) a per well decrease of pollutants discharged due to improved technical performance of SBFs. EPA estimates that the rule will result in annual savings of $48.9 million and no adverse economic impacts to the industry as a whole. Further, after considerable study, EPA's record indicates that there will be no significant economic impacts to any small entity subject to the rule. The SBF Economic Analysis describes these results in more detail. We have therefore conducted that today's final rule will relieve regulatory burden for all small entities.

C. Submission to Congress and the General Accounting Office

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit 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 United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective February 21, 2001.

D. Paperwork Reduction Act

The Office of Management and Budget (OMB) has approved the information collection requirements contained in this rule under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2040–0230.

The information collection requirements are related to the optional use of Best Management Practices (BMPs) in order to reduce SBF-cuttings monitoring. Operators that elect to not use the BMP alternative are not subject to the information collection requirements in today's final rule. BMPs are inherently pollution prevention practices. BMPs may include the universe of pollution prevention encompassing production modifications, operational changes, material substitution, materials and water conservation, and other such measures. BMPs include methods to prevent toxic and hazardous pollutants from reaching receiving waters. Because BMPs are most effective when organized into a comprehensive facility BMP Plan, EPA is requiring operators to complete a BMP Plan when they select the BMP alternative.

The BMP alternative requires operators to develop and, when appropriate, amend plans specifying how operators will implement the specified BMP alternative, and to certify to the permitting authority that they have done so in accordance with good engineering practices and the requirements of the regulation. The purpose of those provisions is, respectively, to facilitate the implementation of BMP alternative on a site-specific basis and to help the regulating authorities to ensure compliance without requiring the submission of actual BMP Plans. Finally, the recordkeeping provisions are intended to facilitate training, to signal the need for different or more vigorously implemented BMPs, and to facilitate compliance assessment.

The information collection requirements in the final rule include, for example: (1) Training personnel; (2) analyzing spills that occur; (3) identifying equipment items that might need to be maintained, upgraded, or repaired; (4) identifying procedures for waste minimization; (5) performing monitoring (including the operation of monitoring systems) to establish equivalence with a numeric cuttings retention limitation and to detect leaks, spills, and intentional diversion; and (6) generally to periodically evaluate the effectiveness of the BMP alternatives.

EPA does not expect that any confidential business information or trade secrets will be required from oil and gas extraction operators as part of this ICR. If information submitted in conjunction with this ICR were to contain confidential business information, the respondent has the authority to request that the information be treated as confidential business information. All data so designated will be handled by EPA pursuant to 40 CFR part 2. This information will be maintained according to procedures outlined in EPA's Security Manual Part III, Chapter 9, dated August 9, 1976. Pursuant to section 308(b) of the CWA, effluent data may not be treated as confidential.

EPA estimated the burden and costs to the regulated community (approximately 67 SBF well drilling facilities annually) and EPA, the NPDES permit control authority, for data collection and record keeping associated with implementation of the BMP alternative. EPA estimates the public reporting burden for the selected BMP option as 787 hours per respondent per year (*i.e.,* (16,750 initial hours/3 years + 47,168 annual hours/year)/67 SBF well operators). EPA also estimated the annual burden for EPA Regions, the NPDES permit controlling authorities, to review BMPs and ensure compliance. EPA estimates that essentially all of the SBF discharges will occur in Federal offshore waters or in Cook Inlet, Alaska, where EPA Region X retains NPDES permit controlling authority. The EPA Regional burden for reviewing BMP Plans is estimated at 380 hours per year (*i.e.,* (536 initial hours/3 years + 201 annual hours/year)).

EPA estimates the public reporting costs as $24,058 per respondent per year (*i.e.,* ($1,235,313 initial costs/3 years + $1,200,138 annual costs/year)/67 SBF well operators). The EPA Regional costs for reviewing BMP Plans is estimated at approximately $12,149 per year (*i.e.,*

($17,152 initial costs/3 years + $6,432 annual costs/year)).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15. EPA is amending the table in 40 CFR part 9 of currently approved ICR control numbers issued by OMB for various regulations to list the information requirements contained in this final rule.

E. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 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. EPA projects that the effect of the rule will be a operational savings. EPA has estimated this savings at $48.9 million (1999$, post-tax). Thus, today's rule is not subject to the requirements of Sections 202 and 205 of the UMRA.

EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. EPA projects that no small governments will be affected by this rule as small governments are not engaged in oil and gas extraction operations in offshore and coastal waters or in issuing NPDES permits for oil and gas extraction operations in offshore and coastal waters. Thus, today's rule is not subject to the requirements of section 203 of the UMRA.

F. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084 EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian Tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 13084 requires EPA to provide to the Office of Management and Budget, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected officials and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Today's rule does not significantly or uniquely affect the communities of Indian tribal governments nor does it impose substantial direct compliance costs on them. EPA has determined that currently, no communities of Indian tribal governments are affected by this rule as Indian tribal governments are not engaged in oil and gas extraction operations in offshore and coastal waters or in issuing NPDES permits for oil and gas extraction operations in offshore and coastal waters. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

G. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The rule establishes effluent limitations and standards imposing requirements that apply to oil and gas extraction operations in offshore and coastal waters. EPA has determined that there are no oil and gas extraction operations in offshore and coastal waters that are owned and operated by State or local governments. Therefore, this rule will not impose any requirements on State or local governments. Further, the rule will not affect State governments' authority to implement CWA and UIC permitting programs. In fact, the final rule may reduce administrative costs on States that have authorized NPDES programs because although these States must incorporate the new limitations and

standards in new and revised NPDES permits, they no longer will need to make Best Professional Judgement (BPJ) determinations regarding the appropriate level of technology control. We recognize that there may be a small administrative cost to the State of Alaska to assist EPA Region 10 in determining whether Coastal Cook Inlet, Alaska, operators qualify for the SBF-cuttings zero discharge exemption (*see* Section V.F). Thus, Executive Order 13132 does not apply to this rule.

H. National Technology Transfer and Advancement Act

As noted in the proposed rule (64 FR 5528), section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Pub L. 104–113 section 12(d) (15 U.S.C. 272 note), directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standard bodies. The NTTAA directs EPA to provide Congress, through the Office of Management and Budget (OMB), explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rule involves technical standards. The rule requires dischargers to measure for two metals, PAH content (as phenanthrene), sediment toxicity, aqueous toxicity, biodegradation rate, formation oil content, and base fluid retained on cuttings. EPA performed a search to identify potentially applicable voluntary consensus standards that could be used to measure the parameters in today's rule. EPA did locate several voluntary consensus standards that required modification for inclusion in the final rule. EPA considered public comments on the proposed rule and worked with stakeholders, including the industry sponsored Synthetic Based Muds Research Consortium (SBMRC), to modify or develop new standards for various parameters (*i.e.,* sediment toxicity, biodegradation rate, PAH content (as phenanthrene), formation oil content, base fluid retained on cuttings). EPA has decided to use modified versions of the following voluntary consensus standards: (1) EPA Method 1654A; (2) ASTM E–1367–92; (3) ISO 11734:1995; and (4) API Recommended Practice 13B–2. As indicated by industry comments on the February 1999 proposal and April 2000 NODA, industry stakeholders support the use of these modified voluntary consensus standards (*see* Docket No. W–98–26, Record No. IV.A.a.13).

I. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The Executive Order 13045, ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This final rule is not subject to E.O. 13045 because it is not ''economically significant'' as defined under Executive Order 12866, and because the rule does not concern an environmental health or safety risk that may have a disproportionate effect on children.

J. Executive Order 13158: Marine Protected Areas

Executive Order 13158 (65 FR 34909, May 31, 2000) requires EPA to ''expeditiously propose new science-based regulations, as necessary, to ensure appropriate levels of protection for the marine environment.'' EPA may take action to enhance or expand protection of existing marine protected areas and to establish or recommend, as appropriate, new marine protected areas. The purpose of the executive order is to protect the significant natural and cultural resources within the marine environment, which means ''those areas of coastal and ocean waters, the Great Lakes and their connecting waters, and submerged lands thereunder, over which the United States exercises jurisdiction, consistent with international law.''

EPA believes that this final rule is consistent with the objectives of the Executive Order to protect the ocean environment. By encouraging the use of appropriately controlled SBFs in the place of more toxic OBFs, the ocean will be protected from the effects of spills of OBFs and from the effects of disposal of OBFs onshore. By encouraging the use of appropriately controlled SBFs over WBFs, there will much less drilling waste generated and discharged to the ocean per well and the drilling waste discharged will be far less toxic and will biodegrade at a much faster rate than those of traditional drilling fluids.

X. Regulatory Implementation

Upon promulgation of these regulations, the effluent limitations for the appropriate subcategory must be applied in all Federal and State NPDES permits issued to affected direct dischargers in the oil and gas extraction industry. This section discusses the relationship of upset and bypass provisions, variances and modifications, and monitoring requirements.

A. Implementation of Limitations and Standards

Upon the promulgation of these regulations, all new and reissued Federal and State NPDES permits issued to direct dischargers in the oil and gas extraction industry must include the effluent limitations for the appropriate subcategory. Permit writers should be aware that EPA has now finalized revisions to 40 CFR 122.44(a) which could be particularly relevant to the development of NPDES permits for the oil and gas extraction point source category (*see* 65 FR 30989, May 15, 2000). As finalized, the revision would require that permits have limitations for all applicable guidelines-listed pollutants but allows for the waiver of sampling requirements for guideline-listed pollutants on a case-by-case basis if the discharger can certify that the pollutant is not present in the discharge or present in only background levels from intake water with no increase due to the activities of the dischargers. New sources and new dischargers are not eligible for this waiver for their first permit term, and monitoring can be re-established through a minor modification if the discharger expands or changes its process. Further, the permittee must notify the permit writer of any modifications that have taken place over the course of the permit term and, if necessary, monitoring can be reestablished through a minor modification.

B. Upset and Bypass Provisions

A ''bypass'' is an intentional diversion of waste streams from any portion of a treatment facility. An ''upset'' is an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. EPA's regulations concerning bypasses and upsets are set forth at 40 CFR 122.41(m) and (n), and 40 CFR 403.16 (upset) and 403.17

(bypass). The reader is also referred to the Offshore Guidelines (58 FR 12501) for a discussion on upset and bypass provisions.

C. Variances and Modifications

The CWA requires application of the effluent limitations and standards established pursuant to section 301, 304, 306, or the pretreatment standards of section 307 to all direct and indirect dischargers. However, section 301(n) provides for the modification of these national requirements in a limited number of circumstances. Moreover, the Agency has established administrative mechanisms to provide an opportunity for relief from the application of national effluent limitations guidelines and pretreatment standards for categories of existing sources for priority, conventional and non-conventional pollutants (*e.g.,* fundamentally different factor variances, removal credits).

The Fundamentally Different Factors (FDF) variances considers those facility specific factors which a permittee may consider to be uniquely different from those considered in the formulation of an effluent limitations guidelines as to make the limitation inapplicable. An FDF variance must be based only on information submitted to EPA during the rulemaking establishing the effluent limitations guidelines from which the variance is being requested, or on information the applicant did not have a reasonable opportunity to submit during the rulemaking process for these effluent limitations guidelines. FDF variance requests must be received by the permitting authority within 180 days of publication of the final rule. The specific regulations covering the requirements for the administration of FDF variances are found at 40 CFR 122.21(m)(1), and 40 CFR part 125, subpart D.

D. Relationship of Effluent Limitations to NPDES Permits and Monitoring Requirements

Effluent limitations act as a primary mechanism to control the discharges of pollutants to waters of the United States. These limitations are applied to individual facilities through NPDES permits issued by EPA or authorized States under section 402 of the Act.

The Agency has developed the limitations for this regulation to cover the discharge of pollutants for this industrial category. In specific cases, the NPDES permitting authority may elect to establish technology-based permit limits for pollutants not covered by this regulation. In addition, if State water quality standards or other provisions of State or Federal Law require limits on pollutants not covered by this regulation (or require more stringent limits on covered pollutants), the permitting authority must apply those limitations.

Working in conjunction with the effluent limitations are the monitoring conditions set out in a NPDES permit. An integral part of the monitoring conditions is the point at which a facility must monitor to demonstrate compliance. The point at which a sample is collected can have a dramatic effect on the monitoring results for that facility. Therefore, it may be necessary to require internal monitoring points in order to ensure compliance. Authority to address internal waste streams is provided in 40 CFR 122.44(i)(1)(iii) and 122.45(h). Permit writers may establish additional internal monitoring points to the extent consistent with EPA's regulations.

An important component of the monitoring requirements established by the permitting authority is the frequency at which monitoring is required. In costing the various technology options for the oil and gas extraction industry, EPA assumed yearly SBF stock limitations monitoring for mercury, cadmium, PAH (as phenanthrene), sediment toxicity, and biodegradation rates and daily or monthly monitoring for diesel oil contamination, formation oil contamination, base fluid retained on cuttings, aqueous toxicity, and sediment toxicity. These monitoring frequencies may be lower than those generally imposed by some permitting authorities, but EPA believes these reduced frequencies are appropriate due to the relative costs of monitoring when compared to the estimated costs of complying with the promulgated limitations.

E. Analytical Methods

Section 304(h) of the Clean Water Act directs EPA to promulgate guidelines establishing test procedures for the analysis of pollutants. These test procedures (methods) are used to determine the presence and concentration of pollutants in wastewater, and are used for compliance monitoring and for filing applications for the NPDES program under 40 CFR 122.21, 122.41, 122.44 and 123.25, and for the implementation of the pretreatment standards under 40 CFR 403.10 and 403.12. To date, EPA has promulgated methods for conventional pollutants, toxic pollutants, and for some non-conventional pollutants. The five conventional pollutants are defined at 40 CFR 401.16. Table I–B at 40 CFR part 136 lists the analytical methods approved for these pollutants. The 65 toxic metals and organic pollutants and classes of pollutants are defined at 40 CFR 401.15. From the list of 65 classes of toxic pollutants EPA identified a list of 126 ''Priority Pollutants.'' This list of Priority Pollutants is shown, for example, at 40 CFR part 423, Appendix A. The list includes non-pesticide organic pollutants, metal pollutants, cyanide, asbestos, and pesticide pollutants.

Currently approved methods for metals and cyanide are included in the table of approved inorganic test procedures at 40 CFR 136.3, Table I–B. Table I–C at 40 CFR 136.3 lists approved methods for measurement of non-pesticide organic pollutants, and Table I–D lists approved methods for the toxic pesticide pollutants and for other pesticide pollutants. Dischargers must use the test methods promulgated at 40 CFR 136.3 or incorporated by reference in the tables, when available, to monitor pollutant discharges from the oil and gas industry, unless specified otherwise in part 435 or by the permitting authority.

As part this rule, EPA is promulgating the use of analytical methods for determining additional parameters that are specific to characterizing SBFs and other drilling fluids which do not disperse in water. These additional stock base fluid parameters include PAH content (as phenanthrene), sediment toxicity, and biodegradation rate. Additional discharge limitations include prohibition of diesel oil discharge, formation (crude) oil contamination, aqueous phase toxicity, sediment toxicity, and quantity of drilling fluid discharged with cuttings.

EPA worked with stakeholders to identify methods for determining these parameters. For PAH content (as phenanthrene), EPA is promulgating the use of EPA Method 1654A. For biodegradation rate, EPA is promulgating the use of the anaerobic closed bottle biodegradation test (*i.e.*, ISO 11734:1995) as modified for the marine environment (*i.e.,* Appendix 4 of subpart A of 40 CFR part 435). For base fluid sediment toxicity, EPA is promulgating the use of the American Society for Testing and Material (ASTM) Method E–1367–92 supplemented with sediment preparation procedures (*i.e.*, Appendix 3 of subpart A of 40 CFR part 435). For drilling fluid sediment toxicity, EPA is promulgating the use of ASTM Method E–1367–92 supplemented with sediment preparation procedures (*i.e.*, Appendix 3 of subpart A of 40 CFR part 435) and reference drilling fluid preparation procedures (*i.e.*, Appendix 8 of subpart

A of 40 CFR part 435). For aqueous toxicity, EPA is promulgating the use of the Suspended Particulate Phase (SPP) toxicity test (Appendix 2 of subpart A of 40 CFR part 435). For formation (crude) oil contamination in drilling fluid, EPA is promulgating the use of two methods: a reverse phase extraction fluorescence test (RPE) and a gas chromatography/mass spectrometry (GC/MS) test. The RPE test (*i.e.,* Appendix 6 of subpart A of 40 CFR part 435) is a screening method that provides a quick and inexpensive determination of oil contamination for use on offshore well drilling sites, while the GC/MS test (*i.e.,* Appendix 5 of subpart A of 40 CFR part 435) provides: (1) A definitive identification and quantification of oil contamination for baseline analysis; and (2) confirmatory results for the RPE when the RPE results need confirmation. For determining the quantity of drilling fluid discharged with cuttings, EPA is promulgating the use of the American Petroleum Institute (API) Retort Method (Recommended Practice 13B–2) with sampling procedures (*i.e.,* Appendix 7 of subpart A of 40 CFR part 435). For determining when Coastal Cook Inlet, Alaska, operators qualify for an exemption from the Coastal requirement of zero discharge for SBF-cuttings, EPA is promulgating the use of the procedure outlined in Appendix 1 of subpart D of 40 CFR part 435.

EPA Method 1654A, ASTM E–1367–92, and ISO 11734:1995 are incorporated by reference into 40 CFR part 435 because they are published methods that are widely available to the public. Modifications to the anaerobic closed bottle biodegradation test (*i.e.,* ISO 11734:1995) are provided in Appendix 4 of subpart A of 40 part 435. The SPP toxicity test is given in Appendix 2 of subpart A of 40 part 435. Supplemental sediment preparation procedures for ASTM E–1367–92 are provided in Appendix 3 of subpart A of 40 CFR part 435. Reference drilling fluid preparation procedures for ASTM E–1367–92 are provided in Appendix 8 of subpart A of 40 CFR part 435. The text of the GC/MS test, RPE test, and the API retort method are provided in Appendices 5–7 of subpart A of 40 CFR part 435. The procedure for determining when Coastal Cook Inlet operators qualify for an exemption from the Coastal requirement of zero discharge for SBF-cuttings is provided in Appendix 1 of subpart D of 40 CFR part 435.

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

Act—Clean Water Act
Agency—U.S. Environmental Protection Agency
AOGCC—Alaska Oil and Gas Conservation Commission
API—American Petroleum Institute
ANL—Argonne National Laboratory (DOE)
ASTM—American Society of Testing and Materials
BADCT—The best available demonstrated control technology, for new sources under section 306 of the Clean Water Act.
BAT—The best available technology economically achievable, under section 304(b)(2)(B) of the Clean Water Act.
bbl—barrel, 42 U.S. gallons
BCT—Best conventional pollutant control technology under section 304(b)(4)(B).
BMP—Best management practices under section 304(e) of the Clean Water Act.
BOD—Biochemical oxygen demand.
BOE—Barrels of oil equivalent
BPJ—Best Professional Judgement
BPT—Best practicable control technology currently available, under section 304(b)(1) of the Clean Water Act.
CERCLA—Comprehensive Environmental Response, Compensation, and Liability Act
CFR—U.S. Code of Federal Regulations
Clean Water Act—Federal Water Pollution Control Act Amendments of 1972 as amended (33 U.S.C. 1251 *et seq*)
Conventional pollutants—Constituents of wastewater as determined by section 304(a)(4) of the Act, including, but no limited to, pollutants classified as biochemical oxygen demanding, suspended solids, oil and grease, fecal coliform, and pH
Direct discharger—A facility which discharges or may discharge pollutants to waters of the United States
D&B—Dun & Bradstreet
DOE—U.S. Department of Energy
DWD—Deep-water development model well
DWE—Deep-water exploratory model well
EMO—Enhanced Mineral Oil Drilling Fluid
EPA—U.S. Environmental Protection Agency
FR—Federal Register
GC—Gas Chromatography
GC/FID—Gas Chromatography with Flame Ionization Detection
GC/MS—Gas Chromatography with Mass Spectroscopy Detection
GOM—Gulf of Mexico
Indirect discharger—A facility that introduces wastewater into a publicly owned treatment works.
IRFA—Initial Regulatory Flexibility Analysis
LC_{50} (or LC50)—The concentration of a test material that is lethal to 50% of the test organisms in a bioassay
mg/l—milligrams per liter
MMS—U.S. Department of Interior, Minerals Management Service
NAF—Non-Aqueous Drilling Fluid (includes OBFs, EMOs, and SBFs)
Non-conventional pollutants—Pollutants that have not been designated as either conventional pollutants or priority pollutants
NODA—Notice of Data Availability (65 FR 21548; April 21, 2000)
NOIA—National Ocean Industries Association
NOW—Nonhazardous Oilfield Waste
NPDES—National Pollutant Discharge Elimination System
NRDC—Natural Resources Defense Council, Inc.
NSPS—New source performance standards under section 306 of the Clean Water Act
NTTAA—National Technology Transfer and Advancement Act
NWQI—Non-Water Quality Environmental Impacts
OBF—Oil-Based Drilling Fluid
OCS—Outer Continental Shelf
OMB—Office of Management and Budget
PAH—Polynuclear Aromatic Hydrocarbon
PDC—Polycrystalline Diamond Compact (drill bit)
POTW—Publicly Owned Treatment Works
ppm—parts per million
PPA—Pollution Prevention Act of 1990
Priority pollutants—The 65 pollutants and classes of pollutants declared toxic under section 307(a) of the Clean Water Act
PSES—Pretreatment standards for existing sources of indirect discharges, under section 307(b) of the Act
PSNS—Pretreatment standards for new sources of indirect discharges, under sections 307(b) and (c) of the Act
RFA—Regulatory Flexibility Act
ROC—Retention on Cuttings
RPE—Reverse Phase Extraction
SBA—U.S. Small Business Administration
SBF—Synthetic Based Drilling Fluid
SBF Development Document—Development Document for Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category (EPA–821–B–00–013)
SBF Economic Analysis—Economic Analysis of Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category (EPA–821–B–00–012)
SBF Environmental Assessment—Environmental Assessment of Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category (EPA–821–B–00–014)
SBF Statistical Support Document—Statistical Analyses Supporting Final Effluent Limitations Guidelines and Standards for Synthetic-Based Drilling Fluids and other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category (EPA–821–B–00–015)
SBMRC—Synthetic Based Muds Research Consortium
SBREFA—Small Business Regulatory Enforcement Fairness Act
SIC—Standard Industrial Classification
SPP—Suspended Particulate Phase toxicity test (Appendix 2 to Subpart A of 40 CFR 435)

SWD—Shallow-water development model well
SWE—Shallow-water exploratory model well
TSS—Total Suspended Solids
UMRA—Unfunded Mandates Reform Act
UIC—Underground Injection Control programs of the Safe Drinking Water Act of 1974 as amended
U.S.C.—United States Code
WBF—Water-Based Drilling Fluid

List of Subjects

40 CFR Part 9

Reporting and recordkeeping requirements.

40 CFR Part 435

Environmental protection, Non-aqueous drilling fluids, Oil and gas extraction, Pollution prevention, Synthetic based drilling fluids, Waste treatment and disposal, Water non-dispersible drilling fluids, Water pollution control.

Dated: December 28, 2000.

Carol M. Browner,

Administrator.

For the reasons set forth in this preamble, 40 CFR parts 9 and 435 are amended as follows:

PART 9—OMB APPROVALS UNDER THE PAPERWORK REDUCTION ACT

1. The authority citation for part 9 continues to read as follows:

Authority: 7 U.S.C. 135 *et seq.*, 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251 *et seq.*, 1311, 1313d, 1314, 1318, 1321, 1326, 1330, 1342, 1344, 1345 (d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857 *et seq.*, 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

2. In § 9.1 the table is amended by adding entries in numerical order under a new heading titled ''Oil and Gas Extraction Point Source Category'' to read as follows:

§ 9.1 OMB approvals under the Paperwork Reduction Act.

* * * * *

40 CFR citation	OMB control No.
* * * * *	
Oil and Gas Extraction Point Source Category:	
435.13	2040–0230
435.15	2040–0230
435.43	2040–0230
435.45	2040–0230
* * * * *	

PART 435—OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

1. The authority citation for Part 435 is revised to read as follows:

Authority: 33 U.S.C. 1311, 1314, 1316, 1317, 1318, 1342 and 1361.

Subpart A—Offshore Subcategory

2. Section 435.11 is amended by revising paragraphs (b) through (cc) and by adding paragraphs (dd) through (tt) to read as follows:

§ 435.11 Special definitions.

* * * * *

(b) *Average of daily values for 30 consecutive days* means the average of the daily values obtained during any 30 consecutive day period.

(c) *Base fluid* means the continuous phase or suspending medium of a drilling fluid formulation.

(d) *Base fluid retained on cuttings* as applied to BAT effluent limitations and NSPS refers to the American Petroleum Institute Recommended Practice 13B–2 supplemented with the specifications, sampling methods, and averaging method for retention values provided in Appendix 7 of Subpart A of this part.

(e) *Biodegradation rate* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings refers to the ISO 11734:1995 method: ''Water quality—Evaluation of the 'ultimate' anaerobic biodegradability of organic compounds in digested sludge—Method by measurement of the biogas production (1995 edition)'' supplemented with modifications in Appendix 4 of 40 CFR part 435, subpart A. 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 National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036. 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, 401 M Street SW., Washington, DC 20460.

(f) *Daily values* as applied to produced water effluent limitations and NSPS means the daily measurements used to assess compliance with the maximum for any one day.

(g) *Deck drainage* means 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.

(h) *Development facility* means any fixed or mobile structure subject to this subpart that is engaged in the drilling of productive wells.

(i) *Diesel oil* refers 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, 100 Barr Harbor Drive, West Conshohocken, PA, 19428. 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, 401 M Street SW., Washington, DC 20460.

(j) *Domestic waste* means 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.

(k) *Drill cuttings* means the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid. Examples of drill cuttings include small pieces of rock varying in size and texture from fine silt to gravel. Drill cuttings are generally generated from solids control equipment and settle out and accumulate in quiescent areas in the solids control equipment or other equipment processing drilling fluid (*i.e.,* accumulated solids).

(1) *Wet drill cuttings* means the unaltered drill cuttings and adhering drilling fluid and formation oil carried out from the wellbore with the drilling fluid.

(2) *Dry drill cuttings* means the residue remaining in the retort vessel after completing the retort procedure specified in appendix 7 of subpart A of this part.

(l) *Drilling fluid* means the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. Classes of drilling fluids are:

(1) *Water-based drilling fluid* means the continuous phase and suspending

medium for solids is a water-miscible fluid, regardless of the presence of oil.

(2) *Non-aqueous drilling fluid* means the continuous phase and suspending medium for solids is a water-immiscible fluid, such as oleaginous materials (*e.g.,* mineral oil, enhanced mineral oil, paraffinic oil, C_{16}–C_{18} internal olefins, and C_8–C_{16} fatty acid/2-ethylhexyl esters).

(i) *Oil-based* means the continuous phase of the drilling fluid consists of diesel oil, mineral oil, or some other oil, but contains no synthetic material or enhanced mineral oil.

(ii) *Enhanced mineral oil-based* means the continuous phase of the drilling fluid is enhanced mineral oil.

(iii) *Synthetic-based* means the continuous phase of the drilling fluid is a synthetic material or a combination of synthetic materials.

(m) *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.

(n) *Exploratory facility* means 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.

(o) *Formation oil* means the oil from a producing formation which is detected in the drilling fluid, as determined by the GC/MS compliance assurance method specified in appendix 5 of subpart A of this part when the drilling fluid is analyzed before being shipped offshore, and as determined by the RPE method specified in appendix 6 of subpart A of this part when the drilling fluid is analyzed at the offshore point of discharge. Detection of formation oil by the RPE method may be confirmed by the GC/MS compliance assurance method, and the results of the GC/MS compliance assurance method shall supercede those of the RPE method.

(p) *M9IM* means those offshore facilities continuously manned by nine (9) or fewer persons or only intermittently manned by any number of persons.

(q) *M10* means those offshore facilities continuously manned by ten (10) or more persons.

(r) *Maximum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings means the maximum concentration allowed as measured in any single sample of the barite for determination of cadmium and mercury content.

(s) *Maximum for any one day* as applied to BPT, BCT and BAT effluent limitations and NSPS for oil and grease in produced water means 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.

(t) *Maximum weighted mass ratio averaged over all NAF well sections* for BAT effluent limitations and NSPS for base fluid retained on cuttings means the weighted average base fluid retention for all NAF well sections as determined by the API Recommended Practice 13B–2, using the methods and averaging calculations presented in Appendix 7 of subpart A of this part.

(u) *Method 1654A* refers to Method 1654, Revision A, entitled ''PAH Content of Oil by HPLC/UV,'' December 1992, which is published in *Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges,* EPA–821–R–92–008. 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 National Technical Information Service, Springfield, VA 22161, 703–605–6000. 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, 401 M Street SW., Washington, DC 20460.

(v) *Minimum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings means the minimum 96-hour LC_{50} value allowed as measured in any single sample of the discharged waste stream. *Minimum* as applied to BPT and BCT effluent limitations and NSPS for sanitary wastes means the minimum concentration value allowed as measured in any single sample of the discharged waste stream.

(w)(1) *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) *Water area* as used in ''site'' in 40 CFR 122.29 and 122.2 means 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) *Significant site preparation work* as used in 40 CFR 122.29 means 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.

(x) *No discharge of free oil* means that waste streams may not be discharged that contain free oil as evidenced by the monitoring method specified for that particular stream, *e.g.,* deck drainage or miscellaneous discharges cannot be discharged when they would cause a film or sheen upon or discoloration of the surface of the receiving water; drilling fluids or cuttings may not be discharged when they fail the static sheen test defined in Appendix 1 of subpart A of this part.

(y) Parameters that are regulated in this Subpart and listed with approved methods of analysis in Table 1B at 40 CFR 136.3 are defined as follows:

(1) *Cadmium* means total cadmium.

(2) *Chlorine* means total residual chlorine.

(3) *Mercury* means total mercury.

(4) *Oil and Grease* means total recoverable oil and grease.

(z) *PAH (as phenanthrene)* means polynuclear aromatic hydrocarbons reported as phenanthrene.

(aa) *Produced sand* means the 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.

(bb) *Produced water* means 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.

(cc) *Production facility* means 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.

(dd) *Sanitary waste* means the human body waste discharged from toilets and

urinals located within facilities subject to this Subpart.

(ee) *Sediment toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings refers to the ASTM E 1367–92 method: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods,'' 1992, with Leptocheirus plumulosus as the test organism and sediment preparation procedures specified in Appendix 3 of 40 CFR part 435, subpart A. 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, 100 Barr Harbor Drive, West Conshohocken, PA, 19428. 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, 401 M Street SW., Washington, DC 20460.

(ff) *Solids control equipment* means shale shakers, centrifuges, mud cleaners, and other equipment used to separate drill cuttings and/or stock barite solids from drilling fluid recovered from the wellbore.

(gg) *SPP toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings refers to the bioassay test procedure presented in Appendix 2 of subpart A of this part.

(hh) *Static sheen test* means the standard test procedure that has been developed for this industrial subcategory for the purpose of demonstrating compliance with the requirement of no discharge of free oil. The methodology for performing the static sheen test is presented in Appendix 1 of subpart A of this part.

(ii) *Stock barite* means the barite that was used to formulate a drilling fluid.

(jj) *Stock base fluid* means the base fluid that was used to formulate a drilling fluid.

(kk) *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. Internal olefins and vegetable esters are two examples of synthetic materials suitable for use by the oil and gas extraction industry in formulating drilling fluids. Internal olefins are synthesized from the isomerization of purified straight-chain (linear) hydrocarbons such as C_{16}–C_{18} linear alpha olefins. C_{16}–C_{18} linear alpha olefins are unsaturated hydrocarbons with the carbon to carbon double bond in the terminal position. Internal olefins are typically formed from heating linear alpha olefins with a catalyst. The feed material for synthetic linear alpha olefins is typically purified ethylene. Vegetable esters are synthesized from the acid-catalyzed esterification of vegetable fatty acids with various alcohols. EPA listed these two branches of synthetic fluid base materials to provide examples, and EPA does not mean 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.

(ll) *Well completion fluids* means 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.

(mm) *Well treatment fluids* means any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

(nn) *Workover fluids* means salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures.

(oo) *4-day* LC_{50} as applied to the sediment toxicity BAT effluent limitations and NSPS means the concentration (milligrams/kilogram dry sediment) of the drilling fluid in sediment that is lethal to 50 percent of the Leptocheirus plumulosus test organisms exposed to that concentration of the drilling fluids after four days of constant exposure.

(pp) *10-day* LC_{50} as applied to the sediment toxicity BAT effluent limitations and NSPS means the concentration (milligrams/kilogram dry sediment) of the base fluid in sediment that is lethal to 50 percent of the Leptocheirus plumulosus test organisms exposed to that concentration of the base fluids after ten days of constant exposure.

(qq) *96-hour* LC_{50} means 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.

(rr) C_{16}–C_{18} *internal olefin* means a 65/35 blend, proportioned by mass, of hexadecene and octadecene, respectively. Hexadecene is an unsaturated hydrocarbon with a carbon chain length of 16, an internal double carbon bond, and is represented by the Chemical Abstracts Service (CAS) No. 26952–14–7. Octadecene is an unsaturated hydrocarbon with a carbon chain length of 18, an internal double carbon bond, and is represented by the Chemical Abstracts Service (CAS) No. 27070–58–2. (Properties available from the Chemical Abstracts Service, 2540 Olentangy River Road, PO Box 3012, Columbus, OH, 43210).

(ss) C_{16}–C_{18} *internal olefin drilling fluid* means a C_{16}–C_{18} internal olefin drilling fluid formulated as specified in Appendix 8 of subpart A of this part.

(tt) C_{12}–C_{14} *ester* and C_8 *ester* means the fatty acid/2-ethylhexyl esters with carbon chain lengths ranging from 8 to 16 and represented by the Chemical Abstracts Service (CAS) No. 135800–37–2. (Properties available from the Chemical Abstracts Service, 2540 Olentangy River Road, PO Box 3012, Columbus, OH, 43210)

3. In § 435.12 the table is amended by removing the entries ''Drilling muds'' and ''Drill cuttings'' and by adding new entries (after ''Deck drainage'') for ''Water based'' and ''Non-aqueous'' to read as follows:

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

* * * * *

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
* * *	* *	*	*
Water-based:			
Drilling fluids	(1)	(1)	NA
Drill Cuttings	(1)	(1)	NA
Non-aqueous:			
Drilling fluids	No discharge	No discharge	NA
Drill Cuttings	(1)	(1)	NA
* * *	* *	*	*

[1] No discharge of free oil.

* * * * *

4. In § 435.13 the table is amended by revising entry (B) under ''Drilling fluids and drill cuttings'' and by revising footnote 2 and adding footnotes 5–11 to read as follows:

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

* * * * *

BAT EFFLUENT LIMITATIONS

Waste source	Pollutant parameter	BAT effluent limitation
* *	* *	* * *
Drilling fluids and drill cuttings:		
* *	* *	* * *
(B) For facilities located beyond 3 miles from shore:		
Water-based drilling fluids and associated drill cuttings.	SPP Toxicity	Minimum 96-hour LC_{50} of the SPP Toxicity Test[2] shall be 3% by volume.
	Free oil	No discharge.[3]
	Diesel oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
Non-aqueous drilling fluids (NAFs).		No discharge.
Drill cuttings associated with non-aqueous drilling fluids:		
Stock Limitations (C_{16}–C_{18} internal olefin).	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Polynuclear Aromatic Hydrocarbons (PAH).	PAH mass ratio[5] shall not exceed $1x10^{-5}$.
	Sediment toxicity	Base fluid sediment toxicity ratio[6] shall not exceed 1.0.
	Biodegradation rate	Biodegradation rate ratio[7] shall not exceed 1.0.
Discharge Limitations	Diesel oil	No discharge.
	SPP Toxicity	Minimum 96-hour LC_{50} of the SPP Toxicity Test[2] shall be 3% by volume.
	Sediment toxicity	Drilling fluid sediment toxicity ratio[8] shall not exceed 1.0.
	Formation Oil	No discharge.[9]
	Base fluid retained on cuttings	For NAFs that meet the stock limitations (C_{16}–C_{18} internal olefin) in this table, the maximum weighted mass ratio averaged over all NAF well sections shall be 6.9 g-NAF base fluid/100 g-wet drill cuttings.[10] For NAFs that meet the C_{12}–C_{14} ester or C_8 ester stock limitations in footnote 11 of this table, the maximum weighted mass ratio averaged over all NAF well sections shall be 9.4 g-NAF base fluid/100 g-wet drill cuttings.

BAT EFFLUENT LIMITATIONS—Continued

Waste source	Pollutant parameter	BAT effluent limitation
* * * * * * *		

* * * * * * *

[2] As determined by the suspended particulate phase (SPP) toxicity test (Appendix 2 of subpart A of this part).

[3] As determined by the static sheen test (Appendix 1 of subpart A of this part).

* * * * * * *

[5] PAH mass ratio = Mass (g) of PAH (as phenanthrene)/Mass (g) of stock base fluid as determined by EPA Method 1654, Revision A, (specified at § 435.11(u)) entitled ''PAH Content of Oil by HPLC/UV,'' December 1992, which is published in *Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges,* EPA–821–R–92–008. 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 National Technical Information Service, Springfield, VA 22161, 703–605–6000. 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, 401 M Street SW., Washington, DC 20460.

[6] Base fluid sediment toxicity ratio = 10-day LC_{50} of C_{16}–C_{18} internal olefin/10-day LC_{50} of stock base fluid as determined by ASTM E 1367–92 [specified at § 435.11(ee)] method: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods,'' 1992, after preparing the sediment according to the method specified in Appendix 3 of subpart A of this part. 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, 100 Barr Harbor Drive, West Conshohocken, PA, 19428. 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, 401 M Street SW., Washington, DC 20460.

[7] Biodegradation rate ratio = Cumulative gas production (ml) of C_{16}–C_{18} internal olefin/Cumulative gas production (ml) of stock base fluid, both at 275 days as determined by ISO 11734:1995 [specified at § 435.11(e)] method: ''Water quality—Evaluation of the 'ultimate' anaerobic biodegradability of organic compounds in digested sludge—Method by measurement of the biogas production (1995 edition)'' as modified for the marine environment (Appendix 4 of subpart A of this part). 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 National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036. 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, 401 M Street SW., Washington, DC 20460.

[8] Drilling fluid sediment toxicity ratio = 4-day LC_{50} of C_{16}–C_{18} internal olefin drilling fluid/4-day LC_{50} of drilling fluid removed from drill cuttings at the solids control equipment as determined by ASTM E 1367–92 (specified at § 435.11(ee)) method: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods,'' 1992, after preparing the sediment according to the method specified in Appendix 3 of subpart A of this part. 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, 100 Barr Harbor Drive, West Conshohocken, PA, 19428. 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, 401 M Street SW., Washington, DC 20460.

[9] As determined before drilling fluids are shipped offshore by the GC/MS compliance assurance method (Appendix 5 of subpart A of this part), and as determined prior to discharge by the RPE method (Appendix 6 of subpart A of this part) applied to drilling fluid removed from drill cuttings. If the operator wishes to confirm the results of the RPE method (Appendix 6 of subpart A of this part), the operator may use the GC/MS compliance assurance method (Appendix 5 of subpart A of this part). Results from the GC/MS compliance assurance method (Appendix 5 of subpart A of this part) shall supercede the results of the RPE method (Appendix 6 of subpart A of this part).

[10] Maximum permissible retention of non-aqueous drilling fluid (NAF) base fluid on wet drill cuttings averaged over drilling intervals using NAFs as determined by the API retort method (Appendix 7 of subpart A of this part). This limitation is applicable for NAF base fluids that meet the base fluid sediment toxicity ratio (Footnote 6), biodegradation rate ratio (Footnote 7), PAH, mercury, and cadmium stock limitations (C_{16}–C_{18} internal olefin) defined above in this table.

[11] Maximum permissible retention of non-aqueous drilling fluid (NAF) base fluid on wet drill cuttings average over drilling intervals using NAFs as determined by the API retort method (Appendix 7 of subpart A of this part). This limitation is applicable for NAF base fluids that meet the ester base fluid sediment toxicity ratio and ester biodegradation rate ratio stock limitations defined as: (a) ester base fluid sediment toxicity ratio = 10-day LC_{50} of C_{12}–C_{14} ester or C_8 ester /10-day LC_{50} of stock base fluid as determined by ASTM E 1367–92 (specified at § 435.11(ee)) method: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods,'' 1992, after preparing the sediment according to the method specified in Appendix 3 of subpart A of this part. 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, 100 Barr Harbor Drive, West Conshohocken, PA, 19428. 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, 401 M Street SW., Washington, DC 20460. (b) ester biodegradation rate ratio = Cumulative gas production (ml) of C_{12}–C_{14} ester or C_8 ester/Cumulative gas production (ml) of stock base fluid, both at 275 days as determined by ISO 11734:1995 (specified at § 435.11(e)) method: ''Water quality—Evaluation of the 'ultimate' anaerobic biodegradability of organic compounds in digested sludge—Method by measurement of the biogas production (1995 edition)'' as modified for the marine environment (Appendix 4 of subpart A of this part). 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 National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036. 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, 401 M Street SW., Washington, DC 20460. (c) PAH mass ratio (Footnote 5), mercury, and cadmium stock limitations (C_{16}–C_{18} internal olefin) defined above in this table.

5. In § 435.14 the table is amended by revising entry (B) under ''Drilling fluids and drill cuttings'' to read as follows:

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

* * * * *

BCT EFFLUENT LIMITATIONS

Waste source	Pollutant parameter	BCT effluent limitation
* * * * * * *		
Drilling fluids and drill cuttings:		

BCT EFFLUENT LIMITATIONS—Continued

Waste source	Pollutant parameter	BCT effluent limitation
* * *	* * *	*
(B) For facilities located beyond 3 miles from shore:		
Water-based drilling fluids and associated drill cuttings	Free Oil	No discharge.[2]
Non-aqueous drilling fluids		No discharge.
Drill cuttings associated with non-aqueous drilling fluids	Free Oil	No discharge.[2]

* * * * * * *

[2] As determined by the static sheen test (Appendix 1 of Subpart A of this part).

* * * * * * *

6. In § 435.15 the table is amended by revising entry (B) under ''Drilling fluids and drill cuttings'' and by revising footnote 2 and adding footnotes 5–11 to read as follows:

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

* * * * *

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Waste source	Pollutant parameter	NSPS
* * *	* * *	*
Drilling fluids and drill cuttings:		
* * *	* * *	*
(B) For facilities located beyond 3 miles from shore:		
Water-based drilling fluids and associated drill cuttings.	SPP Toxicity	Minimum 96-hour LC_{50} of the SPP Toxicity Test[2] shall be 3% by volume.
	Free oil	No discharge.[3]
	Diesel oil	No charge.
	Mercury	1mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
Non-aqueous drilling fluids		No charge.
Drill cuttings associated with non-aqueous drilling fluids:		
Stock Limitations (C_{16}–C_{18} internal olefin.	Mercury	1mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
	Polynuclear Aromatic Hydrocarbons (PAH).	PAH mass ratio[5] shall not exceed 1×10^{-5}
	Sediment toxicity	Base fluid sediment toxicity ratio[6] shall not exceed 1.0.
	Biodegradation rate	Biodegradation rate ratio[7] shall not exceed 1.0.
Discharge Limitations	Diesel oil	No discharge.
	SPP Toxicity	Minimum 96-hour LC_{50} of the SPP Toxicity Test[2] shall be 3% by volume.
	Sediment toxicity	Drilling fluid sediment toxicity ratio[8] shall not exceed 1.0.
	Formation Oil	No discharge.[9]
	Base fluid retained on cuttings	For NAFs that meet the stock limitations (C_{16}–C_{18} internal olefin) in this table, the maximum weighted mass ratio averaged over all NAF well sections shall be 6.9 g–NAF base fluid/100 g-wet drill cuttings.[10] For NAFs that meet the C_{12}–C_{14} ester or C_8 ester stock limitations in footnote 11 of this table, the maximum weighted mass ratio averaged over all NAF well sections shall be 9.4 g–NAF base fluid/100 g-wet drill cuttings.
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[2] As determined by the suspended particulate phase (SPP) toxicity test (Appendix 2 of subpart A of this part).

[3] As determined by the static sheen test (appendix 1 of subpart A of this part).

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[5] PAH mass ratio = Mass (g) of PAH (as phenanthrene)/Mass (g) of stock base fluid as determined by EPA Method 1654, Revision A, (specified at § 435.11(u)) entitled ''PAH Content of Oil by HPLC/UV,'' December 1992, which is published in *Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges*, EPA–821–R–92–008. 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 National Technical Information Service, Springfield, VA 22161, 703–605–6000. 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, 401 M Street SW., Washington, DC 20460.

[6] Base fluid sediment toxicity ratio = 10-day LC_{50} of C_{16}–C_{18} internal olefin/10-day LC_{50} of stock base fluid as determined by ASTM E 1367–92 (specified at § 435.11(ee)) method: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods,'' 1992, after preparing the sediment according to the method specified in Appendix 3 of subpart A of this part. 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, 100 Barr Harbor Drive, West Conshohocken, PA, 19428. 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, 401 M Street SW., Washington, DC 20460.

[7] Biodegradation rate ratio = Cumulative gas production (ml) of C_{16}–C_{18} internal olefin/Cumulative gas production (ml) of stock base fluid, both at 275 days as determined by ISO 11734:1995 (specified at § 435.11(e)) method: ''Water quality—Evaluation of the 'ultimate' anaerobic biodegradability of organic compounds in digested sludge—Method by measurement of the biogas production (1995 edition)'' as modified for the marine environment (Appendix 4 of subpart A of this part). 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 National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036. 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, 401 M Street SW., Washington, DC 20460.

[8] Drilling fluid sediment toxicity ratio = 4-day LC_{50} of C_{16}–C_{18} internal olefin drilling fluid/4-day LC_{50} of drilling fluid removed from drill cuttings at the solids control equipment as determined by ASTM E 1367–92 (specified at § 435.11(ee)) method: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods,'' 1992, after preparing the sediment according to the method specified in Appendix 3 of subpart A of this part. 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, 100 Barr Harbor Drive, West Conshohocken, PA, 19428. 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, 401 M Street SW., Washington, DC 20460.

[9] As determined before drilling fluids are shipped offshore by the GC/MS compliance assurance method (Appendix 5 of subpart A of this part), and as determined prior to discharge by the RPE method (Appendix 6 of subpart A of this part) applied to drilling fluid removed from drill cuttings. If the operator wishes to confirm the results of the RPE method (Appendix 6 of subpart A of this part), the operator may use the GC/MS compliance assurance method (Appendix 5 of subpart A of this part). Results from the GC/MS compliance assurance method (Appendix 5 of subpart A of this part) shall supercede the results of the RPE method (Appendix 6 of subpart A of this part).

[10] Maximum permissible retention of non-aqueous drilling fluid (NAF) base fluid on wet drill cuttings averaged over drilling intervals using NAFs as determined by the API retort method (Appendix 7 of subpart A of this part). This limitation is applicable for NAF base fluids that meet the base fluid sediment toxicity ratio (Footnote 6), biodegradation rate ratio (Footnote 7), PAH, mercury, and cadmium stock limitations (C_{16}–C_{18} internal olefin) defined above in this table.

[11] Maximum permissible retention of non-aqueous drilling fluid (NAF) base fluid on wet drill cuttings average over drilling intervals using NAFs as determined by the API retort method (Appendix 7 of subpart A of this part). This limitation is applicable for NAF base fluids that meet the ester base fluid sediment toxicity ratio and ester biodegradation rate ratio stock limitations defined as: (a) Ester base fluid sediment toxicity ratio = 10-day LC_{50} of C_{12}–C_{14} ester or C_8 ester /10-day LC_{50} of stock base fluid as determined by ASTM E 1367–92 [specified at § 435.11(ee)] method: ''Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods,'' 1992, after preparing the sediment according to the method specified in Appendix 3 of subpart A of this part. 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, 100 Barr Harbor Drive, West Conshohocken, PA, 19428. 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, 401 M Street SW., Washington, DC 20460; (b) Ester biodegradation rate ratio = Cumulative gas production (ml) of C_{12}–C_{14} ester or C_8 ester/Cumulative gas production (ml) of stock base fluid, both at 275 days as determined by ISO 11734:1995 (specified at § 435.11(e)) method: ''Water quality—Evaluation of the 'ultimate' anaerobic biodegradability of organic compounds in digested sludge—Method by measurement of the biogas production (1995 edition)'' as modified for the marine environment (Appendix 4 of subpart A of this part). 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 National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036. 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, 401 M Street SW., Washington, DC 20460; and (c) PAH mass ratio (Footnote 5), mercury, and cadmium stock limitations (C_{16}–C_{18} internal olefin) defined above in this table.

7. Subpart A of this part is amended by adding Appendices 3 through 8 as follows:

Appendix 3 to Subpart A of Part 435—Procedure for Mixing Base Fluids with Sediments

This procedure describes a method for amending uncontaminated and nontoxic (control) sediments with the base fluids that are used to formulate synthetic-based drilling fluids and other non-aqueous drilling fluids. Initially, control sediments shall be press-sieved through a 2000 micron mesh sieve to remove large debris. Then press-sieve the sediment through a 500 micron sieve to remove indigenous organisms that may prey on the test species or otherwise confound test results. Homogenize control sediment to limit the effects of settling that may have occurred during storage. Sediments should be homogenized before density determinations and addition of base fluid to control sediment. Because base fluids are strongly hydrophobic and do not readily mix with sediment, care must be taken to ensure base fluids are thoroughly homogenized within the sediment. All concentrations are weight-to-weight (mg of base fluid to kg of dry control sediment). Sediment and base fluid mixing shall be accomplished by using the following method.

1. Determine the wet to dry ratio for the control sediment by weighing approximately 10 g subsamples of the screened and homogenized wet sediment into tared aluminum weigh pans. Dry sediment at 105 °C for 18–24 h. Remove sediment and cool in a desiccator until a constant weight is achieved. Re-weigh the samples to determine the dry weight. Determine the wet/dry ratio by dividing the net wet weight by the net dry weight:

[Wet Sediment Weight (g)]/[Dry Sediment Weight (g)] = Wet to Dry Ratio [1]

2. Determine the density (g/mL) of the wet control or dilution sediment. This shall be used to determine total volume of wet sediment needed for the various test treatments.

[Mean Wet Sediment Weight (g)]/[Mean Wet Sediment Volume (mL)] = Wet Sediment Density (g/mL) [2]

3. To determine the amount of base fluid needed to obtain a test concentration of 500 mg base fluid per kg dry sediment use the following formulas:

Determine the amount of wet sediment required:

[Wet Sediment Density (g/mL)] × [Volume of Sediment Required per Concentration (mL)] = Weight Wet Sediment Required per Conc. (g) [3]

Determine the amount of dry sediment in kilograms (kg) required for each concentration:

{[Wet Sediment per Concentration (g)]/[Mean Wet to Dry Ratio]} × (1kg/1000g) = Dry Weight Sediment (kg) [4]

Finally, determine the amount of base fluid required to spike the control sediment at each concentration:

[Conc. Desired (mg/kg)] × [Dry Weight Sediment (kg)] = Base Fluid Required (mg) [5]

For spiking test substances other than pure base fluids (*e.g.*, whole mud formulations), determine the spike amount as follows:

[Conc. Desired (mL/kg)] × [Dry Weight Sediment (kg)] × [Test Substance Density (g/mL)] = Test Substance Required (g) [6]

4. For primary mixing, place appropriate amounts of weighed base fluid into stainless mixing bowls, tare the vessel weight, then add sediment and mix with a high-shear dispersing impeller for 9 minutes. The concentration of base fluid in sediment from this mix, rather than the nominal concentration, shall be used in calculating LC_{50} values.

5. Tests for homogeneity of base fluid in sediment are to be performed during the procedure development phase. Because of

difficulty of homogeneously mixing base fluid with sediment, it is important to demonstrate that the base fluid is evenly mixed with sediment. The sediment shall be analyzed for total petroleum hydrocarbons (TPH) using EPA Methods 3550A and 8015M, with samples taken both prior to and after distribution to replicate test containers. Base-fluid content is measured as TPH. After mixing the sediment, a minimum of three replicate sediment samples shall be taken prior to distribution into test containers. After the test sediment is distributed to test containers, an additional three sediment samples shall be taken from three test containers to ensure proper distribution of base fluid within test containers. Base-fluid content results shall be reported within 48 hours of mixing. The coefficient of variation (CV) for the replicate samples must be less than 20%. If base-fluid content results are not within the 20% CV limit, the test sediment shall be remixed. Tests shall not begin until the CV is determined to be below the maximum limit of 20%. During the test, a minimum of three replicate containers shall be sampled to determine base-fluid content during each sampling period.

6. Mix enough sediment in this way to allow for its use in the preparation of all test concentrations and as a negative control. When commencing the sediment toxicity test, range-finding tests may be required to determine the concentrations that produce a toxic effect if these data are otherwise unavailable. The definitive test shall bracket the LC_{50}, which is the desired endpoint. The results for the base fluids shall be reported in mg of base fluid per kg of dry sediment.

References

American Society for Testing and Materials (ASTM). 1996. Standard Guide for Collection, Storage, Characterization, and Manipulation of Sediments for Toxicological Testing. ASTM E 1391–94. Annual Book of ASTM Standards, Volume 11.05, pp. 805–825.

Ditsworth, G.R., D.W. Schults and J.K.P. Jones. 1990. Preparation of benthic substrates for sediment toxicity testing, Environ. Toxicol. Chem. 9:1523–1529.

Suedel, B.C., J.H. Rodgers, Jr. and P.A. Clifford. 1993. Bioavailability of fluoranthene in freshwater sediment toxicity tests. Environ. Toxicol. Chem. 12:155–165.

U.S. EPA. 1994. Methods for Assessing the Toxicity of Sediment-associated Contaminants with Estuarine and Marine Amphipods. EPA/600/R–94/025. Office of Research and Development, Washington, DC.

Appendix 4 to Subpart A of Part 435—Determination of Biodegradation of Synthetic Base Fluids in a Marine Closed Bottle Test System: Summary of Modifications to ISO 11734:1995

The six modifications specified in this Appendix shall apply to the determination of the biodegradability of synthetic base fluids as measured by ISO 11734:1995. These modifications make the test more applicable to a marine environment and are listed below:

1. The laboratory shall use sea water in place of freshwater media.

1.1 The sea water may be either natural or synthetic. The allowable salinity range is 20–30 ppt.

1.2 To reduce the shock to the microorganisms in the sediment, the salinity of the sediment's porewater shall be between 20–30 ppt.

2. The laboratory shall use natural marine or estuarine sediments in place of digested sludge as an inoculum. The VS of the sediments must be no less than 2%.

2.1 Sediment should be used for testing as soon as possible after field collection. If required, the laboratory can store the sediment for a maximum period of two months prior to use. The test sediment shall be stored in the dark at 4°C.

2.2 The laboratory shall use the sediment mixing procedure specified in Appendix 3 to Subpart A of part 435 to spike the test sediment with base fluids. The final concentration will be 2000 mg carbon/Kg dry weight sediment. No less than 25 g dry weight of the spiked sediment shall be used per 125 ml serum bottle. The volume of sediment and seawater in the bottle shall be 75 ml.

3. The temperature of incubation shall be 29±1°C.

4. The pH is maintained at the level of natural sea water, not at 7.0 as referenced in ISO 11734:1995.

5. The optional use of a trace metals solution as specified in method ISO 11734:1995 shall not be used as part of these test modifications.

6. The laboratory shall conduct the test for 275 days. The laboratory may seek approval of alternate test durations under the approval procedures specified at 40 CFR 136.4 and 136.5. Any modification of this method, beyond those expressly permitted, shall be considered a major modification subject to application and approval of alternate test procedures under 40 CFR 136.4 and 136.5.

Appendix 5 to Subpart A of Part 435—Determination of Crude Oil Contamination in Non-Aqueous Drilling Fluids by Gas Chromatography/Mass Spectrometry (GC/MS)

1.0 Scope and Application

1.1 This method determines crude (formation) oil contamination, or other petroleum oil contamination, in non-aqueous drilling fluids (NAFs) by comparing the gas chromatography/mass spectrometry (GC/MS) fingerprint scan and extracted ion scans of the test sample to that of an uncontaminated sample.

1.2 This method can be used for monitoring oil contamination of NAFs or monitoring oil contamination of the base fluid used in the NAF formulations.

1.3 Any modification of this method beyond those expressly permitted shall be considered as a major modification subject to application and approval of alternative test procedures under 40 CFR 136.4 and 136.5.

1.4 The gas chromatography/mass spectrometry portions of this method are restricted to use by, or under the supervision of analysts experienced in the use of GC/MS and in the interpretation of gas chromatograms and extracted ion scans. Each laboratory that uses this method must generate acceptable results using the procedures described in Sections 7, 9.2, and 12 of this appendix.

2.0 Summary of Method

2.1 Analysis of NAF for crude oil contamination is a step-wise process. The analyst first performs a qualitative assessment of the presence or absence of crude oil in the sample. If crude oil is detected during this qualitative assessment, the analyst must perform a quantitative analysis of the crude oil concentration.

2.2 A sample of NAF is centrifuged to obtain a solids free supernate.

2.3 The test sample is prepared by removing an aliquot of the solids free supernate, spiking it with internal standard, and analyzing it using GC/MS techniques. The components are separated by the gas chromatograph and detected by the mass spectrometer.

2.4 Qualitative identification of crude oil contamination is performed by comparing the Total Ion Chromatograph (TIC) scans and Extracted Ion Profile (EIP) scans of test sample to that of uncontaminated base fluids, and examining the profiles for chromatographic signatures diagnostic of oil contamination.

2.5 The presence or absence of crude oil contamination observed in the full scan profiles and selected extracted ion profiles determines further sample quantitation and reporting requirements.

2.6 If crude oil is detected in the qualitative analysis, quantitative analysis must be performed by calibrating the GC/MS using a designated NAF spiked with known concentrations of a designated oil.

2.7 Quality is assured through reproducible calibration and testing of GC/MS system and through analysis of quality control samples.

3.0 Definitions

3.1 A NAF is one in which the continuous— phase is a water immiscible fluid such as an oleaginous material (e.g., mineral oil, enhance mineral oil, paraffinic oil, or synthetic material such as olefins and vegetable esters).

3.2 TIC—Total Ion Chromatograph.

3.3 EIP—Extracted Ion Profile.

3.4 TCB—1,3,5-trichlorobenzene is used as the internal standard in this method.

3.5 SPTM—System Performance Test Mix standards are used to establish retention times and monitor detection levels.

4.0 Interferences and Limitations

4.1 Solvents, reagents, glassware, and other sample processing hardware may yield artifacts and/or elevated baselines causing misinterpretation of chromatograms.

4.2 All Materials used in the analysis shall be demonstrated to be free from interferences by running method blanks. Specific selection of reagents and purification of solvents by distillation in all-glass systems may be required.

4.3 Glassware shall be cleaned by rinsing with solvent and baking at 400 °C for a minimum of 1 hour.

4.4 Interferences may vary from source to source, depending on the diversity of the samples being tested.

4.5 Variations in and additions of base fluids and/or drilling fluid additives (emulsifiers, dispersants, fluid loss control agents, etc.) might also cause interferences and misinterpretation of chromatograms.

4.6 Difference in light crude oils, medium crude oils, and heavy crude oils will result in different responses and thus different interpretation of scans and calculated percentages.

5.0 Safety

5.1 The toxicity or carcinogenicity of each reagent used in this method has not been precisely determined; however each chemical shall be treated as a potential health hazard. Exposure to these chemicals should be reduced to the lowest possible level.

5.2 Unknown samples may contain high concentration of volatile toxic compounds. Sample containers should be opened in a hood and handled with gloves to prevent exposure. In addition, all sample preparation should be conducted in a fume hood to limit the potential exposure to harmful contaminates.

5.3 This method does not address all safety issues associated with its use. The laboratory is responsible for maintaining a safe work environment and a current awareness file of OSHA regulations regarding the safe handling of the chemicals specified in this method. A reference file of material safety data sheets (MSDSs) shall be available to all personnel involved in these analyses. Additional references to laboratory safety can be found in References 16.1 through 16.3.

5.4 NAF base fluids may cause skin irritation, protective gloves are recommended while handling these samples.

6.0 Apparatus and Materials

Note: Brand names, suppliers, and part numbers are for illustrative purposes only. No endorsement is implied. Equivalent performance may be achieved using apparatus and materials other than those specified here, but demonstration of equivalent performance meeting the requirements of this method is the responsibility of the laboratory.

6.1 Equipment for glassware cleaning.

6.1.1 Laboratory sink with overhead fume hood.

6.1.2 Kiln—Capable of reaching 450 °C within 2 hours and holding 450 °C within ±10 °C, with temperature controller and safety switch (Cress Manufacturing Co., Santa Fe Springs, CA B31H or X31TS or equivalent).

6.2 Equipment for sample preparation.

6.2.1 Laboratory fume hood.

6.2.2 Analytical balance—Capable of weighing 0.1 mg.

6.2.3 Glassware.

6.2.3.1 Disposable pipettes—Pasteur, 150 mm long by 5 mm ID (Fisher Scientific 13–678–6A, or equivalent) baked at 400 °C for a minimum of 1 hour.

6.2.3.2 Glass volumetric pipettes or gas tight syringes—1.0-mL ± 1% and 0.5-mL ± 1%.

6.2.3.3 Volumetric flasks—Glass, class A, 10-mL, 50-mL and 100-mL.

6.2.3.4—Sample vials—Glass, 1- to 3-mL (baked at 400 °C for a minimum of 1 hour) with PTFE-lined screw or crimp cap.

6.2.3.5 Centrifuge and centrifuge tubes—Centrifuge capable of 10,000 rpm, or better, (International Equipment Co., IEC Centra MP4 or equivalent) and 50-mL centrifuge tubes (Nalgene, Ultratube, Thin Wall 25×89 mm, #3410–2539).

6.3 Gas Chromatograph/Mass Spectrometer (GC/MS):

6.3.1 Gas Chromatograph—An analytical system complete with a temperature-programmable gas chromatograph suitable for split/splitless injection and all required accessories, including syringes, analytical columns, and gases.

6.3.1.1 Column—30 m (or 60 m) × 0.32 mm ID (or 0.25 mm ID) 1µm film thickness (or 0.25µm film thickness) silicone-coated fused-silica capillary column (J&W Scientific DB–5 or equivalent).

6.3.2 Mass Spectrometer—Capable of scanning from 35 to 500 amu every 1 sec or less, using 70 volts (nominal) electron energy in the electron impact ionization mode (Hewlett Packard 5970MS or comparable).

6.3.3 GC/MS interface—the interface is a capillary-direct interface from the GC to the MS.

6.3.4—Data system—A computer system must be interfaced to the mass spectrometer. The system must allow the continuous acquisition and storage on machine-readable media of all mass spectra obtained throughout the duration of the chromatographic program. The computer must have software that can search any GC/MS data file for ions of a specific mass and that can plot such ion abundance versus retention time or scan number. This type of plot is defined as an Extracted Ion Current Profile (EIP). Software must also be available that allows integrating the abundance in any total ion chromatogram (TIC) or EIP between specified retention time or scan-number limits. It is advisable that the most recent version of the EPA/NIST Mass Spectral Library be available.

7.0 Reagents and Standards

7.1 Methylene chloride—Pesticide grade or equivalent. Use when necessary for sample dilution.

7.2 Standards—Prepare from pure individual standard materials or purchase as certified solutions. If compound purity is 96% or greater, the weight may be used without correction to compute the concentration of the standard.

7.2.1 Crude Oil Reference—Obtain a sample of a crude oil with a known API gravity. This oil shall be used in the calibration procedures.

7.2.2 Synthetic Base Fluid—Obtain a sample of clean internal olefin (IO) Lab drilling fluid (as sent from the supplier—has not been circulated downhole). This drilling fluid shall be used in the calibration procedures.

7.2.3 Internal standard—Prepare a 0.01 g/mL solution of 1,3,5-trichlorobenzene (TCB). Dissolve 1.0 g of TCB in methylene chloride and dilute to volume in a 100-mL volumetric flask. Stopper, vortex, and transfer the solution to a 150-mL bottle with PTFE-lined cap. Label appropriately, and store at –5 °C to 20 °C. Mark the level of the meniscus on the bottle to detect solvent loss.

7.2.4 GC/MS system performance test mix (SPTM) standards—The SPTM standards shall contain octane, decane, dodecane, tetradecane, tetradecene, toluene, ethylbenzene, 1,2,4-trimethylbenzene, 1-methylnaphthalene and 1,3-dimethylnaphthalene. These compounds can be purchased individually or obtained as a mixture (i.e. Supelco, Catalog No. 4–7300). Prepare a high concentration of the SPTM standard at 62.5 mg/mL in methylene chloride. Prepare a medium concentration SPTM standard at 1.25 mg/mL by transferring 1.0 mL of the 62.5 mg/mL solution into a 50 mL volumetric flask and diluting to the mark with methylene chloride. Finally, prepare a low concentration SPTM standard at 0.125 mg/mL by transferring 1.0 mL of the 1.25 mg/mL solution into a 10-mL volumetric flask and diluting to the mark with methylene chloride.

7.2.5 Crude oil/drilling fluid calibration standards—Prepare a 4-point crude oil/drilling fluid calibration at concentrations of 0% (no spike—clean drilling fluid), 0.5%, 1.0%, and 2.0% by weight according to the procedures outlined in this appendix using the Reference Crude Oil:

7.2.5.1 Label 4 jars with the following identification: Jar 1—0%Ref-IOLab, Jar 2—0.5%Ref-IOLab, Jar 3—1%Ref-IOLab, and Jar 4—2%Ref-IOLab.

7.2.5.2 Weigh 4, 50-g aliquots of well mixed IO Lab drilling fluid into each of the 4 jars.

7.2.5.3 Add Reference Oil at 0.5%, 1.0%, and 2.0% by weight to jars 2, 3, and 4 respectively. Jar 1 shall not be spiked with Reference Oil in order to retain a ''0%'' oil concentration.

7.2.5.4 Thoroughly mix the contents of each of the 4 jars, using clean glass stirring rods.

7.2.5.5 Transfer (weigh) a 30-g aliquot from Jar 1 to a labeled centrifuge tube. Centrifuge the aliquot for a minimum of 15 min at approximately 15,000 rpm, in order to obtain a solids free supernate. Weigh 0.5 g of the supernate directly into a tared and appropriately labeled GC straight vial. Spike the 0.5-g supernate with 500 µL of the 0.01g/mL 1,3,5-trichlorobenzene internal standard solution (*see* Section 7.2.3 of this appendix), cap with a Teflon lined crimp cap, and vortex for ca. 10 sec.

7.2.5.6 Repeat step 7.2.5.5 except use an aliquot from Jar 2.

7.2.5.7 Repeat step 7.2.5.5 except use an aliquot from Jar 3.

7.2.5.8 Repeat step 7.2.5.5 except use an aliquot from Jar 4.

7.2.5.9 These 4 crude/oil drilling fluid calibration standards are now used for qualitative and quantitative GC/MS analysis.

7.2.6 Precision and recovery standard (mid level crude oil/drilling fluid calibration standard)—Prepare a mid point crude oil/drilling fluid calibration using IO Lab drilling fluid and Reference Oil at a concentration of 1.0% by weight. Prepare this standard according to the procedures outlined in Section 7.2.5.1 through 7.2.5.5 of this appendix, with the exception that only ''Jar

3'' needs to be prepared. Remove and spike with internal standard, as many 0.5-g aliquots as needed to complete the GC/MS analysis (*see* Section 11.6 of this appendix—bracketing authentic samples every 12 hours with precision and recovery standard) and the initial demonstration exercise described in Section 9.2 of this appendix.

7.2.7 Stability of standards

7.2.7.1 When not used, standards shall be stored in the dark, at −5 to −20 °C in screw-capped vials with PTFE-lined lids. Place a mark on the vial at the level of the solution so that solvent loss by evaporation can be detected. Bring the vial to room temperature prior to use.

7.2.7.2 Solutions used for quantitative purposes shall be analyzed within 48 hours of preparation and on a monthly basis thereafter for signs of degradation. A standard shall remain acceptable if the peak area remains within ±15% of the area obtained in the initial analysis of the standard.

8.0 Sample Collection Preservation and Storage

8.1 Collect NAF and base fluid samples in 100- to 200-mL glass bottles with PTFE- or aluminum foil lined caps.

8.2 Samples collected in the field shall be stored refrigerated until time of preparation.

8.3 Sample and extract holding times for this method have not yet been established. However, based on initial experience with the method, samples should be analyzed within seven to ten days of collection and extracts should be analyzed within seven days of preparation.

8.4 After completion of GC/MS analysis, extracts shall be refrigerated at 4 °C until further notification of sample disposal.

9.0 Quality Control

9.1 Each laboratory that uses this method is required to operate a formal quality assurance program (Reference 16.4). The minimum requirements of this program shall consist of an initial demonstration of laboratory capability, and ongoing analysis of standards, and blanks as a test of continued performance, analyses of spiked samples to assess accuracy and analysis of duplicates to assess precision. Laboratory performance shall be compared to established performance criteria to determine if the results of analyses meet the performance characteristics of the method.

9.1.1 The analyst shall make an initial demonstration of the ability to generate acceptable accuracy and precision with this method. This ability shall be established as described in Section 9.2 of this appendix.

9.1.2 The analyst is permitted to modify this method to improve separations or lower the cost of measurements, provided all performance requirements are met. Each time a modification is made to the method, the analyst is required to repeat the calibration (Section 10.4 of this appendix) and to repeat the initial demonstration procedure described in Section 9.2 of this appendix.

9.1.3 Analyses of blanks are required to demonstrate freedom from contamination. The procedures and criteria for analysis of a blank are described in Section 9.3 of this appendix.

9.1.4 Analysis of a matrix spike sample is required to demonstrate method accuracy. The procedure and QC criteria for spiking are described in Section 9.4 of this appendix.

9.1.5 Analysis of a duplicate field sample is required to demonstrate method precision. The procedure and QC criteria for duplicates are described in Section 9.5 of this appendix.

9.1.6 Analysis of a sample of the clean NAF(s) (as sent from the supplier—i.e., has not been circulated downhole) used in the drilling operations is required.

9.1.7 The laboratory shall, on an ongoing basis, demonstrate through calibration verification and the analysis of the precision and recovery standard (Section 7.2.6 of this appendix) that the analysis system is in control. These procedures are described in Section 11.6 of this appendix.

9.1.8 The laboratory shall maintain records to define the quality of data that is generated.

9.2 Initial precision and accuracy—The initial precision and recovery test shall be performed using the precision and recovery standard (1% by weight Reference Oil in IO Lab drilling fluid). The laboratory shall generate acceptable precision and recovery by performing the following operations.

9.2.1 Prepare four separate aliquots of the precision and recovery standard using the procedure outlined in Section 7.2.6 of this appendix. Analyze these aliquots using the procedures outlined in Section 11 of this appendix.

9.2.2 Using the results of the set of four analyses, compute the average recovery (X) in weight percent and the standard deviation of the recovery(s) for each sample.

9.2.3 If s and X meet the acceptance criteria of 80% to 110%, system performance is acceptable and analysis of samples may begin. If, however, s exceeds the precision limit or X falls outside the range for accuracy, system performance is unacceptable. In this event, review this method, correct the problem, and repeat the test.

9.2.4 Accuracy and precision—The average percent recovery (P) and the standard deviation of the percent recovery (Sp) Express the accuracy assessment as a percent recovery interval from $P-2S_p$ to $P+2S_p$. For example, if P=90% and S_p=10% for four analyses of crude oil in NAF, the accuracy interval is expressed as 70% to 110%. Update the accuracy assessment on a regular basis.

9.3 Blanks—Rinse glassware and centrifuge tubes used in the method with 30 mL of methylene chloride, remove a 0.5-g aliquot of the solvent, spike it with the 500 µL of the internal standard solution (Section 7.2.3 of this appendix) and analyze a 1-µL aliquot of the blank sample using the procedure in Section 11 of this appendix. Compute results per Section 12 of this appendix.

9.4 Matrix spike sample—Prepare a matrix spike sample according to procedure outlined in Section 7.2.6 of this appendix. Analyze the sample and calculate the concentration (% oil) in the drilling fluid and % recovery of oil from the spiked drilling fluid using the methods described in Sections 11 and 12 of this appendix.

9.5 Duplicates—A duplicate field sample shall be prepared according to procedures outlined in Section 7.3 of this appendix and analyzed according to Section 11 of this appendix. The relative percent difference (RPD) of the calculated concentrations shall be less than 15%.

9.5.1 Analyze each of the duplicates per the procedure in Section 11 of this appendix and compute the results per Section 12 of this appendix.

9.5.2 Calculate the relative percent difference (RPD) between the two results per the following equation:

$$RPD = [D_1 - D_2]/[(D_1 + D_2)/2] \times 100 \quad [1]$$

where:

D_1 = Concentration of crude oil in the sample; and

D_2 = Concentration of crude oil in the duplicate sample.

9.5.3 If the RPD criteria are not met, the analytical system shall be judged to be out of control, and the problem must be immediately identified and corrected, and the sample batch re-analyzed.

9.6 Prepare the clean NAF sample according to procedures outlined in Section 7.3 of this appendix. Ultimately the oil-equivalent concentration from the TIC or EIP signal measured in the clean NAF sample shall be subtracted from the corresponding authentic field samples in order to calculate the true contaminant concentration (% oil) in the field samples (*see* Section 12 of this appendix).

9.7 The specifications contained in this method can be met if the apparatus used is calibrated properly, and maintained in a calibrated state. The standards used for initial precision and recovery (Section 9.2 of this appendix) and ongoing precision and recovery (Section 11.6 of this appendix) shall be identical, so that the most precise results will be obtained. The GC/MS instrument will provide the most reproducible results if dedicated to the setting and conditions required for the analyses given in this method.

9.8 Depending on specific program requirements, field replicates and field spikes of crude oil into samples may be required when this method is used to assess the precision and accuracy of the sampling and sample transporting techniques.

10.0 Calibration

10.1 Establish gas chromatographic/mass spectrometer operating conditions given in Table 1 of this appendix. Perform the GC/MS system hardware-tune as outlined by the manufacture. The gas chromatograph shall be calibrated using the internal standard technique.

Note: Because each GC is slightly different, it may be necessary to adjust the operating conditions (carrier gas flow rate and column temperature and temperature program) slightly until the retention times in Table 2 of this appendix are met.

TABLE 1.—GAS CHROMATOGRAPH/MASS SPECTROMETER (GC/MS) OPERATION CONDITIONS

Parameter	Setting
Injection pot	280 °C

TABLE 1.—GAS CHROMATOGRAPH/MASS SPECTROMETER (GC/MS) OPERATION CONDITIONS—Continued

Parameter	Setting
Transfer line	280 °C
Detector	280 °C
Initial Temperature	50 °C
Initial Time	5 minutes
Ramp	50 to 300 °C @ 5 °C per minute
Final Temperature	300 °C
Final Hold	20 minutes or until all peaks have eluted
Carrier Gas	Helium
Flow rate	As required for standard operation
Split ratio	As required to meet performance criteria (~1:100)
Mass range	35 to 600 amu

TABLE 2.—APPROXIMATE RETENTION TIME FOR COMPOUNDS

Compound	Approximate retention time (minutes)
Toluene	5.6
Octane, n – C_8	7.2
Ethylbenzene	10.3
1,2,4-Trimethylbenzene	16.0
Decane, – C_{10}	16.1
TCB (Internal Standard)	21.3
Dodecane, – C_{12}	22.9
1-Methylnaphthalene	26.7
1-Tetradecene	28.4
Tetradecane, – C_{14}	28.7
1,3-Dimethylnaphthalene	29.7

10.2 Internal standard calibration procedure—1,3,5-trichlorobenzene (TCB) has been shown to be free of interferences from diesel and crude oils and is a suitable internal standard.

10.3 The system performance test mix standards prepared in Section 7.2.4 of this appendix shall be used to establish retention times and establish qualitative detection limits.

10.3.1 Spike a 500-mL aliquot of the 1.25 mg/mL SPTM standard with 500 µL of the TCB internal standard solution.

10.3.2 Inject 1.0 µL of this spiked SPTM standard onto the GC/MS in order to demonstrate proper retention times. For the GC/MS used in the development of this method, the ten compounds in the mixture had typical retention times shown in Table 2 of this appendix. Extracted ion scans for m/z 91 and 105 showed a maximum abundance of 400,000.

10.3.3 Spike a 500-mL aliquot of the 0.125 mg/mL SPTM standard with 500 µL of the TCB internal standard solution.

10.3.4 Inject 1.0 µL of this spiked SPTM standard onto the GC/MS to monitor detectable levels. For the GC/MS used in the development of this test, all ten compounds showed a minimum peak height of three times signal to noise. Extracted ion scans for m/z 91 and 105 showed a maximum abundance of 40,000.

10.4 GC/MS crude oil/drilling fluid calibration—There are two methods of quantification: Total Area Integration (C_8–C_{13}) and EIP Area Integration using m/z's 91 and 105. The Total Area Integration method should be used as the primary technique for quantifying crude oil in NAFs. The EIP Area Integration method should be used as a confirmatory technique for NAFs. However, the EIP Area Integration method shall be used as the primary method for quantifying oil in enhanced mineral oil (EMO) based drilling fluid. Inject 1.0 µL of each of the four crude oil/drilling fluid calibration standards prepared in Section 7.2.5 of this appendix into the GC/MS. The internal standard should elute approximately 21–22 minutes after injection. For the GC/MS used in the development of this method, the internal standard peak was (35 to 40)% of full scale at an abundance of about 3.5e+07.

10.4.1 Total Area Integration Method—For each of the four calibration standards obtain the following: Using a straight baseline integration technique, obtain the total ion chromatogram (TIC) area from C_8 to C_{13}. Obtain the TIC area of the internal standard (TCB). Subtract the TCB area from the C_8–C_{13} area to obtain the true C_8–C_{13} area. Using the C_8–C_{13} and TCB areas, and known internal standard concentration, generate a linear regression calibration using the internal standard method. The r^2 value for the linear regression curve shall be greater than or equal to 0.998. Some synthetic fluids might have peaks that elute in the window and would interfere with the analysis. In this case the integration window can be shifted to other areas of scan where there are no interfering peaks from the synthetic base fluid.

10.4.2 EIP Area Integration—For each of the four calibration standards generate Extracted Ion Profiles (EIPs) for m/z 91 and 105. Using straight baseline integration techniques, obtain the following EIP areas:

10.4.2.1 For m/z 91 integrate the area under the curve from approximately 9 minutes to 21–22 minutes, just prior to but not including the internal standard.

10.4.2.2 For m/z 105 integrate the area under the curve from approximately 10.5 minutes to 26.5 minutes.

10.4.2.3 Obtain the internal standard area from the TCB in each of the four calibration standards, using m/z 180.

10.4.2.4 Using the EIP areas for TCB, m/z 91 and m/z105, and the known concentration of internal standard, generate linear regression calibration curves for the target ions 91 and 105 using the internal standard method. The r^2 value for each of the EIP linear regression curves shall be greater than or equal to 0.998.

10.4.2.5 Some base fluids might produce a background level that would show up on the extracted ion profiles, but there should not be any real peaks (signal to noise ratio of 1:3) from the clean base fluids.

11.0 Procedure

11.1 Sample Preparation—

11.1.1 Mix the authentic field sample (drilling fluid) well. Transfer (weigh) a 30-g aliquot of the sample to a labeled centrifuge tube.

11.1.2 Centrifuge the aliquot for a minimum of 15 min at approximately 15,000 rpm, in order to obtain a solids free supernate.

11.1.3 Weigh 0.5 g of the supernate directly into a tared and appropriately labeled GC straight vial.

11.1.4 Spike the 0.5-g supernate with 500 µL of the 0.01g/mL 1,3,5-trichlorobenzene internal standard solution (*see* Section 7.2.3 of this appendix), cap with a Teflon lined crimp cap, and vortex for ca. 10 sec.

11.1.5 The sample is ready for GC/MS analysis.

11.2 Gas Chromatography.

Table 1 of this appendix summarizes the recommended operating conditions for the GC/MS. Retention times for the n-alkanes obtained under these conditions are given in Table 2 of this appendix. Other columns, chromatographic conditions, or detectors may be used if initial precision and accuracy requirements (Section 9.2 of this appendix) are met. The system shall be calibrated according to the procedures outlined in Section 10 of this appendix, and verified every 12 hours according to Section 11.6 of this appendix.

11.2.1 Samples shall be prepared (extracted) in a batch of no more than 20 samples. The batch shall consist of 20 authentic samples, 1 blank (Section 9.3 of this appendix), 1 matrix spike sample (9.4), and 1 duplicate field sample (9.5), and a prepared sample of the corresponding clean NAF used in the drilling process.

11.2.2 An analytical sequence shall be analyzed on the GC/MS where the 3 SPTM standards (Section 7.2.4 of this appendix) containing internal standard are analyzed first, followed by analysis of the four GC/MS crude oil/drilling fluid calibration standards (Section 7.2.5 of this appendix), analysis of the blank, matrix spike sample, the duplicate sample, the clean NAF sample, followed by the authentic samples.

11.2.3 Samples requiring dilution due to excessive signal shall be diluted using methylene chloride.

11.2.4 Inject 1.0 µL of the test sample or standard into the GC, using the conditions in Table 1 of this appendix.

11.2.5 Begin data collection and the temperature program at the time of injection.

11.2.6 Obtain a TIC and EIP fingerprint scans of the sample (Table 3 of this appendix).

11.2.7 If the area of the C_8 to C_{13} peaks exceeds the calibration range of the system, dilute a fresh aliquot of the test sample weighing 0.50-g and re-analyze.

11.2.8 Determine the C_8 to C_{13} TIC area, the TCB internal standard area, and the areas for the m/z 91 and 105 EIPs. These shall be used in the calculation of oil concentration in the samples (see Section 12 of this appendix).

TABLE 3.—RECOMMENDED ION MASS NUMBERS

Selected ion mass numbers	Corresponding aromatic compounds	Typical rentention time (minutes)
91	Methylbenzene	6.0
	Ethylbenzene	10.3
	1,4-Dimethylbenzene	10.9
	1,3-Dimethylbenzene	10.9
	1,2-Dimethylbenzene	11.9
105	1,3,5-Trimethylbenzene	15.1
	1,2,4-Trimethylbenzene	16.0
	1,2,3-Trimethylbenzene	17.4
156	2,6-Dimethylnaphthalene	28.9
	1,2-Dimethylnaphthalene	29.4
	1,3-Dimethylnaphthalene	29.7

11.2.9 Observe the presence of peaks in the EIPs that would confirm the presence of any target aromatic compounds. Using the EIP areas and EIP linear regression calibrations compare the abundance of the aromatic peaks, and if appropriate, determine approximate crude oil contamination in the sample for each of the target ions.

11.3 Qualitative Identification—See Section 17 of this appendix for schematic flowchart.

11.3.1 Qualitative identification shall be accomplished by comparison of the TIC and EIP area data from an authentic sample to the TIC and EIP area data from the calibration standards (Section 12.4 of this appendix). Crude oil shall be identified by the presence of C_{10} to C_{13} n-alkanes and corresponding target aromatics.

11.3.2 Using the calibration data, establish the identity of the C_8 to C_{13} peaks in the chromatogram of the sample. Using the calibration data, establish the identity of any target aromatics present on the extracted ion scans.

11.3.3 Crude oil is not present in a detectable amount in the sample if there are no target aromatics seen on the extracted ion scans. The experience of the analyst shall weigh heavily in the determination of the presence of peaks at a signal-to-noise ratio of 3 or greater.

11.3.4 If the chromatogram shows n-alkanes from C_8 to C_{13} and target aromatics to be present, contamination by crude oil or diesel shall be suspected and quantitative analysis shall be determined. If there are no n-alkanes present that are not seen on the blank, and no target aromatics are seen, the sample can be considered to be free of contamination.

11.4 Quantitative Identification—

11.4.1 Determine the area of the peaks from C_8 to C_{13} as outlined in the calibration section (10.4.1 of this appendix). If the area of the peaks for the sample is greater than that for the clean NAF (base fluid) use the crude oil/drilling fluid calibration TIC linear regression curve to determine approximate crude oil contamination.

11.4.2 Using the EIPs outlined in Section 10.4.2 of this appendix, determine the presence of any target aromatics. Using the integration techniques outlined in Section 10.4.2 of this appendix, obtain the EIP areas for m/z 91 and 105. Use the crude oil/drilling fluid calibration EIP linear regression curves to determine approximate crude oil contamination.

11.5 Complex Samples—

11.5.1 The most common interferences in the determination of crude oil can be from mineral oil, diesel oil, and proprietary additives in drilling fluids.

11.5.2 Mineral oil can typically be identified by its lower target aromatic content, and narrow range of strong peaks.

11.5.3 Diesel oil can typically be identified by low amounts of n-alkanes from C_7 to C_9, and the absence of n-alkanes greater than C_{25}.

11.5.4 Crude oils can usually be distinguished by the presence of high aromatics, increased intensities of C_8 to C_{13} peaks, and/ or the presence of higher hydrocarbons of C_{25} and greater (which may be difficult to see in some synthetic fluids at low contamination levels).

11.5.4.1 Oil condensates from gas wells are low in molecular weight and will normally produce strong chromatographic peaks in the C_8–C_{13} range. If a sample of the gas condensate crude oil from the formation is available, the oil can be distinguished from other potential sources of contamination by using it to prepare a calibration standard.

11.5.4.2 Asphaltene crude oils with API gravity 20 may not produce chromatographic peaks strong enough to show contamination at levels of the calibration. Extracted ion peaks should be easier to see than increased intensities for the C_8 to C_{13} peaks. If a sample of asphaltene crude from the formation is available, a calibration standard shall be prepared.

11.6 System and Laboratory Performance—

11.6.1 At the beginning of each 8-hour shift during which analyses are performed, GC crude oil/drilling fluid calibration and system performance test mixes shall be verified. For these tests, analysis of the medium-level calibration standard (1-% Reference Oil in IO Lab drilling fluid, and 1.25 mg/mL SPTM with internal standard) shall be used to verify all performance criteria. Adjustments and/or re-calibration (per Section 10 of this appendix) shall be performed until all performance criteria are met. Only after all performance criteria are met may samples and blanks be analyzed.

11.6.2 Inject 1.0 µL of the medium-level GC/MS crude oil/drilling fluid calibration standard into the GC instrument according to the procedures in Section 11.2 of this appendix. Verify that the linear regression curves for both TIC area and EIP areas are still valid using this continuing calibration standard.

11.6.3 After this analysis is complete, inject 1.0 µL of the 1.25 mg/mL SPTM (containing internal standard) into the GC instrument and verify the proper retention times are met (*see* Table 2 of this appendix).

11.6.4 Retention times—Retention time of the internal standard. The absolute retention time of the TCB internal standard shall be within the range 21.0 ± 0.5 minutes. Relative retention times of the n-alkanes: The retention times of the n-alkanes relative to the TCB internal standard shall be similar to those given in Table 2 of this appendix.

12.0 Calculations

The concentration of oil in NAFs drilling fluids shall be computed relative to peak areas between C_8 and C_{13} (using the Total Area Integration method) or total peak areas from extracted ion profiles (using the Extracted Ion Profile Method). In either case, there is a measurable amount of peak area, even in clean drilling fluid samples, due to spurious peaks and electrometer ''noise'' that contributes to the total signal measured using either of the quantification methods. In this procedure, a correction for this signal is applied, using the blank or clean sample correction technique described in American Society for Testing Materials (ASTM) Method D–3328–90, Comparison of Waterborne Oil by Gas Chromatography. In this method, the ''oil equivalents'' measured in a blank sample by total area gas chromatography are subtracted from that determined for a field sample to arrive at the most accurate measure of oil residue in the authentic sample.

12.1 Total Area Integration Method

12.1.1 Using C_8 to C_{13} TIC area, the TCB area in the clean NAF sample and the TIC linear regression curve, compute the oil equivalent concentration of the C_8 to C_{13} retention time range in the clean NAF.

Note: The actual TIC area of the C_8 to C_{13} is equal to the C_8 to C_{13} area minus the area of the TCB.

12.1.2 Using the corresponding information for the authentic sample, compute the oil equivalent concentration of the C_8 to C_{13} retention time range in the authentic sample.

12.1.3 Calculate the concentration (% oil) of oil in the sample by subtracting the oil

equivalent concentration (% oil) found in the clean NAF from the oil equivalent concentration (% oil) found in the authentic sample.

12.2 EIP Area Integration Method

12.2.1 Using either m/z 91 or 105 EIP areas, the TCB area in the clean NAF sample, and the appropriate EIP linear regression curve, compute the oil equivalent concentration of the in the clean NAF.

12.2.2 Using the corresponding information for the authentic sample, compute its oil equivalent concentration.

12.2.3 Calculate the concentration (% oil) of oil in the sample by subtracting the oil equivalent concentration (% oil) found in the clean NAF from the oil equivalent concentration (% oil) found in the authentic sample.

13.0 Method Performance

13.1 Specification in this method are adopted from EPA Method 1663, Differentiation of Diesel and Crude Oil by GC/FID (Reference 16.5).

13.2 Single laboratory method performance using an Internal Olefin (IO) drilling fluid fortified at 0.5% oil using a 35 API gravity oil was:

Precision and accuracy 94±4%
Accuracy interval—86.3% to 102%
Relative percent difference in duplicate analysis—6.2%

14.0 Pollution Prevention

14.1 The solvent used in this method poses little threat to the environment when recycled and managed properly.

15.0 Waste Management

15.1 It is the laboratory's responsibility to comply with all federal, state, and local regulations governing waste management, particularly the hazardous waste identification rules and land disposal restriction, and to protect the air, water, and land by minimizing and controlling all releases from fume hoods and bench operations. Compliance with all sewage discharge permits and regulations is also required.

15.2 All authentic samples (drilling fluids) failing the RPE (fluorescence) test (indicated by the presence of fluorescence) shall be retained and classified as contaminated samples. Treatment and ultimate fate of these samples is not outlined in this SOP.

15.3 For further information on waste management, consult ''The Waste Management Manual for Laboratory Personnel'', and ''Less is Better: Laboratory Chemical Management for Waste Reduction'', both available from the American Chemical Society's Department of Government Relations and Science Policy, 1155 16th Street NW, Washington, DC 20036.

16.0 References

16.1 Carcinogens—''Working With Carcinogens.'' Department of Health, Education, and Welfare, Public Health Service, Centers for Disease Control (available through National Technical Information Systems, 5285 Port Royal Road, Springfield, VA 22161, document no. PB–277256): August 1977.

16.2 ''OSHA Safety and Health Standards, General Industry [29 CFR 1910], Revised.'' Occupational Safety and Health Administration, OSHA 2206. Washington, DC: January 1976.

16.3 ''Handbook of Analytical Quality Control in Water and Wastewater Laboratories.'' USEPA, EMSSL–CI, EPA–600/4–79–019. Cincinnati, OH: March 1979.

16.4 ''Method 1663, Differentiation of Diesel and Crude Oil by GC/FID, Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges, EPA 821–R–92–008, Office of Water Engineering and Analysis Division, Washington, DC: December 1992.

Appendix 6 to Subpart A of Part 435—Reverse Phase Extraction (RPE) Method for Detection of Oil Contamination in Non-Aqueous Drilling Fluids (NAF)

1.0 Scope and Application

1.1 This method is used for determination of crude or formation oil, or other petroleum oil contamination, in non-aqueous drilling fluids (NAFs).

1.2 This method is intended as a positive/negative test to determine a presence of crude oil in NAF prior to discharging drill cuttings from offshore production platforms.

1.3 This method is for use in the Environmental Protection Agency's (EPA's) survey and monitoring programs under the Clean Water Act, including monitoring of compliance with the Gulf of Mexico NPDES General Permit for monitoring of oil contamination in drilling fluids.

1.4 This method has been designed to show positive contamination for 5% of representative crude oils at a concentration of 0.1% in drilling fluid (vol/vol), 50% of representative crude oils at a concentration of 0.5%, and 95% of representative crude oils at a concentration of 1%.

1.5 Any modification of this method, beyond those expressly permitted, shall be considered a major modification subject to application and approval of alternate test procedures under 40 CFR Parts 136.4 and 136.5.

1.6 Each laboratory that uses this method must demonstrate the ability to generate acceptable results using the procedure in Section 9.2 of this appendix.

2.0 Summary of Method

2.1 An aliquot of drilling fluid is extracted using isopropyl alcohol.

2.2 The mixture is allowed to settle and then filtered to separate out residual solids.

2.3 An aliquot of the filtered extract is charged onto a reverse phase extraction (RPE) cartridge.

2.4 The cartridge is eluted with isopropyl alcohol.

2.5 Crude oil contaminates are retained on the cartridge and their presence (or absence) is detected based on observed fluorescence using a black light.

3.0 Definitions

3.1 A NAF is one in which the continuous phase is a water immiscible fluid such as an oleaginous material (e.g., mineral oil, enhance mineral oil, paraffinic oil, or synthetic material such as olefins and vegetable esters).

4.0 Interferences

4.1 Solvents, reagents, glassware, and other sample-processing hardware may yield artifacts that affect results. Specific selection of reagents and purification of solvents may be required.

4.2 All materials used in the analysis shall be demonstrated to be free from interferences under the conditions of analysis by running laboratory reagent blanks as described in Section 9.5 of this appendix.

5.0 Safety

5.1 The toxicity or carcinogenicity of each reagent used in this method has not been precisely determined; however, each chemical shall be treated as a potential health hazard. Exposure to these chemicals should be reduced to the lowest possible level. Material Safety Data Sheets (MSDSs) shall be available for all reagents.

5.2 Isopropyl alcohol is flammable and should be used in a well-ventilated area.

5.3 Unknown samples may contain high concentration of volatile toxic compounds. Sample containers should be opened in a hood and handled with gloves to prevent exposure. In addition, all sample preparation should be conducted in a well-ventilated area to limit the potential exposure to harmful contaminants. Drilling fluid samples should be handled with the same precautions used in the drilling fluid handling areas of the drilling rig.

5.4 This method does not address all safety issues associated with its use. The laboratory is responsible for maintaining a safe work environment and a current awareness file of OSHA regulations regarding the safe handling of the chemicals specified in this method. A reference file of material safety data sheets (MSDSs) shall be available to all personnel involved in these analyses. Additional information on laboratory safety can be found in References 16.1–16.2.

6.0 Equipment and Supplies

Note: Brand names, suppliers, and part numbers are for illustrative purposes only. No endorsement is implied. Equivalent performance may be achieved using apparatus and materials other than those specified here, but demonstration of equivalent performance that meets the requirements of this method is the responsibility of the laboratory.

6.1 Sampling equipment.

6.1.1 Sample collection bottles/jars—New, pre-cleaned bottles/jars, lot-certified to be free of artifacts. Glass preferable, plastic acceptable, wide mouth approximately 1–L, with Teflon-lined screw cap.

6.2 Equipment for glassware cleaning.

6.2.1 Laboratory sink.

6.2.2 Oven—Capable of maintaining a temperature within ±5°C in the range of 100–250 °C.

6.3 Equipment for sample extraction.

6.3.1 Vials—Glass, 25 mL and 4 mL, with Teflon-lined screw caps, baked at 200–250 °C for 1–h minimum prior to use.

6.3.2 Gas-tight syringes—Glass, various sizes, 0.5 mL to 2.5 mL (if spiking of drilling fluids with oils is to occur).

6.3.3 Auto pipetters—various sizes, 0.1 mL, 0.5 mL, 1 to 5 mL delivery, and 10 mL

delivery, with appropriate size disposable pipette tips, calibrated to within ±0.5%.

6.3.4 Glass stirring rod.

6.3.5 Vortex mixer.

6.3.6 Disposable syringes—Plastic, 5 mL.

6.3.7 Teflon syringe filter, 25-mm, 0.45µm pore size—Acrodisc® CR Teflon (or equivalent).

6.3.8 Reverse Phase Extraction C_{18} Cartridge—Waters Sep-Pak®Plus, C_{18} Cartridge, 360 mg of sorbent (or equivalent).

6.3.9 SPE vacuum manifold—Supelco Brand, 12 unit (or equivalent). Used as support for cartridge/syringe assembly only. Vacuum apparatus not required.

6.4 Equipment for fluorescence detection.

6.4.1 Black light—UV Lamp, Model UVG 11, Mineral Light Lamp, Shortwave 254 nm, or Longwave 365 nm, 15 volts, 60 Hz, 0.16 amps (or equivalent).

6.4.2 Black box—cartridge viewing area. A commercially available ultraviolet viewing cabinet with viewing lamp, or alternatively, a cardboard box or equivalent, approximately 14″×7.5″×7.5″ in size and painted flat black inside. Lamp positioned in fitted and sealed slot in center on top of box. Sample cartridges sit in a tray, ca. 6″ from lamp. Cardboard flaps cut on top panel and side of front panel for sample viewing and sample cartridge introduction, respectively.

6.4.3 Viewing platform for cartridges. Simple support (hand made vial tray—black in color) for cartridges so that they do not move during the fluorescence testing.

7.0 Reagents and Standards

7.1 Isopropyl alcohol—99% purity.

7.2 NAF—Appropriate NAF as sent from the supplier (has not been circulated downhole). Use the clean NAF corresponding to the NAF being used in the current drilling operation.

7.3 Standard crude oil—NIST SRM 1582 petroleum crude oil.

8.0 Sample Collection, Preservation, and Storage

8.1 Collect approximately one liter of representative sample (NAF, which has been circulated downhole) in a glass bottle or jar. Cover with a Teflon lined cap. To allow for a potential need to re-analyze and/or re-process the sample, it is recommended that a second sample aliquot be collected.

8.2 Label the sample appropriately.

8.3 All samples must be refrigerated at 0–4 °C from the time of collection until extraction (40 CFR Part 136, Table II).

8.4 All samples must be analyzed within 28 days of the date and time of collection (40 CFR Part 136, Table II).

9.0 Quality Control

9.1 Each laboratory that uses this method is required to operate a formal quality assurance program (Reference 16.3). The minimum requirements of this program consist of an initial demonstration of laboratory capability, and ongoing analyses of blanks and spiked duplicates to assess accuracy and precision and to demonstrate continued performance. Each field sample is analyzed in duplicate to demonstrate representativeness.

9.1.1 The analyst shall make an initial demonstration of the ability to generate acceptable accuracy and precision with this method. This ability is established as described in Section 9.2 of this appendix.

9.1.2 Preparation and analysis of a set of spiked duplicate samples to document accuracy and precision. The procedure for the preparation and analysis of these samples is described in Section 9.4 of this appendix.

9.1.3 Analyses of laboratory reagent blanks are required to demonstrate freedom from contamination. The procedure and criteria for preparation and analysis of a reagent blank are described in Section 9.5 of this appendix.

9.1.4 The laboratory shall maintain records to define the quality of the data that is generated.

9.1.5 Accompanying QC for the determination of oil in NAF is required per analytical batch. An analytical batch is a set of samples extracted at the same time, to a maximum of 10 samples. Each analytical batch of 10 or fewer samples must be accompanied by a laboratory reagent blank (Section 9.5 of this appendix), corresponding NAF reference blanks (Section 9.6 of this appendix), a set of spiked duplicate samples blank (Section 9.4 of this appendix), and duplicate analysis of each field sample. If greater than 10 samples are to be extracted at one time, the samples must be separated into analytical batches of 10 or fewer samples.

9.2 Initial demonstration of laboratory capability. To demonstrate the capability to perform the test, the analyst shall analyze two representative unused drilling fluids (e.g., internal olefin-based drilling fluid, vegetable ester-based drilling fluid), each prepared separately containing 0.1%, 1%, and 2% or a representative oil. Each drilling fluid/concentration combination shall be analyzed 10 times, and successful demonstration will yield the following average results for the data set:

0.1% oil—Detected in <20% of samples
1% oil—Detected in >75% of samples
2% oil—Detected in <90% of samples

9.3 Sample duplicates.

9.3.1 The laboratory shall prepare and analyze (Section 11.2 and 11.4 of this appendix) each authentic sample in duplicate, from a given sampling site or, if for compliance monitoring, from a given discharge.

9.3.2 The duplicate samples must be compared versus the prepared corresponding NAF blank.

9.3.3 Prepare and analyze the duplicate samples according to procedures outlined in Section 11 of this appendix.

9.3.4 The results of the duplicate analyses are acceptable if each of the results give the same response (fluorescence or no fluorescence). If the results are different, sample non-homogenicity issues may be a concern. Prepare the samples again, ensuring a well-mixed sample prior to extraction. Analyze the samples once again.

9.3.5 If different results are obtained for the duplicate a second time, the analytical system is judged to be out of control and the problem shall be identified and corrected, and the samples re-analyzed.

9.4 Spiked duplicates—Laboratory prepared spiked duplicates are analyzed to demonstrate acceptable accuracy and precision.

9.4.1 Preparation and analysis of a set of spiked duplicate samples with each set of no more than 10 field samples is required to demonstrate method accuracy and precision and to monitor matrix interferences (interferences caused by the sample matrix). A field NAF sample expected to contain less than 0.5% crude oil (and documented to not fluoresce as part of the sample batch analysis) shall be spiked with 1% (by volume) of suitable reference crude oil and analyzed as field samples, as described in Section 11 of this appendix. If no low-level drilling fluid is available, then the unused NAF can be used as the drilling fluid sample.

9.5 Laboratory reagent blanks—Laboratory reagent blanks are analyzed to demonstrate freedom from contamination.

9.5.1 A reagent blank is prepared by passing 4 mL of the isopropyl alcohol through a Teflon syringe filter and collecting the filtrate in a 4-mL glass vial. A Sep Pak® C_{18} cartridge is then preconditioned with 3 mL of isopropyl alcohol. A 0.5-mL aliquot of the filtered isopropyl alcohol is added to the syringe barrel along with 3.0 mL of isopropyl alcohol. The solvent is passed through the preconditioned Sep Pak® cartridge. An additional 2-mL of isopropyl alcohol is eluted through the cartridge. The cartridge is now considered the ''reagent blank'' cartridge and is ready for viewing (analysis). Check the reagent blank cartridge under the black light for fluorescence. If the isopropyl alcohol and filter are clean, no fluorescence will be observed.

9.5.2 If fluorescence is detected in the reagent blank cartridge, analysis of the samples is halted until the source of contamination is eliminated and a prepared reagent blank shows no fluorescence under a black light. All samples shall be associated with an uncontaminated method blank before the results may be reported for regulatory compliance purposes.

9.6 NAF reference blanks—NAF reference blanks are prepared from the NAFs sent from the supplier (NAF that has not been circulated downhole) and used as the reference when viewing the fluorescence of the test samples.

9.6.1 A NAF reference blank is prepared identically to the authentic samples. Place a 0.1 mL aliquot of the ''clean'' NAF into a 25-mL glass vial. Add 10 mL of isopropyl alcohol to the vial. Cap the vial. Vortex the vial for approximately 10 sec. Allow the solids to settle for approximately 15 minutes. Using a 5-mL syringe, draw up 4 mL of the extract and filter it through a PTFE syringe filter, collecting the filtrate in a 4-mL glass vial. Precondition a Sep Pak® C_{18} cartridge with 3 mL of isopropyl alcohol. Add a 0.5-mL aliquot of the filtered extract to the syringe barrel along with 3.0 mL of isopropyl alcohol. Pass the extract and solvent through the preconditioned Sep Pak® cartridge. Pass an additional 2-mL of isopropyl alcohol through the cartridge. The cartridge is now considered the NAF blank cartridge and is ready for viewing (analysis). This cartridge is used as the reference cartridge for determining the absence or presence of fluorescence in all authentic drilling fluid

samples that originate from the same NAF. That is, the specific NAF reference blank cartridge is put under the black light along with a prepared cartridge of an authentic sample originating from the same NAF material. The fluorescence or absence of fluorescence in the authentic sample cartridge is determined relative to the NAF reference cartridge.

9.6.2 Positive control solution, equivalent to 1% crude oil contaminated mud extract, is prepared by dissolving 87 mg of standard crude oil into 10.00 mL of methylene chloride. Then mix 40 µL of this solution into 10.00 mL of IPA. Transfer 0.5 mL of this solution into a preconditioned C18 cartridge, followed by 2 ml of IPA.

10.0 Calibration and Standardization

10.1 Calibration and standardization methods are not employed for this procedure.

11.0 Procedure

This method is a screening-level test. Precise and accurate results can be obtained only by strict adherence to all details.

11.1 Preparation of the analytical batch.

11.1.1 Bring the analytical batch of samples to room temperature.

11.1.2 Using a large glass stirring rod, mix the authentic sample thoroughly.

11.1.3 Using a large glass stirring rod, mix the clean NAF (sent from the supplier) thoroughly.

11.2 Extraction.

11.2.1 Using an automatic positive displacement pipetter and a disposable pipette tip transfer 0.1-mL of the authentic sample into a 25-mL vial.

11.2.2 Using an automatic pipetter and a disposable pipette tip dispense a 10-mL aliquot of solvent grade isopropyl alcohol (IPA) into the 25 mL vial.

11.2.3 Cap the vial and vortex the vial for ca. 10–15 seconds.

11.2.4 Let the sample extract stand for approximately 5 minutes, allowing the solids to separate.

11.2.5 Using a 5-mL disposable plastic syringe remove 4 mL of the extract from the 25-mL vial.

11.2.6 Filter 4 mL of extract through a Teflon syringe filter (25-mm diameter, 0.45 µm pore size), collecting the filtrate in a labeled 4-mL vial.

11.2.7 Dispose of the PFTE syringe filter.

11.2.8 Using a black permanent marker, label a Sep Pak® C_{18} cartridge with the sample identification.

11.2.9 Place the labeled Sep Pak® C_{18} cartridge onto the head of a SPE vacuum manifold.

11.2.10 Using a 5-mL disposable plastic syringe, draw up exactly 3-mL (air free) of isopropyl alcohol.

11.2.11 Attach the syringe tip to the top of the C_{18} cartridge.

11.2.12 Condition the C_{18} cartridge with the 3-mL of isopropyl alcohol by depressing the plunger slowly.

Note: Depress the plunger just to the point when no liquid remains in the syringe barrel. Do not force air through the cartridge. Collect the eluate in a waste vial.

11.2.13 Remove the syringe temporarily from the top of the cartridge, then remove the plunger, and finally reattach the syringe barrel to the top of the C_{18} cartridge.

11.2.14 Using automatic pipetters and disposable pipette tips, transfer 0.5 mL of the filtered extract into the syringe barrel, followed by a 3.0-mL transfer of isopropyl alcohol to the syringe barrel.

11.2.15 Insert the plunger and slowly depress it to pass only the extract and solvent through the preconditioned C_{18} cartridge.

Note: Depress the plunger just to the point when no liquid remains in the syringe barrel. Do not force air through the cartridge. Collect the eluate in a waste vial.

11.2.16 Remove the syringe temporarily from the top of the cartridge, then remove the plunger, and finally reattach the syringe barrel to the top of the C_{18} cartridge.

11.2.17 Using an automatic pipetter and disposable pipette tip, transfer 2.0 mL of isopropyl alcohol to the syringe barrel.

11.2.18 Insert the plunger and slowly depress it to pass the solvent through the C_{18} cartridge.

Note: Depress the plunger just to the point when no liquid remains in the syringe barrel. Do not force air through the cartridge. Collect the eluate in a waste vial.

11.2.19 Remove the syringe and labeled C_{18} cartridge from the top of the SPE vacuum manifold.

11.2.20 Prepare a reagent blank according to the procedures outlined in Section 9.5 of this appendix.

11.2.21 Prepare the necessary NAF reference blanks for each type of NAF encountered in the field samples according to the procedures outlined in Section 9.6 of this appendix.

11.2.22 Prepare the positive control (1% crude oil equivalent) according to Section 9.6.2 of this appendix.

11.3 Reagent blank fluorescence testing.

11.3.1 Place the reagent blank cartridge in a black box, under a black light.

11.3.2 Determine the presence or absence of fluorescence for the reagent blank cartridge. If fluorescence is detected in the blank, analysis of the samples is halted until the source of contamination is eliminated and a prepared reagent blank shows no fluorescence under a black light. All samples must be associated with an uncontaminated method blank before the results may be reported for regulatory compliance purposes.

11.4 Sample fluorescence testing.

11.4.1 Place the respective NAF reference blank (Section 9.6 of this appendix) onto the tray inside the black box.

11.4.2 Place the authentic field sample cartridge (derived from the same NAF as the NAF reference blank) onto the tray, adjacent and to the right of the NAF reference blank.

11.4.3 Turn on the black light.

11.4.4 Compare the fluorescence of the sample cartridge with that of the negative control cartridge (NAF blank, Section 9.6.1 of this appendix) and positive control cartridge (1% crude oil equivalent, Section 9.6.2 of this appendix).

11.4.5 If the fluorescence of the sample cartridge is equal to or brighter than the positive control cartridge (1% crude oil equivalent, Section 9.6.2 of this appendix), the sample is considered contaminated. Otherwise, the sample is clean.

12.0 Data Analysis and Calculations

Specific data analysis techniques and calculations are not performed in this SOP.

13.0 Method Performance

This method was validated through a single laboratory study, conducted with rigorous statistical experimental design and interpretation (Reference 16.4).

14.0 Pollution Prevention

14.1 The solvent used in this method poses little threat to the environment when recycled and managed properly.

15.0 Waste Management

15.1 It is the laboratory's responsibility to comply with all Federal, State, and local regulations governing waste management, particularly the hazardous waste identification rules and land disposal restriction, and to protect the air, water, and land by minimizing and controlling all releases from bench operations. Compliance with all sewage discharge permits and regulations is also required.

15.2 All authentic samples (drilling fluids) failing the fluorescence test (indicated by the presence of fluorescence) shall be retained and classified as contaminated samples. Treatment and ultimate fate of these samples is not outlined in this SOP.

15.3 For further information on waste management, consult ''The Waste Management Manual for Laboratory Personnel,'' and ''Less is Better: Laboratory Chemical Management for Waste Reduction,'' both available from the American Chemical Society's Department of Government Relations and Science Policy, 1155 16th Street, NW, Washington, DC 20036.

16.0 References

16.1 ''Carcinogen—Working with Carcinogens,'' Department of Health, Education, and Welfare, Public Health Service, Center for Disease Control, National Institute for Occupational Safety and Health, Publication No. 77–206, August 1977.

16.2 ''OSHA Safety and Health Standards, General Industry,'' (29 CFR 1910), Occupational Safety and Health Administration, OSHA 2206 (Revised, January 1976).

16.3 ''Handbook of Analytical Quality Control in Water and Wastewater Laboratories,'' USEPA, EMSL-Ci, Cincinnati, OH 45268, EPA–600/4–79–019, March 1979.

16.4 Report of the Laboratory Evaluation of Static Sheen Test Replacements—Reverse Phase Extraction (RPE) Method for Detecting Oil Contamination in Synthetic Based Mud (SBM). October 1998. Available from API, 1220 L Street, NW, Washington, DC 20005–4070, 202–682–8000.

Appendix 7 to Subpart A of Part 435—API Recommended Practice 13B–2

1. Description

a. This procedure is specifically intended to measure the amount of non-aqueous drilling fluid (NAF) base fluid from cuttings generated during a drilling operation. This procedure is a retort test which measures all oily material (NAF base fluid) and water released from a cuttings sample when heated

in a calibrated and properly operating ''Retort'' instrument.

b. In this retort test a known mass of cuttings is heated in the retort chamber to vaporize the liquids associated with the sample. The NAF base fluid and water vapors are then condensed, collected, and measured in a precision graduated receiver.

Note: Obtaining a representative sample requires special attention to the details of sample handling (e.g., location, method, frequency). See Addendum A and B for minimum requirements for collecting representative samples. Additional sampling procedures in a given area may be specified by the NPDES permit controlling authority.

2. Equipment

a. Retort instrument—The recommended retort instrument has a 50-cm^3 volume with an external heating jacket.

Retort Specifications:

1. Retort assembly—retort body, cup and lid.

(a) Material: 303 stainless steel or equivalent.

(b) Volume: Retort cup with lid.

Cup Volume: 50-cm^3.

Precision: ±0.25-cm^3.

2. Condenser—capable of cooling the oil and water vapors below their liquification temperature.

3. Heating jacket—nominal 350 watts.

4. Temperature control—capable of limiting temperature of retort to at least 930 °F (500 °C) and enough to boil off all NAFs.

b. Liquid receiver (10-cm^3, 20-cm^3)—the 10-cm^3 and 20-cm^3 receivers are specially designed cylindrical glassware with rounded bottom to facilitate cleaning and funnel-shaped top to catch falling drops. For compliance monitoring under the NPDES program, the analyst shall use the 10-cm^3 liquid receiver with 0.1 ml graduations to achieve greater accuracy.

1. Receiver specifications:

Total volume: 10-cm^3, 20-cm^3.

Precision (0 to 100%): ±0.05 cm^3, ±0.05 cm^3.

Outside diameter: 10-mm, 13-mm.

Wall thickness: 1.5±0.1mm, 1.2±0.1mm.

Frequency of graduation marks (0 to 100%): 0.10-cm^3, 0.10-cm^3.

Calibration: To contain ''TC'' @ 20°C.

Scale: cm^3, cm^3

2. Material—Pyrex® or equivalent glass.

c. Toploading balance—capable of weighing 2000 g and precision of at least 0.1 g. Unless motion is a problem, the analyst shall use an electronic balance. Where motion is a problem, the analyst may use a triple beam balance.

d. Fine steel wool (No. 000)—for packing retort body.

e. Thread sealant lubricant: high temperature lubricant, e.g. Never-Seez® or equivalent.

f. Pipe cleaners—to clean condenser and retort stem.

g. Brush—to clean receivers.

h. Retort spatula—to clean retort cup.

i. Corkscrew—to remove spent steel wool.

3. Procedure

a. Clean and dry the retort assembly and condenser.

b. Pack the retort body with steel wool.

c. Apply lubricant/sealant to threads of retort cup and retort stem.

d. Weigh and record the total mass of the retort cup, lid, and retort body with steel wool. This is mass (A), grams.

e. Collect a representative cuttings sample (*see* **Note** in Section 1 of this appendix).

f. Partially fill the retort cup with cuttings and place the lid on the cup.

g. Screw the retort cup (with lid) onto the retort body, weigh and record the total mass. This is mass (B), grams.

h. Attach the condenser. Place the retort assembly into the heating jacket.

i. Weigh and record the mass of the clean and dry liquid receiver. This is mass (C), grams. Place the receiver below condenser outlet.

j. Turn on the retort. Allow it to run a minimum of 1 hour.

Note: If solids boil over into receiver, the test shall be rerun. Pack the retort body with a greater amount of steel wool and repeat the test.

k. Remove the liquid receiver. Allow it to cool. Record the volume of water recovered. This is (V), cm^3.

Note: If an emulsion interface is present between the oil and water phases, heating the interface may break the emulsion. As a suggestion, remove the retort assembly from the heating jacket by grasping the condenser. Carefully heat the receiver along the emulsion band by gently touching the receiver for short intervals with the hot retort assembly. Avoid boiling the liquids. After the emulsion interface is broken, allow the liquid receiver to cool. Read the water volume at the lowest point of the meniscus.

l. Weigh and record the mass of the receiver and its liquid contents (oil plus water). This is mass (D), grams.

m. Turn off the retort. Remove the retort assembly and condenser from the heating jacket and allow them to cool. Remove the condenser.

n. Weigh and record the mass of the cooled retort assembly without the condenser. This is mass (E), grams.

o. Clean the retort assembly and condenser.

4. Calculations

a. Calculate the mass of oil (NAF base fluid) from the cuttings as follows:

1. Mass of the wet cuttings sample (M_w) equals the mass of the retort assembly with the wet cuttings sample (B) minus the mass of the empty retort assembly (A).

$$M_w = B - A \quad [1]$$

2. Mass of the dry retorted cuttings (M_D) equals the mass of the cooled retort assembly (E) minus the mass of the empty retort assembly (A).

$$M_D = E - A \quad [2]$$

3. Mass of the NAF base fluid (M_{BF}) equals the mass of the liquid receiver with its contents (D) minus the sum of the mass of the dry receiver (C) and the mass of the water (V).

$$M_{BF} = D - (C + V) \quad [3]$$

Note: Assuming the density of water is 1 g/cm^3, the volume of water is equivalent to the mass of the water.

b. Mass balance requirement:

The sum of M_D, M_{BF}, and V shall be within 5% of the mass of the wet sample.

$$(M_D + M_{BF} + V)/M_w = 0.95 \text{ to } 1.05 \quad [4]$$

The procedure shall be repeated if this requirement is not met.

c. Reporting oil from cuttings:

1. Assume that all oil recovered is NAF base fluid.

2. The mass percent NAF base fluid retained on the cuttings (%BF_i) for the sampled discharge ''i'' is equal to 100 times the mass of the NAF base fluid (M_{BF}) divided by the mass of the wet cuttings sample (M_w).

$$\%BF_i = (M_{BF}/M_w) \times 100 \quad [5]$$

Operators discharging small volume NAF-cuttings discharges which do not occur during a NAF-cuttings discharge sampling interval (i.e., displaced interfaces, accumulated solids in sand traps, pit clean-out solids, or centrifuge discharges while cutting mud weight) shall either: (a) Measure the mass percent NAF base fluid retained on the cuttings (%BF_{SVD}) for each small volume NAF-cuttings discharges; or (b) use a default value of 25% NAF base fluid retained on the cuttings.

3. The mass percent NAF base fluid retained on the cuttings is determined for all cuttings wastestreams and includes fines discharges and any accumulated solids discharged [*see* Section 4.c.6 of this appendix for procedures on measuring or estimating the mass percent NAF base fluid retained on the cuttings (%BF) for dual gradient drilling seafloor discharges performed to ensure proper operation of subsea pumps].

4. A mass NAF-cuttings discharge fraction (X, unitless) is calculated for all NAF-cuttings, fines, or accumulated solids discharges every time a set of retorts is performed (*see* Section 4.c.6 of this appendix for procedures on measuring or estimating the mass NAF-cuttings discharge fraction (X) for dual gradient drilling seafloor discharges performed to ensure proper operation of subsea pumps). The mass NAF-cuttings discharge fraction (X) combines the mass of NAF-cuttings, fines, or accumulated solids discharged from a particular discharge over a set period of time with the total mass of NAF-cuttings, fines, or accumulated solids discharged into the ocean during the same period of time (*see* Addendum A and B of this appendix). The mass NAF-cuttings discharge fraction (X) for each discharge is calculated by direct measurement as:

$$X_i = (F_i)/(G) \quad [6]$$

where:

X_i = Mass NAF-cuttings discharge fraction for NAF-cuttings, fines, or accumulated solids discharge ''i'', (unitless)

F_i = Mass of NAF-cuttings discharged from NAF-cuttings, fines, or accumulated solids discharge ''i'' over a specified period of time (*see* Addendum A and B of this appendix), (kg)

G = Mass of all NAF-cuttings discharges into the ocean during the same period of time as used to calculate F_i, (kg)

If an operator has more than one point of NAF-cuttings discharge, the mass faction (X_i) must be determined by: (a) Direct measurement (*see* Equation 6 of this

Appendix); (b) using the following default values of 0.85 and 0.15 for the cuttings dryer (e.g., horizontal centrifuge, vertical centrifuge, squeeze press, High-G linear shakers) and fines removal unit (e.g., decanting centrifuges, mud cleaners), respectively, when the operator is only discharging from the cuttings dryer and the fines removal unit; or (c) using direct measurement of ''F_i'' (*see* Equation 6 of this Appendix) for fines and accumulated solids, using Equation 6A of this Appendix to calculate ''G_{EST}'' for use as ''G'' in Equation 6 of this Appendix, and calculating the mass (kg) of NAF-cuttings discharged from the cuttings dryer (F_i) as the difference between the mass of ''G_{EST}'' calculated in Equation 6A of this appendix (kg) and the sum of all fines and accumulated solids mass directly measured (kg) (*see* Equation 6 of this Appendix).

G_{EST} = Estimated mass of all NAF-cuttings discharges into the ocean during the same period of time as used to calculate F_i (*see* Equation 6 of this Appendix), (kg) [6A]

where:

G_{EST} = Hole Volume (bbl) × (396.9 kg/bbl) × (1 + Z/100)

Z = The base fluid retained on cuttings limitation or standard (%) which apply to the NAF being discharge (*see* §§ 435.13. and 435.15).

Hole Volume (bbl) = [Cross-Section Area of NAF interval (in^2)] × Average Rate of Penetration (feet/hr) × period of time (min) used to calculate F_i (*see* Equation 6 of this Appendix) × (1 hr/60 min) × (1 bbl/5.61 ft^3) × (1 ft/12 in)^2

Cross-Section Area of NAF interval (in^2) = (3.14 × [Bit Diameter (in)]^2)/4

Bit Diameter (in) = Diameter of drilling bit for the NAF interval producing drilling cuttings during the same period of time as used to calculate F_i (*see* Equation 6 of this Appendix)

Average Rate of Penetration (feet/hr) = Arithmetic average of rate of penetration into the formation during the same period of time as used to calculate F_i (*see* Equation 6 of this Appendix)

Note: Operators with one NAF-cuttings discharge may set the mass NAF-cuttings discharge fraction (X_i) equal to 1.0.

5. Each NAF-cuttings, fines, or accumulated solids discharge has an associated mass percent NAF base fluid retained on cuttings value (%BF) and mass NAF-cuttings discharge fraction (X) each time a set of retorts is performed. A single total mass percent NAF base fluid retained on cuttings value ($\%BF_T$) is calculated every time a set of retorts is performed. The single total mass percent NAF base fluid retained on cuttings value ($\%BF_T$) is calculated as:

$\%BF_{T,j} = \Sigma(X_i)\times(\%BF_i)$ [7]

where:

$\%BF_{T,j}$ = Total mass percent NAF base fluid retained on cuttings value for retort set ''j'' (unitless as percentage, %)

X_i = Mass NAF-cuttings discharge fraction for NAF-cuttings, fines, or accumulated solids discharge ''i'', (unitless)

$\%BF_i$ = Mass percent NAF base fluid retained on the cuttings for NAF-cuttings, fines, or accumulated solids discharge ''i'' , (unitless as percentage, %)

Note: $\Sigma X_i = 1$.

Operators with one NAF-cuttings discharge may set $\%BF_{T,j}$ equal to $\%BF_i$.

6. Operators performing dual gradient drilling operations may require seafloor discharges of large cuttings (>¼″) to ensure the proper operation of subsea pumps (e.g., electrical submersible pumps). Operators performing dual gradient drilling operations which lead to seafloor discharges of large cuttings for the proper operation of subsea pumps shall either: (a) Measure the mass percent NAF base fluid retained on cuttings value (%BF) and mass NAF-cuttings discharge fraction (X) for seafloor discharges each time a set of retorts is performed; (b) use the following set of default values, (%BF=14%; X=0.15); or (c) use a combination of (a) and (b) (e.g., use a default value for %BF and measure X).

Additionally, operators performing dual gradient drilling operations which lead to seafloor discharges of large cuttings for the proper operation of subsea pumps shall also perform the following tasks:

(a) Use side scan sonar or shallow seismic to determine the presence of high density chemosynthetic communities. Chemosynthetic communities are assemblages of tube worms, clams, mussels, and bacterial mats that occur at natural hydrocarbon seeps or vents, generally in water depths of 500 meters or deeper. Seafloor discharges of large cuttings for the proper operation of subsea pumps shall not be permitted within 1000 feet of a high density chemosynthetic community.

(b) Seafloor discharges of large cuttings for the proper operation of subsea pumps shall be visually monitored and documented by a Remotely Operated Vehicle (ROV) within the tether limit (approximately 300 feet). The visual monitoring shall be conducted prior to each time the discharge point is relocated (cuttings discharge hose) and conducted along the same direction as the discharge hose position. Near-seabed currents shall be obtained at the time of the visual monitoring.

(c) Seafloor discharges of large cuttings for the proper operation of subsea pumps shall be directed within a 150 foot radius of the wellbore.

7. The weighted mass ratio averaged over all NAF well sections ($\%BF_{well}$) is the compliance value that is compared with the ''maximum weighted mass ratio averaged over all NAF well sections'' BAT discharge limitations (*see* the table in § 435.13 and footnote 5 of the table in § 435.43) or the ''maximum weighted mass ratio averaged over all NAF well sections'' NSPS discharge limitations (*see* the table in § 435.15 and footnote 5 of the table in § 435.45). The weighted mass ratio averaged over all NAF well sections ($\%BF_{well}$) is calculated as the arithmetic average of all total mass percent NAF base fluid retained on cuttings values ($\%BF_T$) and is given by the following expression:

$\%BF_{well} = [j=1 \text{ to } j=n\ \Sigma\ (\%BF_{T,j})]/n$ [8]

where:

$\%BF_{well}$ = Weighted mass ratio averaged over all NAF well sections (unitless as percentage, %)

$\%BF_{T,j}$ = Total mass percent NAF base fluid retained on cuttings value for retort set ''j'' (unitless as percentage, %)

n = Total number of retort sets performed over all NAF well sections (unitless)

Small volume NAF-cuttings discharges which do not occur during a NAF-cuttings discharge sampling interval (i.e., displaced interfaces, accumulated solids in sand traps, pit clean-out solids, or centrifuge discharges while cutting mud weight) shall be mass averaged with the arithmetic average of all total mass percent NAF base fluid retained on cuttings values (see Equation 8 of this Appendix). An additional sampling interval shall be added to the calculation of the weighted mass ratio averaged over all NAF well sections ($\%BF_{well}$). The mass fraction of the small volume NAF-cuttings discharges (X_{SVD}) will be determined by dividing the mass of the small volume NAF-cuttings discharges (F_{SVD}) by the total mass of NAF-cuttings discharges for the well drilling operation ($G_{WELL} + F_{SVD}$).

$X_{SVD} = F_{SVD} / (G_{WELL} + F_{SVD})$ [9]

where:

X_{SVD} = mass fraction of the small volume NAF-cuttings discharges (unitless)

F_{SVD} = mass of the small volume NAF-cuttings discharges (kg)

G_{WELL} = mass of total NAF-cuttings from the well (kg)

The mass of small volume NAF-cuttings discharges (F_{SVD}) shall be determined by multiplying the density of the small volume NAF-cuttings discharges (ρ_{svd}) times the volume of the small volume NAF-cuttings discharges (V_{SVD}).

$F_{SVD} = \rho_{svd} \times V_{SVD}$ [10]

where:

F_{SVD} = mass of small volume NAF-cuttings discharges (kg)

ρ_{svd} = density of the small volume NAF-cuttings discharges (kg/bbl)

V_{SVD} = volume of the small volume NAF-cuttings discharges (bbl)

The density of the small volume NAF-cuttings discharges shall be measured. The volume of small volume discharges (V_{SVD}) shall be either: (a) Be measured or (b) use default values of 10 bbl of SBF for each interface loss and 75 bbl of SBM for pit cleanout per well.

The total mass of NAF-cuttings discharges for the well (G_{WELL}) shall be either: (a) Measured; or (b) calculated by multiplying 1.0 plus the arithmetic average of all total mass percent NAF base fluid retained on cuttings values [see Equation 8 of this Appendix] times the total hole volume (V_{WELL}) for all NAF well sections times a default value for the density the formation of 2.5 g/cm^3 (396.9 kg/bbl).

$$G_{WELL} = \left(1 + \left(\left[i = 1 \text{ to } j = n \sum \left(\%BF_{Tj}\right)\right]/n\right)\right) \times V_{WELL}(\text{bbl}) \times 396.9 \text{ (kg/bbl)} \qquad [11]$$

where:

G_{WELL} = total mass of NAF-cuttings discharges for the well (kg)
$[j = 1 \text{ to } j = n\ \Sigma 2(\%BF_{Tj})]/n$ = see Equation 8 of this Appendix (unitless as a percentage)
V_{WELL} = total hole volume (V_{WELL}) for all NAF well sections (bbl)

The total hole volume of NAF well sections (V_{WELL}) will be calculated as:

$$V_{WELL}\text{ (barrels)} = \sum \frac{\text{Bit diameter (in)}^2}{1029} \times \text{change in measured depth (ft)} \qquad [12]$$

For wells where small volume discharges associated with cuttings are made, $\%BF_{WELL}$ becomes:

$$\%BF_{WELL} = \left(\left(1 - X_{SVD}\right) \times \left[i = 1 \text{ to } j = n \sum \left(\%BF_{Tj}\right)\right]/n\right) + X_{SVD} \times \%BF_{SVD} \qquad [13]$$

Note: See Addendum A and B to determine the sampling frequency to determine the total number of retort sets required for all NAF well sections.

8. The total number of retort sets (n) is increased by 1 for each sampling interval (*see* Section 2.4, Addendum A of this appendix) when all NAF cuttings, fines, or accumulated solids for that sampling interval are retained for no discharge. A zero discharge interval shall be at least 500 feet up to a maximum of three per day. This action has the effect of setting the total mass percent NAF base fluid retained on cuttings value ($\%BF_T$) at zero for that NAF sampling interval when all NAF cuttings, fines, or accumulated solids are retained for no discharge.

9. Operators that elect to use the Best Management Practices (BMPs) for NAF-cuttings shall use the procedures outlined in Addendum B.

Addendum A to Appendix 7 to Subpart A of Part 435—Sampling of Cuttings Discharge Streams for use with API Recommended Practice 13B–2

1.0 Sampling Locations

1.1 Each NAF-cuttings waste stream that discharges into the ocean shall be sampled and analyzed as detailed in Appendix 7. NAF-cuttings discharges to the ocean may include discharges from primary shakers, secondary shakers, cuttings dryer, fines removal unit, accumulated solids, and any other cuttings separation device whose NAF-cuttings waste is discharged to the ocean. NAF-cuttings wastestreams not directly discharged to the ocean (*e.g.,* NAF-cuttings generated from shake shakers and sent to a cuttings dryer for additional processing) do not require sampling and analysis.

1.2 The collected samples shall be representative of each NAF-cuttings discharge. Operators shall conduct sampling to avoid the serious consequences of error (*i.e.,* bias or inaccuracy). Operators shall collect NAF-cuttings samples near the point of origin and before the solids and liquid fractions of the stream have a chance to separate from one another. For example, operators shall collect shale shaker NAF-cuttings samples at the point where NAF-cuttings are coming off the shale shaker and not from a holding container downstream where separation of larger particles from the liquid can take place.

1.3 Operators shall provide a simple schematic diagram of the solids control system and sample locations to the NPDES permit controlling authority.

2.0 Type of Sample and Sampling Frequency

2.1 Each NAF-cuttings, fines, or accumulated solids discharge has an associated mass percent NAF base fluid retained on cuttings value (%BF) and mass NAF-cuttings discharge fraction (X) for each sampling interval (*see* Section 2.4 of this addendum). Operators shall collect a single discrete NAF-cuttings sample for each NAF-cuttings waste stream discharged to the ocean during every sampling interval.

2.2 Operators shall use measured depth in feet from the Kelly bushing when samples are collected.

2.3 The NAF-cuttings samples collected for the mass fraction analysis (*see* Equation 6, Appendix 7 of Subpart A of this part) shall also be used for the retort analysis (*see* Equations 1–5, Appendix 7 of Subpart A of this part).

2.4 Operators shall collect and analyze at least one set of NAF-cuttings samples per day while discharging. Operators engaged in fast drilling (*i.e.,* greater than 500 linear NAF feet advancement of drill bit per day) shall collect and analyze one set of NAF-cuttings samples per 500 linear NAF feet of footage drilled. Operators are not required to collect and analyze more than three sets of NAF-cuttings samples per day (*i.e.,* three sampling intervals). Operators performing zero discharge of all NAF-cuttings (*i.e.,* all NAF cuttings, fines, or accumulated solids retained for no discharge) shall use the following periods to count sampling intervals: (1) One sampling interval per day when drilling is less than 500 linear NAF feet advancement of drill bit per day; and (2) one sampling interval per 500 linear NAF feet of footage drilled with a maximum of three sampling intervals per day.

2.5 The operator shall measure the individual masses (F_i, kg) and sum total mass (G, kg) (*see* Equation 6, Appendix 7 of subpart A of this part) over a representative period of time (*e.g.,* <10 minutes) during steady-state conditions for each sampling interval (*see* Section 2.4 of this addendum). The operator shall ensure that all NAF-cuttings are capture for mass analysis during the same sampling time period (*e.g.,* <10 minutes) at approximately the same time (*i.e.,* all individual mass samples collected within one hour of each other).

2.6 Operators using Best Management Practices (BMPs) to control NAF-cuttings discharges shall follow the procedures in Addendum B to Appendix 7 of subpart A of 40 CFR 435.

3.0 Sample Size and Handling

3.1 The volume of each sample depends on the volumetric flow rate (cm^3/s) of the NAF-cuttings stream and the sampling time period (*e.g.,* <10 minutes). Consequently, different solids control equipment units producing different NAF-cuttings waste streams at different volumetric flow rates will produce different size samples for the same period of time. Operators shall use appropriately sized sample containers for each NAF-cuttings waste stream to ensure no NAF-cuttings are spilled during sample collection. Operators shall use the same time period (*e.g.,* <10 minutes) to collect NAF-cuttings samples from each NAF-cuttings waste stream. Each NAF-cuttings sample size shall be at least one gallon. Operators shall clearly mark each container to identify each NAF-cuttings sample.

3.2 Operators shall not decant, heat, wash, or towel the NAF-cuttings to remove NAF base fluid before mass and retort analysis.

3.3 Operators shall first calculate the mass of each NAF-cuttings sample and perform the mass ratio analysis (*see* Equation 6, Appendix 7 of subpart A of this part). Operators with only one NAF-cuttings discharge may skip this step (*see* Section 4.c.4, Appendix 7 of subpart A of this part).

3.4 Operators shall homogenize (*e.g.,* stirring, shaking) each NAF-cuttings sample prior to placing a sub-sample into the retort cup. The bottom of the NAF-cuttings sample container shall be examined to be sure that solids are not sticking to it.

3.5 Operators shall then calculate the NAF base fluid retained on cuttings using the retort procedure (*see* Equations 1–5, Appendix 7 of subpart A of this part). Operators shall start the retort analyses no more than two hours after collecting the first individual mass sample for the sampling interval .

3.6 Operators shall not discharge any sample before successfully completing the mass and retort analyses [i.e., mass balance

requirements (*see* Section 4.b, Appendix 7 of subpart A of this part) are satisfied]. Operators shall immediately re-run the retort analyses if the mass balance requirements (*see* Equation 4, Appendix 7 of subpart A of this part) are not within a tolerance of 5% (*see* Section 4.b, Equation 4, Appendix 7 of subpart A of this part).

4.0 Calculations

4.1 Operators shall calculate a set of mass percent NAF base fluid retained on cuttings values (%BF) and mass NAF-cuttings discharge fractions (X) for each NAF-cuttings waste stream (*see* Section 1.1 of this addendum) for each sampling interval (*see* Section 2.4 of this addendum) using the procedures outlined in Appendix 7 of subpart A of this part.

4.2 Operators shall tabulate the following data for each individual NAF-cuttings sample: (1) Date and time of NAF-cuttings sample collection; (2) time period of NAF-cuttings sample collection (*see* Section 3.1 of this addendum); (3) mass and volume of each NAF-cuttings sample; (4) measured depth (feet) at NAF-cuttings sample collection (*see* Section 2.2 of this addendum); (5) respective linear feet of hole drilled represented by the NAF-cuttings sample (feet); and (6) the drill bit diameter (inches) used to generate the NAF-cuttings sample cuttings.

4.3 Operators shall calculate a single total mass percent NAF base fluid retained on cuttings value ($\%BF_T$) for each sampling interval (*see* Section 2.4 of this addendum) using the procedures outlined in Appendix 7 of Subpart A of this part.

4.4 Operators shall tabulate the following data for each total mass percent NAF base fluid retained on cuttings value ($\%BF_T$) for each NAF-cuttings sampling interval: (1) Date and starting and stopping times of NAF-cuttings sample collection and retort analyses; (2) measured depth of well (feet) at start of NAF-cuttings sample collection (*see* Section 2.2 of this addendum); (3) respective linear feet of hole drilled represented by the NAF-cuttings sample (feet); (4) the drill bit diameter (inches) used to generate the NAF-cuttings sample cuttings; and (5) annotation when zero discharge of NAF-cuttings is performed.

4.5 Operators shall calculate the weighted mass ratio averaged over all NAF well sections ($\%BF_{well}$) using the procedures outlined in Appendix 7 of Subpart A of this part.

4.6 Operators shall tabulate the following data for each weighted mass ratio averaged over all NAF well sections ($\%BF_{well}$) for each NAF well: (1) Starting and stopping dates of NAF well sections; (2) measured depth (feet) of all NAF well sections; (3) total number of sampling intervals (*see* Section 2.4 and Section 2.6 of this addendum); (4) number of sampling intervals tabulated during any zero discharge operations; (5) total volume of zero discharged NAF-cuttings over entire NAF well sections; and (6) identification of whether BMPs were employed (*see* Addendum B of Appendix 7 of subpart A of this part).

Addendum B to Appendix 7 to Subpart A of Part 435— Best Management Practices (BMPs) for use with API Recommended Practice 13B–2

1.0 Overview of BMPs

1.1 Best Management Practices (BMPs) are inherently pollution prevention practices. BMPs may include the universe of pollution prevention encompassing production modifications, operational changes, material substitution, materials and water conservation, and other such measures. BMPs include methods to prevent toxic and hazardous pollutants from reaching receiving waters. Because BMPs are most effective when organized into a comprehensive facility BMP Plan, operators shall develop a BMP in accordance with the requirements in this addendum.

1.2 The BMP requirements contained in this appendix were compiled from several Regional permits, an EPA guidance document (i.e., Guidance Document for Developing Best Management Practices (BMP)'' (EPA 833–B–93–004, U.S. EPA, 1993)), and draft industry BMPs. These common elements represent the appropriate mix of broad directions needed to complete a BMP Plan along with specific tasks common to all drilling operations.

1.3 Operators are not required to use BMPs if all NAF-cuttings discharges are monitored in accordance with Appendix 7 of Subpart A of this part.

2.0 BMP Plan Purpose and Objectives

2.1 Operators shall design the BMP Plan to prevent or minimize the generation and the potential for the discharge of NAF from the facility to the waters of the United States through normal operations and ancillary activities. The operator shall establish specific objectives for the control of NAF by conducting the following evaluations.

2.2 The operator shall identify and document each NAF well that uses BMPs before starting drilling operations and the anticipated total feet to be drilled with NAF for that particular well.

2.3 Each facility component or system controlled through use of BMPs shall be examined for its NAF-waste minimization opportunities and its potential for causing a discharge of NAF to waters of the United States due to equipment failure, improper operation, natural phenomena (e.g., rain, snowfall).

2.4 For each NAF wastestream controlled through BMPs where experience indicates a reasonable potential for equipment failure (e.g., a tank overflow or leakage), natural condition (e.g., precipitation), or other circumstances to result in NAF reaching surface waters, the BMP Plan shall include a prediction of the total quantity of NAF which could be discharged from the facility as a result of each condition or circumstance.

3.0 BMP Plan Requirements

3.1 The BMP Plan may reflect requirements within the pollution prevention requirements required by the Minerals Management Service (*see* 30 CFR 250.300) or other Federal or State requirements and incorporate any part of such plans into the BMP Plan by reference.

3.2 The operator shall certify that its BMP Plan is complete, on-site, and available upon request to EPA or the NPDES Permit controlling authority. This certification shall identify the NPDES permit number and be signed by an authorized representative of the operator. This certification shall be kept with the BMP Plan. For new or modified NPDES permits, the certification shall be made no later than the effective date of the new or modified permit. For existing NPDES permits, the certification shall be made within one year of permit issuance.

3.3 The BMP Plan shall:

3.3.1 Be documented in narrative form, and shall include any necessary plot plans, drawings or maps, and shall be developed in accordance with good engineering practices. At a minimum, the BMP Plan shall contain the planning, development and implementation, and evaluation/reevaluation components. Examples of these components are contained in ''Guidance Document for Developing Best Management Practices (BMP)'' (EPA 833–B–93–004, U.S. EPA, 1993).

3.3.2 Include the following provisions concerning BMP Plan review.

3.3.2.1 Be reviewed by permittee's drilling engineer and offshore installation manager (OIM) to ensure compliance with the BMP Plan purpose and objectives set forth in Section 2.0.

3.3.2.2 Include a statement that the review has been completed and that the BMP Plan fulfills the BMP Plan purpose and objectives set forth in Section 2.0. This statement shall have dated signatures from the permittee's drilling engineer and offshore installation manager and any other individuals responsible for development and implementation of the BMP Plan.

3.4 Address each component or system capable of generating or causing a release of significant amounts of NAF and identify specific preventative or remedial measures to be implemented.

4.0 BMP Plan Documentation

4.1 The operator shall maintain a copy of the BMP Plan and related documentation (e.g., training certifications, summary of the monitoring results, records of NAF-equipment spills, repairs, and maintenance) at the facility and shall make the BMP Plan and related documentation available to EPA or the NPDES Permit controlling authority upon request.

5.0 BMP Plan Modification

5.1 For those NAF wastestreams controlled through BMPs, the operator shall amend the BMP Plan whenever there is a change in the facility or in the operation of the facility which materially increases the generation of those NAF-wastes or their release or potential release to the receiving waters.

5.2 At a minimum the BMP Plan shall be reviewed once every five years and amended within three months if warranted. Any such changes to the BMP Plan shall be consistent with the objectives and specific requirements listed in this addendum. All changes in the BMP Plan shall be reviewed by the permittee's drilling engineer and offshore installation manager.

5.3 At any time, if the BMP Plan proves to be ineffective in achieving the general objective of preventing and minimizing the generation of NAF-wastes and their release and potential release to the receiving waters and/or the specific requirements in this addendum, the permit and/or the BMP Plan shall be subject to modification to incorporate revised BMP requirements.

6.0 Specific Pollution Prevention Requirements for NAF Discharges Associated with Cuttings

6.1 The following specific pollution prevention activities are required in a BMP Plan when operators elect to control NAF discharges associated with cuttings by a set of BMPs.

6.2 Establishing programs for identifying, documenting, and repairing malfunctioning NAF equipment, tracking NAF equipment repairs, and training personnel to report and evaluate malfunctioning NAF equipment.

6.3 Establishing operating and maintenance procedures for each component in the solids control system in a manner consistent with the manufacturer's design criteria.

6.4 Using the most applicable spacers, flushes, pills, and displacement techniques in order to minimize contamination of drilling fluids when changing from water-based drilling fluids to NAF and vice versa.

6.5 A daily retort analysis shall be performed (in accordance with Appendix 7 to subpart A of Part 435) during the first 0.33 X feet drilled with NAF where X is the anticipated total feet to be drilled with NAF for that particular well. The retort analyses shall be documented in the well retort log. The operators shall use the calculation procedures detailed in Appendix 7 to subpart A of part 435 (*see* Equations 1 through 8) to determine the arithmetic average ($\%BF_{well}$) of the retort analyses taken during the first 0.33 X feet drilled with NAF.

6.5.1 When the arithmetic average ($\%BF_{well}$) of the retort analyses taken during the first 0.33 X feet drilled with NAF is less than or equal to the base fluid retained on cuttings limitation or standard (*see* §§ 435.13 and 435.15), retort monitoring of cuttings may cease for that particular well. The same BMPs and drilling fluid used during the first 0.33 X feet shall be used for all remaining NAF sections for that particular well.

6.5.2 When the arithmetic average ($\%BF_{well}$) of the retort analyses taken during the first 0.33 X feet drilled with NAF is greater the base fluid retained on cuttings limitation or standard (*see* §§ 435.13 and 435.15), retort monitoring shall continue for the following (second) 0.33 X feet drilled with NAF where X is the anticipated total feet to be drilled with NAF for that particular well. The retort analyses for the first and second 0.33 X feet shall be documented in the well retort log.

6.5.2.1 When the arithmetic average ($\%BF_{well}$) of the retort analyses taken during the first 0.66 X feet (i.e., retort analyses taken from first and second 0.33 X feet) drilled with NAF is less than or equal to the base fluid retained on cuttings limitation or standard (*see* §§ 435.13 and 435.15), retort monitoring of cuttings may cease for that particular well. The same BMPs and drilling fluid used during the first 0.66 X feet shall be used for all remaining NAF sections for that particular well.

6.5.2.2 When the arithmetic average ($\%BF_{well}$) of the retort analyses taken during the first 0.66 X feet (i.e., retort analyses taken from first and second 0.33 X feet) drilled with NAF is greater than the base fluid retained on cuttings limitation or standard (*see* §§ 435.13 and 435.15), retort monitoring shall continue for all remaining NAF sections for that particular well. The retort analyses for all NAF sections shall be documented in the well retort log.

6.5.3 When the arithmetic average ($\%BF_{well}$) of the retort analyses taken over all NAF sections for the entire well is greater that the base fluid retained on cuttings limitation or standard (*see* §§ 435.13 and 435.15), the operator is in violation of the base fluid retained on cuttings limitation or standard and shall submit notification of these monitoring values in accordance with NPDES permit requirements. Additionally, the operator shall, as part of the BMP Plan, initiate a reevaluation and modification to the BMP Plan in conjunction with equipment vendors and/or industry specialists.

6.5.4 The operator shall include retort monitoring data and dates of retort-monitored and non-retort-monitored NAF-cuttings discharges managed by BMPs in their NPDES permit reports.

6.6 Establishing mud pit and equipment cleaning methods in such a way as to minimize the potential for building-up drill cuttings (including accumulated solids) in the active mud system and solids control equipment system. These cleaning methods shall include but are not limited to the following procedures.

6.6.1 Ensuring proper operation and efficiency of mud pit agitation equipment.

6.6.2 Using mud gun lines during mixing operations to provide agitation in dead spaces.

6.6.3 Pumping drilling fluids off of drill cuttings (including accumulated solids) for use, recycle, or disposal before using wash water to dislodge solids.

Appendix 8 to Subpart A of Part 435—Reference C_{16}–C_{18} Internal Olefin Drilling Fluid Formulation

The reference C_{16}–C_{18} internal olefin drilling fluid used to determine the drilling fluid sediment toxicity ratio and compliance with the BAT sediment toxicity discharge limitation (*see* § 435.13) and NSPS (*see* § 435.15) shall be formulated to meet the specifications in Table 1 of this appendix.

Drilling fluid sediment toxicity ratio = 4-day LC_{50} of C_{16}–C_{18} internal olefin drilling fluid/4-day LC_{50} of drilling fluid removed from cuttings at the solids control equipment as determined by ASTM E1367–92 [incorporated by reference and specified at § 435.11(ee)] and supplemented with the sediment preparation procedure (Appendix 3 of subpart A of this part).

TABLE 1.—PROPERTIES FOR REFERENCE C_{16}–C_{18} IOS SBF USED IN DISCHARGE SEDIMENT TOXICITY TESTING

Mud weight of SBF discharged with cuttings (pounds per gallon)	Reference C_{16}–C_{18} IOs SBF (pounds per gallon)	Reference C_{16}–C_{18} IOs SBF synthetic to water ratio (%)
8.5–11	9.0	75/25
11–14	11.5	80/20
>14	14.5	85/15
Plastic Viscosity (PV), centipoise (cP)	12–30	
Yield Point (YP), pounds/100 sq. ft	10–20	
10-second gel, pounds/100 sq. ft	8–15	
10-minute gel, pounds/100 sq. ft	12–30	
Electrical stability, V	>300	

Subpart D—Coastal Subcategory

8. Section 435.41 is amended by revising paragraphs (b) through (ff) and by adding paragraphs (gg) through (ii) to read as follows:

§ 435.41 Special definitions.

* * * * *

(b) *Average of daily values for 30 consecutive days* means the average of the daily values obtained during any 30 consecutive day period.

(c) *Base fluid* means the continuous phase or suspending medium of a drilling fluid formulation.

(d) *Base fluid retained on cuttings* as applied to BAT effluent limitations and NSPS refers to the American Petroleum Institute Recommended Practice 13B–2

supplemented with the specifications, sampling methods, and averaging method for retention values provided in Appendix 7 of subpart A of this part.

(e) *Biodegradation rate* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings refers to the ISO 11734:1995 method: ''Water quality—Evaluation of the 'ultimate' anaerobic biodegradability of organic compounds in digested sludge—Method by measurement of the biogas production (1995 edition)'' (Available from the American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036) supplemented with modifications in Appendix 4 of subpart A of this part.

(f) *Cook Inlet* refers to coastal locations north of the line between Cape Douglas on the West and Port Chatham on the east.

(g) *Daily values* as applied to produced water effluent limitations and NSPS means the daily measurements used to assess compliance with the maximum for any one day.

(h) *Deck drainage* means 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.

(i) *Development facility* means any fixed or mobile structure subject to this Subpart that is engaged in the drilling of productive wells.

(j) *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).

(k) *Diesel oil* refers 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, 401 M Street SW., Washington, DC 20460.

(l) *Domestic waste* means the 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.

(m) *Drill cuttings* means the particles generated by drilling into subsurface geologic formations and carried out from the wellbore with the drilling fluid. Examples of drill cuttings include small pieces of rock varying in size and texture from fine silt to gravel. Drill cuttings are generally generated from solids control equipment and settle out and accumulate in quiescent areas in the solids control equipment or other equipment processing drilling fluid (i.e., accumulated solids).

(1) *Wet drill cuttings* means the unaltered drill cuttings and adhering drilling fluid and formation oil carried out from the wellbore with the drilling fluid.

(2) *Dry drill cuttings* means the residue remaining in the retort vessel after completing the retort procedure specified in Appendix 7 of subpart A of this part.

(n) *Drilling fluid* means the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. Classes of drilling fluids are:

(1) *Water-based drilling fluid* means the continuous phase and suspending medium for solids is a water-miscible fluid, regardless of the presence of oil.

(2) *Non-aqueous drilling fluid* means the continuous phase and suspending medium for solids is a water-immiscible fluid, such as oleaginous materials (e.g., mineral oil, enhanced mineral oil, paraffinic oil, C_{16}–C_{18} internal olefins, and C_8–C_{16} fatty acid/2-ethylhexyl esters).

(i) *Oil-based* means the continuous phase of the drilling fluid consists of diesel oil, mineral oil, or some other oil, but contains no synthetic material or enhanced mineral oil.

(ii) *Enhanced mineral oil-based* means the continuous phase of the drilling fluid is enhanced mineral oil.

(iii) *Synthetic-based* means the continuous phase of the drilling fluid is a synthetic material or a combination of synthetic materials.

(o) *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.

(p) *Exploratory facility* means 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.

(q) *Formation oil* means the oil from a producing formation which is detected in the drilling fluid, as determined by the GC/MS compliance assurance method specified in Appendix 5 of subpart A of this part when the drilling fluid is analyzed before being shipped offshore, and as determined by the RPE method specified in Appendix 6 of subpart A of this part when the drilling fluid is analyzed at the offshore point of discharge. Detection of formation oil by the RPE method may be confirmed by the GC/MS compliance assurance method, and the results of the GC/MS compliance assurance method shall supercede those of the RPE method.

(r) *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; 401 M Street SW., Washington DC 20460.

(s) *M9IM* means those offshore facilities continuously manned by nine (9) or fewer persons or only intermittently manned by any number of persons.

(t) *M10* means those offshore facilities continuously manned by ten (10) or more persons.

(u) *Maximum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings means the maximum concentration allowed as measured in any single sample of the barite for determination of cadmium and mercury content.

(v) *Maximum for any one day* as applied to BPT, BCT and BAT effluent limitations and NSPS for oil and grease in produced water means 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.

(w) *Minimum* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings means the minimum 96-hour LC_{50} value allowed as measured in any single sample of the discharged waste stream.

Minimum as applied to BPT and BCT effluent limitations and NSPS for sanitary wastes means the minimum concentration value allowed as measured in any single sample of the discharged waste stream.

(x)(1) *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) *Water area* as used in ''site'' in 40 CFR 122.29 and 122.2 means 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) *Significant site preparation work* as used in 40 CFR 122.29 means 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.

(y) *No discharge of free oil* means that waste streams may not be discharged that contain free oil as evidenced by the monitoring method specified for that particular stream, e.g., deck drainage or miscellaneous discharges cannot be discharged when they would cause a film or sheen upon or discoloration of the surface of the receiving water; drilling fluids or cuttings may not be discharged when they fail the static sheen test defined in Appendix 1 of subpart A of this part.

(z) Parameters that are regulated in this subpart and listed with approved methods of analysis in Table 1B at 40 CFR 136.3 are defined as follows:

(1) *Cadmium* means total cadmium.

(2) *Chlorine* means total residual chlorine.

(3) *Mercury* means total mercury.

(4) *Oil and Grease* means total recoverable oil and grease.

(aa) *Produced sand* means the 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.

(bb) *Produced water* means 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.

(cc) *Production facility* means 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.

(dd) *Sanitary waste* means the human body waste discharged from toilets and urinals located within facilities subject to this subpart.

(ee) *SPP toxicity* as applied to BAT effluent limitations and NSPS for drilling fluids and drill cuttings refers to the bioassay test procedure presented in Appendix 2 of subpart A of this part.

(ff) *Static sheen test* means the standard test procedure that has been developed for this industrial subcategory for the purpose of demonstrating compliance with the requirement of no discharge of free oil. The methodology for performing the static sheen test is presented in Appendix 1 of subpart A of this part.

(gg) *Stock barite* means the barite that was used to formulate a drilling fluid.

(hh) *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. Internal olefins and vegetable esters are two examples of synthetic materials suitable for use by the oil and gas extraction industry in formulating drilling fluids. Internal olefins are synthesized from the isomerization of purified straight-chain (linear) hydrocarbons such as C_{16}–C_{18} linear alpha olefins. C_{16}–C_{18} linear alpha olefins are unsaturated hydrocarbons with the carbon to carbon double bond in the terminal position. Internal olefins are typically formed from heating linear alpha olefins with a catalyst. The feed material for synthetic linear alpha olefins is typically purified ethylene. Vegetable esters are synthesized from the acid-catalyzed esterification of vegetable fatty acids with various alcohols. EPA listed these two branches of synthetic fluid base materials to provide examples, and EPA does not mean 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.

(ii) *Well completion fluids* means 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.

(jj) *Well treatment fluids* means any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

(kk) *Workover fluids* means salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair or abandonment procedures.

(ll) *96-hour LC_{50}* means 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.

9. In § 435.42 the table is amended by removing the entries ''Drilling fluids'' and ''Drill cuttings'' and by adding new entries (after ''Deck drainage'') for ''Water based'' and ''Non-aqueous'' to read as follows:

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

* * * * *

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
* * *	* *	*	*
Water-based:			
Drilling fluids	(1)	(1)	NA
Drill Cuttings	(1)	(1)	NA
Non-aqueous:			
Drilling fluids	No discharge	No discharge	NA
Drill Cuttings	(1)	(1)	NA
* * *	* *	*	*

[1] No discharge of free oil.

* * * * *

10. In § 435.43 the table is amended by revising entry (B) under ''Drilling fluids, drill cuttings, and dewatering effluent'' and by revising footnote 4 and adding footnote 5 to read as follows:

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

* * * * *

BAT EFFLUENT LIMITATIONS

Waste source	Pollutant parameter	BAT effluent limitation
* *	* *	* * *
Drilling fluids, Drill cuttings, and Dewatering effluent: [1]		
* *	* *	* * *
(B) Cook Inlet:		
Water-based drilling fluids, drill cuttings, and dewatering effluent.	SPP Toxicity	Minimum 96-hour LC_{50} of the SPP Toxicity Test [4] shall be 3% by volume.
	Free oil	No discharge.[2]
	Diesel oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
Non-aqueous drilling fluids and dewatering effluent.		No discharge.
Drill cuttings associated with non-aqueous drilling fluids.		No discharge.[5]
* *	* *	* * *

[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 of Subpart A of this part).

* * * * * * *

[4] As determined by the suspended particulate phase (SPP) toxicity test (*see* Appendix 2 of Subpart A of this part).

[5] When Cook Inlet operators cannot comply with this no discharge requirement due to technical limitations (*see* Appendix 1 of Subpart D of this part), Cook Inlet operators shall meet the same stock limitations (C_{16}-C_{18} internal olefin) and discharge limitations for drill cuttings associated with non-aqueous drilling fluids for operators in Offshore waters (*see* § 435.13) in order to discharge drill cuttings associated with non-aqueous drilling fluids.

11. In § 435.44 the table is amended by revising the entry for ''Cook Inlet'' under the entry for ''Drilling fluids and drill cuttings and dewatering effluent'' to read as follows:

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

* * * * *

BCT EFFLUENT LIMITATIONS

Waste source	Pollutant parameter	BCT effluent limitation
* * *	* * *	*
Drilling fluids, Drill cuttings, and Dewatering effluent: [1]		
* * *	* * *	*
Cook Inlet:		
Water-based drilling fluids, drill cuttings, and dewatering effluent.	Free Oil	No discharge.[2]
Non-aqueous drilling fluids and dewatering effluent		No discharge.
Drill cuttings associated with non-aqueous drilling fluids	Free Oil	No discharge.[2]

[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 of Subpart A of this part).

* * * * *

12. In § 435.45 the table is amended by revising entry (B) under ''Drilling fluids, drill cuttings, and dewatering effluent'' and by revising footnote 4 and adding footnote 5 to read as follows:

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

* * * * *

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Waste Source	Pollutant parameter	NSPS
* *	* * *	*
Drilling fluids, Drill cuttings, and Dewatering effluent: [1]		
* *	* * *	*
(B) Cook Inlet:		
Water-based drilling fluids, drill cuttings, and dewatering effluent.	SPP Toxicity	Minimum 96-hour LC_{50} of the SPP Toxicity Test[4] shall be 3% by volume.
	Free oil	No discharge.[2]
	Diesel oil	No discharge.
	Mercury	1 mg/kg dry weight maximum in the stock barite.
	Cadmium	3 mg/kg dry weight maximum in the stock barite.
Non-aqueous drilling fluids and dewatering effluent.		No discharge.
Drill cuttings associated with non-aqueous drilling fluids.		No discharge.[5]
* *	* * *	*

[1] NSPS for dewatering effluent are applicable prospectively. NSPS 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 of subpart A of this part).
* * * * * * *
[4] As determined by the suspended particulate phase (SPP) toxicity test (*see* Appendix 2 of subpart A of this part).
[5] When Cook Inlet operators cannot comply with this no discharge requirement due to technical limitations (*see* Appendix 1 of subpart D of this part), Cook Inlet operators shall meet the same stock limitations (C_{16}–C_{18} internal olefin) and discharge limitations for drill cuttings associated with non-aqueous drilling fluids for operators in Offshore waters (*see* § 435.15) in order to discharge drill cuttings associated with non-aqueous drilling fluids.

13. Subpart D is amended by adding Appendix 1 as follows:

Appendix 1 to Subpart D of Part 435—Procedure for Determining When Coastal Cook Inlet Operators Qualify for an Exemption from the Zero Discharge Requirement for EMO-Cuttings and SBF-Cuttings in Coastal Cook Inlet, Alaska

1.0 Scope and Application

This appendix is to be used to determine whether a Cook Inlet, Alaska, operator in Coastal waters (Coastal Cook Inlet operator) qualifies for the exemption to the zero discharge requirement established by 40 CFR 435.43 and 435.45 for drill cuttings associated with the following non-aqueous drilling fluids: enhanced mineral oil based drilling fluids (EMO-cuttings) and synthetic-based drilling fluids (SBF-cuttings). Coastal Cook Inlet operators are prohibited from discharging oil-based drilling fluids. This appendix is intended to define those situations under which technical limitations

preclude Coastal Cook Inlet operators from complying with the zero discharge requirement for EMO-cuttings and SBF-cuttings. Coastal Cook Inlet operators that qualify for this exemption may be authorized to discharge EMO-cuttings and SBF-cuttings subject to the limitations applicable to operators in Offshore waters (*see* subpart A of this part).

2.0 Method

2.1 Any Coastal Cook Inlet operator must achieve the zero discharge limit for EMO-cuttings and SBF-cuttings unless it successfully demonstrates that technical limitations prevent it from being able to dispose of its EMO-cuttings or SBF-cuttings through on-site annular disposal, injection into a Class II underground injection control (UIC) well, or onshore land application.

2.2 To successfully demonstrate that technical limitations prevent it from being able to dispose of its EMO-cuttings or SBF-cuttings through on-site annular disposal, a Coastal Cook Inlet operator must show that it has been unable to establish formation injection in nearby wells that were initially considered for annular or dedicated disposal of EMO-cuttings or SBF-cuttings or prove to the satisfaction of the Alaska Oil and Gas Conservation Commission (AOGCC) that the EMO-cuttings or SBF-cuttings will be confined to the formation disposal interval. This demonstration must include:

a. Documentation, including engineering analysis, that shows (1) an inability to establish formation injection (e.g., formation is too tight), (2) an inability to confine EMO-cuttings or SBF-cuttings in disposal formation (e.g., no confining zone or adequate barrier to confine wastes in formation), or (3) the occurrence of high risk emergency (e.g., mechanical failure of well, loss of ability to inject that risks loss of well which would cause significant economic harm or create a substantial risk to safety); and

b. A risk analysis of alternative disposal options, including environmental assessment, human health and safety, and economic impact, that shows discharge as the lowest risk option.

2.3 To successfully demonstrate that technical limitations prevent it from being able to dispose of its EMO-cuttings or SBF-cuttings through injection into a Class II UIC well, a Coastal Cook Inlet operator must show that it has been unable to establish injection into a Class II UIC well or prove to the satisfaction of the Alaska Oil and Gas Conservation Commission (AOGCC) that the EMO-cuttings or SBF-cuttings will be confined to the formation disposal interval. This demonstration must include:

a. Documentation, including engineering analysis, that shows the inability to confine EMO-cuttings or SBF-cuttings in a Class II UIC well (e.g., no confining zone or adequate barrier to confine wastes in formation);

b. Documentation demonstrating that no Class II UIC well is accessible (e.g., operator does not own, competitor will not allow injection); and

c. A risk analysis of alternative disposal option, including environmental assessment, human health and safety, and economic impact, that shows discharge as the lowest risk option.

2.4 To successfully demonstrate that technical limitations prevent it from being able to dispose of its EMO-cuttings or SBF-cuttings through land application, a Coastal Cook Inlet operator must show that it has been unable to handle drilling waste or dispose of EMO-cuttings or SBF-cuttings at an appropriate land disposal site. This demonstration must include:

a. Documentation of site restrictions that preclude land application (e.g., no land disposal sites available);

b. Documentation of the platform's lack of capacity for adequate storage of EMO-cuttings or SBF-cuttings (e.g., limited storage or room for cuttings transfer); or

c. Documentation of inability to transfer EMO-cuttings or SBF-cuttings from platform to land for disposal (e.g., extremely low tides, high wave action).

3.0 Procedure

3.1 Except as described in Section 3.2 of this appendix, a Coastal Cook Inlet operator believing that it qualifies for the exemption to the zero discharge requirement for EMO-cuttings or SBF-cuttings must apply for and obtain an individual NPDES permit prior to discharging EMO-cuttings or SBF-cuttings to waters of the United States.

3.2 Discharges occurring as the result a high risk emergency (e.g., mechanical failure of well, loss of ability to inject that risks loss of well which would cause significant economic harm or safety) may be authorized by a general NPDES permit provided that:

a. The Coastal Cook Inlet operator satisfactorily demonstrates to EPA Region 10 the fulfillment of the other exemption requirements described in Section 2.0 of this appendix, or

b. The general permit allows for high risk emergency discharges and provides Reporting Requirements to EPA Region 10 immediately upon commencing discharge.

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