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.”

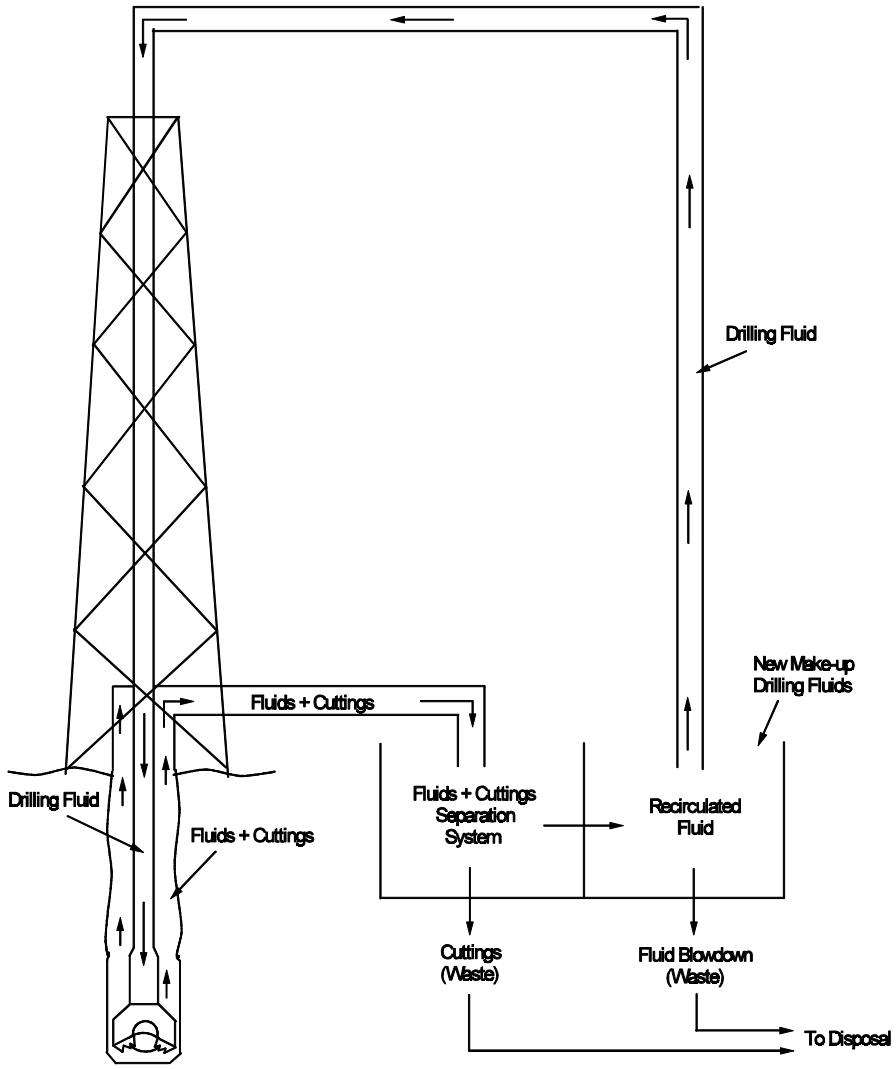

Figure IV-1
Generalized Drilling Fluids Circulation Systems

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:

- Total Gulf of Mexico WBF/SBF/OBF Wells: 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]

- Gulf of Mexico SBF Wells: 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

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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.

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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.

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