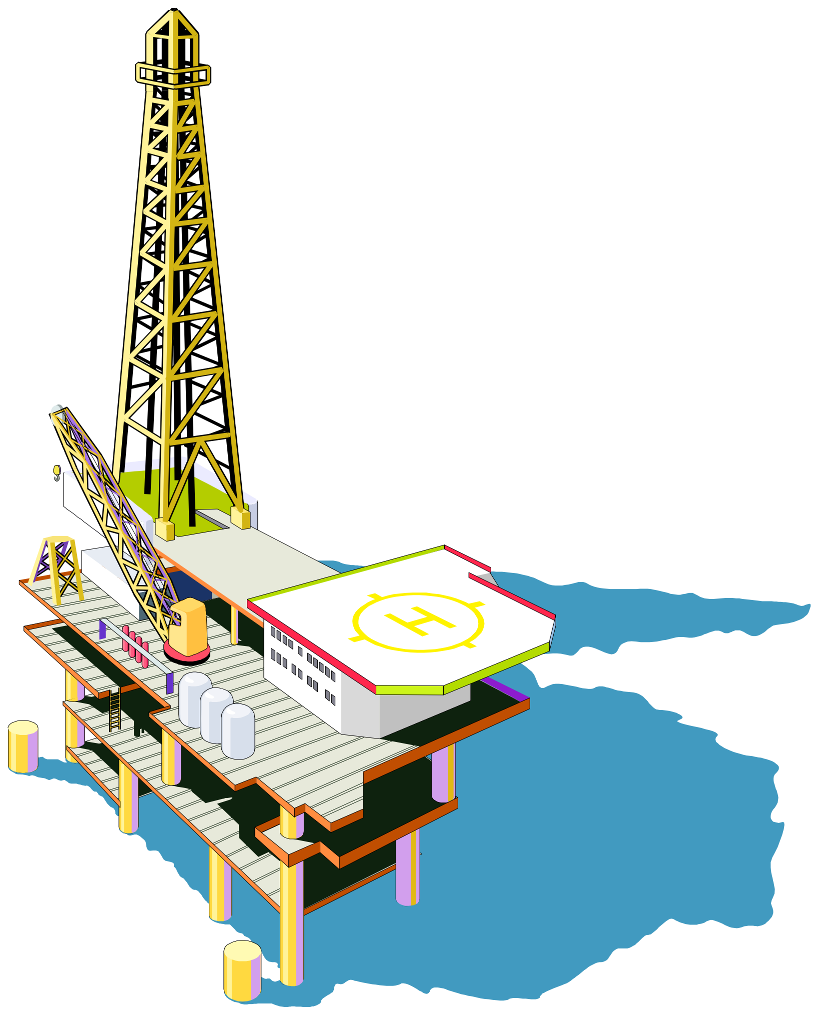
United States
Environmental Protection
Agency

Office of Water
4303

EPA-821-B-98-021
February 1999

Development Document for Proposed 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-98-021

DEVELOPMENT DOCUMENT FOR PROPOSED 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

FEBRUARY 1999

Office of Water
Office of Science and Technology
Engineering and Analysis Division
U.S. Environmental Protection Agency
Washington, D.C. 20460

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

LIST OF FIGURES

LIST OF TABLES

LIST OF TABLES
(continued)

Page

CHAPTER I

INTRODUCTION

1.0 LEGAL AUTHORITY

The Environmental Protection Agency (EPA) is proposing Effluent Limitations Guidelines and New Source Performance Standards for discharges associated with the use of synthetic-based drilling fluids (SBFs) and other non-aqueous drilling fluids in portions of the Offshore Subcategory and Cook Inlet portion of the Coastal Subcategory of the Oil and Gas Extraction Point Source Category under the authority of Sections 301, 304 (b), (c), and (e), 306, 307, 308, 402, and 501 of the Clean Water Act (CWA) (the Federal Water Pollution Control Act); 33 U.S.C. 1311, 1314 (b), (c), and (e), 1316, 1317, 1318, 1342, and 1361. The proposed regulation and supporting technical information is presented in the proceeding chapters of this document. This chapter describes EPA's legal authority for issuing the rule, as well as background information on prior regulations and litigation related to this proposal.

2.0 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 limitation guidelines and new source performance standards in National Pollutant Discharge Elimination System ("NPDES") permits; indirect dischargers must comply with pretreatment standards. EPA issues these guidelines and standards for categories of industrial dischargers based on the degree of control that can be achieved using various levels of pollution control technology. The guidelines and standards are summarized below.

2.1 BEST PRACTICABLE CONTROL TECHNOLOGY CURRENTLY AVAILABLE (BPT)

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

2.2 BEST CONVENTIONAL POLLUTANT CONTROL TECHNOLOGY (BCT)

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

Section 304(a)(4) designates the following as conventional pollutants: biochemical oxygen demanding pollutants (measured as 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).

2.3 BEST AVAILABLE TECHNOLOGY ECONOMICALLY ACHIEVABLE (BAT)

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

2.4 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

NSPS are based on the best available demonstrated control technology (BADCT) and apply to all pollutants (conventional, nonconventional, and toxic)(CWA section 306). NSPS are at least as stringent as BAT. New plants have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. Under NSPS, EPA is to consider the best demonstrated process changes, in-plant controls, and end-of-process control and treatment technologies that reduce pollution to the maximum extent feasible. In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.

2.5 PRETREATMENT STANDARDS FOR EXISTING SOURCES (PSES) AND PRETREATMENT STANDARDS FOR NEW SOURCES (PSNS)

Pretreatment standards are designed to prevent the discharge of pollutants to a publicly-owned treatment works (POTW) which pass through, interfere, or are otherwise incompatible with the operation of the POTW (CWA section 307(b)). Since none of the facilities to which this rule applies discharge to a POTW, pretreatment standards are not being considered as part of this rulemaking.

2.6 BEST MANAGEMENT PRACTICES (BMPs)

Section 304(e) of the CWA gives the Administrator the authority to publish regulations, in addition to the effluent limitations guidelines and standards listed above, to control plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage which the Administrator determines may contribute significant amounts of toxic and hazardous pollutants to navigable waters. Section 402(a)(1) also authorizes best management practices (BMPs) as necessary to carry out the purposes and intent of the CWA. See 40 CFR Part 122.44(k).

3.0 CWA SECTION 304(m) REQUIREMENTS AND LITIGATION

Section 304(m) of the CWA, added by the Water Quality Act of 1987, requires EPA to establish schedules for (i) reviewing and revising existing effluent limitations guidelines and standards and (ii) promulgating new effluent guidelines. On January 2, 1990, EPA published an Effluent Guidelines Plan (55 FR 80), in which schedules were established for developing new and revised 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 September 4, 1998 (63 FR 47285). This plan requires, among other things, that EPA propose the Synthetic-Based Drilling Fluids Guidelines by 1998 and take final action on the Guidelines by 2000.

4.0 POLLUTION PREVENTION ACT

The Pollution Prevention Act of 1990 (PPA) (42 U.S.C. 13101 et seq., Pub. L. 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 this proposed rule, EPA supports pollution prevention technology by encouraging the use of synthetic-based drilling fluids (SBFs) based on certain synthetic materials and other similarly performing materials in place of traditional oil-based drilling fluids (OBFs) based on diesel oil and mineral oil. The waste generated from SBFs is anticipated to have lower toxicity, lower bioaccumulation potential, faster biodegradation, and elimination of polynuclear aromatic hydrocarbons, including those which are priority pollutants. With these improved characteristics, and to encourage their use in place of OBFs, EPA is proposing to allow the controlled on-site discharge of the cuttings associated with SBF (SBF-cuttings). Use of SBF in place of OBF will eliminate the need to barge to shore or inject oily waste cuttings, reducing fuel use, air emissions, and land disposal. It also eliminates the risk of OBF and OBF-cuttings spills. In addition, the proposed regulatory option includes efficient closed-loop recycling systems to reduce the quantity of SBF discharged with the drill cuttings.

5.0 PRIOR FEDERAL RULEMAKINGS AND OTHER NOTICES

On March 4, 1993, EPA published final effluent guidelines for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category (58 FR 12454). The data and information gathering phase for this rulemaking thus corresponded to the introduction of SBFs in the Gulf of Mexico. Because of this timing, the range of drilling fluids for which data and information were available to EPA was limited to water-based drilling fluids (WBFs) and OBFs using diesel and mineral oil. Industry representatives, however, submitted information on SBFs during the comment period concerning environmental benefits of SBFs over OBFs and WBFs, and problems with false positives of free oil in the static sheen test applied to SBFs.

The requirements in the offshore rule applicable to drilling fluids and drill cuttings consist of mercury and cadmium limitations on the stock barite, a diesel oil discharge prohibition, a toxicity limitation on the suspended particulate phase (SPP) generated when the drilling fluids or drill cuttings are mixed in seawater, and no discharge of free oil as determined by the static sheen test.

While the SPP toxicity test and the static sheen test, and their limitations, were developed for use with WBF, the offshore regulation does not specify the types of drilling fluids and drill cuttings to which these limitations apply. Thus, under the rule, any drilling waste in compliance with the discharge limitations could be discharged. When the offshore rule was proposed, EPA believed that all drilling fluids, be they WBFs, OBFs, or SBFs, could be controlled by the SPP toxicity and static sheen tests. This is because OBFs based on diesel oil or mineral oil failed one or both of the SPP toxicity test and no free oil static sheen test. In addition, OBFs based on diesel oil were subject to the diesel oil discharge prohibition.

EPA thought SBFs could also be adequately controlled by the regulation based on comments received from industry. After the offshore rule was proposed, EPA received several industry comments which focused on the fact that the static sheen test could often be interpreted as giving a false positive for the presence of diesel oil, mineral oil, or formation hydrocarbons. For this reason, the industry commenters contended that SBFs should be exempt from compliance with the no free oil limitation required by the proposed offshore effluent guidelines.

In the final rulemaking record in 1993, EPA's response to these comments was that the prohibition on discharges of free oil was an appropriate limitation for discharge of drill fluids and drill cuttings, including SBFs. While EPA agreed that some of the newer SBFs may be less toxic and more readily biodegradable than many of the OBFs, EPA was concerned that no alternative method was offered for determining compliance with the no free oil standard to replace the static sheen test. In other words, if EPA were to exclude certain fluids from the requirement, there would be no way to determine if at that particular facility, diesel oil, mineral oil or formation hydrocarbons were also being discharged.

Also in the final offshore rule, EPA encouraged the use of drilling fluids that were less toxic and biodegraded faster. EPA solicited data on alterative ways of monitoring for the no free oil discharge requirement, such as gas chromatography or other analytical methods. EPA also solicited information on technology issues related to the use of SBFs, any toxicity data or biodegradation data on these newer fluids, and cost information.

By focusing on the issue of false positives with the static sheen test, EPA interpreted the offshore effluent guidelines to mean that SBFs could be discharged provided they complied with the current discharge requirements. Based on industry comments, however, EPA did not think that many, if any, SBFs would be able to meet the no free oil requirement.

In the final coastal effluent guidelines, EPA raised the issue of false negatives with the static sheen test as opposed to the issue of false positives raised during the offshore rulemaking. EPA had information indicating that the static sheen test does not adequately detect the presence of diesel, mineral, or formation oil in SBFs. In addition, EPA raised other concerns regarding the inadequacy of the current effluent guidelines to control of SBF wastestreams. Thus the final coastal effluent guidelines, published on December 16, 1996 (61 FR 66086), constitute the first time EPA identified, as part of a rulemaking, the inadequacies of the current regulations and the need for new BPT, BAT, BCT, and NSPS controls for discharges associated with SBFs.

The coastal rule adopted the offshore discharge requirements to allow discharge of drilling wastes in one geographic area of the coastal subcategory; Cook Inlet, Alaska, and prohibited the discharge of drilling wastes in all other coastal areas.

Due to the lack of information concerning appropriate controls, EPA could not provide controls specific to SBFs as a part of the coastal rule. However, the coastal rulemaking solicited comments on SBFs. In responding to these comments, EPA again identified certain environmental benefits of using SBFs, and stated that allowing the controlled discharge of SBF-cuttings would encourage their use in place of OBFs. EPA also raised the inadequacies of the current effluent guidelines to control the SBF wastestreams, and provided an outline of the parameters which EPA saw as important for adequate control. The inadequacies cited include the inability of the static sheen test to detect formation oil or other oil contamination in SBFs and the inability of the SPP toxicity test to adequately measure the toxicity of SBFs. EPA offered alternative tests of gas chromatography (GC) and a benthic toxicity test to verify the results of the static sheen and the SPP toxicity testing currently required. EPA also mentioned the potential need for controls on the base fluid used to formulate the SBF, based on one or more of the following parameters: PAH content, toxicity (preferably sediment toxicity), rate of biodegradation, and bioaccumulation potential.

The final coastal rule also incorporated clarifying definitions of drilling fluids for both the offshore and coastal subcategories to better differentiate between the types of drilling fluids. The rule provided guidance to permit writers needing to write limits for SBFs on a best professional judgement (BPJ) basis as using GC as a confirmation tool to assure the absence of free oil in addition to meeting the current no free oil (static sheen), toxicity, and barite limits on mercury and cadmium. EPA recommended Method 1663 as described in EPA 821-R-92-008 as a gas chromatograph with flame ionization detection (GC/FID) method to identify an increase in n-alkanes due to crude oil contamination of the synthetic materials coating the drill cuttings. Additional tests, such as benthic toxicity conducted on the synthetic material prior to use or whole SBF prior to discharge, were also suggested for controlling the discharge of cuttings contaminated with drilling fluid.

EPA stated intentions to evaluate further the test methods for benthic toxicity and determine an appropriate limitation if this additional test is warranted. In addition, test methods and results for bioaccumulation and biodegradation, as indications of the rate of recovery of the cuttings piles on the sea floor, were to be evaluated. EPA recognized that evaluations of such new testing protocols may be beyond the technical expertise of individual permit writers, and so stated that these efforts would be coordinated as a continuing effluent guidelines effort. This proposed rule is a result of these efforts.

6.0 CURRENT NPDES PERMIT STATUS

Four EPA Regions currently issue or review permits for offshore and coastal oil and gas well drilling activities in areas where drilling wastes may be discharged: Region 4 in the Eastern Gulf of Mexico (GOM), Region 6 in the Central and Western GOM, Region 9 in offshore California, and Region 10 in offshore and Cook Inlet, Alaska. Permits in Regions 4, 9 and 10 never allowed the discharge of SBFs, and those three Regions are currently preparing final general permits that either specifically disallow SBF discharges until adequate discharge controls are available to control the SBF wastestreams, or allow a limited use of SBF to facilitate information gathering.

Discharge of drill cuttings contaminated with SBF (SBF-cuttings) has occurred under the Region 6 offshore continental shelf (OCS) general permit issued in 1993 (58 FR 63964), and the general permit reissued on November 2, 1998 (63 FR 58722) again does not specifically disallow the continued discharge of SBF-cuttings. The reason for these differences between Region 6 and the other EPA Regions relates to the timing of the 1993 Region 6 general permit and the issues raised in comments during the issuance of that permit.

The previous individual and general permits of Regions 4, 9 and 10 were issued long before SBFs were developed and used. In Region 6, however, the first SBF well was drilled in June of 1992 and the development of the Region 6 OCS general permit, published December 3, 1993 (58 FR 63964), thus corresponded to the introduction of SBF use in the GOM. After proposal of this permit, industry representatives commented that the no free oil limitation as measured by the static sheen test should be waived for SBFs, due to the occurrence of false positives. They contended that a sheen was sometimes perceived when the SBF was known to be free of diesel oil, mineral oil or formation oil. These comments were basically the same as those submitted as part of the offshore rulemaking, which occurred in the same time frame. EPA responded as it had in the offshore rulemaking, maintaining the static sheen test until there existed a replacement test to determine the presence of free oil. EPA stated that if the current discharge requirements could be met then the drilling fluid and associated wastes could be discharged. This response indicated EPA's position that SBF drilling wastes could be discharged as long as the discharge met permit requirements. But again, in the context of these comments, EPA did not expect that many, if any SBFs, would be able to meet the static sheen requirements.

In addition to the requirements of the offshore guidelines, the Region 6 OCS general permit also prohibited the discharge of oil-based and inverse emulsion drilling fluids. Although SBFs are, in chemistry terms, inverse emulsion drilling fluids, the definition in the permit limited the term "inverse emulsion drilling fluids" to mean "an oil-based drilling fluid which also contains a large amount of water." Further, the permit provides a definition for oil-based drilling fluid as having "diesel oil, mineral oil, or some other oil as its continuous phase with water as the dispersed phase." Since the SBFs clearly do not have diesel or mineral oil as the continuous phase, there was a question of whether synthetic base fluids (and more broadly, other oleaginous base fluids) used to formulate the SBFs are "some other oil." With consideration of the intent of the inverse emulsion discharge prohibition, and the known differences in polynuclear aromatic hydrocarbon content, toxicity, and biodegradation between diesel and mineral oil versus the synthetics, EPA determined that SBFs were not inverse emulsion drilling fluids as defined in the Region 6 general permit. This determination is exemplified by the separate definitions for OBFs and SBFs introduced with the Coastal Effluent Guidelines (see 61 FR 66086, December 16, 1996).

In late 1998 and early 1999, all four Regions are (re)issuing their general permits for offshore (Regions 4, 6 and 9) and coastal (Region 10) oil and gas wells. Once the effluent guidelines or guidance becomes available, EPA intends to reopen the permits to add requirements that adequately control SBF drilling wastes.

EPA intends for this proposed rule to act as guidance such that the Regions do not have to wait until issuance of a final rule planned for December 2000, but may propose to add the appropriate discharge controls through best professional judgement (BPJ). In this manner, the controlled discharge of SBF may be used to further aid EPA in gathering information subsequent to the publication of this proposal.

CHAPTER II

PURPOSE AND SUMMARY OF THE PROPOSED REGULATION

1.0 PURPOSE OF THIS RULEMAKING

The purpose of this rulemaking is to amend the effluent limitations guidelines and standards for the control of discharges of certain pollutants associated with the use of synthetic-based drilling fluids (SBFs) and other non-aqueous drilling fluids in portions of the Offshore Subcategory and Cook Inlet portion of the Coastal Subcategory of the Oil and Gas Extraction Point Source Category. These proposed limitations apply to discharges or effluent generated when oil and gas wells are drilled using SBFs or other non-aqueous drilling fluids (henceforth collectively referred to simply as SBFs) in coastal and offshore regions in locations where drilling wastes may be discharged. The processes and operations that comprise the offshore and coastal oil and gas subcategories are currently regulated under 40 CFR Part 435, Subparts A (offshore) and D (coastal).

These proposed regulations present EPA's preferred technology approach and several others that are being considered in the regulation development process. The proposed rule is based on a detailed evaluation of the available data acquired during the development of the proposed limitations. EPA is interested in gathering additional information and data in support for the final rule.

2.0 SUMMARY OF PROPOSED SBF GUIDELINES

EPA proposes to establish regulations based on the "best practicable control technology currently available" (BPT), "best conventional pollutant control technology" (BCT), "best available technology economically achievable" (BAT), and the best available demonstrated control technology (BADCT) for new source performance standards (NSPS), for the wastestream of synthetic-based drilling fluids and other non-aqueous drilling fluids, and cuttings contaminated with these drilling fluids.

For certain drilling situations, such as drilling in reactive shales, high angle and/or high displacement directional drilling, and drilling in deep water, progress with water-based drilling fluids (WBFs) can be slow, costly, or even impossible, and often creates a large amount of drilling waste. In these situations, the well is normally drilled with traditional oil-based drilling fluids (OBFs), which use diesel oil or mineral oil as the base fluid. Because EPA rules require zero discharge of these wastes, they are either sent to shore for disposal in non-hazardous oil field waste (NOW) sites or injected into disposal wells.

Since about 1990, the oil and gas extraction industry has developed many new oleaginous (oil-like) base materials from which to formulate high performance drilling fluids. A general class of these are called the synthetic materials, such as the vegetable esters, poly alpha olefins, internal olefins, linear alpha olefins, synthetic paraffins, ethers, linear alkyl benzenes, and others. Other oleaginous materials have also been developed for this purpose, such as the enhanced mineral oils and non-synthetic paraffins. Industry developed SBFs with these synthetic and non-synthetic oleaginous materials as the base fluid to provide the drilling performance characteristics of traditional OBFs based on diesel and mineral oil, but with lower environmental impact and greater worker safety through lower toxicity, elimination of polynuclear aromatic hydrocarbons (PAHs), faster biodegradability, lower bioaccumulation potential, and, in some drilling situations, less drilling waste volume. EPA believes that this product substitution approach is an excellent example of pollution prevention that can be accomplished by the oil and gas industry.

EPA intends that these proposed regulations would control the discharge of SBFs in a way that reflects application of appropriate levels of technology, while also encouraging their use as a replacement to the traditional mineral oil and diesel oil-based fluids. Based on EPA's information to date, the record indicates that use of SBFs and discharge of the cuttings waste with proper controls would overall be environmentally preferable to the use of OBFs. This is because OBFs are subject to zero discharge requirements, and thus, must be shipped to shore for land disposal or injected underground, resulting in higher air emissions, increased energy use, and increased land disposal of oily wastes. By contrast, the discharge of cuttings associated with SBFs would eliminate those impacts. At the same time EPA recognizes that the discharge of SBFs may have impacts to the receiving water. Because SBFs are water non-dispersible and sink to the seafloor, the primary potential environmental impacts are associated with the benthic community. EPA's information to date, including limited seabed surveys in the Gulf of Mexico, indicate that the effect zone of the discharge of certain SBFs is within a few hundred meters of the discharge point and may be significantly recovered in one to two years. EPA believes that impacts are primarily due to smothering by the drill cuttings, changes in sediment grain size and composition (physical alteration of habitat), and anoxia (absence of oxygen) caused by the decomposition of the organic base fluid. The benthic smothering and changes in grain size and composition from the cuttings are effects that are also associated with the discharge of WBFs and associated cuttings.

Based on the record to date, EPA finds that these impacts, which are believed to be of limited duration, are less harmful to the environment than the non-water quality environmental impacts associated with the zero discharge requirement applicable to OBFs. Compared to the zero discharge option EPA estimates that allowing discharge will reduce air emissions of the criteria air pollutants by 450 tons per year, decrease fuel use by 29,000 barrels per year of oil equivalent, and reduce the generation of oily drill cutting wastes requiring off-site disposal by 212 million pounds per year. In addition, EPA estimates that compliance with these proposed limitations would result in a yearly decrease in the discharge of 11.7 million pounds of toxic and nonconventional pollutants in the form of SBFs. These estimates are based on the current industry practice of discharging SBF-cuttings outside of 3 miles in the Gulf of Mexico and no discharge of SBFs in any other areas, including 3 miles offshore of California and in Cook Inlet, Alaska.

As SBFs came into commercial use, EPA determined that the current discharge monitoring methods, which were developed to control the discharge of WBFs, did not appropriately control the discharge of these new drilling fluids. Since WBFs disperse in water, oil contamination of WBFs with formation oil or other sources can be measured by the static sheen test, and any toxic components of the WBFs will disperse in the aqueous phase and be detected by the suspended particulate phase (SPP) toxicity test. With SBFs, which do not disperse in water but instead sink as a mass, formation oil contamination has been shown to be less detectible by the static sheen test. Similarly, the potential toxicity of the discharge is not apparent in the current SPP toxicity test.

EPA has therefore sought to identify methods to control the discharge of cuttings associated with SBFs (SBF-cuttings) in a way that reflects the appropriate level of technology. One way to do this is through stock limitations on the base fluids from which the drilling fluids are formulated. This would ensure that substitution of synthetic and other oleaginous base fluids for traditional mineral oil and diesel oil reflects the appropriate level of technology. In other words, EPA wants to ensure that only the SBFs formulated from the “best” base fluids are allowed for discharge. Parameters that distinguish the various base fluid are the polynuclear aromatic hydrocarbon (PAH) content, sediment toxicity, rate of biodegradation, and potential for bioaccumulation.

EPA also thinks that the SBF-cuttings should be controlled with discharge limitations, such as a limitation on the toxicity of the SBF at the point of discharge, and a limitation on the mass (as volume) or concentration of SBFs discharged. The latter type of limitation would take advantage of the solids separation efficiencies achievable with SBFs, and consequently minimize the discharge of organic and toxic components. EPA believes that SBFs separated from drill cuttings should meet zero discharge requirements, as this is the current industry practice due to the value of these drilling fluids.

Thus, EPA is proposing limits appropriate to SBF-cuttings. EPA is proposing zero discharge of neat SBFs (not associated with cuttings), which reflects current practice. The new limitations applicable to cuttings contaminated with SBFs would be as follows:

- Stock Limitations on Base Fluids: (BAT/NSPS):
  - Maximum PAH content 10 ppm (wt. based on phenanthrene/wt. base fluid).
  - Minimum rate of biodegradation (biodegradation equal to or faster than C_{16} - C_{18} internal olefin by solid phase test).
  - Maximum sediment toxicity (as toxic or less toxic than C_{16} - C_{18} internal olefin by 10-day sediment toxicity test).
- Discharge Limitations on Cuttings Contaminated with SBFs:
  - No free oil by the static sheen test. (BPT/BCT/NSPS)
  - Maximum formation oil contamination (95 percent of representative formation oils failing 1 percent by volume in drilling fluid). (BAT/NSPS)
  - Maximum well-average retention of SBF on cuttings (10.2 percent base fluid on wet cuttings). (BAT/NSPS)
- Discharges remain subject to the following requirements already applicable to all drilling waste discharges and thus these requirements are not within the scope of this rulemaking:
  - Mercury limitation in stock barite of 1 mg/kg. (BAT/NSPS)
  - Cadmium limitation in stock barite of 3 mg/kg. (BAT/NSPS)
  - Diesel oil discharge prohibition. (BAT/NSPS)

- EPA may require these additional or alternative controls as part of the discharge option based on method development and data gathering subsequent to publication of this proposal:
    - Maximum sediment toxicity of drilling fluid at point of discharge (minimum LC_{50}, mL drilling fluid/kg dry sediment by 10-day sediment toxicity test or amended test). (BAT/NSPS)
    - Maximum aqueous phase toxicity of drilling fluid at point of discharge (minimum LC_{50} by SPP test or amended SPP test). (BAT/NSPS)
    - Maximum potential for bioaccumulation of stock base fluid (maximum concentration in sediment-eating organisms). (BAT/NSPS)

- EPA is also considering a zero discharge option in the event that EPA has an insufficient basis upon which to develop appropriate discharge controls for SBF-cuttings:
    - Zero discharge of drill cuttings contaminated with SBFs and other non-aqueous drilling fluids. (BPT/BCT/BAT/NSPS)

While EPA is proposing limitations on these parameters, many of the test methods that would be used to demonstrate attainment with the limitations are still under development at this time, or additional data needs to be gathered towards validating methods, proving the variability and appropriateness of the methods, and assessing appropriate limitations for the parameters. For example, as noted in the list above, EPA is considering limitations in addition, or as an alternative, to the limitations of this proposal. The reason for this is that EPA has insufficient data at this time to determine how to best control toxicity and whether a bioaccumulation limitation is necessary to adequately control the SBF-cuttings wastestream.

EPA would prefer to control sediment toxicity at the point of discharge. While there is an EPA approved sediment toxicity test to do this, EPA has concerns about the uniformity of the sediment used in the toxicity test, the discriminatory power and variability of the test so applied. Since the test is 10 days long, it poses a practical problem for operators who would prefer to know immediately whether cuttings may be discharged. Applying EPA's existing sediment toxicity test to the base fluid as a stock limitation ameliorates these concerns, such that, at this stage of the development of the test, EPA thinks that it is more likely to be practically applied. As this would be the preferred method of control, EPA intends to continue research into the test as applied to the drilling fluid at the point of discharge. Industry also has been conducting research to develop a sediment toxicity test that may be applied to SBFs at the point of discharge with the cuttings. Further, EPA intends to perform research into the aquatic toxicity test to see if it can be used to adequately control the discharge through modification. EPA may then consider applying an aqueous phase toxicity test, either alone or in conjunction with a sediment toxicity test of either the stock base fluid or drilling fluid at the point of discharge.

In terms of the retention of SBF on cuttings, while EPA has enough information to propose a limitation, EPA is still evaluating methods to determine attainment of this limit. For the parameter of biodegradation, EPA is proposing a numerical limit, but the analytic method for measuring attainment of the limit has not yet been validated. EPA wishes to do additional studies to validate the method and provide public notice of any subsequently developed numerical limit.

Because EPA plans to gather significant additional information in support of the final rule, EPA intends to publish a supplemental notice for public comment providing the proposed limitations and specific test methods. These data gathering activities are described in Chapter V of this document. Therefore, the purpose of this proposal is to request comment on the candidate requirements listed above, identify the additional work that EPA intends to perform towards promulgation of the limitations, and request comments and additional data towards the selection of parameters, methods and limitations development. EPA also intends that this proposal serve as guidance to permit writers such that the proposed methods can be incorporated into permits through best professional judgement (BPJ). Such permits can be used to gather supporting information towards selection of parameters, methods development, and appropriate limitations.

The current regulations establish the geographic areas where drilling wastes may be discharged: the offshore subcategory waters beyond 3 miles from the shoreline, and in Alaska offshore waters with no 3-mile restriction. The only coastal subcategory waters where drilling wastes may be discharged is in Cook Inlet, Alaska. EPA is retaining the zero discharge limitations in areas where discharge is currently prohibited and these requirements are not within the scope of this rulemaking.

EPA is limiting the scope of this proposed rulemaking to locations where drilling wastes may be discharged because these are the only locations for which EPA has evaluated the non-water quality environmental impacts of zero discharge versus the environmental impacts of discharging drill cuttings associated with SBFs. For example, EPA has only assessed the non-water quality environmental impacts of zero discharge beyond three miles from shore. EPA expects these impacts to be less where the wastes are generated closer to shore. In addition, EPA has not assessed the environmental effects of these discharges in coastal areas. The current zero discharge areas are more likely to be environmentally sensitive due to the presence of spawning grounds, wetlands, lower energy (currents), and more likely to be closer to recreational swimming and fishing areas. Further, dischargers are in compliance with the zero discharge requirement and have only expressed an interest in the use of these newer fluids where drilling wastes may be currently discharged.

3.0 CORRECTION TO THE REGULATORY LIMIT FOR RETENTION OF BASE FLUID ON CUTTINGS

An error was made in the draft statistical analysis of the Gulf of Mexico data of retention of base fluid on drill cuttings. Correction of this error changes the regulatory limit for retention of base fluid on cuttings as presented in the preamble to the SBF proposed rule from 10.2 to 9.42 percent.[1] Since this error has only recently been identified, EPA did not have sufficient time to correct this regulatory limitation in the preamble. For consistency with the preamble, this SBF Development Document also uses the same erroneous values except for in this error notification section. The purpose of this section is to identify and explain the error of the draft statistical analysis, and present the final values and corrected limits.

Cost and loadings calculations presented in this and other SBF technical support documents are not affected by this correction, because the cost and loadings calculations were based on the round numbers of 11 percent and 7 percent base fluid on cuttings, respectively, for current practice and BAT technology.

Specifically, correction of the error has resulted in a reduction in the long term average and recommended limit for percent retention of drilling fluids on drill cuttings generated by primary and secondary shale shakers in the Gulf of Mexico. The error that occurred relates to the length of hole drilled per drill cuttings sample. The regulatory limit of percent retention of base fluid on drill cuttings is based on a volume weighted average over the sections of the well drilled with SBFs. This means that each retention value is weighted by the volume of hole, determined by the length and diameter of the hole associated with that particular cuttings sample. The data analyzed for the Gulf of Mexico consisted of base fluid retention on cuttings at a specific well depth. The cuttings samples were taken every few hundred feet or so. The error occurred when the total depth of the well, in the range of tens of thousands of feet, was used in calculating the volume represented by the cuttings sample, instead of using the difference in well depth from the previous cuttings sample, which is in the range of a few hundred feet.

This error has been corrected to give the values presented in this paragraph.[2] For primary shakers the mean percent retention on cutting is 10.5. For secondary shakers the mean percent retention on cuttings is 14.9 and the 95th percentile (used in calculating the corrected limit) is 18.2. This correction to the volume-weighted average values affects the long term average for the current practice and discharge option, and the proposed regulatory limit for the retention of base fluid on cuttings.

The error did not occur when EPA analyzed the North Sea data, which was used to determine the performance of the vibrating centrifuge (BAT technology). For the vibrating centrifuge the values remain 5.14 percent for the mean (also called the long-term average) and 7.22 for the 95th percentile (used in calculating the proposed limit).

EPA estimates that in current practice, 80 percent of the cuttings wastestream comes from the primary shale shaker and the remaining 20 percent comes from the secondary shale shakers.[3] Under the model technology of the discharge option, the cuttings from the primary shale shaker, or 80 percent of the cuttings, are further treated by the vibrating centrifuge. Applying the retention values above and the 80/20 split in the cuttings wastestream, the well average percent base fluid on cuttings is corrected to 11.4 for current practice and 7.09 for BAT technology, and the recommended limit is corrected to 9.42. These values were calculated as follows:

Long-Term Well Average

Current Practice: 0.80 x 10.5% + 0.20 x 14.9% = 11.4% base fluid on wet cuttings

BAT Technology: 0.80 x 5.14% + 0.20 x 14.9% = 7.09% base fluid on wet cuttings

Recommended Limit

BAT Technology: 0.80 x 7.22% + 0.20 x 18.2% = 9.42% base fluid on wet cuttings

4.0 REFERENCES

1. Daly, J.M., U.S. EPA, Memorandum to SBF Regulatory Record regarding "Correction to the Regulatory Limits for Retention of Base Fluid on Cuttings as Presented in the Preamble to the SBF Proposed Rule from 10.2 to 9.42 Percent," January 29, 1999.

2. White, C.E., U.S. EPA, Memorandum to Daly, J.M., U.S. EPA, regarding "Current Performance, when using Synthetic-Based Drilling Fluids, for Primary Shakers, Secondary Shakers, and Vibrating Centrifuge and Model Limits for Percent Retention of Base Fluids on Cuttings for Secondary Shakers and Vibrating Centrifuge," January 29, 1999.

3. Annis, Max R., "Procedures for Sampling and Testing Cuttings Discharged While Drilling with Synthetic-Based Muds," prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 19, 1998.

CHAPTER III

DEFINITION OF SBF AND ASSOCIATED WASTESTREAMS

1.0 INTRODUCTION

This chapter describes the industry, geographic areas and wastestreams to which this regulation would apply.

2.0 INDUSTRY DEFINITION

This proposed rule would apply to certain coastal and offshore facilities included in the following standard industrial classification codes: 1311 - Crude Petroleum and Natural Gas, 1381 - Drilling Oil and Gas Wells, 1382 - Oil and Gas Field Exploration Services, and 1389 - Oil and Gas Field Services, not classified elsewhere.

This regulation would apply to offshore and coastal facilities located in waters where drilling wastes are allowed for discharge under the current effluent guidelines at 40 CFR Part 435, Subparts A (Offshore) and D (Coastal). The offshore subcategory of the oil and gas extraction point source category, as defined in 40 CFR 435.10, is comprised of those structures involved in exploration, development, and production operations seaward of the inner boundary of the territorial seas (shoreline). The discharge of drilling waste is allowed within the offshore subcategory beyond three miles from shore, except in offshore Alaska where there is no three mile discharge prohibition. The coastal subcategory of the oil and gas extraction point source category, as defined in 40 CFR 435.40, is comprised of those facilities involved in exploration, development, and production operations in waters of the United States landward of the inner boundary of the territorial seas (shoreline). The only area where discharge of drilling waste is allowed in the coastal subcategory is in Cook Inlet, Alaska.

To summarize, this regulation is applicable to facilities engaged in the drilling of oil and gas wells in a) offshore waters greater that three miles from shore, except in Alaska offshore waters from the shoreline out, and b) the coastal waters of Cook Inlet, Alaska.

3.0 WASTESTREAMS REGULATED BY THE SBF GUIDELINES

This proposed rule would apply to wastes generated when oil and gas wells are drilled with synthetic-based drilling fluids (SBFs) and other non-aqueous drilling fluids by facilities in coastal and offshore locations where drilling wastes may be discharged. These wastes include the drilling fluids themselves, and drill cuttings contaminated with the drilling fluids.

This proposed rule also amends the current effluent guidelines such that the current guidelines are applicable only to water-based drilling fluids (WBF), while the proposed discharge requirements would be applicable to all other drilling fluids. To achieve this, EPA proposes to define WBFs and non-aqueous drilling fluids such that all drilling fluids will fall into one classification or the other. In this way, all drilling fluids would be controlled by either applying the current requirements for WBFs or the proposed requirements for non-aqueous drilling fluids. The definition would be based on the miscibility (solubility) of the base fluid in water. The proposed definitions for various drilling fluids are as follows:

- A **water-based drilling fluid** has water or a water miscible fluid as the continuous phase and the suspending medium for solids, whether or not oil is present.
- A **non-aqueous drilling fluid** is one in which the continuous phase is a water immiscible fluid such as an oleaginous material (e.g., mineral oil, enhanced

mineral oil, paraffinic oil, or synthetic material such as olefins and vegetable esters).

- An **oil-based drilling fluid** has diesel oil, mineral oil, or some other oil, but neither a synthetic material nor enhanced mineral oil, as its continuous phase with water as the dispersed phase. Oil-based drilling fluids are a subset of non-aqueous drilling fluids.

- An **enhanced mineral oil-based drilling fluid** has an enhanced mineral oil as its continuous phase with water as the dispersed phase. Enhanced mineral oil-based drilling fluids are a subset of non-aqueous drilling fluids.

- A **synthetic-based drilling fluid** has a synthetic material as its continuous phase with water as the dispersed phase. Synthetic-based drilling fluids are a subset of non-aqueous drilling fluids.

There could be other types of non-aqueous drilling fluids that are not listed in the definitions above. For example, drilling fluids based on synthetic linear paraffins would be considered non-aqueous drilling fluids.

CHAPTER IV

INDUSTRY DESCRIPTION

1.0 INTRODUCTION

This chapter describes the major processes associated with the offshore oil and gas extraction industry, and presents the current and projected drilling activities for this industry.

2.0 DRILLING ACTIVITIES

There are two types of operations associated with drilling for oil and gas: exploratory and development. Exploratory drilling includes those operations that involve the drilling of wells to determine potential hydrocarbon reserves. Development drilling includes those operations that involve the drilling of production wells, once a hydrocarbon reserve has been discovered and delineated. Although the rigs used in exploratory and development drilling sometimes differ, the drilling process is generally the same for both types of drilling operations.

The water depth in which either exploratory and development drilling occurs may determine the operator's choice of drill rigs and drilling systems, including the type of drilling fluid. The Minerals Management Service (MMS) and the drilling industry classify wells as located in either deep water or shallow water, depending on whether drilling is in water depths greater than 1,000 feet or less than 1,000 feet, respectively.

2.1 EXPLORATORY DRILLING

Exploration for hydrocarbon-bearing strata consists of several indirect and direct methods. Indirect methods, such as geological and geophysical surveys, identify the physical and chemical properties of formations through surface instrumentation. Geological surveys determine subsurface stratigraphy to identify rock formations that are typically associated with hydrocarbon bearing formations. Geophysical surveys establish the depth and nature of subsurface rock formations and identify underground conditions favorable to oil and gas deposits. There are three types of geophysical surveys: magnetic, gravity, and seismic. These surveys are conducted from the surface with equipment specially designed for this purpose. Direct exploratory drilling, however, is the only method to confirm the presence of hydrocarbons and to determine the quantity of hydrocarbons after the indirect methods have indicated hydrocarbon potential. Exploratory wells are also referred to as "wildcats."

Exploratory wells may be drilled to shallow or deep footage, depending on the purpose of the well. Shallow exploratory wells are usually drilled in the initial phases of exploration to discover the presence of oil and gas reservoirs. Deep exploratory wells are usually drilled to establish the extent of the oil or gas reservoirs, once they have been discovered. These types of exploration activities are usually of short duration, involve a small number of wells, and are conducted from mobile drilling rigs.

2.1.1 Drilling Rigs

Mobile drilling rigs are used to drill exploratory wells because they can be easily moved from one drilling location to another. These units are self contained and include all equipment necessary to conduct the drilling operation plus living quarters for the crew. The two basic types of mobile drilling units are bottom-supported units and floating units. Bottom-supported units include submersibles and jackups. Floating units include inland barge rigs, semisubmersibles, drill ships, and ship-shaped barges.[1]

Bottom-supported drilling units are typically used in the Gulf of Mexico region when drilling occurs in shallow waters. Submersibles are barge-mounted drilling rigs that are towed to the drill site and sunk to the bottom. There are two common types of submersible rigs: posted barge and bottle-type.

Jackups are barge-mounted drilling rigs that have extendable legs that are retracted during transport. At the drill site, the legs are extended to the seafloor. As the legs continue to extend, the barge hull is lifted above the water. Jackup rigs can be used in waters up to 300 feet deep. There are two basic types of design for jackup rigs: columnar leg and open-truss leg.

Floating drilling units are typically used when drilling occurs in deep waters and at locations far from shore. Semisubmersible units are able to withstand rough seas with minimal rolling and pitching tendencies. Semisubmersibles are hull-mounted drilling rigs that float on the surface of the water when empty. At the drilling site, the hulls are flooded and sunk to a certain depth below the surface of the water. When the hulls are fully submerged, the unit is stable and not susceptible to wave motion due to its low center of gravity. The unit is moored with anchors to the seafloor. There are two types of semisubmersible rigs: bottle-type and column-stabilized.

Drill ships and ship-shaped barges are vessels equipped with drilling rigs that float on the surface of the water. These vessels maintain position above the drill site by anchors on the seafloor or the use of propellers mounted fore, aft, and on both sides of the vessel. Drill ships and ship–shaped barges are susceptible to wave motion since they float on the surface of the water, and thus are not suitable for use in heavy seas.

2.1.2 Formation Evaluation

The operator constantly evaluates characteristics of the formation during the drilling process. The evaluation involves measuring properties of the reservoir rock and obtaining samples of the rock fluids from the formation. Three common evaluation methods are well logging, coring, and drill stem testing. Well logging uses instrumentation that is placed in the wellbore and measures electrical, radioactive, and acoustic properties of the rocks. Coring consists of extracting rock samples from the formation and characterizing the rocks. Drill stem testing brings fluids from the formation to the surface for analysis.[1]

2.2 DEVELOPMENT DRILLING

Development of the oil and gas reservoirs involves drilling of wells into the reservoirs to initiate hydrocarbon extraction, increase production or replace wells that are not producing on existing production sites. Development wells tend to be smaller in diameter than exploratory wells because, since the geological and geophysical properties of the producing formation are known, drilling difficulties can be anticipated and the number of workovers (remedial procedures) during drilling minimized.

The two most common types of rigs used in developmental drilling operations are the platform rig and the mobile offshore drilling unit. Development wells are often drilled from fixed platforms because once the exploratory drilling has confirmed that an extractable quantity of hydrocarbons exists, a platform is constructed at that site for drilling and production operations.

To extract hydrocarbons from the reservoir, several wells are drilled into different parts of the formation. Since all wells must originate directly below the platform, a special drilling technique, called "controlled directional drilling," is used to steer the direction of the hole and penetrate different portions of the reservoir. Directional drilling involves drilling the top part of the well straight and then directing the wellbore to the desired location in non-vertical directions. This requires special drilling tools and devices that measure the direction and angle of the hole. Directional drilling also requires the use of drilling fluids that provide more lubricity to prevent temperature build up and stuck pipe incidents due to the increased friction on the drill bit and drill string.

2.2.1 Well Drilling

The process of preparing the first few hundred feet of a well is referred to as "spudding." This process consists of extending a large diameter pipe, known as the conductor casing, from a few hundred feet below the seafloor up to the drilling rig. The conductor casing, which is approximately two feet in diameter, is either hammered, jetted, or placed into the seafloor depending on the composition of the seafloor. If the composition of the seafloor is soft, the conductor casing can be hammered into place or lowered into a hole created by a high-pressure jet of seawater. In areas where the seafloor is composed of harder material, the casing is placed in a hole created by rotating a large-diameter drill bit on the seafloor. In all cases, the cuttings or solids displaced from setting the casing are not brought to the surface and are expended onto the seafloor.

Rotary drilling is the drilling process used to drill the well. Rotary drilling equipment uses a drill bit attached to the end of a drill pipe, referred to as the "drill string," which makes a hole in the ground when rotated. Once the well is spudded and the conductor casing is in place, the drill string is lowered through the inside of the casing to the bottom of the hole. The bit rotates and is slowly lowered as the hole is formed. As the hole deepens, the walls of the hole tend to cave in and widen, so periodically the drill string is lifted out of the hole and casing is placed into the newly formed portion of the hole to protect the wellbore. This process of drilling and adding sections of casing is continued until final well depth is reached.

Rotary drilling utilizes a system of circulating drilling fluid to move drill cuttings away from the bit and out of the borehole. The drilling fluid, or mud, is a mixture of water or sometimes other base fluids, special clays, and certain minerals and chemicals. The drilling fluid is pumped downhole through the drill string and is ejected through the nozzles in the drill bit with great speed and pressure. The jets of fluid lift the cuttings off the bottom of the hole and away from the bit so that the cuttings do not interfere with the effectiveness of the drill bit. The drilling fluid is circulated to the surface through the space between the drill string and the casing, called the annulus.   At the surface, the drill cuttings, silt, sand, and any gases are removed from the drilling fluid before returning it downhole through the drill string to the bit. The cuttings, sand, and silt are separated from the drilling fluid by a solids separation process which typically includes a shale shaker, desilter, and desander, and sometimes centrifuges. Figure IV-1 presents a schematic flow diagram of a generalized drilling fluid circulation system. Some of the drilling fluid remains with the cuttings after solids separation. Following solids separation, the cuttings are disposed in one of three ways, depending on the type of drilling fluid used and the oil content of the cuttings. The disposal methods, which are described in detail in Chapter VII, are discharge, transport to shore for land-based disposal, and onsite subsurface injection.

Drilling fluids function to cool and lubricate the bit, stabilize the walls of the borehole, and maintain equilibrium between the borehole and the formation pressure. The drilling fluid must exert a higher pressure in the wellbore than exists in the surrounding formation, to prevent formation fluids (water, oil, and gas) from entering the wellbore which will otherwise migrate from the formation into the wellbore, and potentially create a blowout. A blowout occurs when drilling fluids are ejected from the well by subsurface pressure and the well flows uncontrolled. To prevent well blowouts, high pressure safety valves called blowout preventers (BOPs) are attached at the top of the well.

Since the formation pressure varies at different depths, the density of the drilling fluid must be constantly monitored and adjusted to the downhole conditions during each phase of the drilling project. One purpose of setting casing strings is to accommodate different fluid pressure requirements at different well depths. Other properties of the drilling fluid, such as lubricity, gel strength, and viscosity, must also be controlled to satisfy changing drilling conditions. The fluid must be replaced if the drilling fluid cannot be adjusted to meet the downhole drilling conditions. This is referred to as a “changeover.”

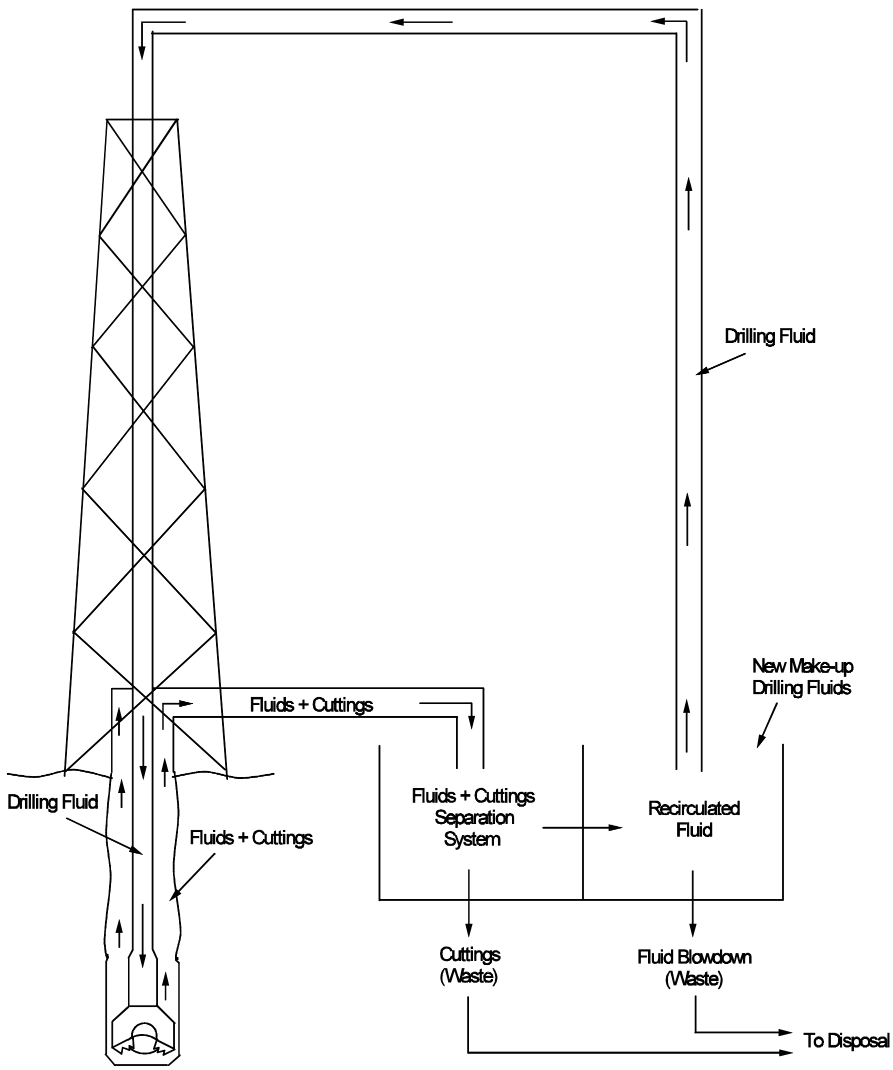


Figure IV-1
Generalized Drilling Fluids Circulation Systems

The solids control system is necessary to maintain constant fluid properties and/or change them as required by the drilling conditions. The ability to remove drill solids from the drilling fluid, referred to as "solids removal efficiency," is dependent on the equipment used and the formation characteristics. High solids content in the drilling fluid, or a low solids removal efficiency, results in increased drilling torque and drag, increased tendency for stuck pipe, increased fluid costs, and reduced wellbore stability. Detailed discussion of solids control systems can be found in Chapter VII. In addition to using solids separation equipment, operators control the solids content of the drilling fluid by adding fresh drilling fluid or components to the circulating fluid system to reduce the percentage of solids and to rebuild the desired rheological properties of the fluid. A disadvantage of dilution is that the portion of the fluid removed, or displaced, from the circulating system must be stored or disposed. Also, additional quantities of fluid additives are required to formulate the replacement fluid. Both of these add expenses to the drilling project.

2.3 DRILLING WITH SUBSEA PUMPING

For use in the relatively new area of deepwater drilling, generally greater than 3,000 feet of water, EPA is aware of a proprietary innovative technology that is claimed by the developer to contribute to a number of environmental and cost benefits.[2] The technology, referred to as "subsea pumping," involves pumping the drilling fluid up a pipe separate from the drill string annulus by means of pumps at or near the seafloor. Rotary drilling methods are generally performed as described above, with the exception that the drilling fluid is boosted by the pump near the seafloor. By boosting the drilling fluid, the adverse effects 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 50 percent reduction in the number of casing strings generally required to line the well wall. Wells are drilled in less time, including less trouble time. The developer of this technology claims that subsea pumping can significantly improve drilling efficiencies and thereby reduce the volume of drilling fluid discharged, as well as reduce the non-water quality effects of fuel use and air emissions. Because fewer casing strings are needed, the hole diameter in the upper sections of the well can be smaller, which reduces the amount of cuttings produced. Also, the well bore will require fewer casing strings of smaller diameter, resulting in a reduction in steel consumption.

To enable the pumping of drilling fluids and cuttings to the surface, about half of the drill cuttings, comprising the cuttings larger than approximately one-quarter inch, are separated from the drilling fluid and discharged at the seafloor since these cuttings cannot reliably be pumped to the surface. With a currently reported design, the drill cuttings that are separated at the seafloor are discharged through an eductor hose at the seafloor within a 300-foot radius of the well site. The drilling fluid, which is boosted at the seafloor and transports the remainder of the drill cuttings back to the surface, is processed as described in the general rotary drilling methods presented in section IV.2.2.1. For purposes of monitoring, samples of the drilling fluid can be taken prior to subsea treatment for separation of the larger cuttings, and transported to the surface for separation of cuttings in a manner identical to that employed at the seafloor.

2.4 TYPES OF DRILLING FLUID

Water-based drilling fluids (WBFs) are the most commonly used drilling fluids and perform well enough to be used for most drilling. The upper well sections are drilled with WBF, and a conversion to OBF will, in general, be made only if cost and technical considerations show a preference towards OBF. WBFs are not only the least expensive drilling fluids on a per barrel basis, but in general they are less expensive to use since the resultant drilling wastes can be discharged onsite provided these wastes pass regulatory requirements.

For certain drilling situations, such as drilling in reactive shales, high angle directional drilling, and drilling in deep water, progress with water-based drilling fluids (WBFs) can be slow, costly, or even impossible, and often creates a large amount of drilling waste. In these situations, the well is normally drilled with traditional oil-based drilling fluids (OBFs), which use diesel oil or mineral oil as the base fluid. Because EPA rules require zero discharge of these wastes, they are either transported to shore for disposal or injected into isolated subsurface formations at the drill site.

Since about 1990, the oil and gas extraction industry has developed many new oleaginous (oil-like) base materials from which to formulate high performance drilling fluids. A general class of these is called the synthetic materials, such as the vegetable esters, poly alpha olefins, internal olefins, linear alpha olefins, synthetic paraffins, ethers, linear alkyl benzenes, and others. Other oleaginous materials have also been developed for this purpose, such as the enhanced mineral oils and non-synthetic paraffins. Industry developed synthetic-based drilling fluids (SBFs) with these synthetic materials as the base fluid to provide the drilling performance characteristics of traditional OBFs based on diesel and mineral oil, but with the potential for lower environmental impact and greater worker safety through lower toxicity, elimination of polynuclear aromatic hydrocarbons (PAHs), faster biodegradability, lower bioaccumulation potential, and, in some drilling situations, less drilling waste volume.

3.0 INDUSTRY PROFILE: CURRENT AND FUTURE DRILLING ACTIVITIES

3.1 ANNUAL WELL COUNT DATA

This proposed regulation would establish discharge limitations for SBFs in areas where drilling fluids and drill cuttings are allowed for discharge. These discharge areas are the offshore waters beyond three miles from shore (excluding the offshore waters of Alaska which has no three mile discharge restriction), and the coastal waters of Cook Inlet, Alaska. Drilling is currently active in three regions in these discharge areas: 1) the offshore waters beyond three miles from shore in the Gulf of Mexico, 2) offshore waters beyond three miles from shore in California, and 3) the coastal waters of Cook Inlet, Alaska.

Table IV-1 presents the number of wells drilled in these three areas for 1995 through 1997. EPA used the average of the number of wells drilled over these three years to project the

TABLE IV-1

ESTIMATED NUMBER OF WELLS DRILLED ANNUALLY BY GEOGRAPHIC AREA

Data Source[a]		Shallow Water (<1,000 ft)		Deep Water (≥ 1,000 ft)		TOTAL WELLS
		Develop.	Explor.	Develop.	Explor.	
Gulf of Mexico						
MMS:	1995	557	314	32	52	955
	1996	617	348	42	73	1,080
	1997	726	403	69	104	1,302
	Average Annual	640	355	48	76	1,119
RRC[b]		5	3	NA	NA	8
Total for Gulf of Mexico		**645**	**358**	**48**	**76**	**1,127**
Offshore California						
MMS:	1995	4	0	15	0	19
	1996	15	0	16	0	31
	1997	14	0	14	0	28
	Average Annual	**11**	**0**	**15**	**0**	**26**
Coastal Cook Inlet						
AOGC:	1995	12	0	0	0	12
	1996	5	1	0	0	6
	1997	5	2	0	0	7
	Average Annual	**7**	**1**	**0**	**0**	**8**

[a] Sources:
MMS: Minerals Management Service, Ref. 4
RRC: Railroad Commission of Texas, Ref. 5
AOGC: Alaska Oil and Gas Commission, Ref. 6

[b] Data provided by the RRC did not distinguish between development and exploratory wells. EPA allocated the estimated 8 wells drilled annually in the Texas offshore area between development and exploratory wells in the same ratio that the average numbers of shallow water wells are distributed in the Gulf of Mexico MMS data.

future annual drilling activity in each geographic area. Table IV-1 also separates the wells into four categories: shallow water development (SWD), shallow water exploratory (SWE), deep water development (DWD), and deep water exploratory (DWE). EPA used these categories to identify model well characteristics for the compliance technology analyses described in later chapters of this document.

Among these three areas, most drilling activity occurs in the Gulf of Mexico. As shown in Table IV-1, 1,302 wells were drilled in the Gulf of Mexico in 1997, compared to 28 wells drilled in California and 7 wells drilled in Cook Inlet. In the Gulf of Mexico, over the last few years, there has been high growth in the number of wells drilled in deep water, defined as water greater than 1,000 feet deep. For example, in 1995, 84 wells were drilled in deep water, comprising 8.6 percent of all Gulf of Mexico wells drilled that year. By 1997, that number increased to 173 wells drilled and comprised over 13 percent of all Gulf of Mexico wells drilled. The increased activity in deep water increases the usefulness of SBFs. Operators drilling in deep water cite the potential for riser disconnect in floating drill ships, which favors SBF over OBF; higher daily drilling cost which more easily justifies use of more expensive SBFs over WBFs; and greater distance to barge drilling wastes that may not be discharged (i.e., OBFs).[3]

Nearly all exploration and development activities in the Gulf are taking place in the Western Gulf of Mexico, that is, the regions off the Texas and Louisiana shores. The Western Gulf Region also is associated with the majority of the current use and discharge of SBF cuttings.

For the federal waters of the Gulf of Mexico, EPA used annual well count data compiled by the Department of the Interior's Minerals Management Service (MMS).[4] The MMS data include wells drilled in offshore waters greater than 3 miles from shore, for all areas where drilling is active, except in Texas. The state of Texas has jurisdiction over oil and gas leases extending seaward three leagues (10.4 miles) instead of three miles. Therefore, EPA requested and received information from the Railroad Commission of Texas regarding the number of wells drilled in Texas jurisdiction from three to 10.4 miles from shore. This area is affected by the proposed rule, but is not included in the MMS data.

Most production activity in the Offshore California region is occurring in an area 3 to 10 miles from shore off of Santa Barbara and Long Beach, California. The MMS data indicate that five operators are actively drilling in the California Offshore Continental Shelf (OCS) region.[4] As shown in Table IV-1, EPA estimates that an average of 26 development wells and no exploratory wells are drilled in the California OCS each year.

Cook Inlet, Alaska, is divided into two regions, Upper Cook Inlet, which is in state waters and is governed by the Coastal Oil and Gas Effluent Guidelines, and Lower Cook Inlet, which is considered Federal OCS waters and is governed by the Offshore Oil and Gas Effluent Guidelines. All references to Cook Inlet mean Upper Cook Inlet unless otherwise identified. There are three operators currently active in Cook Inlet.[7] EPA projects eight wells per year will be drilled in Cook Inlet.[6]

The offshore Alaska region comprises several areas, which are located both in state waters and in federal OCS areas. The most active area for exploration has been the Beaufort Sea, the northern-most offshore area on the Alaska coastline. Other areas where some exploration has occurred include Chukchi Sea to the northwest, Norton Sound to the West, Navarin Basin to the west, St. George Basin to the southwest, Lower Cook Inlet to the south, and Gulf of Alaska, along the Alaska panhandle. The only commercial production is occurring in the Beaufort Sea region.

To EPA's knowledge, no operations are discharging any drilling fluids or cuttings in the offshore Alaska region. No discharge is occurring in state waters due to state law requiring operators to meet zero discharge. In the federal offshore region, the Offshore Guidelines do not specifically prohibit discharge of SBF cuttings, but all operators historically have injected their drilling wastes. No commercial production has occurred in any federal offshore area.

Since the beginning of exploration in the Alaska Offshore region, 82 exploratory wells have been drilled in federal offshore waters, primarily in the Beaufort Sea, where nearly 40 percent of all exploratory wells in the Alaska federal offshore region have been drilled.[8] Exploratory well drilling in federal waters has slacked off significantly in recent years. From a peak of about 20 wells per year in 1985, no wells were drilled in 1994, 1995, and 1996, and two were drilled in 1997, for an average of less than one well drilled per year.[8] EPA assumes that no significant drilling activity will be occurring in the federal offshore regions of Alaska. Offshore Alaska, therefore, is within the scope of the regulation but is not expected to be associated with costs or savings as a result of the proposed effluent guidelines, either in state offshore waters (because of state law) or in federal waters (due to historic practice and lack of drilling activity). Wells drilled in this region are not included in the count of potentially affected wells.

Based on the information in Table IV-1, EPA further estimated the numbers of wells drilled annually using WBF, OBF, and SBF in each geographic area, as presented in Table IV-2. Following are the assumptions and methods EPA used to estimate the well counts in Table IV-2:

- <u>Total Gulf of Mexico WBF/SBF/OBF Wells</u>: For the Gulf of Mexico, EPA estimates that 80% of the average annual wells are drilled using WBF exclusively (902 wells), 10% (113 wells) are drilled with SBF, and 10% (112) are drilled with OBF.[9]

- <u>Gulf of Mexico SBF Wells</u>: EPA learned that approximately 75% of all deep water wells in the Gulf of Mexico are drilled with either SBF or OBF.[9] Further, EPA learned that operators are reluctant to use OBF in deep water operations because of the possibility of riser disconnect.[3] For this reason, EPA determined that in deep water: no OBF wells are drilled, 75% use SBF, and 25% use WBF exclusively. Thus, EPA estimated that 36 of 48 DWD wells and 57 of 76 DWE wells are drilled with SBF annually. Subtracting the deep water wells from the 113 SBF wells yielded 20 SBF wells drilled in shallow water. The distribution of SWD and SWE wells drilled with SBF was made equal to the distribution of these well types in the total well population (i.e., 64.3% of shallow water wells are development, 35.7% are exploratory).

TABLE IV-2

ESTIMATED NUMBER OF WELLS DRILLED ANNUALLY BY DRILLING FLUID

Drilling Fluid	Shallow Water (<1,000 ft)		Deep Water (≥ 1,000 ft)		TOTAL WELLS
	Develop.	Explor.	Develop.	Explor.	
Gulf of Mexico					
Total Wells Drilled Annually	645	358	48	76	1,127
Wells Drilled Using WBF (80%)	560	311	12	19	902
Wells Drilled Using SBF (10%)	13	7	36	57	113
Wells Drilled Using OBF (10%)	72	40	0	0	112
Offshore California					
Total Wells Drilled Annually	11	0	15	0	26
Wells Drilled Using WBF	10	0	4	0	14
Wells Drilled Using OBF	1	0	11	0	12
Coastal Cook Inlet					
Total Wells Drilled Annually	7	1	0	0	8
Wells Drilled Using WBF	6	1	0	0	7
Wells Drilled Using OBF	1	0	0	0	1

- Gulf of Mexico OBF Wells: Since EPA estimated that OBFs were not used in the deep water, all 112 OBF wells in offshore Gulf of Mexico are shallow water wells. The distribution of SWD and SWE wells drilled with OBF was made equal to the distribution of these well types in the total well population, as described above for SBF shallow water wells.

- Offshore California and Coastal Cook Inlet SBF/OBF Wells: EPA learned that no wells are currently drilled with SBF in offshore California and coastal Cook Inlet.[7] Therefore, all wells drilled in these areas are either WBF or OBF wells. The distribution of OBF wells drilled in shallow and deep waters was based on the distribution of OBF/SBF wells in Gulf of Mexico shallow and deep waters, as follows: 13.2% of shallow water wells are drilled with OBF; 75% of deep water wells are drilled with OBF. All other wells were assumed to be drilled exclusively with WBF.

- WBF Wells: The numbers of WBF wells distributed among the four model well types are simply the difference between the numbers of SBF/OBF wells and the total well population for a given model well. These numbers are presented here for completeness, and do not appear in any further analysis in this document. Also, the top portion of SBF and OBF wells are drilled with WBF, but this portion of the well is not included in EPA's analysis.

This proposed rule applies to existing and new sources, as defined in Chapter III. Based on the well information presented above and expansion of the industry into new lease blocks in the deep water areas of the Gulf of Mexico, EPA estimated that 5% of SWD and 50% of DWD wells that use SBFs will be new sources. Industry was unable to provide any more specific estimates. Thus, of the estimated 13 SWD wells drilled annually with SBF in the Gulf of Mexico, EPA estimated that one of these will be a new source. Of the estimated 36 DWD wells drilled annually, EPA estimated that 18 of these will be new sources. Exploratory wells, by definition, are not new source wells. EPA does not project any new source wells to be drilled in offshore California or coastal Cook Inlet, Alaska.

4.0 REFERENCES

1. Baker, Ron, "A Primer of Offshore Operations," Second Edition, Petroleum Extension Service, University of Texas at Austin, 1985.

2. Confidential Business Information regarding subsea pumping system, 1998.

3. American Petroleum Institute, responses to EPA's "Technical Questions for Oil and Gas Exploration and Production Industry Representatives," attached to e-mail sent by Mike Parker, Exxon Company, U.S.A., to Joseph Daly, U.S. EPA, August 7, 1998.

4. U.S. Department of the Interior, Minerals Management Service, Herndon, VA, TIMS Database, MMS 97-007, 1997.

5. Covington, James C., U.S. EPA, Memorandum regarding well count data from the Railroad Commission of Texas, June 15, 1998.

6. Daly, Joseph, U.S. EPA, Memorandum regarding "Phone Conversation Regarding Number of Wells Drilled in Cook Inlet, Alaska," October 23, 1998.

7. Veil, John A., Argonne National Laboratory, Washington, D.C., "Data Summary of Offshore Drilling Waste Disposal Practices," prepared for the U.S. Environmental Protection Agency, Engineering and Analysis Division, and the U.S. Department of Energy, Office of Fossil Energy, November 1998.

8. U.S. Environmental Protection Agency, "Economic Analysis of Proposed 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-98-020, February 1999.

9. Daly, Joseph, U.S. EPA, Memorandum regarding "October 13, 1998 Teleconference Regarding SBF Use," October 20, 1998.

CHAPTER V

DATA AND INFORMATION GATHERING

1.0 INTRODUCTION

This chapter describes the sources and methods EPA used to gather data and information for the proposed SBF Guidelines. The following sections discuss the expedited guidelines approach for this rulemaking and EPA's identification of information needs.

1.1 EXPEDITED GUIDELINES APPROACH

This regulation is being developed using an expedited rulemaking process. This process relies on stakeholder support to develop the initial technology and regulatory options. The proposed rule is a tool to identify the candidate requirements, and request comments and additional data. EPA plans to continue this expedited rulemaking process of relying on industry, environmental groups, and other stakeholder support for the further regulatory development after proposal.

Throughout regulatory development, EPA worked with representatives from the oil and gas industry and several trade associations, including the National Ocean Industries Association (NOIA) and the American Petroleum Institute (API), SBF vendors, solids control equipment vendors, the U.S. Department of Energy, the U.S. Department of Interior Minerals Management Service (MMS), the Railroad Commission of Texas (RRC), and research and regulatory bodies of the United Kingdom and Norway, to develop effluent limitations guidelines and standards that represent the appropriate level of technology (e.g., BAT). The Agency also discussed the progress of the rulemaking with the Natural Resources Defense Council (NRDC) and invited its participation. The Cook Inlet Keepers participated in the rulemaking as well.

In order to expedite the rulemaking process, EPA has chosen not to gather data using the time consuming approach of a Clean Water Act section 308 questionnaire, but rather by using data submitted by industry, vendors, academia, and others, along with data EPA can develop in a limited period of time. Because all of the facilities affected by this proposal are direct dischargers, the Agency did not conduct an outreach survey to POTWs.

Subsequent to the proposal, EPA intends to continue its data gathering efforts for support of the final rule. These continuing efforts are discussed below in conjunction with the information already gathered. Because of these continuing information gathering activities, EPA expects that it will publish a subsequent notice of any data either generated by EPA or submitted after this proposal that will be used to develop the final rule.

1.2 IDENTIFICATION OF INFORMATION NEEDS

As part of the final Coastal Oil and Gas effluent guidelines, published on December 16, 1996 (61 FR 66086), EPA stated that appropriate and adequate discharge controls would be necessary to allow the discharge of SBF-cuttings under BPT, BAT, BCT, and NSPS in NPDES permits. In the final Coastal effluent guidelines, EPA recommended gas chromatography (GC) as a test for formation oil contamination, and a sediment toxicity test as a replacement for the suspended particulate phase (SPP) toxicity testing currently required. EPA also mentioned the potential need for controls on the base fluid used to formulate the SBF, controlling one or more of the following parameters: PAH content, toxicity (preferably sediment toxicity), rate of biodegradation, and bioaccumulation potential. In addition, EPA summarized the information available from seabed surveys at SBF-cuttings discharge sites.

EPA conducted literature reviews and in September 1997 published documents entitled "Bioaccumulation of Synthetic-Based Drilling Fluids," "Biodegradation of Synthetic-Based Drilling Fluids," "Assessment and Comparison of Available Drilling Waste Data from Wells Drilled Using Water Based Fluids and Synthetic Based Fluids," and "Seabed Survey Review and Summary."[1,2,3,4] The purpose of these documents was to help direct EPA's and other stakeholder's research efforts in defining BPT, BAT, BCT, and NSPS, and assist permit authorities' implementation of CWA Section 403(c) ocean discharge requirements.

Industry stakeholders, with the motivation of having SBFs addressed in NPDES permits that allow the discharge of SBF-cuttings, assisted EPA in the development of methods and data gathering to describe currently available technologies. Thus, by means of meetings, conferences, and other stakeholder meetings, EPA detailed the methods and/or types of information required in order to support BPT, BCT, BAT, and NSPS controls in NPDES permits. The past and anticipated future efforts by various stakeholder groups and the EPA are presented below.

2.0 STAKEHOLDERS RESEARCH WORK GROUPS

In order to concentrate efforts on certain technical issues, in May of 1997 industry stakeholders began studies on the following subjects: a) the determination of formation oil contamination in SBFs, b) toxicity testing of SBFs and base fluids, c) quantity of SBF discharged (retention of base fluid on cuttings), and d) seabed surveys at SBF-cuttings discharge sites.[5] Industry representatives formed work groups to address these issues. The sections below describe their work.

2.1 FORMATION OIL CONTAMINATION DETERMINATION

The goal of this work group was to define the monitoring and compliance method to determine crude oil (or other oil such as mineral oil) contamination of SBF-cuttings. The work group has issued several reports concerning the static sheen test, and developed two replacement tests for formation oil contamination, one based on fluorescence and the other on gas chromatography with mass spectroscopy detection(GC/MS). The reports on the work group's findings were prepared in three phases, as described below.

On September 28, 1998, the work group published the Phase I report entitled "Evaluation of Static Sheen Test for Water-based Muds, Synthetic-based Muds and Enhanced Mineral Oils."[6,7] The conclusions of the report are that the static sheen test is not a good indicator of crude oil contamination in SBFs, and that in WBFs formation oil contamination is often detected at 1.0 percent and sometimes as low as 0.5 percent.

On October 21, 1998, the work group published the Phase II report entitled "Survey of Monitoring Approaches for the Detection of Oil Contamination in Synthetic-based Drilling Muds."[8] This document lists thirteen methods that the work group considered as a replacement to the static sheen test. From these thirteen, EPA selected for the proposed regulation the reverse phase extraction method to be used on offshore drilling sites, and the GC/MS method for onshore baseline measurements.

On November 16, 1998, the work group published the Phase III reports entitled "Laboratory Evaluation of Static Sheen Replacements: RPE Method,"[9] and "Laboratory Evaluation of Static Sheen Replacements: GC/MS Method."[10] These reports provide the proposed procedures for the methods. The future work of the Analytical Work Group is to validate these methods.

2.2 RETENTION ON CUTTINGS

The goals of this work group were to determine the SBF retention on cuttings attainable by the equipment currently used in the Gulf of Mexico (GOM), and investigate ways of determining the total quantity of SBF discharged when drilling a well. To address the first goal, API reported and analyzed data from GOM wells on the amount of synthetic base fluid retained on drill cuttings. The results were published on August 29, 1997, in a report entitled "Retention of Synthetic-Based Drilling Material on Cuttings Discharged to the Gulf of Mexico."[11]

To address the second goal of determining the total quantity of SBF discharged, the work group created a spreadsheet that records information allowing two independent analyses of the SBF quantity discharged.[12] One method is based on a mass balance of the SBF, and the other is based on retort measurements of the cuttings wastestream. Both methods of analysis carry certain benefits and drawbacks. By comparing the results from the two analyses, EPA intends to select one method as preferred for the final rule. The work group is currently gathering these comparative data. The preferred method will then be validated for inclusion in the final rule. At this time, EPA thinks that the retort measurement is preferable to implement due to questions of accuracy with the mass balance method when downhole losses occur. For this reason, the retort method is the primary proposed method. As further information is gathered, however, EPA may decide that attainment of the limit in the final rule is to be determined by the mass balance method, or a combination of the two methods.

2.3 TOXICITY TESTING

The goal of this work group was to define the toxicity test for monitoring and compliance of SBF-cuttings. EPA believes the test could be performed on either the stock base fluid, or the SBF separated from the cuttings at the point of discharge.

Through data generated by members of the work group, the work group showed that SBF and synthetic base fluid toxicity are mainly evident in the sedimentary phase.[13] When measured in the suspended particulate phase (SPP) in the current Mysid shrimp toxicity test (40 CFR Part 435, Subpart A, Appendix 2), the toxicity is not evident and the results are highly variable, and are easily affected by the intensity of stirring and emulsifier content of the SBF.

Having shown that an aqueous phase test is unlikely to yield satisfactory results with SBFs and synthetic base fluids, the work group has been investigating sediment toxicity tests, mainly the 10-day sediment toxicity test with amphipods (ASTM E1367-92). To effect this work, API funded a currently ongoing contract to evaluate four test methods. Three of these are 10-day acute sediment toxicity tests that use the organisms a) *Ampelisca abdita*, b) *Leptocheirus plumulosus*, and c) *Mysidopsis bahia*. One of these tests, the MICROTOX™ test (ASTM D5660-96), uses inhibition of the luminescent marine bacterium *Photobacterium phosphoreum* in vitro. The main issues that the work group hopes to resolve are discriminatory power of the method and variability in results. Since the API contract work began, the work group has tested the variables of the sediment toxicity test to ameliorate these problems. The work group is investigating: organisms other than amphipods, such as Mysid shrimp and polychaetes; shortening the length of the test, i.e., from 10 days to 4 days; and the use of formulated sediments in place of natural sediments. Work continues to determine the most appropriate method to evaluate the toxic effect of the SBF discharged with drill cuttings.

2.4 ENVIRONMENTAL EFFECTS / SEABED SURVEYS

The goal of this work group was to determine the spacial and temporal recovery of the seafloor at sites where SBF-cuttings had been discharged, and compare these effects with effects caused by the discharge of WBF and WBF-cuttings.

The work group performed a five-day screening cruise at three offshore oil platforms where SBFs have been used and SBF-cuttings discharged for the purpose of gathering preliminary environmental effects information. This screening cruise, and its planning, was performed in collaboration with EPA and with the use of the EPA Ocean Survey Vessel Peter W. Anderson. The study included a preliminary evaluation of offshore discharge locations and determined the areal extent of observable physical, chemical, and biological impact. EPA intended that this base information would provide a) information relative to the immediate concerns on impacts, and b) valuable preliminary information for designing future offshore assessments.

The study provided preliminary information on cuttings deposition, SBF content of nearfield marine sediments, anoxia in nearfield sediments, qualitative information on biological communities in the area, and toxicity of field collected sediments. The results of this survey were published on October 21, 1998, in a report entitled “Joint EPA/Industry Screening Survey to Assess the Deposition of Drill Cuttings and Associated Synthetic Based Mud on the Seabed of the Louisiana Continental Shelf, Gulf of Mexico.”[14]

The ongoing effort of the work group is to address CWA 403(c) permit requirements for seabed surveys by organizing collaborative industry seabed surveys at selected SBF-discharge sites.

3.0 EPA RESEARCH ON TOXICITY, BIODEGRADATION, AND BIOACCUMULATION

Subsequent to this proposal, EPA plans to compare the relative environmental effects of SBFs and OBFs in terms of a) sediment and aquatic toxicity, b) biodegradation, and c) bioaccumulation. The methods development to occur as part of this research, and the resulting data, are intended to be used in developing the final stock base fluid limitations and SBF discharge limitations.

The base fluids that EPA will consider in the sediment toxicity, biodegradation, and bioaccumulation tests are the full range of synthetic and oleaginous base fluids. These include the synthetic oils such as vegetable esters, linear alpha olefins, internal olefins and poly alpha olefins, the traditional base oils of mineral oil and diesel oil, and the newer more refined and treated oils such as enhanced mineral oil and paraffinic oils. The common feature of these oily base fluids is that they are immiscible (do not mix) with water, and form drilling fluids that do not disperse in water.

The outline of EPA's research plan in terms of goals and considerations is as follows:

- Sediment toxicity: EPA intends to investigate the effects of base fluid, whole mud formulation, and crude oil contamination on sediment toxicity as measured by the 10-day acute sediment toxicity test performed in natural sediment with *Ampelisca abdita* and *Leptocheirus plumulosus*. The goals of this research are threefold:

    1) Amend the EPA 10-day acute sediment toxicity test for application to SBFs and base fluids.

    2) Determine the LC_{50} values for the base fluids by this method, potentially for determination of stock limitations values.

    3) Determine the effects of mud formulation and crude oil contamination on sediment toxicity by maintaining the base fluid constant. The purpose is to investigate the parameters which affect toxicity in SBFs.

- Aqueous phase toxicity: EPA intends to investigate whether any correlation exists between aqueous phase toxicity to Mysid shrimp and sediment toxicity.

- Biodegradation: EPA intends to perform the solid phase test or modified solid phase test as developed by the Scottish Office Agriculture, Environment and Fisheries Department for a range of oily base fluids, and environments of the Gulf of Mexico, Offshore California, Cook Inlet Alaska, and Offshore Alaska.

- Bioaccumulation: EPA intends to test bioconcentration in *Macoma nasuta* and *Nereis virens*.

The research concerning sediment toxicity testing that API supports is seen as complementary to, and not overlapping with, this EPA plan. API's goal is to identify a bioassay test organism and protocol to accurately and reliably evaluate the toxicity of SBF and OBF in sediments. The API research is concentrating efforts on using both formulated and natural sediments, and possibly a test period shorter than the standard 10-day EPA method. Thus, while EPA is focusing on investigating the parameters that affect toxicity of SBFs, the API research is looking ahead to discharge monitoring requirements with the goal of identifying an appropriate and reliable test method.

4.0 INVESTIGATION OF DRILLING SOLIDS CONTROL TECHNOLOGIES

As part of its investigation of solids control equipment used on offshore drilling platforms, EPA visited Amoco's Marlin deepwater drilling project aboard the Amirante semi-submersible drilling platform located in Viosca Knoll Block 915 approximately 100 miles south of Mobile, Alabama. The primary purpose of this site visit was to observe the demonstration of a vibrating centrifuge drilling fluid recovery device heretofore used mainly on North Sea drilling projects. The device reportedly can produce drill cuttings containing less than six percent by weight synthetic drilling fluid on wet cuttings when well operated and maintained and used in conjunction with shale shakers that are well operated and maintained. The information gathered by the EPA during this trip is described in a report dated August 7, 1998, entitled "Demonstration of the 'Mud 10' Drilling Fluid Recovery Device at the Amoco Marlin Deepwater Drill Site."[15]

EPA contacted numerous vendors of solids control equipment and requested information on performance and cost of the various solids separation units currently available and used throughout the offshore industry. The specific vendors and the data they provided are identified in Chapters VII, VIII, and IX of this Development Document.

For the purpose of evaluating solids control equipment performance, EPA statistically analyzed drill cuttings discharge data from two sources: the 1997 API Retention-On-Cuttings Work Group report,[11] and the vendor of a vibrating centrifuge technology.[16,17] The data reported the quantity of drilling fluid retained on the cuttings waste streams discharged from primary and secondary shale shakers, as well as from the vibrating centrifuge. EPA compiled the data and reported summary statistics.[18]

5.0 ASSISTANCE FROM STATE AND FEDERAL AGENCIES

The United States Department of Interior Minerals Management Service (MMS) maintains a data base of the number of wells drilled in offshore waters under MMS jurisdiction, i.e., those that are not territorial seas or those that are outside of 3 leagues off Texas and Florida. Except for offshore Texas and Florida, this data base covers the offshore waters beyond three miles from the shoreline, which corresponds with the area where drilling wastes are currently allowed for discharge and so is the same area affected by this proposed rule. MMS supplied EPA with data for years 1995, 1996, and 1997 of the number of wells drilled in the GOM and offshore California according to depth (less than or greater than 1000 feet water depth) and type of well (exploratory or development).[19] Since Texas jurisdiction over oil and gas leases extends out to 3 leagues, or 10.4 miles, information was requested and received from the Railroad Commission of Texas regarding the number of wells drilled in Texas territorial seas from 3 miles to 10.4 miles from shore.[20] This is the area in the GOM that is affected by this proposed rule, but not included in the MMS data. Currently, there is no drilling activity that allows discharge in the offshore waters of Florida from 3 miles to 3 leagues.

Information concerning the number of wells drilled in the state waters of Upper Cook Inlet, Alaska was gathered from the Alaska Oil and Gas Commission.[21] The Alaska Oil and Gas Commission provided the number of wells drilled in Upper Cook Inlet for the years 1995, 1996, and 1997, according to type of well as exploratory or development.

The United States Department of Energy (DOE) has been active in assisting EPA to gather information concerning drilling waste disposal methods and costs, and type of fuel used on offshore platforms. In November 1998 Argonne National Laboratory, under contract with DOE, published the results of this information gathering effort in a report entitled “Data Summary of Offshore Drilling Waste Disposal Practices.”[22]

Also under contract with DOE, Brookhaven National Laboratory developed a comparative risk assessment for the discharge of SBFs. The risk assessment, published November 1998, is entitled "Framework for a Comparative Environmental Assessment of Drilling Fluids."[23]

6.0 ASSISTANCE FROM THE AMERICAN PETROLEUM INSTITUTE

In lieu of preparing and distributing a questionnaire to the industry, EPA requested industry profile information from members of API who are active in the workgroups described above. EPA submitted a list of questions to API,[24] and API provided responses in writing.[25] API stated that they surveyed four Gulf of Mexico operators, who collectively represent an estimated 46% of the offshore wells drilled annually using SBFs, with individual percentages as follows: Shell 27%; Chevron 9%; Texaco 8%; and Exxon 2%.[26] The API responses included the profile for the four model offshore wells that EPA used as the basis for the technical analyses presented in this Development Document. EPA is not certain as to whether these 46% of the offshore wells are statistically representative of all offshore wells using SBFs, but absent additional information, believes this is adequate for purposes of the rule. EPA also notes that the API respondents reportedly do not engage in certain practices (e.g., hauling SBF-cuttings to shore) that operators reported using in the document prepared for DOE by Argonne National Laboratory.[22] Therefore, EPA seeks additional information from all operators using SBFs to be considered in developing the final rule.

7.0 REFERENCES

1. Avanti Corporation, "Bioaccumulation of Synthetic-Based Drilling Fluids," prepared for the U.S. Environmental Protection Agency, contract 68-C5-0035, September 30, 1997.

2. Avanti Corporation, "Biodegradation of Synthetic-Based Drilling Fluids," prepared for the U.S. Environmental Protection Agency, contract 68-C5-0035, September 30, 1997.

3. Avanti Corporation, "Assessment and Comparison of Available Drilling Waste Data from Wells Drilled Using Water Based Fluids and Synthetic Based Fluids," prepared for the U.S. Environmental Protection Agency, contract 68-C5-0035, September 30, 1997.

4. Avanti Corporation, "Seabed Survey Review and Summary," prepared for the U.S. Environmental Protection Agency, contract 68-C5-0035, September 30, 1997.

5. Daly, Joseph, U.S. EPA, Memorandum regarding "May 8-9, 1997, Meeting in Houston, Texas-Inception of Industry/Stakeholder Work Groups to Address Issues of Discharges Associated with Synthetic-Based Drilling Fluids (SBF)," January 14, 1999.

6. Weintritt, D. and R. Benjamin, "Evaluation of Static Sheen Test for Water-Based Muds, Synthetic-Based Muds, and Enhanced Mineral Oils (Draft)," August 1998, with cover letter from Robert J. Moran, National Ocean Industries Association, to Joseph M. Daly, U.S. EPA, September 29, 1998.

7. Daly, Joseph, U.S. EPA, E-mail letter to Roger Claff, API, regarding "Comments on Static Sheen Report," October 15, 1998.

8. Uhler, A.D. and J.M. Neff, Battelle, "Survey of Monitoring Approaches for the Detection of Oil Contamination in Synthetic-Based Drilling Muds," prepared for the American Petroleum Institute, August, 1998, with cover letter from Robert Moran, National Ocean Industries Association, to Joseph Daly, U.S. EPA, October 21, 1998.

9. Uhler, A.D., J.A. Seavey, and G.S. Durell, Battelle, "Laboratory Evaluation of Static Sheen Replacements: RPE Method (Final Draft Report)," plus addendum, November 16, 1998, with cover letter from Robert Moran, National Ocean Industries Association, to Joseph Daly, U.S. EPA, November 16, 1998.

10. Uhler, A.D., J.A. Seavey, and G.S. Durell, Battelle, "Laboratory Evaluation of Static Sheen Replacements: GC/MS Method (Draft Report)," November 16, 1998, with cover letter from Robert Moran, National Ocean Industries Association, to Joseph Daly, U.S. EPA, November 19, 1998.

11. Annis, Max R., "Retention of Synthetic-Based Drilling Material on Cuttings Discharged to the Gulf Of Mexico," prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 29, 1997.

12. Annis, Max R., "Procedures for Sampling and Testing Cuttings Discharged While Drilling With Synthetic-Based Muds," prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 19, 1998.

13. Hood, C.A., Baker-Hughes Inteq, Letter to Joseph Daly, U.S. EPA, with unpublished sediment toxicity data from Baker-Hughes Inteq, July 9, 1997.

14. Continental Shelf Associates, Inc., "Joint EPA/Industry Screening Survey to Assess the Deposition of Drill Cuttings and Associated Synthetic Based Mud on the Seabed of the Louisiana Continental Shelf, Gulf of Mexico," prepared for the API Health and Environmental Sciences Department, October 21, 1998.

15. The Pechan-Avanti Group, "Demonstration of the 'Mud 10' Drilling Fluid Recovery Device at the Amoco Marlin Deepwater Drill Site," August 7, 1998.

16. Daly, Joseph, U.S. EPA, Memorandum regarding "Data Showing the Performance of the Mud 10 with North Sea Oil Wells," January 14, 1999.

17. Martin, Neil, Enaco PLC, letter to Joseph Daly, U.S. EPA, regarding the MUD 10 Fluid Recovery Unit, with attached literature and data, July 22, 1997.

18. White, Charles E., and Henry D. Kahn, U.S. EPA, Statistics Analysis Section, Memorandum to Joseph Daly, U.S. EPA, Energy Branch, regarding "Current Performance, when using Synthetic-Based Drilling Fluids, for Primary Shakers, Secondary Shakers, and Vibrating Centrifuge and Model Limits for Percent Retention of Base Fluids on Cuttings for Secondary Shakers and Vibrating Centrifuge," January 29, 1999.

19. U.S. Department of the Interior, Minerals Management Service, Herndon, VA, TIMS Database, MMS 97-007, 1997.

20. Covington, James C., U.S. EPA, Memorandum regarding well count data from the Railroad Commission of Texas, June 15, 1998.

21. Daly, Joseph, U.S. EPA, Memorandum regarding "Phone Conversation Regarding Number of Wells Drilled in Cook Inlet, Alaska," October 23, 1998.

22. Veil, John A., Argonne National Laboratory, Washington, D.C., "Data Summary of Offshore Drilling Waste Disposal Practices," prepared for the U.S. Environmental Protection Agency, Engineering and Analysis Division, and the U.S. Department of Energy, Office of Fossil Energy, November 1998.

23. Meinhold, Anne, "Framework for a Comparative Environmental Assessment of Drilling Fluids," prepared for the U.S. Department of Energy, National Petroleum Technology Office, November 1998.

24. Daly, Joseph, U.S. EPA, letter to Larry Henry, Chevron USA Production Co., regarding "Technical Questions for Oil and Gas Exploration and Production Industry Representatives," with attachment, April 1, 1998.

25. American Petroleum Institute, responses to EPA's "Technical Questions for Oil and Gas Exploration and Production Industry Representatives," attached to e-mail sent by Mike Parker, Exxon Company, U.S.A., to Joseph Daly, U.S. EPA, August 7, 1998.

26. Daly, Joseph, U.S. EPA, Memorandum regarding "Market Share of Respondents to Technical Questions, August 17, 1998.

CHAPTER VI

SELECTION OF POLLUTANT PARAMETERS

1.0 INTRODUCTION

This section presents information concerning the selection of the pollutants to be limited for the proposed SBF Effluent Limitations Guidelines and Standards. The information consists of identifying the pollutants for which limitations and standards are proposed. The discussion is presented in terms of the pollutant parameters associated with either the stock base fluids that are used to formulate the SBFs, or the drilling fluids and cuttings at the point of discharge.

2.0 STOCK LIMITATIONS OF BASE FLUIDS

2.1 GENERAL

EPA is proposing to establish BAT and NSPS that would require the synthetic materials and other oleaginous materials which form the base fluid of the SBFs and other non-aqueous drilling fluids to meet limitations on poly aromatic hydrocarbon (PAH) content, sediment toxicity and biodegradation. The technology basis for meeting these limits would be product substitution, or zero discharge based on land disposal or injection if these limits are not met. These parameters are being regulated to control the discharge of certain toxic and nonconventional pollutants. A large range of synthetic, oleaginous, and water miscible materials have been developed for use as base fluids. These stock limitations on the base fluid are intended to encourage product substitution reflecting best available technology wherein only those synthetic materials and other base fluids which minimize potential loadings and toxicity may be discharged.

2.2 PAH CONTENT

EPA proposes to regulate 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 on the order of 5% to 10% PAH in diesel oil and 0.35% PAH in mineral oil.[1] The PAHs typically found in diesel and mineral oil include the toxic priority pollutants fluorene, naphthalene, phenanthrene, and others, and nonconventional pollutants such as alkylated benzenes and biphenyls.[2] Thus, this stock limitation would be one component of a rule reflecting the use of the best available technology.

2.3 SEDIMENT TOXICITY

EPA proposes to regulate sediment toxicity in base fluids and SBFs as a nonconventional pollutant parameter, as an indicator for toxic components of base fluids or drilling fluid. Some of the toxic components of the base fluids may include enhanced mineral oils, internal olefins, linear alpha olefins, paraffinic oils, vegetable esters of 2-hexanol and palm kernel oil, and other oleaginous materials.[3] Some of the possible toxic components of drilling fluids may include the same components as the base fluid, and in addition mercury, cadmium, arsenic, chromium, copper, lead, nickel, and zinc, formation oil contaminants, and other intended or unintended components of the drilling fluid. 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.[2] Many of the synthetic base fluids have been shown to have lower toxicity than diesel and mineral oil, but among the synthetic and other oleaginous base fluids some are more toxic than others.[4,5,6] The proposed discharge option includes a sediment toxicity limitation of the SBF's base fluid stock material, as measured by the 10-day sediment toxicity test (ASTM E1367-

92) using a natural sediment and *Leptocheirus plumulosus* as the test organism.

Subsequent to this proposal and before the final rule, EPA intends to gather information to determine how to most appropriately control toxicity and solicit comment on these findings. The sediment toxicity test may be altered, for instance, in terms of test organism (other amphipods or possibly a polychaete), sediment type (formulated in place of natural), or length of test (to shorten the 10-day test period). Further, while this proposal includes a sediment toxicity limitation of the base fluid stock material, the final discharge option to control toxicity might consist of a different option.

EPA would prefer to control sediment toxicity at the point of discharge as opposed to controlling the base fluid. EPA realizes, however, that the sediment toxicity test may be impractical to implement as a discharge requirement due to potential problems in the availability of uniform sediment and other factors affecting test variability. If EPA finds, through subsequent research, that the sediment toxicity test at the point of discharge is both practical and superior to the base fluid toxicity as an indicator of the toxicity of the SBF at the point of discharge, EPA might apply the sediment toxicity test to the SBF at the point of discharge in place of the proposed method of the sediment toxicity test to the base fluid.

If the sediment toxicity test of neither the SBF at point of discharge nor synthetic base fluid as a stock limitation is found to be practical due to variability, lack of discriminatory power, or other problems, EPA will search for an alternative toxicity test. One candidate is modification to the current suspended particulate phase (SPP) toxicity test, or aquatic phase toxicity test. EPA has several concerns with applying the current SPP test to SBFs. EPA has received information from industry sources and testing laboratories that the results from the SPP test applied to SBFs are highly dependent on both the agitation when mixing the seawater with the SBF and the amount and type of emulsifiers in the SBF formulation.[7] Further, results to date show that, compared to the aquatic toxicity test, the sediment toxicity test provides a better correlation with known toxicity effects of the various synthetic and oleaginous base fluids, and the experimental situation more closely mimics the actual fate of the drilling fluid. While EPA does not think that the current SPP test is useful for application to SBFs, modifications to either the method or limitation may render it functional. Thus, EPA intends to investigate the aquatic phase toxicity test as a possible control in the event that the sediment toxicity test of the drilling fluid is impractical and the sediment toxicity test of the base fluid is either impractical or inadequate to control the toxicity of the SBF at the point of discharge.

EPA intends, therefore, to investigate further the most appropriate test method for controlling toxicity of SBF discharges, and to validate this method. EPA intends to publish any additional data concerning this limitation in a notice prior to publication of the final rule.

2.4 BIODEGRADATION

EPA proposes to limit biodegradation as an indicator of the extent, in level and duration, of the toxic effect of toxic components of nonconventional pollutants present in the base fluids, e.g., poly alpha olefins, enhanced mineral oils, internal olefins, linear alpha olefins, paraffinic oils, and vegetable ester of 2-hexanol and palm kernel oil. The various base fluids vary widely in biodegradation rate, as measured by the solid phase test and simulated seabed tests.[8] Based on results from seabed surveys at sites where various base fluids have been discharged with drill cuttings, EPA believes that the results from both measurement methods are indicative of the relative rates of biodegradation in the marine environment (see Table 9-2 in the Environmental Assessment).[9] In addition, EPA thinks this parameter correlates strongly with the rate of recovery of the seabed where SBF-cuttings have been discharged.

While EPA is proposing to use the solid phase test to measure compliance with the biodegradation limitation, this test is not yet an EPA validated method. In addition to validating the method for the final rule, EPA intends to gather additional data in support of the biodegradation rate limitation. EPA plans to present any additional data it collects towards this limitation in a notice subsequent to publication of this proposed rule and before the final rule.

2.5 BIOACCUMULATION

While not a part of this proposal, EPA is also considering establishing BAT and NSPS that would require the synthetic materials and other base fluids used in non-aqueous drilling fluids to meet limitations on bioaccumulation potential. The regulated parameters would be the nonconventional and toxic priority pollutants that bioaccumulate. Based on current information, EPA believes that the base fluid controls on PAH content, sediment toxicity, and biodegradation rate being proposed are sufficient to control bioaccumulation. EPA intends, however, to study the bioaccumulation potential of the various synthetic base fluids for comparison, and subsequently solicit comments on the results if EPA thinks that some measure of bioaccumulation potential is needed to control adequately the SBF-cuttings wastestream.

3.0 DISCHARGE LIMITATIONS

3.1 FREE OIL

Under BPT and BCT limitations for SBF-cuttings, EPA would retain the prohibition on the discharge of free oil as determined by the static sheen test. Under this prohibition, drill cuttings may not be discharged when the associated drilling fluid would fail the static sheen test defined in Appendix 1 to 40 CFR Part 435, Subpart A. 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 pollutants oil and grease which separate from the SBF and cause 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 (such as 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 synthetic material comprising the SBF may rise to the surface to cause a sheen. These 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 this proposal 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, however, is not intended to control formation oil contamination nor the total quantity of conventional pollutants discharged.

3.2 FORMATION OIL CONTAMINATION

Formation oil contamination of the SBF associated with the cuttings would be limited under BAT and NSPS. Formation oil is an "indicator" pollutant for the many toxic and priority pollutant components present in formation (crude) oil, such as aromatic and polynuclear aromatic hydrocarbons. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. (See Development Document Chapter VII). The primary limitation is based on a fluorescence test.[10] This test is considered an appropriately "weighted" test because crude oils containing more toxic aromatic and PAH components tend to show brighter fluorescence and hence noncompliance at a lower level of contamination. Since fluorescence is a relative brightness test, gas chromatography with mass spectroscopy detection (GC/MS) is provided as a baseline method before the drilling fluid is delivered for use, and is also available as an assurance method when the results from the fluorescence compliance method are in doubt.

3.3 RETENTION OF SBF ON CUTTINGS

The retention of SBF on drill cuttings would be limited under BAT and NSPS.   This limitation controls the quantity of SBF discharged with the drill cuttings. Both nonconventional and priority toxic pollutants would be controlled by this limitation. Nonconventionals include the SBF base fluids, such as vegetable esters, internal olefins, linear alpha olefins, paraffinic oils, mineral oils, and others. This limitation would also limit the toxic effect of the drilling fluid and the persistence or biodegradation of the base fluid. Several toxic and priority pollutant metals are present in the barite weighting agent, including arsenic, chromium, copper, lead, mercury, nickel, and zinc, and nonconventional pollutants such as aluminum and tin.[2]

The emulsifying and wetting agents of the SBF would also be controlled by limiting the amount of SBF discharged. EPA solicits information concerning the composition of the wetting and emulsifying agents so that they can be classified as conventional, nonconventional, or toxic pollutants.

The proposed rule uses the retort method to determine compliance with the limit. The limit is expressed as percentage base fluid on wet cuttings (weight/weight), averaged over the well sections drilled with SBF. This method has not yet been validated by EPA. Further, EPA is currently researching a mass balance method as an alternative method to determine the quantity of SBF discharged.[11] After EPA has gathered sufficient data using the two methods in a comparative analysis, EPA intends to validate the preferred method and solicit comment concerning the method to be applied for the final rule.

4.0 MAINTENANCE OF CURRENT REQUIREMENTS

EPA would retain the existing BAT and NSPS limitations on the stock barite of 1 mg/kg mercury and 3 mg/kg cadmium. These limitations would 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.[2]

EPA also would retain the 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 components of petroleum products.

5.0 REFERENCES

1. Daly, Joseph, U.S. EPA, Memorandum regarding “Meeting with Oil and Gas Industry Representatives Regarding Synthetic Drilling Fluids,” July 2, 1996, with two attachments: 1) Information package entitled “Enhanced Mineral Oils (EMO) for Drilling,” presented by Exxon Co., U.S.A Marketing, Donald F. Jacques, Ph. D., June 25, 1996, and 2) Letter from Michael E. Parker, P.E., Exxon Company U.S.A., to M. B. Rubin, U.S. EPA, September 17, 1996.

2. U.S. Environmental Protection Agency, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, Final, EPA 821-R-93-003, January 1993.

3. Vik, E.A., S. Dempsey and B. Nesgard, “Evaluation of Available Test Results from Environmental Studies of Synthetic Based Drilling Muds,” OLF Project Acceptance Criteria for Drilling Fluids, Aquateam Report No. 96-010, July 29, 1996.

4. Still, I. and J. Candler, “Benthic Toxicity Testing of Oil-Based and Synthetic-Based Drilling Fluids,” Eighth International Symposium on Toxicity Assessment, Perth, Western Australia, May 25-30, 1997.

5. Hood, C.A., Baker-Hughes Inteq, Letter to Joseph Daly, U.S. EPA, with unpublished sediment toxicity data from Baker-Hughes Inteq, July 9, 1997.

6. Candler, J., R. Herbert and A.J.J. Leuterman, “Effectiveness of a 10-day ASTM Amphipod Sediment Test to Screen Drilling Mud Base Fluids for Benthic Toxicity,” SPE 37890, Society of Petroleum Engineers Inc., March 1997.

7. Rabke, S., et al., “Interlaboratory Comparison of 96-hour *Mysidopsis bahia* Bioassay Using a Water Insoluble Synthetic-Based Drilling Fluid,” presented at the 19th Annual Meeting of the Society of Environmental Toxicology and Chemistry, Charlotte, NC, 1998.

8. Munro, P.D., C.F. Moffet, L. Couper, N.A. Brown, B. Croce, and R.M. Stagg, “Degradation of Synthetic Mud Base Fluids in a Solid-Phase Test System,” the Scottish Office of Agriculture and Fisheries Department, Fisheries Research Services Report No. 1/97, January 1997.

9. U.S. EPA, Environmental Assessment of Proposed 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-98-019, February 1999.

10. Uhler, A.D., J.A. Seavey, and G.S. Durell, Battelle, “Laboratory Evaluation of Static Sheen Replacements: RPE Method (Final Draft Report),” plus addendum, November 16, 1998, with cover letter from Robert Moran, National Ocean Industries Association, to Joseph Daly, U.S. EPA, November 16, 1998.

11. Annis, Max R., “Procedures for Sampling and Testing Cuttings Discharged While Drilling With Synthetic-Based Muds,” prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 19, 1998.

CHAPTER VII

DRILLING WASTES CHARACTERIZATION, CONTROL, AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

The first three parts of this chapter describe the sources, characteristics, and volumes of drilling wastes generated from oil and gas drilling operations that use SBFs. The last part of this chapter describes the control and treatment technologies currently available to recover SBF from drill cuttings, which reduce the volume of drilling wastes and the quantities of pollutants discharged to surface waters.

2.0 DRILLING WASTE SOURCES

Drilling fluids and drill cuttings are the most significant wastestreams from exploratory and development well drilling operations. EPA proposes limitations for the wastestream of SBF and associated cuttings, hereafter referred to as SBF-cuttings, generated when SBFs or other non-aqueous drilling fluids are used. All other wastestreams and drilling fluids have current applicable limitations that are outside the scope of this rulemaking. The following sections discuss the sources of SBF and SBF-cuttings in terms of the drilling operations that generate this wastestream.

2.1 DRILLING FLUID SOURCES

SBFs, used or unused, are considered 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. Compared to WBFs, SBFs are relatively easy to separate from the drill cuttings because the drill cuttings do not disperse in the drilling fluid to the same extent. 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 as neat drilling fluid (drilling fluid not associated with cuttings).

The top of the well 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 a water dispersible drilling fluid such as a WBF, or a water non-dispersible drilling fluid such as an SBF. The decision to change the system from a WBF water dispersible system to an OBF or SBF water non-dispersible system depends on many factors including[1]:

- the operational considerations, i.e., rig type (risk of riser disconnects with floating drilling rigs), rig equipment, distance from support facilities,
- the relative drilling performance of one type of fluid compared to another, e.g., rate of penetration, well angle, hole size/casing program options, horizontal deviation,

- 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, potential for gas hydrate formation,

- drilling fluid cost - base cost plus daily operating cost,

- drilling operation cost - rig cost plus logistics and operation support, and

- 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.[1] This is due to the fact that these operations are higher cost and can therefore better justify the higher initial cost of SBF use.

The recovery of SBF from drill cuttings serves two purposes. The first is to deliver drilling fluid for reintroduction to the active drilling fluid system, and the second is to minimize the discharge of SBF. The recovery of drilling fluid from the cuttings is a conflicting concern, because as more aggressive methods are used to recover the drilling fluid from the cuttings, the cuttings tend to break down into small particles, called fines. The fines are not only more difficult to separate from the drilling fluid, but they also deteriorate the properties of the drilling fluid. Increased recovery from the cuttings is more problematic for WBFs than with SBFs because WBFs encourage 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. These more aggressive methods may be justified for SBF-cuttings so as to reduce the discharge of SBF. This, consequently, will reduce the potential to cause anoxia (lack of oxygen) in the receiving sediment as well as reduce the quantity of toxic organic and metallic components of the drilling fluid discharged.

Environmental impacts can be caused by toxic, conventional, and non-conventional pollutants in the SBF that adheres to the discharged drill cuttings. The adhered SBF drilling fluid is mainly composed, on a volumetric basis, of the synthetic material, or more broadly speaking, oleaginous (oil-like) material. This oleaginous material may cause hypoxia (reduction in oxygen) or anoxia in the immediate sediment, depending on currents, temperature, and rate of biodegradation. Oleaginous materials that biodegrade quickly will deplete oxygen more rapidly than more slowly degrading materials. EPA, however, thinks that fast biodegradation is environmentally preferable to persistence despite the increased risk of anoxia that accompanies fast biodegradation. This is because recolonization of the area impacted by the discharge of SBF-cuttings or OBF-cuttings has been correlated with the disappearance of the base fluid in the sediment, and does not seem to be correlated with anoxic effects that may result while the base fluid is disappearing. In studies conducted in the North Sea, base fluids that biodegrade faster have been found to disappear more quickly, and recolonization at these sites has been more rapid.[2,3,4] The oleaginous material may also be toxic or bioaccumulate, and it may contain priority pollutants such as polynuclear aromatic hydrocarbons (PAHs). However, SBF base fluids typically do not contain PAHs (see discussion of drilling fluid pollutant selection in section VI.2.0).

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, 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. See section VII.3.1 for the list of pollutants EPA identified as associated with synthetic drilling fluid.

2.2 DRILL CUTTINGS SOURCES

Drill cuttings are produced continuously at the bottom of the hole at a rate proportionate to the advancement of the drill bit. These 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 down hole, provided it still has the characteristics required to meet technical drilling requirements. Various sizes of drill cuttings are separated by the solids separations equipment, and it is necessary to remove the fines as well as the large cuttings from the drilling fluid to maintain the required flow properties (see section VII.5.3.4 for discussion of solids control system design).

The drill cuttings range in size from large particles on the order of a centimeter in size to small particles a fraction of a millimeter in size (i.e., fines). As the drilling fluid returns from down hole laden with drill cuttings, it normally is first passed through primary shale shakers that remove the largest cuttings, ranging in size of approximately 1 to 5 millimeters. The drilling fluid may then be passed over secondary shale shakers to remove smaller drill cuttings. Finally, a portion or all of the drilling fluid may be passed through a centrifuge or other shale shaker with a very fine mesh screen, for the purpose of removing the fines. It is important to remove fines from the drilling fluid in order to maintain the desired flow properties of the active drilling fluid system. Thus, the cuttings wastestream normally consists of larger cuttings from the primary shale shakers and fines from a fine mesh shaker or centrifuge, and may also consist of smaller cuttings from a secondary shale shaker.

Before being discharged, the larger cuttings are sometimes sent through another separation device in order to recover additional drilling fluid.

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. Total suspended solids (TSS) makes up the bulk of the pollutant loadings, and 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 that are added to modify the viscosity. Because the quantity of TSS is so high and consists of mainly large particles that settle quickly, discharge of SBF drill cuttings can cause benthic smothering and/or sediment grain size alteration resulting in potential damage to invertebrate populations and potential alterations in spawning grounds and feeding habits.

3.0 DRILLING WASTE CHARACTERISTICS

The wastestream discharged from drilling operations that use SBFs or other non-aqueous drilling fluids consists of three components: adhering drilling fluid, drill cuttings, and formation oil. Table VII-1 lists the waste characteristic data for these components that EPA compiled as the basis for the compliance costs, pollutant reductions, and non-water quality environmental impacts analyses. The following sections discuss the sources and scope of these characteristics for each waste component.

3.1 DRILLING FLUID CHARACTERISTICS

Based on per-well data provided by API, EPA assumed a model SBF drilling fluid having a formulation consisting of 47% by weight synthetic base fluid, 33% solids, and 20% water.[5] This formulation represents a 70%/30% ratio of synthetic base fluid to water, typical of commercially available SBFs.[6] Because there are no available data to the contrary, EPA further assumed that this formulation remains unchanged in the wastestream, although it is likely that the relative proportions of the three components would be altered in the drilling and solids control operations.

The synthetic base fluid is one of two sources of the conventional pollutant oil and grease, as shown in Table VII-1. In lieu of oil and grease concentration data for SBFs, EPA substituted "total oil" for the oil and grease measurement, assuming that the total amount of synthetic base fluid (plus formation oil) is equivalent to the total oil content of the wastestream. A total oil concentration of 190 lbs of synthetic base fluid per bbl of SBF (as shown in Table VII-1) was calculated based on the SBF formulation described above, and a specific gravity of 0.8 (280 lbs/bbl).[7,8]

EPA assumed that all solids in the drilling fluid are barite, based on standard formulation data.[6,13] Barite is used to control the density of drilling fluids and is the primary source of toxic

TABLE VII-1
SBF DRILLING WASTE CHARACTERISTICS

Waste Characteristics	Value	References
SBF formulation	47% synthetic base fluid, 33% barite, 20% water (by weight)	Calculated from industry data (Ref. 5)
Synthetic base fluid density	280 pounds per barrel	Ref. 7 and 8
Barite density	1,506 pounds per barrel	Ref. 9
SBF drilling fluid density	9.6 pounds per gallon	Calculated from industry data (Ref. 5)
Percent (vol.) formation oil	0.2%	See section VII.3.3
Pollutant Concentrations in SBF		
Conventionals	**lbs/bbl of SBF**	**Reference**
Total Oil as synthetic base fluid Total Oil as formation oil TSS as barite	190 0.59 133	Derived from SBF formulation and densities listed above
Priority Pollutant Organics	**lbs/bbl of SBF**	**Reference**
Naphthalene Fluorene Phenanthrene Phenol	0.0010052 0.0005483 0.0013004 7.22E-08	Calculated from diesel oil composition in Offshore Development Document, Table VII-9 (Ref. 10 and 11)
Priority Pollutant Metals	**mg/kg Barite**	**Reference**
Cadmium Mercury Antimony Arsenic Berylium Chromium Copper Lead Nickel Selenium Silver Thallium Zinc	1.1 0.1 5.7 7.1 0.7 240.0 18.7 35.1 13.5 1.1 0.7 1.2 200.5	Offshore Development Document, Table XI-6 (Ref. 10)
Non-Conventional Metals	**mg/kg Barite**	**Reference**
Aluminum Barium Iron Tin Titanium	9,069.9 120,000 15,344.3 14.6 87.5	Offshore Development Document, Table XI-6 (Ref. 10), except for barium, which was estimated (Ref. 12)
Non-Conventional Organics	**lbs/bbl of SBF**	**Reference**
Alkylated benzenes Alkylated naphthalenes Alkylated fluorenes Alkylated phenanthrenes Alkylated phenols Total biphenyls Total Dibenzothiophenes	0.0056587 0.0531987 0.0064038 0.0080909 0.0000006 0.0105160 0.0000092	Calculated from diesel oil composition in Offshore Development Document, Table VII-9 (Ref. 10 and 11)

metal pollutants. The characteristics of raw barite will determine the concentrations of metals found in the adhering drilling fluid. In order to control the concentration of heavy metals in drilling fluids, EPA promulgated regulations requiring that stock barite that meet the maximum limitations 3 mg/l for cadmuim and 1 mg/l for mercury (58 FR 12454, March 4, 1993). Table VII-1 includes the metals concentration profile for barite.

The barite in the SBF is also one of two sources of the conventional pollutant TSS. The other source of TSS is drill cuttings, as mentioned above in section VII.2.2. The TSS as barite concentration of 133 lbs/bbl of SBF listed in Table VII-1 was calculated from the SBF formulation described above, and a barite density of 1,506 lbs/bbl.[9]

Applying the densities of the synthetic base fluid, barite, and water to the drilling fluid formulation described above, EPA calculated a drilling fluid weight of 9.6 lbs/gal (405 lbs/bbl).[5] EPA recognizes that this weight is lower than typical SBF weights, which can range from 10 to 17 pounds per gallon.[6,14] This lower weight is a result of limiting the model formulation to only three components. Additional solid compounds are typically present in SBFs that add to the weight of the fluid, but vary too much in weight fraction and type to be included in EPA estimates.

3.2 DRILL CUTTINGS CHARACTERISTICS

As described in section VII.2.2, drill cuttings contribute the greatest quantity to the pollutant loadings in the form of TSS. For the purpose of estimating pollutant reductions, EPA assumed that the TSS concentration attributable to drill cuttings in the wastestream is based on the density of the dry weight of cuttings, quoted in the literature as 910 lbs/bbl.[9] As explained later in section VII.4.2.3, the actual concentration of cuttings in the waste stream varies with the amount of drilling fluid estimated to adhere to the cuttings following treatment. However, the total amount of cuttings generated per well is always equal to the volume of the hole drilled.

3.3 FORMATION OIL CONTAMINATION

In addition to the base fluid, formation oil is the second source of oil and grease, and is the only source of priority pollutant and non-conventional pollutant organics in SBFs. For the proposed rule, the majority of formation oils would cause failure when present in SBFs at a concentration of about 0.5%. With this limitation, and based on anecdotal information from the industry concerning formation oil contamination of drilling fluids[15], EPA estimates that, on average, the adhering drilling fluid in a model SBF-cuttings wastestream will contain 0.2% by volume formation oil. Since the composition of formation (crude) oil varies widely, diesel oil was used to model the organic pollutant concentrations associated with 0.2% formation oil contamination. The organic pollutant concentrations, both priority and non-conventional, were obtained from analytical data presented in the Offshore Oil and Gas Development Document for Gulf of Mexico diesel.[10] The total oil concentration of 0.59 lbs of formation oil per bbl SBF shown in Table VII-1 was calculated from the SBF formulation described above, and a specific gravity of 0.84 (294 lbs/bbl) quoted in the literature for diesel oil.[9]

4.0 DRILLING WASTE VOLUMES

4.1 FACTORS AFFECTING DRILLING WASTE VOLUMES

The volume of drill cuttings generated depends primarily on the dimensions (depth and diameter) of the well drilled and on the percent washout. Washout is the enlargement of a drilled hole due to the sloughing of material from the walls of the hole. The greatest volumes of drill cuttings are generated during the initial stages of drilling when the borehole diameter is large and washout tends to be higher. Data gathered by EPA for the Coastal Oil and Gas Rulemaking effort indicate that while percent washout varies depending on the type of formation being drilled, it generally decreases with hole depth.[16] Continuous and/or intermittent discharges are normal occurrences in the operation of solids control equipment. Such discharges occur for periods from less than one hour to 24 hours per day, depending on the type of operation and well conditions.

The volume of drill cuttings generated also depends on the type of formation being drilled, the type of bit, and the type of drilling fluid used. Soft formations, especially hydrating shales, are more susceptible to borehole washout than hard formations. The type of drilling fluid used can affect the amount of borehole washout and shale sloughing. Intervals drilled with water-based drilling fluids (WBFs) can experience washout of 100 percent and greater, while intervals drilled with OBFs or SBFs are typically closer to gage size (wherein washout is zero percent). A rule-of-thumb value of 5 to 10% washout was recently cited by a Gulf of Mexico operator for intervals drilled with SBF.[17] The type of drill bit determines the characteristics of the cuttings (particle size). Depending on the formation and the drilling characteristics, the total volume of drill solids generated will be at least equal to the borehole volume, but is most often greater due to the breaking up of the compacted formation material.

The amount of drilling fluid that adheres to the cuttings depends on the type and efficiency of the solids control equipment used, the drill particle size, and the type of drilling fluid used. The solids control system, described in detail in section VII.5.3.4, is a step-wise operation designed to remove drill cuttings from the drilling fluid by separating successively smaller particles. Each separation unit in the system produces a cuttings wastestream of a particular particle size distribution, and with an amount of adhering drilling fluid that, on average, is characteristic of that unit. The efficiency of a particular separation unit, as measured by the amount of drilling fluid retained on the cuttings, is maximized through vigilant operation and maintenance. Other operating factors, such as whether the drilling platform is stationary or floating, can also affect drilling fluid retention on cuttings.

Small and fine cuttings have greater surface area and generally retain more drilling fluid than larger cuttings. Therefore, higher retention values are associated with the solids control units that generate smaller or fine particle cuttings. Data submitted to EPA for wells drilled with SBF indicate that retention values are generally lower for the primary separation unit that produces the larger size cuttings, as compared with the secondary separation unit that produces smaller cuttings.[18,19] As stated in section VII.2.1, cuttings are generally easier to separate from

OBFs or SBFs than WBFs because the drill solids do not disperse and break up into finer particles to the same extent.

4.2 ESTIMATES OF DRILLING WASTE VOLUMES

Based on the waste characteristics presented above in Table VII-1 and well volume data supplied by industry operators, EPA calculated drilling waste volumes generated from four model wells. The following sections present the data and methods EPA used to estimate per-well volumes of drill cuttings, drilling fluid, and formation oil in the wastestream.

4.2.1 Waste SBF/OBF Drill Cuttings Volumes

EPA developed model well characteristics from information provided by the American Petroleum Institute (API) for the purpose of estimating costs to comply with, and pollutant reductions resulting from, the proposed discharge option and the zero-discharge option.[1] API provided well size data for four types of wells currently drilled in the Gulf of Mexico: development and exploratory wells in both deep water (i.e., greater than or equal to 1,000 feet) and shallow water (i.e., less than 1,000 feet). The following text, as well as text throughout the Development Document, refers to these wells by the acronyms DWD (deep-water development), DWE (deep-water exploratory), SWD (shallow-water development), and SWE (shallow-water exploratory).

The model well information provided by API included the length of hole drilled for successive hole diameters, or intervals.[1] API provided data for all intervals drilled per well, which included intervals drilled with WBF and intervals drilled with SBF. From this, EPA calculated the gage hole volume for the well intervals that API identified as being drilled with SBF. To calculate the waste cuttings volume, EPA further estimated, based on information provided by an industry source[17], that the gage hole volume would increase by an average 7.5 percent due to washout. EPA also estimated that the amount of washout incurred using SBF is the same for intervals drilled with OBF, based on industry source information stating that there is essentially no difference in the performance of the two drilling fluid types.[20] 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 the dry cuttings. Table VII-2 presents the data provided by API, and the hole volumes and total waste cuttings volumes that EPA calculated based on these data.

4.2.2 Drilling Fluid Retention Values

The amount of drilling fluid that adheres to drill cuttings is measurable by retort analysis. The published retort method currently used by drilling operators and drilling fluid manufacturing companies is API's Recommended Practice 13B-2: Field Testing Oil-Based Drilling Fluids, Appendix B: Oil and Water Content From Cuttings For Percentage Greater Than 10% (API RP 13B-2). This method is designed to measure the relative weights of liquid and solid components in a sample of wet drill cuttings. A summary description of the method is presented by Annis as follows[18]:

> In this "Retort Procedure," a known weight of wet cuttings is heated in a retort chamber to vaporize the liquids contained in the sample. The liquids (synthetic-based drilling material and water vapors) are then condensed, collected, and measured in a precision graduated receiver. The API recommended practice...recommends use of a retort sample cup volume of 50-cm^3 $\pm$ 0.25-cm^3...
>
> According to API RP 13B-2, the following measurements are made during the retort procedure:

TABLE VII-2

MODEL WELL VOLUME DATA[a]

Model Well	Hole Diameter[b] (inches)	Depth Interval[b] (feet)	Gage Volume (cu. feet)	Gage Volume (barrels)	Gage Volume plus 7.5% Washout (barrels)
SWD	8.5	7,500	**2,955**	**526**	**565**
SWE	12.25	6,000	4,911	873	
	8.5	2,500	985	175	
	6	1,500	295	52	
			6,190	**1,101**	**1,184**
DWD	12.25	4,500	3,683	655	
	8.5	2,000	788	140	
			4,471	**795**	**855**
DWE	17.5	4,500	7,517	1,337	
	12.25	2,000	1,637	291	
	8.5	2,000	788	140	
			2,425	**1,768**	**1,901**

[a]Data represent only those intervals API identified as being drilled with SBF.[1] Numbers in bold typeface are totals for the given model well.
[b]Source: API responses to EPA Technical Questions.[1]

A Weight (API PR 13B-2 uses mass in grams) of the clean and dry retort assembly (cup, lid, and retort body with steel wool).
B Weight of the retort assembly and wet cuttings sample.
C Weight of the clean and dry liquid receiver.
D Weight of the receiver and its liquid contents (synthetic-based drilling material and water).
E Weight of the cooled retort assembly without the condenser.
V Volume of water recovered from cooled liquid receiver.

To calculate the weight % of synthetic-based drilling material on the discharged cuttings perform the following calculations:

1. Weight of the wet cuttings sample (M_w) equals the weight of the retort assembly and wet cuttings sample (B) minus the weight of the clean and dry retort assembly (A).

$$M_w = B - A$$

2. Weight of the dry retorted cuttings (M_d) equals the weight of the cooled retort assembly (E) minus the weight of the clean and dry retort assembly (A).

$$M_d = E - A$$

3. Weight of the synthetic-based drilling material (M_o) equals the weight of the liquids receiver with its contents (D) minus the sum of the weight of the dry receiver (C) and the weight of the water (V). Assume the density of water is 1 g/cm^3 the weight of the water is equivalent to the volume of water.

$$M_o = D - (C + V)$$

The sum of M_d, M_o, and V should be within 5 percent of the weight of the wet sample (M_w). If it is not, the procedure should be repeated.

API has recently reviewed the method in API RP 13B-2 with the intention of standardizing the sampling, testing, and recording procedures for determining the retention of synthetic base fluid on cuttings.[21] In addition to the above retort measurements and calculations, the new procedures include guidelines for sampling, and a worksheet for calculating the amounts of total waste and waste components generated. API's goal in writing the new procedures is to "develop a definitive data base on retention of synthetic material in cuttings discharge streams."[21]

EPA determined average drilling fluid retention values for solids control equipment currently used in most offshore drilling operations in the U.S., hereafter referred to as baseline solids control, and for solids control equipment currently used in North Sea drilling operations capable of achieving retention values consistently lower than baseline solids control, hereafter referred to as add-on solids control technology. API provided a database of well-specific retention data for baseline solids control equipment, compiled from service companies that supply offshore operators with synthetic-based drilling fluid.[18] This database contains the results of retort analyses of SBF-cuttings discarded from what the report calls primary shale shakers, secondary shale shakers, and centrifuges. Other than these labels for the equipment, the database provides no further information regarding the arrangement of the solids control systems associated with the individual wells. While a primary shale shaker can be assumed to be the first unit in the solids control train, the location and purpose of a what the database calls a "secondary" shale shaker is ambiguous without additional information. A "secondary" unit could receive either the drilling fluid or the drill cuttings that exit the primary shakers. Because the database retention values of the cuttings from the secondary shale shakers are, on average, higher than those from the primary shakers, EPA assumed that the secondary shakers received and treated the drilling fluid rather than the cuttings from the primary shakers. The centrifuge data were too limited to utilize in EPA's analysis. Based on the API database, EPA calculated a long-term average retention value, weighted by hole volume, of 10.6% by weight of synthetic base fluid on wet cuttings for a primary shale shaker, and 15.0% for a secondary shale shaker.[19] Due to EPA's assumption that SBF and OBF performance is equivalent, these retention values apply equally to SBF-cuttings and OBF-cuttings in the baseline analysis.

Retention data for the add-on solids control technology were provided by the manufacturer of a vibrating centrifuge currently used by operators located in the North Sea to recover SBF from the SBF-cuttings that exit the primary shale shaker.[22] Based on these data, EPA calculated a long-term average retention value, weighted by hole volume, of 5.14% by weight of synthetic base fluid on cuttings for the vibrating centrifuge. The data show that the vibrating centrifuge is likely to perform at least as well if not better in the Gulf of Mexico than in the North Sea. This is because the cuttings entering the vibrating centrifuge already have lower retention values in the Gulf of Mexico compared to the North Sea. The observed performance for the primary shale shakers used in series before the vibrating centrifuge was a volume-weighted average retention of 12.4%.[19] This is 1.9 percentage points higher than the average volume-weighted retention of 10.5% observed for the primary shale shakers in the Gulf of Mexico. In the North Sea, all cuttings came from primary shale shakers, absent the use of secondary shale shakers, thereby eliminating the separate wastestream of cuttings from the secondary shale shakers. Elimination of the finer cuttings from the secondary shale shakers may also be possible in the Gulf of Mexico. Based on current information, however, EPA assumes that in Gulf of Mexico operations a portion of the cuttings will be from the secondary shale shakers.

For the purpose of estimating incremental compliance costs, pollutant reductions, and non-water quality environmental impacts, EPA calculated weighted average retention values for the baseline and compliance-level (based on add-on technology) solids control systems. Based on information provided by API[21], EPA estimated that the cuttings from the primary shale shaker comprise 80% of the cuttings stream, and the remaining 20% is removed by either the secondary shale shaker or other devices to remove very small cuttings, or fines. Thus, the following calculation was used to estimate system-wide retention for the baseline solids control system:

Weighted Average Baseline Solids Control Retention: (0.8 x 10.6%) + (0.2 x 15.0%) = 11.5%.

The assumed 80/20 split of the cuttings wastestream was also applied to the compliance-level solids control system, in which the vibrating centrifuge receives and treats all cuttings from the primary shale shaker. The weighted average retention for this system is as follows:

Weighted Average Compliance-Level Solids Control Retention: (0.8 x 5.14%) + (0.2 x 15.0%) = 7.11%.

The retention values of 11.5% (wt.) for baseline solids control and 7.11% (wt.) for compliance-level solids control were rounded to 11% and 7% for all of EPA's cost and pollutant loadings calculations. This was done because the cost and loadings calculations were performed before all solids control data could be analyzed in detail. With a simple arithmetic average of these same data[18,22], EPA was able to determine the rounded figures of 11% and 7% retention independent of the later statistical analysis that resulted in 11.5% and 7.11%.

4.2.3 Calculation of Model Well Drilling Waste Volumes

For each of the four model wells, EPA calculated drilling waste volumes for intervals drilled with SBF or OBF. The calculations specified per-well volumes for the wastestream components, including:

- dry cuttings (equivalent to gage hole volume plus 7.5% washout),
- synthetic base fluid (and oil base fluid in the baseline analysis),
- water,
- barite,
- whole SBF or OBF (the sum of the synthetic or oil base fluid, water, and barite),
- formation oil, and
- total waste generated (the sum of whole SBF, formation oil, and dry cuttings).

The general approach to this method was to calculate the total waste generated based on the relative proportions of the above components in the wastestream as defined by the model drilling fluid formulation, the average drilling fluid retention values, and the assumed 0.2% by volume of formation oil present in the wastestream. Waste volumes were calculated for each model well for the two retention values of 11% for the baseline analysis and 7% for the compliance-level analysis. The input data and generalized equations used for these calculations are shown in Table VII-3. Appendix VII-1 presents the detailed calculations for the four model wells, based on the equations in Table VII-3. Table VII-4 presents the summary model well waste volume data that EPA calculated and used as the basis for the subsequent compliance analyses.

5.0 CONTROL AND TREATMENT TECHNOLOGIES

EPA investigated the technological aspects and costs of four drilling waste management technologies as potential means of complying with the proposed effluent limitations guidelines, including:

TABLE VII-3

INPUT DATA AND GENERAL EQUATIONS FOR CALCULATING PER-WELL WASTE VOLUMES

Input Data and Assumptions

- Drilling fluid formulation, wt./wt.: 47% synthetic or oil base fluid, 33% barite, 20% water (Ref. 5)
- Densities, converted to pounds per barrel for:
    1. synthetic base fluid = 280 lbs/bbl (Ref. 7 and 8)
    2. barite = 1,506 lbs/bbl (Ref. 9)
    3. water = 350 lbs/bbl
    4. dry cuttings = 910 lbs/bbl (Ref. 9)
    5. formation oil (as diesel) = 294 lbs/bbl (Ref. 9)
- Retort analysis results, wt./wt.: 11% for standard solids control; 7% for compliance-level solids control (see section VII.4.2.2)

Dry drill cuttings volume (equivalent to gage hole volume plus washout)

$$\text{hole volume (ft}^3) = \{\text{length (ft)} \times \pi \times [\text{diameter (ft)}/2]^2\} \times (1 + \text{washout fraction of } 0.075) \quad (1)$$

$$\text{drill cuttings (bbls)} = \text{hole volume (ft}^3) \times 0.1781 \text{ bbls/ft}^3 \quad (2)$$

$$\text{drill cuttings (lbs)} = \text{drill cuttings (bbls)} \times 910 \text{ lbs/bbl} \quad (3)$$

Waste Components in lbs (algebraic calculation of lbs of waste components in the given drilled interval)

$$TW = \underbrace{(RF \times TW)}_{\text{(base fluid)}} + \underbrace{\{[RF \times (WF/SF)] \times TW\}}_{\text{(water)}} + \underbrace{\{[RF \times (BF/SF)] \times TW\}}_{\text{(barite)}} + \underbrace{(DF \times TW)}_{\text{(drill cuttings)}} \quad (4)$$

where:

TW = total waste (whole drilling fluid + dry cuttings), in lbs
RF = retort weight fraction of synthetic base fluid, decimal number (e.g., 0.11 or 0.07)
WF = water weight fraction from drilling fluid formulation, decimal number
SF = synthetic base fluid weight fraction from drilling fluid formulation, decimal number
BF = barite weight fraction from drilling fluid formulation, decimal number
DF = drill cuttings weight fraction, calculated as follows:

$$DF = 1 - \{RF \times [1 + (WF/SF) + (BF/SF)]\} \quad (5)$$

In order to calculate TW, equations (4) and (5) are first used to calculate DF. Then TW is calculated as follows:

$$TW = \text{drill cuttings (lbs)} / DF \quad (6)$$

Waste Component Amounts Converted from lbs to bbls

$$\text{synthetic base fluid (bbls)} = [RF \times TW \text{ (lbs)}] / (280 \text{ lbs/bbl})$$

$$\text{water (bbls)} = \{[RF \times (WF/SF)] \times TW \text{ (lbs)}\} / (350 \text{ lbs/bbl})$$

$$\text{barite (bbls)} = \{[RF \times (BF/SF)] \times TW \text{ (lbs)}\} / (1{,}506 \text{ lbs/bbl})$$

Whole Drilling Fluid Volume

$$\text{whole SBF volume (bbls)} = \text{synthetic base fluid (bbls)} + \text{water (bbls)} + \text{barite (bbls)} \quad (7)$$

0.2% (vol.) Formation Oil in Whole Mud Discharged

$$\text{formation oil (bbls)} = 0.002 \times \text{whole SBF volume (bbls)} \quad (8)$$

TABLE VII-4
SUMMARY MODEL WELL WASTE VOLUME ESTIMATES

Waste Component	Shallow Water (1,000 ft)				Deep Water (≥ 1,000 ft)			
	Development		Exploratory		Development		Exploratory	
	bbls	lbs	bbls	lbs	bbls	lbs	bbls	lbs
Waste Volumes Calculated for Standard Solids Control System @ 11% (wt.) Retention								
Synthetic base fluid (or oil base fluid)	264	73,834	553	154,724	399	111,730	887	248,420
Water	90	31,413	188	65,828	136	47,536	302	105,692
Barite	34	51,818	72	108,588	52	78,414	116	174,346
Dry cuttings (includes 7.5% washout)	565	514,150	1,184	1,077,440	855	778,050	1,901	1,729,910
Cuttings and adhering drilling fluid generated from SBF/OBF interval	953	671,214	1,997	1,406,580	1,442	1,015,731	3,206	2,258,368
Whole SBF/OBF adhering to cuttings	388	157,064	813	329,140	587	237,681	1,305	528,458
Formation oil (0.2% of adhering drilling fluid)	0.8	228	1.6	478	1.2	345	2.6	767
Waste Volumes Calculated for Add-on Solids Control System @ 7% (wt.) Retention								
Synthetic base fluid	151	42,287	316	88,616	229	63,992	508	142,279
Water	51	18,002	108	37,725	78	27,242	173	60,570
Barite	20	29,661	41	62,158	30	44,886	66	99,799
Dry cuttings (includes 7.5% washout)	565	514,150	1,184	1,077,440	855	778,050	1,901	1,729,910
Cuttings and adhering drilling fluid generated from SBF/OBF interval	787	604,101	1,650	1,265,938	1,191	914,170	2,648	2,032,558
Whole SBF/OBF adhering to cuttings	222	89,951	466	188,498	336	136,120	747	302,648
Formation oil (0.2% of adhering drilling fluid)	0.4	131	0.9	274	0.7	198	1.5	440

- product substitution,
- solids control equipment,
- land-based treatment and disposal, and
- onsite subsurface injection.

The following sections discuss EPA's findings regarding the current status of these technologies as applied to drilling wastes associated with SBFs and OBFs.

5.1 BPT/BCT TECHNOLOGY

EPA is proposing to maintain the current BPT and BCT requirement of no free oil as determined by the static sheen test. This requirement for drilling fluid wastes was first published on April 13, 1979 (44 FR 22069). At that time, EPA determined that drilling product substitution, or the use of more environmentally benign products, combined with onshore disposal was the best practicable control method available. An example of product substitution is the use of WBF in place of OBF such that the discharged cuttings would pass the no-free-oil limit. Since SBF-cuttings are currently discharged in the Gulf of Mexico in compliance with the static sheen test, industry has shown the ability of SBFs to pass the static sheen test by varying the SBF formulation. Effluent limitations based on this technology allow no discharge of free oil in drilling fluids and drill cuttings. As applied to SBFs, this is meant to control the occurrence of oily sheen on the surface of receiving waters when SBF-cuttings are discharged. The static sheen test is performed on the SBF that has been removed from the cuttings.

5.2 PRODUCT SUBSTITUTION: SBF BASE FLUID SELECTION

EPA is proposing BAT and NSPS effluent limitations guidelines for three characteristics of the stock base fluid used in synthetic and other non-aqueous drilling fluids, namely: polyaromatic hydrocarbon (PAH) content, sediment toxicity, and biodegradation rate. EPA anticipates that these limitations would be achieved by product substitution of the base fluid. The following sections discuss the technical achievability of the proposed limitations on stock base fluids.

5.2.1 Currently Available Synthetic and Non-Aqueous Base Fluids

As SBFs have developed over the past few years, the industry has come to use mainly a few primary base fluids. These include the vegetable esters, internal olefins, linear alpha olefins, and poly alpha olefins. Thus, these are the base fluids for which EPA has data and costs to develop the effluent limitations of this proposed rule. More recently, the industry has moved away from using poly alpha olefins, and has begun to use various paraffinic oils, both synthetic and non-synthetic. However, at present, EPA does not have sufficient data to perform the analyses for the newer paraffinic oil base fluids. In this Development Document, vegetable ester means a monoester of 2-ethylhexanol and saturated fatty acids with chain lengths in the range C_8 - C_{16}, internal olefin means a series of isomeric forms of C_{16} and C_{18} alkenes, linear alpha olefin means a series of isomeric forms of C_{14} and C_{16} monoenes, and poly alpha olefins means 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%). EPA also has data on other oleaginous base fluids, such as enhanced mineral oil, paraffinic oils, and the traditional OBF base fluids mineral oil and diesel oil.[23,24,25]

5.2.2 PAH Content of Base Fluids

EPA proposes to establish a PAH content limitation of 0.001 percent, or 10 parts per million (ppm), weight percent PAH expressed as phenanthrene, as measured by EPA Method 1654A.[26] Producers of several SBF base fluids have reported to EPA that their base fluids are free of PAHs.[27] The base fluids that suppliers have reported are free of PAHs include linear alpha olefins, vegetable esters, certain enhanced mineral oils, synthetic paraffins, certain non-synthetic paraffins, and others. Diesel oil typically contains on the order of 5% to 10% PAH and mineral oil typically contains approximately 0.35% PAH.[27]

5.2.3 Sediment Toxicity of Base Fluids

EPA is proposing a sediment toxicity stock base fluid limitation that would allow only the discharge of SBF-cuttings using base fluids as toxic or less toxic, but not more toxic, than C_{16}-C_{18} internal olefins. Based on information available to EPA at this time, the only base fluids that would attain this limitation are the internal olefins and vegetable esters.

Various researchers have performed toxicity testing of the synthetic base fluids with the 10-day sediment toxicity test (ASTM E1367-92) using a natural sediment and *Leptocheirus plumulosus* as the test organism.[25,28,29] The synthetic base fluids have been shown to have lower toxicity than diesel and mineral oil, and among the synthetic and other oleaginous base fluids some are more toxic than others. For example, Still et al. reported the following 10-day LC_{50} results, expressed as mg base fluid/Kg dry sediment: diesel LC_{50} of 850, enhanced mineral oil LC_{50} of 251, internal olefin LC_{50} of 2,944, and poly alpha olefin LC_{50} of 9,636. A higher LC_{50} value means the material is less toxic. Similar results, with the same trend in toxicity in the base fluids above, have been reported by Hood et al. Candler et al. performed the 10-day sediment toxicity test with the amphipod *Ampelicsa abdita* in place of *Leptocheirus plumulosus,* and again obtained very similar results as follows: diesel LC_{50} of 879, enhanced mineral oil LC_{50} of 557, internal olefin LC_{50} of 3,121, and PAO LC_{50} of 10,680.

None of these researchers reported sediment toxicity values for vegetable esters. Recently, industry has evaluated a number of base fluids including vegetable esters.[30,31] While the absolute values are not comparable because the tests were performed on the drilling fluid and not just the base fluid, the results showed the vegetable ester to be less toxic that the internal olefin.

Researchers in the United Kingdom and Norway investigating effects in the North Sea have conducted sediment toxicity tests on other organisms, namely *Corophium volutator* and *Abra alba*.[32] Similar trends were seen in the measured toxicity, with vegetable ester having very low sediment toxicity (very high LC_{50}), poly alpha olefin having a mid range toxicity, and internal olefin having a higher toxicity, in this comparison.

While the poly alpha olefins were found to have the lowest toxicity of the measured base fluids (excludes vegetable esters), EPA did not base the toxicity limitation on poly alpha olefins because, as presented below, they biodegrade much more slowly and so are unlikely to pass the biodegradation limitation. EPA intends to generate and gather additional data comparing the toxicity of the various base fluids, especially to compare the vegetable ester toxicity with that of the olefins since, at this time, directly comparable data are not available. If vegetable esters are found to have significantly reduced toxicity compared to the other base fluids, EPA may choose to base the toxicity limitation on vegetable esters. EPA has concerns, however, over the technical performance and possible non-water quality implications with the use of vegetable ester as the only technology available to meet the stock base fluid limitations, as discussed below under biodegradation.

5.2.4 Biodegradation Rate of Base Fluids

EPA proposes a limitation of biodegradation rate for the base fluid, as determined by the solid phase test [33], equal to or faster than the rate of a C_{16}-C_{18} internal olefin. The proposed method can be found in Appendix 4 to Subpart A of the proposed amendments to 40 CFR Part 435. With this limitation the base fluids currently available for use include vegetable ester, linear alpha olefin, internal olefins, and possibly certain linear paraffins. Applying the biodegradation rate, PAH content and sediment toxicity limitations on stock base fluid, EPA data indicate that internal olefins and vegetable esters would attain all three limitations.

EPA also investigated an alternative numerical limitation of a minimum biodegradation rate of 68 percent base fluid dissipation at 120 days for the standardized solid phase test. If EPA pursues this approach, EPA expects that it may need to revise this numerical limitation as additional test results are generated.

As with the sediment toxicity test presented above, due to the lack of data from the biodegradation test, EPA intends to propose a limitation based on comparative testing rather than propose a numerical limitation. Therefore, if SBFs based on fluids other than internal olefins and

vegetable esters are to be discharged with drill cuttings, data showing the biodegradation of the base fluid should be presented with data, generated in the same series of tests, showing the biodegradation of the internal olefin as a standard. EPA prefers this approach rather than a numerical limitation at this time because of the small amount of data available to EPA upon which to base a numerical limitation. EPA sees this as an interim solution to the problem of having insufficient information at the time of this proposal to provide a numerical limitation, in that it still provides a limitation based on the performance of available technologies.

Rates of biodegradation for synthetic and mineral oil base fluids have been determined by both the solid phase and the simulated seabed test, and the relative rates of biodegradation among these two tests agree.[34] These tests have found that the order of degradation, from fastest to slowest, is as follows: vegetable ester > linear alpha olefin > internal olefin > linear paraffin > mineral oil > poly alpha olefin.

EPA has selected internal olefins as the basis for the biodegradation rate limitation instead of vegetable esters for two reasons: technical performance and non-water quality environmental impacts. SBFs formulated with vegetable esters have higher viscosity, which makes vegetable ester SBFs more difficult to pump, and may even be impractical for deepwater drilling due to the cooler temperatures and long drill string inherent in deepwater drilling. The cooler temperatures further increase viscosity, and the long drill string at this higher viscosity requires high pump pressures to circulate the SBF. Cost is a factor in encouraging the use of SBFs in place of OBFs. Industry representatives have told EPA that vegetable ester SBF costs about twice as much as internal olefin SBF.[24] EPA believes that if the lower cost internal olefin SBFs can be discharged, then more wells currently drilled with OBF would be encouraged to convert to SBF than if only the more expensive vegetable ester SBFs were available for discharge. This conversion is preferable for the improvements in non-water quality environmental impacts (see Chapter IX). If future research shows that vegetable esters have a significantly reduced toxicity in addition to the proven faster rate of biodegradation, EPA may consider more stringent stock base fluid limitations to favor the use of vegetable ester SBFs for the final rule.

5.2.5 Product Substitution Costs

The stock base fluid limitations proposed above allow use of the currently popular SBFs based on internal olefins ($195/bbl) and vegetable esters ($380/bbl).[24] For comparison, diesel oil-based drilling fluid costs about $65/bbl, and mineral oil-based drilling fluid costs about $75/bbl.[24] According to industry sources, the SBFs that are most widely used and discharged in the Gulf of Mexico are based on, in order of use, internal olefins, linear alpha olefins, and vegetable esters.[35] Since the proposed stock limitations allow the continued use of the preferred internal olefin and vegetable ester SBFs, EPA attributes no additional cost due to the stock base fluid requirements other than monitoring (testing and certification) costs. EPA expects that these monitoring costs will fall upon the base fluid suppliers as a marketing cost.

5.3 SOLIDS CONTROL: WASTE MINIMIZATION/POLLUTION PREVENTION

The function of a solids control system, regardless of the type of drilling fluid in use, is to separate drill cuttings from the drilling fluid so as to maintain the required flow properties of the drilling fluid. As stated above in section VII.2.1, drilling fluid properties degrade as the amount of fine particles in the drilling fluid increases. The solids control equipment can cause an increase in the amount of fine particle solids in the drilling fluid due to the breakdown of larger drill cuttings as they pass over and through vibrating screens, centrifuges, and other separation devices. Therefore, the solids control system is designed and operated to limit the mechanical destruction of the cuttings while maximizing the removal of undesirable solids from the drilling fluid.

The type of drilling fluid in use affects the ease with which drill solids can be separated. Cuttings are generally more difficult to remove from WBFs than SBFs because of the tendency for solids to disperse in the water phase of the WBFs. The approach to solids control can therefore be markedly different for WBF systems compared to OBF or SBF systems. Additional equipment such as hydrocyclones and chemical flocculation units are sometimes employed for WBFs.[16] Such separation steps are generally not necessary when SBFs or OBFs are used for drilling, and are often avoided because they result in additional losses of drilling fluid with the discarded solids wastestreams. EPA has also learned that there is no distinguishable difference in the separability of cuttings from OBF as compared to SBF.[20,36]

A typical solids control system for SBF/OBF drilling consists of at least some of the following equipment, depending on the drilling program: primary and secondary shale shakers which perform the initial separation of drill cuttings from drilling fluid, a "drying" shale shaker or centrifuge to recover drilling fluid from the cuttings wastestream, a "high-g" shale shaker or centrifuge to remove fine solids from the drilling fluid stream, and sand traps. Figure VII-1 illustrates the arrangement of primary, secondary, and drying shale shakers in a generalized solids control system. The following sections describe these unit processes as they are currently utilized in SBF/OBF drilling.

5.3.1 Shale Shakers

Shale shakers, also called vibrating screens, usually occupy the primary and secondary positions in the solids control equipment train. The function of the primary shale shaker (often referred to as the "scalp" shaker) is to remove the largest drill cuttings from the active drilling fluid system and to protect downstream equipment from unnecessary wear and damage from abrasion. The primary shale shaker receives cuttings and drilling fluid returned from the well and separates them into a coarse cuttings wastestream and a drilling fluid stream. The secondary shale shaker, sometimes referred to as a "mud cleaner," receives the drilling fluid stream from the primary shaker and removes smaller cuttings and fine particles. The drill cuttings that leave the primary shale shaker may be further treated by an additional shale shaker, herein referred to as a "drying" shaker to indicate that it treats cuttings as opposed to the secondary shale shaker which treats drilling fluid. The drying shaker is used to remove additional drilling fluid from the waste cuttings before they are discharged, injected, or transported offsite for disposal.

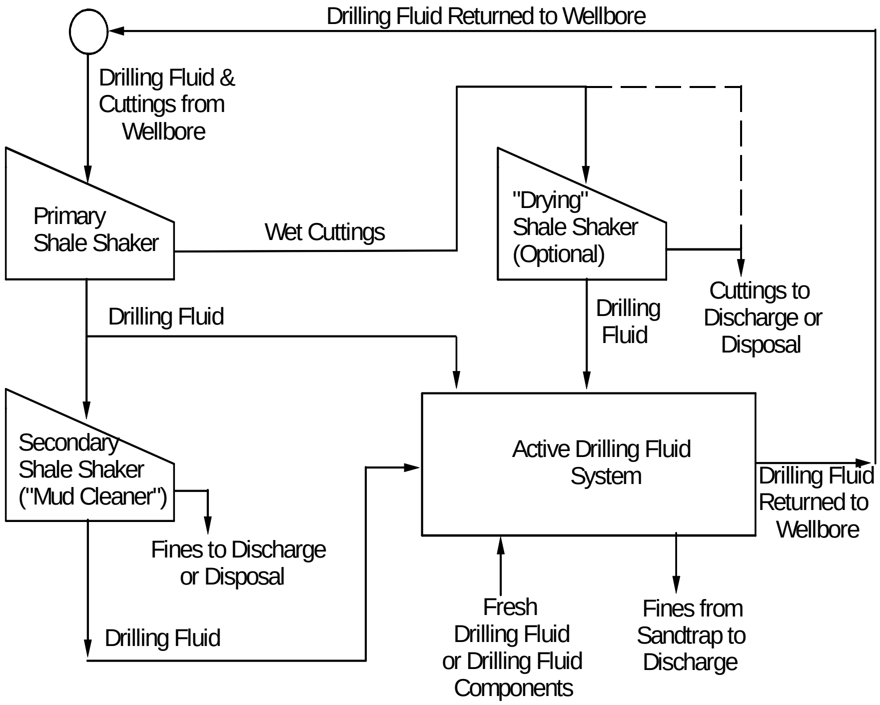


Figure VII-1. Generalized Solids Control System

Variables involved in shale shaker design include screen cloth characteristics, type of motion, position of screen, and arrangement of multiple screens. The Development Document for the Coastal Oil and Gas rulemaking provides a general discussion of how these variables are reflected in shale shaker design.[16] The application of these variables distinguishes the three types of shale shakers used with SBF/OBF drilling fluid systems. In general, the factor that distinguishes primary and secondary solids separation equipment design is the size of the solids removed by each unit. The primary shale shaker has screens with the lowest mesh (i.e., the least number of openings per linear inch, giving the largest screen hole size) to separate the largest cuttings. Secondary and drying shale shakers have finer mesh screens to remove smaller cuttings and fine particles.

In addition to mesh size, screen shape and orientation vary according to the level of separation required. Both the shape and orientation of the screen affect the retention time, or the time the process stream is exposed to the separation unit. A longer retention time on a shale shaker allows for potentially greater separation of solids from drilling fluid, but also increases the mechanical degradation of the solids.   Flat screens provide the least surface area and retention time, compared to other designs. Flat screens were the first design used in drilling operations and continue to be used on primary shale shakers to minimize the amount of time the largest cuttings are exposed to mechanical degradation. More recent designs feature corrugated screens that, compared to flat screens, have greater surface area, longer retention times, and greater capacity.[9] Corrugated screens are sometimes used on secondary and drying shale shakers. Screen orientation also varies as needed, with a “downward” slope for faster conveyance and less retention time, and an “upward” slope for slower conveyance and more retention time.

The impetus to maximize the amount of valuable OBF and SBF returned to the active drilling system encouraged the development of “high-g” shale shakers, so named for the higher-than-standard g-force they apply to the shaker screen. The applied g-force in this type of shaker can range from 6 to 8.0 Gs, as compared with approximately 2 to 4 Gs for standard shakers.[9,37] High-g shakers are sometimes used to remove the finest particles from the drilling fluid in order to control viscosity. High-g shakers can also be used as drying shakers to retrieve drilling fluid from the cuttings wastestream. The greater impact force of high-g shakers has both positive and negative effects: it promotes greater separation of liquid from the solids, but also increases the mechanical degradation of the solids. The effects of mechanical degradation can be counteracted with finer mesh screens. Shale shaker manufacturers differ on the best approach to the operation of high-g shale shakers. One manufacturer notes its field tests have shown that 4 to 5 Gs is the optimum force for a drying shale shaker because greater g-forces move the cuttings too quickly over the screen and increase the drilling fluid retained on the cuttings.[9] Another manufacturer claims that high-g dryers (with g-forces of 8 Gs and greater) may be used as primary shale shakers, secondary shale shakers, or "high performance" mud cleaners.[37]

EPA recently observed the operation of primary and secondary shale shakers, with both flat and corrugated screen designs, at an offshore Gulf of Mexico drilling operation that was using SBF at the time of the site visit.[17] The first, or primary units in the solids control train at this site were four two-tier shale shakers aligned in parallel. The two tiers of each unit worked in series, with gravity feed of the drilling fluid from the top tier to the bottom tier. The top tier of these shakers was equipped with screens consisting of four flat panels. As shown in Figure VII-2, the four top screen panels were tilted at increasing angles toward the discharge end. The cuttings discarded by the top screens were gravel-like bits and clumps of solid material on the order of a few millimeters in size, many of which retained the shape imparted by the drill bit. This shape was cited by the operator as indicative of cuttings generated from an interval of shale drilled with synthetic or diesel based drilling fluid.[17] The downward sloping flat screens also minimized the mechanical degradation of the cuttings on the top tier. The bottom tier of these shakers was equipped with a corrugated screen that was slightly (less than 3 degrees) sloped upward toward the discharge end. The cuttings discarded by the lower screens consisted of smaller cuttings and finer mud-like solids.

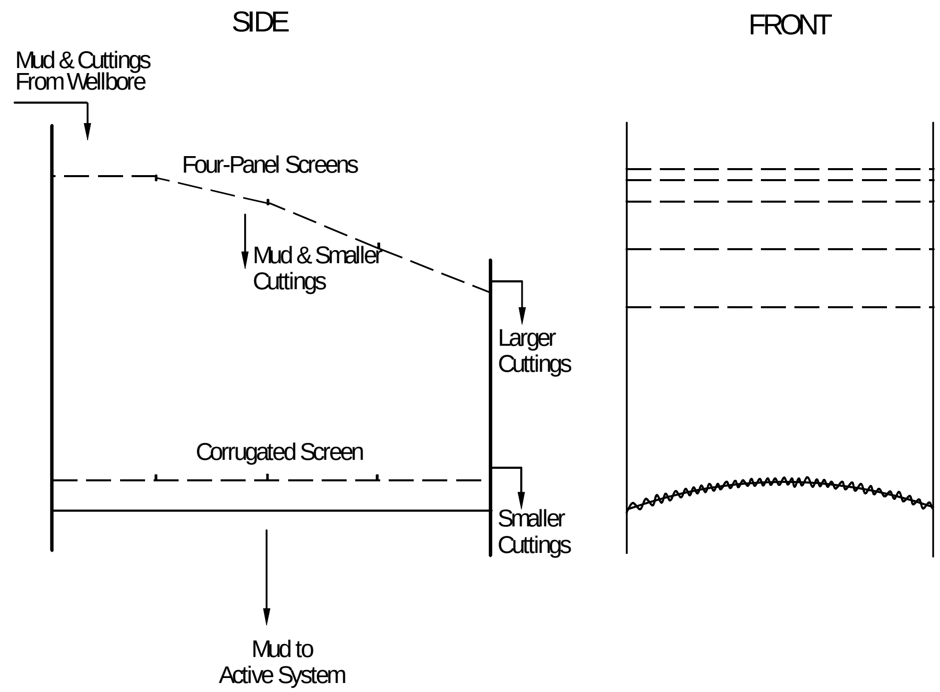


Figure VII-2.
Schematic Side and Front Views of Two-Tiered Shale Shakers

In addition to the two-tiered shale shakers, EPA observed a high-g shale shaker at this drill site, equipped with an upward sloping corrugated screen, that received approximately one third of the drilling fluid stream from the primary shakers.[17] The function of this shale shaker was to remove fine particles from the synthetic drilling fluid to reduce its viscosity. The manufacturer's literature indicates that the maximum g-force attainable by this equipment is 8.0 G.[37] The solids that were discharged from the high-g shaker had a mud-like appearance similar to the solids discharged from the lower screens of the four parallel shakers, but with even finer particles.

For comparison purposes, EPA reviewed current literature from three major shale shaker manufacturers. Table VII-5 lists selected design and operating characteristics of shale shakers and centrifuges commercially available to U.S. drilling operators. All three manufacturers claim their shale shakers can reduce the amount of SBF or OBF retained on the cuttings to less than 10% base fluid by weight. In a side comment, one company stated that drilling fluid retention would likely be higher (approximately12%) on a floating platform.[38] Cost information provided by these companies indicates that the day rate for shale shakers ranges from $190 to $250, for an average $213 per day, not including installation or labor (see Table VII-5).

5.3.2 Centrifuges

Centrifuges are used in solids control systems either in place of or in addition to shale shakers. When used as part of a standard solids control system, centrifuges can increase the solids removal efficiency by 30 to 40 percent.[43] Two centrifuge designs currently in use are decanting centrifuges and perforated rotor centrifuges. The Coastal Oil and Gas Development Document presents a detailed description of these centrifuge designs.[16]

In weighted SBF or OBF applications, centrifuges are used to remove fine solids from drilling fluid discharged by upstream separation equipment, such as a primary or secondary shale shaker. Some operators avoid this application, however, citing excessive loss of valuable SBF or OBF with the fine solids.[17]

TABLE VII-5

DRILLING FLUID RECOVERY DEVICES[a]

Manufacturer	Device Name	Device Type	Performance (Wt % SBF Retention Reported by Co.)	Capacity	Size (LxWxH, inches)	Max. G-Force Applied to Cuttings	Cost Information (1998$ unless otherwise noted)
Shale Shakers							
Brandt (Ref. 9 and 38)	ATL-Dryer SDW-25	Linear motion shale shakers	Stationary Rigs: 8-10% Floating Rigs: 12%	ATL: 8 SDW: 7 tons/hr	ATL: 100x71x57 SDW: 134x78x109	ATL: 4.2 SDW: 7	Day Rate: $200-$250/day Capital Cost: $30K-$40K O&M: $50/day
Derrick Equipment (Ref. 37 and 39)	HI-G Dryer	Linear motion shale shaker	<10%	Up to 1,200 gal/min	142x71x74	8.0	Day Rate: $225/day Capital Cost: $47.5K O&M: $600/week
Swaco (Ref. 40)	ATL-II	Linear motion shale shaker	6-8%	500 gal/min	129x63x61	6.25	Day Rate: $190/day
Centrifuges							
Broadbent (Ref. 41)	NA[b]	Decanting centrifuges	<10%	5.5-27.5 tons/hr	NA	NA	£2MM in 1989 (~$3.8MM)
Mud Recovery Systems, Ltd. (MRS) (Ref. 17 and 42)	MUD 6 MUD 10	Vibrating centrifuge	<7%	M-6: 11 M-10: 88 tons/hr	M-6: 59x54x52 M-10: 89x74x67	130	Day Rate for Amoco Demo of Mud-10: $1200 (incl. one FTE[c])
Centrifugal Services, Inc. (CSI) (Ref. 36)	Centrifugal Dryer	Vertical axis centrifuge	2.5-3%	25 tons/hr	footprint: 96x96	800	Technology not yet commercially available.

[a] Information presented in this table was either quoted or derived from information provided in company literature or telephone communications with company representatives.

[b] Not available.

[c] Full-time equivalent.

A more recent application for large capacity centrifuges is to recover SBF from the larger drill cuttings. These units are installed in place of the drying shale shaker. Such centrifuges must be large enough to process all the coarse and smaller cuttings discharged by the primary and secondary shale shakers. Table VII-5 lists centrifuges manufactured by three companies for use as drilling fluid recovery devices. The first centrifuge listed is a decanting centrifuge that was manufactured and marketed in the North Sea until zero discharge became the prominent cuttings management method for North Sea operators in the early 1990s.[41] Solids control systems installed by this manufacturer were sized to process all the cuttings returning from the well, using two primary and two secondary centrifuges in parallel. The second and third centrifuges listed in Table VII-5 represent the newest generation of drilling fluid recovery devices. The "Mud 10" combines design features from both centrifuge and shale shaker, with an internal rotating cone that also vibrates, thereby achieving the second lowest reported retention of drilling fluid on cuttings among the devices EPA reviewed. Unlike the Mud 10 whose internal cone rotates around a horizontal axis, the "Centrifugal Dryer" features a vertically oriented screen centrifuge that achieves highest reported g-forces, and the lowest reported retention values.[36] At the time EPA obtained this information, the Centrifugal Dryer was under development and not commercially available. The Mud 10 was developed by a manufacturer serving North Sea operators, and has a record of proven performance with wells drilled using SBF.[22]

EPA observed a demonstration of the Mud 10 drilling fluid recovery device during the site visit to the offshore SBF drilling operation in the Gulf of Mexico.[17] Figure VII-3 illustrates the arrangement of the solids control equipment at this site. The cuttings discharged from the four two-tiered shale shakers dropped off the screens into a trough located on the floor at the foot of the shakers, in which an auger conveyor rotated. The cuttings were conveyed laterally to an opening in the center of the bottom of the trough, and fell from the opening through a 10-inch pipe to the inlet of the Mud 10 unit located on the deck immediately below the shale shakers and trough. The manufacturer's literature gives the dimensions of the Mud 10 as: length 1500 mm (89 inches) x width1375 mm (74 inches) x height 1325 mm (67 inches).[42] On the drilling rig, the Mud 10 unit was mounted on a platform, adding two to three feet to its height.

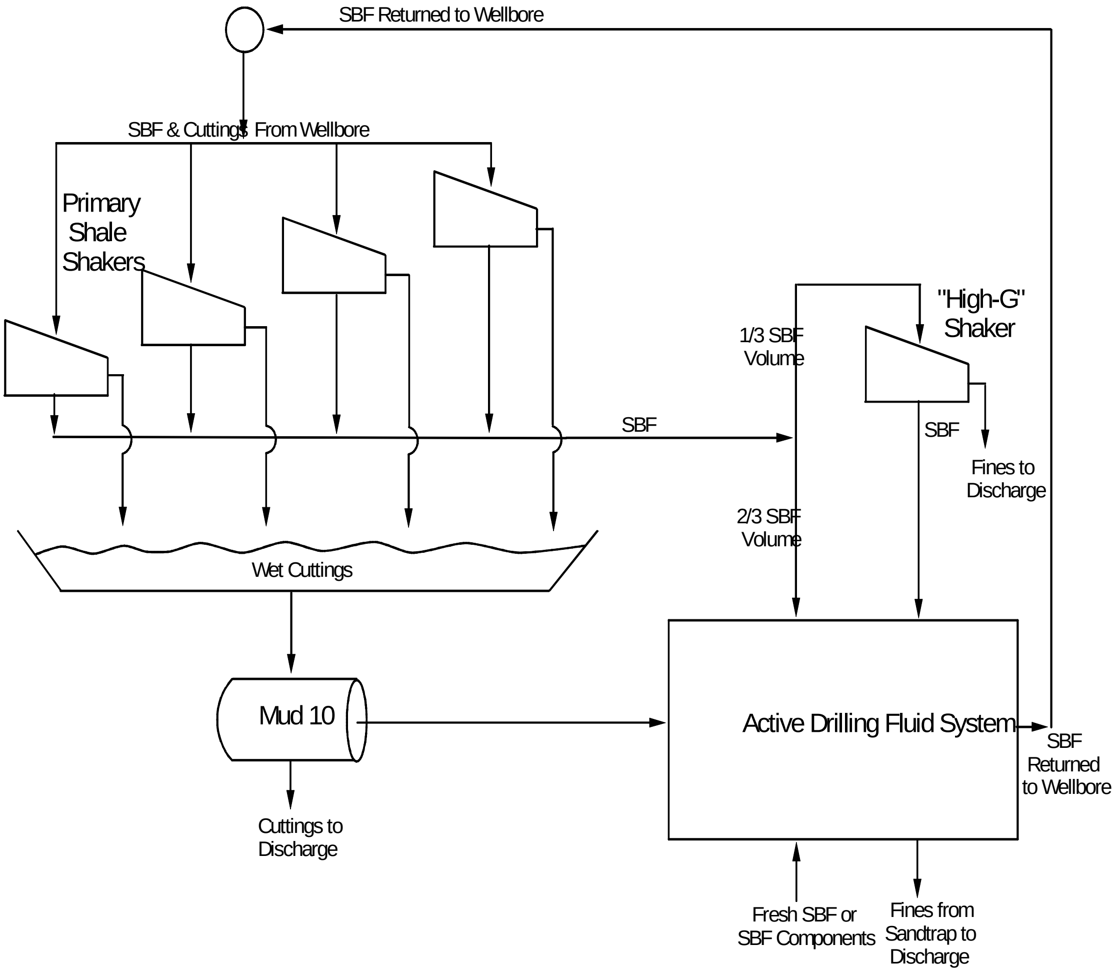


Figure VII-3. Configuration of Amirante Solids Control Equipment

The Mud 10 unit was completely enclosed, so the cuttings were not visible as they passed through this separation step. The manufacturer's literature describes the inner-operation of the Mud 10 as follows [42]:

> The system induces a centrifugal force of up to 130 G on all of the drill cuttings produced from the well separating the oil based mud and sub 200 micron drill cuttings from the main stream of cuttings...Drill cuttings fall into the inlet pipe and are fed by gravity to the distribution cone/support disc. The distribution cone removes the cuttings from the discharge end of the inlet pipe and accelerates and spreads them evenly onto the inner circumference of the conical wedge wire screen. The drill cuttings are retained on the inner circumference of the wedge wire screen by centrifugal force. Linear motion is induced axially into the conical wedge wire screen thus conveying the retained drill cuttings to the discharge end of the conical wedge wire screen. The oil based mud is forced through the apertures in the wedge wire screen by the centrifugal force. The recovered mud then flows from the discharge point to be collected for secondary treatment.

The Mud 10 can process up to 88 tons per hour, and was handling the full flow of the cuttings from the two-tiered shakers without problems.[17] A sample of the cuttings discharged by the Mud 10 appeared to be considerably drier than those discharged from the two-tiered shakers. The cost of renting the Mud 10, including one man dedicated to its operation, was $1,200 per day.

5.3.3 Screw Presses

In addition to shale shakers and centrifuges, screw presses have been used to separate adhering drilling fluid from the bulk cuttings wastestream prior to discharge. Screw presses generally operate by squeezing the cuttings as they are extruded through the unit, producing a drilling fluid stream and a compressed mass of cuttings. EPA does not have information concerning the performance or cost of screw presses. EPA has been told that the screw presses create brick-like solid chunks of cuttings waste with entrapped drilling fluid. Screw presses are not widely utilized by U.S. drilling operators for recovering drilling fluid from cuttings.

5.4 LAND-BASED TREATMENT AND DISPOSAL

Since the time of the 1993 Offshore Oil and Gas rulemaking, offshore drilling operators continue to utilize commercial land-based disposal facilities as the predominant means of meeting zero discharge requirements for OBF drilling waste. An informal survey of offshore operators recently showed that 11 of the14 Gulf of Mexico operators in the survey transport 50% to 100% of their OBF-cuttings to onshore disposal facilities.[44] The remainder of the OBF-cuttings are injected on site. For SBF-cuttings, the survey indicated that all of the 14 Gulf of Mexico operators use SBF, with one reporting onshore disposal of all its SBF-cuttings.

For the purpose of estimating costs and environmental impacts associated with transporting and land-disposing OBF- and SBF-cuttings, EPA reviewed the pertinent assumptions and data compiled in the Offshore and Coastal Oil and Gas rulemaking efforts, and updated cost and operating information where available. The following sections present EPA's most recent findings regarding the transportation, land treatment and disposal, and land-based subsurface injection of OBF- and SBF-cuttings.

5.4.1 Transportation to Land-Based Facilities

Drill cuttings earmarked for land disposal are first placed in cuttings boxes and transported from offshore platforms to coastal ports or transfer locations by ocean-going supply boat. Cuttings boxes in the Gulf of Mexico and California are reusable containers available in 15- and 25-barrel sizes, with footprints ranging from 20 to 40 square feet.[45,46,47] EPA used the 25-barrel box for its estimates in the Offshore Oil and Gas rulemaking, and updated the current per-box rental rate to $25 per day[44,46] for the proposed SBF rulemaking. Cuttings boxes used by operators in Cook Inlet, Alaska are single-use lined wooden crates measuring 4 feet x 4 feet x 4 feet, with an average eight-barrel capacity and a 1995 purchase price of $125 per box.[16]

Standard sizes for supply boats that service offshore platforms were reported to be 180 and 220 feet in length, with an estimated deck capacity of 80 or more 25-barrel cuttings boxes.[47,48] EPA estimated a deck capacity of 132 eight-barrel cuttings boxes for Cook Inlet supply boats, based on 3,300 square feet of deck space 461 and a 25-square foot footprint per cuttings box (16 ft^2 plus a half-foot perimeter clear space). Supply boat rental rates were recently quoted to range from $7,800 to $9,000 per day, with an industry-wide average of $8,500 per day.[47,48]

Information supporting the Offshore Oil and Gas rulemaking stated that a regularly scheduled supply boat visits a drilling rig approximately every four days.[45] This source further estimated that regularly scheduled supply boats would pick up 12 25-barrel cuttings boxes per trip because that number equals the average drilling rig capacity for storing cuttings boxes. The same source document provided additional supply boat information, including average speed (11.5 miles per hour), and the average distance between the port and drilling rig for Gulf of Mexico and offshore California (100 miles in both areas), with additional distance estimates between the rig, coastal transfer stations, and port in the Gulf of Mexico (117 miles and 60 miles, respectively). One disposal company owns a number of coastal transfer stations in the Gulf of Mexico where cuttings are moved from operator supply boats to disposal company barges that take the cuttings to port.[44,49,50] The estimate of supply boat distance for Cook Inlet, Alaska was developed in the Coastal Oil and Gas rulemaking and remains unchanged at 25 miles between port and rig.[16] Estimates for supply boat idling, maneuvering, and loading/unloading time were adopted without change from the Offshore Oil and Gas rulemaking. Chapters VIII and IX present the source data and detailed methodology EPA used to apply these estimates in compliance cost and other pertinent analyses.

In all three geographic areas, drill cuttings are transferred to trucks at the port and hauled to the land disposal site. Truck capacities were obtained from both dated and new sources. Trucks serving the Gulf of Mexico have a capacity of 5,000 gallons (119 barrels), according to the same source document that provided supply boat information for the Offshore Oil and Gas rulemaking.[45] Truck information for offshore California was updated to a capacity of two 25-barrel cuttings boxes.[51] Truck capacity for the Cook Inlet area was presented in the Coastal Oil and Gas rulemaking and remains unchanged at 22 tons per truckload.[52] However, the number of eight-barrel cuttings boxes in a 22-ton load was reduced from 10 to eight boxes, to reflect the higher density of cuttings containing 11% by weight adhering OBF (704 lbs/bbl) as compared with the original estimate that was based on a drilling fluid/cuttings mixture weighing 526 lbs/bbl.[16] Estimated trucking distances also vary between geographic areas, as follows: 20 miles round trip between port and disposal facility in the Gulf of Mexico; 300 miles round trip between port and disposal facility in California (estimated mileage between Ventura and Bakersfield); and 2,200 miles one way from Kenai, Alaska to a disposal facility in Arlington, Oregon.[16] Trucking costs were estimated for California and Cook Inlet, Alaska, but not for the Gulf of Mexico where trucking is included in the cost imposed by the disposal facility (see section VII.5.4.2 below). The trucking rate for California was estimated to be $65 per hour.[53] The 1995 trucking rate for Cook Inlet was $1,800 per truckload, as used in the Coastal guidelines effort.[52] Chapters VIII and IX present the application of these data in the compliance cost and other pertinent analyses.

5.4.2 Land Treatment and Disposal

Centralized commercial land treatment and disposal facilities are generally owned by independent companies. These facilities receive drilling wastes in vacuum trucks, dump trucks, cuttings boxes, or barges, from both onshore and offshore drilling operations. Most of these facilities employ a landfarming technique whereby the wastes are spread over small areas and are allowed to biodegrade until they become claylike substances that can be stockpiled outside of the landfarming area. Another common practice at centralized commercial facilities is the processing of drilling waste into a reusable construction material. This process consists of dewatering the drilling waste and mixing the solids with binding and solidification agents. The oil and metals are stabilized within the solids matrix and cannot leach from the solids. The resulting solids are then used as daily cover at a Class I municipal landfill. Other potential uses for the stabilized material include use as a base for road construction and levee maintenance.[54] The Development Document for the Coastal Oil and Gas rulemaking presents a stepwise description of the treatment and disposal processes employed by a commercial facility located in southeast Louisiana.[16]

EPA determined that existing land disposal facilities in the areas accessible to the Gulf of Mexico offshore and coastal oil and gas subcategories have 5.5 million barrels annual capacity available for oil and gas field wastes.[10] This is more than sufficient capacity to manage the 202 thousand barrels per year of drilling waste that EPA estimates would go to land-based disposal facilities in the Gulf of Mexico region under the zero discharge option discussed in Chapters VIII and IX. Land disposal facilities accessible to California oil and gas operations in the offshore and coastal subcategories are estimated to have 19.4 million barrels annual capacity.[10] The zero discharge option presented in later chapters includes no additional drilling wastes, above that currently accounted for, going to land-based disposal facilities in California.

EPA updated current disposal facility costs for the three geographic areas. In the Gulf of Mexico, current disposal prices range from $9.50 per barrel[55] to $10.75 per barrel[56] to dispose of OBF-cuttings. If the drilling operator offloads the waste at a coastal transfer station, the facility charges an additional $4.75 per barrel for the offloading and transportation of the waste to the facility.[55] For California, EPA calculated a unit disposal cost of $12.32 per barrel, based on a price of $35 per ton for a disposal facility located near Bakersfield[51], and the calculated density of 704 lbs/bbl for cuttings with 11% by weight adhering OBF (see Table VII-4). For drilling waste generated in coastal Cook Inlet, the unit disposal cost of $500 per eight-barrel cuttings box ($62.50 per barrel) was used in the 1995 Coastal Oil and Gas rulemaking for a disposal facility located in Arlington, Oregon.[57] EPA updated the Oregon disposal cost to 1997 dollars (see Chapter VIII), and assumed that this unit price includes all additional waste handling fees imposed by the disposal facility.

5.4.3 Land-Based Subsurface Injection

In addition to land treatment and disposal, land-based disposal facilities use subsurface injection as a means of disposing drilling wastes, including both drilling fluids and drill cuttings. One of the two major commercial oilfield waste disposal companies serving the Gulf of Mexico industry currently operates three injection disposal sites in Texas: Port Arthur, Big Hill (30 miles from Port Arthur), and one in West Texas.[50] These three facilities collectively operate 15 injection wells with an estimated one billion barrel total capacity. This company specializes in the use of depleted salt domes, or limestones associated with other domes, which allow easy pumping into the dome for disposal. These sites were located by reviewing drilling records to see where extensive lost circulation problems occurred, indicating a void. The company claims that its use of existing underground domes is primarily responsible for the large quantities of oilfield wastes it has disposed. For example, 15 million barrels of petroleum wastes have been disposed in the Big Hill site since 1993. This company is working toward expanding its injection disposal sites into Louisiana and Mississippi.

The unit cost for commercial injection of OBF drilling waste at these Gulf of Mexico locations is comparable to that of land treatment: $9.50 per barrel for waste containing greater than 10% oil and grease.[50] An additional $3.50 per barrel covers ancillary waste handling and transport conducted by the disposal company.

5.5 ONSITE SUBSURFACE INJECTION

The interest in and use of onsite injection to dispose of drilling wastes at offshore platforms has increased since the Offshore Oil and Gas rulemaking in 1993. At that time, subsurface injection was generally limited to disposal of produced water, with drilling waste injection still in the early stages of development.[10] Since then, interest in injection as an alternative to hauling drilling wastes to landfills has created a market supported by a growing number of commercial injection service companies. However, the extent to which offshore drilling operations currently use onsite injection is difficult to estimate from available information. A recent informal survey of fourteen Gulf of Mexico drilling operators and four commercial onsite injection companies provided varied responses regarding this issue.[44] Of the fourteen Gulf of Mexico operators, four reported using onsite injection to dispose of a portion of their OBF-cuttings. The proportion of OBF-cuttings disposed by injection as reported by the four operators ranged from 5% to 50%, the remainder of which was hauled to land-based disposal facilities. In addition, four commercial onsite injection companies reported a total of 66 injection jobs occurring at offshore Gulf of Mexico sites in the past year. When the survey author compared an estimated 100 offshore Gulf of Mexico wells drilled with OBF annually with the reported numbers of onsite injection jobs, the comparison suggested that nearly two-thirds of OBF wells are disposing of drill cuttings by onsite injection.[44] However, as noted by the survey author, the commercial injection companies also provided estimates of industry-wide use of injection for OBF-cuttings disposal ranging from 10% to 20%. Given these contrasting estimates, EPA recognizes a need for additional information and study regarding the current practice of onsite injection of drilling wastes.

The survey of drilling operators also provided information about injection of OBF-cuttings in areas other than the Gulf of Mexico.[44] In California, two out of the five surveyed operators use OBF, and both haul OBF-cuttings to shore. One of these operators attempted injection unsuccessfully, indicating that there is an interest in this technology among offshore California operators. In Cook Inlet, Alaska, all of the three operators contacted in the survey stated they inject 100% of their OBF-cuttings. However, one of these operators mentioned that they recently decided to stop drilling off a particular Cook Inlet platform because the State of Alaska informed them that injection of OBF drilling wastes "was no longer an option for any future wells."[44] In a separate conversation with the commercial injection company that worked at this Cook Inlet site, EPA learned that approximately 50,000 barrels of cuttings from four newly drilled wells were successfully injected through the annulus of a single well.[58] The North Slope area of Alaska was the first active drilling area to engage in large-scale grinding and injection programs[10,16], and continues to lead the industry in this regard. The survey contacted the only operator actively drilling in the offshore waters of northern Alaska, who reported a volume of 105,000 barrels of drilling waste injected annually.[44] This operator injects all of its waste WBF, WBF-cuttings and OBF-cuttings into a dedicated injection well.

Onsite injection differs from commercial land-based injection because its success depends on the availability of viable receiving formations and confining zones located at the drill site, whereas commercial facilities are located at large-capacity receiving formations. In onsite disposal projects, drilling wastes may be injected into either the annulus of the well being drilled or a dedicated disposal well. One source estimates that approximately half of the offshore injection jobs utilize annular injection down the well being drilled while the other half uses other wells on the same platform for disposal.[58] The critical parameters that affect the performance of any grinding and injection system are: drilled solids particle size, the injectable fluid density and viscosity, percent solids in the injectable fluid, injection pressure, and the characteristics of the receiving formation. These parameters and their effect on the design of the grinding and injection system are discussed in detail in the Development Document for the Coastal Oil and Gas rulemaking.[16]

EPA contacted two of the commercial injection companies that serve the offshore Gulf of Mexico drilling industry for current information regarding the equipment, processes, and prices for onsite injection of drilling wastes. Both companies use a licensed process originally developed by ARCO, that includes grinding, slurrification, and pumping the cuttings slurry downhole.[58,59] As an example, one of the companies uses two basic equipment sets to grind and inject cuttings: the viscosifier system and the slurrification skid.[58] The viscosifier system picks up cuttings coming off the rig shale shaker using an auger or vacuum system, and puts them in a tank where the viscosity is adjusted to put the cuttings into suspension for pumping. For OBF, the cuttings are suspended in a polymer. Water, mineral oil, and other material can be used to adjust the viscosity. A grinding or "shredding" pump is used to reduce particle size to 100 microns. From the viscosifier, a centrifugal pump sends the slurry to the slurrification skid. There, a tank maintains the slurry and provides suction to a high pressure injection pump. This company reports that it usually achieves a disposal rate at Gulf of Mexico sites of 2 to 3 barrels per minute.[58]

Costs associated with onsite injection have been provided in two forms: as daily rental rates and as unit costs per barrel of cuttings disposed. The daily rates, generally representing the equipment and labor associated with the injection system, are similar between the three reporting companies, including quotes of $2,000 per day[44], $2,500 per day[58], and $2,500-$3,000 per day[60]. One of these companies provided costs for additional equipment, specifically $250 per day for an auger or $1,200-$1,300 per day for a vacuum system to transport the cuttings from the rig shale shaker to the injection system, plus additional labor at $28-$30 per hour to operate the vacuum system.[60] Quotes of unit costs per barrel of cuttings disposed vary widely between sources, from a low of $3 per barrel to a high of $20 per barrel.[44] The costs of onsite injection are dependent on many variables, including hole size (wherein a larger hole might require additional labor at the start)[58], the type of cuttings transfer equipment selected, and whether any downhole problems are encountered that might cause delays or changes to the disposal program. It is the issue of unforeseeable downhole problems that concerns drilling operators, who have noted that any savings realized through onsite injection are sensitive to the ability to inject.[61]

5.6 ADDITIONAL CONTROL METHODOLOGIES CONSIDERED

As part of the Offshore Oil and Gas rulemaking, EPA investigated four different thermal distillation and oxidation processes for the removal of oil from drilling wastes (53 FR 41375, October 21, 1998). The details of EPA's findings are presented in the Development Document for the Offshore Oil and Gas rulemaking.[10] Although these technologies appeared to be capable of reducing the oil content in oil-based drilling wastes, EPA rejected them from further consideration because of difficulties associated with the placement of such equipment at offshore drilling sites, operation of the equipment, intermediate handling of raw wastes to be processed, and handling of processed wastes and by-products streams.

EPA notes that interest in thermal distillation technologies persists among onshore commercial disposal companies as a means of treating drilling waste and recovering valuable SBF and OBF for reconditioning and reuse.[36,40] EPA did not investigate this technology any further because its application is at land-based rather than offshore facilities.

6.0 REFERENCES

1. American Petroleum Institute, responses to EPA's "Technical Questions for Oil and Gas Exploration and Production Industry Representatives," attached to e-mail sent by Mike Parker, Exxon Company, U.S.A., to Joseph Daly, U.S. EPA, August 7, 1998.

2. Candler, J.E., S. Hoskin, M. Churan, C.W. Lai and M. Freeman. "Sea-floor Monitoring for Synthetic-Based Mud Discharged in the Western Gulf of Mexico," SPE 29694 Society of Petroleum Engineers Inc., March 1977.

3. Daan, R., K. Booij, M. Mulder, and E. Van Weerlee, "Environmental Effects of a Discharge of Cuttings Contaminated with Ester-Based Drilling Muds in the North Sea," *Environmental Toxicology and Chemistry*, Vol. 15, No. 10, pp. 1709-1722, April 9, 1996.

4. Smith, J. and S.J. May, "Ula Wellsite 7/12-9 Environmental Survey 1991," a report to SINTEF SI from the Field Studies Council Research Centre, November 1991.

5. The Pechan-Avanti Group, Worksheet regarding "Calculation of Model SBF Drilling Fluid Formulation," October 26, 1998.

6. Baker-Hughes Inteq, Product information sheet featuring "Typical Formulation, 14.0 lb/gal / 70/30 SWR," 1995.

7. Friedheim, J. E., and H.L. Conn, "Second Generation Synthetic Fluids in the North Sea: Are They Better?" IADC/SPE 35061, 1996.

8. Baker-Hughes Inteq, Product Bulletin for "ISO-TEQ™," 1994.

9. Brandt/EPI, "The Handbook on Solids Control and Waste Management," 4th edition, 1996.

10. U.S. Environmental Protection Agency, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, Final, EPA 821-R-93-003, January 1993.

11. The Pechan-Avanti Group, Worksheet regarding "Calculation of Organics in Waste Cuttings Due to Crude Contamination," January 20, 1999.

12. SAIC, Worksheet regarding "Calculations for Average Density of Dry Solids in Cook Inelt Drilling Mud," June 6, 1994.

13. Baker-Hughes Inteq, Material Safety Data Sheet for "MIL-BAR" (Barite), March 21,1994.

14. Baker-Hughes Inteq, Case history information featuring synthetic-based drilling fluid properties, 1995.

15. Daly, Joseph, U.S. EPA, Memorandum regarding “Contamination of Synthetic-Based Drilling Fluid (SBF) with Crude Oil,” January 14, 1999.

16. U.S. Environmental Protection Agency, Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-96-023, October 1996.

17. The Pechan-Avanti Group, “Demonstration of the ‘Mud 10’ Drilling Fluid Recovery Device at the Amoco Marlin Deepwater Drill Site,” August 7, 1998.

18. Annis, Max R., “Retention of Synthetic-Based Drilling Material on Cuttings Discharged to the Gulf Of Mexico,” prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 29, 1997.

19. White, Charles E., and Henry D. Kahn, U.S. EPA, Statistics Analysis Section, Memorandum to Joseph Daly, U.S. EPA, Energy Branch, regarding “Current Performance, when using Synthetic-Based Drilling Fluids, for Primary Shakers, Secondary Shakers, and Vibrating Centrifuge and Model Limits for Percent Retention of Base Fluids on Cuttings for Secondary Shakers and Vibrating Centrifuge,” January 29, 1999.

20. McIntyre, Jamie, Avanti Corporation, Memorandum to Joseph Daly, U.S. EPA, regarding “Summary of December 2 Meeting with David Wood of Mud Recovery Systems,” December 18, 1997.

21. Annis, Max R., “Procedures for Sampling and Testing Cuttings Discharged While Drilling with Synthetic-Based Muds,” prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 19, 1998.

22. Daly, Joseph, U.S. EPA, Memorandum regarding “Data Showing the Performance of the Mud 10 with North Sea Oil Wells,” January 14, 1999.

23. Munro, P.D., C.F Moffet and R.M. Stagg, “Biodegradation of Base Fluids Used in Synthetic Drilling Muds in a Solid-Phase Test System,” SPE 37861, 1997.

24. Daly, Joseph, U.S. EPA, Memorandum regarding “Cost of Synthetic-Based Drilling Fluids (SBF),” January 15, 1999.

25. Still, I. and J. Candler, "Benthic Toxicity Testing of Oil-Based and Synthetic-Based Drilling Fluids," Eighth International Symposium on Toxicity Assessment, Perth, Western Australia, May 25-30, 1997.

26. U.S. EPA, "EPA Method 1654A: Polynuclear Aromatic Hydrocarbon Content of Oil by High Performance Liquid Chromatography with an Ultraviolet Detector" in Methods for the Determination of Diesel, Mineral, and Crude Oils in Offshore Oil and Gas Industry Discharges, EPA-821-R-92-008, December 1992.

27. Daly, Joseph, U.S. EPA, Memorandum regarding "Meeting with Oil and Gas Industry Representatives Regarding Synthetic Drilling Fluids," July 2, 1996, with two attachments: 1) Information package entitled "Enhanced Mineral Oils (EMO) for Drilling," presented by Exxon Co., U.S.A Marketing, Donald F. Jacques, Ph. D., June 25, 1996, and 2) Letter from Michael E. Parker, P.E., Exxon Company U.S.A., to M. B. Rubin, U.S. EPA, September 17, 1996.

28. Hood, C.A., Baker-Hughes Inteq, Letter to Joseph Daly, U.S. EPA, with unpublished sediment toxicity data from Baker-Hughes Inteq, July 9, 1997.

29. Candler, J., R. Herbert and A.J.J. Leuterman, "Effectiveness of a 10-day ASTM Amphipod Sediment Test to Screen Drilling Mud Base Fluids for Benthic Toxicity," SPE 37890, Society of Petroleum Engineers Inc., March 1997.

30. American Petroleum Institute, Information package regarding "Data Tables for the Conference Call for Review of 2nd Round of Range-Finders," API Drilling Mud Issue Work Group *ad hoc* SBM Sediment Toxicity Protocol Development Work Group, September 11, 1998.

31. American Petroleum Institute, Information package regarding "Conference Call for Review of 3rd Round of Range-Finders," API Drilling Mud Issue Work Group *ad hoc* SBM Sediment Toxicity Protocol Development Work Group, December 11, 1998.

32. Vik, E.A., S. Dempsey and B. Nesgard, "Evaluation of Available Test Results from Environmental Studies of Synthetic Based Drilling Muds," OLF Project Acceptance Criteria for Drilling Fluids, Aquateam Report No. 96-010, July 29, 1996.

33. Munro, P.D., C.F. Moffet, L. Couper, N.A. Brown, B. Croce, and R.M. Stagg, "Degradation of Synthetic Mud Base Fluids in a Solid-Phase Test System," the Scottish Office of Agriculture and Fisheries Department, Fisheries Research Services Report No. 1/97, January 1997.

34. U.S. EPA, Environmental Assessment of Proposed 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-98-019, February 1999.

35. M-I Drilling Fluids, Bar graph entitled "M-I's Synthetics Marketplace," with notation it was handed to J. Daly by J. Candler on January 30, 1997.

36. McIntyre, Jamie, Avanti Corporation, Telephone Communication Report on conversation with Peter Matthews, Newpark Drilling Fluids, regarding "'Centrifugal Dryer' for Drill Cuttings," May 29, 1998.

37. Derrick Equipment Company, Product brochure entitled "Derrick HI-G™ Dryer with Optional Hydrocyclone Packages," October 1997.

38. McIntyre, J., Avanti Corporation, Telephone Communication Report on conversation with Mike Montgomery, Brandt Company, regarding "Questions regarding Brandt solids control equipment," with attached product bulletins, April 13, 1998.

39. McIntyre, J., Avanti Corporation, Telephone Communication Report on conversation with George Potts, Derrick Equipment Company, regarding "Questions regarding Derrick solids control equipment," with attached price information, April 24, 1998.

40. McIntyre, J., Avanti Corporation, Telephone Communication Report on conversations with Paul Hanson (on April 20, 1998), and George Murphy (on April 24, 1998) of SWACO, regarding "Questions regarding SWACO solids control equipment," with attached product brochures.

41. McIntyre, J., Avanti Corporation, Telephone Communication Report on conversation with Bryan Murry, Broadbent, Inc., regarding "Questions regarding Broadbent solids control equipment," with attached product brochure, April 15, 1998.

42. Mud Recovery Systems, Ltd., Product brochure entitled "M.U.D. 10 and M.U.D. 6 Mud Recovery and Cuttings Cleaning System," undated.

43. Walters, Herb, "Dewatering of Drilling Fluids," in <u>Petroleum Engineer International</u>, February 1991.

44. Veil, John A., Argonne National Laboratory, Washington, D.C., "Data Summary of Offshore Drilling Waste Disposal Practices," prepared for the U.S. Environmental Protection Agency, Engineering and Analysis Division, and the U.S. Department of Energy, Office of Fossil Energy, November 1998.

45. Carriere, J. and E. Lee, Walk, Haydel and Associates, Inc., "Water-Based Drilling Fluids and Cuttings Disposal Study Update," Offshore Effluent Guidelines Comments Research Fund Administered by Liskow and Lewis, January 1989.

46. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with personnel at Frances Torque Service, regarding "Cuttings box rental costs (Gulf of Mexico area)," June 4, 1998.

47. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with John Belsome, Seabulk Offshore Ltd., regarding “Offshore supply boat costs and specifications,” June 3, 1998.

48. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with George Bano, Sea Mar Management, regarding “Offshore supply boat costs and specifications,” June 3, 1998.

49. U.S. EPA, “Trip Report to Campbell Wells Land Treatment, Bourg, Louisiana, March 12, 1992,” May 29, 1992.

50. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with Frank Lyon, Newpark Environmental, regarding “Drilling Waste Zero Discharge Disposal Costs,” May 19, 1998.

51. McIntyre, Jamie, The Pechan-Avanti Group, Telecommunications Report on conversation with Darron Stankey, McKittrick Solid Waste Disposal Facility, regarding “California Prices for Land Disposal of Drilling Wastes,” October 16,1998.

52. McIntyre, Jamie, SAIC, Telecon on conversation with Josh Stenson, Carlisle Trucking, regarding “Costs to Truck Wastes from Kenai, Alaska to Arlington, Oregon,” May 23, 1995.

53. Montgomery, Richard, The Pechan-Avanti Group, Telecommunication Report on conversation with Shane Morgan, Ecology Control Incorporated, regarding “costs associated with land and water transport of drill cuttings and drilling fluids for offshore oil platforms operating off the California coast,” May 9, 1998.

54. Weideman, Allison, U.S. EPA, “Trip Report to Alaska Cook Inlet and North Slope Oil and Gas Facilities, August 25-29, 1993,” August 31, 1994.

55. Newpark Environmental Services, Facsimile of Price List, Effective May 1, 1998, from Lisa L. Denman to Kerri Kennedy, May 26, 1998.

56. U.S. Liquids of Louisiana, Facsimile of Price List, from “Betty” to Jamie McIntyre, May 26, 1998.

57. McIntyre, Jamie, SAIC, Telecon on conversation with Alan Katel, Chemical Waste Management of the Northeast, regarding “Cost of Disposing Drilling Wastes and Possible Transportation Routes,” May 9, 1995.

58. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with Todd Franklin, Apollo Services, regarding “Apollo Services drilling waste zero discharge practices and cost,” May 19, 1998.

59. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with Nubon Guidry, National Injection Services, regarding "Zero discharge practices for OBM and SBM," April 29, 1998.

60. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with Gene Kraemer, National Injection Services, regarding "Zero discharge costs and space requirements: Onsite injection," May 19, 1998.

61. Daly, Joseph, U.S. EPA, Memorandum regarding "October 13, 1998 Teleconference Regarding SBF Use," October 20, 1998.

CHAPTER VIII

COMPLIANCE COST AND POLLUTANT REDUCTION DETERMINATION OF DRILLING FLUIDS AND DRILL CUTTINGS

1.0 INTRODUCTION

This chapter presents the incremental costs and pollutant reductions for the technology based options considered for control of drill cuttings. Incremental compliance costs beyond current industry practices and NPDES permit requirements were developed for the two control options for the Gulf of Mexico, offshore California, and coastal Cook Inlet, Alaska. Compliance costs were not developed for the other offshore regions where oil and gas activity exists or is expected, because, as is discussed in earlier chapters of this document, discharges of drill cuttings do not occur in these areas.

2.0 OPTIONS CONSIDERED AND SUMMARY COSTS

Two technology based options were considered for control and treatment of SBF drill cuttings for this rule. These options are:

- Discharge: Limitations on stock synthetic base fluid (PAH content, biodegradation rate, sediment toxicity); limitations on discharged SBF cuttings (no free oil, formation oil contamination, retention of SBF on cuttings); limitations on Hg and Cd in stock barite; prohibition of diesel oil discharge.
- Zero Discharge: Zero discharge for all areas.

Table VIII-1 presents the annual incremental compliance costs and pollutant reductions calculated for each option, for both existing and new sources. Both the costs and pollutant reductions are based on current annual drilling activity in each of the three geographic regions, as well as model well volumes and waste characteristics. The derivation of these costs and pollutant reductions is described in detail in the remainder of this chapter.

3.0 COMPLIANCE COST METHODOLOGY

The costs considered as part of the compliance cost analysis are only those that EPA believes will be affected by this rulemaking effort, including costs associated with the technologies used to control and manage drill cuttings contaminated with SBF and OBF (hereafter referred to as SBF-cuttings and OBF-cuttings) under the discharge and zero discharge options, as well as savings incurred from the recovery of SBF.

The following sections describe first the general assumptions and input data on which the cost analysis is based, followed by a detailed discussion of the methodology used to calculate the annual incremental compliance costs for both BAT and NSPS levels of regulatory control.

3.1 DATA AND ESTIMATES USED TO GENERATE COSTS

3.1.1 Drilling Activity

Chapter IV of this document describes the accounting of wells drilled annually in each of the three geographic areas, distinguishing between wells drilled using WBF, OBF, and SBF (see section IV.3.1). For the purposes of calculating compliance costs, pollutant reductions, and non-water quality environmental impacts, a population of wells considered to be affected by this rule was derived from the total numbers of wells drilled annually that are listed in Table IV-2. The affected well population, hereafter referred to as “in-scope wells,” is a subset of the total annual well counts. Wells currently drilled with SBF are included in the analysis, and also OBF wells

TABLE VIII-1

ANNUAL INCREMENTAL COMPLIANCE COSTS AND POLLUTANT REDUCTIONS FOR DRILL CUTTINGS BAT AND NSPS OPTIONS

Option	Incremental Cost (1997$/yr)	Incremental Pollutant Reductions (lbs/yr)	
BAT Options for Existing Sources			
Discharge with 7% retention of base drilling fluid on cuttings	($6,586,322)	Conventionals Priority Organics Priority Metals Non-Conventionals Total	(16,334,088) 86 2,083 573,071 (15,758,848)
Zero Discharge	$6,963,896	Conventionals Priority Organics Priority Metals Non-Conventionals Total	157,248,923 267 6,690 1,847,872 159,103,752
NSPS Options for New Sources			
Discharge with 7% retention of base drilling fluid on cuttings	($619,475)[a]	Conventionals Priority Organics Priority Metals Non-Conventionals Total	1,519,236 16 337 90,805 1,610,394
Zero Discharge	$1,594,418	Conventionals Priority Organics Priority Metals Non-Conventionals Total	18,073,733 32 770 212,379 18,286,914
Total Costs and Pollutant Reductions (BAT + NSPS)			
Discharge with 7% retention of base drilling fluid on cuttings	($7,205,797)[a]	Conventionals Priority Organics Priority Metals Non-Conventionals Total	(14,814,852) 102 2,420 663,876 (14,148,454)
Zero Discharge	$8,558,314	Conventionals Priority Organics Priority Metals Non-Conventionals Total	175,322,656 299 7,460 2,060,251 177,390,666

[a]These numbers are slightly higher than the corresponding numbers ($569,600 and $7,155,921) in the *Federal Register* notice for this proposed regulation because the results from the last revision were inadvertently excluded from the *Federal Register* notice.

that EPA anticipates will convert to SBF upon completion of this rule. However, wells currently using OBF and not converting to SBF would not incur costs or realize savings in the analysis. EPA assumed that only those wells using SBF or OBF currently would potentially use SBF in the future, and so wells drilled exclusively with WBF do not incur costs or realize savings in this analysis. Also, of the wells that are in the analysis because they use SBFs or OBFs, the upper sections of the well that are drilled with WBF do not result in costs or savings in the analysis.

Referring to Table IV-2, the 113 SBF wells in the Gulf of Mexico are in scope. While the rule applies to any wells discharging SBFs in areas where drilling wastes may be discharged, this Development Document uses the phrase “in scope” to indicate facilities that incur costs or realize savings under the rule. In addition, all OBF wells that are projected to convert to SBF are in scope. This includes the 12 OBF wells in offshore California, one OBF well in Cook Inlet, and a subset of the OBF wells in the Gulf of Mexico. Based on information provided by industry sources, EPA estimated that 20% of the 112 Gulf of Mexico OBF wells accounted for in Table IV-2, or 22.4 wells, would convert to SBF in the discharge option.[1] To avoid calculations using fractions of wells, this number was rounded to the next whole number, or 23 OBF wells. Thus, the total number of in-scope wells in the discharge option is 149 wells per year (i.e., 113+12+1+23).   In offshore California and Cook Inlet, Alaska, EPA projected that all OBF wells will convert to SBF because of the higher cost to drill, the greater expense of OBF-cuttings discharge and an ever-greater concern for non-water quality environmental impacts in these areas as compared to the Gulf of Mexico. For example, disposal of OBF-cuttings in Cook Inlet would likely require the trucking or barging of the waste to the lower 48 states. Air quality in California is a continuing concern, and there is pressure to keep air emissions from oil and gas drilling activities in the neighboring offshore waters at a minimum. Also, this will be the first opportunity for operators in California and Alaska to discharge SBF-cuttings, whereas in the Gulf of Mexico, they already have the choice of using SBF and discharging the SBF-cuttings.

For comparison purposes, EPA varied the number of OBF wells in the Gulf of Mexico that are assumed to convert from OBF to SBF in the discharge option. Compliance costs and pollutant reductions were calculated assuming zero%, 20%, and 100% of OBF wells in the Gulf of Mexico would convert to SBF. The comparative results of these analyses are presented in sections 3.2 and 4.2.2 of this chapter.

For the zero discharge option, only wells currently drilled using SBF are in-scope because wells currently drilled with OBF are already at the zero-discharge level of compliance. Thus, the total number of in-scope wells (those that would incur costs or realize savings) for the zero discharge option is 113 SBF wells drilled per year in the Gulf of Mexico, including both existing and new sources of drill cuttings.

3.1.2 Model Well Characteristics

Sections 3.0 and 4.0 of Chapter VII present the pollutant characteristics and drilling waste volumes that EPA calculated on a per-well basis for the four model wells. Table VII-4 lists the drilling fluid and drill cuttings waste volumes that are the basis for the compliance cost, pollutant reduction, and non-water quality environmental impact analyses.

In addition to the per-well waste volumes, EPA estimated the number of days to drill each model well, using the per-well retort data provided by API.[2,3] These days represent the number of days of active drilling using SBF, and do not represent the entire time that the drilling rig and associated equipment are onsite. Active drilling days comprise approximately 40% of the time the drilling equipment is onsite.[4] These so-called active drilling days are used in equipment rental cost estimates, and are the basis for estimating waste hauling requirements. The estimated number of drilling days for the well sections drilled with SBF are as follows: 3.6 days for a SWD, 7.5 for a SWE, 5.4 for a DWD, and 12.0 for a DWE. This range of drilling days was confirmed by an industry source to be typical for drilling SBF intervals.[4]

3.1.3 Onsite Solids Control Technology Costs

Costs associated with the onsite treatment of drill cuttings were estimated for both baseline and BAT/NSPS compliance levels of control. The types of solids control equipment currently used in the offshore oil and gas industry are described in detail in Chapter VII. The following sections present the unit costs that comprise the line-items in the solids control technology costs.

3.1.3.1 Baseline Solids Control Technology Costs

For the purpose of calculating incremental compliance costs, EPA identified a baseline level of solids control consisting of a primary shale shaker (or multiple primary shakers aligned in parallel), from which drill cuttings are either discharged without further treatment or collected for transport to shore, followed by a secondary shale shaker that receives drilling fluid from the primary shale shaker and discharges smaller drill solids than the primary shaker. The purpose of the primary shaker is to receive the drilling fluid and drill cuttings that return from down hole, and to make the first separation of cuttings from the drilling fluid. The purpose of the secondary shaker is to remove the smaller solid particles that pass through the primary shaker, thereby controlling the buildup of fine solids in the drilling fluid. In some cases, a centrifuge is used in place of the secondary shale shaker, or as a tertiary treatment unit to return more SBF to the active drilling system. Data supplied by API support the assumption that standard solids control systems for wells drilled with SBF most often consist of primary and secondary shale shakers.[3] As discussed in section VII.4.2.2, EPA estimated that the OBF- or SBF-cuttings discharged by a standard solids control system have an average 11% retention of base fluid on a wet weight basis.

The line items in the baseline cost analysis for Gulf of Mexico wells that currently drill with SBF consist of the cost of the currently-required SPP toxicity monitoring test and the cost of SBF lost with the discharged cuttings. The SPP toxicity monitoring test was estimated to cost $575 per test, at a frequency of once per well.[5] The unit cost of SBF lost with discharged cuttings was estimated to be $200 per barrel (bbl) based on current prices for SBFs using internal olefin as the base fluid.[6,7] The volume of SBF adhering to the discharged cuttings, included in Table VII-4 for each model well, is based on the weighted average 11% (wt.) retention value calculated for the baseline solids control system, and varies with the model well size. No other baseline costs (e.g., maintenance or labor costs) were attributed to the operation of solids control equipment that EPA assumes to be standard in all drilling operations.

3.1.3.2 BAT/NSPS Compliance Solids Control Technology Costs

The BAT/NSPS compliance levels of control are based on a solids control technology capable of reducing the retention of drilling fluid on cuttings consistently below that of standard primary shale shakers. The technology is a vibrating centrifuge that receives drill cuttings from the primary shale shaker and removes additional drilling fluid from the cuttings before they are discharged.[8] This unit is an add-on rather than a replacement technology. As discussed in Chapter VII, compared to a primary shale shaker that produces cuttings with an estimated average 10.6% (wt.) of base fluid (either synthetic or oil), the vibrating centrifuge reduces the retention of base fluid to an estimated average 5.14% (wt.). When added to a baseline solids control system, the vibrating centrifuge reduces the system-wide average retention of base fluid on cuttings to 7% (wt.) (see section VII.4.2.2). Although the vibrating centrifuge is not currently in wide-spread use in the U.S. offshore industry, it is a proven technology with widespread use in the North Sea and demonstrated use in the Gulf of Mexico. Domestic interest in this equipment was witnessed by EPA in a recent demonstration of this technology at an offshore drilling operation in the Gulf of Mexico.[7] EPA is also aware of recent efforts on the part of a solids control company that serves the Gulf of Mexico region to develop and market a centrifuge device capable of treating cuttings to low retention values, comparable to the one used in the North Sea.[9]

Line-item BAT/NSPS costs in the discharge option analysis consist of the following:

- <u>Costs associated with the use of an add-on solids control device:</u> The cost of the add-on technology is the daily rental cost for the vibrating centrifuge device, estimated to be

$1,200 per day.[7] The rental cost includes all equipment, labor and materials. The number of rental days was calculated based on the assumption that active drilling days comprise approximately 40% of the time the drilling equipment is onsite.[4] The number of rental days varies with the model well size, ranging from nine to 30 days.

- Cost to retrofit platform space to accommodate the device: The unit retrofit cost was derived from the Offshore Oil and Gas compliance cost analysis in which deck space was estimated to be $250/ft^2.[10] This cost was adjusted to 1997 dollars using the Engineering News Record's Construction Cost Index (ENR CCI) ratio of 1997$/1993$ (1.356), resulting in an updated unit retrofit cost of $340/ft^2.[11] The amount of space required is the sum of the footprints for the vibrating centrifuge (45.7 ft^2), a drilling fluid holding tank (20 ft^2), plus a one-foot perimeter of free space around both footprints (8 ft^2), for a total of 75 ft^2 of retrofit space required.[7,8] Retrofit costs were assigned to all existing sources but not to new sources.

- Value of the SBF discharged with the cuttings: The unit cost of SBF lost with discharged cuttings varies between the geographic areas. In the Gulf of Mexico, the cost is $200 per barrel (bbl).[6,7] The unit cost in California was estimated to be $320/bbl, calculated by multiplying the Gulf of Mexico unit cost by the geographic area cost multiplier for California, 1.6.[12] Geographic area cost multipliers, developed for the Offshore Oil and Gas Rulemaking effort to estimate regional compliance costs, are the ratio of equipment installation costs in a particular area compared to the costs for the same equipment installation in the Gulf of Mexico, whose multiplier is 1.[12] The unit SBF cost in Cook Inlet was estimated to be $400/bbl, based on a multiplier of 2. The multipliers are used here to reflect shipping costs for materials manufactured in the Gulf of Mexico area.

  The volume of SBF adhering to the discharged cuttings, included in Table VII-4, is based on the weighted average 7% (wt.) retention value calculated for the add-on solids control system, and varies with the model well size.

- Cost of performing the waste monitoring analyses: Analytical monitoring costs are included for the proposed test for crude oil contamination of drill cuttings and retort analysis for SBF retention on cuttings. The crude contamination test, estimated to cost $50 per test[13], would be administered once per well. The retort analysis for SBF retention, estimated to cost $50 per test, would be required for each of the two streams of discharged cuttings at a frequency of once per 500 feet of hole drilled.[14] Therefore, the per-well cost of retort monitoring tests varies with model well depth.

3.1.4 Transportation and Onshore Disposal Costs

Costs associated with the transportation and land-based disposal of drill cuttings were estimated for both baseline and BAT/NSPS compliance levels of control. Chapter VII describes the modes of transportation and land disposal technologies currently used by the offshore oil and gas industry. The following sections present the unit costs that comprise the line-items in the transport and land disposal costs.

3.1.4.1 Baseline Transport and Disposal Costs

Wells currently drilled with OBF must either transport OBF-cuttings to shore for disposal at land-based facilities or inject OBF-cuttings on site. As discussed in section VIII.3.1.1, EPA estimated that 112 Gulf of Mexico wells, 12 offshore California wells, and one Cook Inlet well are drilled annually using OBF. The line-item costs in the baseline transport and disposal analysis include the following:

- Supply Boat Costs: In all three geographic areas, drill cuttings are assumed to be transported in supply boats for a day rate of $8,500 per day.[15,16] The number of supply boat days required to transport cuttings to shore was estimated using a methodology developed in the Offshore Oil and Gas Rulemaking effort[17], and varies with model well size and geographic area. Appendix VIII-1 shows the calculation of supply boat transport days for all three geographic areas.

- Trucking Costs: Trucking costs are included as a separate line item for the offshore California and coastal Cook Inlet baselines, while this cost is included as part of the disposal facility cost in the Gulf of Mexico. The California trucking distance was estimated as the distance between a port in the Oxnard/Ventura area and a disposal facility in the vicinity of Bakersfield.[17,18] The trucking rate for California was calculated to be $354 per truckload, based on a 300 mile round trip at 55 mph and $65 per hour.[19] Each truck can carry two 25-bbl cuttings boxes[18], so for example, the number of truckloads required for a DWD model well is 29 (1,442 bbl/50 bbl per truckload). Appendix VIII-1 shows the calculation of truck trips for all three geographic areas.

  Due to the limited availability of land-based disposal facilities in the Cook Inlet area, costs were developed for trucking the cuttings to a facility in Oregon. This approach to zero-discharge cost estimating for Cook Inlet was adopted from the Coastal Oil and Gas Rulemaking effort.[20] The trucking rate for Cook Inlet was calculated to be $1,917 per truckload, updated from the 1995 cost of $1,800 per truckload used in the Coastal guidelines effort[20] using the ENR CCI ratio of 1997$/1995$ (1.065). The $1,800 per truckload was based on a quote provided by a trucking company in Anchorage for hauling wastes from the Kenai, Alaska area to a disposal facility in Arlington, Oregon.[21] Each truck has a capacity of 22 tons[21] and can carry eight 8-bbl cuttings boxes, so that the number of truckloads required for a SWD model well is 15.

- <u>Disposal and Handling Costs</u>: In the Gulf of Mexico, an average unit disposal cost of $10.13/bbl was calculated from current prices provided by two Gulf of Mexico area companies for disposal of OBF cuttings (i.e., $9.50/bbl[22] and 10.75/bbl[23]). This cost is for activities at the disposal facility. An additional waste handling cost of $4.75/bbl was included for dock usage, waste offloading with cranes, and transportation of the wastes from the transfer station to the facility.[22]

  The unit disposal cost for offshore California was calculated to be $12.32/bbl, based on a unit cost of $35/ton[18] and a density of 704 lbs/bbl cuttings (from the model well characteristics presented in VII.4.2.3). Because this disposal cost is close to the per-barrel disposal cost estimated for the Gulf of Mexico, a waste handling cost of $5.79/bbl was added to the unit disposal cost of $12.32/bbl based on the ratio of handling to disposal costs for the Gulf of Mexico (i.e., 0.47).

  The unit disposal cost for drilling wastes generated in coastal Cook Inlet and transported to Oregon was calculated to be $533 per 8-bbl box, updated from the 1995 cost of $500 per cuttings box used in the Coastal guidelines effort[20] using the ENR CCI ratio of 1997$/1995$ (1.065). Because this cost translates to a higher per-barrel disposal cost ($66.63/bbl) than those quoted for facilities in the Gulf of Mexico and California areas, it was assumed that the handling cost was included in the disposal cost and therefore was not added as a separate cost.

- <u>Container Rental Costs</u>: In both the Gulf of Mexico and offshore California, 25-bbl reusable storage boxes are used to transport waste cuttings.[15,17,24] In the Gulf of Mexico, 25-bbl cuttings boxes currently rent for an estimated $25/day.[24,25] The rental rate in California was estimated to be $40/day, calculated by multiplying the Gulf of Mexico rental rate by the geographic area cost multiplier for California, 1.6.[12]

  In coastal Cook Inlet, cuttings boxes hold eight barrels of waste cuttings, must be purchased, and cannot be reused.[20] The purchase price was estimated to be $133/box, updated from the 1995 price of $125/box used in the Coastal guidelines effort[20] using the ENR CCI ratio of 1997$/1995$ (1.065).

  For all three geographic areas, the number of cuttings boxes needed per well varies with model well size. The number of cuttings box rental days was estimated to be equal to the supply boat transport days. Appendix VIII-1 shows the calculation of the supply boat transport days for all three areas.

- Value of the OBF disposed with the cuttings: In the baseline analysis, EPA assumed that cuttings transported to shore for disposal would first be treated onsite by the baseline solids control technology to an estimated 11% (wt.) retention of OBF on the disposed cuttings. The unit cost of OBF was estimated to be $75/bbl for OBF wells in the Gulf of Mexico[6], adjusted to $120/bbl for offshore California and $150/bbl for coastal Cook Inlet using their respective geographic area multipliers 1.6 and 2.0.[12] The volume of OBF adhering to the disposed cuttings, included in Table VII-4, varies with the model well size.

3.1.4.2 BAT/NSPS Transport and Disposal Costs

Based on information provided by the industry, EPA assumed that all Gulf of Mexico deep water wells would use SBF regardless of the level of regulatory control placed on the discharged cuttings, due to the potential for riser disconnect and the spill of drilling fluid.[26,27] Therefore, in the zero discharge option, EPA assumed that deep water wells would incur the cost of lost SBF, rather than OBF, with the disposed cuttings. The unit cost of SBF lost with disposed cuttings was estimated to be $200/bbl.[6,7] Other than this line-item cost for deep water wells, zero discharge option compliance costs are the same as the baseline zero discharge costs described above in section VIII.3.1.4.1.

3.1.5 Onsite Grinding and Injection Costs

Costs associated with onsite grinding and injection of drill cuttings were estimated for both baseline and BAT/NSPS compliance levels of control. As discussed in section VII.5.5, only Gulf of Mexico operators currently employ onsite injection, although it has been tried recently in both offshore California and coastal Cook Inlet.[25] Based on information provided by industry sources, EPA estimated that 20% of the wells that currently practice zero discharge in the Gulf of Mexico do so by onsite injection.[25] Preliminary information gathered regarding the use of onsite injection in the Gulf of Mexico is inconsistent between sources, ranging from an estimated 10% of zero discharge wells to as much as 67%.[25] Additional information indicates that, while some operators have expressed concern over uncertainties related to injection (e.g., the ultimate fate of the injected wastes and the costs associated with unsuccessful injection projects), interest in onsite injection has increased throughout the industry since the time of the Offshore Oil and Gas Rulemaking effort, and continues to grow.[25,28] Chapter VII describes the injection technology currently used by the offshore oil and gas industry.

The line-item and unit costs associated with onsite injection are identical for the baseline and BAT/NSPS compliance cost analyses. Line-item costs include the day rate rental cost for a turnkey injection system and the value of lost drilling fluid, all in the Gulf of Mexico geographic area. The injection system cost of $4,280 per day includes all equipment, labor, and associated services.[29] The rental days for injection equipment were calculated by the same method used for rental of the add-on vibrating centrifuge (see section VIII.3.1.3.2), based on the assumption that active drilling days comprise approximately 40% of the time the drilling equipment is onsite.[4] The number of rental days varies with the model well size, ranging from nine to 30 days. The unit cost of drilling fluid injected with the cuttings was $75/bbl[6] for the wells that EPA assumed would convert to OBF under the zero discharge option, and $200/bbl for the wells that EPA assumed would continue to use SBF under the zero discharge option.[6,7]

3.2 DETAILED ANALYSES OF COMPLIANCE COST OPTIONS

EPA first estimated baseline costs from current industry waste management practices, and then estimated the cost to comply with each regulatory option. EPA then calculated the incremental compliance costs, or the difference between baseline and compliance costs. Tables VIII-2 and VIII-3 list, for existing and new sources respectively, the total annual baseline, compliance, and incremental compliance costs calculated for each geographic area for both regulatory options.

The compliance cost analysis was a step-wise process that began with the development of a framework of “in-scope” wells that defined the well populations for each segment of the

TABLE VIII-2

SUMMARY ANNUAL BASELINE, COMPLIANCE, AND INCREMENTAL COMPLIANCE COSTS FOR MANAGEMENT OF SBF-CUTTINGS FROM EXISTING SOURCES (1997$/year)

Technology Basis	Gulf of Mexico	Offshore California	Cook Inlet, Alaska	Total
Baseline Costs				
Discharge with 11% retention of base fluid on cuttings	$19,113,650	NA	NA	$19,113,650
Zero Discharge (current OBF-drilled wells only)	$2,821,816	$2,157,023	$207,733	$5,186,572
Total Baseline Costs per Area	$21,935,466	$2,157,023	$207,733	$24,300,222
Compliance Costs				
Discharge with 7% retention of base fluid on cuttings	$15,590,550	$1,647,883	$115,467	$17,713,900
Zero Discharge via land disposal or on-site injection	$26,077,546	$0	$0	$26,077,546
Incremental Compliance Costs (Savings)				
Discharge Option Costs	($5,984,916)	($509,140)	($92,265)	($6,586,322)
Zero Discharge Option	$6,963,896	$0	$0	$6,963,896

analysis.   As discussed in section VIII.3.1.1 above, the wells that incur costs or realize savings in the compliance cost analysis are a subset of the total population of wells that EPA identified as being drilled annually in the three geographic areas. Table VIII-4 shows the numbers of wells, per model well, that EPA identified as in-scope for the cost analysis, shown separately for existing and new sources.

TABLE VIII-3

SUMMARY ANNUAL BASELINE, COMPLIANCE, AND INCREMENTAL COMPLIANCE COSTS FOR MANAGEMENT OF SBF-CUTTINGS FROM NEW SOURCES (1997$/year)

	Technology Basis	Costs (Savings)
Baseline Costs	Discharge with 11% retention of base fluid on cuttings	$2,201,725
NSPS Compliance Costs	Discharge with 7% retention of base fluid on cuttings	$1,632,125
	Zero Discharge via land disposal or on-site injection	$3,796,143
Incremental NSPS Compliance Costs	Discharge with 7% retention of base fluid on cuttings	($619,475)[a]
	Zero Discharge via land disposal or on-site injection	$1,594,418

[a]This number is slightly higher than the corresponding number ($569,600) in the *Federal Register* notice for this proposed regulation because the results from the last revision were inadvertently excluded from the *Federal Register* notice.

The next step of the analysis was the calculation of per-well costs developed from the line-item costs detailed in section VIII.3.1 above. Referring to Table VIII-4, each box in the table represents a set of wells for which a distinct per-well cost was calculated based on the line-items appropriate to each set. The per-well costs were then multiplied by the number of wells in each set, the results of which were then combined to calculate the industry-wide baseline, compliance, and incremental compliance costs. Appendix VIII-2 consists of the detailed worksheets that calculate the per-well costs, organized as follows:

TABLE VIII-4

ESTIMATED NUMBER OF IN-SCOPE WELLS DRILLED ANNUALLY[a]

Cost Analysis Framework	Shallow Water (<1,000 ft)		Deep Water (≥ 1,000 ft)		TOTAL WELLS
	Develop.	Explor.	Develop.	Explor.	
Gulf of Mexico: Existing Sources					
Baseline SBF Wells[b]	12	7	18	57	94
Baseline OBF Wells[c]	15	8	0	0	23
Discharge Option SBF Wells[d]	27	15	18	57	117
Discharge Option OBF Wells[d]	0	0	0	0	0
Zero Discharge Option SBF Wells[e]	0	0	18	57	75
Zero Discharge Option OBF Wells[e]	12	7	0	0	19
Gulf of Mexico: New Sources[f]					
Baseline SBF Wells[b]	1	0	18	0	19
Discharge Option SBF Wells[d]	1	0	18	0	19
Zero Discharge Option SBF Wells[e]	1	0	18	0	19
Offshore California: Existing Sources[g]					
Baseline OBF Wells[c]	1	0	11	0	12
Discharge Option SBF Wells[d]	1	0	11	0	12
Coastal Cook Inlet: Existing Sources[g]					
Baseline OBF Wells[c]	1	0	0	0	1
Discharge Option SBF Wells[d]	1	0	0	0	1

[a] The numbers in this table are a subset of the estimated number of wells drilled annually, shown in Table IV-2.

[b] The sum of the existing and new source baseline SBF wells is 113, the number of wells EPA estimates is drilled annually using SBF (see section IV.3.1).

[c] EPA estimates that 20% of the 112 wells currently drilled using OBF in the Gulf of Mexico and all OBF wells in offshore California and coastal Cook Inlet will convert to SBF use under the discharge option (see section VIII.3.1.1).

[d] All baseline wells are included in the discharge option.

[e] Only baseline SBF wells are included in the zero discharge option. EPA assumes that all baseline shallow-water SBF wells will convert to OBF for economic reasons, and that all baseline deep-water wells will continue to use SBF for technical reasons (see section VIII.3.2.2.1). No baseline OBF wells are included in the zero discharge option because current practice for these wells is zero discharge.

[f] Of the 13 SWD wells drilled annually in the Gulf of Mexico, EPA estimates that 5% or 1 well is a “new source” well, and of the 36 DWD wells drilled annually, 50% or 18 wells are “new source” wells (see section VIII.3.2.3).

[g] EPA estimates that no “new source” wells will be drilled in offshore California and coastal Cook Inlet (see section VIII.3.2.3).

Worksheets 1 through 3: Baseline costs for the Gulf of Mexico, offshore California, and coastal Cook Inlet, respectively.

Worksheets 4 through 6: Discharge option costs for the three geographic areas (in the same order as Worksheets 1-3).

Worksheets 7 through 9: Zero discharge option costs for transport and land-disposal, onsite injection, and the weighted average costs, respectively.

The following sections describe the development of the per-well costs and the calculations used for each regulatory option.

3.2.1 Discharge Option Compliance Costs

3.2.1.1 Baseline Discharge Option Costs

The baseline analysis for the discharge option consisted of all baseline wells listed in Table VIII-4, including both SBF and OBF wells. Worksheets 1, 2, and 3 in Appendix VIII-2 show the detailed calculations of the per-well and area-wide baseline costs for the Gulf of Mexico, offshore California, and coastal Cook Inlet, respectively. For baseline SBF wells in the Gulf of Mexico, the line-item costs for discharge following solids control to an average 11% (wt.) retention of synthetic base fluid (section VIII.3.1.3.1) were added to calculate the per-well costs, which range from $78,175 for a SWD well to $261,575 for a DWE well. As in all other per-well calculations, the per-well costs vary proportionately with the volume of waste generated per model well. However, on a per-well basis, the baseline cost is the same for all model wells in the Gulf of Mexico. The unit baseline cost for all wells that currently use SBF is $82 per barrel of SBF-cuttings discharged.

Costs for baseline OBF wells in the Gulf of Mexico were calculated based on the assumption that 80% of these wells transport cuttings to shore for disposal, and 20% inject cuttings onsite.[25] For each of the two baseline shallow-water OBF wells, per-well costs were calculated for transport and disposal and for injection. Then for each model well, a weighted average per-well cost was calculated as follows:

Baseline GOM OBF Well Cost = (0.8 x Per-Well Transport & Disposal Cost) + (0.2 x Per-Well Injection Cost)

The per-well costs for baseline OBF wells in the Gulf of Mexico are $91,355 for a SWD well and $181,437 for a SWE well. The unit baseline costs for these wells are $96 and $91 per barrel of OBF-cuttings disposed, respectively. The total annual discharge option baseline cost for the Gulf of Mexico is $22 MM (see Table VIII-2).

As stated in section VIII.3.1.4.1, the baseline costs for OBF wells in offshore California and coastal Cook Inlet are for transport and disposal of OBF-cuttings. The per-well baseline costs for offshore California are $184,725 for a DWD well and $125,046 for a SWD well. The unit baseline costs for these wells are $128 and $131 per barrel of OBF-cuttings disposed, respectively. The per-well baseline cost for coastal Cook Inlet is $207,733 for a SWD well, with a corresponding unit cost of $218 per barrel of OBF-cuttings disposed. The per-well costs for these areas differ from the Gulf of Mexico transport and disposal costs due to comparatively higher costs of some line items in these areas (see section VIII.3.1.4.1). For example, the per-well cost to transport and dispose cuttings from a SWD well in the Gulf of Mexico is $97,288, while the per-well disposal cost for the same model well in offshore California is $125,046. The total annual baseline costs for offshore California and Cook Inlet are $2.2 MM and $0.2 MM, respectively, and the total industry-wide baseline cost is $24 MM (see Table VIII-2).

3.2.1.2 BAT Discharge Option Compliance Costs

The discharge option compliance cost analysis estimates the cost to discharge SBF-cuttings following secondary treatment by a solids control device that, when added on to other standard solids control equipment, reduces the average retention from 11% to 7% base fluid on wet cuttings. Worksheets 4, 5, and 6 in Appendix VIII-2 present the detailed calculations of the per-well and area-wide discharge option compliance costs for the Gulf of Mexico, offshore

California, and coastal Cook Inlet, respectively.

In the Gulf of Mexico, the per-well discharge compliance costs for wells currently drilled with SBF range from $60,673 to $191,073 across the four model wells. Worksheet 4 of Appendix VIII-2 shows unit costs for the Gulf of Mexico wells ranging from $72 to $77 per barrel of SBF-cuttings discharged. The total annual discharge compliance cost for Gulf of Mexico wells is $16 MM (see Table VIII-2).

The line-item discharge compliance costs for offshore California and coastal Cook Inlet are the same as those estimated for the Gulf of Mexico adjusted higher using geographic area multipliers (see section VIII.3.1.3.2). The per-well discharge compliance costs for offshore California wells are $141,067 for a DWD well and $96,147 for a SWD well, with corresponding unit costs of $118 and $122 per barrel of SBF-cuttings discharged. The per-well discharge compliance cost for coastal Cook Inlet is $115,467 for a SWD well, with a unit cost of $147 per barrel of SBF-cuttings discharged. The total annual discharge option compliance costs for offshore California and Cook Inlet are $1.6 MM and $0.1 MM, respectively, and the total annual industry-wide compliance cost for the discharge option is $17.7 MM, as shown in Table VIII-2.

3.2.1.3 Incremental BAT Discharge Option Compliance Costs

The incremental cost is the difference between the baseline and the compliance cost, as presented in Table VIII-2. The two components of the incremental costs are 1) the costs associated with the compliance technology and 2) the value of the drilling fluid discharged with the cuttings. Table VIII-5 shows the incremental compliance costs for the discharge option separated into technology costs and drilling fluid costs. The overriding factor in the Gulf of Mexico incremental discharge option cost is that, according to EPA analysis of baseline SBF wells, the value of the recovered SBF, at $8.1 MM, is $5.0 MM greater than the $3.1 MM cost of implementing the vibrating centrifuge model technology. Therefore, for baseline SBF wells in the Gulf of Mexico, a net savings of $5.0 MM results from the discharge option. For baseline

TABLE VIII-5

DETAILED INCREMENTAL BAT DISCHARGE OPTION COMPLIANCE COSTS (1997$/year)

Wells by Drilling Fluid	Cost Item	Gulf of Mexico	Offshore California	Coastal Cook Inlet
Baseline SBF Wells	Add-on Discharge Technology	$3,102,419	NA	NA
	Drilling Fluid	($8,149,000)	NA	NA
	Net Incremental Cost	($5,046,581)	NA	NA
Baseline OBF Wells (assumed to convert to SBF under the discharge option)	Conversion from Zero Discharge to Discharge Technology	($1,425,635)	($941,500)	($122,865)
	Drilling Fluid (conversion from OBF to SBF)	$487,300	($432,360)	$30,600
	Net Incremental Cost	($938,335)	($509,140)	($92,265)
All In-scope Discharge Option Wells	**TOTAL Incremental Discharge Option Costs**	**($5,984,916)**	**($509,140)**	**($92,265)**

OBF wells that EPA assumed would convert to SBF in the discharge option, the cost of losing SBF with the discharged cuttings ($0.49 MM cost) is overshadowed by the savings realized as these wells move from baseline zero discharge technology to the model discharge technology ($1.43 MM savings). The net savings for baseline OBF wells in the discharge option is $0.94 MM in the Gulf of Mexico. Combining these two savings gives a total savings (negative net incremental discharge compliance cost) of $6.0 MM for Gulf of Mexico wells in the discharge option.

Incremental discharge option costs for offshore California and coastal Cook Inlet include savings incurred as wells move from the zero discharge baseline to discharge, and increased cost of SBF over the baseline OBF cost. For both of these areas, the net incremental discharge compliance cost is negative, resulting in savings of $509 K for offshore California and $92 K for coastal Cook Inlet. Combining these savings with the $6.0 MM for Gulf of Mexico wells gives a total annual incremental discharge option compliance cost savings of $6.6 MM.

For comparison purposes, two additional discharge option compliance cost analyses were performed in which the fraction of current Gulf of Mexico shallow water OBF wells that are assumed to convert to SBF was varied.[30,31] In the analysis presented above, this fraction is 20%, based on information provided by industry sources.[1] Due to the uncertainty of predicting future industry activity, the Agency investigated the range of discharge option compliance costs that would result assuming that either zero% or 100% of these wells would convert to SBF use. The "zero% convert" analysis resulted in an annual incremental cost savings of $5.6 MM industry wide, and the "100% convert" analysis resulted in an annual incremental savings of $10.2 MM. The savings for the "20% convert" analysis falls between these values, at $6.6 MM. Thus, regardless of the number of wells assumed to convert from OBF to SBF, the discharge option results in industry-wide incremental cost savings.

3.2.2 Zero Discharge Option Compliance Costs

3.2.2.1 Baseline Zero Discharge Option Costs

The zero discharge option compliance cost analysis includes Gulf of Mexico wells identified as currently being drilled with SBF. The wells included in the offshore California and coastal Cook Inlet analyses, and the wells currently drilled with OBF in the Gulf of Mexico do not incur costs in the zero discharge option because they are at zero discharge in the baseline. Furthermore, the population of wells currently drilled with SBF is divided into those that are assumed to continue using SBF under zero discharge requirements due to technical concerns (i.e., potential spills as a result of riser disconnect in the deep water), and those that would convert to OBF under zero discharge requirements to use a less expensive drilling fluid. This division is shown in Table VIII–4.

The $19 MM baseline cost for the zero discharge option is the sum of the per-well baseline costs for the four model wells that currently use SBF multiplied by the corresponding number of in-scope wells from Table VIII-4. The per-well baseline costs for SBF wells are the same as those described above in section VIII.3.2.1.1. The detailed calculation of these per-well baseline costs is shown in Worksheet 1 of Appendix VIII-2.

3.2.2.2 BAT Zero Discharge Option Costs

Per-well zero discharge compliance costs incorporate the assumption that, of all zero discharge cuttings generated in the Gulf of Mexico, 80% is hauled to shore for land-based disposal and 20% is injected on-site (see also section VIII.3.1.5).[25]

Worksheets 7, 8, and 9 in Appendix VIII-2 present the calculation of per-well BAT zero discharge costs. Worksheet 7 shows the per-well costs for transporting cuttings to land-based disposal, Worksheet 8 shows injection costs, and Worksheet 9 calculates the weighted average per-well costs using the equation presented in section VIII.3.2.1.1 above. The weighted average per-well costs for zero discharge range from $91,355 for a SWD well to $350,990 for a DWE well. The weighted average unit costs range from $91 per barrel of OBF-cuttings disposed for a SWE well to $143 per barrel of SBF-cuttings disposed for a DWD well. The total annual zero discharge compliance cost resulting from this analysis is $26 MM (see Table VIII-2).

3.2.2.3 Incremental Zero Discharge Option Costs

The positive incremental costs under the zero discharge option (total annual = $7.0 MM) are the costs that Gulf of Mexico baseline SBF wells would incur moving from discharge to zero discharge (see Table VIII-2).

3.2.3 NSPS Compliance Cost Analysis

Table VIII-3 lists the summary results for the NSPS cost analysis. As shown in Table VIII-4, EPA assumed that new source wells are located only in the Gulf of Mexico because of the lack of activity in new lease blocks in offshore California and coastal Cook Inlet. New source wells are defined in the offshore guidelines, 40 CFR 435.11(q), and exclude exploratory wells by definition.[12,20] EPA estimated that 50% of the DWD wells in the Gulf of Mexico would be new sources because of the rapid expansion in the deep water areas. Because of the slower expansion in Gulf of Mexico shallow water areas, EPA estimated that 5% of SWD wells would be new sources.

The NSPS cost analysis consists of the same line-item costs as in the analysis for existing sources, with the exception that retrofit (for the add-on discharge technology) is not necessary on new platforms. The baseline for NSPS costs differs from the baseline for existing sources in that it includes only SBF wells that discharge cuttings and does not include any OBF wells practicing zero discharge. Appendix VIII-3 includes five worksheets that present the baseline costs (Worksheet 1), the discharge option costs (Worksheet 2), and the zero discharge option costs (Worksheets 3, 4, and 5) for new source wells. The per-well baseline costs for the NSPS wells are $117,975 for a DWD well and $78,175 for a SWD well, with a unit cost of $82 per barrel of SBF-cuttings discharged for both wells. The total NSPS baseline cost is $2.2 MM.

The discharge option per-well costs for NSPS wells are $84,750 for DWD wells and $56,750 for SWD wells, with corresponding unit costs of $71 and $72 per barrel of SBF-cuttings discharged. The total NSPS discharge option cost is $1.6 MM. The incremental NSPS compliance cost for the discharge option ($1.6 MM minus $2.2 MM) is $-0.57 MM, or a savings of $570,000.

The weighted average per-well costs for the zero discharge option, in which 80% of the costs represent disposal via land disposal and 20% represent on-site injection, are $205,822 for

DWD wells and $91,355 for SWD wells, with corresponding unit costs of $143 per barrel of SBF-cuttings disposed and $96 per barrel of OBF-cuttings disposed. The total NSPS zero discharge cost is $3.8 MM. The incremental NSPS cost for the zero discharge option ($3.8 MM minus $2.2 MM) is $1.6 MM.

4.0 POLLUTANT REDUCTIONS

The methodology for estimating pollutant loadings and incremental pollutant reductions effectively parallels that of the compliance cost analysis. The pollutant reduction analysis is based on the size and number of the four model wells identified in Table VIII-4, as well as pollutant characteristics of the cuttings wastestream compiled from previous rulemaking efforts and from industry sources. The following sections describe first the estimates and input data on which the pollutant reductions analysis is based, followed by a detailed discussion of the methodology used to calculate the annual incremental reductions for both BAT and NSPS levels of regulatory control.

4.1 DATA AND ESTIMATES USED TO GENERATE POLLUTANT REDUCTIONS

To calculate per-well pollutant loadings and incremental pollutant reductions, EPA characterized the cuttings wastestream in terms of pollutant concentrations. The pollutant concentrations derive from three sources: mineral oil-based drilling fluid or internal olefin synthetic-based drilling fluid, drill cuttings, and formation oil. Sections VII.3.1, VII.3.2 and VII.3.3 of this document present detailed discussions of the characteristics of these sources that EPA considered in its analysis of pollutant loadings and reductions. Table VII-1 lists the pollutant concentrations that EPA used to calculate pollutant loadings.

In addition to pollutant concentrations, EPA estimated per-well waste volumes, as presented in section VII.4.2.3. For each model well, two sets of calculations were developed, at 11% and 7% retentions, to determine the per-well volumes of mineral oil or synthetic base fluid, water, barite, dry cuttings and formation oil in the wastestream. Table VII-4 lists the specific waste volumes EPA calculated for the four model wells.

The general assumptions EPA used to develop model waste volumes and pollutant concentrations are summarized as follows:

- Model drilling waste volumes are based on four model wells, as shown in Table VII-4.
- Total hole volume equals gage hole plus 7.5% additional volume due to washout (see section VII.4.2.1).
- There is no difference in the performance of OBF and SBF with regard to solids separation processes (see section VII.5.2).
- Model formulation for SBFs and OBFs is 47% (wt.) base fluid, 33% (wt.) solids, 20% (wt.) water, and this formulation remains constant throughout the solids control system (see section VII.3.1).
- All solids in a model drilling fluid are barite (see section VII.3.1).
- Model drilling waste components are drilling fluid (SBF or OBF), dry cuttings, and 0.2% (vol.) formation oil (see section VII.3.3).
- Model retention values for drilling fluid on cuttings is 11% for baseline wells and 7% for discharge option wells (see section VIII.4.2.2).

4.2 INCREMENTAL POLLUTANT REDUCTIONS METHODOLOGY

The waste volume estimates listed in Table VII-4 were multiplied by the pollutant concentrations in Table VII-1 to determine the per-well pollutant loadings. As in the compliance cost analysis, the per-well values were then multiplied by the numbers of wells in each option and each geographic area, as listed in Table VIII-4, to determine the total industry-wide pollutant loadings. Incremental pollutant reductions were then calculated as the difference between baseline loadings and compliance loadings. Appendix VIII-4 consists of the detailed worksheets that calculate the per-well loadings and reductions, organized as follows:

Worksheets 1 through 4: Baseline loadings for DWD, DWE, SWD, and SWE wells, respectively.

Worksheets 5 through 8: Discharge option loadings and incremental reductions for the four model wells (in the same order as Worksheets 1-4).

Worksheets 9 through 12: Zero discharge option loadings and incremental reductions for the four model wells (in the same order as Worksheets 1-4).

All worksheets mentioned in the following text are from Appendix VIII-4.

The per-well loadings and reductions in Appendix VIII-4 were then multiplied by the corresponding numbers of in-scope wells from Table VIII-4. Table VIII-6 presents the industry-wide results in terms of baseline loadings, compliance loadings, and incremental reductions, for both the discharge and zero discharge options, discussed below.

4.2.1 BAT Baseline Pollutant Loadings

As in the compliance cost analysis, EPA established a BAT baseline by calculating pollutant loadings for the baseline wells identified as in-scope in Table VIII-4. For wells that currently discharge (baseline SBF wells), baseline pollutant loadings were calculated assuming the current practice of treating cuttings to 11% retention (see section VIII.3.1.3.1). The total baseline loading for SBF wells is 159 MM lbs (see Table VIII-6). Baseline OBF wells in offshore California, coastal Cook Inlet, and the Gulf of Mexico all have baseline loadings of zero because OBF wells meet zero discharge requirements.

4.2.2 BAT Discharge Option Pollutant Reductions

In addition to baseline loadings, EPA calculated pollutant loadings resulting from compliance with the discharge option add-on technology (see section VIII.3.1.3.2). In the Gulf of Mexico, discharge option loadings are measured from two baselines: 1) SBF wells that move

TABLE VIII-6

SUMMARY ANNUAL POLLUTANT LOADINGS AND INCREMENTAL REDUCTIONS FOR MANAGEMENT OF SBF CUTTINGS FROM EXISTING SOURCES (lbs/year)

	Gulf of Mexico	Offshore California	Cook Inlet, Alaska	Total
Baseline Technology Loadings				
Discharge with 11% retention of base fluid on cuttings	159,103,752	NA	NA	159,103,752
Zero Discharge via land disposal or on-site injection	0	0	0	0
Compliance Option Loadings				
Discharge with 7% retention of base fluid on cuttings	163,851,174	10,420,876	590,550	174,862,600
Zero Discharge via land disposal or on-site injection	0	0	0	0
Incremental Pollutant Reductions (Loadings)				
Discharge with 7% retention of base fluid on cuttings	(4,747,422)	(10,420,876)	(590,550)	(15,758,848)
Zero Discharge via land disposal or on-site injection	159,103,752	0	0	159,103,752

from 11% to 7% retention and 2) OBF wells that move from zero discharge to discharge at 7% retention. The total annual discharge option loading for the Gulf of Mexico, shown in Table VIII-6 as 164 MM lbs, resulted from the per-well loadings in Worksheets 5 through 8 multiplied by the numbers of corresponding “discharge option SBF wells” listed in Table VIII-4. Likewise, the per-well loadings in Worksheets 5 through 8 were multiplied by the numbers of “discharge option SBF wells” in offshore California and coastal Cook Inlet for the respective total annual loadings of 10.4 MM lbs and 0.6 MM lbs (see Table VIII-6).

The incremental pollutant reductions were calculated by subtracting the compliance loadings from the baseline loadings. For all three geographic areas, the discharge option compliance loadings are greater than the baseline loadings, resulting in incremental increases. These increases are indicated in Table VIII-6 as negative pollutant reductions. However, EPA projects that only the discharge of dry cuttings will increase, while the amounts of discharged synthetic drilling fluid and formation oil will decrease. The results of the incremental analysis broken out by pollutant source are as follows:

SBF base fluid and barite: Discharges decreased by 10,142,406 lbs
Formation oil: Discharges decreased by 17,366 lbs
Dry cuttings: Discharges increased by 25,918,620 lbs.

This yields a net increase of 15.8 MM lbs discharged annually, due to the increased amount of drill cuttings discharged from OBF wells that convert to SBF wells (see Table VIII-6).

As stated in section VIII.3.2.1.3, EPA investigated the range of incremental compliance costs and pollutant reductions that result assuming that, in the discharge option, either zero% or 100% of current OBF wells convert to SBF. The analysis above is based on 20% of the OBF wells converting to SBF. The "zero% convert" analysis resulted in an annual incremental pollutant reduction of 3 MM lbs industry wide, and the "100% convert" analysis resulted in an incremental increase of 89 MM lbs per year.[32,33] The increased discharges for the "20% convert" analysis fall between these values, at 15.8 MM lbs (see Table VIII-6). In the 100% convert scenario, the 89 MM lbs consists of 76 MM lbs of dry cuttings and 13 MM lbs of associated SBFs.

4.2.3 BAT Zero Discharge Option Pollutant Reductions

As shown in Table VIII-6, the pollutant loadings for compliance with the zero discharge option are zero. The incremental pollutant reduction is the difference between the baseline loading of currently discharging SBF wells at 11% retention and the loading of zero at zero discharge. Table VIII-6 shows the annual incremental pollutant reduction for the zero discharge option is 159 MM lbs.

4.2.4 NSPS Pollutant Reductions Analysis

The method of estimating pollutant loadings and reductions for new sources is the same as described above for existing sources. As shown in Table VIII-4, EPA estimated that 19 new sources wells are drilled in the Gulf of Mexico annually. Table VIII-7 shows the baseline loadings, compliance loadings, and incremental compliance pollutant reductions for new source wells. In this analysis, there are incremental pollutant reductions for both the discharge option and the zero discharge option because all new source wells move from a baseline of discharge at an average 11% retention of synthetic base fluid on cuttings to discharge at 7% retention under the discharge option or to zero discharge under the zero discharge option. No OBF wells are in the NSPS baseline, so no wells incur pollutant discharge increases. The total annual NSPS incremental pollutant reduction for the discharge option is 1.6 MM lbs, consisting of approximately 1.6 MM lbs of SBF and a small amount (2,800 lbs) of formation oil. The annual NSPS incremental reduction for the zero discharge option is 18.3 MM lbs.

5.0 BCT COMPLIANCE COSTS AND POLLUTANT REDUCTIONS

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 preferred discharge option 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 VIII-7

SUMMARY ANNUAL POLLUTANT LOADINGS AND INCREMENTAL REDUCTIONS FOR MANAGEMENT OF SBF CUTTINGS FROM NEW SOURCES (lbs/year)

	Technology Basis	Loadings/Reductions
Baseline Loadings	Discharge with 11% retention of base fluid on cuttings	18,286,914
NSPS Pollutant Loadings	Discharge with 7% retention of base fluid on cuttings	16,676,538
	Zero Discharge via land disposal or on-site injection	0
Incremental NSPS Pollutant Reductions	Discharge with 7% retention of base fluid on cuttings	1,610,394
	Zero Discharge via land disposal or on-site injection	18,286,914

6.0 REFERENCES

1. Daly, Joseph, U.S. EPA, Memorandum regarding "Phone Conversations Regarding Number of Wells Likely to Switch from Using OBF to SBF Post SBF Effluent Guidelines," October 28, 1998.

2. The Pechan-Avanti Group, Worksheet regarding "Number of Days to Drill Model SBF Wells," October 27, 1998.

3. Annis, Max R., "Retention of Synthetic-Based Drilling Material on Cuttings Discharged to the Gulf Of Mexico," prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 29, 1997.

4. Daly, Joseph, U.S. EPA, Memorandum regarding "October 13, 1998 Teleconference Regarding SBF Use," October 20, 1998.

5. Montgomery, Richard, The Pechan-Avanti Group, Telecommunication report on conversation with David Daniel, Environmental Enterprises, regarding "Cost Associated with Drilling Fluid Regulatory Options," October 15, 1998.

6. Daly, Joseph, U.S. EPA, Memorandum regarding "Cost of Synthetic-Based Drilling Fluids (SBF)," January 15, 1999.

7. The Pechan-Avanti Group, "Demonstration of the 'Mud 10' Drilling Fluid Recovery Device at the Amoco Marlin Deepwater Drill Site," August 7, 1998.

8. Mud Recovery Systems, Ltd., Product brochure entitled "M.U.D. 10 and M.U.D. 6 Mud Recovery and Cuttings Cleaning System," undated.

9. McIntyre, Jamie, Avanti Corporation, Telephone Communication Report on conversation with Peter Matthews, Newpark Drilling Fluids, regarding "'Centrifugal Dryer' for Drill Cuttings," May 29, 1998.

10. Science Applications International Corporation, "Final: Offshore Oil and Gas Industry: Analysis of the Cost and Pollutant Removal Estimates for the BCT, BAT, and NSPS Options for the Drill Cuttings and Drilling Fluid Streams," submitted to the U.S. Environmental Protection Agency, Engineering and Analysis Division, January 13, 1993.

11. Engineering News Record, "Construction Cost Index History (1908-1997)," website address http://www.enr.com/cost/costcci.htm, June 8, 1998.

12. U.S. Environmental Protection Agency, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, Final, EPA 821-R-93-003, January 1993.

13. McIntyre, Jamie, The Pechan-Avanti Group, Telecommunication Report on conversation with John Candler, M-I Drilling Fluids, regarding “Cost Estimates for Proposed RPE Method,” October 16, 1998.

14. Annis, Max R., “Procedures for Sampling and Testing Cuttings Discharged While Drilling with Synthetic-Based Muds,” prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 19, 1998.

15. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with John Belsome, Seabulk Offshore Ltd., regarding “Offshore supply boat costs and specifications,” June 3, 1998.

16. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with George Bano, Sea Mar Management, regarding “Offshore supply boat costs and specifications,” June 3, 1998.

17. Carriere, J. and E. Lee, Walk, Haydel and Associates, Inc., “Water-Based Drilling Fluids and Cuttings Disposal Study Update,” Offshore Effluent Guidelines Comments Research Fund Administered by Liskow and Lewis, January 1989.

18. McIntyre, Jamie, The Pechan-Avanti Group, Telecommunications Report on conversation with Darron Stankey, McKittrick Solid Waste Disposal Facility, regarding “California Prices for Land Disposal of Drilling Wastes,” October 16,1998.

19. Montgomery, Richard, The Pechan-Avanti Group, Telecommunication Report on conversation with Shane Morgan, Ecology Control Incorporated, regarding “costs associated with land and water transport of drill cuttings and drilling fluids for offshore oil platforms operating off the California coast,” May 9, 1998.

20. U.S. Environmental Protection Agency, Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-96-023, October 1996.

21. McIntyre, Jamie, SAIC, Telecon on conversation with Josh Stenson, Carlisle Trucking, regarding “Costs to Truck Wastes from Kenai, Alaska to Arlington, Oregon,” May 23, 1995.

22. Newpark Environmental Services, Facsimile of Price List, Effective May 1, 1998, from Lisa L. Denman to Kerri Kennedy, May 26, 1998.

23. U.S. Liquids of Louisiana, Facsimile of Price List, from “Betty” to Jamie McIntyre, May 26, 1998.

24. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with personnel at Frances Torque Service, regarding “Cuttings box rental costs (Gulf of Mexico area),” June 4, 1998.

25. Veil, John A., Argonne National Laboratory, Washington, D.C., “Data Summary of Offshore Drilling Waste Disposal Practices,” prepared for the U.S. Environmental Protection Agency, Engineering and Analysis Division, and the U.S. Department of Energy, Office of Fossil Energy, November 1998.

26. American Petroleum Institute, responses to EPA’s “Technical Questions for Oil and Gas Exploration and Production Industry Representatives,” attached to e-mail sent by Mike Parker, Exxon Company, U.S.A., to Joseph Daly, U.S. EPA, August 7, 1998.

27. Daly, Joseph, U.S. EPA, Memorandum regarding “May 8-9, 1997, Meeting in Houston, Texas-Inception of Industry/Stakeholder Work Groups to Address Issues of Discharges Associated with Synthetic-Based Drilling Fluids (SBF),” January 14, 1999.

28. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with Mike Singler, National Injection Services, regarding “NIS Drilling Waste Zero Discharge Technology and Costs,” May 11, 1998.

29. The Pechan-Avanti Group, Worksheet regarding “Calculation of Daily Onsite Injection Cost, October 30, 1998.

30. The Pechan-Avanti Group, “BAT Compliance Cost Analysis: ‘0% OBF Wells Convert’ Scenario,” prepared for Joseph Daly, U.S. EPA, Office of Water, Engineering and Analysis Division, January 21, 1999.

31. The Pechan-Avanti Group, “BAT Compliance Cost Analysis: ‘100% OBF Wells Convert’ Scenario,” prepared for Joseph Daly, U.S. EPA, Office of Water, Engineering and Analysis Division, January 21, 1999.

32. The Pechan-Avanti Group, “BAT Pollutant Reductions Analysis: ‘0% OBF Wells Convert’ Scenario,” prepared for Joseph Daly, U.S. EPA, Office of Water, Engineering and Analysis Division, January 20, 1999.

33. The Pechan-Avanti Group, “BAT Compliance Cost Analysis: ‘100% OBF Wells Convert’ Scenario,” prepared for Joseph Daly, U.S. EPA, Office of Water, Engineering and Analysis Division, January 20, 1999.

CHAPTER IX

NON-WATER QUALITY ENVIRONMENTAL IMPACTS AND OTHER FACTORS

1.0 INTRODUCTION

The elimination or reduction of one form of pollution has the potential to aggravate other environmental problems, an effect frequently referred to as cross-media impacts. Under sections 304(b) and 306 of the Clean Water Act, EPA is required to consider non-water quality environmental impacts in developing effluent limitations guidelines and new source performance standards. Accordingly, EPA has evaluated the effect of these regulations on air pollution, energy consumption, solid waste generation and management, and consumptive water use. Safety, impacts of marine traffic, and other factors related to implementation were also considered. EPA evaluated the non-water quality environmental impacts on a geographic as well as an industry-wide basis.

2.0 SUMMARY OF NON-WATER QUALITY ENVIRONMENTAL IMPACTS

Regulatory options were developed to analyze the costs and pollutant loadings/reductions for drill cuttings in each of the three geographic areas: Gulf of Mexico, offshore California, and coastal Cook Inlet, Alaska (see Chapter VIII). Non-water quality environmental impacts (NWQEI) were estimated for the technologies considered to be the bases for each of the selected regulatory options and areas. The control technology bases for compliance with the options considered for drill cuttings are 1) an add-on solids control device to reduce the amount of adhering SBF in the cuttings wastestream for the discharge option, and 2) a combination of transportation of drill cuttings to shore for disposal and onsite grinding followed by subsurface injection for the zero discharge option. In order to assess the incremental impact of each of the options, baseline impacts of current solids control practices were also determined. The incremental reductions of NWQEI associated with the treatment and control of these wastes from existing and new sources are summarized in Table IX-1.

For existing and new sources under the discharge option, EPA estimates that air emissions would be reduced by a total of 72 tons per year, whereas if the zero discharge option were selected, air emissions would increase by 380 tons per year. Therefore, in moving from the zero discharge option to the discharge option, NWQEI in terms of air emissions would be reduced by 452 tons per year. In addition, EPA estimates that 29,359 BOE less fuel would be used (see Table IX-1).

Other favorable NWQEI occur with the elimination of the long-term disposal of OBF-cuttings onshore, because such disposal can adversely affect ambient air, soil, and groundwater quality. EPA estimates that allowing discharge of SBF-cuttings compared to zero discharge would decrease the amount of OBF-cuttings disposed at land based facilities by 86,000 tons per year, and the amount injected by 20,000 tons per year. The methodology used to arrive at these results is described in the sections that follow.

3.0 ENERGY REQUIREMENTS AND AIR EMISSIONS

EPA calculated energy requirements and air emissions for both BAT and NSPS regulatory levels of control. The assumptions and analyses presented in this section follow directly from the assumptions and data used in the compliance cost and pollutant reductions analyses presented in Chapter VIII.

TABLE IX-1

SUMMARY ANNUAL NWQEI FOR DRILL CUTTINGS[a]

Option	Reduction in Air Emissions (tons/yr)	Reduction in Fuel Usage (BOE/yr)[b]	Reduction in Solid Waste Disposed by Zero Discharge Technologies (tons/yr)[c]
BAT Options for Existing Sources			
Discharge with 7% retention of base drilling fluid on cuttings	73.31	2,613	16,918
Zero Discharge	(338.55)	(24,125)	(82,455)
NSPS Options for New Sources			
Discharge with 7% retention of base drilling fluid on cuttings	(1.28)	(311)	0
Zero Discharge	(41)	(2,932)	(6,549)
Total BAT and NSPS Option NWQEI			
Discharge with 7% retention of base drilling fluid on cuttings	72.03	2,302	16,918
Zero Discharge	(379.55)	(27,057)	(89,004)

[a] The positive numbers in this table represent reduced impacts as measured from the baseline, and the numbers in parentheses represent increased impacts as measured from the baseline.
[b] BOE (barrels of oil equivalent) is the sum of the diesel (42 gal diesel = 1 BOE) and natural gas (1,000 scf = 0.178 BOE) estimated for each compliance option.
[c] Landfill and subsurface injection.

In general, EPA estimated energy requirements by calculating the fuel consumption (in terms of the fuel usage rate) of the equipment and activities associated with each of the regulatory options. The fuel usage rate is expressed as barrels of oil equivalents (BOE) because the fuel source for cuttings management can be either diesel oil or natural gas. BOE equates natural gas fuel usage with that of diesel by expressing both fuel types in terms of barrels of oil. EPA calculated diesel fuel usage by multiplying the time of equipment operation by the fuel consumption rate specific to the activity or equipment. For diesel, the conversion factor to BOE is 42 gallons = 1 BOE. The natural gas fuel usage was calculated by first determining the power requirements of the equipment (expressed in horsepower) and multiplying it by the natural gas usage rate. For natural gas, the conversion factor to BOE is 1,000 standard cubic feet (scf) = 0.178 BOE.[1]

EPA estimated air emissions of operations associated with each of the regulatory options by using emission factors relating the production of air pollutants to period of time that the equipment is operated and the amount of fuel consumed.

As in the cost analysis, energy requirements and air emissions were estimated using a step-wise methodology. First, impacts were determined for current baseline activities (see sections VIII.3.1.1 and VIII.3.2 for full discussions of baseline activities). Then compliance impacts were estimated from the activities associated with each of the regulatory options (discharge and zero discharge). Finally, the incremental impacts for each of the options were calculated by subtracting the compliance impacts from the baseline impacts. Table IX-2 presents the results of each of these steps for both air emissions and fuel usage.

Appendix IX-1 consists of the detailed worksheets that calculate the per-well energy requirements and air emissions, organized as follows:

> Worksheets 1 through 3: Baseline energy requirements and air emissions for wells in the Gulf of Mexico, offshore California, and coastal Cook Inlet, respectively.
>
> Worksheets 4 through 6: BAT discharge option energy requirements and air emissions for the three geographic areas (in the same order as in Worksheets 1-3).
>
> Worksheets 7 through 9: BAT zero discharge option energy requirements and air emissions for transport and land-disposal, onsite injection, and the weighted average impacts, respectively.

These worksheets are referred to throughout the following sections.

TABLE IX-2

SUMMARY BAT AIR EMISSIONS
AND FUEL USAGE

Compliance Technology	Air Emissions (tons/yr)				Fuel Usage (BOE/yr)			
	Gulf Of Mexico	**Offshore CA**	**CI, Alaska**	**Total**	**Gulf Of Mexico**	**Offshore CA**	**CI, Alaska**	**Total**
Baseline Emissions & Fuel Usage								
Discharge at 11% retention (SBF users only)	0	NA	NA	0	0	NA	NA	0
Zero Discharge (OBF users only)	47.92	36.61	2.08	86.61	3,433	2,121	285	5,839
Total Compliance Emissions & Fuel Usage								
Discharge at 7% Option	12.54	0.76	0.01	13.30	3,035	187	4	3,226
Zero Discharge Option	338.55	NA	NA	338.55	24,125	NA	NA	24,125
Incremental Compliance Emissions & Fuel Usage Reductions (Increases)								
Discharge at 7% Option	35.38	35.86	2.07	73.31	398	1,934	281	2,613
Zero Discharge Option	(338.55)	0	0	(338.55)	(24,125)	0	0	(24,125)

3.1 ENERGY REQUIREMENTS

The following sections present the detailed assumptions, per-well data, and methodology used to calculate incremental energy requirements and fuel usage resulting from each regulatory option.

3.1.1 Baseline Energy Requirements

In developing baseline energy requirements, EPA assumed that the 94 wells drilled annually in the Gulf of Mexico with SBF discharge SBF-cuttings with an average 11% base fluid. Also, wells currently drilled with OBF that convert to SBF are included in the baseline, with the assumption that they currently practice zero discharge by either hauling waste OBF-cuttings to shore for land-based disposal or by onsite injection. This includes 20%, or 23 wells, of the 112 OBF wells drilled annually in the GOM, all 12 OBF wells drilled annually in offshore California, and one OBF well drilled annually in Cook Inlet, Alaska. Table VIII-4 presents the framework of “in-scope” wells (wells that would incur costs or realize savings as a result of this rule) that EPA estimates would be affected by the proposed regulation, distinguished by the type of drilling fluid used at baseline and compliance levels. In the context of the NWQEI analysis, SBF wells using standard solids control equipment and discharging SBF-cuttings at 11% retention are defined as the baseline. Increases or decreases in NWQEIs are compared to this baseline. For example, current OBF wells that EPA projects would convert to SBF in the discharge option are assigned baseline impacts because these wells use energy consuming technologies (i.e., transportation for disposal or injection) beyond standard solids control equipment.

The total baseline energy requirements were determined by summing the individual energy consuming activities currently performed on a per-well basis and multiplying by the number of in-scope wells per geographic area. A summary of the baseline energy requirements is presented in Table IX-2 by geographic area.

The assumptions, data, and methods used to develop the per-well baseline zero discharge fuel usage rates are identical to those used in the zero discharge option compliance analysis. Therefore, this section presents an overview of the methodology in terms of the baseline analysis, and section IX.3.1.3, “Zero Discharge Option Energy Requirements,” presents the detailed line-item assumptions and data applicable to both the baseline and compliance zero discharge analyses.

Per-well baseline fuel usage rates for OBF wells in offshore California and coastal Cook Inlet derive from activities associated with transporting waste drill cuttings to shore and land-disposing the cuttings. For this analysis, EPA applied the methods developed to estimate zero discharge impacts under the Offshore Rulemaking for offshore California wells[2] and under the Coastal Rulemaking for coastal Cook Inlet wells.[3] Worksheets 2 and 3 in Appendix IX-1 present the detailed calculation of per-well fuel usage for baseline wells in offshore California and coastal Cook Inlet, respectively. EPA used the volumes of drilling waste requiring onshore disposal to calculate the number of supply boat trips necessary to haul the waste to shore. Projections made regarding boat use included types of boats used for waste transport, the distance traveled by the boats, allowances for maneuvering, idling and loading operations at the drill site, and in-port activities at the dock. EPA calculated fuel required to operate the cranes at the drill site and in-port based on projections of crane usage. EPA determined crane usage by considering the drilling waste volumes to be handled and estimates of crane handling capacity. EPA also used drilling waste volumes to determine the number of truck trips required. The number of truck trips, in conjunction with the distance traveled between the port and the disposal site, enabled a calculation of fuel usage. The use of land-spreading equipment at the disposal site was based on the drilling waste volumes and the projected capacity of the equipment. Based on these line-items, the per-well baseline fuel usage rates for offshore California were calculated as 180 BOE for a DWD well and 143 BOE for a SWD well. For coastal Cook Inlet, the baseline fuel usage rate for a SWD well was 285 BOE. The total annual baseline fuel usage rates for these geographic areas, 2,121 BOE for offshore California and 285 BOE for Cook Inlet, were calculated by multiplying the per-well rates by the corresponding numbers of baseline wells listed in Table VIII-4.

Per-well baseline fuel usage rates (and all other NWQEI analyses) for baseline OBF wells in the Gulf of Mexico are based on the estimate that 80% of these wells use land-disposal for zero discharge and the remaining 20% use on-site injection to dispose of OBF cuttings. This estimate is discussed further in sections VIII.3.1.3 and VIII.3.1.4. As in the per-well zero discharge compliance cost analysis discussed in section VIII.3.2.1.1, the per-well zero discharge environmental impacts for Gulf of Mexico wells were calculated as weighted averages reflecting this distribution of zero discharge compliance methods. For the OBF model wells in the baseline (SWD and SWE), per-well impacts were calculated for transport and disposal and for injection. Then for each model well, a weighted average per-well impact was calculated as follows:

$$\text{Baseline GOM OBF Well Impact} = (0.8 \times \text{Per-Well Transportation \& Disposal Impact}) + (0.2 \times \text{Per-Well Injection Impact})$$

Per-well baseline fuel usage rates for land disposal in the Gulf of Mexico were calculated using the same line-items as described above for offshore California and coastal Cook Inlet wells. Per-well baseline fuel usage rates for onsite injection are weighted averages of diesel usage rates and natural gas usage rates, according to the estimate that 85% of wells use diesel and 15% use natural gas as primary power sources in the Gulf of Mexico.[4] Worksheet 1 in Appendix IX-1 shows the detailed per-well calculations for baseline wells in the Gulf of Mexico. EPA calculated a per-well baseline fuel usage rate of 130 BOE for SWD wells and 186 BOE for SWE wells. These per-well rates, multiplied by the corresponding numbers of baseline wells listed in Table VIII-4 resulted in the total annual baseline fuel usage rate for the Gulf of Mexico existing sources of 3,433 BOE. The sum of the baseline fuel usage rates or existing sources for the three geographic areas is 5,839 BOE per year (Table IX-2).

3.1.2 BAT Discharge Option Energy Requirements

Energy consumption for the discharge option was calculated by identifying the equipment and activities associated with the addition of a vibrating centrifuge device to reduce the retention of the synthetic base fluid on drill cuttings from an average 11% to 7%, measured on a wet-weight basis. A summary of the total discharge option energy requirements for existing sources in the three geographic areas is presented in Table IX-2. The remainder of this section presents the detailed calculations developed for each of the three geographic areas.

Per-well fuel usage rates were calculated for the four model wells in the Gulf of Mexico. As stated in section IX.3.1.1, EPA estimated that 85% of Gulf of Mexico wells use diesel as their primary source of fuel, and 15% use natural gas.[4] Therefore, the per-well fuel usage rates for the Gulf of Mexico are weighted averages of two distinct per-well rates based on diesel usage and natural gas usage, respectively. These rates are identified in Worksheet 4 of Appendix IX-1 as separate line-items under each model well. The per-well diesel usage rate was calculated by multiplying the vibrating centrifuge operating time (equal to the number of drilling days) by the consumption rate for diesel generators, estimated to be 6 gal/hr.[5] An example diesel usage calculation for a DWD model well is as follows:

(5.4 days) x (24 hr/day) x (6 gal/hr) = 777.6 gal diesel/well

(777.6 gal/well)/(42 gal/BOE) = 18.5 BOE/well

The per-well natural gas usage rate was calculated for gas turbines using an average heating value of 1,050 Btu per standard cubic foot (scf) of natural gas and an average fuel consumption of 10,000 Btu per horsepower-hour (hp-hr), or 9.5 (10,000/1,050) scf/hp-hr.[6] Multiplying the turbine consumption rate by the power demand of the vibrating centrifuge (20.5 kW = 27.49 hp)[7] and the number of drilling days results in the per-well natural gas usage rate. An example natural gas usage calculation for a DWD model well is:

(27.49 hp) x (5.4 days) x (24hrs/day) x (9.5 scf/hp-hr) = 33,845.7 scf natural gas/well

(33,845.7 scf/well) x (0.178BOE/1,000 scf) = 6.0 BOE/well

The total energy requirements for the 18 DWD wells drilled annually in the Gulf of Mexico are:

[(18.5 BOE/well) x (85% wells using diesel)+(6.0 BOE/well) x (15% wells using nat. gas)] x 18 DWD wells/yr = 299 BOE/yr for DWD wells

The same methodology shown in the above calculations was applied to the other three model wells in the Gulf of Mexico and summed for the total energy requirement of 3,035 BOE per year.

Based on information regarding fuel use in offshore California, EPA estimated that all shallow water wells use natural gas as fuel for generating electricity on the platforms.[8] For deep water wells, the estimate that 85% of the drilling operations use diesel and 15% use natural gas was applied for the offshore California area. Worksheet 5 in Appendix IX-1 shows that the fuel usage for the eleven (11) DWD wells in offshore California is 183 BOE per year, and 4 BOE per year for the single SWD well drilled annually, for a total of 187 BOE per year for the area.

Only one SWD well is represented in the discharge option fuel usage analysis for Cook Inlet, Alaska. Based on information from the Coastal Oil and Gas Rulemaking effort, EPA estimated that the fuel used on Cook Inlet platforms for generating electricity is exclusively natural gas.[3] Thus, the previous example calculation of per-well natural gas usage was used for coastal Cook Inlet. Work-sheet 6 in Appendix IX-1 shows that the per-well, and total discharge option fuel usage for Cook Inlet is 4 BOE per year.

3.1.3 BAT Zero Discharge Option Energy Requirements

Energy consumption for compliance with the zero discharge option was calculated only for Gulf of Mexico wells that currently discharge SBF cuttings, because all other wells are currently at zero discharge and would not contribute impacts under this option. Fuel usage rates were estimated by identifying the equipment and activities associated with two zero discharge technologies currently in use in the Gulf of Mexico: 1) transporting waste cuttings to shore for land-based disposal; and 2) on-site injection. As stated in section IX.3.1.1, EPA estimated that 80% of all Gulf of Mexico wells employing zero discharge technology use land-disposal for waste cuttings, while 20% use onsite injection. Worksheets 7 and 8 of Appendix IX-1 list the line-item activities for the land-disposal and onsite injection technologies, respectively. Worksheet 9 presents the weighted average energy requirements base on this proportion of wells using the corresponding zero discharge technology. The following sections present the detailed estimates and data used to develop the per-well zero discharge fuel requirements associated with these technologies.

3.1.3.1 Transportation and Onshore Disposal Energy Requirements

The per-well energy requirements associated with the transportation and onshore disposal of drill cuttings varied between model wells and between geographic areas. Variations between model wells were due to differences in the per-well waste volumes calculated for each model well, as listed in Table VII-4. The model well waste volumes define the frequency of boat and truck trips required to transport the waste. Variations between geographic areas were due to differences in travel distances. Below are the assumptions and data that comprise the line-items in Worksheets 7, 8, and 9 of Appendix IX-1 specific to the transportation and onshore disposal of cuttings:

- **Supply Boats:** Appendix VIII-1 presents the supply boat frequencies calculated for each model well. The frequency of supply boats needed to haul drill cuttings from the platform depends on the volume and rate of generation of the cuttings. Because the waste generation rate is nearly 11 boxes per day (for all model wells) and the platform storage capacity is 12 boxes (in all geographic areas), EPA determined that a supply boat is available at the platform to receive the waste, independent of any requirements proposed in this rule.

  Based on information compiled in the Offshore Oil and Gas Rulemaking effort, EPA determined the cuttings box capacity to be 25 bbl for the Gulf of Mexico and offshore California areas.[5] Based on similar information used in the Coastal Rulemaking effort, an 8-bbl capacity was applied for the coastal Cook Inlet area.[3] These capacities determined the number of cuttings boxes needed to be transferred to the supply boats and hauled to shore per model well and per geographic area.

  Two types of supply boats provide service to the platform during drilling operations:

  1) *Dedicated supply boats* are rented to provide service for special tasks. In the NWQEI analysis, EPA estimated that dedicated supply boats would provide

service solely for offloading SBF or OBF cuttings. Dedicated supply boats are used for all model wells in all areas. The dedicated supply boat capacity in both the Gulf of Mexico and offshore California is 3,000 bbl (or 80 25-bbl cuttings boxes).[9] In coastal Cook Inlet, the capacity is 1,050 bbl (or 132 8-bbl cuttings boxes).[3] Except for Gulf of Mexico deep water exploratory model wells, the waste generated from all other model wells in all geographic areas can be transported to shore with the use of only one dedicated supply boat.

2) *Regularly scheduled supply boats* are contracted at the beginning of drilling operations to arrive at the platform at regular intervals, bring supplies, and offload no longer needed materials. EPA estimated that regularly scheduled supply boats arrive at a drilling platform every four days.[5] For the purposes of the NWQEI analysis, EPA estimated that a regularly scheduled supply boat would be used only after the capacity of a dedicated supply boat (see below) was reached and additional cuttings still needed to be hauled to shore. This was only required in the Gulf of Mexico for deep water exploratory model wells. The capacity of a regularly scheduled supply boat in the Gulf of Mexico is 300 bbl (or twelve 25-bbl cuttings boxes).[5]

<u>Transit Fuel Consumption</u>: Supply boats consume 130 gallons of diesel per hour while in transit.[10] Average supply boat speed is 11.5 miles per hour.[5] The distance the supply boat travels depends on whether the boat is a dedicated supply boat for which the entire travel distance is used in the analysis or if it is a regularly scheduled supply boat for which only the additional distance to travel to the disposal facility is used. The roundtrip distance is dependent on the geographic area as follows (also, see Appendix VIII-1):

Gulf of Mexico: 277 miles for dedicated supply boats; 77 miles for regularly scheduled boats[5]
Offshore California: 200 miles for dedicated supply boats[5]
Cook Inlet, Alaska: 50 miles for dedicated supply boats[3]

<u>Maneuvering Fuel Consumption</u>: Supply boats maneuver at the platform for an average of one hour per visit.[11] The maneuvering fuel use factor is 15% of full throttle fuel consumption (169 gal/hr), or 25.3 gallons of diesel per hour.[11]

<u>Loading Fuel Consumption</u>: Due to ocean current and wave action, boats must maintain engines idling while unloading empty cuttings boxes and loading full boxes at the platforms. An additional 1.6 hours is included to account for potential delays in the transfer process.[2] For dedicated supply boats, it is estimated that the boats are available until either all of the waste is loaded or boat capacity is reached.

Auxiliary Electrical Generator: An auxiliary generator is needed for electrical power when propulsion engines are shut down. This only occurs when the supply boats are in port. The average in-port time for unloading drill cuttings, tank cleanout, and demurrage is 24 hours per supply boat trip.[5] Estimates of fuel requirements are based on the auxiliary generator rating at 120 horsepower (hp), operating at 50% load (or 60 hp), and consuming 6 gallons of diesel per hour.[5]

- **Barges:** Barges are used only in the Gulf of Mexico to haul waste from the transfer station to the disposal site. The average round-trip distance is 100 miles.[12] Barges consume fuel at a rate of 24 gallons of diesel per hour and travel an average of 6 miles per hour.[2]

- **Cranes:** Cranes used to unload empty cuttings boxes and load full cuttings boxes at the drill site and in port (or at the transfer station, as in the case of the Gulf of Mexico) are diesel powered, require 170 horsepower operating at 80% load (or 136 hp), and consume 8.33 gallons of diesel per hour.[5] Cranes make 10 lifts per hour.[5] The total time to transfer the waste is dependent on the volume of drill cuttings as determined by the number of full/empty cuttings boxes to be transferred and varies for each model well as follows:

  Gulf of Mexico and Offshore California (cuttings box capacity = 25 bbl)
  Deep Water Development: (116 boxes to unload & load at drill site)/(10 lifts/hr)=11.6 hrs
  Deep Water Exploratory: (258 boxes to unload & load at drill site)/(10 lifts/hr)=25.8 hrs
  Shallow Water Development: (78 boxes to unload & load at drill site)/(10 lifts/hr)=7.8 hrs
  Shallow Water Exploratory: (160 boxes to unload & load at drill site)/(10 lifts/hr)=16.0 hrs

  Cook Inlet, Alaska (cuttings box capacity = 8 bbl)
  Shallow Water Development: (240 boxes to unload & load at drill site)/(10 lifts/hr)=24.0 hrs

- **Trucks:** Trucks transport drill cuttings from port to the disposal site. For the Gulf of Mexico and Cook Inlet areas, truck fuel usage is assumed to be 4 miles per gallon[3] and for California, 7 miles per gallon.[13] The truck capacity and distance traveled vary by geographic area as follows (see also Appendix VIII-1):

Gulf of Mexico:	capacity = 119 bbls[5];
	distance = 20 miles[3]
Offshore California:	capacity = 50 bbls[14];
	distance = 300 miles (Appendix VIII-1)
Cook Inlet, Alaska:	capacity = 64 bbls (Appendix VIII-1);
	distance = 2,200 miles[3]

  The number of truck trips depends on the volume of drill cuttings hauled per model well and the capacity of the truck as listed above. Appendix VIII-1 presents in detail the number of truck trips per model well and geographic area.

- **Land Disposal Equipment:** Estimates regarding energy-consuming land disposal equipment are as follows:

  Wheel Tractor: Wheel tractors are used at the disposal facility for grading. One day (8 hours) of tractor operation is required to grade the drill cuttings waste volume from one well. The estimated fuel consumption rate for a wheel tractor is 1.67 gallons of diesel per hour.[5]

  Track-Type Dozer/Loader: A track-type dozer/loader is required at the facility for waste spreading. Two days (16 hours) of dozer operation are required to spread drill cuttings generated from one well. The estimated fuel consumption rate for a dozer is 22 gallons of diesel per hour.[5]

3.1.3.2 Onsite Grinding and Injection Energy Requirements

According to information available to EPA, zero discharge via on-site grinding and injection is practiced by a growing number of operators in the Gulf of Mexico geographic area (see section VII.5.6). The waste volume of cuttings injected varies per model well and is presented in Table VII-4. Following are the identified equipment and activities required for onsite injection and the corresponding power and fuel requirements.

- **Cuttings Transfer:** Cuttings transfer equipment consists of one 100-hp vacuum pump.[15] The time of operation needed for transfer is equal to the length of time required to drill the corresponding model well in hours. Drilling days are discussed in section VIII.3.1.2.

- **Cuttings Grinding and Processing:** The equipment used for grinding and processing the drill cuttings consists of: one 75 hp grinding pump, two 10 hp mixing pumps, two 10 hp vacuum pumps, and one 5 hp shale shaker motor.[15] The total power requirement is 120 hp. The time of operation for this equipment is equal to the length of time required to drill each of the model wells in hours.

- **Cuttings Injection:** One 600 hp injection pump rated at 2.5 barrels per minute is used for cuttings injection.[15]

- **Fuel Requirements:** EPA calculated fuel requirements for both diesel and natural gas fuel sources according to the assumptions that 85% of Gulf of Mexico wells use diesel and 15% use natural gas.[4] For diesel generators, the fuel usage rate for all of the grinding and injection equipment was 6 gallons of diesel/hour of operation.[5] For natural gas, the fuel requirements were calculated for gas turbines using an average heating value of 1,050 Btu per standard cubic foot (scf) of natural gas and an average fuel consumption of 10,000 Btu per horsepower-hour (hp-hr), or 9.5 (10,000/1,050) scf/hp-hr.[3]

3.2 AIR EMISSIONS

The total air emissions for each of the regulatory options as presented in Table IX-1 were calculated as the sum of the air emissions from each of the three geographic areas using the total system energy utilization rate (horsepower-hours or miles traveled) and emission factors developed for the various engines and fuels used. Table IX-3 presents the air emissions by geographic area and model well for existing source wells. As in the Offshore Rulemaking effort, EPA used emissions factors for uncontrolled sources. The term "uncontrolled" refers to the emissions resulting from a source that does not utilize add-on control technologies to reduce the emissions of specific pollutants. The use of "uncontrolled" emission factors provides conservatively higher estimates of total emissions resulting from drill cuttings disposal. Table IX-4 presents the uncontrolled emission factors for different types of diesel and natural gas driven engines used to calculate air emissions from activities related to the discharge, onshore disposal, or onsite injection of drill cuttings. For the discharge option, emission factors for either diesel generators or natural gas turbines were used to calculate emissions associated with the vibrating centrifuge. These emission factors were also used to calculate emissions associated with the grinding and injection equipment. As mentioned above in section IX.3.1.1, 85% of the Gulf of Mexico platforms utilize diesel as a fuel source and 15% utilize natural gas. This proportion was applied to all of the model wells represented in the Gulf of Mexico and to deep water development wells in offshore California. EPA assumed that the shallow water development model wells in offshore California and coastal Cook Inlet use natural gas exclusively (see section IX.3.1.2). Detailed calculations of the air emissions from each type of engine used are presented in Appendix IX-1.

TABLE IX-3

SUMMARY BAT AIR EMISSIONS (tons/yr)

Baseline Technology	Gulf of Mexico				Offshore California		Cook Inlet, Alaska	Total
	DWD	DWE	SWD	SWE	DWD	SWD	SWD	
Baseline Emissions								
Discharge at 11% retention (current SBF users only)	0	0	0	0	NA	NA	NA	0
Zero Discharge (current OBF users only)	NA	NA	27.0	20.9	34.7	1.9	2.1	86.6
Total Compliance Emissions								
Discharge at 7% Option	1.2	8.7	1.2	1.4	0.8	0.0	0.0	13.3
Zero Discharge Option	39.2	259.5	21.6	18.3	NA	NA	NA	338.6
Reduction (Increase) in Emissions								
Discharge at 7% Option	(1.2)	(8.7)	25.8	19.5	33.9	1.9	2.1	73.3
Zero Discharge Option	(39.2)	(259.5)	(21.6)	(18.3)	NA	NA	NA	(338.6)

EPA calculated the baseline and total compliance air emissions for both the discharge and zero discharge options. The incremental air emissions for each of the options were determined by subtracting the corresponding total compliance from the baseline (see Table IX-3).

3.3 NSPS ENERGY REQUIREMENTS AND AIR EMISSIONS

As described in Chapter VIII, section 3.2, EPA projects that an estimated 19 new source SBF wells will be drilled annually in the Gulf of Mexico, consisting of 18 deep water

TABLE IX-4

UNCONTROLLED EMISSION FACTORS FOR DRILL CUTTINGS MANAGEMENT ACTIVITIES

Category	Emission Factors					
	Units	NOx	THC	SO2	CO	TSP
Supply Boats[a]						
Transit	lb/gal	0.3917	0.168	0.02848[b]	0.0783	0.033
Maneuvering	lb/gal	0.4196	0.226	0.02848[b]	0.0598	0.033
Loading/Unloading	lb/gal	0.4196	0.226	0.02848[b]	0.0598	0.033
Demurrage	g/bhp-hr	14	1.12	0.931	3.03	1
Barge Transit[a]	lb/gal	0.3917	0.168	0.02848	0.0783	0.033
Supply Boat Cranes[c]	g/bhp-hr	14	1.12	0.931	3.03	1
Barge Cranes[c]	g/bhp-hr	14	1.12	0.931	3.03	1
Trucks[d]	g/mile	11.23	2.49	NA	8.53	NA
Wheel Tractor[e]	lb/hr	1.269	0.188	0.09	3.59	0.136
Dozer/Loader[e]	lb/hr	0.827	0.098	0.076	0.201	0.058
Diesel Generator[f]	g/bhp-hr	14	1.12	0.931	3.03	1
Natural Gas Fired Turbines[g]	g/bhp-hr	1.3	0.18	0.002[h]	0.83	NA

[a] Source: Table II-3.3, AP-42 Volume II, September 1985.[16]
[b] Based on assumed 0.20% sulfur content of fuel and fuel density of 7.12 lbs/gal (AP-42 Volume II, September 1985).[16]
[c] Source: Table 3.3-1, AP-42 Volume I, Supplement F, July 1993.[17] Note: bhp is brake horsepower.
[d] Source: Table 1.7.1, AP-42 Volume II, September 1985.[16]
[e] Source: Table II-7.1, AP-42 Volume II, September 1985.[16]
[f] Source: Table 3.2-1, AP-42 Volume I, Supplement F, July 1993.[17]
[g] Source: Table 3.3-1, AP-42 Volume I, January 1975.[18] Note: bhp is brake horsepower.
[h] This factor depends on the sulfur content of the fuel used. For natural gas fired turbines, AP-42, 1976 (Table 3.2-1) gives this emission factor based on assumed sulfur content of pipeline gas of 2,000 g/10^6 scf (AP-42 Vol. I, April 1976).[6]

NA = Not Applicable

TABLE IX-5

SUMMARY NSPS AIR EMISSIONS (tons/yr)
AND FUEL USAGE (BOE/yr)

Baseline Technology	Air Emissions					Fuel Usage				
	DWD	**DWE**	**SWD**	**SWE**	**Total**	**DWD**	**DWE**	**SWD**	**SWE**	**Total**
Baseline Emissions										
Discharge at 11% retention	0	NA	0	NA		0	NA	0	NA	0
Total Compliance Emissions										
Discharge at 7% Option	1.23	NA	0.05	NA	1.28	300	NA	11	NA	311
Zero Discharge Option	39.2	NA	1.8	NA	41.0	2,802	NA	130	NA	2,932
Reduction (Increase) in Emissions										
Discharge at 7% Option	(1.23)	NA	(0.05)	NA	(1.28)	(300)	NA	(11)	NA	(311)
Zero Discharge Option	(39.2)	NA	(1.8)	NA	(41.0)	(2,802)	NA	(130)	NA	(2,932)

development wells and one shallow water development well. No new source wells are projected for offshore California and coastal Cook Inlet because of the lack of activity in new lease blocks in these areas.

Table IX-5 summarizes the baseline, compliance, and incremental compliance energy requirements (i.e., fuel usage) and air emissions for Gulf of Mexico new sources. The method used to calculate the per-well impacts for new source wells are the same as for existing sources, described above in sections IX.3.1 and IX.3.2. The per-well impacts were multiplied by the corresponding number of wells (18 DWD, 1 SWD) and summed for each of the options. Appendix VIII-2 includes three worksheets that present the baseline impacts (Worksheet 1), the discharge option impacts (Worksheet 2), and the zero discharge option impacts (Worksheet 3) for new source wells. The incremental compliance impacts were calculated by subtracting the compliance impacts from the baseline impacts.

4.0 SOLID WASTE GENERATION

EPA does not expect that the regulatory options considered for this rule will change the overall volume of solid waste generated. EPA does expect, however, that the rule would change the characteristics of the waste generated. EPA projects that the regulatory options will affect whether the wastes are discharged to water or disposed of onshore or injected onsite. Implementation of the discharge option will result in reductions of solid waste currently disposed at land-based facilities and by injection, due to the OBF wells converting to SBF wells.

Table IX-6 summarizes, for baseline, compliance, and incremental compliance levels for existing and new sources, the amounts of solid waste disposed by onshore disposal and onsite injection. Table VII-4 presents the model well data on which solid waste amounts were based. For each model well, the total waste generated (in pounds) was multiplied by the number of wells affected for the corresponding option and geographic area for the baseline and compliance scenarios. EPA then calculated incremental compliance levels by subtracting compliance from baseline solid waste values. For the discharge option, the negative values shown indicate the amounts of waste that would not be disposed by zero-discharge technologies, as compared with the baseline.

5.0 CONSUMPTIVE WATER USE

Neither of the two regulatory options is projected to affect consumptive water use.

TABLE IX-6

SOLID WASTE DISPOSED BY ZERO DISCHARGE TECHNOLOGIES FOR EXISTING AND NEW SOURCE WELLS
(pounds per year)

Option	Gulf of Mexico			Offshore California	Cook Inlet, Alaska	Totals		
	Onshore	Injection	Total	Onshore	Onshore	Onshore	Injection	Total
Existing Sources								
Baseline Discharge	0	0	0	NA	NA	0	0	0
Baseline Zero Discharge	17,056,680	4,264,170	21,320,850	11,844,255	671,214	29,572,149	4,264,170	33,836,319
Compliance Discharge	0	0	0	0	0	0	0	0
Compliance Zero Discharge	131,928,610	32,982,152	164,910,762	0	0	131,928,610	32,982,152	164,910,762
Incremental Discharge	(17,056,680)	(4,264,170)	(21,320,850)	(11,844,255)	(671,214)	(29,572,149)	(4,264,170)	(33,836,319)
Incremental Zero Discharge	131,928,610	32,982,152	164,910,762	0	0	131,928,610	32,982,152	164,910,762
New Sources								
Baseline Discharge	0	0	0	NA	NA	0	0	0
Baseline Zero Discharge	NA	NA	NA	NA	NA	NA	NA	NA
Compliance Discharge	0	0	0	NA	NA	0	0	0
Compliance Zero Discharge	10,478,066	2,619,517	13,097,583	NA	NA	10,478,066	2,619,517	13,097,583
Incremental Discharge	0	0	0	NA	NA	0	0	0
Incremental Zero Discharge	10,478,066	2,619,517	13,097,583	NA	NA	10,478,066	2,619,517	13,097,583

6.0 OTHER FACTORS

6.1 IMPACT OF MARINE TRAFFIC

EPA estimated the changes in vessel traffic that would result from the implementation of either the discharge or the zero discharge option using the same methodology as the energy consumption and air emissions impacts analyses described above. Appendix VIII-1 presents the source data and calculations for the per-well estimate of boat trips required for compliance.

To comply with the zero discharge option, EPA estimated that the 113 existing and new source wells in the Gulf of Mexico currently drilled with SBF would implement zero discharge technologies. Based on the assumption that 80% of these wells would transport waste drill cuttings to shore and each well requires one dedicated supply boat, an estimated total of 91 boat trips per year would be required. No additional boat trips would be required in offshore California and coastal Cook Inlet because these geographic areas are currently at zero discharge of SBF-cuttings.

Under the discharge option, 23 GOM wells, the 12 offshore California wells, and the one Cook Inlet well currently drilled with OBF would convert to SBF usage, thereby eliminating the need for hauling OBF cuttings to shore. Baseline supply boat trips per year were estimated as follows: 18 trips for the 23 wells in the Gulf of Mexico where 18 wells transport drill cuttings to shore and the other 5 inject onsite; 12 trips for the 12 wells in offshore California; and one trip for the well in coastal Cook Inlet. Therefore, EPA projects that supply boat traffic would decrease by 31 boat trips per year. Compared to the zero discharge option which led to 91 additional boat trips per year in the GOM, the discharge option reduces boat traffic over the three regions by 122 boat trips per year, and in the GOM by 109 boat trips per year. As cited in the Offshore Oil and Gas Development Document, 10% of the total Gulf of Mexico commercial vessel traffic, or approximately 25,000 vessels, service oil and gas operations. Therefore, compared to the zero discharge option, the discharge option decreases commercial boat traffic by 0.04% in the Gulf of Mexico.

6.2 SAFETY

EPA investigated the possibility of an increase in injuries and fatalities that would occur as a result of hauling additional volumes of drilling waste to shore under the zero discharge option. EPA reviewed data regarding personnel casualties occurring on mobile offshore drilling units (MODUs) and offshore supply vessels (OSV).[19] One of the conclusions of this evaluation is that since the number of increased crane handling events in the Gulf of Mexico is very small in relation to the total number of handling operations occurring at drilling and production sites, no discernable increase in casualties attributable to onshore disposal of drill cuttings is anticipated. In a document submitted by the Department of Energy, increased safety risks under a zero discharge option is a stated concern but the data do not clearly establish a correlation between injury incidence and onshore disposal of drill cuttings.[20]

7.0 REFERENCES

1. Mason, T. Avanti Corporation, Memorandum regarding "Conversion Factor to BOE (Barrels of Oil Equivalents) for Natural Gas and Diesel Fuel," July 12, 1996.

2. U.S. Environmental Protection Agency, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, Final, EPA 821-R-93-003, January 1993.

3. U.S. Environmental Protection Agency, Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-96-023, October 1996.

4. Daly, Joseph, U.S. EPA, Memorandum regarding "Market Share of Respondents to Technical Questions, August 17, 1998.

5. Carriere, J. and E. Lee, Walk, Haydel and Associates, Inc., "Water-Based Drilling Fluids and Cuttings Disposal Study Update," Offshore Effluent Guidelines Comments Research Fund Administered by Liskow and Lewis, January 1989.

6. U.S. EPA, "Compilation of Air Pollutant Emission Factors," AP-42, Volume I, April 1976.

7. McIntyre, Jamie, Avanti Corporation, Memorandum to Joseph Daly, U.S. EPA, regarding "Summary of December 2 Meeting with David Wood of Mud Recovery Systems," December 18, 1997.

8. Veil, John A., Argonne National Laboratory, Washington, D.C., "Data Summary of Offshore Drilling Waste Disposal Practices," prepared for the U.S. Environmental Protection Agency, Engineering and Analysis Division, and the U.S. Department of Energy, Office of Fossil Energy, November 1998.

9. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with John Belsome, Seabulk Offshore Ltd., regarding "Offshore supply boat costs and specifications," June 3, 1998.

10. U.S. EPA, "Trip Report to Campbell Wells Landfarms and Transfer Stations in Louisiana," June 30, 1992.

11. Jacobs Engineering Group, "Air Quality Impact of Proposed Lease Sale No. 95," prepared for U.S. Department of the Interior, Minerals Management Service, June 1989.

12. Sunda, John, SAIC, Memorandum to Allison Wiedeman, U.S. EPA, regarding "The assumptions used in the development of the cost of commercial disposal of produced water using barge transportation," March 10, 1994.

13. Montgomery, Richard, The Pechan-Avanti Group, Telecommunication Report on conversation with Shane Morgan, Ecology Control Incorporated, regarding "costs associated with land and water transport of drill cuttings and drilling fluids for offshore oil platforms operating off the California coast," May 9, 1998.

14. McIntyre, Jamie, The Pechan-Avanti Group, Telecommunications Report on conversation with Darron Stankey, McKittrick Solid Waste Disposal Facility, regarding "California Prices for Land Disposal of Drilling Wastes," October 16,1998.

15. Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with personnel at Apollo Services regarding "Detailed Information Regarding Apollo's Cuttings Injection System," July 9, 1998.

16. U.S. EPA, "Compilation of Air Pollutant Emission Factors," AP-42, Volume II, September 1985.

17. U.S. EPA, "Compilation of Air Pollutant Emission Factors," AP-42, Volume I, Supplement F, July 1993.

18. U.S. EPA, "Compilation of Air Pollutant Emission Factors," AP-42, Volume I, January 1975.

19. SAIC, "Evaluation of Personnel Injury/Casualty Data Associated with Drilling Activity for the Offshore Oil and Gas Industry," prepared for U.S. EPA, Engineering and Analysis Division, January 11, 1992.

20. Meinhold, Anne, "Framework for a Comparative Environmental Assessment of Drilling Fluids," prepared for the U.S. Department of Energy, National Petroleum Technology Office, November 1998.

CHAPTER X

OPTIONS SELECTION RATIONALE

1.0 INTRODUCTION

This chapter presents the options EPA has selected for control of the SBF and SBF-cuttings wastestreams. A discussion of the rationale for option selection is also included.

2.0 REGULATORY OPTIONS CONSIDERED FOR SBFs NOT ASSOCIATED WITH DRILL CUTTINGS

EPA proposes, under BPT, BCT, BAT, and NSPS, zero discharge for SBFs not associated with drill cuttings. This option is technically available and economically achievable. Because of the value of the SBFs, this option is already current industry practice and thus is technically available. Also, because this option is current practice, there are no costs associated with this regulatory option, and thus it is economically achievable and has no non-water quality environmental impacts.

3.0 REGULATORY OPTIONS CONSIDERED FOR SBFs ASSOCIATED WITH DRILL CUTTINGS

EPA considered two options for the proposed rule for SBFs associated with drill cuttings, or SBF-cuttings: a discharge option and a zero discharge option. EPA has selected the discharge option as the basis for this proposal. This discharge option controls under BAT and NSPS the stock base fluid through limitations on PAH content, sediment toxicity, and biodegradation rate, and controls at the point of discharge under BPT and BCT sheen formation and under BAT and NSPS formation oil content and quantity of SBF discharged. The discharge option maintains current requirements of stock limitations on barite of mercury and cadmium, and the diesel oil discharge prohibition. EPA at this time thinks that all of these components are essential for appropriate control of the SBF cuttings wastestream.

Although not the basis for this proposal, EPA considered zero discharge as an option for BPT, BCT, BAT, and NSPS. Under zero discharge all pollutants would be controlled in SBF discharges. This option was clearly technically feasible and economically achievable because in the past SBFs did not exist, and industry was able to operate using only the traditional non-dischargeable OBFs based on diesel oil and mineral oil.

EPA presently rejects zero discharge as the preferred option because it would result in unacceptable non-water quality environmental impacts. If EPA were to choose zero discharge for SBF-cuttings, operators would not have an incentive to use SBFs since they are more expensive than OBFs. Thus, if EPA requires zero discharge, OBF-cuttings would continue to be injected or shipped to shore for land disposal. EPA's analysis shows that under this option as compared to the discharge option, for existing and new sources combined, there would be 172 million pounds of OBF-cuttings annually shipped to shore for disposal in non-hazardous oilfield waste sites and 40 million pounds annually injected, with associated fuel use of 29,000 BOE and annual air emissions of 450 tons. EPA believes these impacts far outweigh the water impacts associated with these discharges. EPA's current analysis shows that the impacts of these discharges to water are of limited scope and duration, particularly if EPA controls the discharges of SBFs to the best environmental performers that also meet the technical requirements needed to drill. By contrast, the landfilling of OBF-cuttings is of a longer term duration and associated pollutants may effect ambient air, soil, and groundwater quality. EPA also believes that the discharge option would result in the generation of less harmful drill cuttings. For these reasons, under EPA's authority to consider the non-water quality environmental impacts of its rule, EPA rejects zero discharge of SBF-cuttings.

Nonetheless, while discharge with adequate controls is preferred over zero discharge, discharge with inadequate controls is not preferred over zero discharge. EPA believes that to allow discharge of SBF-cuttings, 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 determination of PAH content, sediment toxicity, biodegradation, bioaccumulation, the quantity of SBF discharged, and formation oil contamination. The successful completion of these efforts is necessary for EPA to continue to reject zero discharge.

3.1 BPT TECHNOLOGY OPTIONS CONSIDERED AND SELECTED

The BPT effluent limitations proposed would control free oil as a conventional pollutant. The limitation is no free oil as measured by the static sheen test, performed on SBF separated from the cuttings. In setting the no free oil limitation, EPA considered the sheen characteristics of currently available SBFs. Since this requirement is currently met by dischargers in the Gulf of Mexico, EPA anticipates no additional costs to the industry to comply with this limitation.

EPA also considered a BPT level of control for the quantity of SBF discharged with the cuttings consisting of improved use of currently existing shale shaker equipment. However, EPA did not have enough information to establish BPT beyond current performance. Further, EPA is not setting a BPT limit based on current performance because operators already have incentive to recover as much SBFs as possible through the optimization of existing equipment due to the value of the SBFs. Therefore, a BPT limitation based on the current equipment, and as it is currently used, would not have any practical effect on the quantity of SBF discharged with the cuttings. Further, given that the BAT and NSPS limitations would be more stringent and control the conventional pollutants in addition to the nonconventional and toxic pollutants, EPA saw no reason to expend time and resources to develop a different, less restrictive BPT limit.

3.2 BCT TECHNOLOGY OPTIONS CONSIDERED AND SELECTED

EPA is proposing to establish a BCT limitation of no free oil equivalent to the BPT limitation of no free oil as determined by the static sheen test. In developing BCT limits, EPA considered whether there are technologies (including drilling fluid formulations) that achieve greater removals of conventional pollutants than proposed 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 than proposed for BPT that are also cost-reasonable under the BCT Cost Test, and accordingly EPA proposes BCT effluent limitations equal to the proposed BPT effluent limitations guidelines.

3.3 BAT TECHNOLOGY OPTIONS CONSIDERED AND SELECTED

EPA proposes BAT effluent limitations for the cuttings contaminated with SBFs. The BAT effluent limitations proposed would control the stock base fluids in terms of PAH content, sediment toxicity, and biodegradation. Controls at the point of discharge include formation oil contamination and the quantity of SBF discharged. This level of control has been developed taking into consideration the availability and cost of oleaginous (SBF) base fluids in terms of PAH content, sediment toxicity, and biodegradation rate; the frequency of formation oil contamination at the control level; the performance and cost of equipment to recover SBF from the drill cuttings. The proposed BAT limitations are as follows:

- Stock Limitations on Base Fluids:
  - Maximum PAH content 10 ppm (wt. based on phenanthrene/wt. base fluid).
  - Minimum rate of biodegradation (biodegradation equal to or faster than C_{16} - C_{18} internal olefin by solid phase test).
  - Maximum sediment toxicity (as toxic or less toxic than C_{16} - C_{18} internal olefin by 10-day sediment toxicity test).

- Discharge Limitations on Cuttings Contaminated with SBFs:

    - Maximum formation oil contamination (95 percent of representative formation oils failing 1 percent by volume in drilling fluid). (BAT/NSPS)

    - Maximum well-average retention of SBF on cuttings (10.2 percent base fluid on wet cuttings). (BAT/NSPS)

3.3.1 Stock Base Fluid Technical Availability and Economic Achievability

The stock base fluid limitations are based on currently available base fluids, and the limitations would be achievable through product substitution. EPA anticipates that the currently available and economically achievable base fluids meeting all requirements would include vegetable esters and internal olefins. EPA also solicits data on linear alpha olefins and certain paraffinic oils to determine whether these base fluids are comparable in terms of sediment toxicity, biodegradation, and bioaccumulation.

EPA finds that the proposed stock base fluid controls are economically achievable. Since these base fluids are commonly used in the Gulf of Mexico, EPA anticipates no additional costs to industry as a result of these stock limitations other than monitoring (testing and certification) costs. EPA anticipates that any costs to comply with the stock limitations due to compliance testing with be minimal because EPA intends that the monitoring be performed only once per production batch for PAH content, and only once per year per trade name for sediment toxicity and biodegradation rate. Further, EPA anticipates that these costs will be absorbed by the supplier, but are not likely to significantly impact the pricing of the base fluids.

Industry representatives have told EPA that while the synthetic base fluids are more expensive than diesel and mineral oil base fluids, the savings in discharging the SBF-cuttings versus land disposal or reinjection of OBF-cuttings more than offsets the increased cost of SBFs. Thus, it reportedly costs less for operators to invest in the more expensive SBF provided it can be discharged. The analysis presented in Chapter VIII supports this claim. Costs for SBFs and OBFs using various base fluids are presented in Chapter VII.

Pursuant to EPA's further research into sediment toxicity and biodegradation, EPA may propose limits for the final rule that are different than the proposed limits. If the limits were to allow only more expensive SBFs, such as the vegetable ester, EPA would likely estimate a cost to comply with the stock base fluid limits for those operators who currently use and discharge the less expensive SBFs, for instance those based on internal olefins.

3.3.2 Discharge Limitations Technical Availability and Economic Achievability

3.3.2.1 Formation Oil Contamination of SBF-Cuttings

The proposed formation oil contamination limitation of the SBF adhered to the drill cuttings is "weighted" to detect contamination by highly aromatic formation oils at lower concentrations than formation oils with lower aromatic contents. Under the proposed limitation approximately 5 percent of all (all meaning a large representative sampling) formation oils would fail (not comply) at 0.1 percent contamination and 95 percent of all formation oils will fail at 1.0 percent contamination. The majority of formation oils would cause failure when present in SBFs at a concentration of about 0.5 percent (vol/vol).

EPA is proposing two methods for the determination of formation oil in SBFs. Analysis by gas chromatography with mass spectroscopy detection (GC/MS) would apply to any SBF being shipped offshore for drilling to allow discharge of the associated cuttings. During drilling, the SBF would be required to comply with the limitation of formation oil contamination as determined by the reverse phase extraction (RPE) method. SBFs found to be non-compliant by the RPE method could, at the operators discretion, be confirmed by testing with the GC/MS method. Results from the GC/MS method would supersede those of the RPE method.[1,2]

EPA intends that the limitation proposed on formation (crude) oil contamination in SBF is no less stringent that the limitation imposed on WBF through the static sheen test. A study concerning this issue found that in WBF, the static sheen test detected formation oil contamination in WBF down to 1 percent in most cases, and down to 0.5 percent in some cases.

Currently, only a very small percent of WBF cannot be discharged due to presence of formation oil as determined by the static sheen test.[3] EPA solicits information regarding the frequency of formation oil contamination at this level of control. EPA has received some anecdotal information to the effect that far less than one percent of SBF cuttings would not be discharged due to formation oil contamination at this level of control. Based on the available information, EPA believes that only a very minimal amount of SBF will be non-compliant with this limitation and therefore be required to dispose of SBF-cutting onshore or by injection. EPA thus finds that this limitation is technically available. EPA also finds this option to be economically achievable because there is no reason why formation oil contamination would occur more frequently under this rule than under the current rules which industry can economically afford. For calculation purposes, EPA has determined that no costs are associated with this requirement other than monitoring and reporting costs, which are minimal costs for this test for this industry.

3.3.2.2 Retention of SBF on Cuttings

This limitation considers the technical availability of methods to recover SBF from the cuttings wastestream. EPA evaluated the performance of several technologies to recover SBF from the cuttings wastestream and their costs, as detailed in Chapter VII of this document. EPA also considered fuel use, safety, and other considerations.

EPA has selected the vibrating centrifuge, treating drill cuttings from the primary shale shaker, as the model technology on which to base the limitation of base fluid on cuttings. The manufacturer of the device has supplied EPA with detailed performance data and some cost information of this device. The performance has been confirmed by one operator, showing retention data for twelve wells and comparing the vibrating centrifuge with shale shaker technology. EPA has analyzed the performance of the vibrating centrifuge, and reported the findings.[4,5] In addition, EPA was invited by an operator in the Gulf of Mexico to observe the operation of the vibrating centrifuge. The operator has informed EPA as to the cost of implementing the vibrating centrifuge, and EPA used this cost information in determining the total cost of implementation. EPA is aware of at least one other company that makes a similar centrifugal device to recover SBFs from drill cuttings, although EPA has not received performance or costs for this machine.

The proposed limitation for retention of SBF is 10.2 percent base fluid on wet cuttings (wt./wt.), averaged by hole volume over the well sections drilled with SBF. Those portions of the cuttings wastestream that are retained for no discharge are factored into the weighted average with a retention value of zero. The limit assumes that SBF-cuttings processed by the vibrating centrifuge technology comprise 80 percent of the wastestream while the remaining 20 percent is comprised of SBF-cuttings from the secondary shale shaker. Thus, from the available data EPA determined that the retention attained for 95 percent of volume-weighted well averages was 7.22 for the vibrating centrifuge and 22.0 for the secondary shale shakers.[4,5] Applying the assumption of an 80/20 split between the two wastestreams, EPA determined the weighted average retention regulatory limit of 10.2 percent.

Based on current performance of the vibrating centrifuge technology, 95 percent of all volume-weighted average values for retention of drilling fluids over the course of drilling a well are expected to be less than the proposed limit. Some, but not all, of the variability between wells is due to factors under the control of the operators. EPA believes that the proposed limit can be met at all times by providing better attention to the operation of the technology and by keeping track of the weighted average for retention as the well is being drilled. If the trend in weighted average retention appears to the operator as if the average retention for a particular well will exceed the limitation prior to completion of the well then EPA recommends that the operator retain some or all of the remaining cuttings for no discharge. This is feasible because retention of SBF on drill cuttings is generally low in the early stages of drilling a well and it increases as the well goes deeper.

The model technology that EPA identified has two wastestreams: 1) cuttings from the primary shale shaker feeding into the vibrating centrifuge, estimated to comprise 80 percent of the cuttings by weight, and 2) cuttings from the secondary shale shaker, estimated to comprise the remaining 20 percent of the cuttings. While the proposed limitation is based on this model technology [4], EPA does not intend to prescribe that this technology be used. The two wastestreams are an artifact of the model technology, so they may not always exist. EPA realizes that it may be possible for operators to treat all drill cuttings as a single wastestream. In fact, such processes are used in the North Sea with the vibrating centrifuge. Therefore, EPA did not want to implicitly prescribe that the two wastestreams of the model technology be used by maintaining limits on each wastestream separately. For this reason EPA has averaged the model limits, based on an estimate from industry representatives of the relative volume (80/20) of the two wastestreams.[6] EPA believes that the proposed limits can be met at all times by: (1) providing better attention to the operation of the technology, (2) keeping track of the average volume-weighted retention as the well is being drilled and (3) barging to shore or injecting a portion of the cuttings wastestream at some reasonable point prior to exceeding the limit, if this is ever necessary.

In the North Sea, the observed performance for the primary shale shakers used in series before the vibrating centrifuge was a volume-weighted average retention of 12.4 percent. This retention is 1.9 percentage points higher than the average volume-weighted retention of 10.5 percent observed for the primary shale shakers of the 21 wells in the Gulf of Mexico. This suggests that the vibrating centrifuge is likely to perform better in the Gulf of Mexico than in the North Sea, since the cuttings entering already have lower retention values. In the North Sea, all cuttings came from primary shale shakers, absent the use of secondary shale shakers, thereby eliminating the separate wastestream of cuttings from the secondary shale shakers. Elimination of the finer cuttings from the secondary shale shakers may also be possible in the Gulf of Mexico. Based on current information, however, EPA assumes that in Gulf of Mexico operations a portion of the cuttings discharges will be from the secondary shale shakers.

EPA finds that a well-average limit of 10.2 percent base fluid on wet cuttings is 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 $ 5.0 MM. This savings results because the value of the SBF recovered is greater than the cost of implementation of the technology, as shown by the detailed calculations presented in Chapter VIII of this document.

EPA thinks that this regulatory limitation is necessary to both hasten and broaden the use of improved SBF recovery devices, even though industry may be inclined to implement the SBF recovery technology to save valuable SBF irrespective of the limitation. There could be several reasons why industry does not already use the model SBF recovery technology even though, in EPA's assessment, it saves the operator money. For one, market acceptance and market penetration of the vibrating centrifuge could be a reason. The vibrating centrifuge recovery technology is a new technology that was developed in the North Sea and has only been demonstrated a few times in the United States. Secondly, the cost and resources devoted to retrofitting might only benefit a small portion of the wells drilled by an operator. This is because only a small fraction of wells, about 13 percent in EPA's analysis, are drilled with SBFs. To counter this, however, is the fact that most SBF wells are concentrated in the deep water. EPA projects that 75 percent of all wells drilled in the deepwater would use SBFs. In addition, retrofitting costs and market forces would encourage the dedication of drill platforms equipped with improved SBF recovery technology to the drilling of SBF wells. The use of improved SBF recovery devices in the North Sea is a case in point. Operators have reported to EPA that in the North Sea they were reluctant to use improved SBF recovery devices, and eventually did so only in response to more stringent regulatory requirements.[7] These operators report that their total cost to drill an SBF well actually went down as they implemented the improved SBF recovery devices because of the value of the SBF recovered.

3.4 NSPS TECHNOLOGY OPTIONS CONSIDERED AND SELECTED

The general approach followed by EPA for developing NSPS options was to evaluate the best demonstrated SBFs and processes for control of priority toxic, nonconventional, 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.[8] Therefore, EPA is proposing that NSPS be established equivalent to BPT for conventional pollutants and BAT for priority and nonconventional pollutants.

3.5 TABLES OF PROPOSED LIMITATIONS

The proposed regulation would amend the tables of 40 CFR Part 435, Subparts A (for offshore) and D (for coastal) in order to incorporate the new requirements for SBFs. The current tables do not specify drilling fluid type. This was appropriate when only WBFs and OBFs existed, because the current test methods were developed for WBFs, and the OBFs either failed the discharge compliance tests or were prohibited from discharge if they contained diesel oil. SBFs fall into the more general category of non-aqueous drilling fluids. The more general category of non-aqueous drilling fluids is used in the regulatory text because what is germane for the discharge is not whether the water immiscible base fluid are termed “synthetic,” but rather the base fluids’ compliance with the performance limitations based on PAH content, sediment toxicity, and biodegradation rate.

The tables shown below apply to both the offshore and coastal subcategories. For BAT and NSPS, the proposed limitations apply only where the discharge of drilling fluids and cuttings is currently allowed. In the offshore subcategory, this includes facilities located beyond 3 miles from shore, except in Alaska which has no three mile restriction. In the coastal subcategory, this includes facilities located in Cook Inlet, Alaska. While the requirements for WBFs have not changed, they are included in these tables to show how the applicability of the current guidelines is being specified for WBFs only. See Chapter III of this document for an explanation of where discharge is currently allowed and detailed definitions of the various drilling fluid types. Tables X-1 through X-3 show the limitations proposed under each option for the wastestream of drilling fluids and drill cuttings.

TABLE X-1

PROPOSED BPT AND BCT EFFLUENT LIMITATIONS

Waste Source	Pollutant Parameter	BPT/BCT Effluent Limitation
Water-based[2]		
Drilling fluids	Free oil	no discharge[1]
Drill cuttings	Free oil	no discharge[1]
Non-aqueous[2]		
Drilling fluids	---	no discharge
Drill cuttings	Free oil	no discharge[1]

[1] No discharge of free oil as determined by the static sheen test

[2] BCT Limitations in the Coastal Subcategory also include dewatering effluent, at the same level of control as drilling fluids.

TABLE X-2
PROPOSED BAT EFFLUENT LIMITATIONS

Waste Source	Pollutant Parameter	BAT Effluent Limitation
Water-based drilling fluids and drill cuttings[1]	SPP Toxicity	Minimum 96-hour LC50 of the SPP shall be 3% by volume[2]
	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[1]	---	No discharge
Cuttings associated with non-aqueous drilling fluids		
Stock Limitations	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)	Maximum 10 ppm wt. PAH based on phenanthrene/wt. of stock base fluid[5]
	Sediment Toxicity	10-day LC_{50} of stock base fluid minus 10-day LC_{50} of C_{16}-C_{18} internal olefin shall not be less than zero[6]
	Biodegradation Rate	Percent stock base fluid degraded at 120 days minus percent C_{16}-C_{18} internal olefin degraded at 120 days shall not be less than zero[7]
Discharge Limitations	Diesel oil	No discharge
	Formation Oil	No discharge[8]
	Base fluid retained on cuttings.	Maximum weighted average for well shall be 10.2 percent.[9,10]

1 BCT Limitations in the Coastal Subcategory also include dewatering effluent, at the same level of control as drilling fluids.

2 As determined by the suspended particulate phase toxicity test 40 CFR 435, Subpart A, Appendix 2.

3 As determined by the static sheen test 40 CFR 435, Subpart A, Appendix 1.

5 Proposed: As determined by *EPA Method 1654A: Polynuclear Aromatic Hydrocarbon Content of Oil by High Performance Liquid Chromatography with an Ultraviolet Detector* 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 (NTIS) (703/605-6000)].

6 Proposed: As determined by *ASTM E1367-92: Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods* (Incorporated by reference and available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA, 19428) supplemented with the sediment preparation procedure in 40 CFR 435, Subpart A, Appendix 3.

7 Proposed: As determined by the biodegradation test 40 CFR 435, Subpart A, Appendix 4.

8 Proposed: As determined by the GC/MS baseline and assurance method (40 CFR 435, Subpart A, Appendix 5), and by the RPE method applied to drilling fluid removed from cuttings at primary shale shakers (40 CFR 435, Subpart A, Appendix 6).

9 Proposed: Maximum permissible retention of base fluid on wet cuttings averaged over drill intervals using non-aqueous drilling fluids as determined by retort method (40 CFR 435, Subpart A, Appendix 7).

10 Corrected limitation would be 9.42 percent (Refs. 4 and 5).

TABLE X-3
PROPOSED NSPS EFFLUENT LIMITATIONS

Waste Source	Pollutant Parameter	NSPS Effluent Limitation
Water-based drilling fluids and drill cuttings[1]	SPP Toxicity	Minimum 96-hour LC50 of the SPP shall be 3% by volume[2]
	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[1]	---	No discharge
Cuttings associated with non-aqueous drilling fluids		
Stock Limitations	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)	Maximum 10 ppm wt. PAH based on phenanthrene/wt. of stock base fluid[5]
	Sediment Toxicity	10-day LC_{50} of stock base fluid minus 10-day LC_{50} of C_{16}-C_{18} internal olefin shall not be less than zero[6]
	Biodegradation Rate	Percent stock base fluid degraded at 120 days minus percent C_{16}-C_{18} internal olefin degraded at 120 days shall not be less than zero[7]
Discharge Limitations	Diesel oil	No discharge
	Free Oil	No Discharge[3]
	Formation Oil	No discharge[8]
	Base fluid retained on cuttings.	Maximum weighted average for well shall be 10.2 percent.[9,10]

1 BCT Limitations in the Coastal Subcategory also include dewatering effluent, at the same level of control as drilling fluids.
2 As determined by the suspended particulate phase toxicity test 40 CFR 435, Subpart A, Appendix 2.
3 As determined by the static sheen test 40 CFR 435, Subpart A,Appendix 1.
5 Proposed: As determined by *EPA Method 1654A: Polynuclear Aromatic Hydrocarbon Content of Oil by High Performance Liquid Chromatography with an Ultraviolet Detector* 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 (NTIS) (703/605-6000)].
6 Proposed: As determined by *ASTM E1367-92: Standard Guide for Conducting 10-day Static Sediment Toxicity Tests with Marine and Estuarine Amphipods* (Incorporated by reference and available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA, 19428) supplemented with the sediment preparation procedure in 40 CFR 435, Subpart A, Appendix 3.
7 Proposed: As determined by the biodegradation test 40 CFR 435, Subpart A, Appendix 4.
8 Proposed: As determined by the GC/MS baseline and assurance method (40 CFR 435, Subpart A, Appendix 5), and by the RPE method applied to drilling fluid removed from cuttings at primary shale shakers (40 CFR 435, Subpart A, Appendix 6).
9 Proposed: Maximum permissible retention of base fluid on wet cuttings averaged over drill intervals using non-aqueous drilling fluids as determined by retort method (40 CFR 435, Subpart A, Appendix 7).
10 Corrected limitation would be 9.42 percent (Refs. 4 and 5).

4.0 REFERENCES

1. Uhler, A.D., J.A. Seavey, and G.S. Durell, Battelle, "Laboratory Evaluation of Static Sheen Replacements: RPE Method (Final Draft Report)," plus addendum, November 16, 1998, with cover letter from Robert Moran, National Ocean Industries Association, to Joseph Daly, U.S. EPA, November 16, 1998.

2. Uhler, A.D., J.A. Seavey, and G.S. Durell, Battelle, "Laboratory Evaluation of Static Sheen Replacements: GC/MS Method (Draft Report)," November 16, 1998, with cover letter from Robert Moran, National Ocean Industries Association, to Joseph Daly, U.S. EPA, November 19, 1998.

3. Daly, Joseph, U.S. EPA, Memorandum regarding "Contamination of Synthetic-Based Drilling Fluid (SBF) with Crude Oil," January 14, 1999.

4. White, Charles E., and Henry D. Kahn, U.S. EPA, Statistics Analysis Section, Memorandum to Joseph Daly, U.S. EPA, Energy Branch, regarding "Current Performance, when using Synthetic-Based Drilling Fluids, for Primary Shakers, Secondary Shakers, and Vibrating Centrifuge and Model Limits for Percent Retention of Base Fluids on Cuttings for Secondary Shakers and Vibrating Centrifuge," January 29, 1999.

5. Daly, Joseph, U.S. EPA, Memorandum regarding "Correction to the Regulatory Limits for Retention of Base Fluid on Cuttings as Presented in the Preamble to the SBF Proposed Rule from 10.2 to 9.42 Percent," January 29, 1999.

6. Annis, Max R., "Procedures for Sampling and Testing Cuttings Discharged While Drilling with Synthetic-Based Muds," prepared for the American Petroleum Institute (API) *ad hoc* Retention on Cuttings Work Group under the API Production Effluent Guidelines Task Force, August 19, 1998.

7. Daly, Joseph, U.S. EPA, Memorandum regarding "Cost Savings Resulting from Increased Recovery of SBF from Drill Cuttings," February 1, 1999.

8. U.S. EPA, Economic Analysis of Proposed 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-98-020, February 1999.

CHAPTER XI

BEST MANAGEMENT PRACTICES

Sections 304(e) and 402(a) of the Act authorizes the Administrator to prescribe "best management practices" (BMPs) to control “plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage.” Section 402(a)(1) and NPDES regulation (40 CFR 122) also provide for best management practices to control or abate the discharge of pollutants when numeric limitations are infeasible. EPA may develop BMPs that apply to all industrial sites or to a designated industrial category and may offer guidance to permit authorities in establishing management practices required by unique circumstances at a given plant.

The proposed rule for SBFs does not establish BMPs. However, EPA is considering the use of BMPs as part of the final rule to address the requirement of zero discharge of SBF not associated with drill cuttings. EPA understands that there are occasional instances when spills of SBF occur, and that the location and perhaps even the timing of these spills is predictable. EPA has solicited comments from industry indicating the types of BMPs that would minimize or prevent SBF spills. EPA has also solicited comments from all stakeholders whether the zero discharge requirement should be controlled in these guidelines using BMPs or other means, such as a specific limitation.

GLOSSARY AND ABBREVIATIONS

Act: The Clean Water Act.

ADEC: Alaska Department of Environmental Conservation.

Agency: The U.S. Environmental Protection Agency.

Annular Injection: Injection of fluids into the space between the drill string or production tubing and the open hole or well casing.

Annulus or Annular Space: The space between the drill string or casing and the wall of the hole or casing.

AOGA: Alaskan Oil and Gas Association.

API: American Petroleum Institute.

ASTM: American Society of Testing and Materials.

Barite: Barium sulfate. An additive used to increase drilling fluid density.

Barrel (bbl): 42 United States gallons at 60 degrees Fahrenheit.

BAT: The best available technology economically achievable, under Section 304(b)(2)(B) of the Clean Water Act.

BADCT: The best available demonstrated control technology, for new sources under Section 306 of the Clean Water Act.

BCT: The best conventional pollutant control technology, under Section 301(b)(2)(E) of the Clean Water Act.

BMP: Best Management Practices under Section 304(e) of the Clean Water Act.

BOD: Biochemical oxygen demand.

BOE: Barrels of oil equivalent. Used to put oil production and gas production on a comparable volume basis. 1 BOE = 42 gallons of diesel and 1,000 scf of natural gas = 0.178 BOE.

bpd: Barrels per day.

BPJ: Best Professional Judgment.

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

bpy: Barrels per year.

Brine: Water saturated with or containing high concentrations of salts including sodium chloride, calcium chloride, zinc chloride, calcium nitrate, etc. Produced water is often called brine.

BTU: British Thermal Unit.

Casing: Large steel pipe used to “seal off” or “shut out” water and prevent caving of loose gravel formations when drilling a well. When the casings are set and cemented, drilling continues through and below the casing with a smaller bit. The overall length of this casing is called the casing string. More than one string inside the other may be used in drilling the same well.

CBI: Confidential Business Information.

Centrifuge: Filtration equipment that uses centrifugal force to separate substances of varying densities. A centrifuge is capable of spinning substances at high speeds to obtain high centrifugal forces. Also called the shake-out or grind-out machine.

cfd: cubic feet per day

CFR: Code of Federal Regulations.

Clean Water Act (CWA): The Federal Water Pollution Control Act of 1972 (33 U.S.C. 1251 et seq.), as amended by the Clean Water Act of 1977 (Pub. L. 95-217) and the Water Quality Act of 1987 (Pub. L. 100-4).

CO: Carbon Monoxide.

Completion: Activities undertaken to finish work on a well and bring it to productive status.

Condensate: Liquid hydrocarbons which are in the gaseous state under reservoir conditions but which become liquid either in passage up the hole or in the surface equipment.

Connate Water: Water that was laid down and entrapped with sedimentary deposits as distinguished from migratory waters that have flowed into deposits after they were laid down.

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

Deck Drainage: All wastes resulting from platform washings, deck washings, spills, rainwater, and runoff from curbs, gutters, and drains, including drip pans and wash areas.

Depth Interval: Interval at which a drilling fluid system is introduced and used, such as from 2,200 to 2,800 ft.

Development Facility: Any fixed or mobile structure addressed by this document that is engaged in the drilling of potentially productive wells.

Dewatering Effluent: The wastewater derived from dewatering drill cuttings.

Diesel Oil: The grade of distillate fuel oil, as specified in the American Society for Testing and Materials' Standard Specification D975-81.

Disposal Well: A well through which water (usually salt water) is returned to subsurface formations.

DOE: Department of Energy

Domestic Waste: Materials discharged from sinks, showers, laundries, and galleys located within facilities addressed by this document. Included with these wastes are safety shower and eye wash stations, hand wash stations, and fish cleaning stations.

DMR: Discharge Monitoring Report.

Drill Cuttings: Particles generated by drilling into subsurface geologic formations and carried to the surface with the drilling fluid.

Drill Pipe: Special pipe designed to withstand the torsion and tension loads encountered in drilling.

Drilling Fluid: The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-based drilling fluid is the conventional drilling fluid in which water is the continuous phase and the suspending medium for solids, whether or not oil is present. An oil-base drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase.

Drilling Fluid System: System consisting primarily of mud storage tanks or pits, mud pumps, stand pipe, kelly hose, kelly, drill string, well annulus, mud return flowline, and solids separation equipment. The primary function of circulating the drilling fluid is to lubricate the drill bit, and to carry drill cuttings rock fragments from the bottom of the hole to the surface where they are separated out.

DWD: Deep-water development well.

DWE: Deep-water exploratory well.

Emulsion: A stable heterogenous mixture of two or more liquids (which are not normally dissolved in each other held in suspension or dispersion, one in the other, by mechanical agitation or, more frequently, by the presence of small amounts of substances known as emulsifiers. Emulsions may be oil-in-water, or water-in-oil.

Enhanced Mineral Oil-Based Drilling Fluid: A drilling fluid that has an enhanced mineral oil as its continuous phase with water as the dispersed phase. Enhanced mineral oil-based drilling fluids are a subset of non-aqueous drilling fluids.

ENR-CCI: Engineering News Record-Construction Indices.

EPA (or U.S. EPA): U.S. Environmental Protection Agency.

Exploratory Well: A well drilled either in search of an as-yet-undiscovered pool of oil or gas (a wildcat well) or to extend greatly the limits of a known pool. It involves a relatively high degree of risk. Exploratory wells may be classified as (1) wildcat, drilled in an unproven area; (2) field extension or step-out, drilled in an unproven area to extend the proved limits of a field; or (3) deep test, drilled within a field area but to unproven deeper zones.

Facility: See Produced Water Separation/ Treatment Facility.

Field: A geographical area in which a number of oil or gas wells produce hydrocarbons from an underground reservoir. A field may refer to surface area only or to underground productive formations as well. A single field may have several separate reservoirs at varying depths.

Flocculation: The combination or aggregation of suspended solid particles in such a way that they form small clumps or tufts resembling wool.

Footprint: The square footage covered by various production equipment.

Formation: Various subsurface geological strata.

Formation Damage: Damage to the productivity of a well resulting from invasion of drilling fluid particles or other substances into the formation.

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.

gph: Gallons per hour.

gpm: Gallons per minute.

hp: Horsepower.

Indirect Discharger: A facility that introduces wastewater into a publically owned treatment works.

Injection Well: A well through which fluids are injected into an underground stratum to increase reservoir pressure and to displace oil, or for disposal of produced water and other wastes.

Internal Olefin (IO): A series of isomeric forms of C_{16} and C_{18} alkenes.

kW: Kilowatt.

LC_{50}: The concentration of a test material that is lethal to 50% of the test organisms in a bioassay.

LDEQ: Louisiana Department of Environmental Quality.

Lease: A legal document executed between a landowner, as lessor, and a company or individual as lessee, that grants the right to exploit the premises for minerals; the instrument that creates a leasehold or working interest in minerals.

Linear Alpha Olefin (LAO): A series of isomeric forms of C_{14} and C_{16} monoenes.

m: Meters.

mcf: Thousand cubic feet.

µg/l: Micrograms per liter.

mg/l: Milligrams per liter.

MM: Million.

MMcfd: Million cubic feet per day.

MMS: Department of Interior Minerals Management Service.

MMscf: Million standard cubic feet.

Mscf: Thousand standard cubic feet.

Mud: Common term for drilling fluid.

Mud Pit: A steel or earthen tank which is part of the surface drilling fluid system.

Mud Pump: A reciprocating, high pressure pump used for circulating drilling fluid.

NO_x: Nitrogen Oxide.

Non-Aqueous Drilling Fluid: A drilling fluid in which the continuous phase is a water-immiscible fluid such as an oleaginous material (e.g., mineral oil, enhanced mineral oil, paraffinic oil, or synthetic material such as olefins and vegetable esters).

Nonconventional Pollutants: Pollutants that have not been designated as either conventional pollutants or priority pollutants.

NOIA: National Ocean Industries Association.

NOW: Nonhazardous Oilfield Waste.

NPDES: National Pollutant Discharge Elimination System.

NPDES Permit: A National Pollutant Discharge Elimination System permit issued under Section 402 of the Act.

NRDC: Natural Resources Defence Council, Incorporated.

NSPS: New source performance standards under Section 306 of the Act.

NWQEI: Non-water quality environmental impact.

O&M: Operating and maintenance.

OCS: Offshore Continental Shelf.

Oil-Based Drilling Fluid (OBF): A drilling fluid that has diesel oil, mineral oil, or some other oil, but neither a synthetic material nor enhanced mineral oil, as its continuous phase with water as the dispersed phase. Oil-based drilling fluids are a subset of non-aqueous drilling fluids.

Oil-based Pill: Mineral or diesel oil injected into the mud circulation system as a slug, for the purpose of freeing stuck pipe.

Offshore Development Document: U.S. EPA, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, Final, EPA 821-R-93-003, January 1993.

Operator: The person or company responsible for operating, maintaining, and repairing oil and gas production equipment in a field; the operator is also responsible for maintaining accurate records of the amount of oil or gas sold, and for reporting production information to state authorities.

PAH: Polynuclear Aromatic Hydrocarbon.

Poly Alpha Olefin (PAO): 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%).

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 Act.

Produced Sand: Slurried particles used in hydraulic fracturing and the accumulated formation sands and other particles that can be generated during production. This includes desander discharge from the produced water waste stream and blowdown of the water phase from the produced water treating system.

Produced Water: Water (brine) brought up from the hydrocarbon-bearing strata with the produced oil and gas. This includes brines trapped with the oil and gas in the formation, injection water, and any chemicals added downhole or during the oil/water separation process.

Produced Water Separation/Treatment Facilities: A “facility” is any group of tanks, pits, or other apparatus that can be distinguished by location, e.g., on-site/off-site or wetland/upland and/or by disposal stream (any produced water stream that is not recombined with other produced water streams for further treatment or disposal, but is further treated and/or disposed of separately). The facility may thus be, for example, an on-site tank battery, an off-site gathering center, or a commercial disposal operation. The primary focus is on treatment produced water, not on treating oil.

Production Facility: Any fixed or mobile facility that is used for active recovery of hydrocarbons from producing formations. The production facility begins operations with the completion phase.

PSES: Pretreatment Standards for Existing Sources of indirect dischargers, under Section 307(b) of the Act.

psi: pounds per square inch.

psig: pounds per square inch gauge.

PSNS: Pretreatment Standards for New Sources of indirect dischargers, under Section 307(b) and (c) of the Act.

RCRA: Resource Conservation and Recovery Act (Pub. L. 94-580) of 1976. Amendments to Solid Waste Disposal Act.

Recompletion: When additional drilling occurs at an existing well after the initial completion of the well and drilling waste is generated.

Reservoir: Each separate, unconnected body of a producing formation.

Rotary Drilling: The method of drilling wells that depends on the rotation of a column of drill pipe with a bit at the bottom. A fluid is circulated to remove the cuttings.

RPE: Reverse Phase Extraction.

RRC: Railroad Commission of Texas.

Sanitary Waste: Human body waste discharged from toilets and urinals located within facilities addressed by this document.

scf: standard cubic feet.

Shut In: To close valves on a well so that it stops producing; said of a well on which the valves are closed.

SIC: Standard Industrial Classification.

SO_2: Sulfur Dioxide.

SPP: Suspended Particulate Phase.

SWD: Shallow-water development well.

SWE: Shallow-water exploratory well.

Synthetic-Based Drilling Fluid (SBF): A drilling fluid that has a synthetic material as its continuous phase with water as the dispersed phase. Synthetic-based drilling fluids are a subset of non-aqueous drilling fluids.

Territorial Seas: The belt of the seas measured from the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters, and extending seaward a distance of 3 miles.

THC: Total hydrocarbons.

TSP: Total suspended particulates.

TSS: Total Suspended Solids.

TWC: Treatment, workover, and completion.

UIC: Underground Injection Control.

Upland Site: A site not located in a wetland area. May be an onshore site or a coastal site under the Chapman Line definition.

U.S.C.: United States Code.

USCG: United States Coast Guard.

USDW: Underground Sources of Drinking Water.

USGS: United States Geological Survey.

Vegetable Ester: A monoester of 2-ethylhexanol and saturated fatty acids with chain lengths in the range C_8 - C_{16}.

Water-Based Drilling Fluid (WBF): A drilling fluid in which water or a water miscible fluid is the continuous phase and the suspending medium for solids, whether or not oil is present.

Workover: The performance of one or more of a variety of remedial operations on a producing oilwell to try to increase production. Examples of workover jobs are deepening, plugging back, pulling and re-setting liners, and squeeze cementing.

APPENDIX VII-1

CALCULATION OF DISCHARGED CUTTINGS COMPOSITION

Deep, Development Model Well Data
Calculation of Discharged Cuttings Composition for Two Levels of Solids Control

11% (wt) Retention of SBF on Cuttings with 0.2% (vol) Crude Contamination

Total Waste in pounds (TW) = 0.11 TW + [0.11 (0.2/0.47)] TW + [0.11(0.33/0.47)] TW + (fraction that is DC) TW
= 0.11 TW + 0.0468TW + 0.0772TW + 0.76601 TW

		lbs	bbls
TW =	DC/0.7660=	1,015,731	**1,442**
synthetic =	0.11 TW =	111,730	399
water =	0.0468 TW=	47,536	136
barite =	0.0772 TW =	78,414	52
cuttings =	model well size =	778,050	855

Adding 0.2% (vol) crude to whole mud discharged:

	bbls	lbs
Total drilling fluid discharged with cuttings =	587	237,681
0.2% (vol) crude:	1.2	345
Total drilling fluid plus crude discharged =	**588**	238,026
Sum of synthetic plus crude =	400	**112,076**

7% (wt) Retention of SBF on Cuttings with 0.2% (vol) Crude Contamination

Total Waste in pounds (TW) = 0.07 TW + [0.07 (0.2/0.47)] TW + [0.07(0.33/0.47)] TW + (fraction that is DC) TW
= 0.07 TW + 0.0298TW + 0.0491TW + 0.8511 TW

		lbs	bbls
TW =	DC/0.8511=	914,170	**1,191**
synthetic =	0.07 TW =	63,992	229
water =	0.0298 TW=	27,242	78
barite =	0.0491 TW =	44,886	30
cuttings =	model well size =	778,050	855

Adding 0.2% (vol) crude to whole mud discharged:

	bbls	lbs
Total drilling fluid discharged with cuttings =	336	136,120
0.2% (vol) crude:	0.7	198
Total drilling fluid plus crude discharged =	**337**	136,318
Sum of synthetic plus crude =	229	**64,190**

Deep, Exploratory Model Well Data
Calculation of Discharged Cuttings Composition for Two Levels of Solids Control

11% (wt) Retention of SBF on Cuttings with 0.2% (vol) Crude Contamination

Total Waste in pounds (TW) = 0.11 TW + [0.11 (0.2/0.47)] TW + [0.11(0.33/0.47)] TW + (fraction that is DC) TW
= 0.11 TW + 0.0468TW + 0.0772TW + 0.7660 TW

		lbs	bbls
TW =	DC/0.7660=	2,258,368	**3,206**
synthetic =	0.11 TW =	248,420	887
water =	0.0468 TW=	105,692	302
barite =	0.0772 TW =	174,346	116
cuttings =	model well size =	1,729,910	1,901

Adding 0.2% (vol) crude to whole mud discharged:

	bbls	lbs
Total drilling fluid discharged with cuttings =	1,305	528,458
0.2% (vol) crude:	2.6	767
Total drilling fluid plus crude discharged =	**1,308**	529,225
Sum of synthetic plus crude =	890	**249,188**

7% (wt) Retention of SBF on Cuttings with 0.2% (vol) Crude Contamination

Total Waste in pounds (TW) = 0.07 TW + [0.07 (0.2/0.47)] TW + [0.07(0.33/0.47)] TW + (fraction that is DC) TW
= 0.07 TW + 0.0298TW + 0.0491TW + 0.8511 TW

		lbs	bbls
TW =	DC/0.8511=	2,032,558	**2,648**
synthetic =	0.07 TW =	142,279	508
water =	0.0298 TW=	60,570	173
barite =	0.0491 TW =	99,799	66
cuttings =	model well size =	1,729,910	1,901

Adding 0.2% (vol) crude to whole mud discharged:

	bbls	lbs
Total drilling fluid discharged with cuttings =	747	302,648
0.2% (vol) crude:	1.5	440
Total drilling fluid plus crude discharged =	**749**	303,087
Sum of synthetic plus crude =	510	**142,719**

Shallow, Development Model Well Data
Calculation of Discharged Cuttings Composition for Two Levels of Solids Control

11% (wt) Retention of SBF on Cuttings with 0.2% (vol) Crude Contamination

Total Waste in pounds (TW) = 0.11 TW + [0.11 (0.2/0.47)] TW + [0.11(0.33/0.47)] TW + (fraction that is DC) TW
= 0.11 TW + 0.0468TW + 0.0772TW + 0.7660 TW

		lbs	bbls
TW =	DC/0.7660=	671,214	**953**
synthetic =	0.11 TW =	73,834	264
water =	0.0468 TW=	31,413	90
barite =	0.0772 TW =	51,818	34
cuttings =	model well size =	514,150	565

Adding 0.2% (vol) crude to whole mud discharged:

	bbls	lbs
Total drilling fluid discharged with cuttings =	388	157,064
0.2% (vol) crude:	0.8	228
Total drilling fluid plus crude discharged =	**389**	157,292
Sum of synthetic plus crude =	264	**74,062**

7% (wt) Retention of SBF on Cuttings with 0.2% (vol) Crude Contamination

Total Waste in pounds (TW) = 0.07TW + [0.07 (0.2/0.47)] TW + [0.07(0.33/0.47)] TW + (fraction that is DC) TW
= 0.07 TW + 0.0298TW + 0.0491TW + 0.8511 TW

		lbs	bbls
TW =	DC/0.8511=	604,101	**787**
synthetic =	0.07 TW =	42,287	151
water =	0.0298 TW=	18,002	51
barite =	0.0491 TW =	29,661	20
cuttings =	model well size =	514,150	565

Adding 0.2% (vol) crude to whole mud discharged:

	bbls	lbs
Total drilling fluid discharged with cuttings =	222	89,951
0.2% (vol) crude:	0.4	131
Total drilling fluid plus crude discharged =	**223**	90,081
Sum of synthetic plus crude =	151	**42,418**

Shallow, Exploratory Model Well Data
Calculation of Discharged Cuttings Composition for Two Levels of Solids Control

11% (wt) Retention of SBF on Cuttings with 0.2% (vol) Crude Contamination

Total Waste in pounds (TW) = 0.11 TW + [0.11 (0.2/0.47)] TW + [0.11(0.33/0.47)] TW + (fraction that is DC) TW
= 0.11 TW + 0.0468TW + 0.0772TW + 0.7660 TW

		lbs	bbls
TW =	DC/0.7660=	1,406,580	**1,997**
synthetic =	0.11 TW =	154,724	553
water =	0.0468 TW=	65,828	188
barite =	0.0772 TW =	108,588	72
cuttings =	model well size =	1,077,440	1,184

Adding 0.2% (vol) crude to whole mud discharged:

	bbls	lbs
Total drilling fluid discharged with cuttings =	813	329,140
0.2% (vol) crude:	1.6	478
Total drilling fluid plus crude discharged =	**814**	329,618
Sum of synthetic plus crude =	554	**155,202**

7% (wt) Retention of SBF on Cuttings with 0.2% (vol) Crude Contamination

Total Waste in pounds (TW) = 0.07 TW + [0.07 (0.2/0.47)] TW + [0.07(0.33/0.47)] TW + (fraction that is DC) TW
= 0.07 TW + 0.0298TW + 0.0491TW + 0.8511 TW

		lbs	bbls
TW =	DC/0.8511=	1,265,938	**1,650**
synthetic =	0.07 TW =	88,616	316
water =	0.0298 TW=	37,725	108
barite =	0.0491 TW =	62,158	41
cuttings =	model well size =	1,077,440	1,184

Adding 0.2% (vol) crude to whole mud discharged:

	bbls	lbs
Total drilling fluid discharged with cuttings =	466	188,498
0.2% (vol) crude:	0.9	274
Total drilling fluid plus crude discharged =	**466**	188,772
Sum of synthetic plus crude =	317	**88,889**

APPENDIX VIII-1

ZERO DISCHARGE:
HAULING AND ONSHORE WASTE DISPOSAL
CALCULATION OF SUPPLY BOAT FREQUENCY

SUPPLY BOAT FREQUENCY WORKSHEET

GULF OF MEXICO

Assumptions:	Source:
1. Cuttings box capacity = 25 bbl	Walk Haydel, 1989
2. Dedicated supply boat capacity = 80 boxes	Kennedy, 1998
3. Regularly scheduled supply boat arrives at rig every 4 days	Walk Haydel, 1989
4. Regularly scheduled supply boat capacity = 12 boxes	Walk Haydel, 1989
5. Supply boat speed = 11.5 miles per hour	Walk Haydel, 1989
6. Platform/rig cuttings storage capacity = 12 boxes	Walk Haydel, 1989
7. Total roundtrip distance for dedicated supply boat = 277 miles (Port to rig = 100 mi.; rig to disposal terminal = 117 mi.; terminal to port = 60 mi.)	Walk Haydel, 1989
8. Incremental mileage for regularly scheduled supply boat = 77 miles (Total roundtrip - regular port to rig roundtrip = 277 - 200 = 77 mi.)	Walk Haydel, 1989
9. Supply boat maneuvering time at rig = 1hr per trip	Jacobs Engineering, 1989
10. Additional boat idling at rig due to potential delays = 1.6 hrs per trip	EPA, 1993
11. Supply boat in-port unloading time and demurrage = 24 hrs per trip	Walk Haydel, 1989
12. Truck capacity = 119 bbls	Walk Haydel, 1989
13. Roundtrip trucking distance from port to disposal facility = 20 miles	EPA, 1996

Deep Water Development Model Wells

Waste volume generated = 1,442 bbl	Table VII-4
Number of boxes of waste generated = 1442/25 = 58 boxes	
Number of days to drill model well = 5.4 days	Pechan-Avanti, 1999
Number of supply boat trips = 1 dedictated trip	

Number of days for supply boat:
(277 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (24 hrs per day*5.4 drilling days) + (24 hr demurrage) = 180.29 hrs = 7.51 days

Number of truck roundtrips = 1442/119 = 13 trips
Total truck miles = 13 * 20 = 260 mi.

Deep Water Exploratory Model Wells

Waste volume generated = 3,206 bbl	Table VII-4
Number of boxes of waste generated = 3206/25 = 129 boxes	
Number of days to drill model well = 12 days	Pechan-Avanti, 1999
Number of supply boat trips = 2 dedictated trips; 1 regularly scheduled trip	

Number of days for first dedicated supply boat:
(277 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (24 hrs per day*7 drilling days) + (24 hr demurrage) = 218.7 hrs = 9.11 days

Number of days for regularly scheduled supply boat:
(77 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (22 boxes/10 boxes per hr loading) + (24 hr demurrage) = 35.50 hrs = 1.48 days

Number of days for second dedicated supply boat:
(277 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (24 hrs per day*4 drilling days) + (24 hr demurrage) = 146.69 hrs = 6.11 days

Supply boat days = 15.22 days for dedicated + 1.48 days for regularly scheduled = 16.70 days

Number of truck roundtrips = 3206/119 = 27 trips
Total truck miles = 27 * 20 = 540 mi.

Shallow Water Development Model Wells

Waste volume generated = 953 bbl	Table VII-4
Number of boxes of waste generated = 953/25 = 39 boxes	
Number of days to drill model well = 3.6 days	Pechan-Avanti, 1999
Number of supply boat trips = 1 dedictated trip	

Number of days for supply boat:
(277 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (24 hrs per day*3.6 drilling days) + (24 hr demurrage) = 137.09 hrs = 5.71 days

Number of truck roundtrips = 953/119 = 8 trips
Total truck miles = 8 * 20 = 160 mi.

Shallow Water Exploratory Model Wells

Waste volume generated = 1,997 bbl	Table VII-4
Number of boxes of waste generated = 1997/25 = 80 boxes	
Number of days to drill model well = 7.5 days	Pechan-Avanti, 1999
Number of supply boat trips = 1 dedictated trip	

Number of days for supply boat:
(277 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (24 hrs per day*7.5 drilling days) + (24 hr demurrage) = 230.69 hrs = 9.61 days

Number of truck roundtrips = 1997/119 = 17 trips
Total truck miles = 17 * 20 = 340 mi.

OFFSHORE CALIFORNIA

Assumptions:	Source:
1. Cuttings box capacity = 25 bbl	Walk Haydel, 1989
2. Dedicated supply boat capacity = 80 boxes	Kennedy, 1998
3. Supply boat speed = 11.5 miles per hour	Walk Haydel, 1989
4. Platform/rig cuttings storage capacity = 12 boxes	Walk Haydel, 1989
5. Total roundtrip distance for dedicated supply boat = 200 miles (Port to rig = 100 mi)	Walk Haydel, 1989
6. Supply boat maneuvering time at rig = 1hr per trip	Jacobs Engineering, 1989
7. Additional boat idling at rig due to potential delays = 1.6 hrs per trip	EPA, 1993
8. Supply boat in-port unloading time and demurrage = 24 hrs per trip	Walk Haydel, 1989
9. Truck capacity = 50 bbls	Walk Haydel, 1989
10. Roundtrip trucking distance from port to disposal facility = 300 miles	Mileage from Bakersfield to Ventura, California

Deep Water Development Model Wells

Waste volume generated = 1,442 bbl	Table VII-4
Number of boxes of waste generated = 1442/25 = 58 boxes	
Number of days to drill model well = 5.4 days	Pechan-Avanti, 1999
Number of supply boat trips = 1 dedictated trip	

Number of days for supply boat:
(200 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (24 hrs per day*5.4 drilling days) + (24 hr demurrage) = 173.59 hrs = 7.23 days

Number of truck roundtrips = 1442/50 = 29 trips
Total truck miles = 29 * 300 = 8700 mi.

Shallow Water Development Model Wells

Waste volume generated = 953 bbl	Table VII-4
Number of boxes of waste generated = 953/25 = 39 boxes	
Number of days to drill model well = 3.6 days	Pechan-Avanti, 1999
Number of supply boat trips = 1 dedictated trip	

Number of days for supply boat:
(200 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (24 hrs per day*3.6 drilling days) + (24 hr demurrage) = 130.39 hrs = 5.43 days
Number of truck roundtrips = 953/50 = 20 trips
Total truck miles = 20 * 300 = 6000 mi.

COOK INLET, ALASKA

Assumptions:	Source:
1. Cuttings box capacity = 8 bbl	EPA, 1996
2. Dedicated supply boat capacity = 132 boxes	EPA, 1996
3. Supply boat speed = 11.5 miles per hour	Walk Haydel, 1989
4. Platform/rig cuttings storage capacity = 12 boxes	Walk Haydel, 1989
5. Total roundtrip distance for dedicated supply boat = 50 miles (Port to rig = 25 mi)	EPA, 1996
6. Supply boat maneuvering time at rig = 1hr per trip	Jacobs Engineering, 1989
7. Additional boat idling at rig due to potential delays = 1.6 hrs per trip	EPA, 1993
8. Supply boat in-port unloading time and demurrage = 24 hrs per trip	Walk Haydel, 1989
9. Truck capacity = 64 bbls	EPA, 1996
10. Trucking distance from port to disposal facility in Oregon = 2,200 miles	EPA, 1996

Shallow Water Development Model Wells

Waste volume generated = 953 bbl	Table VII-4
Number of boxes of waste generated = 953/25 = 39 boxes	
Number of days to drill model well = 3.6 days	Pechan-Avatni, 1999
Number of supply boat trips = 1 dedictated trip	

Number of days for supply boat:
(50 mi/11.5 mi per hr) + (1 hr maneuvering) + (1.6 hrs add. idling at rig) + (24 hrs per day*3.6 drilling days) + (24 hr demurrage) = 117.35 hrs = 4.89 days

Number of truck trips = 953/64 = 15 trips
Total truck miles = 15 * 2200 = 11,000 mi.

Sources:

Walk Haydel: Carriere, J. and E. Lee, Walk, Haydel and Associates, Inc., "Water-Based Drilling Fluids and Cuttings Disposal Study Update," Offshore Effluent Guidelines Comments Research Fund Administered by Liskow and Lewis, January 1989.

Kennedy, 1998: Kennedy, Kerri, The Pechan-Avanti Group, Telecommunications Report on conversation with John Belsome, Seabulk Offshore Ltd., regarding "Offshore supply boat costs and specifications," June 3, 1998.

Jacobs Engineering: Jacobs Engineering Group, "Air Quality Impact of Proposed Lease Sale No. 95," prepared for U.S. Department of the Interior, Minerals Management Service, June 1989.

EPA, 1993: U.S. Environmental Protection Agency, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, Final, EPA 821-R-93-003, January 1993.

EPA, 1996: U.S. Environmental Protection Agency, Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category, EPA 821-R-96-023, October 1996.

Pechan-Avanti: The Pechan-Avanti Group, Worksheet regarding "Number of Days to Drill Model SBF Wells," October 27, 1998.

APPENDIX VIII-2

BAT COMPLIANCE COST CALCULATIONS

Summary BAT Costs for Management of SBF Cuttings (1997$)
"20% OBF Wells Convert" Scenario

Baseline Costs: Total Annual

Baseline Technology	GOM	CA-Offshore	AK-Cook	**Total Per Techn.**	NOTES
Discharge with 11% retention of base fluid on cuttings (94 SBF wells in GOM)	19,113,650	0	0	**19,113,650**	From Worksheet No. 1
Zero Discharge--current OBF users only (23 GOM wells; 12 CA wells; 1 AK well)	2,821,816	2,157,023	207,733	**5,186,572**	From Worksheet No.s 1, 2, and 3
TOTAL Per Region	**21,935,466**	**2,157,023**	**207,733**	**24,300,222**	

Compliance Costs: Total Annual

Option	GOM	CA-Offshore	AK-Cook	Total	NOTES
Discharge with 7% retention of base fluid on cuttings*	15,950,550	1,647,883	115,467	**17,713,900**	From Worksheet No.s 4, 5, and 6
Zero Discharge (94 current SBF wells)	26,077,546	NA	NA	**26,077,546**	From Worksheet No.s 7, 8, and 9

*For GOM: 94 current SBF wells + 23 current OBF wells
For CA: 12 wells
For Cook Inlet, AK: 1 well

Incremental Compliance Costs: Total Annual

Option	GOM	CA-Offshore	AK-Cook	Total	NOTES
Discharge with 7% retention of base fluid on cuttings	(5,984,916)	(509,140)	(92,265)	**(6,586,322)**	Diff. btwn compliance and total baseline cost
Zero Discharge**	6,963,896	0	0	**6,963,896**	Diff. btwn compliance cost and discharge baseline cost

**Compares zero-discharge compliance costs to baseline discharge costs for 94 wells currently using SBF and discharging SBF-coated cuttings.

Worksheet No. 1
Compliance Cost Estimates: Baseline Current Practice

Region:	Offshore Gulf of Mexico
Technologies:	Discharge of SBF-cuttings via primary and secondary shale shakers w/ average retention of 11% (wt) base fluid on cuttings Zero discharge of OBF cuttings via haul & land-dispose (80%) plus on-site grinding and injection (20%)
Model Well Types:	All four types: Deep- and Shallow-water, Development and Exploratory
Per-Well Waste Volumes:	
Deep-water Development:	1,442 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination) 587 bbls SBF/OBF lost with cuttings
Deep-water Exploratory:	3,206 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination) 1,305 bbls SBF/OBF lost with cuttings
Shallow-water Development:	953 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination) 388 bbls SBF/OBF lost with cuttings
Shallow-water Exploratory:	1,997 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination) 813 bbls SBF/OBF lost with cuttings

Cost Item	Deep-Water Using SBF		Shallow-Water Using SBF		Shallow-Water Using OBF		TOTAL	Notes
	Development	Exploratory	Developmen	Exploratory	Development	Exploratory		
Drilling Fluid Costs for Wells Currently Using SBF (SBF@ $200/bbl lost w/ cuttings)	117,400	261,000	77,600	162,600	---	---		**Section VIII.3.1.3.2**
SPP Toxicity Monitoring Test	575	575	575	575				**Section VIII.3.1.3.1**
Per-Well Cost to Haul and Dispose ($/well)	---	---	---	---	97,288	191,490		**From Worksheet No. 7 (GOM Haul & Dispose); includes cost of drilling fluid lost w/ cuttings**
Per-Well Cost to Grind and Inject ($/well)	---	---	---	---	67,620	141,225		**From Worksheet No. 8 (GOM Injection); includes cost of drilling fluid lost w/ cuttings**
Per Well Baseline Cost ($/well)	117,975	261,575	78,175	163,175	91,355	181,437		**Assumes for wells currently using OBF: 80% hauls and 20% injects**
Unit Cost ($/bbl)	82	82	82	82	96	91		
No. Wells	18	57	12	7	15	8		**For wells currently using OBF, 20% (23 of 112 will convert from OBF to SBF**
TOTAL ANNUAL BASELINE GOM COST ($)	2,123,550	14,909,775	938,100	114,222	1,370,318	1,451,498	21,935,466	**Per-well costs x no. of wells**
	Subtotal for SBF Wells:			**19,113,650**				
	Subtotal for OBF Wells:					**2,821,816**		

Worksheet No. 2
Compliance Cost Estimates: Baseline Current Practice

Region:	Offshore California	
Technology:	Zero-Discharge via Haul and Land-Dispose	
Model Well Types:	Deep- and Shallow-water Development Wells	
Per-Well Waste Volumes:		
Deep-water Devel.:	1,442	bbls waste OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	587	bbls OBF lost with cuttings
Shallow-water Devel:	953	bbls waste OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	388	bbls OBF lost with cuttings

Cost Item	Deep-Water Devel. Well	Shallow-Water Devel. Well	**TOTAL**	Notes
Disposal Cost ($12.32/bbl)	17,765	11,741		Vendor quote of $35/ton x 704 lbs cuttings/bbl (Section VIII.3.1.4.1)
Handling Cost ($7.52/bbl)	8,350	5,518		Handling costs = 47% of disposal costs (proportion from GOM costs)
Container Rental ($40/box/day * "x" boxes* "y" days to fill & haul)	16,704	8,424		GOM vendor quote times geographic area multiplier: ($25/box/day x 1.6) (Section VIII.3.1.4.1)
Supply Boat Cost ($8,500/day)	61,200	45,900		Vendors (Section VIII.3.1.4.1)
Trucking Cost ($354/truck load)	10,266	6,903		Truck rate ($65/hr x 300 mi r.t. @55mph) x "x" boxes @ 2 boxes per truck (Section VIII.3.1.4.1)
Drilling Fluid Costs (OBF lost with cuttings @ $120/bbl)	70,440	46,560		GOM vendor quote times geographic area multiplier ($75/bbl x 1.6) (Section VIII.3.1.4.1)
TOTAL Cost per Model Well ($)	**184,725**	**125,046**		
Unit Cost ($/bbl)	**128**	**131**		
No. Wells	**11**	**1**		
TOTAL ANNUAL BASELINE CA COST ($)	**2,031,977**	**125,046**	**2,157,023**	Per-well costs x no. of wells

Worksheet No. 3
Compliance Cost Estimates: Baseline Current Practice

Region: Cook Inlet, Alaska
Technology: Zero-Discharge via Haul and Land-Dispose
Model Well Types: Shallow-Water Development Wells
Per-Well Waste Volumes:
Shallow-water Devel: 953 bbls waste OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
388 bbls OBF lost with cuttings

Cost Item	Shallow-Water Development Well	Notes
Disposal Cost ($533 per 8-bbl box)	63,494	Vendor quote of $500/box in 1995; ENR CCI ratio of 1997$/1995$ = 1.065 (Section VIII.3.1.4.1)
8-bbl Cuttings Box Purchase Cost ($133/box)	15,844	Operator quotes of $125/box in 1995; ENR CCI ratio of 1997$/1995$ = 1.065 (Section VIII.3.1.4.1)
Supply Boat Cost ($8,500/day)	41,650	Vendors (Section VIII.3.1.4.1)
Trucking Cost ($1,917 per 8-box truckload)	28,545	Vendor quote of $1,800 per 22-ton truckload in 1995, ENR CCI ratio of 1997$/1995$ = 1.065 (Section VIII.3.1.4.1)
Drilling Fluid Cost (OBF lost with cuttings @ $150/bbl)	58,200	Vendor quote times geographic area multiplier of 2 for Cook Inlet (Section VIII.3.1.4.1)
TOTAL Cost per Model Well ($)	207,733	
Unit Cost ($/bbl)	218	
No. Wells	1	
TOTAL ANNUAL BASELINE Cook Inlet COST($)	**207,733**	Per-well costs x 1 shallow-water development wells

Worksheet No. 4
Compliance Cost Estimates: Discharge with Improved Solids Control

Region:	Offshore Gulf of Mexico
Technology:	Discharge via add-on drill cuttings "dryer" with average retention of 7% (wt) base fluid on cuttings
Model Well Types:	All four types: Deep- and Shallow-water, Development and Exploratory
Per-Well Waste Volumes:	
Deep-water Development:	1,191 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude contamination) 336 bbls SBF lost with cuttings
Deep-water Exploratory:	2,648 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude contamination) 747 bbls SBF lost with cuttings
Shallow-water Development:	787 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude contamination) 222 bbls SBF lost with cuttings
Shallow-water Exploratory:	1,650 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude contamination) 466 bbls SBF lost with cuttings

Cost Item	Deep Water Devel. Well	Deep Water Explor. Well	Shallow Water Devel. Well	Shallow Water Explor. Well	TOTAL	Notes
GOM Wells Currently Using SBF and Discharging Cuttings						
Add-on Solids Control Equipment @ $1200/day (Cuttings dryer that reduces base fluid retention from 11% to 7%; drilling days = 40% of time on rig)	16,200	36,000	10,800	22,500		Includes all equipment, labor, and materials (e.g., retort analysis); days of rental from industry (Section VIII.3.1.3.2)
Retrofit Additional Deck Space @ $340/sq ft (Add 75 sq ft for equipment plus tank per rig)	3,923	3,923	3,923	3,923		Costs and wells-per-rig from offshore model; space required from Amoco trip report (Section VIII.3.1.3.2)
Drilling Fluid Costs (SBF lost with cuttings @ $200/bbl)	67,200	149,400	44,400	93,200		Cost from Amoco trip report, and additional industry sources (Section VIII.3.1.3.2)
Monitoring Analyses						
Crude Contamination of Drilling Fluid @ $50/test	50	50	50	50		Cost from vendor (Section VIII.3.1.3.2)
Retention of Base Fluids by Retort @ $50/test	1,300	1,700	1,500	2,000		Retort measured twice per 500 ft drilled; cost from vendor (Section VIII.3.1.3.2)
TOTAL Cost Per Well ($)	**88,673**	**191,073**	**60,673**	**121,673**		
Unit Cost ($/bbl)	**74**	**72**	**77**	**74**		
No. Wells	**18**	**57**	**12**	**7**		
TOTAL ANNUAL GOM Cost for SBF Wells ($)	**1,596,115**	**10,891,165**	**728,077**	**851,712**	**14,067,069**	Per-well costs x no. of wells
GOM Wells Currently Using OBF Assumed to Switch to SBF (20% Convertion Scenario)						
Add-on Solids Control Equipment @ $1200/day (Cuttings dryer that reduces base fluid retention from 11% to 7%; drilling days = 40% of time on rig)	---	---	10,800	22,500		Includes all equipment, labor, and materials (e.g., retort analysis); days of rental from industry (Section VIII.3.1.3.2)
Retrofit Additional Deck Space @ $340/sq ft (Add 75 sq ft for equipment plus tank per rig)	---	---	3,923	3,923		Costs and wells-per-rig from offshore model; space required from Amoco trip report (Section VIII.3.1.3.2)
Drilling Fluid Costs (SBF lost with cuttings @ $200/bbl)	---	---	44,400	93,200		Cost from Amoco trip report, and additional industry sources (Section VIII.3.1.3.2)
Monitoring Analyses						
Crude Contamination of Drilling Fluid @ $50/test	---	---	50	50		Cost from vendor (Section VIII.3.1.3.2)
Retention of Base Fluids by Retort @ $50/test	---	---	1,500	2,000		Retort measured twice per 500 ft drilled; cost from vendor (Section VIII.3.1.3.2)
TOTAL Cost Per Well ($)	---	---	**60,673**	**121,673**		
Unit Cost ($/bbl)	---	---	**77**	**74**		
No. Wells	---	---	**15**	**8**		No. of wells reflects 20% of OBF users that will convert to SBF under this option.
TOTAL ANNUAL GOM Cost for OBF Wells ($)	---	---	**910,096**	**973,385**	**1,883,481**	Per-well costs x no. of wells
TOTAL ANNUAL GOM Cost for Improved Solids Control ($)					**15,950,550**	

Worksheet No. 5
Compliance Cost Estimates: Discharge with Improved Solids Control

Region:	Offshore California
Technology:	Discharge via add-on drill cuttings "dryer" with average retention of 7% (wt) base fluid on cuttings
Model Well Types:	Deep- and Shallow-Water Development Wells
Per-Well Waste Volumes:	
Deep-water Development:	1,191 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude contamination)
	336 bbls SBF lost with cuttings
Shallow-water Development:	787 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude contamination)
	222 bbls SBF lost with cuttings

Cost Item	Deep-Water Development	Shallow-Water Development	**TOTAL**	Notes
Add-on Solids Control Equipment @ $1920/day (Cuttings dryer that reduces base fluid retention from 11% to 7%; drilling days = 40% of time on rig)	25,920	17,280		Includes all equipment, labor, and materials (e.g., retort analysis); Geographic Area Cost Multiplier of 1.6 from Offshore DD; rental days from industry (Section VIII.3.1.3.2)
Retrofit Additional Deck Space @ $544/sq ft (Add 75 sq ft for equipment plus tank per rig)	6,277	6,277		Costs and wells-per-rig from offshore model; space required from Amoco trip report (Section VIII.3.1.3.2)
Drilling Fluid Costs (SBF lost with cuttings @ $320/bbl)	107,520	71,040		Cost from Amoco trip report, and additional industry sources; Geographic Area Cost Multiplier of 1.6 from Offshore DD (Section VIII.3.1.3.2)
Monitoring Analyses				
Crude Contamination of Drilling Fluid @ $50/test	50	50		Cost from vendor (Section VIII.3.1.3.2)
Retention of Base Fluids by Retort @ $50/test	1,300	1,500		Retort measured twice per 500 ft drilled; cost from vendor (Section VIII.3.1.3.2)
TOTAL Cost Per Well ($)	141,067	96,147		
Unit Cost ($/bbl)	118	122		
No. Wells	11	1		
TOTAL ANNUAL CA Cost ($)	1,551,736	96,147	**1,647,883**	Per-well costs x no. of wells

Worksheet No. 6
Compliance Cost Estimates: Discharge with Improved Solids Control

Region:	Cook Inlet, Alaska
Technology:	Discharge via add-on drill cuttings "dryer" with average retention of 7% (wt) base fluid on cuttings
Model Well Types:	Shallow-Water Development Wells
Per-Well Waste Volumes:	
Shallow-water Development:	787 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude contamination)
	222 bbls SBF lost with cuttings

Cost Item	Shallow-Water Development	Notes
Add-on Solids Control Equipment @ $2400/day (Cuttings dryer that reduces base fluid retention from 11% to 7%; drilling days = 40% of time on rig)	21,600	Includes all equipment, labor, and materials (e.g., retort analysis); Geographic Area Cost Multiplier of 2 from Offshore DD (Section VIII.3.1.3.2)
Retrofit Additional Deck Space @ $680/sq ft (Add 75 sq ft for equipment plus tank per rig; applied to all platforms)	3,517	Costs from offshore model; wells-per-rig from Coastal DD; space required from Amoco trip report (Section VIII.3.1.3.2)
Drilling Fluid Costs (SBF lost with cuttings @ $400/bbl)	88,800	Cost from Amoco trip report, and additional industry sources; Geographic Area Cost Multiplier of 2 from Offshore DD (Section VIII.3.1.3.2)
Monitoring Analyses		
Crude Contamination of Drilling Fluid @ $50/test	50	Cost from vendor (Section VIII.3.1.3.2)
Retention of Base Fluids by Retort @ $50/test	1,500	Retort measured twice per 500 ft drilled; cost from vendor (Section VIII.3.1.3.2)
TOTAL Cost Per Well ($)	115,467	
Unit Cost ($/bbl)	147	
No. Wells	1	
TOTAL ANNUAL Cook Inlet Cost ($)	**115,467**	Per-well costs x 1 shallow-water development well

Worksheet No. 7
Compliance Cost Estimates: Zero Discharge GOM

Region: Offshore Gulf of Mexico
Technology: Zero-Discharge via Haul and Land-Dispose
Model Well Types: All four types: Deep- and Shallow-water, Development and Exploaratory
Per-Well Waste Volumes:

Deep-water Development:	1,442	bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	587	bbls SBF/OBF lost with cuttings
Deep-water Exploratory:	3,206	bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	1,305	bbls SBF/OBF lost with cuttings
Shallow-water Development:	953	bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	388	bbls SBF/OBF lost with cuttings
Shallow-water Exploratory:	1,997	bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	813	bbls SBF/OBF lost with cuttings

Cost Item	Deep-Water Develop. Well	Deep-Water Explor. Well	Shallow Water Devel. Well	Shallow Water Explor. Well	Notes
GOM Wells Using SBF Assumed to Switch to OBF Under Zero Discharge					
Disposal Cost ($10.13/bbl)	---	---	9,654	20,230	Average of $9.50 and $10.75, quoted from vendors (Section VIII.3.1.4.1)
Handling Cost ($4.75/bbl)	---	---	4,527	9,486	Vendor quote; includes crains, labor, trucks to landfill, etc. (Section VIII.3.1.4.1)
Container Rental ($25/box/day * "x" boxes* "y" days to fill & haul)	---	---	5,558	19,200	Vendor (Section VIII.3.1.4.1)
Supply Boat Cost ($8,500/day)	---	---	48,450	81,600	Vendors (Section VIII.3.1.4.1)
Drilling Fluid Costs (OBF lost with cuttings @ $75/bbl)	---	---	29,100	60,975	Vendor quote (Section VIII.3.1.4.1)
TOTAL Cost per Model Well ($)	---	---	**97,288**	**191,490**	
Unit Cost to Haul and Dispose ($/bbl)	---	---	**102**	**96**	
GOM Wells Using SBF Assumed to Retain SBF Under Zero Discharge					
Disposal Cost ($10.13/bbl)	14,607	32,477	---	---	Average of $9.50 and $10.75, quoted from vendors (Section VIII.3.1.4.1)
Handling Cost ($4.75/bbl)	6,850	15,228	---	---	Vendor quote; includes crains, labor, trucks to landfill, etc. (Section VIII.3.1.4.1)
Container Rental ($25/box/day * "x" boxes* "y" days to fill & haul)	10,875	53,858	---	---	Vendor (Section VIII.3.1.4.1)
Supply Boat Cost ($8,500/day)	63,750	141,950	---	---	Vendors (Section VIII.3.1.4.1)
Drilling Fluid Costs (SBF lost with cuttings @ $200/bbl)	117,400	97,875	---	---	Vendor and operator quotes (Section VIII.3.1.3.2)
TOTAL Cost per Model Well ($)	**213,482**	**341,388**	---	---	
Unit Cost to Haul and Dispose ($/bbl)	**148**	**106**	---	---	

Worksheet No. 8
Compliance Cost Estimates: Zero Discharge GOM

Region: Offshore Gulf of Mexico
Technology: Zero-Discharge via On-site Grinding and Injection
Model Well Types: All four types: Deep- and Shallow-water, Development and Exploaratory
Per-Well Waste Volumes:

Deep-water Development:	1,442 bbls waste OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	587 bbls OBF lost with cuttings
Deep-water Exploratory:	3,206 bbls waste OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	1,305 bbls OBF lost with cuttings
Shallow-water Development:	953 bbls waste OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	388 bbls OBF lost with cuttings
Shallow-water Exploratory:	1,997 bbls waste OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	813 bbls OBF lost with cuttings

Cost Item	Deep-Water		Shallow-Water		Notes
	Development	Exploratory	Development	Exploratory	
GOM Wells Using SBF Assumed to Switch to OBF Under Zero Discharge					
Onsite Injection System @ $4280/day (drilling days = 40% of time on rig)	---	---	38,520	80,250	Includes all equipment, labor, and services; vacuum system used to transport cuttings (Section
Drilling Fluid Costs (OBF lost with cuttings @ $75/bbl)	---	---	29,100	60,975	
TOTAL Cost per Model Well ($)	**---**	**---**	**67,620**	**141,225**	
Unit Cost to Grind and Inject ($/bbl)	**---**	**---**	**71**	**71**	
GOM Wells Using SBF Assumed to Retain SBF Under Zero Discharge					
Onsite Injection System @ $4280/day (drilling days = 40% of time on rig)	57,780	128,400	---	---	Includes all equipment, labor, and services; vacuum system used to transport cuttings (Section
Drilling Fluid Costs (OBF lost with cuttings @	117,400	261,000	---	---	
TOTAL Cost per Model Well ($)	**175,180**	**389,400**	**---**	**---**	
Unit Cost to Grind and Inject ($/bbl)	**121**	**121**	**---**	**---**	

Worksheet No. 9
Compliance Cost Estimates: Zero Discharge GOM

Region: Offshore Gulf of Mexico
Technology: Zero-Discharge via Haul & Land-Dispose (80%) plus On-site Grinding and Injection (20%)
Model Well Types: All four types: Deep- and Shallow-water, Development and Exploaratory
Per-Well Waste Volumes:

Deep-water Development:	1,442 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	587 bbls SBF/OBF lost with cuttings
Deep-water Exploratory:	3,206 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	1,305 bbls SBF/OBF lost with cuttings
Shallow-water Development:	953 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	388 bbls SBF/OBF lost with cuttings
Shallow-water Exploratory:	1,997 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	813 bbls SBF/OBF lost with cuttings

Cost Item	Deep-Water		Shallow-Water		TOTAL	Notes
	Development	Exploratory	Development	Exploratory		
GOM Wells Using SBF Assumed to Switch to OBF Under Zero Discharge						
Unit Cost to Haul and Dispose ($/well)	---	---	97,288	191,490		From Worksheet No. 7
Unit Cost to Grind and Inject ($/well)	---	---	67,620	141,225		From Worksheet No. 8
Weighted Average Per Well Cost ($/well)	---	---	91,355	181,437		Assumes 80% hauls and 20% injects
Weighted Average Unit Cost ($/bbl)	---	---	96	91		
No. Wells	---	---	12	7		
SUBTOTAL ANNUAL GOM ZD COST ($)	---	---	1,096,254	1,270,061	**2,366,315**	Per-well costs x no. of wells
GOM Wells Using SBF Assumed to Retain SBF Under Zero Discharge						
Unit Cost to Haul and Dispose ($/well)	213,482	341,388	---	---		From Worksheet No. 7
Unit Cost to Grind and Inject ($/well)	175,180	389,400	---	---		From Worksheet No. 8
Weighted Average Per Well Cost ($/well)	205,822	350,990	---	---		Assumes 80% hauls and 20% injects
Weighted Average Unit Cost ($/bbl)	143	109	---	---		
No. Wells	18	57	---	---		
SUBTOTAL ANNUAL GOM ZD COST ($)	3,704,788	20,006,443	---	—	**23,711,231**	Per-well costs x no. of wells
Total Annual GOM Costs for Zero Discharge ($)					**26,077,546**	

APPENDIX VIII-3

NSPS COMPLIANCE COST CALCULATIONS

Summary NSPS Costs for Management of SBF Cuttings (1997$)

Baseline Costs: Total Annual

Baseline Technology	GOM	NOTES
Discharge with 11% retention of base fluid on cuttings	2,201,725	From Worksheet No. 1; applies to 19 SBF wells

NSPS Compliance Costs: Total Annual

Option	GOM	NOTES
Discharge	0	From Worksheet No. 2; applies to 19 SBF wells
Zero Discharge	3,796,143	From Worksheet No. 5; applies to 19 SBF wells

Incremental NSPS Compliance Costs: Total Annual

Option	GOM	NOTES
Discharge	(2,201,725)	Diff. between compliance and baseline costs
Zero Discharge	1,594,418	Diff. between compliance and baseline costs

Worksheet No. 1
NSPS Compliance Cost Estimates: Baseline Current Practice

Region:	Offshore Gulf of Mexico
Technology:	Discharge of SBF cuttings via add-on cuttings "dryer" w/ avg. ret.'n of 11% (wt) base fluid on cuttings
Model Well Types:	Deep- and Shallow-water Development
Per-Well Waste Volumes:	
Deep-water Development:	1,442 bbls waste SBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	587 bbls SBF lost with cuttings
Shallow-water Development:	953 bbls waste SBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	388 bbls SBF lost with cuttings

Cost Item	Deep-Water Development	Shallow-Water Development	**TOTAL**	Notes
Drilling Fluid Costs for Wells Currently Using SBF (SBF@ $200/bbl lost w/ cuttings)	117,400	77,600		Costs from Amoco trip report and additional industry sources (Section VIII.3.1.3.2)
SPP Toxicity Monitoring Test	575	575		Average cost for full analysis (Section VIII.3.1.3.1)
Per Well Baseline Cost ($/well)	117,975	78,175		
Unit Cost ($/bbl)	82	82		
No. Wells	18	1		
TOTAL ANNUAL BASELINE GOM COST ($)	2,123,550	78,175	**2,201,725**	Per-well costs x no. of wells

Worksheet No. 2
NSPS Compliance Cost Estimates: Discharge with Improved Solids Control

Region:	Offshore Gulf of Mexico
Technology:	Discharge via add-on drill cuttings "dryer" with average achievable retention of 7% (wt) base fluid
Model Well Types:	Deep- and Shallow-water Development
Per-Well Waste Volumes:	
Deep-water Development:	1,191 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude
	336 bbls SBF lost with cuttings
Shallow-water Development:	787 bbls waste SBF-cuttings (generated with 7% retention, 0.2% crude
	222 bbls SBF lost with cuttings

Cost Item	Deep-Water Development Well	Shallow-Water Development Well	**TOTAL**	Notes
GOM Wells Currently Using SBF and Discharging				
Improved Solids Control Equipment @ $1200/day (Cuttings dryer that reduces base fluid retention from 11% to 7%; drilling days = 40% of time on rig)	16,200	10,800		Includes all equipment, labor, and materials (e.g., retort analysis); days of rental from industry (Section VIII.3.1.3.2)
Drilling Fluid Costs (SBF lost with cuttings @ $200/bbl)	67,200	44,400		Cost from Amoco trip report, and additional industry sources (Section VIII.3.1.3.2)
Monitoring Analyses				
Crude Contamination of Drilling Fluid @ $50/test	50	50		Cost from vendor (Section VIII.3.1.3.2)
Retention of Base Fluids by Retort @ $50/test	1,300	1,500		Retort measured twice per 500 ft drilled cost from vendor (Section VIII.3.1.3.2)
TOTAL Cost Per Well ($)	84,750	56,750		
Unit Cost ($/bbl)	71	72		
No. Wells	18	1		
TOTAL ANNUAL GOM Cost for SBF Wells ($)	**1,525,500**	**56,750**	**1,582,250**	Per-well costs x no. of wells

Worksheet No. 3
NSPS Compliance Cost Estimates: Zero Discharge GOM

Region:	Offshore Gulf of Mexico
Technology:	Zero-Discharge via Haul and Land-Dispose
Model Well Types:	Deep- and Shallow-water Development
Per-Well Waste Volumes:	
Deep-water Development:	1,442 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contam.)
	587 bbls SBF/OBF lost with cuttings
Shallow-water Development:	953 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contam.)
	388 bbls SBF/OBF lost with cuttings

Cost Item	Deep-Water Development Well	Shallow-Water Development Well	Notes
GOM Wells Using SBF Assumed to Switch to OBF Under Zero Discharge			
Disposal Cost ($10.13/bbl)	—	9,654	Average of $9.50 and $10.75, quoted from vendors (Section VIII.3.1.4.1)
Handling Cost ($4.75/bbl)	---	4,527	Vendor quote; includes crains, labor, trucks to landfill, etc. (Section VIII.3.1.4.1)
Container Rental ($25/box/day * "x" boxes* "y" days to fill & haul)	---	5,558	Vendor (Section VIII.3.1.4.1)
Supply Boat Cost ($8,500/day)	---	48,450	Vendors (Section VIII.3.1.4.1)
Drilling Fluid Costs (OBF lost with cuttings @ $75/bbl)	---	29,100	Vendor quote (Section VIII.3.1.4.1)
TOTAL Cost per Model Well ($)	---	**97,288**	
Unit Cost to Haul and Dispose ($/bbl)	---	**102**	
GOM Wells Using SBF Assumed to Retain SBF Under Zero Discharge			
Disposal Cost ($10.13/bbl)	14,607	---	Average of $9.50 and $10.75, quoted from vendors (Section VIII.3.1.4.1)
Handling Cost ($4.75/bbl)	6,850	---	Vendor quote; includes crains, labor, trucks to landfill, etc. (Section VIII.3.1.4.1)
Container Rental ($25/box/day * "x" boxes* "y" days to fill & haul)	10,875	---	Vendor (Section VIII.3.1.4.1)
Supply Boat Cost ($8,500/day)	63,750	---	Vendors (Section VIII.3.1.4.1)
Drilling Fluid Costs (SBF lost with cuttings @ $200/bbl)	117,400	---	Vendor and operator quotes (Section VIII.3.1.4.1)
TOTAL Cost per Model Well ($)	**213,482**	---	
Unit Cost to Haul and Dispose ($/bbl)	**148**	---	

Worksheet No. 4
NSPS Compliance Cost Estimates: Zero Discharge GOM

Region: Offshore Gulf of Mexico
Technology: Zero-Discharge via On-site Grinding and Injection
Model Well Types: Deep- and Shallow-water Development
Per-Well Waste Volumes:

Deep-water Development: 1,442 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contam.)
587 bbls OBF lost with cuttings

Shallow-water Development: 953 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contam.)
388 bbls OBF lost with cuttings

Cost Item	Deep-Water Development Well	Shallow-Water Development Well	Notes
GOM Wells Using SBF Assumed to Switch to OBF Under Zero Discharge			
Onsite Injection System @ $4280/day (drilling days = 40% of time on rig)	---	38,520	Includes all equipment, labor, and services; vacuum system used to transport cuttings (Section VIII.3.1.5)
Drilling Fluid Costs (OBF lost with cuttings @ $75/bbl)	---	29,100	Cost from vendor (Section VIII.3.1.4.1)
TOTAL Cost per Model Well ($)	**---**	**67,620**	
Unit Cost to Grind and Inject ($/bbl)	**---**	**71**	
GOM Wells Using SBF Assumed to Retain SBF Under Zero Discharge			
Onsite Injection System @ $4280/day (drilling days = 40% of time on rig)	57,780	---	Includes all equipment, labor, and services; vacuum system used to transport cuttings (Section VIII.3.1.5)
Drilling Fluid Costs (SBF lost with cuttings @ $200/bbl)	117,400	---	Cost from Amoco trip report and vendor (Section VIII.3.1.3.2)
TOTAL Cost per Model Well ($)	**175,180**	**---**	
Unit Cost to Grind and Inject ($/bbl)	**121**	**---**	

Worksheet No. 5
NSPS Compliance Cost Estimates: Zero Discharge GOM

Region:	Offshore Gulf of Mexico
Technology:	Zero-Discharge via Haul & Land-Dispose (80%) plus On-site Grinding and Injection (20%)
Model Well Types:	Deep- and Shallow-water Development
Per-Well Waste Volumes:	
Deep-water Development:	1,442 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	587 bbls SBF/OBF lost with cuttings
Shallow-water Development:	953 bbls waste SBF/OBF-cuttings (generated with 11% retention, 0.2% crude contamination)
	388 bbls SBF/OBF lost with cuttings

Cost Item	Deep-Water Development	Shallow-Water Development	**TOTAL**	Notes
GOM Wells Using SBF Assumed to Switch to OBF Under Zero Discharge				
Unit Cost to Haul and Dispose ($/well)	---	97,288		From Worksheet No. 3
Unit Cost to Grind and Inject ($/well)	---	0		From Worksheet No. 4
Weighted Average Per Well Cost ($/well)	---	91,355		Assumes 80% hauls and 20% injects
Weighted Average Unit Cost ($/bbl)	---	96		
No. Wells	---	1		
SUBTOTAL ANNUAL GOM ZD COST ($)	---	91,355	**91,355**	Per-well costs x no. of wells
GOM Wells Using SBF Assumed to Retain SBF Under Zero Discharge				
Unit Cost to Haul and Dispose ($/well)	213,482	---		From Worksheet No. 3
Unit Cost to Grind and Inject ($/well)	205,822	---		From Worksheet No. 4
Weighted Average Per Well Cost ($/well)	205,822	---		Assumes 80% hauls and 20% injects
Weighted Average Unit Cost ($/bbl)	143	---		
No. Wells	18	---		
SUBTOTAL ANNUAL GOM ZD COST ($)	3,704,788	---	**3,704,788**	Per-well costs x no. of wells
Total Annual GOM Costs for Zero Discharge			**3,796,143**	

APPENDIX VIII-4

POLLUTANT LOADINGS AND REDUCTIONS CALCULATIONS

Summary Pollutant Loadings and Reductions for SBF-Cuttings from Existing Sources
(Assuming Gulf of Mexico Well Counts for "20% Convert" Scenario)

Baseline Pollutant Loadings: Total Annual

Baseline Technology	GOM	CA-Offshore	AK-Cook Inlet	Total
Discharge with 11% retention on cuttings	159,103,752	0	0	0
Zero Discharge	0	0	0	0
TOTALL	159,103,752	0	0	159,103,752

Compliance Pollutant Loadings: Total Annual

Option	GOM	CA-Offshore	AK-Cook Inlet	Total
Discharge with 7% retention on cuttings	163,851,174	0	590,550	164,441,724
Zero Discharge	0	0	0	0

Incremental Pollutant Reductions: Total Annual

Option	GOM	CA-Offshore	AK-Cook Inlet	Total
Discharge with 7% retention on cuttings	(4,747,422)	0	(590,550)	(5,337,972) 0
Zero Discharge	159,103,752	0	0	159,103,752

Gulf of Mexico Annual Loadings and Reductions Summary for Existing Sources (lbs per year)
Well Counts for "20% Convert" Scenario

Number of Wells:

	Deep Water		Shallow Water		
	Development	Exploratory	Development	Exploratory	Total
Using SBF (current=11%):	18	57	12	7	94
Using OBF (current=0 dis):	0	0	15	8	23

Gulf of Mexico Baseline Pollutant Loadings Summary

Baseline Technology	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Discharge w/11% retention	17,639,334	124,194,108	7,770,960	9,499,350	159,103,752	94 SBF wells; From Worksheet No.s 1-4
Zero Discharge	--	--	0	0	0	23 OBF wells; From Worksheet No.s 7-8

Gulf of Mexico BAT Pollutant Loadings Summary

Option (a)	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Discharge w/ 7% retention	16,085,988	113,257,176	15,944,850	18,563,160	163,851,174	94 SBF plus 23 OBF wells; From Worksheet No.s 5-8
Zero Discharge	0	0	0	0	0	94 SBF wells; From Worksheet No.s 9-12

Gulf of Mexico Incremental Pollutant Reductions Summary (b)

Option (a)	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Discharge w/ 7% retention	1,553,364	10,936,932	(8,173,902)	(9,063,810)	(4,747,416)	Difference between BAT loadings and baseline loadings for 94 SBF and 23 OBF wells; negative incremental reductions indicate loadings.
Zero Discharge	17,639,334	124,194,108	7,770,960	9,499,350	159,103,752	Difference between zero discharge BAT loadings and baseline discharge loadings for 94 wells currently using SBF.

(a) For the discharge option, it is assumed that wells currently using OBF will switch to SBF.

(b) Incremental Reductions = BAT Loadings - Baseline Loadings.

California Offshore Loadings and Reductions Summary for Existing Sources (lbs)

Number of Wells:

	Deep Water		Shallow Water	
	Development	Exploratory	Development	Exploratory
(using SBF):	11	0	1	0

California Offshore Baseline Pollutant Loadings Summary

	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)			
Option	**Development**	**Exploratory**	**Development**	**Exploratory**	**Total**	**Notes**
Zero Discharge	0	--	0	--	0	All California Offshore wells are currently at zero discharge.

California Offshore BAT Pollutant Loadings Summary

	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)			
Option	**Development**	**Exploratory**	**Development**	**Exploratory**	**Total**	**Notes**
Discharge	9,830,326	--	590,550	--	10,420,876	From Worksheet No.s 5 and 7.
Zero Discharge	0	--	0	--	0	From Worksheet No.s 9 and 11.

California Offshore Incremental Pollutant Reductions Summary (a)

	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)			
Option	**Development**	**Exploratory**	**Development**	**Exploratory**	**Total**	**Notes**
Discharge	(9,830,326)	--	(590,550)	--	(10,420,876)	Difference between BAT loadings and baseline loadings; negative incremental reductions indicate loadings.
Zero Discharge	0	--	0	--	0	No reduction between baseline and zero discharge.

(a) Incremental Reductions = BAT Loadings - Baseline Loadings.

Cook Inlet, Alaska Loadings and Reductions Summary for Existing Sources (lbs)

Number of Wells:

	Deep Water		Shallow Water	
	Development	Exploratory	Development	Exploratory
(using SBF):	0	0	1	0

Cook Inlet, Alaska Baseline Pollutant Loadings Summary

Option	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Zero Discharge	--	--	0	--	0	All Cook Inlet, Alaska wells are currently at zero discharge.

Cook Inlet, Alaska BAT Pollutant Loadings Summary

Option	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Discharge	--	--	590,550	--	590,550	From Worksheet No. 7.
Zero Discharge	--	--	0	--	0	From Worksheet No 11.

Cook Inlet, Alaska Incremental Pollutant Reductions Summary (a)

Option	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Discharge	--	--	(590,550)	--	(590,550)	Difference between BAT loadings and baseline loadings; negative incremental reductions indicate loadings.
Zero Discharge	--	--	0	--	0	No reduction between baseline and zero discharge.

(a) Incremental Reductions = BAT Loadings - Baseline Loadings; negative incremental reductions represent loadings.

NSPS Annual Loadings and Reductions Summary for New Sources (lbs per year)

Number of Wells:

	Deep Water		Shallow Water		
	Development	Exploratory	Development	Exploratory	Total
GOM NSPS wells:	18	0	1	0	19

NSPS Baseline Pollutant Loadings Summary

Baseline Technology	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Discharge w/11% retention	17,639,334	--	647,580	--	18,286,914	19 SBF wells; From Worksheet No.s 1 and 3.

NSPS BAT Pollutant Loadings Summary

Option (a)	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Discharge w/ 7%	16,085,988	--	590,550	--	16,676,538	From Worksheet No.s 5 and 7.
Zero Discharge	0	--	0	--	0	From Worksheet No.s 9 and 11.

NSPS Incremental Pollutant Reductions Summary (a)

Option (a)	Deep Water (>1,000 ft)		Shallow Water (<1,000 ft)		Total	Notes
	Development	Exploratory	Development	Exploratory		
Discharge w/ 7%	1,553,364	--	57,030	--	1,610,394	Difference between BAT loadings and baseline loadings
Zero Discharge	17,639,334	--	647,580	--	18,286,914	Difference between zero discharge BAT loadings.

(a) Incremental Reductions = BAT Loadings - Baseline Loadings.

WORKSHEET 1: Baseline Loadings

Deep Water Development Well

Technology = Discharge Assuming 11% (wt) Retention on Discharged Cuttings and 0.2% (vol.) Crude Contamination

Dry Cuttings Generated per Well =	778,050	lbs
Whole Drilling Fluid Discharged per Well =	588	bbls

Pollutant Name	Pollutants in Drilling Waste	Pollutant Loadings per Well	Reductions Per Well
Conventional Pollutants		**lbs**	**lbs**
TSS (as barite)		78,414	0
TSS (as dry cuttings)		778,050	0
TSS (total)		856,464	0
Total Oil (base fluid plus crude)		112,075	0
Priority Pollutant Organics	**lbs/bbl drilling fluid**		
Naphthalene	0.0010052	0.5911	0.0000
Fluorene	0.0005483	0.3224	0.0000
Phenanthrene	0.0013004	0.7647	0.0000
Phenol	7.22e-08	0.0000	0.0000
Total Priority Pollutant Organics		1.6782	0.0000
Priority Pollutants, Metals	**lbs/lb barite**		
Cadmium	0.0000011	0.0863	0.0000
Mercury	0.0000001	0.0078	0.0000
Antimony	0.0000057	0.4470	0.0000
Arsenic	0.0000071	0.5567	0.0000
Berylium	0.0000007	0.0549	0.0000
Chromium	0.0002400	18.8194	0.0000
Copper	0.0000187	1.4663	0.0000
Lead	0.0000351	2.7523	0.0000
Nickel	0.0000135	1.0586	0.0000
Selenium	0.0000011	0.0863	0.0000
Silver	0.0000007	0.0549	0.0000
Thallium	0.0000012	0.0941	0.0000
Zinc	0.0002005	15.7220	0.0000
Total Priority Pollutant Metals		41.21	0.00
Non-Conventional Metals	**lbs/lb barite**		
Aluminum	0.0090699	711.2071	0.0000
Barium	0.1200000	9,409.6800	0.0000
Iron	0.0153443	1,203.2079	0.0000
Tin	0.0000146	1.1448	0.0000
Titanium	0.0000875	6.8612	0.0000
Non-Conventional Organics	**lbs/bbl drilling fluid**		
Alkylated benzenes	0.0056587	3.3273	0.0000
Alkylated naphthalenes	0.0531987	31.2808	0.0000
Alkylated fluorenes	0.0064038	3.7654	0.0000
Alkylated phenanthrenes	0.0080909	4.7574	0.0000
Alkylated phenlos	0.0000006	0.0004	0.0000
Total biphenyls	0.0105160	6.1834	0.0000
Total dibenzothiophenes	0.0000092	0.0054	0.0000
Total Non-Conventional Pollutants		11,381.42	0.00
Total Loadings and Reductions (lbs per well)		**979,963**	**0**

WORKSHEET 2: Baseline

Deep Water Exploratory Well

Technology = Discharge Assuming 11% (wt) Retention on Discharged Cuttings and 0.2% (vol.) Crude Contamination

Dry Cuttings Generated per Well =	1,729,910	lbs
Whole Drilling Fluid Discharged per Well =	1308	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well	Reductions Per Well
Conventional Pollutants		**lbs**	**lbs**
TSS (as barite)		174,346	0
TSS (as dry cuttings)		1,729,910	0
TSS (total)		1,904,256	0
Total Oil (base fluid plus crude)		249,187	0
Priority Pollutant Organics	**lbs/bbl drilling fluid**		
Naphthalene	0.0010052	1.3148	0.0000
Fluorene	0.0005483	0.7172	0.0000
Phenanthrene	0.0013004	1.7010	0.0000
Phenol	7.22e-08	0.0001	0.0000
Total Priority Pollutant Organics		3.7331	0.0000
Priority Pollutants, Metals	**lbs/lb barite**		
Cadmium	0.0000011	0.1918	0.0000
Mercury	0.0000001	0.0174	0.0000
Antimony	0.0000057	0.9938	0.0000
Arsenic	0.0000071	1.2379	0.0000
Berylium	0.0000007	0.1220	0.0000
Chromium	0.0002400	41.8430	0.0000
Copper	0.0000187	3.2603	0.0000
Lead	0.0000351	6.1195	0.0000
Nickel	0.0000135	2.3537	0.0000
Selenium	0.0000011	0.1918	0.0000
Silver	0.0000007	0.1220	0.0000
Thallium	0.0000012	0.2092	0.0000
Zinc	0.0002005	34.9564	0.0000
Total Priority Pollutant Metals		91.62	0.00
Non-Conventional Metals	**lbs/lb barite**		
Aluminum	0.0090699	1,581.3008	0.0000
Barium	0.1200000	20,921.5200	0.0000
Iron	0.0153443	2,675.2173	0.0000
Tin	0.0000146	2.5455	0.0000
Titanium	0.0000875	15.2553	0.0000
Non-Conventional Organics	**lbs/bbl drilling fluid**		
Alkylated benzenes	0.0056587	7.4016	0.0000
Alkylated naphthalenes	0.0531987	69.5839	0.0000
Alkylated fluorenes	0.0064038	8.3762	0.0000
Alkylated phenanthrenes	0.0080909	10.5829	0.0000
Alkylated phenlos	0.0000006	0.0008	0.0000
Total biphenyls	0.0105160	13.7550	0.0000
Total dibenzothiophenes	0.0000092	0.0120	0.0000
Total Non-Conventional Pollutants		25,305.55	0.00
Total Loadings and Reductions (lbs per well)		**2,178,844**	**0**

WORKSHEET 3: Baseline Loadings

Shallow Water Development Well

Technology = Discharge Assuming 11% (wt) Retention on Discharged Cuttings and 0.2% (vol.) Crude Contamination

Dry Cuttings Generated per Well =	514,150	lbs
Whole Drilling Fluid Discharged per Well =	389	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well	Reductions Per Well
Conventional Pollutants		**lbs**	**lbs**
TSS (as barite)		51,818	0
TSS (as dry cuttings)		514,150	0
TSS (total)		565,968	0
Total Oil (base fluid plus crude)		74,062	0
Priority Pollutant Organics	**lbs/bbl drilling fluid**		
Naphthalene	0.0010052	0.3910	0.0000
Fluorene	0.0005483	0.2133	0.0000
Phenanthrene	0.0013004	0.5059	0.0000
Phenol	7.22e-08	0.0000	0.0000
Total Priority Pollutant Organics		1.1102	0.0000
Priority Pollutants, Metals	**lbs/lb barite**		
Cadmium	0.0000011	0.0570	0.0000
Mercury	0.0000001	0.0052	0.0000
Antimony	0.0000057	0.2954	0.0000
Arsenic	0.0000071	0.3679	0.0000
Berylium	0.0000007	0.0363	0.0000
Chromium	0.0002400	12.4363	0.0000
Copper	0.0000187	0.9690	0.0000
Lead	0.0000351	1.8188	0.0000
Nickel	0.0000135	0.6995	0.0000
Selenium	0.0000011	0.0570	0.0000
Silver	0.0000007	0.0363	0.0000
Thallium	0.0000012	0.0622	0.0000
Zinc	0.0002005	10.3895	0.0000
Total Priority Pollutant Metals		27.23	0.00
Non-Conventional Metals	**lbs/lb barite**		
Aluminum	0.0090699	469.9841	0.0000
Barium	0.1200000	6,218.1600	0.0000
Iron	0.0153443	795.1109	0.0000
Tin	0.0000146	0.7565	0.0000
Titanium	0.0000875	4.5341	0.0000
Non-Conventional Organics	**lbs/bbl drilling fluid**		
Alkylated benzenes	0.0056587	2.2012	0.0000
Alkylated naphthalenes	0.0531987	20.6943	0.0000
Alkylated fluorenes	0.0064038	2.4911	0.0000
Alkylated phenanthrenes	0.0080909	3.1473	0.0000
Alkylated phenlos	0.0000006	0.0002	0.0000
Total biphenyls	0.0105160	4.0907	0.0000
Total dibenzothiophenes	0.0000092	0.0036	0.0000
Total Non-Conventional Pollutants		7,521.17	0.00
Total Loadings and Reductions (lbs per well)		**647,580**	**0**

WORKSHEET 4: Baseline Loadings

Shallow Water Exploratory Well

Technology = Discharge Assuming 11% (wt) Retention on Discharged Cuttings and 0.2% (vol.) Crude

Dry Cuttings Generated per Well =	1,077,440	lbs
Whole Drilling Fluid Discharged per Well =	814	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well	Reductions Per Well
Conventional Pollutants		**lbs**	**lbs**
TSS (as barite)		108,588	0
TSS (as dry cuttings)		1,077,440	0
TSS (total)		1,186,028	0
Total Oil (base fluid plus crude)		155,202	0
Priority Pollutant Organics	**lbs/bbl drilling fluid**		
Naphthalene	0.0010052	0.8182	0.0000
Fluorene	0.0005483	0.4463	0.0000
Phenanthrene	0.0013004	1.0586	0.0000
Phenol	7.22e-08	0.0001	0.0000
Total Priority Pollutant Organics		2.3232	0.0000
Priority Pollutants, Metals	**lbs/lb barite**		
Cadmium	0.0000011	0.1194	0.0000
Mercury	0.0000001	0.0109	0.0000
Antimony	0.0000057	0.6190	0.0000
Arsenic	0.0000071	0.7710	0.0000
Berylium	0.0000007	0.0760	0.0000
Chromium	0.0002400	26.0611	0.0000
Copper	0.0000187	2.0306	0.0000
Lead	0.0000351	3.8114	0.0000
Nickel	0.0000135	1.4659	0.0000
Selenium	0.0000011	0.1194	0.0000
Silver	0.0000007	0.0760	0.0000
Thallium	0.0000012	0.1303	0.0000
Zinc	0.0002005	21.7719	0.0000
Total Priority Pollutant Metals		57.06	0.00
Non-Conventional Metals	**lbs/lb barite**		
Aluminum	0.0090699	984.8823	0.0000
Barium	0.1200000	13,030.5600	0.0000
Iron	0.0153443	1,666.2068	0.0000
Tin	0.0000146	1.5854	0.0000
Titanium	0.0000875	9.5015	0.0000
Non-Conventional Organics	**lbs/bbl drilling fluid**		
Alkylated benzenes	0.0056587	4.6062	0.0000
Alkylated naphthalenes	0.0531987	43.3038	0.0000
Alkylated fluorenes	0.0064038	5.2127	0.0000
Alkylated phenanthrenes	0.0080909	6.5860	0.0000
Alkylated phenlos	0.0000006	0.0005	0.0000
Total biphenyls	0.0105160	8.5600	0.0000
Total dibenzothiophenes	0.0000092	0.0074	0.0000
Total Non-Conventional Pollutants		15,761.01	0.00
Total Loadings and Reductions (lbs per well)		**1,357,050**	**0**

WORKSHEET 5: Discharge Option Loadings and Incremental

Deep Water Development Well

Technology = Discharge Assuming 7% (wt) Retention on Discharged Cuttings and 0.2% (vol) Crude Contamination

Dry Cuttings Generated per Well =	778,050	lbs
Whole Drilling Fluid Discharged Per Well =	337	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well (lbs)		Reductions Per Well
		Current Practice (11% Retention)	Discharge at 7% Retention	
Conventional Pollutants				
TSS (as barite)		78,414	44,886	33,528
TSS (as dry cuttings)		778,050	778,050	0
TSS (total)		856,464	822,936	33,528
Total Oil (base fluid plus crude)		112,075	64,190	47,885
Priority Pollutants, Organics	**lbs/bbl drilling fluid**			
Naphthalene	0.0010052	0.5911	0.3388	0.2523
Fluorene	0.0005483	0.3224	0.1848	0.1376
Phenanthrene	0.0013004	0.7647	0.4382	0.3264
Phenol	7.22e-08	0.0000	0.0000	0.0000
Total Priority Pollutants, Organics		1.6782	0.9618	0.7164
Priority Pollutants, Metals	**lbs/lb barite**			
Cadmium	0.0000011	0.0863	0.0494	0.0369
Mercury	0.0000001	0.0078	0.0045	0.0034
Antimony	0.0000057	0.4470	0.2559	0.1911
Arsenic	0.0000071	0.5567	0.3187	0.2380
Berylium	0.0000007	0.0549	0.0314	0.0235
Chromium	0.0002400	18.8194	10.7726	8.0467
Copper	0.0000187	1.4663	0.8394	0.6270
Lead	0.0000351	2.7523	1.5755	1.1768
Nickel	0.0000135	1.0586	0.6060	0.4526
Selenium	0.0000011	0.0863	0.0494	0.0369
Silver	0.0000007	0.0549	0.0314	0.0235
Thallium	0.0000012	0.0941	0.0539	0.0402
Zinc	0.0002005	15.7220	8.9996	6.7224
Total Priority Pollutant Metals		41.21	23.59	17.62
Non-Conventional Metals	**lbs/lb barite**			
Aluminum	0.0090699	711.2071	407.1115	304.0956
Barium	0.1200000	9,409.6800	5,386.3200	4,023.3600
Iron	0.0153443	1,203.2079	688.7442	514.4637
Tin	0.0000146	1.1448	0.6553	0.4895
Titanium	0.0000875	6.8612	3.9275	2.9337
Non-Conventional Organics	**lbs/bbl drilling fluid**			
Alkylated benzenes	0.0056587	3.3273	1.9070	1.4203
Alkylated naphthalenes	0.0531987	31.2808	17.9280	13.3529
Alkylated fluorenes	0.0064038	3.7654	2.1581	1.6074
Alkylated phenanthrenes	0.0080909	4.7574	2.7266	2.0308
Alkylated phenols	0.0000006	0.0004	0.0002	0.0002
Total biphenyls	0.0105160	6.1834	3.5439	2.6395
Total dibenzothiophenes	0.0000092	0.0054	0.0031	0.0023
Total Non-Conventional Pollutants		11,381.42	6,515.03	4,866
Total Loadings and Reductions (lbs per		**979,963**	**893,666**	**86,298**

WORKSHEET 6: Discharge Option Loadings and Incremental Reductions

Deep Water Exploratory Well

Technology = Discharge Assuming 7% (wt) Retention on Discharged Cuttings and 0.2% (vol) Crude Contamination

Dry Cuttings Generated per Well = 1,729,910 lbs
Whole Drilling Fluid Discharged Per Well = 749 bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well (lbs)		Reductions Per Well
		Current (11% Retention)	Discharge at 7% Retention	
Conventional Pollutants				
TSS (as barite)		174,346	99,799	74,547
TSS (as dry cuttings)		1,729,910	1,729,910	0
TSS (total)		1,904,256	1,829,709	74,547
Total Oil (base fluid plus crude)		249,187	142,719	106,468
Priority Pollutants, Organics	**lbs/bbl drilling fluid**			
Naphthalene	0.0010052	1.3148	0.7529	0.5619
Fluorene	0.0005483	0.7172	0.4107	0.3065
Phenanthrene	0.0013004	1.7010	0.9740	0.7269
Phenol	7.22e-08	0.0001	0.0001	0.0000
Total Priority Pollutants, Organics		3.7331	2.1377	1.5954
Priority Pollutants, Metals	**lbs/lb barite**			
Cadmium	0.0000011	0.1918	0.1098	0.0820
Mercury	0.0000001	0.0174	0.0100	0.0075
Antimony	0.0000057	0.9938	0.5689	0.4249
Arsenic	0.0000071	1.2379	0.7086	0.5293
Berylium	0.0000007	0.1220	0.0699	0.0522
Chromium	0.0002400	41.8430	23.9518	17.8913
Copper	0.0000187	3.2603	1.8662	1.3940
Lead	0.0000351	6.1195	3.5029	2.6166
Nickel	0.0000135	2.3537	1.3473	1.0064
Selenium	0.0000011	0.1918	0.1098	0.0820
Silver	0.0000007	0.1220	0.0699	0.0522
Thallium	0.0000012	0.2092	0.1198	0.0895
Zinc	0.0002005	34.9564	20.0097	14.9467
Total Priority Pollutant Metals		91.62	52.44	39.17
Non-Conventional Metals	**lbs/lb barite**			
Aluminum	0.0090699	1,581.3008	905.1670	676.1338
Barium	0.1200000	20,921.5200	11,975.8800	8,945.6400
Iron	0.0153443	2,675.2173	1,531.3458	1,143.8715
Tin	0.0000146	2.5455	1.4571	1.0884
Titanium	0.0000875	15.2553	8.7324	6.5229
Non-Conventional Organics	**lbs/bbl drilling fluid**			
Alkylated benzenes	0.0056587	7.4016	4.2384	3.1632
Alkylated naphthalenes	0.0531987	69.5839	39.8458	29.7381
Alkylated fluorenes	0.0064038	8.3762	4.7965	3.5797
Alkylated phenanthrenes	0.0080909	10.5829	6.0601	4.5228
Alkylated phenols	0.0000006	0.0008	0.0005	0.0004
Total biphenyls	0.0105160	13.7550	7.8765	5.8785
Total dibenzothiophenes	0.0000092	0.0120	0.0069	0.0051
Total Non-Conventional Pollutants		25,305.55	14,485.41	10,820
Total Loadings and Reductions (lbs per		**2,178,844**	**1,986,968**	**191,876**

WORKSHEET 7: Discharge Option Loadings and Incremental Reductions

Shallow Water Development Well

Technology = Discharge Assuming 7% (wt) Retention on Discharged Cuttings and 0.2% (vol) Crude Contamination

SBF-using Facilities = Change from 11% to 7% retention on discharged cuttings
OBF-using Facilities = Change from zero discharge to 7% retention on discharged cuttings

Dry Cuttings Generated per Well = 514,150 lbs
Whole Drilling Fluid Discharged Per Well = 223 bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well (lbs)			SBF-using Well	OBF-using Well
		Current Practice, SBF Wells (11% Retention)	Current Practice, OBF Wells (0 discharge)	Discharge at 7% Retention	Reductions Per Well	Reductions Per Well
Conventional Pollutants						
TSS (as barite)		51,818	0	29,661	22,157	(29,661)
TSS (as dry cuttings)		514,150	0	514,150	0	(514,150)
TSS (total)		565,968	0	543,811	22,157	(543,811)
Total Oil (base fluid plus crude)		74,062	0	42,418	31,644	(42,418)
Priority Pollutants, Organics	**lbs/bbl drilling fluid**					
Naphthalene	0.0010052	0.3910	0	0.2242	0.1669	(0.2242)
Fluorene	0.0005483	0.2133	0	0.1223	0.0910	(0.1223)
Phenanthrene	0.0013004	0.5059	0	0.2900	0.2159	(0.2900)
Phenol	7.22e-08	0.0000	0	0.0000	0.0000	(0.0000)
Total Priority Pollutants, Organics		1.1102	0	0.6364	0.4738	(0.6364)
Priority Pollutants, Metals	**lbs/lb barite**					
Cadmium	0.0000011	0.0570	0	0.0326	0.0244	(0.0326)
Mercury	0.0000001	0.0052	0	0.0030	0.0022	(0.0030)
Antimony	0.0000057	0.2954	0	0.1691	0.1263	(0.1691)
Arsenic	0.0000071	0.3679	0	0.2106	0.1573	(0.2106)
Berylium	0.0000007	0.0363	0	0.0208	0.0155	(0.0208)
Chromium	0.0002400	12.4363	0	7.1186	5.3177	(7.1186)
Copper	0.0000187	0.9690	0	0.5547	0.4143	(0.5547)
Lead	0.0000351	1.8188	0	1.0411	0.7777	(1.0411)
Nickel	0.0000135	0.6995	0	0.4004	0.2991	(0.4004)
Selenium	0.0000011	0.0570	0	0.0326	0.0244	(0.0326)
Silver	0.0000007	0.0363	0	0.0208	0.0155	(0.0208)
Thallium	0.0000012	0.0622	0	0.0356	0.0266	(0.0356)
Zinc	0.0002005	10.3895	0	5.9470	4.4425	(5.9470)
Total Priority Pollutant Metals		27.23	0	15.59	11.64	(15.59)
Non-Conventional Metals	**lbs/lb barite**					
Aluminum	0.0090699	469.9841	0	269.0223	200.9618	(269.0223)
Barium	0.1200000	6,218.1600	0	3,559.3200	2,658.8400	(3,559.3200)
Iron	0.0153443	795.1109	0	455.1273	339.9837	(455.1273)
Tin	0.0000146	0.7565	0	0.4331	0.3235	(0.4331)
Titanium	0.0000875	4.5341	0	2.5953	1.9387	(2.5953)
Non-Conventional Organics	**lbs/bbl drilling fluid**					
Alkylated benzenes	0.0056587	2.2012	0	1.2619	0.9393	(1.2619)
Alkylated naphthalenes	0.0531987	20.6943	0	11.8633	8.8310	(11.8633)
Alkylated fluorenes	0.0064038	2.4911	0	1.4280	1.0630	(1.4280)
Alkylated phenanthrenes	0.0080909	3.1473	0	1.8043	1.3431	(1.8043)
Alkylated phenols	0.0000006	0.0002	0	0.0001	0.0001	(0.0001)
Total biphenyls	0.0105160	4.0907	0	2.3451	1.7457	(2.3451)
Total dibenzothiophenes	0.0000092	0.0036	0	0.0020	0.0015	(0.0020)
Total Non-Conventional Pollutants		7,521.17	0	4,305.20	3,216	(4,305.20)
Total Loadings and Reductions (lbs per well)		**647,580**	**0**	**590,550**	**57,029**	**(590,550)**

WORKSHEET 8: Discharge Option Loadings and Incremental Reductions

Shallow Water Exploratory Well

Technology = Discharge Assuming 7% (wt) Retention on Discharged Cuttings and 0.2% (vol) Crude Contamination

SBF-using Facilities = Change from 11% to 7% retention on discharged cuttings
OBF-using Facilities = Change from zero discharge to 7% retention on discharged cuttings

Dry Cuttings Generated per Well =	1,077,440	lbs
Whole Drilling Fluid Discharged Per Well =	466	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well (lbs) Current Practice, SBF Wells (11% Retention)	Current Practice, OBF Wells (0 discharge)	Discharge at 7% Retention	SBF-using Well Reductions Per Well	OBF-using Well Loadings Per Well
Conventional Pollutants						
TSS (as barite)		108,588	0	62,158	46,430	(62,158)
TSS (as dry cuttings)		1,077,440	0	1,077,440	0	(1,077,440)
TSS (total)		1,186,028	0	1,139,598	46,430	(1,139,598)
Total Oil (base fluid plus crude)		155,202	0	88,890	66,312	(88,890)
Priority Pollutants, Organics	**lbs/bbl drilling fluid**					
Naphthalene	0.0010052	0.8182	0	0.4684	0.3498	(0.4684)
Fluorene	0.0005483	0.4463	0	0.2555	0.1908	(0.2555)
Phenanthrene	0.0013004	1.0586	0	0.6060	0.4526	(0.6060)
Phenol	7.22e-08	0.0001	0	0.0000	0.0000	(0.0000)
Total Priority Pollutants, Organics		2.3232	0	1.3300	0.9932	(1.3300)
Priority Pollutants, Metals	**lbs/lb barite**					
Cadmium	0.0000011	0.1194	0	0.0684	0.0511	(0.0684)
Mercury	0.0000001	0.0109	0	0.0062	0.0046	(0.0062)
Antimony	0.0000057	0.6190	0	0.3543	0.2647	(0.3543)
Arsenic	0.0000071	0.7710	0	0.4413	0.3297	(0.4413)
Berylium	0.0000007	0.0760	0	0.0435	0.0325	(0.0435)
Chromium	0.0002400	26.0611	0	14.9179	11.1432	(14.9179)
Copper	0.0000187	2.0306	0	1.1624	0.8682	(1.1624)
Lead	0.0000351	3.8114	0	2.1817	1.6297	(2.1817)
Nickel	0.0000135	1.4659	0	0.8391	0.6268	(0.8391)
Selenium	0.0000011	0.1194	0	0.0684	0.0511	(0.0684)
Silver	0.0000007	0.0760	0	0.0435	0.0325	(0.0435)
Thallium	0.0000012	0.1303	0	0.0746	0.0557	(0.0746)
Zinc	0.0002005	21.7719	0	12.4627	9.3092	(12.4627)
Total Priority Pollutant Metals		57.06	0	32.66	24.40	(32.66)
Non-Conventional Metals	**lbs/lb barite**					
Aluminum	0.0090699	984.8823	0	563.7668	421.1155	(563.7668)
Barium	0.1200000	13,030.5600	0	7,458.9600	5,571.6000	(7,458.9600)
Iron	0.0153443	1,666.2068	0	953.7710	712.4358	(953.7710)
Tin	0.0000146	1.5854	0	0.9075	0.6779	(0.9075)
Titanium	0.0000875	9.5014	0	5.4388	4.0626	(5.4388)
Non-Conventional Organics	lbs/bbl drilling fluid					
Alkylated benzenes	0.0056587	4.6062	0	2.6369	1.9692	(2.6369)
Alkylated naphthalenes	0.0531987	43.3038	0	24.7906	18.5132	(24.7906)
Alkylated fluorenes	0.0064038	5.2127	0	2.9842	2.2285	(2.9842)
Alkylated phenanthrenes	0.0080909	6.5860	0	3.7703	2.8156	(3.7703)
Alkylated phenols	0.0000006	0.0005	0	0.0003	0.0002	(0.0003)
Total biphenyls	0.0105160	8.5600	0	4.9005	3.6596	(4.9005)
Total dibenzothiophenes	0.0000092	0.0074	0	0.0043	0.0032	(0.0043)
Total Non-Conventional Pollutants		15,761.01	0	9,021.93	6,739	(9,021.9313)
Total Loadings and Reductions (lbs per well)		**1,357,050**	**0**	**1,237,544**	**119,506**	**(1,237,544)**

WORKSHEET 9: Zero Discharge Option Incremental Reductions

Deep Water Development Well

Technology = Zero Discharge Assuming 11% (wt) Retention on Discharged Cuttings and 0.2% Crude Contamination

Dry Cuttings Generated per Well =	778,050	lbs
Whole Drilling Fluid Disposed per Well =	588	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well (lbs)		Reductions Per Well
		Current Practice (11% Retention)	Zero Discharge	
Conventional Pollutants				
TSS (as barite)		78,414	0	78,414
TSS (as dry cuttings)		778,050	0	778,050
TSS (total)		856,464	0	856,464
Total Oil (base fluid plus crude)		112,075	0	112,075
Priority Pollutant Organics	**lbs/bbl drilling fluid**			
Naphthalene	0.0010052	0.5911	0.0000	0.5911
Fluorene	0.0005483	0.3224	0.0000	0.3224
Phenanthrene	0.0013004	0.7647	0.0000	0.7647
Phenol	7.22e-08	0.0000	0.0000	0.0000
Total Priority Pollutant Organics		1.6782	0.0000	1.6782
Priority Pollutants, Metals	**lbs/lb barite**			
Cadmium	0.0000011	0.0863	0.0000	0.0863
Mercury	0.0000001	0.0078	0.0000	0.0078
Antimony	0.0000057	0.4470	0.0000	0.4470
Arsenic	0.0000071	0.5567	0.0000	0.5567
Berylium	0.0000007	0.0549	0.0000	0.0549
Chromium	0.0002400	18.8194	0.0000	18.8194
Copper	0.0000187	1.4663	0.0000	1.4663
Lead	0.0000351	2.7523	0.0000	2.7523
Nickel	0.0000135	1.0586	0.0000	1.0586
Selenium	0.0000011	0.0863	0.0000	0.0863
Silver	0.0000007	0.0549	0.0000	0.0549
Thallium	0.0000012	0.0941	0.0000	0.0941
Zinc	0.0002005	15.7220	0.0000	15.7220
Total Priority Pollutant Metals		41.21	0.00	41.21
Non-Conventional Metals	**lbs/lb barite**			
Aluminum	0.0090699	711.2071	0.0000	711.2071
Barium	0.1200000	9,409.6800	0.0000	9,409.6800
Iron	0.0153443	1,203.2079	0.0000	1,203.2079
Tin	0.0000146	1.1448	0.0000	1.1448
Titanium	0.0000875	6.8612	0.0000	6.8612
Non-Conventional Organics	**lbs/bbl drilling fluid**			
Alkylated benzenes	0.0056587	3.3273	0.0000	3.3273
Alkylated naphthalenes	0.0531987	31.2808	0.0000	31.2808
Alkylated fluorenes	0.0064038	3.7654	0.0000	3.7654
Alkylated phenanthrenes	0.0080909	4.7574	0.0000	4.7574
Alkylated phenlos	0.0000006	0.0004	0.0000	0.0004
Total biphenyls	0.0105160	6.1834	0.0000	6.1834
Total dibenzothiophenes	0.0000092	0.0054	0.0000	0.0054
Total Non-Conventional Pollutants		11,381.42	0.00	11,381
Total Loadings and Reductions (lbs per well)		**979,963**	**0**	**979,963**

WORKSHEET 10: Zero Discharge Option Incremental Reductions

Deep Water Exploratory Well

Technology = Zero Discharge Assuming 11% (wt) Retention on Discharged Cuttings and 0.2% Crude Contamination

Dry Cuttings Generated per Well =	1,729,910	lbs
Whole Drilling Fluid Disposed per Well =	1308	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well (lbs)		Reductions Per Well
		Current Practice (11% Retention)	Zero Discharge	
Conventional Pollutants				
TSS (as barite)		174,346	0	174,346
TSS (as dry cuttings)		1,729,910	0	1,729,910
TSS (total)		1,904,256	0	1,904,256
Total Oil (base fluid plus crude)		249,187	0	249,187
Priority Pollutant Organics	**lbs/bbl drilling fluid**			
Naphthalene	0.0010052	1.3148	0.0000	1.3148
Fluorene	0.0005483	0.7172	0.0000	0.7172
Phenanthrene	0.0013004	1.7010	0.0000	1.7010
Phenol	7.22e-08	0.0001	0.0000	0.0001
Total Priority Pollutant Organics		3.7331	0.0000	3.7331
Priority Pollutants, Metals	**lbs/lb barite**			
Cadmium	0.0000011	0.1918	0.0000	0.1918
Mercury	0.0000001	0.0174	0.0000	0.0174
Antimony	0.0000057	0.9938	0.0000	0.9938
Arsenic	0.0000071	1.2379	0.0000	1.2379
Berylium	0.0000007	0.1220	0.0000	0.1220
Chromium	0.0002400	41.8430	0.0000	41.8430
Copper	0.0000187	3.2603	0.0000	3.2603
Lead	0.0000351	6.1195	0.0000	6.1195
Nickel	0.0000135	2.3537	0.0000	2.3537
Selenium	0.0000011	0.1918	0.0000	0.1918
Silver	0.0000007	0.1220	0.0000	0.1220
Thallium	0.0000012	0.2092	0.0000	0.2092
Zinc	0.0002005	34.9564	0.0000	34.9564
Total Priority Pollutant Metals		91.62	0.00	91.62
Non-Conventional Metals	**lbs/lb barite**			
Aluminum	0.0090699	1,581.3008	0.0000	1,581.3008
Barium	0.1200000	20,921.5200	0.0000	20,921.5200
Iron	0.0153443	2,675.2173	0.0000	2,675.2173
Tin	0.0000146	2.5455	0.0000	2.5455
Titanium	0.0000875	15.2553	0.0000	15.2553
Non-Conventional Organics	**lbs/bbl drilling fluid**			
Alkylated benzenes	0.0056587	7.4016	0.0000	7.4016
Alkylated naphthalenes	0.0531987	69.5839	0.0000	69.5839
Alkylated fluorenes	0.0064038	8.3762	0.0000	8.3762
Alkylated phenanthrenes	0.0080909	10.5829	0.0000	10.5829
Alkylated phenlos	0.0000006	0.0008	0.0000	0.0008
Total biphenyls	0.0105160	13.7550	0.0000	13.7550
Total dibenzothiophenes	0.0000092	0.0120	0.0000	0.0120
Total Non-Conventional Pollutants		25,305.55	0.00	25,306
Total Loadings and Reductions (lbs per well)		**2,178,844**	**0**	**2,178,844**

WORKSHEET 11: Zero Discharge Option Incremental Reductions

Shallow Water Development Well

Technology = Zero Discharge Assuming 11% (wt) Retention on Discharged Cuttings and 0.2% Crude Contamination

Dry Cuttings Generated per Well =	514,150	lbs
Whole Drilling Fluid Disposed per Well =	389	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well (lbs) Current Practice (11% Retention)	Zero Discharge	Reductions Per Well
Conventional Pollutants				
TSS (as barite)		51,818	0	51,818
TSS (as dry cuttings)		514,150	0	514,150
TSS (total)		565,968	0	565,968
Total Oil (base fluid plus crude)		74,062	0	74,062
Priority Pollutant Organics	**lbs/bbl drilling fluid**			
Naphthalene	0.0010052	0.3910	0.0000	0.3910
Fluorene	0.0005483	0.2133	0.0000	0.2133
Phenanthrene	0.0013004	0.5059	0.0000	0.5059
Phenol	7.22e-08	0.0000	0.0000	0.0000
Total Priority Pollutant Organics		1.1102	0.0000	1.1102
Priority Pollutants, Metals	**lbs/lb barite**			
Cadmium	0.0000011	0.0570	0.0000	0.0570
Mercury	0.0000001	0.0052	0.0000	0.0052
Antimony	0.0000057	0.2954	0.0000	0.2954
Arsenic	0.0000071	0.3679	0.0000	0.3679
Berylium	0.0000007	0.0363	0.0000	0.0363
Chromium	0.0002400	12.4363	0.0000	12.4363
Copper	0.0000187	0.9690	0.0000	0.9690
Lead	0.0000351	1.8188	0.0000	1.8188
Nickel	0.0000135	0.6995	0.0000	0.6995
Selenium	0.0000011	0.0570	0.0000	0.0570
Silver	0.0000007	0.0363	0.0000	0.0363
Thallium	0.0000012	0.0622	0.0000	0.0622
Zinc	0.0002005	10.3895	0.0000	10.3895
Total Priority Pollutant Metals		27.23	0.00	27.23
Non-Conventional Metals	**lbs/lb barite**			
Aluminum	0.0090699	469.9841	0.0000	469.9841
Barium	0.1200000	6,218.1600	0.0000	6,218.1600
Iron	0.0153443	795.1109	0.0000	795.1109
Tin	0.0000146	0.7565	0.0000	0.7565
Titanium	0.0000875	4.5341	0.0000	4.5341
Non-Conventional Organics	**lbs/bbl drilling fluid**			
Alkylated benzenes	0.0056587	2.2012	0.0000	2.2012
Alkylated naphthalenes	0.0531987	20.6943	0.0000	20.6943
Alkylated fluorenes	0.0064038	2.4911	0.0000	2.4911
Alkylated phenanthrenes	0.0080909	3.1473	0.0000	3.1473
Alkylated phenlos	0.0000006	0.0002	0.0000	0.0002
Total biphenyls	0.0105160	4.0907	0.0000	4.0907
Total dibenzothiophenes	0.0000092	0.0036	0.0000	0.0036
Total Non-Conventional Pollutants		7,521.17	0.00	7,521
Total Loadings and Reductions (lbs per well)		**647,580**	**0**	**647,580**

WORKSHEET 12: Zero Discharge Option Incremental Reductions

Shallow Water Exploratory Well

Technology = Zero Discharge Assuming 11% (wt) Retention on Discharged Cuttings and 0.2% Crude Contamination

Dry Cuttings Generated per Well =	1,077,440	lbs
Whole Drilling Fluid Disposed per Well =	814	bbls

Pollutant Name	Avg. Conc. of Pollutants in Drilling Waste	Pollutant Loadings per Well (lbs)		Reductions Per Well
		Current Practice (11% Retention)	Zero Discharge	
Conventional Pollutants				
TSS (as barite)		108,588	0	108,588
TSS (as dry cuttings)		1,077,440	0	1,077,440
TSS (total)		1,186,028	0	1,186,028
Total Oil (synthetic plus crude)		155,202	0	155,202
Priority Pollutant Organics	**lbs/bbl drilling fluid**			
Naphthalene	0.0010052	0.8182	0.0000	0.8182
Fluorene	0.0005483	0.4463	0.0000	0.4463
Phenanthrene	0.0013004	1.0586	0.0000	1.0586
Phenol	7.22e-08	0.0001	0.0000	0.0001
Total Priority Pollutant Organics		2.3232	0.0000	2.3232
Priority Pollutants, Metals	**lbs/lb barite**			
Cadmium	0.0000011	0.1194	0.0000	0.1194
Mercury	0.0000001	0.0109	0.0000	0.0109
Antimony	0.0000057	0.6190	0.0000	0.6190
Arsenic	0.0000071	0.7710	0.0000	0.7710
Berylium	0.0000007	0.0760	0.0000	0.0760
Chromium	0.0002400	26.0611	0.0000	26.0611
Copper	0.0000187	2.0306	0.0000	2.0306
Lead	0.0000351	3.8114	0.0000	3.8114
Nickel	0.0000135	1.4659	0.0000	1.4659
Selenium	0.0000011	0.1194	0.0000	0.1194
Silver	0.0000007	0.0760	0.0000	0.0760
Thallium	0.0000012	0.1303	0.0000	0.1303
Zinc	0.0002005	21.7719	0.0000	21.7719
Total Priority Pollutant Metals		57.06	0.00	57.06
Non-Conventional Metals	**lbs/lb barite**			
Aluminum	0.0090699	984.8823	0.0000	984.8823
Barium	0.1200000	13,030.5600	0.0000	13,030.5600
Iron	0.0153443	1,666.2068	0.0000	1,666.2068
Tin	0.0000146	1.5854	0.0000	1.5854
Titanium	0.0000875	9.5015	0.0000	9.5014
Non-Conventional Organics	**lbs/bbl drilling fluid**			
Alkylated benzenes	0.0056587	4.6062	0.0000	4.6062
Alkylated naphthalenes	0.0531987	43.3038	0.0000	43.3038
Alkylated fluorenes	0.0064038	5.2127	0.0000	5.2127
Alkylated phenanthrenes	0.0080909	6.5860	0.0000	6.5860
Alkylated phenlos	0.0000006	0.0005	0.0000	0.0005
Total biphenyls	0.0105160	8.5600	0.0000	8.5600
Total dibenzothiophenes	0.0000092	0.0074	0.0000	0.0074
Total Non-Conventional Pollutants		15,761.01	0.00	15,761
Total Loadings and Reductions (lbs per well)		**1,357,050**	**0**	**1,357,050**

APPENDIX IX-1

BAT NON-WATER QUALITY ENVIRONMENTAL IMPACT CALCULATIONS FOR EXISTING SOURCES

Summary BAT NWQEI of SBF Cuttings Management

Baseline NWQEI: Total Annual

Baseline Technology	Gulf of Mexico Air Emissions (tons)	Gulf of Mexico Fuel Usage (BOE), (a)	Offshore California Air Emissions (tons)	Offshore California Fuel Usage (BOE), (a)	Cook Inlet, Alaska Air Emissions (tons)	Cook Inlet, Alaska Fuel Usage (BOE), (a)	Total Air Emissions (tons)	Total Fuel Usage (BOE), (a)	Notes
Discharge with 11% retention of base fluid on cuttings (b)	0	0	NA	NA	NA	NA	**0.00**	**0.00**	
Zero Discharge: current OBF users only (c)	47.92	3,432.82	36.61	2,120.72	2.08	285.15	**86.61**	**5,838.68**	From Worksheets No.s 1, 3, and 5
Total Baseline NWQEI	47.92	3,432.82	36.61	2,120.72	2.08	285.15	**86.61**	**5,838.68**	

Compliance NWQEI: Total Annual

Option	Gulf of Mexico Air Emissions (tons)	Gulf of Mexico Fuel Usage (BOE), (a)	Offshore California Air Emissions (tons)	Offshore California Fuel Usage (BOE), (a)	Cook Inlet, Alaska Air Emissions (tons)	Cook Inlet, Alaska Fuel Usage (BOE), (a)	Total Air Emissions (tons)	Total Fuel Usage (BOE), (a)	Notes
Discharge Option (d)	12.54	3,034.95	0.76	187.07	0.01	4.02	**13.30**	**3,226.03**	From Worksheets No.s 7, 9, and 11
Zero Discharge Option (b)	338.55	24,124.56	NA	NA	NA	NA	**338.55**	**24,124.56**	From Worksheet No. 14

Incremental Compliance NWQEI Reductions: Total Annual

Option	Gulf of Mexico Air Emissions (tons)	Gulf of Mexico Fuel Usage (BOE), (a)	Offshore California Air Emissions (tons)	Offshore California Fuel Usage (BOE), (a)	Cook Inlet, Alaska Air Emissions (tons)	Cook Inlet, Alaska Fuel Usage (BOE), (a)	Total Air Emissions (tons)	Total Fuel Usage (BOE), (a)	Notes
Discharge Option (d)	35.38	397.87	35.86	1,933.65	2.07	281.13	**73.31**	**2,612.65**	Difference between total baseline and compliance discharge option NWQIs
Zero Discharge Option (b)	(338.55)	(24,124.56)	0	0	0	0	**(338.55)**	**(24,124.56)**	Difference between discharge baseline and zero discharge option NWQIs

(a) BOE (barrels of oil equivalent) is the sum of the volumes of diesel (by the factor 1 BOE = 42 gal diesel) and natural gas (1,000 scf = 0.178 BOE) estimated for each compliance option.

(b) For Gulf of Mexico, NWQEI analysis conducted for 94 wells currently using SBF.

(c) Current zero discharge impacts apply only to wells drilled using OBF that are projected to convert to SBF: 23 Gulf of Mexico, 12 California and 1 Alaska well.

(d) Both OBF and SBF drilled wells are included in the discharge option NWQEI analysis as follows: GOM: 94 current SBF wells + 23 current OBF wells; CA: 12 current OBF wells; AK: 1 current OBF well.

Worksheet No. 1
Non-Water Quality Environmental Impacts: Baseline Current Practice

Region: Offshore Gulf of Mexico

Technology: Discharge of SBF cuttings via add-on cuttings "dryer" w/average achievable retention of 11% (wt) base fluid on cuttings
Zero Discharge of OBF cuttings via haul and land dispose (80%) plus on-site grinding and injection (20%)

Model Well Types: Deep Water Development, Deep Water Exploratory, Shallow Water Development, Shallow Water Exploratory

	Air Emissions (tons)							Fuel Usage (BOE)							
	Wells Using SBF				Wells Using OBF			Wells Using SBF				Wells Using OBF			
NWQEI	**DWD**	**DWE**	**SWD**	**SWE**	**SWD**	**SWE**	**TOTAL**	**DWD**	**DWE**	**SWD**	**SWE**	**SWD**	**SWE**	**TOTAL**	**Notes**
Discharge with 11% retention of base fluid on cuttings (85% diesel, 15% nat. gas usage)	0.00	0.00	0.00	0.00	--	--		0.00	0.00	0.00	0.00	--	--	0.00	
Hauling and Onshore Disposal (diesel fuel source)	--	--	--	--	2.2358	3.2222		--	--	--	–	155.41	217.72		From Worksheet No. 7
Grinding and Injection (diesel fuel source)	--	--	--	--	0.0850	0.1782		--	--	--	--	25.59	53.33	0.00	From Worksheet No. 8
Grinding and Injection (natural gas fuel source)	--	--	--	--	0.0098	0.0205		--	--	--	--	38.59	80.47	0.00	From Worksheet No. 8
Weighted Average Grinding and Injection	--	--	--	--	0.0737	0.1545		--	--	--	--	27.54	57.40	0.00	Weighted avg. assumes 85% of wells use diesel and 15% use nat. gas for electricity generation
Weighted Average Per Well Baseline NWQEIs	0.00	0.00	0.00	0.00	1.80	2.61		0.00	0.00	0.00	0.00	129.84	185.66		Weighted avg. assumes 80% of wells haul wastes and 20% grind and inject.
No. of Wells	18	57	12	7	15	8		18	57	12	7	15	8		
TOTAL ANNUAL GOM BASELINE NWQEIs	0.00	0.00	0.00	0.00	27.05	20.87	**47.92**	0.00	0.00	0.00	0.00	1,947.58	1,485.24	**3,432.82**	

Worksheet No. 2
Non-Water Quality Environmental Impacts: Baseline Current Practice
Page 1 of 4

Region:	Offshore California
Technology:	Zero Discharge via Haul and Land Dispose
Model Well Types:	Deep Water Development Shallow Water Development

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)	No. of Cuttings Boxes	No. of Dedicated Boat Trips (Cap.=80 boxes)	Dedicated Boat Idling Time (hrs)	No. of Truck Trips (Cap.= 50 bbl)
Deep Water Development	1,442	5.4	58	1	129.6	29
Shallow Water Development	953	3.6	39	1	86.4	20

Fuel-Consuming Activity	**Diesel Fuel Consumed (gal)** **Deep Water Development**	 **Shallow Water Development**	**Notes (All information below is detailed in Section IX.3.1.3.1)**
Supply Boat Transit (distance (mi)/boat speed(mi/hr) * diesel usage rate (gal/hr))	2,260.87	2,260.87	Distance traveled by supply boats for all wells = 200 mi. Supply boat average speed = 11.5 mi/hr. Supply boat diesel usage rate = 130 gal/hr.
Supply Boat Maneuvering (no. of boat trips * maneuvering time per trip (hrs) * diesel usage rate (gal/hr))	25.30	25.30	Average maneuvering time per trip = 1 hour. Supply boat diesel usage rate during maneuvering = 25.3 gal/hr.
Dedicated Supply Boat Loading (Idling time per trip(hr) + additional loading time per trip (hr)) * no. of trips * diesel usage rate (gal/hr)	3,319.36	2,226.40	A dedicated supply boat is assumed to be moored and idling at the platform until it has reached capacity or until all SBF generated cuttings from the drilling operation are loaded. Idling supply boat diesel usage rate = 25.3 gal/hr. Additional loading time to account for potential delays = 1.6 hrs.
Supply Boat Auxiliary Generator (in Port Demurrage) (no. of boat trips * generator hrs per trip * diesel usage rate (gal/hr))	144.00	144.00	Generator usage time in port = 24 hrs. Generator diesel usage rate in port = 6 gal/hr.

Worksheet No. 2
Non-Water Quality Environmental Impacts: Baseline Current Practice
Page 2 of 4

Region:	Offshore California
Technology:	Zero Discharge via Haul and Land Dispose
Model Well Types:	Deep Water Development Shallow Water Development

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)	No. of Cuttings Boxes	No. of Dedicated Boat Trips (Cap.=80 boxes)	Dedicated Boat Idling Time (hrs)	No. of Truck Trips (Cap.= 50 bbl)
Deep Water Development	1,442	5.4	58	1	129.6	29
Shallow Water Development	953	3.6	39	1	86.4	20

Fuel-Consuming Activity	Diesel Fuel Consumed (gal) Deep Water Development	Diesel Fuel Consumed (gal) Shallow Water Development	Notes (All information below is detailed in Section IX.3.1.3.1)
Supply Boat Cranes ((no. of lifts at drill site + no of lifts in port)/ crane lifts per hour)) * diesel usage rate	193.26	129.95	Supply boat crane loading/unloading rate = 10 lifts per hour. Supply boat crane diesel usage rate = 8.33 gal/hr.
Trucks (no. of truck trips*roundtrip miles per trip)/ diesel usage rate (mi/gal)	1,242.86	857.14	Roundtrip distance from the port to the disposal facility = 300 miles. Truck diesel usage rate = 7 mi/gal.
Wheel Tractor for Grading at Landfarm (tractor time per well) * diesel usage rate	13.36	13.36	Tractor time per well for all well types = 8 hrs. Tractor diesel usage rate = 1.67 gal/hr.
Track-Type Dozer/Loader for Spreading Waste at Landfarm (dozer time per well) * diesel usage rate	352.00	352.00	Dozer time per well for all well types = 16 hrs. Dozer diesel usage rate = 22 gal/hr.
TOTAL Diesel Per Well (Gal)	**7,551.00**	**6,009.02**	

Energy-Consuming Activity	Power Requirements (hp-hr) Deep Water Development	Power Requirements (hp-hr) Shallow Water Development	Notes (All information below is detailed in Section IX.3.1.3.1)
Supply Boat Auxiliary Generator (in Port Demurrage) no. of boat trips * generator hrs per trip * generator power rating	1,440.00	1,440.00	In port use of auxiliary electrical generator for power = 24 hrs. Generator power rating = 60 hp.
Supply Boat Cranes ((no. of lifts at drill site + no of lifts in port)/ crane lifts per hour)) * generator power rating	3,155.20	2,121.60	Generator power rating = 136 hp.
TOTAL Power Requirements Per Well	**4,595.20**	**3,561.60**	

Worksheet No. 2
Non-Water Quality Environmental Impacts: Baseline Current Practice
Air Emissions

Region: Offshore California
Technology: Zero Discharge via Haul and Land Dispose

Model Well Types: Deep Water Development
Shallow Water Development

Deep Water Development Well Air Emissions

Category	Air Emissions (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Supply Boats						
Transit	0.443	0.190	0.032	0.089	0.037	0.791
Maneuvering	0.005	0.003	0.000	0.001	0.000	0.010
Loading	0.696	0.375	0.047	0.099	0.055	1.273
Demurrage	0.022	0.002	0.001	0.005	0.002	0.032
Supply Boat Cranes	0.049	0.004	0.003	0.011	0.003	0.070
Trucks	0.108	0.024	--	0.817	--	0.949
Wheel Tractor	0.005	0.001	0.000	0.014	0.001	0.021
Dozer/Loader	0.007	0.001	0.001	0.002	0.000	0.010
Total	**1.33**	**0.60**	**0.09**	**1.04**	**0.10**	**3.15**

Shallow Water Development Well Air Emissions

Category	Air Emissions (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Supply Boats						
Transit	0.443	0.190	0.032	0.089	0.037	0.791
Maneuvering	0.005	0.003	0.000	0.001	0.000	0.010
Loading	0.467	0.252	0.032	0.067	0.037	0.854
Demurrage	0.022	0.002	0.001	0.005	0.002	0.032
Supply Boat Cranes	0.033	0.003	0.002	0.007	0.002	0.047
Trucks	0.074	0.016	--	0.056	--	0.147
Wheel Tractor	0.005	0.001	0.000	0.014	0.001	0.021
Dozer/Loader	0.007	0.001	0.001	0.002	0.000	0.010
Total	**1.06**	**0.47**	**0.07**	**0.24**	**0.08**	**1.91**

Worksheet No. 2
Non-Water Quality Environmental Impacts: Baseline Current Practice

Region: Offshore California

Technology: Zero Discharge via Haul and Land Dispose

Model Well Types: Deep Water Development, Shallow Water Development

Per Well NWQEI	Air Emissions (tons) DWD	SWD	TOTAL	Fuel Usage (BOE) DWD	SWD	TOTAL	Notes
Hauling and Onshore Disposal (diesel fuel source)	3.1548	1.9111		179.79	143.07		From Worksheet No. 2, page 3
Total NWQEI Per Well	3.15	1.91		179.79	143.07		
No. of Wells	11	1		11	1		
TOTAL ANNUAL CA BASELINE NWQEIs	34.70	1.91	**36.61**	1,977.64	143.07	**2,120.72**	

Worksheet No. 3
Non-Water Quality Environmental Impacts: Baseline Current Practice

Region: Cook Inlet, Alaska
Technology: Zero Discharge via Haul and Land Dispose

Model Well Types: Shallow Water Development

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)	No. of Cuttings Boxes	No. of Dedicated Boat Trips (Cap.=132 boxes)	Dedicated Boat Idling Time (hrs)	No. of Truck Trips (Cap.= 64 bbl)
Shallow Water Development	953	3.6	120	1	86.4	15

Fuel-Consuming Activity	Diesel Fuel Consumed (gal) Shallow Water Development	Notes (All information below is detailed in Section IX.3.1.3.1)
Supply Boat Transit (distance (mi)/boat speed(mi/hr) * diesel usage rate (gal/hr))	565.22	Distance traveled by supply boats = 50 mi. Supply boat average speed = 11.5 mi/hr. Supply boat diesel usage rate = 130 gal/hr.
Supply Boat Maneuvering (no. of boat trips * maneuvering time per trip (hrs) * diesel usage rate (gal/hr))	25.30	Average maneuvering time per trip = 1 hour. Supply boat diesel usage rate during maneuvering = 25.3 gal/hr.
Dedicated Supply Boat Loading (Idling time per trip(hr) + additional loading time per trip (hr)) * no. of trips * diesel usage rate (gal/hr)	2,226.40	A dedicated supply boat is assumed to be moored and idling at the platform unitl it has reached capacity or until all SBF generated cuttings from the drilling operation are loaded. Idling supply boat diesel usage rate = 25.3 gal/hr. Additional loading time to account for potential delays = 1.6 hrs.
Supply Boat Auxiliary Generator (in Port Demurrage) (no. of boat trips * generator hrs per trip* diesel usage rate (gal/hr))	144.00	Generator usage time in port = 24 hrs. Generator diesel usage rate in port = 6 gal/hr.

Worksheet No. 3
Non-Water Quality Environmental Impacts: Baseline Current Practice

Region:	Cook Inlet, Alaska
Technology:	Zero Discharge via Haul and Land Dispose
Model Well Types:	Shallow Water Development

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)	No. of Cuttings Boxes	No. of Dedicated Boat Trips (Cap.=132 boxes)	Dedicated Boat Idling Time (hrs)	No. of Truck Trips (Cap.= 64 bbl)
Shallow Water Development	953	3.6	120	1	86.4	15

Fuel-Consuming Activity	Diesel Fuel Consumed (gal) Shallow Water Development	Notes (All information below is detailed in Section IX.3.1.3.1)
Supply Boat Cranes ((no. of lifts at drill site + no of lifts in port)/ crane lifts per hour)) * diesel usage rate	399.84	Supply boat crane loading/unloading rate = 10 lifts per hour. Supply boat crane diesel usage rate = 8.33 gal/hr.
Trucks (no. of truck trips*roundtrip miles per trip)/ diesel usage rate (mi/gal)	8,250.00	Distance from the port to the disposal facility = 2,200 miles. Truck diesel usage rate = 4 mi/gal.
Wheel Tractor for Grading at Landfarm (tractor time per well) * diesel usage rate	13.36	Tractor time per well for all well types = 8 hrs. Tractor diesel usage rate = 1.67 gal/hr.
Track-Type Dozer/Loader for Spreading Waste at Landfarm (dozer time per well) * diesel usage rate	352.00	Dozer time per well for all well types = 16 hrs. Dozer diesel usage rate = 22 gal/hr.
TOTAL Diesel Per Well (Gal)	**11,976.12**	

Energy-Consuming Activity	Power Requirements (hp-hr) Shallow Water Development	Notes (All information below is detailed in Section IX.3.1.3.1)
Supply Boat Auxiliary Generator (in Port Demurrage) no. of boat trips * generator hrs per trip * generator power rating	1,440.00	In port use of auxiliary electrical generator for power = 24 hrs. Generator power rating = 60 hp.
Supply Boat Cranes ((no. of lifts at drill site + no of lifts in port)/ crane lifts per hour)) * generator power rating	6,528.00	Generator power rating = 136 hp.
TOTAL Power Requirements Per Well	**7,968.00**	

Worksheet No. 3
Non-Water Quality Environmental Impacts: Baseline Current Practice
Air Emissions
Page 3 of 4

Region: Cook Inlet, Alaska
Technology: Zero Discharge via Haul and Land Dispose

Model Well Types: Shallow Water Development

Shallow Water Development Well Air Emissions

	Air Emissions (tons/per well drilled)					
Category	**NOx**	**THC**	**SO2**	**CO**	**TSP**	**Total**
Supply Boats						
Transit	0.111	0.047	0.008	0.022	0.009	0.198
Maneuvering	0.005	0.003	0.000	0.001	0.000	0.010
Loading	0.467	0.252	0.032	0.067	0.037	0.854
Demurrage	0.022	0.002	0.001	0.005	0.002	0.032
Supply Boat Cranes	0.101	0.008	0.007	0.022	0.007	0.144
Trucks	0.408	0.091	--	0.310	--	0.809
Wheel Tractor	0.005	0.001	0.000	0.014	0.001	0.021
Dozer/Loader	0.007	0.001	0.001	0.002	0.000	0.010
Total	**1.13**	**0.40**	**0.05**	**0.44**	**0.06**	**2.08**

Worksheet No. 3
Non-Water Quality Environmental Impacts: Baseline Current Practice
Page 4 of 4

Region: Cook Inlet, Alaska
Technology: Zero Discharge via Haul and Land Dispose

Model Well Types: Shallow Water Development

Per Well NWQEI	Air Emissions (tons) SWD	Air Emissions (tons) TOTAL	Fuel Usage (BOE) SWD	Fuel Usage (BOE) TOTAL	Notes
Hauling and Onshore Disposal (diesel fuel source)	2.0771		285.15		From Worksheet No. 3, page 3
Total NWQEI Per Well	2.08		285.15		
No. of Wells	1		1		
TOTAL ANNUAL AK BASELINE NWQEIs	**2.08**	**2.08**	**285.15**	**285.15**	

Worksheet No. 4
Non-Water Quality Environmental Impacts: Discharge
Page 1 of 2

Region: Offshore Gulf of Mexico
Technology: Discharge via add-on drill cuttings "dryer" with average retention of 7%(wt) base fluid on cuttings.

Model Well Types: Deep Water Development, Deep Water Exploratory, Shallow Water Development, Shallow Water Exploratory

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)
Deep Water Development	1,442	5.4
Deep Water Exploratory	3,206	12
Shallow Water Development	953	3.6
Shallow Water Exploratory	1,997	7.5

Fuel-Consuming Activity	Power Requirements (hp-hr)				Notes (All information below is detailed in Section IX.3.1.2)
	Deep Water		Shallow Water		
	Development	Exploratory	Development	Exploratory	
Improved Solids Control Equipment (hp * hrs to drill SBF well interval)	3,562.70	7,917.12	2,375.14	4,948.20	Total horsepower of solids control equipment = 27.49 hp.
Total Power Requirements Per Well	3,562.70	7,917.12	2,375.14	4,948.20	
Total Natural Gas Usage Per Well (scf)	33,845.69	75,212.64	22,563.79	47,007.90	
Total Diesel Usage Per Well (gal)	777.60	1,728.00	518.40	1,080.00	Fuel consumption rate = 6 gal/hr.

Fuel Type used on Platforms: Diesel Fuel

Category	Air Emissions From Additional Solids Control Equipment (tons/per well drilled)				Total
	THC	SO2	CO	TSP	
Deep Water Development	0.0044	0.0037	0.0119	0.0039	0.0788
Deep Water Exploratory	0.0098	0.0081	0.0264	0.0087	0.1751
Shallow Water Development	0.0029	0.0024	0.0079	0.0026	0.0525
Shallow Water Exploratory	0.0061	0.0051	0.0165	0.0055	0.1094

Fuel Type used on Platforms: Natural Gas

Category	Air Emissions From Additional Solids Control Equipment (tons/per well drilled)				Total
	THC	SO2	CO	TSP	
Deep Water Development	0.0007	0.0000	0.0033	0.0000	0.0091
Deep Water Exploratory	0.0016	0.0000	0.0072	0.0000	0.0202
Shallow Water Development	0.0005	0.0000	0.0022	0.0000	0.0060
Shallow Water Exploratory	0.0010	0.0000	0.0045	0.0000	0.0126

Worksheet No. 4
Non-Water Quality Environmental Impacts: Discharge
Page 2 of 2

Region: Offshore Gulf of Mexico

Technology: Discharge via add-on drill cuttings "dryer" with average retention of 7%(wt) base fluid on cuttings.

Model Well Types: Deep Water Development, Deep Water Exploratory, Shallow Water Development, Shallow Water Exploratory

Per Well	Air Emissions (tons)					Fuel Usage (BOE)					
NWQEI	DWD	DWE	SWD	SWE	TOTAL	DWD	DWE	SWD	SWE	TOTAL	Notes
GOM Wells Currently Using SBF and Discharging Cuttings											
Discharge Option (diesel fuel source)	0.0788	0.1751	0.0525	0.1094		18.51	41.14	12.34	25.71		From Worksheet No. 4, page 1
Discharge Option (natural gas fuel source)	0.0091	0.0202	0.0060	0.0126		6.02	13.39	4.02	8.37		From Worksheet No. 4, page 1
Weighted Average Per Well NWQEIs	0.07	0.15	0.05	0.09		16.64	36.98	11.09	23.11		Weighted avg. assumes 85% of wells use diesel and 15% use nat. gas for electricity generation.
No. of Wells	18	57	12	7		18	57	12	7		
Subtotal Annual GOM NWQEIs for SBF Wells	1.23	8.66	0.55	0.66	**11.10**	299.53	2,107.84	133.13	161.79	**2,702.28**	
GOM Wells Currently Using OBF Assumed to Switch to SBF											
Discharge Option (diesel fuel source)	--	--	0.0525	0.1094		--	--	12.34	25.71		From Worksheet No. 4, page 1
Discharge Option (natural gas fuel source)	--	--	0.0060	0.0126		--	--	0.09	0.19		From Worksheet No. 4, page 1
Weighted Average Per Well NWQEIs	--	--	0.05	0.09		--	--	10.51	21.89		Weighted avg. assumes 85% of wells use diesel and 15% use nat. gas for electricity generation.
No. of Wells	--	--	15	8		--	--	15	8		
Subtotal Annual GOM NWQEIs for OBF Wells	--	--	0.68	0.76	**1.44**	--	--	157.58	175.09	**332.67**	
TOTAL ANNUAL GOM Discharge NWQEIs					**12.54**					**3,034.95**	

Worksheet No. 5
Non-Water Quality Environmental Impacts: Discharge

Region: Offshore California

Technology: Discharge via add-on drill cuttings "dryer" with average retention of 7%(wt) base fluid on cuttings.

Model Well Types: Deep Water Development, Shallow Water Development

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)
Deep Water Development	1,442	5.4
Shallow Water Development	953	3.6

Fuel-Consuming Activity	Power Requirements (hp-hr)		Notes (All information below is detailed in Section IX.3.1.2)
	Deep Water Development	Shallow Water Development	
Improved Solids Control Equipment (hp * hrs to drill SBF well interval)	3,562.70	2,375.14	Total horsepower of solids control equipment = 27.49 hp.
Total Power Requirements Per Well	3,562.70	2,375.14	
Total Natural Gas Usage Per Well (scf)	33,845.69	22,563.79	Shallow water wells drilled in Offshore California use natural gas as fuel for generating power.
Total Diesel Usage Per Well (gal)	777.60		Fuel consumption rate = 6 gal/hr.

Fuel Type used on Platforms: Diesel Fuel

Category	Air Emissions From Additional Solids Control Equipment (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Deep Water Development	0.0549	0.0044	0.0037	0.0119	0.0039	0.0788

Fuel Type used on Platforms: Natural Gas

Category	Air Emissions From Additional Solids Control Equipment (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Deep Water Development	0.0051	0.0007	0.0000	0.0033	0.0000	0.0091
Shallow Water Development	0.0034	0.0005	0.0000	0.0022	0.0000	0.0060

Worksheet No. 5
Non-Water Quality Environmental Impacts: Discharge

Region: Offshore California

Technology: Discharge via add-on drill cuttings "dryer" with average retention of 7%(wt) base fluid on cuttings.

Model Well Types: Deep Water Development, Shallow Water Development

Per Well	Air Emissions (tons)			Fuel Usage (BOE)			
NWQEI	**DWD**	**SWD**	**TOTAL**	**DWD**	**SWD**	**TOTAL**	**Notes**
Discharge Option (diesel fuel source for deep water wells only)	0.0788			18.51			From Worksheet No. 5, page 1
Discharge Option (natural gas fuel source)	0.0091	0.0060		6.02	4.0164		From Worksheet No. 5, page 1
Weighted Average or Total Per Well NWQEIs	0.07	0.0060		16.64	4.0164		Weighted avg. assumes 85% of wells use diesel and 15% use nat. gas for electricity generation.
No. of Wells	11	1		11	1		
TOTAL ANNUAL CA DISCHARGE NWQEIs	0.75	0.01	**0.76**	183.05	4.02	**187.07**	

Worksheet No. 6
Non-Water Quality Environmental Impacts: Discharge
Page 1 of 2

Region: Cook Inlet, Alaska

Technology: Discharge via add-on drill cuttings "dryer" with average retention of 7%(wt) base fluid on cuttings.

Model Well Types: Shallow Water Development

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)
Shallow Water Development	953	3.6

Fuel-Consuming Activity	Power Requirements (hp-hr) Shallow Water Development	Notes (All information below is detailed in Section IX.3.1.2)
Improved Solids Control Equipment (hp * hrs to drill SBF well interval)	2,375.14	Total horsepower of solids control equipment = 27.49 hp.
Total Power Requirements Per Well	2,375.14	
Total Natural Gas Usage Per Well (scf)	22,563.79	Wells drilled in Cook Inlet, Alaska use natural gas as fuel for generating power

Fuel Type used on Platforms: Natural Gas

Category	Air Emissions From Additional Solids Control Equipment (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Shallow Water Development	0.0034	0.0005	0.0000	0.0022	0.0000	0.0060

Worksheet No. 6
Non-Water Quality Environmental Impacts: Discharge
Page 2 of 2

Region: Cook Inlet, Alaska

Technology: Discharge via add-on drill cuttings "dryer" with average retention of 7%(wt) base fluid on cuttings.

Model Well Types: Shallow Water Development

Per Well	Air Emissions (tons)		Fuel Usage (BOE)		
NWQEI	SWD	TOTAL	SWD	TOTAL	Notes
Discharge Option (natural gas fuel source)	0.0060		4.0164		From Worksheet No. 6, page 1
Total Per Well NWQEIs	0.0060		4.0164		
No. of Wells	1		1		
TOTAL ANNUAL AK DISCHARGE NWQEIs	0.01	0.01	4.02	4.02	

Worksheet No. 7
Non-Water Quality Environmental Impacts: Zero Discharge GOM
Page 1 of 4

Region:	Offshore Gulf of Mexico
Technology:	Zero Discharge via Haul and Land Dispose
Model Well Types:	Deep Water Development, Deep Water Exploratory, Shallow Water Development, Shallow Water Exploratory

Model Well Characteristics (Chapter VIII):	Waste Cuttings Vol. (bbls)	Drilling Length (days)	No. of Cuttings Boxes	No. of Dedicated Boat Trips (Cap.=80 boxes)	Dedicated Boat Idling Time (hrs)	No. of Regular Boat Trips (Cap.=12 boxes)	No. of Truck Trips (Cap.=119 bbl)
Deep Water Development	1,442	5.4	58	1	129.6	0	13
Deep Water Exploratory	3,206	12	129	2	264.0	1	27
Shallow Water Development	953	3.6	39	1	86.4	0	8
Shallow Water Exploratory	1,997	7.5	80	1	180.0	0	17

Fuel-Consuming Activity	Diesel Fuel Consumed (gal) Deep Water Development	Deep Water Exploratory	Shallow Water Development	Shallow Water Exploratory	Notes (All information below is detailed in Section IX.3.1.3.1)
Supply Boat Transit (distance (mi)/boat speed(mi/hr) * diesel usage rate (gal/hr))	3,131.30	7,133.04	3,131.30	3,131.30	Distance travelled by supply boats for all wells except deep exploratory = 277 mi.; for deep exploratory wells, supply boat distance = 631 mi. Supply boat average speed = 11.5 mi/hr. Supply boat diesel usage rate = 130 gal/hr.
Tug/Barge Transit (distance/speed *diesel usage rate)	400.00	400.00	400.00	400.00	Barge capacity = 240 boxes. Only 1 barge trip is needed for all well types. Barging distance = 100 mi. Tug speed = 6 mi/hr. Tug diesel usage rate = 24 gal/hr.
Supply Boat Maneuvering (no. of boat trips * maneuvering time per trip (hrs) * diesel usage rate (gal/hr))	25.30	75.90	25.30	25.30	Average maneuvering time per trip = 1 hour. Supply boat diesel usage rate during maneuvering = 25.3 gal/hr.
Dedicated Supply Boat Loading (Idling time per trip(hr) + additional loading time per trip (hr)) no. of trips * diesel usage rate (gal/hr)	3,319.36	6,760.16	2,226.40	4,594.48	Dedicated supply boats are assumed to be moored and idling at the platform until it has reached capacity or until all SBF generated cuttings from the drilling operation are loaded. Idling supply boat diesel usage rate = 25.3 gal/hr.
Regular Supply Boat Loading ((empty boxes + full boxes)/loading rate) + additional loading time per trip (hr) * no. of trips * diesel usage rate (gal/hr)	0	96.14	0	0	Loading rate = 10 boxes/hr. Additional loading time per trip = 1.6 hrs. Supply boat diesel usage rate during loading = 25.3 gal/hr.
Supply Boat Auxiliary Generator (in Port Demurrage) (no. of boat trips * generator hrs per trip * diesel usage rate (gal/hr))	144.00	432.00	144.00	144.00	Generator usage time in port = 24 hrs. Supply boat diesel usage rate in port = 6 gal/hr.

Worksheet No. 7
Non-Water Quality Environmental Impacts: Zero Discharge GOM
Page 2 of 4

Region:	Offshore Gulf of Mexico
Technology:	Zero Discharge via Haul and Land Dispose
Model Well Types:	Deep Water Development Deep Water Exploratory Shallow Water Development Shallow Water Exploratory

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)	No. of Cuttings Boxes	No. of Dedicated Boat Trips (Cap.=80 boxes)	Dedicated Boat Idling Time (hrs)	No. of Regular Boat Trips (Cap.=12 boxes)	No. of Truck Trips (Cap.=119 bbl)
Deep Water Development	1,442	5.4	58.0	1	129.6	0	13
Deep Water Exploratory	3,206	12.0	129.0	2	264.0	1	27
Shallow Water Development	953	3.6	39.0	1	86.4	0	8
Shallow Water Exploratory	1,997	7.5	80.0	1	180.0	0	17

Fuel-Consuming Activity	Diesel Fuel Consumed (gal)				Notes (All information below is detailed in Section IX.3.1.3.1)
	Deep Water		Shallow Water		
	Development	Exploratory	Development	Exploratory	
Supply Boat Cranes ((no. of lifts at drill site + no of lifts in port)/ crane lifts per hour)) * diesel usage rate	193.26	429.83	129.95	266.56	Supply boat crane loading/unloading rate = 10 lifts per hour. Supply boat crane diesel usage rate = 8.33 gal/hr.
Barge Cranes ((no. of lifts)/crane lifts per hour) * diesel usage rate (gal/hr)	96.63	214.91	64.97	133.28	Barge crane loading/unloading rate = 10 lifts per hour. Barge crane diesel usage rate = 8.33 gal/hr.
Trucks (no. of truck trips*roundtrip miles per trip)/ diesel usage rate (mi/gal)	65.00	134.71	40.04	83.91	Roundtrip distance from the port to the disposal facility = 20 miles. Truck diesel usage rate = 4 mi/gal.
Wheel Tractor for Grading at Landfarm (tractor time per well) * diesel usage rate	13.36	13.36	13.36	13.36	Tractor time per well for all well types = 8 hrs. Tractor diesel usage rate = 1.67 gal/hr.
Track-Type Dozer/Loader for Spreading Waste at Landfarm (dozer time per well) * diesel usage rate	352.00	352.00	352.00	352.00	Dozer time per well for all well types = 16 hrs. Dozer diesel usage rate = 22 gal/hr.
TOTAL Diesel Per Well (Gal)	**7,740.21**	**16,042.05**	**6,527.33**	**9,144.19**	

Region: Offshore Gulf of Mexico
Technology: Zero Discharge via Haul and Land Dispose

Model Well Types: Deep Water Development
Deep Water Exploratory
Shallow Water Development
Shallow Water Exploratory

Model Well Characteristics (Chapter VIII):

	Waste Cuttings Vol. (bbls)	Drilling Length (days)	No. of Cuttings Boxes	No. of Dedicated Boat Trips (Cap.=80 boxes)	Dedicated Boat Idling Time (hrs)	No. of Regular Boat Trips (Cap.=12 boxes)	No. of Truck Trips (Cap.=119 bbl)
Deep Water Development	1,442	5.4	58	1	129.6	0	13
Deep Water Exploratory	3,206	12.0	129	2	264.0	1	27
Shallow Water Development	953	3.6	39	1	86.4	0	8
Shallow Water Exploratory	1,997	7.5	80	1	180.0	0	17

Energy-Consuming Activity	**Power Requirements (hp-hr)**				**Notes (All information below is detailed in Section IX.3.1.3.1)**
	Deep Water		**Shallow Water**		
	Development	**Exploratory**	**Development**	**Exploratory**	
Supply Boat Auxiliary Generator (in Port Demurrage) no. of boat trips * generator hrs per trip * generator power rating	1,440.00	4,320.00	1,440.00	1,440.00	In port use of auxiliary electrical generator power = 24 hrs. Generator power rating = 60 hp.
Supply Boat Cranes ((no. of lifts at drill site + no of lifts in port)/ crane lifts per hour)) * generator power rating	3,155.20	7,017.60	2,121.60	4,352.00	Generator power rating = 136 hp.
Barge Cranes ((no. of lifts at drill site + no of lifts in port)/ crane lifts per hour)) * generator power rating	1,577.60	3,508.80	1,060.80	2,176.00	Generator power rating = 136 hp.
TOTAL Power Requirements Per Well	6,172.80	14,846.40	4,622.40	7,968.00	

Worksheet No. 7
Non-Water Quality Environmental Impacts: Zero Discharge GOM
Air Emissions
Page 4 of 4

Region: Offshore Gulf of Mexico
Technology: Zero Discharge via Haul and Land Dispose

Model Well Types: Deep Water Development
Deep Water Exploratory
Shallow Water Development
Shallow Water Exploratory

Deep Water Development Well Air Emissions

Category	Air Emissions (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Supply Boats						
Transit	0.613	0.263	0.045	0.123	0.052	1.095
Maneuvering	0.005	0.003	0.000	0.001	0.000	0.010
Loading	0.696	0.375	0.047	0.099	0.055	1.273
Demurrage	0.022	0.002	0.001	0.005	0.002	0.032
Barge						
Transit	0.078	0.034	0.006	0.016	0.007	0.140
Supply Boat Cranes	0.049	0.004	0.003	0.011	0.003	0.070
Barge Cranes	0.024	0.002	0.002	0.005	0.002	0.035
Trucks	0.003	0.001	--	0.002	--	0.006
Wheel Tractor	0.005	0.001	0.000	0.014	0.001	0.021
Dozer/Loader	0.007	0.001	0.001	0.002	0.000	0.010
Total Per Well	**1.50**	**0.68**	**0.11**	**0.28**	**0.12**	**2.69**

Deep Water Exploratory Well Air Emissions

Category	Air Emissions (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Supply Boats						
Transit	1.397	0.599	0.102	0.279	0.118	2.495
Maneuvering	0.016	0.009	0.001	0.002	0.001	0.029
Loading	1.418	0.764	0.096	0.202	0.112	2.592
Demurrage	0.067	0.005	0.004	0.014	0.005	0.096
Barge						
Transit	0.078	0.034	0.006	0.016	0.007	0.140
Supply Boat Cranes	0.108	0.009	0.007	0.023	0.008	0.155
Barge Cranes	0.054	0.004	0.004	0.012	0.004	0.078
Trucks	0.007	0.001	--	0.005	--	0.013
Wheel Tractor	0.005	0.001	0.000	0.014	0.001	0.021
Dozer/Loader	0.007	0.001	0.001	0.002	0.000	0.010
Total Per Well	**3.16**	**1.43**	**0.22**	**0.57**	**0.25**	**5.63**

Shallow Water Development Well Air Emissions

Category	Air Emissions (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Supply Boats						
Transit	0.613	0.263	0.045	0.123	0.052	1.095
Maneuvering	0.005	0.003	0.000	0.001	0.000	0.010
Loading	0.467	0.252	0.032	0.067	0.037	0.854
Demurrage	0.022	0.002	0.001	0.005	0.002	0.032
Barge						
Transit	0.078	0.034	0.006	0.016	0.007	0.140
Supply Boat Cranes	0.033	0.003	0.002	0.007	0.002	0.047
Barge Cranes	0.016	0.001	0.001	0.004	0.001	0.023
Trucks	0.002	0.000	--	0.002	--	0.004
Wheel Tractor	0.005	0.001	0.000	0.014	0.001	0.021
Dozer/Loader	0.007	0.001	0.001	0.002	0.000	0.010
Total Per Well	**1.25**	**0.56**	**0.09**	**0.24**	**0.10**	**2.24**

Shallow Water Exploratory Well Air Emissions

Category	Air Emissions (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Supply Boats						
Transit	0.613	0.263	0.045	0.123	0.052	1.095
Maneuvering	0.005	0.003	0.000	0.001	0.000	0.010
Loading	0.964	0.519	0.065	0.137	0.076	1.762
Demurrage	0.022	0.002	0.001	0.005	0.002	0.032
Barge						
Transit	0.078	0.034	0.006	0.016	0.007	0.140
Supply Boat Cranes	0.067	0.005	0.004	0.015	0.005	0.096
Barge Cranes	0.034	0.003	0.002	0.007	0.002	0.048
Trucks	0.004	0.001	0.000	0.003	0.000	0.008
Wheel Tractor	0.005	0.001	0.000	0.014	0.001	0.021
Dozer/Loader	0.007	0.001	0.001	0.002	0.000	0.010
Total Per Well	**1.80**	**0.83**	**0.13**	**0.32**	**0.14**	**3.22**

Worksheet No. 8
Non-Water Quality Environmental Impacts: Zero Discharge GOM
Page 1 of 2

Region:	Offshore Gulf of Mexico
Technology:	Zero Discharge via On-site Grinding and Injection

Model Well Types:
- Deep Water Development
- Deep Water Exploratory
- Shallow Water Development
- Shallow Water Exploratory

Model Well Characteristics: (Chapter VIII)	Waste Cuttings Vol. (bbls)	Drilling Length (days)
Deep Water Development	1,442	5.4
Deep Water Exploratory	3,206	12.0
Shallow Water Development	953	3.6
Shallow Water Exploratory	1,997	7.5

Fuel Type used on Platforms: Diesel Fuel

Fuel-Consuming Activity	Diesel Fuel Consumed (gal)				Notes (All information below is detailed in Section IX.3.1.3.2)
	Deep Water		Shallow Water		
	Development	Exploratory	Development	Exploratory	
Cuttings Transfer hrs of operation * diesel usage rate	777.60	1,728.00	518.40	1,080.00	Hours of operation equals the drilling length in days multiplied by 24 hrs. per day The transfer equipment utilizes one (1) 100 hp vacuum pump. Diesel usage rate of the vacuum pump = 6 gal/hr.
Cuttings Grinding and Processing hrs of operation * diesel usage rate	777.60	1,728.00	518.40	1,080.00	Hours of operation equals the drilling length in days multiplied by 24 hrs. per day The grinding and processing equipment that utilize fuel include: one(1) 75 hp grinding pump, two (2) 10 hp mixing pumps, two (2) 10 hp vacuum pumps, and one (1) 5 hp shaker motor. Diesel usage rate of the grinding and processing equipment = 6 gal/hr.
Cuttings Injection hrs of operation * diesel usage rate	57.68	128.24	38.12	79.88	Hours of operation is based on one injection pump rated at 2.5 barrels per minute. Diesel usage rate of the injection pump = 6 gal/hr.
TOTAL Diesel Consumed Per Well (gal)	**1,612.88**	**3,584.24**	**1,074.92**	**2,239.88**	

Fuel Type used on Platforms: Natural Gas

Fuel-Consuming Activity	Natural Gas Fuel Usage (scf)				Notes (All information below is detailed in Section IX.3.1.3.2)
	Deep Water		Shallow Water		
	Development	Exploratory	Development	Exploratory	
Cuttings Transfer hrs of operation * hp * 9.5 scf/hp-hr	123,120	273,600	82,080	171,000	Hours of operation equals the drilling length in days multiplied by 24 hrs. per day The transfer equipment utilizes one (1) 100 hp vacuum pump.
Cuttings Grinding and Processing hrs of operation * hp * 9.5 scf/hp-hr	147,744	328,320	98,496	205,200	Hours of operation equals the drilling length in days multiplied by 24 hrs. per day The grinding and processing equipment that utilize fuel include: one(1) 75 hp grinding pump, two (2) 10 hp mixing pumps, two (2) 10 hp vacuum pumps, and one (1) 5 hp shaker motor.
Cuttings Injection hrs of operation * hp * 9.5 scf/hp-hr	54,796	121,828	36,214	75,886	Hours of operation is based on one (1) 600 hp injection pump rated at 2.5 barrels per minute.
TOTAL Natural Gas Usage Per Well (scf)	**325,660**	**723,748**	**216,790**	**452,086**	

Worksheet No. 8
Non-Water Quality Environmental Impacts: Zero Discharge GOM
Air Emissions
Page 2 of 2

Region:	Offshore Gulf of Mexico
Technology:	Zero Discharge via On-site Grinding and Injection

Model Well Types:

- Deep Water Development
- Deep Water Exploratory
- Shallow Water Development
- Shallow Water Exploratory

Model Well Characteristics:

	Volume (bbls)	Drilling Length (days)
Deep Water Development	1,442	5.4
Deep Water Exploratory	3,206	12.0
Shallow Water Development	953	3.6
Shallow Water Exploratory	1,997	7.5

Fuel-Consuming Activity	Total Equipment hp-hr				Notes (All information below is detailed in Section IX.3.1.3.2)
	Deep Water		Shallow Water		
	Development	Exploratory	Development	Exploratory	
Cuttings Transfer hrs of operation * horsepower	22.50	50.00	15.00	31.25	Hours of operation equals the drilling length in days multiplied by 24 hrs. per day. The transfer equipment utilizes one (1) 100 hp vacuum pump.
Cuttings Grinding and Processing hrs of operation * horsepower	27.00	60.00	18.00	37.50	Hours of operation equals the drilling length in days multiplied by 24 hrs. per day. The grinding and processing equipment that utilize fuel include: one(1) 75 hp grinding pump, two (2) 10 hp mixing pumps, two (2) 10 hp vacuum pumps, and one (1) 5 hp shaker motor.
Cuttings Injection hrs of operation * horsepower	5,768.00	12,824.00	3,812.00	7,988.00	Hours of operation is based on one injection pump rated at 2.5 barrels per minute.
TOTAL Power Requirements Per Well (hp-hr)	**5,817.50**	**12,934.00**	**3,845.00**	**8,056.75**	

Fuel Type used on Platforms: Diesel Fuel

Category	Air Emissions From Grinding and Injection Operations (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Deep Water Development	0.0897	0.0072	0.0060	0.0194	0.0064	0.1287
Deep Water Exploratory	0.1994	0.0160	0.0133	0.0432	0.0142	0.2860
Shallow Water Development	0.0593	0.0047	0.0039	0.0128	0.0042	0.0850
Shallow Water Exploratory	0.1242	0.0099	0.0083	0.0269	0.0089	0.1782

Fuel Type used on Platforms: Natural Gas

Category	Air Emissions From Grinding and Injection Operations (tons/per well drilled)					Total
	NOx	THC	SO2	CO	TSP	
Deep Water Development	0.0083	0.0012	0.0000	0.0053	0.0000	0.0148
Deep Water Exploratory	0.0185	0.0026	0.0000	0.0118	0.0000	0.0329
Shallow Water Development	0.0055	0.0008	0.0000	0.0035	0.0000	0.0098
Shallow Water Exploratory	0.0115	0.0016	0.0000	0.0074	0.0000	0.0205

Worksheet No. 9
Non-Water Quality Environmental Impacts: Zero Discharge GOM

Region: Offshore Gulf of Mexico
Technology: Zero Discharge

Model Well Types: Deep Water Development, Deep Water Exploratory, Shallow Water Development, Shallow Water Exploratory

Per Well	Air Emissions (tons)					Fuel Usage (BOE)					
NWQEI	DWD	DWE	SWD	SWE	TOTAL	DWD	DWE	SWD	SWE	TOTAL	Notes
GOM Wells Currently Using SBF Assuming to Switch to OBF Under Zero Discharge											
Hauling and Onshore Disposal (diesel fuel source)			2.2358	3.2222				155.41	217.72		From Worksheet No.7
Grinding and Injection (diesel fuel source)	--	--	0.0850	0.1782		--	--	25.59	53.33		From Worksheet No.8
Grinding and Injection (natural gas fuel source)	--	--	0.0098	0.0205		--	--	38.59	80.47		From Worksheet No.8
Weighted Average Grinding and Injection			0.0737	0.1545				27.54	57.40		Weighted avg. assumes 85% of wells use diesel and 15% use nat. gas for electricity generation.
Weighted Average NWQEI Per Well			1.80	2.61				129.84	185.66		Weighted avg. assumes 80% of wells haul wastes and 20% grind and inject.
No. of Wells			12	7				12	7		
Subtotal Annual GOM NWQEIs for OBF Wells			21.64	18.26	**39.90**			1,558.06	1,299.59	**2,857.65**	
GOM Wells Currently Using SBF Assumed to Retain SBF Under Zero Discharge											
Hauling and Onshore Disposal (diesel fuel source)	2.6916	5.6286	--	--		184.29	381.95	--	--		From Worksheet No.7
Grinding and Injection (diesel fuel source)	0.1287	0.2860	--	--		38.40	85.34	--	--		From Worksheet No.8
Grinding and Injection (natural gas fuel source)	0.0148	0.0329	--	--		57.97	128.83	--	--		From Worksheet No.8
Weighted Average Grinding and Injection	0.1116	0.2481				41.34	91.86				Weighted avg. assumes 85% of wells use diesel and 15% use nat. gas for electricity generation.
Weighted Average NWQEI Per Well	2.18	4.55				155.70	323.94				Weighted avg. assumes 80% of wells haul wastes and 20% grind and inject.
No. of Wells	18	57				18	57				
Subtotal Annual GOM NWQEIs for SBF Wells	39.16	259.49			**298.65**	2,802.60	18,464.31			**21,266.91**	
TOTAL Annual GOM Zero Discharge NWQEIs					**338.55**					**24,124.56**	

APPENDIX IX-2

NSPS NON-WATER QUALITY ENVIRONMENTAL IMPACT CALCULATIONS FOR NEW SOURCES

Summary NSPS NWQEI of SBF Cuttings Management (a)

Baseline NWQEI: Total Annual

	Gulf of Mexico		Total		
Baseline Technology	**Air Emissions (tons)**	**Fuel Usage (BOE), (b)**	**Air Emissions (tons)**	**Fuel Usage (BOE), (b)**	**Notes**
Discharge with 11% retention of base fluid on cuttings	0	0	0.00	0.00	

Compliance NWQEI: Total Annual

	Gulf of Mexico		Total		
Option	**Air Emissions (tons)**	**Fuel Usage (BOE), (b)**	**Air Emissions (tons)**	**Fuel Usage (BOE), (b)**	**Notes**
Discharge Option	1.28	310.63	1.28	310.63	From Worksheet 2
Zero Discharge Option	40.96	2,932.44	40.96	2,932.44	From Worksheet 3

Incremental Compliance NWQEI Reductions: Total Annual

	Gulf of Mexico		Total		
Option	**Air Emissions (tons)**	**Fuel Usage (BOE), (b)**	**Air Emissions (tons)**	**Fuel Usage (BOE), (b)**	**Notes**
Discharge Option	(1.28)	(310.63)	(1.28)	(310.63)	Difference between total baseline and compliance discharge option NWQEIs
Zero Discharge Option	(40.96)	(2,932.44)	(40.96)	(2,932.44)	Difference between discharge baseline and zero discharge option NWQEIs

(a) The NSPS NWQEI analysis was conducted for 18 DWD wells and 1 SWD well currently using SBF in the Gulf of Mexico.

(b) BOE (barrels of oil equivalent) is the sum of the volumes of diesel (1 BOE = 42 gal diesel) and natural gas (1,000 scf = 0.178 BOE) estimated for each compliance option.

Worksheet No. 1

Non-Water Quality Environmental Impacts: Baseline Current Practice

Region: Offshore Gulf of Mexico

Technology: Discharge of SBF cuttings via add-on cuttings "dryer" w/average achievable retention of 11% (wt) base fluid on cuttings

Model Well Types: Deep Water Development, Deep Water Exploratory, Shallow Water Development, Shallow Water Exploratory

	Air Emissions (tons)					Fuel Usage (BOE)					
NWQEI	**DWD**	**DWE**	**SWD**	**SWE**	**TOTAL**	**DWD**	**DWE**	**SWD**	**SWE**	**TOTAL**	**Notes**
Discharge with 11% retention of base fluid on cuttings (85% diesel, 15% nat. gas usage)	0.00	--	0.00	--	0.00	0.00	--	0.00	–	0.00	
Average Per Well Baseline NWQEIs	0.00	–	0.00	–		0.00	–	0.00	–		
No. of New Source Wells	18	--	1	--		18	--	1	--		
TOTAL ANNUAL GOM BASELINE NWQEIs (New Sources)	0.00		0.00		**0.00**	0.00		0.00		**0.00**	

Worksheet No. 2
Non-Water Quality Environmental Impacts: Discharge

Region: Offshore Gulf of Mexico

Technology: Discharge via add-on drill cuttings "dryer" with average retention of 7%(wt) base fluid on cuttings.

Model Well Types: Deep Water Development, Deep Water Exploratory, Shallow Water Development, Shallow Water Exploratory

Per Well	**Air Emissions (tons)**					**Fuel Usage (BOE)**					
NWQEI	**DWD**	**DWE**	**SWD**	**SWE**	**TOTAL**	**DWD**	**DWE**	**SWD**	**SWE**	**TOTAL**	**Notes**
Discharge Option (diesel fuel source)	0.0788	--	0.0525	--		18.51	--	12.34	--		Worksheet No. 4, Appendix IX-1
Discharge Option (natural gas fuel source)	0.0091	--	0.0060	--		6.02	--	4.02	--		Worksheet No. 4, Appendix IX-1
Weighted Average Per Well NWQEIs	0.07	--	0.05	--		16.64		11.09			Weighted avg. assumes 85% of wells use diesel and 15% use nat. gas for electricity generation.
No. of New Wells	18		1			18		1			
Subtotal Annual GOM NWQEIs for SBF Wells	1.23		0.05		**1.28**	299.53		11.09		**310.63**	
TOTAL ANNUAL GOM Discharge NWQEIs					**1.28**					**310.63**	

Worksheet No. 3
Non-Water Quality Environmental Impacts: Zero Discharge GOM

Region: Offshore Gulf of Mexico
Technology: Zero Discharge

Model Well Types: Deep Water Development, Deep Water Exploratory, Shallow Water Development, Shallow Water Exploratory

Per Well	Air Emissions (tons)					Fuel Usage (BOE)					
NWQEI	**DWD**	**DWE**	**SWD**	**SWE**	**TOTAL**	**DWD**	**DWE**	**SWD**	**SWE**	**TOTAL**	**Notes**
Hauling and Onshore Disposal (diesel fuel source)	2.6916		2.2358			184.29		155.41			Worksheet No. 7, Appendix IX-1
Grinding and Injection (diesel fuel source)	0.1287	--	0.0850			38.40	--	25.59			Worksheet No. 8, Appendix IX-1
Grinding and Injection (natural gas fuel source)	0.0148	--	0.0098			57.97	--	38.59			Worksheet No. 8, Appendix IX-1
Weighted Average Grinding and Injection	0.1116		0.0737			41.34		27.54			Weighted avg. assumes 85% of wells use diesel and 15% use nat. gas for electricity generation.
Weighted Average NWQEI Per Well	2.18		1.80			155.70		129.84			Weighted avg. assumes 80% of wells haul wastes and 20% grind and inject.
No. of New Source Wells	18		1			18		1			
Subtotal Annual GOM NWQEIs for New Wells	39.16		1.80		**40.96**	2,802.60		129.84		**2,932.44**	
TOTAL Annual GOM Zero Discharge NWQEIs (New Sources)					**40.96**					**2,932.44**	