

Sunshine Act Meetings

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This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

CONTENTS

	Item
Federal Energy Regulatory Commission	1
International Trade Commission	2
National Transportation Safety Board ..	3

1

FEDERAL ENERGY REGULATORY COMMISSION

"Federal Register" CITATION OF PREVIOUS ANNOUNCEMENT: May 28, 1985, 50 FR 21688.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 10:00 a.m., May 30, 1985.

CHANGES IN THE MEETING: (1) The following items have been added:

Item No., Docket No., and Company

M-2—Docket No. RM85-17-000, Regulation of Electricity Sales-For-Resale and Transmission Services.

M-3—Docket No. RM85-1-000, Parts A-D, Regulations of Natural Gas Pipelines after Partial Wellhead Decontrol.

(2) The Commission meeting for May 30, 1985, originally scheduled to be held in Room 9306 will be held in Hearing Room A.

Kenneth F. Plumb,

Secretary

[FR Doc. 85-13262 Filed 5-31-85; 9:43 am]

BILLING CODE 6717-02-M

2

INTERNATIONAL TRADE COMMISSION

[USITC SE-85-24]

TIME AND DATE: Wednesday, June 12, 1985, at 2:00 p.m.

PLACE: Room 331, 701 E Street, NW., Washington, D.C. 20436.

STATUS: Open to the public.

MATTERS TO BE CONSIDERED:

1. Agenda.
2. Minutes.
3. Ratification List.
4. Petitions and Complaints.
5. Investigation 731-TA-196 [Final] (Certain red raspberries for Canada)—briefing and vote.
6. Investigation 731-TA-199 [Final] (Certain dried salted codfish for Canada)—briefing and vote.
7. Investigation 731-TA-261 [Preliminary] (12-volt lead-acid type storage batteries from Korea)—briefing and vote.
8. Investigation TA-201-55 (Nonrubber footwear)—briefing and vote on remedy.
9. Any item left over from previous agenda.

CONTACT PERSON FOR MORE INFORMATION: Kenneth R. Mason, Secretary, (202) 523-0161.

[FR Doc. 85-13466 Filed 5-31-85 10:29 am]

BILLING CODE 7020-02-M

3

NATIONAL TRANSPORTATION SAFETY BOARD

[NM-85-10]

TIME AND DATE: 9 a.m., Wednesday, June 12, 1985.

PLACE: NTSB Board Room, Eighth Floor, 800 Independence Ave., SW., Washington, D.C. 20594.

STATUS: The first six items are open to the public; the last item is closed under Exemption 10 of the government in the Sunshine Act.

MATTERS TO BE CONSIDERED:

1. Railroad/Highway Accident Report: Grade Crossing Collision of a Florida East Coast Railway Company Freight Train and Indian River Academy Schoolbus, Port St. Lucie, Florida, September 27, 1984.
2. Aircraft Accident Report: Vieques Air Link, Inc., Britten-Norman BN-2A-6 Islander, N589 Sa, Vieques, P.R., August 2, 1984.
3. Safety Study: "Air Carrier Overwater Emergency Equipment and Procedures".
4. Pipeline Accident Report: Arizona Public Service Company, Natural Gas Explosion and Fire, Phoenix, Arizona, September 24, 1984.
5. Aircraft Accident/Incident Summary Report & Brief of Accident: Eastern Airlines Boeing 727-225A, N812EA, Miami International Airport, Miami, Florida, November 1, 1983.
6. Recommendations: to the Federal Aviation Administration, Concerning Explosive Failures of Tires in Wheel Wells of B-727 Airplanes.
7. Opinion and Order: Administrator v. Miller, Docket SE-3701; disposition of the appeals of both parties.

CONTACT PERSON FOR MORE INFORMATION: Catherine T. Kaputa, (202) 382-6525.

Catherine T. Kaputa,
Alternate Federal Register Liaison Officer.
May 30, 1985.

[FR Doc. 85-13492 Filed 5-31-85; 2:07 pm]

BILLING CODE 7533-01-M

Register

Tuesday
June 4, 1985

Part II

Environmental Protection Agency

Final General NPDES Permit for Oil and
Gas Operations on the Outer Continental
Shelf (OCS) of Alaska; Norton Sound;
Notice

ENVIRONMENTAL PROTECTION AGENCY

[OW-FRL 2843-8]

Final General NPDES Permit for Oil and Gas Operations on the Outer Continental Shelf (OCS) of Alaska; Norton Sound

AGENCY: Environmental Protection Agency.

ACTION: Notice of final general NPDES permit.

SUMMARY: The Regional Administrator, Region 10, is today issuing a final general National Pollutant Discharge Elimination System (NPDES) permit for oil and gas stratigraphic test and exploration wells on the Outer Continental Shelf (OCS) of Alaska.

The final Norton Sound general permit authorizes discharges from oil and gas stratigraphic test and exploration operations only (not development or production operations) in all areas offered for lease by the U.S. Department of the Interior, Minerals Management Service (MMS) during Federal Lease Sale 57 (Norton Sound). A general NPDES permit previously issued (48 FR 54881, December 7, 1983) for this same area expired on June 30, 1984, after which time permits must impose limitations which reflect Best Available Technology Economically Achievable (BAT) and Best Conventional Pollutant Control Technology (BCT).

This general NPDES permit establishes new effluent limitations, standards, prohibitions, and other conditions on discharges from these facilities. These conditions are based on the administrative record. EPA regulations and the permit contain a procedure which allows the owner or operator of a point source discharge to apply for an individual permit instead of coverage under the general permit.

On February 15, 1985, Region 10 of the Environmental Protection Agency published in 50 FR 6385 a notice of the draft general permit which is being issued in final form today. Today's notice reviews the basis for the conditions and requirements in the general permit. Copies of the permit and the Agency's response to comments received are printed below. Changes in the final permit and the justification for the change from the draft permit are presented in the Agency's response to comments.

Requests for Coverage

Written request for authorization to discharge under the general permit shall be provided, as described in Part I.A. of this permit, to EPA, Region 10, at least

60 days prior to initiation of discharges. The 60-day notification requirement will be waived for those permittees who notified EPA during the public comment period for the draft permit.

Authorization to discharge requires written notification from EPA that coverage has been granted and that a specific permit number has been assigned to operations at the discharge site. The permit also requires permittees to notify EPA within 7 days prior to the initiation of discharges at the site.

Administrative Record

The administrative record for this permit is available for public review at EPA, Region 10, Room 10D, at the address listed below.

ADDRESS: Requests for coverage and notifications should be sent to: Environmental Protection Agency, Region 10, Attn: Ocean Programs Section M/S 430, 1200 Sixth Avenue, Seattle, Washington 98101.

FOR FURTHER INFORMATION CONTACT: John Gabrielson or Janis Hastings, Region 10, at the address listed above (telephone (206) 442-1756 or (206) 442-8504, respectively). Copies of today's publication, and the permit will be provided upon request.

SUPPLEMENTARY INFORMATION:

I. General Permits and Requests for Individual NPDES Permits

Section 301(a) of the Clean Water Act (the Act) provides that the discharge of pollutants is unlawful except in accordance with the terms of an NPDES permit. Under EPA's regulations (40 CFR 122.28), EPA may issue a single general permit to a category of point sources located within the same geographic area if the regulated point sources:

- (1) Involve the same or substantially similar types of operations;
- (2) Discharge the same types of wastes;
- (3) Require the same effluent limitations or operating conditions;
- (4) Require similar monitoring requirements; and
- (5) In the opinion of the Regional Administrator, are more appropriately controlled under a general permit than under individual permits.

In addition, under EPA regulations (40 CFR 122.28(c)(1)), the Regional Administrator is required to issue general permits covering discharges from offshore oil and gas facilities within the Region's jurisdiction. Where the offshore area includes areas, for which separate permit conditions are required, such as areas of environmental concern, a separate individual or

general permit may be required by the Regional Administrator.

The Regional Administrator has determined that exploratory oil and gas facilities operating in the area described in this general NPDES permit are more appropriately controlled by a general permit than by individual permits. The decision of the Regional Administrator is based on an evaluation of the section 403(c) Ocean Discharge Criteria (40 CFR Part 125, Subpart M) for discharges from exploratory operations in Norton Basin, and the Agency's recent permit decisions in other Alaskan OCS areas.

Any owner and/or operator authorized to discharge under a general permit may request to be excluded from coverage under the general permit by applying for an individual permit as provided by 40 CFR 122.28(b). The operator shall submit an application together with the reasons supporting the request to the Director, Water Division, EPA, Region 10 ("Director"). A source located within a general permit area, excluded from coverage under the general permit solely because it already has an individual permit (i.e., a permit that has not been continued under the Administrative Procedures Act), may request that its individual permit be revoked, and that it be covered by the general permit. Upon revocation of the individual permit, the general permit shall apply. Procedures for modification, revocation, termination, and processing of NPDES permits are provided by 40 CFR 122.62-122.64. As in the case of individual permits, violation of any condition of a general permit constitutes a violation of the Act that is enforceable under section 309 of the Act.

II. Nature of Discharges and Covered Facilities

The general permit issued today authorizes the discharge of drilling muds, drill cuttings and associated operational wastewaters from exploratory operations in federal waters. Exploratory operations are defined as those operations involving the drilling of wells to determine the nature of potential hydrocarbon reserves. Under the permit, they are limited to a maximum of five wells at a single site. Exploration facilities covered by the Norton Sound general permit are included in the Offshore Subcategory of the Oil and Gas Extraction Point Source Category (40 CFR Part 435).

This general permit authorizes the following discharges: Drilling mud; drill cuttings and washwater; deck drainage; sanitary wastes; domestic wastes; desalination unit wastes; blowout preventer fluid; boiler blowdown; fire

control system test water; non-contact cooling water; uncontaminated ballast water; uncontaminated bilge water; excess cement slurry; mud, cuttings, and cement at the seafloor; and test fluids. Descriptions of discharges are given in Part II.A. of the final permit.

Drilling muds and cuttings are the major pollutant sources discharged from exploratory drilling operations.

III. Statutory Basis for Permit Conditions

Sections 301(b), 304, 306, 401, 402, and 403 of the Clean Water Act provide the basis for the permit conditions contained in the final permit. The general requirements of these sections fall into three categories, which are described below. A discussion of the basis for specific permit conditions follows in Part IV.

A. Technology-Based Effluent Limitations

1. *BPT Effluent Limitations.* The Clean Water Act requires particular classes of industrial dischargers to meet effluent limitations established by EPA. EPA promulgated effluent limitations guidelines requiring Best Practicable Control Technology Currently Available (BPT) for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category (40 CFR Part 435, Subpart A) on April 13, 1979 (44 FR 22069).

BPT effluent limitations guidelines required "no discharge of free oil" for discharges of deck drainage, drilling muds, drill cuttings, and well treatment fluids. This limitation required that a discharge shall not cause a film or sheen upon or discoloration on the surface of the water or adjoining shorelines, or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines (40 CFR 435.11(d)). The BPT effluent limitations guideline for sanitary waste required that the concentration of chlorine be maintained as close to 1 mg/l as possible in discharges from facilities housing ten or more persons. For facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons, the BPT effluent limitations guideline for sanitary waste required no discharge of floating solids. A "no floating solids" guideline also applied to domestic waste. BPT limitations on oil and grease in produced water allowed a daily maximum of 72 mg/l and a monthly average of 48 mg/l.

2. *BAT and BCT Effluent Limitations.* All permits issued after July 1, 1984, are required by section 301(b)(2) of the Act to contain effluent limitations for all categories and classes of point sources which: (1) Control toxic pollutants (40

CFR 401.15) through the use of Best Available Technology Economically Achievable (BAT), and (2) represent Best Conventional Pollutant Control Technology (BCT). BCT effluent limitations apply to conventional pollutants (pH, BOD, oil and grease, suspended solids, and fecal coliform). In no case may BCT or BAT be less stringent than BPT. Permits must impose effluent limitations which control nonconventional pollutants by means of BAT not later than July 1, 1987.

BAT/BCT effluent limitations guidelines and New Source Performance Standards (NSPS) are currently under development and will be proposed in the near future for the Offshore Subcategory. In the absence of effluent limitations guidelines for the Offshore Subcategory, permit conditions must be established using Best Professional Judgment (BPJ) procedures (40 CFR 122.43, 122.44, and 125.3). This permit incorporates BAT and BCT effluent limitations based on the Agency's Best Professional Judgment. Previous BPJ determinations for offshore oil and gas exploratory operations were incorporated into the general permits for the Bering Sea and the Beaufort Sea (49 FR 23734, June 7, 1984).

As required by section 304(b)(2)(B) of the Act, in developing the BPJ/BAT permit conditions, the Agency considered the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Director deemed appropriate.

The type of equipment and processes employed in exploratory drilling operations are well known to the Agency. Region 10 has issued numerous general and individual permits for such operations. The records for this permit and those earlier permits thoroughly discuss the types of equipment, facilities and processes employed in exploratory drilling operations. Concerning the factor of engineering aspects of the application of various types of control techniques, the only permit limitation based on installation of control equipment is the limitation on the oil content of cuttings. Region 10 established the 10 percent limit based on the use of cuttings washers. All other new permit limitations can be achieved through product substitution, the technology basis for the limitations in this permit. Any costs of achieving the effluent limitations and any non-water quality environmental impacts were also

evaluated and a discussion of such evaluations is presented below with respect to any limitation where applicable.

As required by section 304(b)(4)(B) of the Act, the Agency considered the same factors in determining BPJ/BCT permit conditions, but with one exception. Rather than considering "the cost of achieving such effluent reduction," any BCT determination includes "consideration of the reasonableness of the relationship between the costs of attaining a reduction in effluents and the effluent reduction benefits derived, and the comparison of the cost and level of reduction of such pollutants from publicly owned treatment works to the cost and level of reduction of such pollutants from a class or category of industrial sources." BCT effluent limitations cannot be less stringent than BPT; therefore, if the candidate industrial technology fails the BCT "cost test", BCT effluent limitations are set equal to BPT.

The Agency's evaluation of the BAT factors, as discussed above, is also applicable to BCT, as well as to the Agency's best professional judgment determinations of BPT in instances where there is no BPT effluent limitation guideline for a particular wastestream. With respect to the BCT "cost test," all BCT limitations are equal to the BPT effluent limitations guidelines or to the Region's best professional judgment determinations of BPT. Therefore, no incremental cost will be incurred.

B. Ocean Discharge Criteria

Section 403 of the Act requires that an NPDES permit for a discharge into marine waters located seaward of the inner boundary of the territorial seas be issued in accordance with guidelines for determining the degradation of the marine environment. These guidelines, referred to as the Ocean Discharge Criteria (40 CFR Part 125, Subpart M), and section 403 are intended to "prevent unreasonable degradation of the marine environment and to authorize imposition of effluent limitations, including a prohibition of discharge, if necessary, to ensure this goal" (45 FR 65942, October 3, 1980).

If EPA determines that the discharge will cause unreasonable degradation, an NPDES permit will not be issued. If a determination of unreasonable degradation cannot be made because of a lack of sufficient information, EPA must then determine whether a discharge will cause irreparable harm to the marine environment and whether there are reasonable alternatives to on-

site disposal. To assess the probability of irreparable harm, EPA is required to make a determination that the discharger, operating under appropriate permit conditions, will not cause permanent and significant harm to the environment during a monitoring period in which additional information is gathered. If data gathered through monitoring indicate that continued discharge may cause unreasonable degradation, the discharge must be halted or additional permit limitations established.

The determination of unreasonable degradation must be based on the following factors: Quantities, composition, and potential for bioaccumulation or persistence of the pollutants discharged; potential transport of such pollutants; the composition and vulnerability of biological communities exposed to such pollutants; the importance of the receiving water area to the surrounding biological community; the existence of special aquatic sites; potential impacts on human health; impacts on recreational and commercial fishing; applicable requirements of approved Coastal Zone Management Plans; marine water quality criteria developed pursuant to section 304(a)(1) of the Act; and other relevant factors. A final Ocean Discharge Criteria Evaluation has been completed for those discharges from exploratory operations in the area covered by this permit.

The Regional Administrator has concluded that, with two exceptions, there is sufficient information to determine that exploratory oil and gas facilities operating under the effluent limitations and conditions in this general permit will not cause unreasonable degradation of the marine environment pursuant to the Ocean Discharge Criteria guidelines. For the two cases for which Region 10 has insufficient information to make this determination, the Region has made a finding that the discharges will not cause irreparable harm while a monitoring program is undertaken. The monitoring results will be evaluated to determine if future discharges are likely to result in unreasonable degradation. The conditions which constitute these two exceptions and the monitoring programs required are discussed below in Part IV.D. Requirements Based on the Ocean Discharge Criteria Evaluation.

C. Section 308 of the Clean Water Act

Under section 308 of the Act and 40 CFR 122.44(i) the Director must require a discharger to conduct monitoring to determine compliance with effluent limitations and to assist in the

development of effluent limitations. EPA has included several monitoring requirements in this permit, as listed in the table below.

IV. Specific Permit Conditions

A. Approach

The determination of appropriate conditions for each discharge was accomplished through:

(1) Consideration of technology-based effluent limitations to control conventional pollutants under BCT;

(2) Consideration of technology-based effluent limitations to control toxic and nonconventional pollutants under BAT; and

(3) Evaluation of the Ocean Discharge Criteria assuming conditions in parts (1) and (2) were in place.

Discussions of the specific effluent limitations and monitoring requirements derived from (1) through (3) appear below in Parts B through D, respectively. For convenience, these conditions and the regulatory basis for each are cross-referenced by discharge in the following table:

Discharge and permit condition	Statutory basis
Drilling muds and cuttings:	
Authorized muds and additives only.	BAT.
No oil-based muds.	BCT.
No diesel.	BAT.
Discharge rate limitations.	Sec. 403(c).
10% max. oil content of cuttings.	BCT.
No free oil.	BCT.
3 mg/kg cadmium and 1 mg/kg mercury in barite.	BAT.
Monitoring of metals and toxicity.	Sec. 308.
Seasonal/depth related limits, monitoring.	Sec. 403(c).
Monitor volume discharged.	Sec. 308.
Inventory of added substances.	Do.
Deck drainage:	
No free oil.	BCT.
Monitor discharge rate.	Sec. 308.
Sanitary wastes:	
No floating solids.	BCT.
Chlorine 1.0 mg/l (facilities with more than 10 people).	BCT.
Monitor discharge rate.	Sec. 308.
Domestic wastes:	
No floating solids.	BCT.
Monitor discharge rate.	Sec. 308.
Miscellaneous discharges (discharges 006 to 014 in the permit):	
No free oil.	BCT.
Monitor discharge rate.	Sec. 308.
Inventory of added substances.	Do.
Test fluids:	
pH 6.5-8.5.	BCT and marine water quality criteria.
No free oil.	BCT.
Oil & grease limits: 48 mg/l monthly avg., 72 mg/l daily max.	BCT.
Monitor volume discharged.	Sec. 308.
All discharges:	
No halogenated phenols, sodium chromate, sodium dichromate, or trisodium nitrotriacetic acid.	BAT.
No floating solids.	BCT.

B. BCT Requirements

1. *Oil and grease in test fluids.* Limited volumes of formation waters which are encountered during testing of the well are authorized for discharge as

test fluids. Under BPT, oil and grease in discharges of produced water were limited to a 48 mg/l monthly average and a 72 mg/l daily maximum based on oil/water separation technologies. Since formation waters may be present in test fluids, these limits are applied to the discharge of test fluids under BCT. This limitation is equal to BPT because Region 10 does not have technology performance data available at this time on which to base a more stringent limitation. As this limitation is equal to the BPT level of control, there is no incremental cost involved.

2. *Free oil and oil-based muds.* No discharge of free oil is permitted from discharges authorized by this permit. Region 10 has determined that the BPT effluent limitations guideline of no discharge of free oil from the discharge of deck drainage, drilling muds, drill cuttings, and well treatment fluids should apply to other discharges, including uncontaminated bilge water, uncontaminated ballast water, test fluids, desalination unit wastes, boiler blowdown, non-contract cooling water, excess cement slurry, blowout preventer fluid, fire control system test water, and mud, cuttings and cement at the seafloor. Thus, the no free oil limitation is Region 10's best professional judgment determination of BPT controls for these discharges. They have been subject to a no free oil limitation in previous permits issued by Region 10, and past practices have not resulted in violations of this limitation. No technology performance data available to Region 10 indicate that a more stringent standard is appropriate at this time. For this permit, therefore, Region 10 has set BCT effluent limitations equal to the BPT level of control and, as such, these limitations impose no incremental costs.

As discussed above, the BCT effluent limitation on free oil for drilling muds is equal to the BPT limitation. The discharge of oil-based drilling muds (with oil as the continuous phase and water as the dispersed phase) is therefore prohibited since oil-based muds would violate the BCT effluent limitation of no discharge of free oil.

The monitoring requirement for determining compliance with the effluent limitation of free oil is in most instances a visual observation of the receiving water. However, the Static Sheen Test is required for monitoring free oil in discharges with the greatest likelihood of oil contamination. These are: (1) Drilling muds and drill cuttings, with the Static Sheen Test required year-round, and (2) deck drainage and bilge water, with the Static Sheen Test

required when ice is present on the receiving water. The Static Sheen Test on drilling muds must be conducted prior to bulk discharges. Thus, a violation of the limitation due to the discharge of oil-contaminated drilling muds can be prevented, something a visual observation of a sheen on the receiving water does not allow.

3. Oil content of cuttings associated with mineral oil-based muds. The discharge of drill cuttings associated with mineral-oil based drilling muds is subject to the no free oil limitation (see 2., above) and to a limitation of the maximum mineral oil content (10 percent, by weight) of drill cuttings.

The limitation of 10 percent, by weight, on the oil content of drill cuttings is based on the efficiency of currently available cuttings washers. Region 10 expects that if oil-based drilling muds are used, drill cuttings would, at a minimum, have to be washed by cuttings washers to meet the no free oil limitation. Therefore, this effluent limitation on the maximum oil content of drill cuttings has been imposed as an additional means to effectively control the discharge of oil from cuttings associated with mineral oil-based muds.

Region 10 expects that cuttings washers with routinely be required only for drilling operations with use mineral oil-based drilling muds and not for all drilling operations. Due to the rare usage of mineral oil-based drilling muds by exploratory drilling operations, very few, if any, Alaskan exploratory facilities will require the installation of cuttings washers. This limitation will not require the Alaskan oil and gas industry to incur any additional cost beyond the cost of monitoring compliance since, at a minimum, such cuttings washers would be required to meet the BCT (equal to BPT) effluent limitation of "no free oil" if oil-based drilling muds are used. Therefore, there is no incremental cost involved, and the limitation passes the BCT cost test.

The permit requires an analysis of drill cuttings for oil content both weekly (during any week when oil-based drilling fluids are used) and immediately on any sample that has failed the Static Sheen Test. The drill cuttings will be monitored daily by the Static Sheen Test. Permittees are required to use one of two analytical methods for determining the oil content of drill cuttings, as specified in the permit: (1) The Soxhlet extraction procedure for oil and grease (as specified in 40 CFR Part 136), or (2) the American Petroleum Institute retort distillation procedure for oil.

4. pH. The pH of discharged test fluids (which may have a substantially different pH from that of the ambient receiving water) has been limited to a range of 6.5-8.5 at the point of discharge. In the Agency's best professional judgment, this limitation appropriately equals to BPT level of control. No more stringent standard has been identified by the Agency at this time. Therefore, the Agency is setting a BCT effluent limitation for the pH of test fluids equal to that of BPT. This limitation will ensure that pH changes greater than 0.2 pH unit will not occur beyond the edge of the 100-meter mixing zone (40 CFR 125.121(c)). This requirement has been and is routinely compiled with by operations under previous BPT permits and thus, reflects no cost incremental to BPT.

5. Floating solids. The BCT prohibition on floating solids is equal to the BPT level of control for sanitary wastes. As with the free oil limitations for other waste streams, Region 10 has determined that the BPT effluent limitations guidelines of no discharge of floating solids from the discharge of sanitary wastes should apply to all other discharges as well. Thus, the no floating solids limitation is Region 10's best professional judgment determination of BPT limitations for these discharges. They have been subject to this limitation in previous permits issued by Region 10, and past practices have not resulted in violations of this limitation. No technology performance data available to Region 10 indicate that a more stringent standard is appropriate at this time. Therefore, Region 10 has determined that the BCT effluent limitation on floating solids from these discharges is equal to the BPT level of control. As such, the extension of this limitation to all discharges will involve no incremental cost.

6. Chlorine. The requirement of maintaining residual chlorine levels as close as possible to, but no less than 1 mg/l in sanitary waste discharges for facilities manned by 10 or more people is a BCT determination equal to BPT. There is therefore no incremental cost to the industry.

C. BAT Requirements

1. Diesel oil. The discharge of muds which have been contaminated by diesel oil (i.e., those drilling muds which have contained diesel) or drill cuttings associated with these muds is prohibited. Diesel, which is sometimes added to a water-based mud system, is a complex mixture of petroleum hydrocarbons, known to be highly toxic to marine organisms and to contain numerous toxic and nonconventional

pollutants. While this limitation thereby controls the toxic as well as nonconventional pollutants present in diesel, the Agency's primary concern is to control the toxic pollutants. The pollutant "diesel oil" is being used as an "indicator" of the listed toxic pollutants present in diesel oil which are controlled through compliance with the effluent limitation (i.e., no discharge). The technology basis for this limitation is product substitution of less toxic mineral oil for diesel oil.

The Agency selected "diesel" as an "indicator" as an alternative to establishing limitations on each of the specific toxic and nonconventional pollutants present in the diesel-contaminated waste streams. The listed toxic pollutants found in various diesel oils include naphthalene, benzene, ethylbenzene, phenanthrene, toluene, fluorene, and phenol. Diesel oil may contain from 20 to 60 percent by volume aromatic hydrocarbons. The light aromatic hydrocarbons, such as benzenes, naphthalenes, and phenanthrenes, constitute the most toxic major components of petroleum products. Mineral oils, with their lower aromatic hydrocarbon content and lower toxicity, contain lower concentrations of toxic pollutants than do diesel oils. Diesel oil also contains a number of nonconventional pollutants, including polynuclear aromatic hydrocarbons such as methylnaphthalene, dimethylnaphthalene, methylphenanthrene, and other alkylated forms of each of the listed toxic pollutants.

The Region has determined that eliminating the discharge of drilling fluids contaminated with diesel oil will reduce the levels of toxic pollutants present in discharged fluids. Studies show that when the amount of diesel is reduced in drilling muds, the concentrations of toxic pollutants and the overall toxicity of the fluid generally is reduced. Available data clearly establish that diesel oils as a class contain significantly higher levels of toxic pollutants than do mineral oils as a class. It is reasonable and appropriate to conclude that BAT-level control of toxic pollutants (i.e., reduction in concentrations through substitution of mineral oil for diesel oil) will be achieved by regulating diesel oil as an indicator pollutant.

Region 10 has concluded that establishing effluent limitations for each of the seven toxic pollutants present in diesel oil is not economically or technically feasible at this time. The level achievable by BAT controls on the

specific toxics can be calculated using available data on the three mineral oils which have been extensively characterized (see response to Comment 7). However, the limited data on the many diesel and mineral oils, mud formulations, and the various additives used, and on the unquantified effects of drilling all frustrate an attempt to develop specific toxic pollutant effluent limitations at this time.

Not only is it infeasible to establish limitations on the specific toxic pollutants, but to comply with specific limitations on each of the toxic pollutants would be costly and technically complex. The analytical costs for specific pollutant analyses would be much greater than the cost of analyzing for diesel by gas chromatography alone. The high cost of compliance monitoring, which may include awaiting results of analyses, which must be conducted onshore, possibly outside the State of Alaska, also would be unwarranted. Either operators would have to delay discharge until monitoring results confirmed compliance or they would discharge and risk permit noncompliance. A permit limitation that prohibits the discharge of diesel oil is economically and technologically feasible and allows a determination of permit compliance prior to discharge.

The prohibition on the discharge of diesel is a technology-based BAT limitation based on product substitution. Low toxicity mineral oils are available as product substitutes for diesel oil, and do not impose unreasonable additional costs on industry. In the permit proposal the Agency relied primarily on the increased cost of mineral oil over diesel oil as a basis for this determination. For example, mineral oil costs Alaskan operators approximately \$2.60 per gallon more than does diesel oil. The increased costs associated with using mineral oil rather than diesel oil for 50 barrels (2,100 gallons) of oil (the maximum amount generally expected in a concentrated spotting or "pill" formulation used to free stuck drill pipe) would therefore be equal to approximately \$5,500. Since the frequency of differential sticking of drill pipe and the use of oil-based spotting formulations is low for exploratory operations (less than once per well on an average), this cost would not be incurred for each operation. The Agency has evaluated other costs associated with either diesel or mineral use in response to comments on the draft permit (see response to Comment 10). Both analyses show that the cost associated with the prohibition on the

discharge of diesel oil clearly is economically achievable.

In the permit proposal Region 10 proposed to limit "free oil," "oil-based drilling fluids," and "oil content of cuttings" as indicators of toxic pollutants. While the Agency has determined that the proposed effluent limitations will control the discharge of toxic pollutants in these oils, it is unnecessary to designate these pollutants as indicators since the same levels of control have been established under BCT, which are equal to levels of control required by the BPT effluent limitations guidelines. Therefore, redundant limitations under BAT have not been imposed for these pollutant parameters.

2. Mercury and cadmium in barite. The final permit contains limitations of 1 mg/kg mercury and 3 mg/kg cadmium in barite, a major constituent of drilling muds. These restrictions are designed to limit the discharge of mercury, cadmium, and other potentially toxic metals which can occur as contaminants in some sources of barite. An identical limitation is included in the general permits for the Bering Sea and the Beaufort Sea (49 FR 23734, June 7, 1984).

As discussed in the fact sheet for the Bering and Beaufort Seas permits, this limitation under BAT is reasonable due to the availability of substitute products; i.e., Alaskan operators can substitute "clean" barite, which meets the above limitations, for contaminated barite which does not. Numerous offshore exploratory wells have been drilled in Alaska over the past year, and chemical analyses have shown that the barite used has not exceeded the limitations in this permit. Given that "clean" barite is available and that operators in the Bering and Beaufort Seas have been complying with an identical limitation, Region 10 believes that this limitation is both technologically feasible and economically achievable. Region 10 has determined that it is impractical at this time to place the limitations on drilling mud until additional data are collected. See Response to Comment 6. Furthermore, if the limitation were placed on the drilling mud rather than on the barite, it would not be feasible for an operator to determine in advance if the discharge complied with the permit requirements since metals analyses must be conducted at commercial laboratories onshore. Such a requirement may impose costly and unreasonable delays while the analyses were being conducted.

EPA does recognize the possibility of changes in the available supply of "clean" barite. The final permit contains

a provision which allows the Water Division Director the discretion to grant a waiver from the limitations on a case-by-case basis if the permittee (1) satisfactorily demonstrates that barite which meets the limitation is not available, and (2) provides results of analyses of the substitute barite. In determining the availability of "clean" barite under this provision, Region 10 will reasonably consider all relevant factors, including the cost of obtaining barite which meets the limitations.

3. Generic muds and authorized additives. The permit limits the discharge of toxic substances in drilling fluids through the generic muds and approved additives concept. The permit authorizes the discharge of only generic drilling muds (listed in Table 1 of the permit) and additives for which acceptable bioassay and chemical data are available. Permittees are required to certify in advance of discharge that only generic drilling muds and authorized additives will be discharged.

Permittees may discharge the specific additives listed in Table 2 of the permit (at concentrations not exceeding the maximum allowable amounts) without special permission. This table is a modified version of Table 2 in the general permits for the Bering and Beaufort Seas (49 FR 23756, June 7, 1984). Over 25 drilling mud constituents and additives have been newly listed as acceptable for discharge. These chemicals have various applications in drilling practice, as outlined in Table 2 of the permit. Region 10 has received numerous requests to allow discharge of these compounds and has determined that they are acceptable for discharge up to the specified concentrations based on bioassay data, chemical data, and other product information. The addition of these additives to Table 2 will simplify the additive authorization process for both the permittees and EPA. The permit contains a provision (see Table 2) which will allow the discharge of additives which are listed in Table 2 of subsequent Region 10 general permits, unless otherwise stated in the new permits. For operations under this permit, any additive receiving authorization in this manner will be evaluated according to the regional criteria used for this permit.

Any discharge of a generic mud which has been modified other than by addition of an additive listed in Table 2 requires submission of information demonstrating that it passes the criteria in Part II.B.1.d.(2) of the permit or prior authorization by Region 10. Permittees may request authorization to discharge additives (including mineral oils) not

listed in Table 2 by submitting appropriate information and bioassay data in advance of discharge. Region 10 will determine whether the use of the requested additives is likely to cause the mud system to be more toxic than Generic Mud No. 1, which is the base formulation which the Agency uses to determine acceptable toxicity levels for discharge of fluids. Other criteria (e.g., persistence and degradation), as appropriate, are also considered in the evaluation process. The permits furthermore contain a provision which allow an exception for the discharge of mineral oil-containing muds which exceed the toxicity of Mud No. 1 if the least toxic available alternative is discharged. See Part II.B.1.f. of the permit and Response to Comments 16 and 21.

In some cases interim authorizations to discharge may be granted if preliminary bioassay data are submitted and the Region determines that additional bioassay testing or other analyses are required. Such testing may be required, for example, to examine possible cumulative or synergistic effects if the additive is to be used in combination with a number of other additives. Because the additional testing may take a considerable amount of time to conduct, interim authorization to discharge may be granted so that operations are not impaired for an unreasonable amount of time. Interim authorizations may also require testing a used drilling mud from a rig.

This approach to limiting toxicity is expected to control the discharge of listed toxic as well as nonconventional pollutants in drilling muds. For example, the toxicity of muds containing lubricants, including mineral oil products, may vary widely, and such additives may greatly increase the toxicity of the mud. Studies on diesel-contaminated drilling muds have shown toxicity to be strongly correlated with content of aromatic hydrocarbons, which include listed toxic pollutants. Some mineral oils also contain aromatic hydrocarbons which are listed toxics, such as fluorene, naphthalene, and phenanthrene. The toxicity of muds containing these oils is assumed to be caused, in part, by the listed toxic pollutants as well as by the nonconventional pollutants. Region 10 has determined that it is technically and economically infeasible to directly limit the toxic pollutants in drilling muds, as discussed in Part IV.C.1. Therefore, the Region has determined that the toxicity limitations (e.g., generic muds and approved additives) constitute a reasonable approach which is expected

to control not only listed toxic pollutants, but other toxic substances (i.e., toxic nonconventional pollutants) as well.

The technology basis for this permit condition is product substitution; i.e., mud additives and components which would cause the toxicity of a mud system to exceed that of Generic Mud No. 1 can be replaced by less toxic mud additives and components.

Under section 308 of the CWA, compliance with this permit condition will be monitored in two ways: First, by requiring that permittees certify that only generic muds and authorized additives will be discharged; and second, by requiring that permittees submit an end-of-well inventory listing all chemicals and the amounts of each added to each mud system. In addition, permittees must analyze one sample from the end-of-well mud system for metals content and toxicity. The metals data will be used to verify that mercury and cadmium limits on barite are adequately controlling metal concentrations in used muds. The Standard Drilling Fluids Toxicity Tests, performed on the end-of-well mud system, will provide a comparison between the toxicity of used muds containing mixtures of additives and the bioassay data submitted on individual additives prior to discharge.

4. *Other toxic and nonconventional compounds.* Under the permit discharge of the following pollutants are prohibited: Halogenated phenol compounds, trisodium nitrilotriacetic acid, sodium chromate, and sodium dichromate. The class of halogenated phenol compounds includes toxic pollutants, and sodium chromate and dichromate contain chromium, also a toxic pollutant. Trisodium nitrilotriacetic acid is a nonconventional pollutant. The discharge of these compounds was previously prohibited in the BPT general permits for the Beaufort Sea and Norton Sound (48 FR 54881, December 7, 1983) as well as in the BAT/BCT general permits for the Bering and Beaufort Seas (48 FR 23734, June 7, 1984). These compounds are therefore subject to BAT limitations. Because operators complied with this provision in the BPT permit, there is no additional cost to the industry.

D. Requirements Based on the Ocean Discharge Criteria Evaluation

1. *Drilling muds, cuttings, and washwater.* Additional restrictions on these discharges are necessary to ensure no unreasonable degradation of the environment. The Lease Sale 57 area includes water depths between 5 and 27 meters. Discharge rate limitations on

muds and cuttings have been established in the Ocean Discharge Criteria Evaluation process in order to allow adequate dispersion of the discharges. These maximum rates will ensure that acceptable toxicity levels will be met at the edge of the 100-meter mixing zone during open water conditions. During stable ice conditions, we have determined that on-ice disposal will ensure no unreasonable degradation of the environment. This is because at ice breakup, ice will tend to move away from Norton Sound to deeper areas, where the deposited discharges are expected to enter the water column at relatively slow rates.

The computer models used to predict dilution and dispersion of drilling muds and our knowledge of the water currents are not adequate to predict the fate of muds and cuttings discharged into shallow waters during unstable or broken ice conditions. Without this knowledge the Agency has insufficient information to determine that no unreasonable degradation of the marine environment will occur from the discharges. No reasonable alternatives to on-site disposal exist during these ice conditions, however, because the risk to the environment and human safety posed by the transportation of muds and cuttings under these conditions would be unacceptably high. EPA believes that no irreparable harm would occur in the general permit area during a monitoring period to evaluate the fate of such discharges because the projected number and volume of such discharges is relatively small. This permit therefore permits discharges under broken or unstable ice conditions, while requiring a field monitoring program to establish the fate of such discharges. It is not EPA's intention to have all operators in a particular area conducting monitoring studies. The first operator wishing to discharge under broken or unstable ice conditions in an area of concern would likely be required to monitor the fate of discharged muds and cuttings. If this monitoring clearly indicates the potential for biological effects, further evaluation or studies (including biological monitoring) may also be required. Similar monitoring by subsequent operators at other locations would be required only if environmental conditions were substantially different from those at the site of the first monitoring program.

The second case of insufficient information involves the discharge of cuttings which have been associated with oil-based muds. The BCT limitations under this permit authorize the discharge of cuttings with up to 10%

oil content if no free oil results from the discharge of such cuttings. Little is known about the fate and effects of oil contaminated cuttings. However, limited numbers of operations are expected to discharge cuttings from oil-based muds under this permit. Information available to Region 10 does not support a finding that there are reasonable alternatives to discharge. Further, the Region 10 has determined that no irreparable harm would occur if such a discharge is allowed while the required monitoring program is conducted to measure its effects.

2. *Other discharges (003-015).* These discharges are adequately controlled by the limitations in Parts II.C.-F. of the final permit to ensure no unreasonable degradation of the marine environment due to those discharges.

V. Other Legal Requirements

A. Oil Spill Requirements

Section 311 of the Act prohibits the discharge of oil and hazardous materials in harmful quantities. Routine discharges specifically controlled by the permit are excluded from the provisions of section 311. However, this permit does not preclude the institution of legal action or relieve permittees from any responsibilities, liabilities, or penalties for other unauthorized discharges of oil and hazardous materials which are covered by section 311 of the Act.

B. Endangered Species Act

Based on information in the Ocean Discharge Criteria Evaluations and in the Environmental Impact Statement prepared for Federal Lease Sale 57, EPA has concluded that the discharges authorized by this general permit will neither jeopardize the continued existence of any endangered or threatened species nor adversely affect their critical habitat. Further, EPA requested comments from the U.S. Fish and Wildlife Service and the National Marine Fisheries Service on the draft permit and received no comments on endangered species. EPA will initiate consultation should new information reveal impacts not previously considered, should the activities be modified in a manner beyond the scope of the original opinion, or should the activities affect a newly listed species.

C. Coastal Zone Management Act

The draft permit and consistency certifications were submitted to the State of Alaska at the time of public notice. The State of Alaska has concurred that the activities allowed by this general permit are consistent with the Alaska Coastal Management Plan.

D. Marine Protection, Research and Sanctuaries Act

No marine sanctuaries as designated by this Act exist in the vicinity of the permit areas.

E. State Water Quality Standards and State Certification

No state waters are included in this permit.

F. Executive Order 12291

The Office of Management and Budget has exempted this action from the review requirements of Executive Order 12291 pursuant to section 8(b) of that order.

G. Paperwork Reduction Act

EPA has reviewed the requirements imposed on regulated facilities in this final general permit under the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 et seq. Most of the information collection requirements have already been approved by the Office of Management and Budget (OMB) in submissions made for the NPDES permit program under the provisions of the Clean Water Act. In addition, the environmental monitoring requirements pursuant to section 403(c) of the Clean Water Act in Part II.B. of this permit are similar to the monitoring requirements that were approved by OMB for the previously issued Beaufort Sea general NPDES permit (June 7, 1984; 49 FR 23734). Comments received during the public comment period on the information collection requirements contained in the draft general permit are addressed in the Response to Comments.

H. *Effective Date.* The final NPDES general permit issued today is effective immediately. Ordinarily, EPA would issue this permit and allow thirty (30) days before making the final permit effective. However, EPA may, under 5 U.S.C. 553(d)(1) make the permit effective immediately because it relieves a restriction on the regulated community by authorizing the discharge of pollutants in compliance with its terms. Without a permit, discharges of pollutants are prohibited under section 301 of the Clean Water Act. In addition, EPA finds that good cause exists under section 553(d)(3), because a later effective date would result in significant economic loss due to delays in the commencement of exploratory drilling operations. The 30-day period between the date of issuance and the date of effectiveness is provided to afford administrative appeal, and this procedure is not available for general permits.

I. The Regulatory Flexibility Act.

After review of the facts presented in the notice of intent printed above, I hereby certify, pursuant to the provisions of 5 U.S.C. 605(b), that this general permit will not have a significant impact on a substantial number of small entities. This certification is based on the fact that the regulated parties have greater than 500 employees and are not classified as small businesses under the Small Business Administration regulations established at 49 FR 5024 et seq. (February 9, 1984). These facilities are classified as Major Group 13—Oil and Gas Extraction SIC 1311 Crude Petroleum and Natural Gas.

Dated: May 22, 1985.

Signed:

Ernesta B. Barnes,
Regional Administrator, Region 10.

Appendix A—Public Comments

Public hearings tentatively scheduled to be held at Anchorage and Nome on March 21 and 22, 1985 were not held due to a lack of expressed interest in hearings at these locations. A public meeting was held on March 19, 1985 at Alakanuk on the Yukon Delta to discuss the concerns of Nunam Kitlutsisti, a non-profit Alaska Native environmental organization.

The following parties responded with written comments during the public comment period:

Alaska Oil and Gas Association (AOGA)
American Petroleum Institute (API)
ARCO Alaska, Inc.
Conoco Inc.
Natural Resources Defense Council (NRDC)
Nunam Kitlutsisti
Texaco U.S.A.
Trustees for Alaska
U.S. Department of the Interior, Fish and Wildlife Service
U.S. Department of the Interior, Minerals Management Service
NRDC, Nunam Kitlutsisti, and Trustees for Alaska submitted comments jointly and are therefore referenced as "NRDC" below.
On April 2, 1985 Exxon Company U.S.A. requested coverage as a permittee under this general NPDES permit.

Significant comments presented during the public comment period and at the public meeting were reviewed by EPA and considered in the formulation of the final decision regarding the proposed permit. These comments and Region 10's responses to the comments are presented below.

1. *Comment:* Conoco Inc. criticized the required notification procedures in this permit. In particular, they felt (a) the request for coverage 60 days prior to discharge was too long; (b) an individual permit number should not be necessary under a general permit; (c) notification of termination of discharges should be reported in the Discharge Monitoring Report (DMR); and (d) the duty to reapply deadline (180 days) is too long.

Response: (a) A 60-day period is necessary to ensure adequate time for Region 10 to determine whether the proposed activity is appropriately covered by this permit and whether the proposed location might require environmental monitoring under Part II.B.3. If environmental monitoring will be required, the specifics of the program will need to be established. (b) When granting coverage under the general permit, an individual permit number is assigned in order to track compliance of the authorized facility with permit requirements. (c) The "Termination of Discharge" notification may be given in a DMR or under separate cover, as long as notification is given within thirty days of each well completion. This notification is required to indicate to EPA's Water Compliance Section that subsequent DMRs for the facility are not required. (d) *Part V.E. Duty to Reapply* is based on 40 CFR 122.21.d. and Region 10 believes at this time that 180 days is necessary to allow sufficient time to issue a new permit.

2. *Comment:* NRDC and the Nunam Kitlutsisti expressed great concern about the ability of EPA to enforce provisions of the permit given the relatively limited enforcement capability, the remoteness of the area covered, and the severity of weather in the permitted areas. It was suggested that an enforcement plan be developed and subject to public review prior to the issuance of any discharge permits.

Response: It is not within the scope of these NPDES permits to rigidly define in advance the way in which enforcement shall occur. EPA, however, routinely targets facilities for compliance verification inspections. Although EPA's staff and resources for on-site monitoring are limited, a joint agreement with the Department of Interior (DOI) was signed on May 31, 1984, which provides for the assistance of DOI's Minerals Management Service personnel in EPA compliance monitoring and inspections efforts. DOI personnel are frequently on-site during rig operations.

3. *Comment:* NRDC strongly recommends that EPA define upset conditions (Part IV.H.2.) in such a way as to eliminate all reasonably

foreseeable emergencies that can be planned for in advance. The same comment applies to the bypass provision (Part IV.G.) of the permit.

Response: The parts referred to are drawn directly from the NPDES regulations (40 CFR 122.41(m) and (n)). Definitions of "bypass" and "upset" are included in Part II.A. of the permit. Although NRDC did not provide suggested specific wording, Region 10 believes the permit's wording accomplishes what NRDC requests.

4. *Comment:* AOGA and Conoco commented that the static sheen test is an unreliable and unproven method which is therefore inappropriate for monitoring compliance with the no free oil limitation. AOGA also commented (Attachments 1 and 5) that the static sheen test is appropriate for monitoring on-ice discharges only, "and even then only marginally so." AOGA recommended that "an API retort protocol" be allowed as an alternative test method during ice conditions and suggested that other alternatives such as a visual observation of the receiving water be required during other seasons.

Response: The static sheen test has been demonstrated to be a reliable and reproducible test method. Not only is it appropriate for the harsh weather (including ice-free as well as ice-cover conditions) and prolonged periods of darkness common in Alaska, but it provides operators with an opportunity to avoid permit violations. Drilling discharges can be tested prior to bulk discharge. A visual observation of the receiving water does not have these advantages. Any variability that may be present in a demonstrated laboratory procedure such as the static sheen test will be far less than that of an over-the-side-of-the-deck observation of the receiving water.

The commenters refer to two studies to support their challenge of the static sheen test, one conducted for EPA by CENTEC Analytical Services, Inc. and another conducted by Maurice Jones. The arguments raised ignore two essential features of the regional methodology (Region 10's "Interim Guidance for the Static (Laboratory) Sheen Test."). The regional guidance, which must be used in conjunction with the detailed protocol in Petrazzuolo (1983), was developed to ensure against any possibility of ambiguous results arising from attempts to detect trace amounts of a sheen or from the use of small sample sizes (with the standard-sized test containers). First, a sheen must cover more than one-half of the test container in order to result in a positive reading (i.e., a trace amount of a sheen is a negative finding). Second,

only the largest of the three sample sizes originally specified in the methodology (Petrazzuolo 1983) is tested, thereby enhancing the possibility of detecting a sheen for any particular sample (i.e., if drilling mud contains free oil, a larger sample size will result in proportionally greater amounts of free oil).

In EPA's study (CENTEC 1984) 354 separate tests were conducted on 54 samples of muds and cuttings in order to assess the reliability and reproducibility of the test methodology, as originally proposed (Petrazzuolo 1983). The findings clearly support Region 10's application of the test method, as discussed in detail in the record. EPA showed the sheen test to be a reliable enforcement tool that does not give false positive readings (i.e., it does not erroneously detect oil when no oil was added). Contrary to the statement in AOGA's Attachment 5, the test did not give false positive results, even when emulsifiers were added. The test was also reproducible. Repeat tests for any one sample type showed high levels of agreement.

The second study used to support AOGA's comment was conducted by Jones (1985) who had 26 observers evaluate 14 test samples. The study design contains several critical flaws. In particular, the study ignored the two essential features of the Region 10 guidance discussed above. Small samples were used (with the standard-size test container). These results, therefore, must be ignored. The test results for the remaining samples cannot be evaluated according to the regional guidance, which requires a trace of a sheen to be read as a negative result. According to Jones' study design and unlike the EPA study (CENTEC 1984), observations of both trace amounts and greater than trace amounts were scored as positives.

Jones furthermore failed to follow specified requirements for lighting conditions and dark test containers (Petrazzuolo 1983). He states that "white dishpans and plastic liners were used due to the relatively low light levels present." By his own admission, "the use of the different colored backgrounds and different lighting conditions could affect result [sic] significantly." These results are used to argue that "variable test conditions (i.e. lighting)" serve to invalidate the procedure. The specified test procedure, however, precludes the use of unsuitable lighting conditions and white test containers. The results of Jones (1985) are inconclusive with regard to Region 10's test method. See further discussion in the record.

Region 10 advises that CENTEC (1984) should be consulted for the EPA test data since Jones (1985) contains several critical typographical errors or omissions in Table 3 ("Results of Sheen Tests by CENTEC Analytical Services").

AOGA did not supply any data demonstrating the suitability of the retort test as a substitute for the sheen test, and Region 10 has no information on the validity of using the retort test for this purpose. Operators are encouraged to supply EPA with study results should they become available from the industry study proposed to address this issue (see AOGA's Attachment 8).

5. *Comment:* AOGA and Conoco requested that Region 10 remove the effluent limitations on mercury and cadmium in barite which "create an unjustified risk to industry of becoming a national precedent" (quote from AOGA). The commenters argue that the discharge of these metals in barite pose no hazard to the marine environment and that the Agency has not fully assessed the potential cost of "limiting Alaska exploratory operations to only one source of barite" (AOGA). Conoco asserts that "the requirement that only barite from Nevada be allowed for use in Alaska may very well be an 'act in restraint of trade' " and contends that the limitation will have nationwide impact on barite costs, affecting not only large but also small oil and gas products. AOGA submitted Attachments 6 and 8 in support of their comments.

Response: The permit limitation is a BAT effluent limitation. Findings under section 403(c) (assessment of "hazard to the marine environment") were not the basis for the limitation. The section 403(c) evaluation assumed that discharged muds would reflect BAT level control. The record, however, demonstrates an environmental concern due to the toxicity and bioaccumulation of mercury and cadmium in other types of wastes and the lack of information on the chemical nature and ultimate bioavailability of these toxic heavy metals in drilling muds. Industry has, in fact, acknowledged the lack of information in these areas (see proposed Offshore Operators Committee studies in AOGA's Attachment 8).

While the use of Nevada barite was the basis for Region 10's determination regarding product substitution of uncontaminated barite for contaminated barite, the permits do not necessarily restrict operators to using Nevada barite. Nevada barite however is the major domestic source of barite and the current principal source for Alaskan operations. Nevada barite is a bedded deposit, which is characteristically low in trace metals. Vein deposits, however,

may also have acceptable levels (AOGA's Attachment 6, Kramer et al. 1980).

The demand for barite by Alaskan operators is not expected to significantly alter barite costs since offshore wells in Alaska account for less than two percent of the total offshore wells drilled in the U.S. Moreover, the permit provides an exemption in cases when the operator is unable to comply due to the lack of barite which meets the limitations. The commenters did not address this provision in their comments.

Attachment 6 (AOGA) fails to provide any useful new data. First, the discussion addresses the impact of more stringent limitations (2 mg/kg cadmium and 1 mg/kg mercury) than were proposed in the draft permit (3 mg/kg cadmium and 1 mg/kg mercury). Second, data on the percent of barite sources (domestic and foreign) that could meet the assumed (incorrect) limitations are presented only in summary form, frustrating any interpretation of the impact of Region 10's proposed limitations on the use of worldwide barite sources in Alaska. Third, the discussion addresses the impact of the assumed (incorrect) barite limitations if they were to be imposed nationwide. Region 10, however, has made a case-specific determination for operations offshore of Alaska and is not required to assess the impacts of this limitation if it were to be imposed nationwide. This issue will be addressed in the guidelines development process or by each region on a similar case-by-case basis, taking into account the cumulative effects of established restrictions. Finally, the comments do not provide information pertinent to Region 10's specific request in the permit proposal (40 FR 6390, February 15, 1985) for "any increased costs that a permittee incurred in meeting the barite limitations contained in the general permits for the Beaufort and Bering Seas."

With respect to small operators, Region 10 notes that only major companies are expected to operate exploratory wells in remote offshore regions of Alaska. Extensive planning and a large financial commitment are required (see Lewis 1983). Leases in the Norton Sound Sale 57 area are held by large oil companies.

6. *Comment:* NRDC, Trustees for Alaska, and Nunam Kitlusiiti ("NRDC") recommended that the mercury and cadmium limitations be placed on drilling muds at levels of 1 mg/kg for each metal. These drilling mud limitations would replace the barite limitations.

Response: Barite accounts for 60 to 85 percent of the mass of drilling mud solids and is expected to be the chief source of heavy metals in the discharged muds. Control of heavy metals in barite is therefore expected to control heavy metals in drilling muds. Region 10 has determined that the most practicable approach at this time is to place a limitation on the barite until sufficient data are collected to allow thorough characterization of the levels in discharge drilling muds. The limitation on the barite provides an operator with an opportunity to plan ahead in order to avoid permit violations. Compliance can be determined by sampling barite prior to discharge rather than by sampling and waiting for analyses to be completed on the used drilling mud.

Region 10 notes that while the cadmium limitation on barite may be slightly less strict than the drilling mud limitation recommended by NRDC, Region 10's mercury limitation is theoretically more strict. For example, if all mercury in drilling mud is derived from barite, then barite with 1 mg/kg will be mixed and diluted with other, less contaminated drilling mud solids, resulting in a discharge of drilling mud with less than 1 mg/kg mercury. Region 10's discharge monitoring data show that mercury levels in drilling muds are generally less than 0.9 mg/kg, dry weight. While cadmium levels in discharged muds have been somewhat more variable, the concentrations generally show levels less than 2 mg/kg.

Region 10 will reevaluate these limitations as additional discharge monitoring data on metals in drilling muds are available. The permit requires end-of-well chemical analyses to be conducted on drilling muds from each well.

7. *Comment:* AOGA (Attachments 1 and 11) and Conoco challenge the Region's use of diesel oil as an indicator pollutant for the listed toxic pollutants present in diesel oil. The commenter first argued that diesel oil is a conventional pollutant and that diesel oil is subject only to a BCT limitation. Second, the commenter argued that the Region's use of diesel oil failed to comply with the requirements of 40 CFR 125.3(h)(1), as amended on September 24, 1984 (previously listed as 40 CFR 125.3(g)(1)). Finally, if the Region used diesel oil as an indicator to control the nonconventional pollutants present in diesel oil, AOGA requested that their comments be considered a request for a section 301(g) waiver of all BPT effluent limitations.

NRDC strongly supports the diesel prohibition but suggested that the

Agency provide a more explicit justification for regulating diesel as an indicator.

Response: The Regional believes that it adequately explained in the proposal its bases and justifications for using diesel oil as an indicator pollutant. However, in order to fully respond to comments, the Region will restate and elaborate on its position and explain why its decision fully complies with the requirements in 40 CFR 125.3(h)(1). The Region has also provided new information and further discussion of this comment in the record, which expands the technical basis for the use of diesel as an indicator.

As the Region has discussed in previous notices, diesel oil is a complex mixture of petroleum hydrocarbons. Diesel oil may contain from 20 to 60 percent by volume aromatic hydrocarbons (Thoresen and Hinds 1983). The light aromatic hydrocarbons, such as benzenes, naphthalenes, and phenanthrenes, constitute the most toxic major components of petroleum products (National Research Council 1983, p. 81). One issue raised is whether diesel oil should be regulated as a conventional, nonconventional, or toxic pollutants. The AOGA comment stated that EPA regulations define "oil and grease," including diesel oil, as a conventional pollutant" (emphasis in original comment). The Region previously acknowledged that the mixture "diesel oil" is not a listed toxic pollutant; however, the Region also has recognized the presence in diesel oil of numerous listed toxic pollutants including naphthalene, benzene, ethylbenzene, phenanthrene, toluene, fluorene, and phenol. The Region furthermore has identified numerous specific nonconventional pollutants in the mixture "diesel oil," including polynuclear aromatic hydrocarbons such as methyl-naphthalene, dimethyl-naphthalene, methylphenanthrene, and other alkylated forms of each of the listed toxic pollutants.

The exercise of arguing over which pollutant category in which to place "diesel oil," however, is in a sense unnecessary. The real issue is how best to regulate and control the numerous listed toxic pollutants present in diesel oil. The Region considered and rejected the option of establishing specific numerical effluent limitations for the conventional pollutant oil and grease in drilling fluids, or for the numerous listed toxic and nonconventional pollutants, the presence or concentration of which would be attributable to diesel oil contamination of the drilling fluid. The

Region has chosen to use "diesel oil" as an indicator of the many toxic pollutants present in that complex mixture. By prohibiting the discharge of diesel oil, the Region will reduce the discharge of toxic pollutants. The Region's decision to take this approach was reasonable and, contrary to AOGA's argument, in full compliance with the applicable permitting regulations in 40 CFR 125.3(h)(1).

Section 125.3(h)(1) authorizes a permit writer to establish limitations for a conventional pollutant more stringent than BCT, or limitations for a nonconventional pollutant which shall not be subject to modification under section 301 (c) or (g), where (in either case): (1) The pollutant has been identified as an indicator in effluent limitations guidelines or (2) the permit writer makes findings warranting use of the pollutant as an indicator.

In the absence of BAT guidelines, Region 10 has acted pursuant to the second provision. See 40 CFR 125.3(h)(1)(ii). First, § 125.3(h)(1)(ii)(B) requires the Region to identify the toxic pollutants to be controlled by the limitation on diesel oil. The listed toxic pollutants found in various diesel oils include naphthalene, benzene, ethylbenzene, phenanthrene, toluene, fluorene, and phenol. The notice published on February 15, 1985 did not provide an inclusive list; however, in response to comments Region 10 has reevaluated the toxic pollutants in diesel and has also considered recently available information. All of the above toxic pollutants were present in a diesel identified as "Alaska diesel" (Requejo et al. 1984).

Second, § 125.3(h)(1)(ii) (A) and (C) require findings that the indicator limitation reflects BAT-level control for the specific toxic pollutants and that establishing effluent limits on the specific toxic pollutants would be economically or technically infeasible. The BAT-level control for the specific toxic pollutants would be the reductions achievable through use of the technology basis for the limitations. Whether the Region chooses to control the indicator pollutant diesel oil or the specific toxic pollutants, the technology basis would be product substitution, i.e., use of mineral oil instead of diesel oil. A treatment system does not exist that could be installed and used on a rig to reduce toxic pollutants in drilling fluids prior to discharge.

The Region has determined that prohibiting the discharge of drilling fluids contaminated with diesel oil (i.e., substitution of mineral oil for diesel oil in drilling fluids) will reduce the levels

of the toxic pollutants present in the discharged fluids. Mineral oils, with their lower aromatic hydrocarbon content and lower toxicity, contain lower concentrations of toxic pollutants than do diesel oils. A report discussed in AOGA's comments and prepared for API by Battelle Laboratories supports the conclusion that the elimination of diesel oil discharges will reduce toxic pollutants discharges (Requejo et al. 1984). AOGA argues in Attachment 11 that the Battelle report "reveals no correlation between diesel concentration and the concentrations of various toxic pollutants" because the concentrations of toxic pollutants vary among different diesel oils. This argument, however, is misdirected. The real issue is whether the levels of toxic pollutants would be reduced by substituting mineral oil for diesel oil. The Battelle report confirms that such a reduction would occur. Appendix I of the report presents the results of analyses for toxic pollutants in three mineral oils and six diesel oils. The results reveal strikingly higher levels of toxic pollutants in the diesel oil samples. For example, naphthalene was detected in only one of the three mineral oil samples and at a level of 0.05 mg/ml. In contrast naphthalene was detected in all six diesel oils at levels ranging from 0.48 mg/ml (mistakenly reported as 0.048 mg/ml in AOGA's Attachment 11) to 3.25 mg/ml. While the levels of naphthalene may vary in diesel oil, as AOGA argues, they routinely and significantly exceed the levels detected in mineral oils. Similarly striking results occurred in the analyses for benzene, ethylbenzene, fluorene, phenanthrene, and phenol, and the alkylated homologues of each of these toxic pollutants, including naphthalene.

It is reasonable and appropriate to conclude that BAT-level control of toxic pollutants (i.e., reduction in concentrations through substitution of mineral oil for diesel oil) will be achieved by regulating diesel oil as an indicator pollutant. The use of mineral oils rather than diesel oils in mud systems will result in a reduction of toxic pollutant levels equivalent to those levels reflecting BAT-level treatment. AOGA contends, however, that Region 10 has not established this fact for "all types of diesel oil." While there may be one diesel oil that may have lower levels of some toxic pollutants than a highly toxic mineral oil, the available data overwhelmingly establish that diesel oils as a class include significantly higher levels of toxic pollutants than do mineral oils as a class. The regulations do not require

EPA to analyze every diesel oil (of which there are many) before concluding that diesel oils contain high levels of toxic pollutants and that controlling the discharge of diesel oils will reduce the discharge of toxic pollutants.

AOGA argues that the Region has not identified specific concentrations of each toxic pollutant which would represent the level achievable by BAT controls on the specific toxics. Such a calculation can be made by multiplying the known concentrations of specific pollutants in mineral oils (e.g., from the Battelle study) by the assumed concentration of oil in the drilling mud, resulting in predicted BAT levels of control. The results of these calculations for numerous toxic pollutants and classes of nonconventional pollutants are contained in the administrative record. The concentrations of these pollutants will vary, as expected, depending on the amount and specific type of mineral oil use. Concentrations of toxic pollutants resulting from 5 percent by volume "Mineral Oil B" in drilling muds, for example, were predicted to range from undetectable amounts of benzene, ethylbenzene, naphthalene, and phenol to up to 10 mg/l of phenanthrene. "Mineral Oil A" and "Mineral Oil C" used in amounts as high as 10 percent of volume in drilling muds would result in undetectable amounts of a number of toxic pollutants and in maximum concentrations for any single pollutant of 5 mg/l naphthalene and 4 mg/l phenanthrene, respectively.

Region 10 has, however, concluded that establishing effluent limitations for each of the toxic pollutants present in diesel oil is not economically or technically feasible at this time. See § 125.3(h)(1)(ii)(C) and today's Notice, Part IV.C.1. Additionally, specific toxic effluent limitations would be contrary to the positions of AOGA and API which request permits that enable operators to determine compliance at the earliest possible date. Either operators would have to delay discharge until monitoring results confirmed compliance or they would discharge and risk permit noncompliance. Delay time while awaiting for monitoring data could result in excessive costs. A permit limitation that prohibits the discharge of diesel oil is economically and technically feasible and allows a determination of permit compliance prior to discharge.

Finally, with respect to the AOGA request that their comment be considered a request for a waiver under section 301(g), Region 10 makes the following observations. First, since

AOGA is not a permittee, it is not the appropriate party to request such a waiver. Second, such a request would require more than a one sentence statement. Third, the use of diesel oil as an indicator for toxic pollutants, precludes the issuance of a section 301(g) waiver. See 40 CFR 125.3(g)(1).

8. *Comment:* AOGA challenges the technology basis (i.e., product substitution) for the prohibition on the discharge of diesel in drilling muds contaminated by a diesel "pill" (also known as a "spotting fluid"). The commenter stated that there is a "present lack of alternatives to diesel as the liquid carrier in 'pill' packages to relieve drill pipe sticking problems" and that the use of diesel represents the "state of currently available technology."

Response: AOGA's Attachment 5 contains a review of three published papers to support their challenge of the diesel prohibition. The author of Attachment 5, Maurice Jones, states that the Region has based the limitation "on the assumption that diesel oil can be easily substituted by mineral oil or other less toxic oils." Region 10 considered two of the referenced papers prior to proposal and has evaluated the third, in addition to all other available information, prior to the final permit decision. A discussion of the arguments raised in AOGA's Attachment 5 follows.

Oil-based fluids (both drilling fluids and spotting fluids) include not only the base oil but also chemical additives such as emulsifiers, surfactants, viscosifiers, and barite. Most oil-based fluids also include emulsified water. The thrust of AOGA's argument is that mineral oils are not suitable substitutes for diesel oil because formulations specifically tailored to mineral oils (and especially to their lower aromatic hydrocarbon content) have not been adequately developed. Diesel oil has had longstanding use in drilling muds because it is readily available from a rig's fuel tanks and cheaper than alternative oils. Simply substituting mineral oil for diesel oil in fluid formulations originally developed for diesel does not always achieve favorable results because chemical additives may have differing solubilities and behavior in different types of oil. EPA recognizes that substitution of a mineral oil pill for a diesel pill generally entails the use of chemical packages specially formulated for mineral oil.

Jones, in AOGA's Attachment 5, acknowledges that operationally effective mineral oil-based fluids can substitute for diesel oil-based fluids, provided that chemical additives

effective in the base mineral oil can be formulated (see also Jones et al. 1983). As shown in the administrative record, chemical additives have been developed which are compatible with mineral oils. The performance of these fluids has been demonstrated in both the laboratory and the field. Information on a number of different mineral oil-based spotting fluids currently marketed and available for use is also contained in the administrative record for this permit. Such products are routinely requested for use and discharge under Region 10's permits. Neither AOGA nor other commenters present data which refute the demonstrated development and performance of mineral oil-based fluids, including spotting fluids.

Jones furthermore misconstrues the information presented in the three references cited in AOGA's Attachment 5. First, Cowan and Brookey (1984) focus on the cost/efficiency of using mineral oil with additive packages originally developed for diesel. They conclude that present diesel packages can be adapted for use in most new oil systems. They note that the cost/efficiency of such formulations are not optimized for mineral oil as they are for diesel, resulting in some sacrifice of drilling cost/performance. They did not, however, evaluate newer oil-based formulations specifically tailored to mineral oil.

Second, Clapper and Salisbury (1984) discuss the chemistry of additives (primary and secondary emulsifiers) used in specially formulated mineral oil-based fluids. They conclude that "while a wide range of effectiveness exists among new emulsifiers designed for use in mineral oil, new product demands basically have been met."

Finally, Bennett (1983) details the development and application of oil-based fluids specially formulated to accommodate a mineral oil base. The first mineral oil-based fluid was available commercially in 1975 as a spotting fluid for differently stuck pipe. Since that time, oil-based fluids have received widespread application. Bennett concludes that "mineral oil-based fluids possess the same characteristics but also have definite advantages over diesel oil-based drilling and spotting fluids. These characteristics and advantages are shown by laboratory evaluations, laboratory toxicity studies and field case histories." Bennett also notes that many emulsifiers and dispersants used in diesel oil-based fluids are very toxic and that less toxic compounds can be used in mineral oil-based fluids.

In conclusion, available data support Region 10's determination that substitution of mineral oil products for diesel oil formulations is technologically feasible.

9. *Comment:* Both Conoco and AOGA requested that EPA allow the discharge of diesel-contaminated drilling muds resulting from the use of a diesel pill. The commenters suggested that such discharges should be allowed if the operators participate in the Diesel Pill Monitoring Program originally proposed for the Gulf of Mexico (see AOGA's Attachment 7). The study would determine the efficiency of pill recovery and the toxicity and diesel content of discharged muds. Conoco recommended omission of the diesel limitation and use of the visual sheen test (over-the-side-of-the-deck observation of the receiving water) pending the results of the study. AOGA (Attachment 1) recommended a limitation on the increase in oil content resulting from diesel pill use (and recovery) of no more than 0.5 percent by volume, as determined by the API (American Petroleum Institute) retort test.

Response: Region 10 has again evaluated and rejected the option of controlling pollutants contained in diesel by means of diesel pill recovery rather than by product substitution of mineral oil for diesel. See 49 FR 32745 and 48 FR 54881. The effectiveness of pill recovery has not been demonstrated.

The record demonstrates a potential for a drilling mud system to be significantly contaminated with diesel, at levels of approximately 1.5 percent by volume, from the use of a diesel pill. AOGA, however, suggested setting a limitation on the maximum increase in oil content equal to 0.5 percent by volume, as determined by the API retort method. Even if an operator were able to meet such a limitation with pill recovery, 0.5 percent diesel would be expected to cause significant increases in acute toxicity and in concentrations of toxic substances in drilling muds. See Comment 7.

Region 10 questions whether the API retort method is sufficiently sensitive to accurately measure diesel increases of 0.5 percent. It appears likely that increases in diesel concentration of nearly 1 percent could easily occur with AOGA's proposed limitation and test method due to difficulties in visually detecting small differences on the measuring scale (i.e., distances along the scale of approximately two hundredths of an inch correspond to a measure of 0.5 percent oil). The lack of sensitivity of the test measurement would allow significant increases in the

concentration of toxic substances in the discharge.

Region 10 also disagrees that the visual sheen test of the receiving water provides "adequate control for discharges of mud and cuttings containing small amounts of diesel" (comment by Conoco). The National Research Council ("NRC", 1983, p. 162) reported that drilling muds containing as much as several percent diesel may not cause a sheen.

In conclusion, Region 10 has evaluated alternative control technologies and suggested control parameters (API retort oil content and sheen on the receiving water). The Region has determined that the prohibition on the discharge of diesel-contaminated drilling muds is reasonable and appropriate since diesel pill recovery is unproven and substitution of a mineral oil pill for diesel is technologically feasible and economically achievable.

10. *Comment:* Conoco noted that "the costs quoted by EPA for use of mineral oil over the costs for diesel do not consider the additional handling, storage, etc. required for mineral oil."

Response: Conoco failed to provide any pertinent information on such costs. Unlike Conoco, other members of AOGA have operated offshore exploratory wells under Region 10's permits (which have prohibited the discharge of diesel since 1983). AOGA, however, did not challenge Region 10's evaluation of costs associated with substitution of mineral oil spotting fluids for diesel pills. Conoco, in fact, did not directly challenge Region 10's conclusion but only whether the costs for the "additional handling, storage, etc." required for mineral oil were considered. Region 10 is, therefore, providing the following supplementary information on the costs associated with mineral oil use. The following cost estimate is derived from API figures (Attachment 7 to AOGA's comments), except where data believed to be more accurate are available. These additional costs have not changed Region 10's final determination regarding economic achievability of the effluent limitation (diesel prohibition). The details of this analysis are in the administrative record. It is summarized as follows:

The total cost per mineral oil pill is estimated to be \$22,765.

A diesel pill is estimated to cost as little as \$18,500. Additional costs incurred by use of the diesel pill, including tank storage for the pill and hauling of it to shore, make the total cost for use of diesel pills between \$19,700 (assuming 200 barrels are disposed of downhole) and \$32,200.

While the above figures provide only general cost estimates, they clearly demonstrate the economic feasibility of produce substitution of a mineral oil pill for a diesel pill.

11. *Comment:* Conoco commented that a GC analysis should not be required since the test results may convey confidential business information due to the exploratory nature of the wells.

Response: EPA has procedures for handling confidential business information. If appropriate, the gas chromatograms will be held in confidentiality by the regional office in accordance with 40 CFR Part 2, Subpart B. The determination stating whether or not diesel was present in the drilling mud will, however, in any case not be eligible for confidential treatment since this determination is required for tracking compliance with the permit conditions. Region 10 does not believe that a statement of whether or not diesel is present conveys confidential business information.

12. *Comment:* AOGA and Conoco requested that a certification statement that diesel was not discharged in muds should replace the requirement for monitoring diesel in drilling mud. Conoco suggested that a certification statement should suffice for other monitoring requirements as well. NRDC fully supported the monitoring requirement for diesel.

AOGA (Attachment 11) requested that the cost of the diesel monitoring requirement be borne by EPA. Regarding general costs of monitoring, AOGA noted that monitoring requirements under the Bering/Beaufort general permits cost from \$2,000 to \$8,000 per well for analyses plus about \$30,000 for an onsite technician.

Response: Monitoring requirements for diesel in discharged drilling muds in addition to a number of other monitoring requirements have been established in order to assure and determine compliance with permit effluent limitations. These conditions are imposed in accordance with 40 CFR 122.44(i) and section 308 of the Act. Compliance monitoring with the permit conditions is the responsibility of the permittee. EPA conducts testing only for compliance inspections. EPA has determined the diesel prohibition and other effluent limitations are economically achievable. The analytical and sampling costs and the cost of a technician, if one were required, do not present costs which make the limitations economically unachievable. Sampling to determine compliance with BAT effluent limitations is expected to require limited effort. The most frequent

monitoring is required to determine compliance with the BCT effluent limitation on free oil in muds and cuttings. This limitation and its monitoring requirement are the same as those incorporated under Region 10's previous BPT permits.

13. *Comment:* AOGA (Attachment 11) and Conoco commented that the GC test method "has been found to mistakenly identify mineral oil as diesel in two recent cases already; one in a laboratory study and one in a monitoring situation" (quote from AOGA). The commenters requested that this test method be deleted (see Comment 12).

Response: Region 10 is familiar with two instances in which industry has claimed that the GC method has erroneously identified the presence of diesel oil. In neither case did the data support this claim. In both instances, the requirement for a comparison of the GC "fingerprint" was ignored. The method in the administrative record for this permit states that "the major peaks present in the standard (e.g., those greater than 1 percent of the total integrated area) should also be present in the sample and in the same relative intensity and pattern."

In the first case, API claimed that the Battelle study (see Comment 7) shows that one mineral oil (Mineral Oil B) cannot be distinguished from diesel oil. In the second case, ARCO claimed that GC data submitted with a Discharge Monitoring Report for operations in the Bering Sea erroneously identified diesel oil in drilling mud when only mineral oil was present. The record (containing the Agency's response to these two cases, and supporting analyses) clearly demonstrates the error of industry's conclusions. ARCO, in fact, recently concurred with Region 10's conclusions regarding the second case, above (letter dated May 10, 1985).

AOGA (Attachment 11) states that while the GC method will cost up to \$200 per sample, an "adequate method" (assumed to be gas chromatography/mass spectrometry) will cost as much as \$2,500 per sample. Due to these cost considerations and the general reliability of the GC method, Region 10 does not believe that a more sophisticated, costly analytical method is required for general effluent monitoring purposes. The permit, however, will allow the use of GC/MS to provide greater resolution of the drilling mud "fingerprint," if an instance should arise where the operator and EPA determine that greater resolution is required to make a determination. Region 10 emphasizes, however, that the GC chromatogram was fully adequate in both cases mentioned above to

determine that the presence of diesel was unlikely.

14. *Comment:* Conoco stated in a general comment that "Region X appears to have adopted the 'product substitution' rationale without full consideration of the true costs involved."

Response: Region 10 believes that it has adequately assessed costs for all requirements based on product substitution. The costs for product substitution of mineral oils and barite have been addressed. See Comments 5 and 10. It can be assumed that additional costs may be involved in substituting less toxic additives for more toxic ones, as required to meet toxicity limitations. While industry has not provided information on costs of such additives, Region 10 does not believe that there are substantial costs involved beyond those already quantified. One clear example known to Region 10 of increased costs from product substitution of drilling mud additives (other than mineral oil) would occur if starch containing toxic paraformaldehyde is substituted with a cellulose polymer. Starch is generally used in amounts of 2 to 6 pounds per barrel; amounts of cellulose polymer are generally less (approximately 2 pounds per barrel). If, for a particular drilling mud, the maximum amount of starch were substituted by approximately 2 pounds per barrel of cellulose polymer, the overall product cost would increase approximately two-fold. The increased cost of the drilling mud, however, would not be substantial, even if other polymers were required, since these additives are not expected to be major drilling mud constituents or among the most costly components of the mud.

In conclusion, Region 10 has adequately addressed and evaluated costs associated with product substitution and has made a reasonable determination that they are economically achievable.

15. *Comment:* NRDC commented that the discharge of chromium should be prohibited under BAT through the use of product substitution.

Response: While NRDC stated that substitutes for chrome lignosulfonates, such as iron lignosulfonate, are available, they did not provide any supporting data. Region 10 has no information at this time that would allow a finding that it is technologically feasible to limit chromium in drilling muds through product substitution.

16. *Comment:* NRDC objected to the mineral oil provision which permits operators to discharge drilling muds more toxic than Mud No. 1 by demonstrating that no other less toxic

mineral oils are available. NRDC recommended deletion of the provision or incorporation of a clear definition of the term "available" as "the only type of mineral oil that can perform the specific function required, not the only type of mineral oil on the rig at the time it is needed."

Response: Region 10 originally incorporated this provision in the general permits for the Bering/Beaufort Seas in recognition that the Agency had limited information on the "characteristics, applications, and toxicities of all available mineral oil." (49 FR 23736, June 7, 1984). Region 10 has determined that there continues to be a lack of information on the effects of mineral oil products on drilling mud toxicity. Available data on several products indicate, however, that their use in most discharged muds would not cause the toxicity to exceed that of Mud No. 1. Interim authorizations, requiring bioassay testing of the used drilling mud, are generally granted for the discharge of these products. However, few of the products have actually been used and discharged.

Region 10 has therefore determined that the provision should remain in the permit. The Region generally agrees with the intent of NRDC's comment. The word "available" will be interpreted by the Region in a reasonable manner on a case-by-case basis, with a consideration of both product performance and availability. As a number of mineral oils have been requested for discharge in Region 10, the Region believes that there are several alternative mineral oils generally available for use offshore of Alaska. These products will be evaluated for availability should the use of any one mineral oil cause a drilling mud to be more toxic than the most toxic generic mud.

17. *Comment:* All industry commenters recommended that the permit allow participation in a "mud additive approval clearinghouse" that is presently being developed for use by other EPA regions. The clearinghouse would determine, in advance, which drilling mud additives could be discharged. AOGA and Texaco recommended that Region 10 adopt additives lists from other Regions, in particular Region 9, "while awaiting formal development of the list of additives through the clearinghouse program." Conoco recommended that all additives currently authorized by Region 10 for operations under other general permits be included in Table 2 of the permit and that new additives be included in Table 2 as they are authorized.

NRDC supported a requirement for advance evaluation and authorization for the discharge of all muds and additives not listed in the permit tables.

Response: Region 10 supports the idea of a National Clearinghouse. However, this concept is still under development and will not be implemented in the timeframe for this permit. If the Clearinghouse is implemented, Region 10 would expect to use the data base to support the regional evaluations.

In the interim, operators may request prior authorization from Region 10 if they wish to discharge muds other than generic muds in Table 1 with additives in Table 2. The regional process provides operators with the same advance assurance of compliance that they request the clearinghouse program provide, but on a regional basis. Operators wishing to discharge additives not listed in Table 2 must either receive prior authorization or demonstrate that they meet criteria in Part II.B.1.d.(2) of the permit.

Region 10 has responded to the comment by listing a number of new additives used in Alaska in Table 2. Permittees may discharge the specific additives listed in Table 2 of the permit (at concentrations not exceeding the maximum allowable amounts) without special permission. The Region, however, cannot include all additives currently authorized under Region 10 permits because some of them were only approved on a case-by-case basis for specific conditions, and the Region does not have sufficient information to approve them for general use. The permit contains a provision (see Table 2) which will allow the discharge of additives which are listed in Table 2 of subsequent Region 10 general permits, unless otherwise stated in the new permits. For operations under this permit, any additive receiving authorization in this manner will be evaluated according to the regional criteria used for this permit.

Other Regions' lists are not directly transferrable to Region 10. For example, Region 9's list has been in existence for some time, and it includes additives tested by a variety of test methods and test species. Many of these test results are not acceptable under Region 10's BAT permit, which generally requires that toxicity tests be conducted in accordance with the Standard Drilling Fluids Toxicity Test.

18. *Comment:* Conoco challenged the use of results from the Standard Drilling Fluids Toxicity Test (i.e., bioassays) which, in their opinion, "are merely an indicator with no actual substantiation of their reliability for effectively predicting environmental impacts in

real-life situations, particularly at the outer edge of the mixing zone." AOGA also stated (Attachment 1) that a limitation of 250 ppm should be imposed because stricter toxicity limitations were more stringent than necessary to protect marine resources under section 403(c) Ocean Discharge Criteria.

Response: The toxicity limitations are BAT effluent limitations, designed to control the nature and concentration of toxic substances, including designated toxic pollutants, in discharged drilling muds. A standard, 96-hour acute toxicity test is an accepted, standard measure of relative toxicity and an appropriate BAT effluent limitation for the control of toxic substances in the discharge. As a technology-based limitation, Region 10 could not establish an LC₅₀ limitation based on the level of toxicity which is minimally necessary to protect against unreasonable degradation of the marine environment.

19. *Comment:* NRDC stated that, according to data from California, an LC₅₀ of 30,000 ppm for the suspended particulate phase (i.e., 3,000 whole mud equivalent, according to Region 10's terminology) allows operators adequate flexibility to use and discharge necessary additives in the majority of cases. NRDC expressed concern, however, that bottom dwelling organisms will be exposed to drilling discharges for long periods of time and that the regional toxicity criterion is not based on solid phase testing, which is most directly applicable to these organisms. NRDC noted the lack of adequate solid phase toxicity data. They therefore suggested that Region 10 decrease the drilling mud toxicity level (i.e., raise the LC₅₀) that is allowed under these permits.

Response: Region 10 agrees that solid phase toxicity data would aid in assessment of the environmental impacts associated with these discharges and supports the development of a standardized solid phase bioassay protocol. The suspended particulate phase test used in this permit is, however, the best test currently available for the purpose of testing and comparing drilling mud toxicities in a standardized fashion. This test is used to limit drilling mud toxicity under BAT. Product substitution of less toxic additives for more toxic ones is the basis for Region 10's BAT determination that drilling muds no more toxic than the most toxic generic mud should generally be discharged. Increasing the LC₅₀ level (decreasing the allowable toxicity) would potentially eliminate one of the generic muds, generic mud No. 1, from discharge. Region 10 does not have data which indicate that this mud type can be

substituted by one of the other, less toxic generic muds. Nor has Region 10 determined, based on available data, that more restrictive effluent limitations are required under section 403(c).

20. *Comment:* Conoco requested deletion of one of the toxicity screening criteria which give operators flexibility to discharge additives prior to authorization if the additive does not cause a substantial increase in drilling mud toxicity. See Part II.A.1.d.(2)(b) of the permit. This formula defines the level of increase in drilling mud toxicity which is allowed due to the discharge of additives prior to their authorization. Conoco stated that the provision is "impracticable and without technical bases."

Response: The purpose of this provision is to provide flexibility for operators to discharge relatively nontoxic additives without special EPA authorization to discharge. If the drilling mud containing the additive(s) passes the criteria in Part II.B.1.d.(2) of the permit, the discharge will have complied with the permit conditions. An operator need not use these provisions if authorization to discharge additives is requested beforehand. Although this approach in essence establishes a toxicity limitation for the discharge of unauthorized additives, similar to AOGA's proposal for unauthorized muds and/or additives, the Region's criteria are far stricter. The Region determined that only minor increases in drilling mud toxicity resulting from unauthorized additives should be allowed prior to EPA's granting authorization. For additives which cause a substantial increase in toxicity, the Region has adopted a regional evaluation/authorization process. When conducting evaluations/authorizations prior to discharge, the Region has an opportunity to assess the adequacy of the toxicity test results (which are often incomplete and on occasion invalid), the necessity for additional information, the chemical nature of the product, and available information on long-term persistence of the constituents.

The basis for this screening criterion is discussed in detail in the administrative record for this permit and in the record for the Bering/Beaufort Seas general permits. The assumption behind Region 10's approach is that toxicities of drilling mud additives will behave in an additive fashion rather than a synergistic one. The limitations of this approach are carefully noted. Conoco did not note specific impracticalities or deficiencies in the technical basis. Their objection to the provision, which is based on the

assumption that toxicity is additive rather than synergistic, is unclear to Region 10 since Conoco also commented elsewhere in their comment letter that they agree that "toxicities of the various components in mud systems should be assumed for bioassay purposes to be somewhat less than additive and certainly not synergistic."

21. *Comment:* Industry commenters requested (1) "emergency" discharge provisions and (2) less stringent or no toxicity limitations. These comments are stated in greater detail below.

AOGA, a "trade association whose member companies account for the bulk of oil and gas exploration, production and transportation activities in Alaska" requested that the permit require "certification of no discharge of any unapproved mud or additive except in emergency situations." AOGA further requested that the permit state, "Where an unapproved mud and/or additive is used, an LC₅₀ for the whole mud, in the range of 250 (plus or minus 100) ppm will be imposed, pending the approval of the mud and additive through the clearinghouse program. Failure to pass the LC₅₀ limit will prohibit the discharge of such muds" (emphasis added).

Although Texaco recommended imposition of the same drilling mud toxicity limitation as AOGA, Texaco, however, stated that "data gathered from the use of muds and additives not yet approved should be used to enhance EPA's data base and should not be used for enforcement action." Conoco commented that a permittee could not absolutely guarantee that a drilling mud would continually meet a toxicity limitation.

Conoco requested that specific approval for use of mineral oil lubricants or spotting fluids with Generic Mud No. 1 be included in the permit.

Response: Region 10 notes that there is clearly a lack of consensus among industry commenters regarding whether the permit should contain toxicity limitations on the discharged mud and whether compliance with such limitations should be enforced. After carefully considering all comments, the course chosen by Region 10 is to authorize additives prior to discharge in lieu of imposing a toxicity limitation on the used, discharged drilling mud (see previous comment). End-of-well bioassays are required to verify the effectiveness of this approach in controlling drilling mud toxicity. These data will be considered in developing future effluent limitations. Detailed responses to these comments follow.

A. *Use of Unauthorized Additives in "Emergency Situations."* Region 10

believes that advance planning and bioassay testing of additives is achievable by industry and essential for the control of drilling mud toxicity. Bioassay testing of drilling mud additives discharged from offshore operations has been commonplace for a number of years (Jones and Hulse 1982). Furthermore, operations in these remote locations require contingency planning to deal with "emergency" situations so that necessary additives are on hand. The Region firmly believes that all materials, including those which will be made available when drilling problems are encountered, should be evaluated with respect to their toxicity prior to discharge. Thus, for products with a similar application, those resulting in unacceptable toxicities can be substituted with less toxic products in order to meet toxicity limitations. Although AOGA correctly notes that an emergency use provision was included in earlier permits, such a provision was not included in the BAT/BCT permits for the Bering and Beaufort Seas (49 FR 23734, June 7, 1984).

B. Maximum Allowable Toxicity of Discharged Muds Under BAT.

AOGA and Texaco base the request for a limitation of 250 ppm (whole mud) on two types of drilling muds, a modified potassium chloride ("KCl") mud and generic mud No. 8 with 5 and 10 percent by volume Mentor 28 (a mineral oil). AOGA states that the toxicity of these muds (in the range of 150 to 350 ppm) "represents available technology for present drilling practices * * * practices which necessitate high concentrations of KCl, biocides and mineral oil lubricity agents (to 10%) in some drilling muds."

First, AOGA (Attachments 2 and 3) uses two bioassay tests to argue that Region 10 should acknowledge that up to 10 percent mineral oil in drilling muds will increase the toxicity (decrease the LC₅₀) to approximately 250 ppm (whole mud; 2500 ppm or 0.25% of the suspended particulate phase). These results are not consistent with EPA's data. The bioassay test results have inadequacies which limit their general applicability to determining the effect of mineral oil lubricants on drilling mud toxicity. Further discussion, provided in the administrative record, points out the limitations of current data for developing specific conclusions regarding the effect of mineral oil lubricants on drilling mud toxicity. For these reasons, Region 10 strongly disagrees that the two bioassay tests on generic mud No. 8 with 5 and 10 percent Mentor 28 (AOGA's Attachment 2) should be used as a basis for a toxicity limitation. Region 10 has therefore

chosen to limit the class of mineral oil additives as a separate, special case under the terms of the permit. While data on some mineral oil products indicate that their use will not cause the toxicity of Mud No. 1 to be exceeded, there are, in general, limited data on the toxic effects of mineral oils. The permit specifically allows these additives to cause a drilling mud to exceed the toxicity criterion if the least toxic available alternative is used through product substitution. Thus, mineral oil lubricants may be added to Generic Mud No. 1. This mineral oil provision grants operators flexibility through the regional additive authorization process to use mineral oils during the period in which further testing is being conducted.

Second, AOGA (Attachments 2 and 3) requests that the permits allow for the discharge of drilling muds such as Exxon's requested modified KCl mud with 80 lb/bbl KCl, a biocide, 10 percent mineral oil, and numerous other additives. Industry has not submitted adequate data on the technological requirement for this mud system. The numerous inadequacies and unanswered questions in the request to discharge this drilling mud are noted by Region 10 in the record. Region 10 also notes that sloughing shales and other drilling problems discussed in AOGA's Attachments 2 and 3 are not new to the industry. Nor is the drilling of offshore wells in Alaska. These wells to date have been drilled with generic muds and authorized additives. The modified KCl mud was originally requested for drilling a directional well from a stable platform in the Beaufort Sea. Wells in Norton Sound, drilled from jackup or other mobile rigs, are not expected to require directional drilling to the extent that operations in the Beaufort Sea do. Region 10 does not intend to impede advances in drilling technology; however, Region 10 notes that best available technology cannot simply be determined to include all "new" drilling formulations requested by industry. Adequate data and information must be provided.

The Region will continue to use the toxicity level of 3,000 ppm (whole mud equivalent; 30,000 ppm of the suspended particulate phase) as a criterion in addition to other factors (e.g., longterm persistence), as appropriate, in authorizing mud systems.

22. *Comment:* Industry representatives and AOGA made several detailed comments concerning the depth-related limitations on muds and cuttings discharge rates. A technical support document, the basis of these limitations, was criticized on two major points: (a)

The Offshore Operators committee (OOC) dilution model should have been used to model dilution in waters of all depths and (b) the standard 96-hour LC_{50} (acute lethal toxicity level) used to calculate the minimum acceptable dilution at the edge of the mixing zone should have been adjusted for exposure time (said to be less than 1 hour for these discharges).

Response: The "Technical Support Document for Regulating Dilution and Deposition of Drilling Muds on the Outer Continental Shelf" (Tetra Tech 1984) is the best analysis available to this agency of the relationship between water depth and dilution rates of discharged drilling muds. The OOC model was not found to reliably simulate the fate of discharges where the discharge plume encounters the bottom with substantial momentum. For this reason, an EPA model was used to simulate discharge dilutions in water depths less than 20 meters. A detailed response by Tetra Tech to this and other technical comments related to the dilution models used has been placed in the Administrative Record.

A 96-hour LC_{50} was used by Tetra Tech to establish maximum discharge rates acceptable in waters of various depths. EPA is required to determine that unreasonable degradation of the marine environment will not occur as a result of permitted discharges. This determination must consider sublethal effects as well as lethal toxicity. LC_{50} 's are defined as the concentration at which 50% of the test organisms will die within a given time of exposure. Standard tests to determine LC_{50} 's are usually done for 96 hours and the resulting 96-hour LC_{50} 's are typically used to evaluate the potential for a substance to cause lethal effects. Sublethal effects are expected to occur at lower concentrations than this.

EPA has determined that exceeding the 96-hour LC_{50} concentration at the edge of the mixing zone would cause unreasonable degradation. The determination of whether unacceptable adverse sublethal effects would result from exposures to concentrations up to the 96-hour LC_{50} level relies on judgment concerning the effects of varying lengths of exposure. Sublethal effects may occur due to short-term acute exposures; however, long-term chronic exposures are in general judged to be more severe. In the case of exploratory wells, discharge of muds and cuttings are sporadic, short-term events. Region 10 has determined that water column exposures will not result in unreasonable degradation of the environment if the 96-hour LC_{50}

concentration is met at the edge of the mixing zone during worst case conditions.

23. Comment: NRDC recommended stricter discharge rate limitations for muds and cuttings, including no discharge in areas less than 10 meters deep, 500 barrels per hour in areas greater than 10 meters deep, and 10:1 predilution for the remaining areas.

Response: The limitations in the permit are based on the best information available at this time and have been determined by Region 10 to be adequate to protect against unreasonable degradation of the marine environment. See the response to Comment 22.

24. Comment: Conoco Inc. stated that the seasonal restrictions in the permit are not "germane." NRDC recommended that no discharge be allowed to shallow waters during unstable or broken ice conditions.

Response: Seasonal restrictions are necessary due to the effects of seasonal ice, generally present in Norton Sound from October into the following June. Current velocities, and therefore, dilution rates during ice conditions, are lower than during the open water season but poorly documented. EPA cannot adequately predict the fate or effects of muds and cuttings discharged to the water during unstable or broken ice conditions (see notice for draft permit, 50 FR 6385). Because the projected number and volume of such discharges is small, EPA believes that no irreparable harm would occur during initial exploratory operations. A monitoring program will allow EPA to evaluate the fate of muds and cuttings discharged under these conditions. Based on the results of this monitoring program, discharge limitations may be modified for future operations under similar conditions.

25. Comment: Environmental monitoring should be required only for areas of "biological concern."

Response: The permit does not require environmental monitoring for all drilling operations covered by the permit. Only operators who propose to drill and discharge to waters less than 20 meters deep under broken or unstable ice conditions will be potentially subject to this requirement. These are conditions under which EPA currently has insufficient information to be able to make a determination of "no unreasonable degradation" (see 40 CFR 125.123(c) and the discussion in "Supplementary Information"). The monitoring program shall be conducted at one facility initially, with monitoring of subsequent operations (if there are more meeting these conditions) required

only in cases where special environmental concerns exist.

26. Comment: The inventory of chemicals added to cooling water and desalination systems is unnecessary data gathering.

Response: While Region 10 currently believes discharges from cooling water and desalination systems from exploratory operations to have little effect on the environment, it is important that EPA know the composition of what is being discharged to verify that determination for each permittee. Only substances other than water or seawater in these discharges need be reported.

27. Comment: NRDC recommends that the Static Sheen Test be required for discharges of deck drainage and bilge water at all times, rather than just during broken, unstable or stable ice conditions.

Response: Bilge water and contaminated deck drainage are minor discharges, which under this permit, must be passed through an oil-water separator prior to discharge. Region 10 is not aware of any violations of the visual or static sheen tests from these sources in the past, and therefore, believes that during open water conditions the visual sheen test provides satisfactory protection to the environment. During broken, unstable or stable ice conditions the Static Sheen Test is still required as potential sheens would not be visible on the "receiving water."

28. Comment: The hydrocarbon analyses required in Part II.B.1.1. of the draft permit are unnecessarily broad and should be deleted.

Response: Region 10 agrees that the hydrocarbon analyses according to Science Applications, Inc. (1984) are unnecessarily extensive for operations under this permit and has deleted this requirement from the final permit.

29. Comment: NRDC recommends that formation waters should not be a permitted discharge (especially in areas less than 10 meters deep).

Response: The discharge of formation waters is not permitted under this permit except for those limited volumes which may be present as a part of test fluid discharges. These fluids must be passed through an oil-water separator prior to discharge. The effluent is covered by oil content and pH limitations under this permit. For the exploratory drilling operations expected in Norton Sound, discharges of test fluids including formation water are likely to be small.

30. Comment: One commenter suggested that Part V.A. of the permit,

requiring screening for toxic pollutants if the discharge is altered, be deleted. This commenter explained that the provision is not needed because the permittee must certify that the facility will only use approved muds and additives, which do not contain toxic components.

Response: This section of the permit is required under 10 CFR 122.42(a) and applies to all existing manufacturing, commercial, mining, and silvicultural dischargers. EPA believes that this provision is a necessary part of the general permit. The intent of this provision is to ensure that a permittee notifies EPA if any toxic pollutant which is not specifically limited in the permit is or will be discharged at levels which exceed the threshold levels in Part V.A. If Region 10 is specifically notified of listed toxic pollutants contained in a drilling mud additive and if the Region lists such toxic pollutants in the authorization to discharge that additive, then the discharge of such toxic pollutants will be considered to be specifically limited by the permit through the additive authorization.

This provision is appropriate in the current permit because during the five-year term of the permit discharge situations might change. If the permittee knows, or has reason to believe, that such changes in discharge conditions will mean that discharges of toxic components in amounts greater than the notification threshold levels will result, then the permittee must notify EPA of that discharge. EPA will use such notification in deciding whether a new permit or a revision to the current permit is required.

31. Comment: U.S. Fish and Wildlife Service (U.S.F.W.S.) supports the need for environmental monitoring (Part II.B.3) and recommends that biochemical oxygen demand (BOD) be included in data to be collected.

Response: When the details of a monitoring program are developed, BOD and dissolved oxygen will be considered as parameters to be measured. U.S.F.W.S. will be consulted at that time.

32. Comment: The physical parameters to be measured in the proposed environmental monitoring program have already been measured in the Norton Sound Cost Well No. 2 Mud Dispersion Study.

Response: While the study mentioned was conducted in Norton Sound waters less than 20 meters deep, it was not done under the conditions of interest for the required monitoring in this permit. Not only was there no broken or unstable ice during the test, but the surface current velocity was approximately 77 cm/sec.

33. Comment: Monitoring required under section 308 of the Act should be discontinued after one year.

Response: The permit provides for EPA to review the need for monitoring periodically to determine if any requirements are not longer necessary. We cannot, however, determine the adequacy of the data before they are collected and evaluated.

34. Comment: Conoco Inc. commented that the comment period of 30 calendar days was too short for such a complex permit.

Response: This permit is the same in most respects to the Bering/Beaufort Seas general permits, which were the first two general permits to incorporate BAT/BCT effluent limitations for the offshore oil and gas industry. Those permits have been challenged by industry, and Conoco is a party to the suit (*API et al. v. EPA* in the U.S. Fifth Circuit Court of Appeals). Conoco is therefore familiar with the majority of the issues raised in the Norton Sound permit. Exxon requested issuance of the permit in time for an exploratory well planned for the end of May. Region 10 therefore decided not to extend the comment period.

35. Comment: The pH limitation on test fluids is unnecessary.

Response: The great majority of exploratory well test fluids are expected to be within the pH range of 6.5 to 8.5. However, about 50 barrels per test may have a pH of 2 and 100 barrels may have a pH of 2 to 5 (Holliday 1984). Although seawater is fairly well buffered, discharges of these low pH fluids would have immediate, potentially lethal effects in the vicinity of the discharge before dilution and buffering would be able to neutralize the acid.

Since pH is a conventional pollutant, it is controlled under section 402 of the Act. The permit limitation is equal to a BPT level of treatment and is routinely achieved under previous BPT and BAT/BCT general permits for exploratory operations.

36. Comment: The permit should contain a volume to mass conversion for drilling mud and drill cutting discharges.

Response: A conversion factor from volume to mass (dry weight basis) would depend on the water content and density of the solids included. These characteristics vary considerably. Conversion factors therefore, would need to be calculated on a case-by-case basis.

37. Comment: The administrative record for the Bering/Beaufort general permits should be added in its entirety to the administrative record for this permit.

Response: Those documents which are relevant and were a significant part of our deliberations in developing this permit have been added to the administrative record for the Norton Sound general NPDES permit.

38. Comment: The definition of diesel oil should be changed to "ASTM Standard D975 Grade 2-D."

Response: For purposes of this permit, "diesel oil" refers to the fuel oil present on the drilling rig during drilling at the permitted location.

39. Comment: Commenters stated that the reduction in oleates in mixed alcohols from 6 to 2 pounds per barrel in Table 2 was unjustified.

Response: In response to comments Region 10 reevaluated all available data on drilling mud additives authorized for discharge under the Region's offshore exploratory drilling permits. Numerous new additives are listed in Table 2 of the permit. The maximum concentration of oleates in mixed alcohols was however reduced. The bioassay report on this additive, tested at a maximum concentration of 3 pounds per barrel, shows an LC₅₀ level close to that of the most toxic generic mud. Furthermore, the test was not conducted according to the Standard Drilling Fluids Toxicity Test. Pending additional bioassay testing, Region 10 determined that general authorization should only be given at the lower concentration previously authorized in Table 2 (2 pounds per barrel). This amount is generally adequate for one of its common uses, as a carrier for powdered, poorly soluble polymers (e.g., Drispac) added to drilling muds.

40. Comment: NRDC recommended that the oil content of cuttings discharged be limited to 5% by weight.

Response: EPA, Region 10, does not have sufficient information at this time on cuttings washer performance and economics to justify reducing the allowable level of oil in cuttings based on this technology. The use of cutting washers will routinely be necessary only for operations which use oil-based drilling muds. Very few, if any operations in Norton Sound are likely to use oil-based drilling muds, based on past exploratory drilling practices in Region 10.

Region 10 evaluated whether a stricter effluent limitation should be imposed under section 403(c). The potential environmental effects of the discharge of oil contaminated cuttings had not in fact been adequately assessed previously by in the ODCE for Norton Sound. The Region has evaluated this issue since proposal of the draft permit and has determined that there is insufficient

information to make a finding that there will be no unreasonable degradation from the discharge of oil-contaminated drill cuttings in Norton Sound. Limited numbers, if any, of exploratory operations are expected to use oil-based muds and discharge the cuttings, however. Information available to Region 10 does not support a finding that there are reasonable alternatives to discharge. Further, the Region has determined that the discharge of such cuttings is not likely to cause irreparable harm during the period in which monitoring is undertaken. A monitoring requirement has therefore been imposed under 40 CFR 125.123(c).

Although this specific monitoring activity was not proposed in the draft permit, the scope of the monitoring does not differ significantly from that proposed for discharges under ice. Monitoring will be limited to a survey of the extent and persistence of such discharges, rather than the biological effects (which are more costly to measure).

41. *Additional Comments:* Region 10's responses to the following comments are the same as provided earlier in response to comments on the draft general permits for the Bering and Beaufort Seas. For this reason, only the comments are provided below and the reader is referred to 49 FR 23734, June 7, 1984, for the Region's responses.

Comment: Concern was expressed that Region 10 has adopted BAT/BCT permit limits in advance of the promulgation of national effluent limitations guidelines. Permit limits should be set at the BPT level with the provision to reopen the general permit following promulgation of national guidelines.

Comment: Conoco Inc. questioned the need for the limit of "a maximum of five wells at a single site."

Comment: NRDC strongly recommended that the monitoring program of Part II.B.3. be subject to public review before being finalized.

Comment: The general permit should cover the entire planning area. If there are areas of special concern within this area, they can be dealt with when an expected discharger submits a request to be covered under the general permit.

Comment: The general permit should cover all blocks offered for lease rather than all blocks leased. A mechanism is also needed to extend the permit to include future lease sale areas in this permit.

A list of references cited herein is available from Region 10 on request. All referenced documents, and other materials which provide the basis for

this permit decision, are contained in the administrative record.

General NPDES Permit, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, Washington 98101

[Permit No. AKG287000 (Norton Sound)]

Authorization To Discharge Under the National Pollutant Discharge Elimination System for Oil and Gas Exploration Facilities on the Outer Continental Shelf

In compliance with the provisions of the Federal Water Pollution Control Act, as amended, (33 U.S.C. 1251 et seq.: the "Act"), the following discharges are authorized:

- Drilling Mud—(Discharge 001).
- Drill Cuttings and Washwater—(Discharge 002).
- Deck Drainage—(Discharge 003).
- Sanitary Wastes—(Discharge 004).
- Domestic Wastes—(Discharge 005).
- Desalination Unit Wastes—(Discharge 006).
- Blowout Preventer Fluid—(Discharge 007).
- Boiler Blowdown—(Discharge 008).
- Fire Control System Test Water—(Discharge 009).
- Non-Contact Cooling Water—(Discharge 010).
- Uncontaminated Ballast Water—(Discharge 011).
- Uncontaminated Bilge Water—(Discharge 012).
- Excess Cement Slurry—(Discharge 013).
- Mud, Cuttings, Cement at Seafloor—(Discharge 014), and
- Test Fluids—(Discharge 015).

from oil and gas exploratory facilities in offshore areas (defined in 40 CFR Part 435, Subpart A), to receiving waters named the Norton Sound, in accordance with effluent limitations, monitoring and reporting requirements, and other conditions set forth in Parts I, II, III, IV, and V hereof.

Permittees who do not request and receive coverage under this general permit as described in Part I are not authorized to discharge to the specified waters unless an individual permit has been issued to the permittee by EPA, Region 10.

The authorized discharge sites include all blocks offered for lease from the U.S. Department of the Interior's Minerals Management Service (MMS) in Federal Lease Sale 57 (Norton Sound).

This permit shall be modified or revoked at any time if, on the basis of any new data, the Director determines that this information would have justified the application of different permit conditions at the time of issuance. Permit modification or revocation shall be conducted in accordance with 40 CFR 122.62, 122.63, and 122.64. In addition to any other grounds specified herein, this permit shall be modified or revoked at any time if, on the basis of any new data, the Director determines that continued discharges may cause unreasonable degradation of the marine environment.

Under 40 CFR 122.44(c)(3), if an applicable standard or limitation is promulgated under sections 301(b)(2) (C) and (D), 304(b)(2), and 307(a)(2) and that effluent standard or limitation is more stringent than any effluent limitation in the permit or controls a pollutant not limited in the permit, the permit shall be

promptly modified or revoked and reissued to conform to that effluent standard or limitation.

This permit shall become effective on June 4, 1985.

This permit and the authorization to discharge shall expire at midnight on May 29, 1990.

Signed this May 22, 1985, day of May 1985.

Ernesta B. Barnes,

Regional Administrator, EPA Region 10.

Part I. Notification Requirements

A. Requests to be Covered by General Permit

Written request to be covered by this permit shall be provided to EPA at least 60 days prior to initiation of discharges. The 60-day notification requirement may be waived for those permittees who notify EPA during the public comment period on the draft permit. The request shall include the following information:

1. Name and address of the permittee.
2. General location (lease and block numbers) of operations and discharges.
3. Any discharge or operating conditions which will require monitoring (Part II.B.3.) or will require special consideration by EPA.
4. Certification that only authorized muds and additives will be discharged (Part II.B.1.c.).
5. Certification of lessee's responsibility. The permittee shall be the owner and/or operator of the facility. However, the lessee may become the permittee after certifying that the lessee assumes responsibility for compliance with the permit. If the lessee has multiple leases, the lessee may submit a single certification for all of its leases. Submission of this certification does not remove the responsibility of the owner or operator for compliance with the conditions of the permit.

B. Authorization to Discharge.

The permittee's discharges are not authorized until written notification is received from EPA that operations at the discharge site have been assigned a permit number under this general permit. A permit number cannot be assigned until the following information is received. This information shall be provided to EPA in the request for coverage, if possible, but in no case less than 30 days prior to commencement of discharges.

1. Location of discharge site, including lease block number and approximate coordinates.
2. Range of water depths in lease block.
3. Initial date and expected duration of operations.
4. Request for authorization to discharge muds or additives not listed in Tables 1 and 2 (Parts II.B.1.e. and f.).

C. Commencement of Discharges

The permittee shall notify EPA Region 10 during the 7 day period prior to initiation of discharges from a new or existing facility at an authorized discharge site. The notification shall include the exact coordinates and water depth at the discharge site, and may be oral or in writing. If notification is given orally,

written confirmation must follow within 7 days.

D. Sites Requiring Environmental Surveys

All operators that locate within the areas covered by this general permit shall submit to EPA copies of any exploration plans, biological surveys, and/or environmental reports required by the Regional Supervisor, Field Operations (RSFO) of the Minerals Management Service for the identification and/or protection of biological populations or habitats. If the final exploration plans and environmental reports are identical to review copies received by Region 10, permittees need not submit them under this permit provision. Permittees shall notify Region 10 in writing when no exploration plan or environmental report will be sent.

E. Termination of Discharges

The permittee shall notify EPA within 30 days following cessation of discharges at the discharge site.

F. Submissions of Requests to be Covered and Other Reports

Reports and notifications required herein shall be submitted to the following addresses:

All requests for coverage and additive authorization—

Director, Water Division, U.S. Environmental Protection Agency, Region 10, Attn: Water Permits and Compliance Branch, M/S 430, 1200 Sixth Avenue, Seattle, Washington 98101, (206) 442-8293

All monitoring reports and notifications of non-compliance—

Director, Water Division, U.S. Environmental Protection Agency, Region 10, Attn: Water Permits and Compliance Branch, M/S 513, 1200 Sixth Avenue, Seattle, Washington 98101, (206) 442-1213

G. Coverage Under Individual Permits.

1. The Director may require any permittee discharging under the authority of this permit to apply for and obtain an individual NPDES permit when any one of the following conditions exist:

- The discharge(s) is (are) a significant contributor of pollution.
- The permittee is not in compliance with the conditions of this general permit.
- A change has occurred in the availability of the demonstrated technology or practices for the control or abatement of pollutants applicable to the point source.
- Effluent limitation guidelines are promulgated for point sources covered by this permit.
- A Water Quality Management Plan containing requirements applicable to such point source is approved.
- The point sources covered by this permit no longer:

- Involve the same or substantially similar types of operations.
- Discharge the same types of wastes,
- Require the same effluent limitations or operating conditions, or
- Require the same or similar monitoring.
- In the opinion of the Director, the discharges are more appropriately controlled

under an individual permit than under a general NPDES permit.

2. The Director may require any permittee authorized by this permit to apply for an individual NPDES permit only if the permittee has been notified in writing that an individual permit application is required.

3. Any permittee authorized by this permit may request to be excluded from the coverage of this general permit by applying for an individual permit. The owner or operator shall submit an application together with the reasons supporting the request to the Director no later than 90 days after the effective date of the permit.

4. When an individual NPDES permit is issued to a permittee otherwise subject to this general permit, the applicability of the general permit to that owner or operator is automatically terminated on the effective date of the individual permit.

Part II. Effluent Limitations and Monitoring Requirements

A. Definitions

- "AAS" means atomic absorption spectrophotometry.
- "Authorized additive" means any drilling mud additive listed in Table 2 or authorized for discharge under Parts II.B.1.d., e. or f.
- "Ballast water" means seawater added or removed to maintain the proper ballast floater level and ship draft.
- "bbl/hr" means barrels (one barrel equals 42 gallons) per hour.
- "Bilge water" means water which collects in the lower internal parts of the drilling vessel hull.
- "Biocide" means any chemical agent used for controlling the growth of nuisance organisms; examples are fungicides, algicides, and bactericides.
- "Blowout preventer fluid" means fluid used to actuate hydraulic equipment on the blowout preventer.
- "Boiler blowdown" means the discharge of water and contained substances drained from boiler drums.
- "Bulk discharge" means the discharge of more than 100 barrels in a one hour period.
- "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility (see Part IV.G.).
- "Cd" means cadmium.
- "Cooling water" means once-through non-contact cooling water.
- "Cuttings"—see "Drill cuttings."
- "Deck drainage" means all waste resulting from platform washings, deck washings, spillings, rainwater, and runoff from curbs, gutters, and drains including drip pans and wash areas.
- "Desalination unit wastes" means wastewater associated with the process of creating freshwater from seawater.
- "Diesel oil" means the class of distillate fuel oil, typically used in conventional oil-based drilling fluids, which contains a number of toxic pollutants. For the purpose of any particular operation under this permit, "diesel oil" shall refer to the fuel oil present on the drilling rig.
- "Domestic wastes" means wastes from showers, sinks, galleys, and laundries.

18. "Drill cuttings" means particles generated by drilling into subsurface geological formations and carried to the surface with the drilling fluid.

19. "Excess cement slurry" means the excess cement and wastes from equipment washdown after a cementing operation.

20. "Exploratory" operations are limited to those operations involving drilling to determine the nature of potential hydrocarbon reserves and does not include drilling of wells once a hydrocarbon reserve has been defined.

21. "Fire control system test water" means the water released during the training of personnel in fire protection and the testing and maintenance of fire protection equipment.

22. "GC" means gas chromatography.

23. "Generic drilling muds" or "generic muds" means the eight primary mud types which have been evaluated and authorized by EPA. These mud types have been authorized for discharge with limitations on composition given in Table 1. A list of authorized specialty additives is given in Table 2. Any type of mud (excluding Mud No. 1) listed in Table 1 which contains one or more components or additives not listed in Table 2, shall also be considered a generic mud if the standard drilling fluids toxicity test for the drilling mud with the additive demonstrates that there has not been a substantial decrease in the LC₅₀ value of the listed generic mud. See Part II.B.1.

24. A "grab" sample is a single sample or measurement taken at a specific time or over as short a period of time as is feasible.

25. "Hg" means mercury.

26. "lb/bbl" means pounds per barrel.

27. "Maximum" as applied to effluent limitations and standards for produced water and drilling fluids means the maximum concentration allowed as measured in any single sample of the discharged waste stream.

28. "MGD" means million gallons per day.

29. "mg/kg" means milligrams per kilogram.

30. "Mineral oils" means a class of low volatility petroleum product, generally of lower aromatic hydrocarbon content and lower toxicity than diesel oil.

31. "mg/l" means milligrams per liter.

32. "Monitoring month" shall mean the period consisting of the calendar weeks which end in a given calendar month.

33. "Monthly average" for discharges means the average flow rate per hour or day during the period of each calendar month.

34. "Monthly maximum" for flow rate means the peak flow rate which occurs during the period of each calendar month.

35. "Monthly maximum" for oil and grease concentration means the maximum value obtained for samples taken during the period of each calendar month.

36. "Muds, cuttings, cement at sea floor" means the materials discharged at the surface of the ocean floor in the early phases of drilling operations, before the well casing is set, and during well abandonment and plugging.

37. "NAA" means neutron activation analysis.

38. "No discharge of free oil" means that waste streams that would cause a film or sheen upon or a discoloration of the surface of the receiving water or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines may not be discharged.

39. "No discharge of diesel oil" in drilling mud means a determination that diesel oil is not present based on a comparison of the gas chromatogram from an extract of the drilling mud and from diesel oil obtained from the drilling rig or platform. GC/MS may also be used.

40. "Production" operations are those operations involving active recovery of hydrocarbons from producing formations.

41. "Sanitary wastes" means human body waste discharged from toilets and urinals.

42. "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

43. "Spent drilling fluid system discharge" means the bulk discharge of an entire drilling fluid system prior to a complete changeover to another drilling fluid system, or at the completion of the drilling of a well.

44. "Stable ice" means ice that is stable enough to support discharged muds and cuttings.

45. "Standard Drilling Fluids Toxicity Test" means a bioassay conducted and reported in accordance with the following standard bioassay methodology: "Proposed Methodology: Drilling Fluids Toxicity Test for the Offshore Subcategory, Oil and Gas Extraction Industry" (Petrizzuolo, 1983) or other methods approved in advance by EPA Region 10.

46. "Static Sheen Test" means those procedures which are described in the draft "Proposed Methodology: Laboratory Sheen Tests for the Offshore Subcategory, Oil and Gas Extraction Industry," prepared by Technical Resources, Inc., April 10, 1983, and EPA Region 10's "Interim Guidance for the Static (Laboratory) Sheen Test," January 10, 1984.

47. "Test fluid" means the discharge which would occur should hydrocarbons be located during exploratory drilling and tested for formation pressure and content. This would consist of fluids sent downhole during testing along with water from the formation.

48. "Unstable or broken ice conditions" means greater than 25% ice coverage within a one (1) mile radius of the discharge site after spring breakup or after the start of slush ice formation in the fall.

49. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of

preventive maintenance, or careless or improper operation (see Part IV.H.).

50. "Water depth" means the depth of the water between the surface and the seafloor as measured at mean lower low water.

51. "XFA" means x-ray fluorescence analysis.

52. "96-HR LC50" means the concentration of a test material that is lethal to 50 percent of the test organisms in a bioassay after 96 hours of constant exposure.

B. Drilling Muds and Cuttings and Washwater Discharges Discharges 001 and 002).

1. *General Requirements.* Such discharge's shall be limited and monitored by the permittee in accordance with Parts II.B.2., II.B.3., II.F., III., and the following requirements. The requirements apply to each of the discharges except where otherwise noted.

Effluent characteristic	Discharge limitation	Monitoring requirements		
		Measurement frequency	Sample type/method	Reported value(s)
Drilling mud constituents	Generic muds and authorized additives only.	(1)	(1)	(1)
Max. flow rate * 5-20 m depth >20-40 m depth.	500 bbl/hr, 750 bbl/hr	Continuous during discharge.	Estimate	Monthly maximum (bbl/hr).
Total volume (bbl)	(2)	Daily	do	Monthly total.
Free oil	No free oil	Daily, and before bulk discharges.	Grab/Static Sheen Test.	Number of days sheen observed.
Oil content of cuttings	10 percent by weight	(3)	Grab (3)	Results of each analysis.
Diesel oil content	No discharge of diesel oil.	(3)	Grab/GC	Presence or absence.
Hg and Cd content of barite.	1 mg/kg Hg, 3 mg/kg Cd, dry wt.	Once per well	AAS	Concentrations (mg/kg dry wt).
Drilling mud metals		do	See Part II.B.1.i.	Concentrations (mg/kg dry wt).
Toxicity of mud		do	See Part II.B.1.j.	96-hr LC50.

* See Parts II.B.1.d., e., f., g., and i.

* Maximum flow rate of total muds and cuttings into waters of given depths and under open water conditions (See Part II.B.2 for additional seasonal limitations).

* Exploratory drilling is limited to no more than five wells at a single drilling site. If a step-out (kick-off) well is drilled from a previously drilled well hole, the step-out (kick-off) well is counted as a new well.

* Analysis is required: (a) Weekly during weeks when oil-based drilling fluids are used, and (b) immediately on any sample that has violated the Static Sheen Test.

* Analysis for oil and grease by Soxhlet extraction (40 CFR 136) or for oil by retort distillation (American Petroleum Institute, Recommended Practice 138, 1980).

* Analysis is required: (a) On a sample collected from the end-of-well drilling mud system used at the greatest well depth, and (b) whenever the Static Sheen Test is violated and a discharge has occurred.

a. *Prohibition on the discharge of all oil-based muds or diesel oil and associated cuttings.*—The discharge of oil-based drilling muds (containing oil as the continuous phase with water as the dispersed phase) is prohibited. The discharge of water-based drilling muds which have contained diesel oil or of cuttings associated with any muds which have contained diesel is also prohibited. Compliance with the limitation on diesel oil shall be demonstrated by analysis of drilling mud collected from the end-of-well mud system. In all cases, the determination of the presence or absence of diesel oil shall be based on a comparison of the GC spectra of the sample and of diesel oil in storage at the facility. The method of GC analysis shall be that described in "Analysis of Diesel Oil in Drilling Fluids and Drill Cuttings" (CENTEC, 1985) available from EPA, Region 10. Gas chromatography/mass spectrometry (GC/MS) may be used if an instance should arise where the operator and EPA determine that greater resolution of the drilling mud "fingerprint" is needed for a particular drilling mud sample.

The end-of-well analysis for diesel oil shall be done in conjunction with the analyses required in Part II.B.1.i. The results and raw data, including the spectra from the GC analysis shall be provided to the Director by written report (a) within 30 days of a positive result with the Static Sheen Test, or (b) for

the end-of-well analysis, with the monthly Discharge Monitoring Report.

b. *No discharge of free oil.*—There shall be no discharge of free oil as a result of the discharge of drill cuttings and/or drilling muds. The permittee shall perform the Static (laboratory) Sheen Test on separate samples of drilling muds and cuttings on each day of discharge and prior to bulk discharges. The test shall be conducted in accordance with "Proposed Methodology: Laboratory Sheen Tests for the Offshore Subcategory, Oil and Gas Extraction Industry" (Petrizzuolo, 1983) and EPA Region 10's "Interim Guidance for the Static (Laboratory) Sheen Test." The discharge of drilling muds or cuttings which fail the Static Sheen Test is prohibited.

Whenever muds or cuttings fail the Static Sheen Test and a discharge has occurred, the permittee is required to immediately collect an undiluted sample of the material which failed the test. The permittee shall analyze this sample by gas chromatography (GC) to determine the presence or absence of diesel oil. The results and raw data, including the spectra, from the GC analysis shall be provided to the Director by written report within 30 days of a positive result with the Static Sheen Test.

c. *Certification of discharge of authorized muds and additives.*—The permittee is required to certify at the time coverage is requested under the general permit that only

generic muds and authorized additives (Part II.B.1.d.) or muds and additives authorized in accordance with Parts II.B.1.e. and f. will be discharged.

d. *Generic drilling muds and authorized additives.*—(1) Only generic drilling muds and authorized additives shall be discharged. The eight generic mud types which have been authorized for discharge are given in Table 1, with specified limitations on composition. A list of additional authorized mud components (specialty additives) are given in Table 2. This table may be revised during the term of this permit based on new information. Unless otherwise stated, the latest version of this table, published in the Federal Register as part of a Region 10 general NPDES permit for coastal or offshore oil and gas drilling, shall be the version applicable to discharges under this permit after the date of publication.

(2) Any type of mud listed in Table 1 which contains one or more components or additives NOT listed in Tables 1 and 2 shall also be considered a generic mud IF the permittee provides the results of the Standard Drilling Fluids Toxicity Test, or other procedures approved in advance by EPA Region 10, which demonstrate that it passes the screening criteria listed below.

(a) For Generic Mud No. 1 (Table 1) there shall be no decrease in the LC_{50} (increase in toxicity) under this provision.

(b) For Generic Muds Nos. 2 through 8 (Table 1) the addition of additives or other components shall not cause an increase in toxicity greater than seven (7) as calculated below. The increase in toxicity is defined as the difference between the inverses of the LC_{50} values multiplied by 10^6 , i.e. by the following formula:

$$\text{Increase in toxicity} = (1/LC_{50a} - 1/LC_{50b}) \cdot 10^6$$

Where LC_{50a} equals the LC_{50} (ppm volume to volume) of the listed generic mud (as determined either by EPA or the permittee) and LC_{50b} equals the measured LC_{50} of that mud with the added components or additives. These LC_{50} values refer to the undiluted mud; LC_{50} values obtained from the suspended particulate phase must be corrected for dilution.

This equation allows a 10% decrease in the LC_{50} of the second most toxic generic mud and a correspondingly greater percentage decrease for those muds which are less toxic. However, the same absolute increase in toxicity applies to all generic muds except Mud No. 1 (see (a) above).

(c) Biocides may only be discharged if prior authorization is obtained under Part II.B.1.e.

The discharge of generic muds does not require prior approval, but is subject to the following reporting requirements, if the generic mud is not listed in Table 1 or has not previously been approved. Prior to discharge or no later than 60 days after the discharge, the permittee shall submit a report containing the following information: A list and description of all drilling mud constituents (including chemical composition), concentration of each constituent (lbs/bbl and % by volume), the estimated total volume of discharge, and bioassay test results conducted in accordance with the standard drilling fluids toxicity test (or other procedures approved in advance by EPA, Region 10). Additional information may be required at the discretion of Region 10.

e. *Authorization to discharge drilling muds and additives not listed in Tables 1 and 2.*—The discharge of drilling muds containing any additive (or component) not allowed under Part II.B.1.d. shall require authorization by Region 10 prior to discharge.

The permittee shall submit the information outlined below with the request for coverage (Part I.B.). In the authorization process Region 10 will evaluate whether the use of the requested additives or components will unacceptably increase the toxicity of the drilling mud. The permittee shall supply the following information to Region 10:

(1) Approximate date and duration of proposed discharge.

(2) Bioassay testing and reporting of results in accordance with the Standard Drilling Fluids Toxicity Test or other procedures approved in advance by Region 10; additives may be tested with this methodology in a standard reference mud, a generic mud, or in the proposed drilling mud system. The bioassay report shall specify the concentration of each constituent in the tested drilling fluid.

(3) Chemical characterization of the additive; estimate of total amount required for any particular well, requested application rate (lb/bbl and % by volume) in the drilling mud, total volume of the drilling mud in which the additive will be dispersed. For the particular well under consideration, a description of drilling mud type and list of other additives, including concentrations (lb/bbl and % by volume) likely to be present in the drilling mud.

Additives may be authorized on an interim basis, at the discretion of EPA, Region 10, if preliminary bioassay data and other information are submitted and if the Water Division Director determines that additional information is required. The requested additional information may include bioassay data on a used drilling mud sample containing the requested additive. Interim authorization of some mineral oil spotting agents may include a requirement that a pill containing the mineral oil spot be removed prior to discharge of the mud system. This information shall be submitted by the date specified in the letter granting interim authorization.

f. *Authorization to discharge mineral oil lubricity or spotting agents.*—Mineral oil lubricity or spotting agents will be authorized as additives in discharged drilling muds (subject to other limitations; e.g., on free oil) in accordance with Part II.B.1.e., above, if (1) the Standard Drilling Fluids Toxicity Test demonstrates that the selected mineral oil would not cause the drilling mud to be more toxic than the most toxic generic mud, or (2) the permittee adequately demonstrates that the use of mineral oils which meet this limitation is not possible and that the requested mineral oil is the least toxic available.

g. *Mercury and cadmium content of barite.*—The permittee shall not discharge a drilling mud to which barite was added if such barite contained mercury in excess of 1 mg/kg or cadmium in excess of 3 mg/kg (dry weight basis). The permittee shall analyze a representative sample to stock barite once prior to drilling each well and submit the

results for total mercury and total cadmium in the Discharge Monitoring Report upon well completion. Analyses for total concentrations shall be conducted by AAS and results expressed as mg/kg (dry weight) of barite.

If the permittee is unable to comply with this provision due to the lack of availability of barite which meets the above limitations, the Water Division Director may on a case-by-case basis allow the discharge of barite which exceeds these limitations. Prior to discharge the permittee shall demonstrate to the satisfaction of the Water Division Director that barite which meets the limitations is unavailable and shall provide the results of analyses of the substitute barite.

h. *End-of-well chemical inventory.*—For each mud system discharged the permittee shall maintain a precise chemical inventory of all constituents added downhole, including all drilling mud additives used to meet specific drilling requirements. The inventory shall include the following for each mud type: (1) The total pounds or barrels, as appropriate, of each constituent added, (2) the total volume of mud in the whole system, (3) the volume of mud discharged, and (4) the maximum concentration of each constituent in the discharged mud. Furthermore, the mud system shall be identified as to its generic mud type from the list in Table 1 if that is the basis of its authorization. The inventory shall be submitted within 45 days following well completion.

i. *End-of-well chemical analysis.*—The permittee shall analyze one drilling mud sample from the end-of-well mud system after the mud is used at its greatest well depth, and prior to any predilution. The drilling mud sample shall be of sufficient size to allow for both chemical and bioassay testing as described here and in Part II.B.1.j. below.

The chemical analysis of the drilling mud shall include the following metals: barium, cadmium, chromium, mercury, zinc, and lead. The results shall be reported in "mg/kg of whole mud (dry weight)" and the moisture content (% by weight) of the original drilling mud sample shall be reported. The total concentration shall be reported for each metal and shall be obtained by the methods given in 40 CFR 136 with the exception of total barium. NAA or XFA shall be used for total barium. Flame of flameless AAS shall be used for mercury, cadmium, zinc and lead. Either NAA or AAS may be used for chromium.

The results of the chemical analyses shall be submitted with the end-of-well chemical inventory (Part II.B.1.h.) and shall identify the corresponding mud system from the end-of-well inventory. This requirement may be discontinued if EPA determines at some point that additional data collection is unnecessary.

j. *Bioassay test.*—The permittee shall complete one bioassay test per well. The sample shall be a representative subsample of that collected for chemical analysis in Part II.B.1.i. above. The testing and reporting of results shall be in accordance with the Standard Drilling Fluids Toxicity Test or other procedures approved in advance by

Region 10. The results of the bioassay testing shall be reported in association with the end-of-well chemical inventory (Part II.B.1.h) and analyses (Part II.B.1.i) for the end-of-well mud system and shall be submitted with the monthly Discharge Monitoring Report (DMR).

The bioassay requirement will be re-evaluated every two years. If EPA determines that sufficient information has been gathered, the requirement may be discontinued.

2. Seasonal and Depth-Related Requirements. a. During unstable or broken ice conditions, the following conditions apply:

(1) Drilling effluents shall be placed on-ice using routine methods or nonroutine methods of discharge whenever practicable.

(2) Discharge to the water column is prohibited, unless it is not practicable to: (i) Store drilling effluents onsite for subsequent discharge on stable ice or during open water, (ii) dispose of the drilling effluents on and, (iii) create an on-ice disposal site by pumping and artificial thickening of the sea ice, and/or (iv) handle the drilling effluent in another manner that prevents below-ice discharge.

(3) If it is not practicable to meet the conditions in (2) above, discharge may be allowed under the following conditions in addition to those in Part II.B.1.

(a) Permittee notifies EPA that discharge will occur. Notification, in writing, shall be received by the Director at least thirty (30) days prior to the discharge. The notification will include:

(i) A comprehensive evaluation of disposal alternatives for drilling muds and cuttings.

(ii) A demonstration that where discharges are to areas shallower than 10 m, these areas are not overwintering areas for significant fish or shellfish populations.

The Director may prohibit discharges if an acceptable alternatives analysis has not been completed, or if a clear demonstration can not be made that significant overwintering fish or shellfish populations are absent from the discharge area. Discharge is not authorized until the permittee receives notification from the Director.

(b) The discharge shall be released no deeper than 2 meters below the surface of the receiving water.

(c) Environmental monitoring is required as specified in part II.B.3.

b. During stable ice conditions the following conditions apply:

(1) Discharges shall be to above-ice locations and shall avoid areas of sea ice cracking or major stress fracturing.

(2) Flow rate restrictions do not apply.

3. Environmental Monitoring

Requirements. a. A monitoring program shall be conducted by the permittee to determine the transport, fate, and, possibly, the biological effects of drilling muds and cuttings discharged during broken or unstable ice conditions. The monitoring program will apply to waters less than 20 m deep and will be designed by EPA in consultation with the Alaska Department of Environmental Conservation (ADEC) and the permittee. The program shall be conducted at one facility initially, with monitoring of subsequent operations required in cases where special environmental concerns exist (e.g., discharges which will occur in a net

depositional area or an area with a vulnerable biological community).

Where a monitoring program is required, monitoring data shall be obtained at the following times:

(1) For baseline conditions, at least 30 days before drilling operations commence;

(2) During well drilling operations and discharges (either single or multiple well operations);

(3) For a period of one year after drilling discharges cease; and

(4) Up to twice per year thereafter until such time as no statistically significant differences in sediment concentrations between pre- and post-discharges are measurable, as determined by EPA, Region 10. This requirement shall continue for a maximum of 5 years.

The data shall include but not be limited to, the following:

(1) Wave heights and depth profiles of current speeds and directions;

(2) Temperature, salinity, and density profiles;

(3) Sediment water content (percent by weight), particle size distribution, and concentrations of heavy metals and hydrocarbons;

(4) Visual (including photographic) observations.

(b) A monitoring program shall be conducted to determine the fate, composition,

and persistence of oil-contaminated cuttings, if cuttings from oil-based drilling muds are discharged. This monitoring requirement may be waived on a case-by-case basis at the discretion of EPA, Region 10, if a significant portion of the well is not drilled with oil-based muds, thereby resulting in only a minor discharged volume of oil-contaminated cuttings. It may also be waived if sufficient information is gathered to determine that such discharges from subsequent wells will not cause unreasonable degradation of the marine environment.

The details of the program will be designed by EPA in consultation with ADEC and the permittee, based on the circumstances of the proposed discharge. The parameters, to be measured at the time of discharge and periodically thereafter, shall include but not be limited to the following:

(1) The distribution of the contaminated cuttings, including the area covered and the depths of the deposits;

(2) The BOD and oil content of the cuttings; and

(3) The toxicity of the cuttings.

C. Deck Drainage, Sanitary Wastes, and Domestic Wastes (Discharges 003-005).

These discharges shall be limited and monitored by the permittee in accordance with Parts II.F., III. and the following requirements.

Outfall/effluent characteristic	Discharge limitation	Monitoring Requirements		
		Measurement frequency	Sample type/method	Reported value(s)
All discharges (003-005) flow rate.		Monthly	Estimate	Monthly average.
Deck drainage (003) * free oil.	No visible sheen	Daily, during discharge	Visual/sheen on receiving water *	Number of days sheen observed.
Sanitary Wastes (004) * Solids	No floating solids	Daily	Observation *	Number of days solids observed.
Residual chlorine *	As close as possible to, but no less than, 1.0 mg/l.	Monthly	Grab *	Concentration (mg/l).

* Area drains for either washdown water or rainfall that may be contaminated with oil and grease shall be separated from those area drains that would not be contaminated. The contaminated deck drainage shall be processed through an oil-water separator prior to discharge.

* If discharge occurs during broken, unstable, or stable ice conditions, the sample type/method shall be "Grab/Static Sheen Test."

* Any facility using a marine sanitation device (MSD) that complies with pollution control standards and regulations under § 312 of the Act shall be deemed to be in compliance with the limitations for this outfall until such time as the device is replaced or is found not to comply with such standards and regulations. The MSD shall be tested yearly for proper operation and test results maintained at the facility. In cases where sanitary and domestic wastes are mixed prior to discharge, and sampling of the sanitary waste component stream is infeasible, the discharge may be sampled after mixing. In such cases, the discharge limitations for sanitary wastes shall apply to the mixed waste stream.

* Monitoring, by visual observation of the surface of the receiving water in the vicinity of the outfall(s), shall be done during daylight at a time of maximum estimated discharge.

* This limitation applies only to facilities continuously manned by ten or more persons.

* Residual chlorine may be monitored according to test procedures approved under 40 CFR 136 or using a Hach Test Kit capable of measuring free chlorine in the range 0-3.5 mg/l with a sensitivity of 0.1 mg/l or better.

D. Miscellaneous Discharges (Discharges 006-014).

1. General Requirements. The following limitations and monitoring requirements in

addition to those in Parts II.F. and III. apply to these discharges.

Outfall/effluent characteristic	Monitoring Requirements			
	Discharge limitation	Measurement frequency	Sample type/method	Reported value(s)
All discharges (006-014):				
Flow rate (MGD)		Monthly	Estimate	Monthly average.
Free oil	No free oil	Once/discharge or once/day as appropriate.	Visual/sheen on receiving water.	Number of days sheen observed.

a. Bilge water (012) shall be processed through an oil-water separator prior to discharge. If discharge of bilge water occurs during broken, unstable, or stable ice conditions, the sample type/method used to determine compliance with the no free oil limitation shall be "Grab/Static Sheen Test."

b. The permittee shall maintain an inventory of the quantities and rates of chemicals (other than water or seawater) added to cooling water (010) and desalination

(006) systems. The inventory shall be submitted with the monthly Discharge Monitoring Report.

E. Test Fluids (Discharge 015).

1. *General Requirements.* This discharge shall be limited and monitored by the permittee in accordance with Parts II.F., III. and the following requirements. Test fluids must be processed through an oil-water separator prior to discharge. Samples when required shall be collected from the effluent of the oil-water separator.

Outfall/effluent characteristic	Monitoring requirements			
	Discharge limitation	Measurement frequency	Sample type/method	Reported value(s)
Volume (bbl)		Once/discharge	Estimate	Total volume/test. ¹
Free oil	No free oil	Once/discharge	Visual/sheen on receiving water.	Number of times sheen observed.
Oil and grease (mg/l)	72 mg/l daily max., 48 mg/l monthly avg.	Once/discharge	Grab	Monthly maximum and average.
pH	6.5-8.5 ²	Once/discharge	Grab	pH.

¹ Volume will be reported as the number of barrels of fluids sent downhole during testing and the number of barrels discharged. The chemical composition of the fluids sent downhole will also be reported.

² Any spent acidic test fluids shall be neutralized before discharge such that the pH at the point of discharge shall not be less than 6.5 or greater than 8.5.

a. The discharge of oil-based test fluids is prohibited. All other test fluids shall be processed through an oil-water separator.

F. Other Discharge Limitations.

1. *Floating Solids, Visible Foam, or Oily Wastes.* There shall be no discharge of floating solids or visible foam in other than trace amounts, nor of oily wastes which produce a sheen on the surface of the receiving water.

2. *Applicable Marine Water Quality Criteria.* There shall be no discharge of any constituent in concentrations which exceed applicable marine water quality criteria after allowance for initial mixing. Initial mixing in federal waters is defined at 40 CFR 227.29 and federal marine water quality criteria at 45 FR 79318, 23 November 1980.

3. *Highly Toxic Compounds and Materials.* There shall be no discharge of diesel oil, halogenated phenol compounds, trisodium nitrilotriacetic acid, sodium chromate or sodium dichromate.

4. *Surfactants, Dispersants, and Detergents.* The discharge of surfactants, dispersants, and detergents shall be minimized except as necessary to comply with the safety requirements of the Occupational Health and Safety Administration and the Minerals Management Service.

Part III. Monitoring, Recording and Reporting Requirements

A. *Representative Sampling.* Samples taken in compliance with the monitoring requirements established under Part II shall be collected from the effluent stream prior to discharge into the receiving waters. Samples and measurements shall be representative of the volume and nature of the monitored discharge.

B. *Monitoring Procedures.* See 40 CFR 122.41(j)(4).

C. *Penalties for Tampering.* See 40 CFR 122.41(j)(5).

D. *Reporting of Monitoring Results.* The permittee shall be responsible for submitting monitoring results.

1. The effluent monitoring requirements in this permit shall take effect upon commencement of discharge. Monitoring results shall be summarized each month on a Discharge Monitoring Report (DMR) form (EPA No. 3320-1). The reports shall be submitted monthly and are to be postmarked by the 10th day of the following month. Legible copies of these, and all other reports, shall be signed and certified in the accordance with the requirements of Part V.H. *Signatory Requirements*, and submitted to EPA at the address specified in Part I.F.

2. The permittee shall include on each DMR a listing which days had (1) unstable or broken ice and (2) stable ice around the discharge site during the month covered by that DMR.

3. If any discharge has more than one discharge point, all permit limitations apply to each discharge point. The discharge points shall be designated as 001A, 001B, 001C, etc. Flow limitations apply to the total discharge of each category of wastes; i.e., to the sum of 001A, 001B, 001C, etc., except where otherwise noted.

4. If any category of waste (outfall) is not applicable due to the type of operation or facility, no reporting is required for that particular outfall. Only DMRs representative of the activities occurring need to be submitted. Information indicating the type of operation should be provided with DMRs.

E. *Compliance Schedules.* See 40 CFR 122.41(i)(5).

F. *Additional Monitoring by the Permittee.* See 40 CFR 122.41(i)(4)(ii). Increased monitoring frequency shall also be indicated.

G. *Records Contents.* See 40 CFR 122.41(j)(3).

H. *Retention of Records.* See 40 CFR 122.41(j)(2). Data collected onsite, copies of Discharge Monitoring Reports, and a copy of this NPDES permit must be maintained onsite during the duration of activity at the permitted location.

I. *Twenty-four Hour Notice of Noncompliance Reporting.*

1. The following occurrences of noncompliance shall be reported by telephone within 24 hours from the time the permittee becomes aware of the circumstances:

a. Any noncompliance which may endanger health or the environment;

b. Any unanticipated bypass which exceeds any effluent limitation in the permit (See Part IV.G. *Bypass of Treatment Facilities*);

c. Any upset which exceeds any effluent limitation in the permit (See Part IV.H. *Upset Conditions*);

d. Violation of a maximum daily discharge limitation for any of the pollutants listed in the permit as requiring violations to be reported within 24 hours.

2. A written submission shall also be provided within five days of the time that the permittee becomes aware of the circumstances. See 40 CFR 122.41(i)(6)(i).

3. The Director may waive the written report on a case-by-case basis if the oral report has been received within 24 hours by the Water Compliance Section in Seattle, Washington, by phone, (206) 442-1213.

4. Reports shall be submitted as specified in Part III.D. *Reporting of Monitoring Results*.

J. *Other Noncompliance Reporting.* Instances of noncompliance not required to be reported within 24 hours shall be reported at the time that monitoring reports for Part III.D. are submitted. The reports shall contain the information listed in Part III.1.2.

K. *Inspection and Entry.* See 40 CFR 122.41(i).

Part IV. Compliance Responsibilities

A. *Duty to Comply.* The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Water Act and is grounds for enforcement action, termination of coverage under the general permit, or for requiring a permittee to apply for and obtain an individual NPDES permit.

B. *Penalties for Violations of Permit Conditions.* See 40 CFR 122.41(a)(2), as revised by 50 FR 6940, February 19, 1985. Except as provided in permit conditions in Part IV.G. *Bypass of Treatment Facilities* and Part IV.H. *Upset Conditions*, nothing in this permit shall be construed to relieve the permittee of the civil or criminal penalties for noncompliance.

C. *Need to Halt or Reduce Activity not a Defense.* See 40 CFR 122.41(c).

D. *Duty to Mitigate.* See 40 CFR 122.41(d).

E. *Proper Operation and Maintenance.* See 40 CFR 122.41(3), as revised September 26, 1984, 49 FR 38049.

F. *Removed Substances.* Solids, sludges, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters shall be disposed of in a manner such as to prevent any pollutant from such materials from entering navigable waters.

G. *Bypass of Treatment Facilities.* See 40 CFR 122.41(m), as revised by 49 FR 38046, September 26, 1984.

H. *Upset Conditions.* See 40 CFR 122.41(n), as revised by 49 FR 38046, September 26, 1984.

I. Toxic Pollutants. The permittee shall comply with effluent standards or prohibitions established under section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish those standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

J. Samples of Wastes. If requested, the permittee shall provide EPA with a sample of any waste in a manner specified by the Agency.

Part V. General Requirements

A. Changes in Discharge of Toxic Substances. See 40 CFR 122.41(a)(1)(i), (ii), and (iv); 40 CFR 122.41(a)(2) (i), (ii), and (iv); as revised by 49 FR 38049, September 28, 1984.

B. Planned Changes. See 40 CFR 122.41(l)(1) (i) and (ii), as revised by 49 FR 38049, September 28, 1984.

C. Anticipated Noncompliance. See 40 CFR 122.41(l)(2).

D. Permit Actions. See 40 CFR 122.41(f).

E. Duty to Reapply. See 40 CFR 122.41(b). The application should be submitted at least 180 days before the expiration date of this permit.

F. Duty to Provide Information. See 40 CFR 122.41(h).

G. Other Information. See 40 CFR 122.41(l)(8), as revised by 40 FR 6940, February 19, 1985.

H. Signatory Requirements. See 40 CFR 122.22, as revised by 49 FR 38047, September 28, 1984.

I. Penalties for Falsification of Reports. See 40 CFR 122.41(k)(2).

J. Availability of Reports. Except for data determined to be confidential under 40 CFR Part 2, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of ADEC and EPA. As required by the Act, permit applications, permits and effluent data shall not be considered confidential.

K. Oil and Hazardous Substance Liability. Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any

responsibilities, liabilities, or penalties to which the permittee is or may be subject under section 311 of the Act.

L. Property Rights. The issuance of this permit does not convey any property rights of any sort, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations.

M. State Laws. Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation under authority preserved by section 510 of the Act.

N. Severability. The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

O. Transfers. See 40 CFR 122.61(b).

Table 1.—Authorized Drilling Mud Types

Components	Maximum allowable concentration (lb/bbl)
1. Seawater/freshwater/potassium/polymer mud:	
KCl	50
Starch	12
Cellulose polymer	5
Xanthan gum polymer	2
Drilled solids	100
Caustic	3
Barite	450
Seawater or freshwater	(¹)
2. Seawater/lignosulfonate mud:	
Attapulgite or bentonite	50
Lignosulfonate, chrome or ferrochrome	15
Lignite, untreated or chrome-treated	10
Caustic	5
Barite	450
Drilled solids	100
Soda ash/sodium bicarbonate	2
Cellulose polymer	5
Seawater	(¹)
3. Lime mud:	
Lime	20

Table 1.—Authorized Drilling Mud Types—Continued

Components	Maximum allowable concentration (lb/bbl)
Bentonite	50
Lignosulfonate, chrome or ferrochrome	15
Lignite, untreated or chrome-treated	10
Caustic	5
Barite	180
Drilled solids	100
Soda ash/sodium bicarbonate	2
Seawater or freshwater	(¹)
4. Nondispersed mud:	
Bentonite	15
Acrylic polymer	2
Barite	180
Drilled solids	70
Seawater or freshwater	(¹)
5. Spud Mud:	
Lime	1
Attapulgite or bentonite	50
Caustic	2
Barite	50
Soda ash/sodium bicarbonate	2
Seawater	(¹)
6. Seawater/freshwater gel mud:	
Lime	2
Attapulgite or bentonite	50
Caustic	3
Barite	50
Drilled solids	100
Soda ash/sodium bicarbonate	2
Cellulose polymer	2
Seawater or freshwater	(¹)
7. Lightly treated Lignosulfonate freshwater/seawater mud:	
Lime	2
Bentonite	50
Lignosulfonate, chrome or ferrochrome	6
Lignite, untreated or chrome-treated	4
Caustic	3
Barite	180
Drilled solids	100
Soda ash/sodium bicarbonate	2
Cellulose polymer	2
Seawater and freshwater in 1:1 ratio	(¹)
8. Lignosulfonate freshwater mud:	
Lime	2
Bentonite	50
Lignosulfonate, chrome or ferrochrome	15
Lignite, untreated or chrome-treated	10
Caustic	5
Barite	450
Drilled solids	100
Soda ash/sodium bicarbonate	2
Cellulose polymer	2
Freshwater	(¹)

¹As needed.

TABLE 2.—AUTHORIZED MUD COMPONENTS/SPECIALTY ADDITIVES

(Table 2 may be updated by EPA, Region 10, during the effective period of this permit. If so, the latest updated version will supersede all earlier versions. Updated versions will be published in the Federal Register as part of future EPA, Region 10, general NPDES permits for Coastal and Offshore Subcategory oil and gas activities. Updates will take effect at the time of Federal Register publication.)

Primary additive function	Generic description ¹	Maximum allowable concentration (lb/bbl unless otherwise noted)	Product name
Substitute for Attapulgite or Bentonite Clay	Sepiolite	See Table 1	Sea Mud, Durogel
Detection of Filtrate Re-Entry into Mud System	Ammonium nitrate	200 mg/l nitrate	
	Sodium nitrate	200 mg/l nitrate	
Detection of formation water intrusion	Sodium chloride	50,000 mg/l chloride	
Mud lag time Measurement	Calcium carbide	As needed	
Corrosion inhibitor (H ₂ S scavenger)	Basic zinc carbonate	do	Mil-Gard
	Zinc carbonate and lime	do	Sulf-Ex ES
	Zinc oxide	do	
Defoamer	Aluminum stearate	0.2	
	Aluminum stearate in propylated oleyl alcohol	10 gal/1500 bbls	LD-6
Dispersant	Dimethyl polysiloxane in an aqueous emulsion	0.1	Bars Brine Defoam
Emulsifier	Sodium polyphosphate	0.5 %	
Filtrate reducer	Sulfonated asphalt residuum	.6 %	Soltex
	Lignite/resin blend	.6 %	Durenex
	Polymer treated humate	.5 %	Chemtrol x
	Polymer treated humate	.4 %	Poly RX
	Reacted phenol-formaldehyde-urea resin containing no free phenol, urea, or formaldehyde	.4 %	Resinex
Flocculant	Vinyl acetate/maleic anhydride copolymer	0.1 %	Ben-ex
Last circulation material	Cellophane flakes	As needed	

TABLE 2.—AUTHORIZED MUD COMPONENTS/SPECIALTY ADDITIVES—Continued

[Table 2 may be updated by EPA, Region 10, during the effective period of this permit. If so, the latest updated version will supersede all earlier versions. Updated versions will be published in the Federal Register as part of future EPA, Region 10, general NPDES permits for Coastal and Offshore Subcategory oil and gas activities. Updates will take effect at the time of Federal Register publication.]

Primary additive function	Generic description ¹	Maximum allowable concentration (lb/bbl unless otherwise noted)	Product name
Lubricant	Crushed granular nut hulls	do	
	Flakes of silicate mineral mica	45	
	Vegetable plus polymer fibers, flakes, and granules	50	
	Fatty acid esters and alkyl phenolic sulfides in a solvent base	2	Bit Lube II.
	Liquid triglycerides in a vegetable oil	6	Torg-Trim II.
	Oleates in mixed alcohols	2	Lube 10B.
	Phosphoric acid esters and triethanolamine	0.4	
	Plastic spheres	8	
	Sulfonated asphalt residuum	6 ²	Softex
	Vegetable ester formulation	2.0% (vol.)	Lubri-Sal
Shale control inhibitor	Poly treated humate	4 ²	Poly RX
	Sulfonated asphalt residuum	6 ²	Softex
Spotting agent	Sulfonated vegetable ester formulation	1.0% (vol.)	Aqua-Spot
Surface active agent	Aqueous solution of nonionic modified phenol	3.0	DMS
	Blend of surfactants	0.5	D-D
	Ethoxylated alcohol formulation	0.04 gal/bbl	Milchem MD
	Fatty acid ester	0.25	MD (IMCO)
Thinner	Water solution of anionic surfactants	0.4	Con Det
	Chrome-free mud thinner containing sulfomethylated tannin	0.5	Desco CF.
	Polymer treated humate	4 ²	Poly RX
	Polymer treated humate	5 ²	Chemtrol x
	Sodium polyphosphate	0.5 ²	
Viscosifier	Organophilic clay	12	VG-69
	Vinyl acetate/maleic anhydride copolymer	0.1 ²	Ben-ex
	Xanthan gum polymer	2	Duovis, XC Polymer.

¹ Any proprietary formulation that contains a substance which is an intentional component of the formulation, other than those specifically described, must be authorized by the Director.

² Total amount allowed for all additive functions.

[FR Doc. 85-13001 Filed 6-3-85; 8:45 am]

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Federal Register

Tuesday
June 4, 1985

Part III

Department of Defense

General Services Administration

National Aeronautics and Space Administration

48 CFR Parts 1, 13, 14, 15, 16, 22, 25,
31, 33, 44, 52, and 53

Federal Acquisition Regulation; Final Rule

DEPARTMENT OF DEFENSE

GENERAL SERVICES
ADMINISTRATIONNATIONAL AERONAUTICS AND
SPACE ADMINISTRATION

48 CFR Parts 1, 13, 14, 15, 16, 22, 25,
31, 33, 44, 52, and 53

[Federal Acquisition Circ. 84-7]

Federal Acquisition Regulation

AGENCIES: Department of Defense (DOD), General Services Administration (GSA), and National Aeronautics and Space Administration (NASA).

ACTION: Final rule.

SUMMARY: Federal Acquisition Circular (FAC) 84-7 amends the Federal Acquisition Regulation (FAR) with respect to the following: OMB Approval Under the Paperwork Reduction Act; Late Proposals and Modifications; Notification to Offerors; Allowable Cost and Payment Clause; Standard Form 99, Notice of Award of Contract; Equal Opportunity Preaward Clearance of Subcontracts; Purchases Under the Trade Agreements Act of 1979; Cost Principle On Insurance and Indemnification; Protests to the General Services Board of Contract Appeals; and Standard Form 24, Bid Bond. The Master List of Contractors for Negotiated Advance Agreements for IR&D/B&P Costs is included as an information item.

EFFECTIVE DATE: April 30, 1985.

FOR FURTHER INFORMATION CONTACT: Roger M. Schwartz, Director, FAR Secretariat, Room 4041, GS Building, Washington, D.C. 20405. Telephone (202) 523-4755.

SUPPLEMENTARY INFORMATION:

A. Public Comments

The revisions to FAR Part 31 concerning the cost principle on insurance and indemnification are significant revisions as defined in FAR 1.501-1. Accordingly, public comments were requested in a notice at 49 FR 18321, April 30, 1984, and were considered in the formulation of the revisions. Public comments have not been solicited with respect to the other revisions in FAC 84-7 since such revisions either (a) do not alter the substantive meaning of any coverage in the FAR having a significant impact on contractors or offerors, or (b) do not have a significant effect beyond agency internal operating procedures.

B. Regulatory Flexibility Act

Pursuant to the provisions of section 3 of the Regulatory Flexibility Act (5 U.S.C. 605(b)), it has been determined that this final rule will not have a significant economic impact on a substantial number of small entities as defined in the Regulatory Flexibility Act, and, therefore, no regulatory flexibility analysis has been prepared.

List of Subjects in 48 CFR Ch. I

Government procurement.

Dated: May 30, 1985.

Roger M. Schwartz,
Director, FAR Secretariat.

Federal Acquisition Circular
[Number 84-7]

Unless otherwise specified, all Federal Acquisition Regulation (FAR) and other directive material contained in FAC 84-7 is effective April 30, 1985.

Dwight Ink,
Acting Administrator.

S.J. Evans,
Assistant Administrator for Procurement,
NASA.

Mary Ann Gilleece,
Deputy Under Secretary (Acquisition Management).

Federal Acquisition Circular (FAC) 84-7 amends the Federal Acquisition Regulation (FAR) as specified below. The following is a summary of the amendments:

Item I—OMB Approval Under the
Paperwork Reduction Act

The Paperwork Reduction Act of 1980 requires that information collection requirements be approved by the Office of Management and Budget (OMB) and that the OMB control numbers assigned to these requirements be displayed in the regulation.

FAR 1.105 is revised to display the current listing of OMB control numbers assigned to FAR requirements.

Item II—Late Proposals and
Modifications

FAR 15.412(c) is revised to delete the authority granted to NASA to accept late proposals and modifications to proposals. NASA has evaluated the history and use of this authority and concluded that its mission would not be significantly affected by the material's deletion.

Item III—Notification to Offerors

FAR 15.1001 (b) and (c) are revised to raise the threshold for prescribed preaward and postaward notices to unsuccessful offerors from \$10,000 to \$25,000. These changes had been made

in Federal Procurement Regulations Temporary Regulation 77 in connection with the revision of the small purchase limitation, but were not made in the FAR.

Item IV—Allowable Cost and Payment
Clause

FAR 16.307 is revised to add references to the applicable cost principles for contracts awarded to an educational institution, State or local government, or other nonprofit organization. FAR 31.105 is revised to add a reference to nonprofit organizations except those exempted under OMB Circular A-122. The preface to the clause at 52.216-7, Allowable Cost and Payment, is revised to remove duplicative language.

Item V—Standard Form 99, Notice of
Award of Contract

FAR 22.608-5(b) is changed to remove the requirement for a contracting officer to submit a Standard Form 99, Notice of Award of Contract, to the Department of Labor if a Standard Form 279, Individual Contract Action Report, is submitted to the Federal Procurement Data System.

Item VI—Equal Opportunity Preaward
Clearance of Subcontracts

FAR 22.810(g) is revised to correct the references to the clause prescriptions in FAR 44.204. The clauses at 52.244-1, 52.244-2, and 52.244-3 are retitled and the clause prescriptions at FAR 44.204 are changed to reflect the new clause titles.

Item VII—Purchases Under the Trade
Agreements Act of 1979

The FAR text and clause concerning the Trade Agreements Act of 1979 have been revised to eliminate citing the applicable dollar threshold. In the future, information concerning revisions made by the U.S. Trade Representative of the dollar threshold will be distributed through agency procedures on an expedited basis. Under this procedure it will no longer be necessary to issue a FAR revision solely to update the dollar threshold determinations of the U.S. Trade Representative.

Item VIII—Cost Principle on Insurance
and Indemnification

FAR 31.205-19(a)(3) is revised to make unallowable insurance costs in excess of the amount calculated by discounting at the Secretary of the Treasury rate of interest in those instances where an actual loss has occurred and the present value of the liability is determined under the provisions of CAS 416.50(a)(3)(ii).

Item IX—Protests to the General Services Board of Contract Appeals

FAC 84-8 added instructions concerning the filing of bid protests on certain ADP acquisitions with the General Services Board of Contract Appeals (GSBCA). FAR 33.105(a)(1), as published in FAC 84-8, requires service of a copy of the protest to the contracting agency within one day after the protest is filed with the GSBCA. The GSBCA has advised that rule 3(b)(2) of the GSBCA rules of procedure is intended to require the protester to serve a copy of the protest on the contracting agency on the same date the protest is filed with the GSBCA. Accordingly, FAR 33.105(a)(1), as published in FAC 84-8, is revised to conform the FAR with the GSBCA requirement.

Item X—Standard Form 24, Bid Bond

The first block of Standard Form 24, Bid Bond, is revised to instruct bidders that the bond must be executed not later than the bid opening date.

Item XI—Master List of Contractors for Negotiated Advance Agreements for IR&D/B&P Costs

The attached Master List of Contractors for Negotiated Advance Agreements for Independent Research and Development/Bid and Proposal Costs (Appendix A) is included as an information item to contracting officers.

Therefore, 48 CFR Chapter I is amended as set forth below.

1. The authority citation for 48 CFR Parts 1, 13, 14, 15, 16, 22, 25, 31, 33, 44, 52, and 53 continues to read as follows:

Authority: 40 U.S.C. 486(c); 10 U.S.C. Chapter 137; and 42 U.S.C. 2453(c).

PART 1—FEDERAL ACQUISITION REGULATIONS SYSTEM

2. Section 1.105 is amended by removing all FAR segments and corresponding OMB Control Numbers and inserting in their place the following numbers:

1.105 OMB Approval under the Paperwork Reduction Act.

FAR Segment	OMB Control No.
3.103	9000-0018
3.4	9000-0003
4.102	9000-0033
4.7	9000-0034
5.405	9000-0036
8.203-2	9000-0017
9.1	9000-0011
9.2	9000-0020
9.5	9000-0019
14.202-4	9000-0040
14.202-5	9000-0039

FAR Segment	OMB Control No.	FAR Segment	OMB Control No.
14.205	9000-0002	52.225-8	9000-0025
14.205-4(c)	9000-0037	52.225-10	9000-0022
14.406	9000-0038	52.228-1	9000-0045
14.5	9000-0041	52.228-2	9000-0045
15.106	9000-0034	52.228-3	9000-0045
15.404	9000-0037	52.229-2	9000-0059
15.7	9000-0078	52.232-5	9000-0070
15.8	9000-0013	52.232-7	9000-0070
19.7	9000-0006	52.232-10	9000-0070
22.103	9000-0065	52.232-12	9000-0073
22.8	1215-0072	52.232-13	9000-0010
22.11	9000-0066	52.232-14	9000-0010
22.13	1215-0072	52.232-15	9000-0010
22.14	1215-0072	52.232-16	9000-0010
28.1	9000-0045	52.232-20	9000-0074
28.2	9000-0045	52.232-21	9000-0074
29.304	9000-0059	52.232-22	9000-0074
31	9000-0072	52.233-1	9000-0035
32.5	9000-0010	52.235-5	9000-0062
32.7	9000-0074	52.236-13	1220-0029
33	9000-0035		and
36.302	9000-0037		9000-0060
36.603	9000-0004	52.236-15	9000-0058
	and	52.236-19	9000-0064
	9000-0005	52.242-12	9000-0056
42.7	9000-0013	52.243-1	9000-0026
42.12	9000-0076	52.243-2	9000-0026
42.13	9000-0076	52.243-3	9000-0026
42.14	9000-0056	52.243-4	9000-0026
42.203	9000-0026	52.243-6	9000-0026
45	9000-0075	52.243-7	9000-0026
46	9000-0077	52.245-2	9000-0075
47	9000-0061	52.245-3	9000-0075
48	9000-0027	52.245-5	9000-0075
49	9000-0028	52.245-7	9000-0075
50	9000-0029	52.245-8	9000-0075
51.1	9000-0031	52.245-9	9000-0075
51.2	9000-0032	52.245-10	9000-0075
52.203-2	9000-0018	52.245-11	9000-0075
52.203-4	9000-0003	52.245-16	9000-0075
52.208-1	9000-0017	52.245-17	9000-0075
52.208-2	9000-0017	52.245-18	9000-0075
52.209-1	9000-0020	52.246-2	9000-0077
52.210-5	9000-0030	52.246-3	9000-0077
52.210-6	9000-0030	52.246-4	9000-0077
52.212-1	9000-0043	52.246-5	9000-0077
52.212-2	9000-0043	52.246-6	9000-0077
52.214-2	9000-0046	52.246-7	9000-0077
52.214-5	9000-0042	52.246-8	9000-0077
52.214-8	9000-0018	52.246-10	9000-0077
52.214-14	9000-0047	52.246-12	9000-0077
52.214-15	9000-0044	52.246-15	9000-0077
52.214-16	9000-0044	52.247-2	9000-0053
52.214-17	9000-0018	52.247-29	9000-0061
52.214-21	9000-0039	52.247-30	9000-0061
52.214-26	9000-0034	52.247-31	9000-0061
52.214-28	9000-0013	52.247-32	9000-0061
52.215-1	9000-0034	52.247-33	9000-0061
52.215-2	9000-0034	52.247-34	9000-0061
52.215-6	9000-0046	52.247-35	9000-0061
52.215-11	9000-0048	52.247-36	9000-0061
52.215-19	9000-0044	52.247-37	9000-0061
52.215-20	9000-0047	52.247-38	9000-0061
52.215-21	9000-0078	52.247-39	9000-0061
52.215-24	9000-0013	52.247-40	9000-0061
52.215-25	9000-0013	52.247-41	9000-0061
52.216-2	9000-0068	52.247-42	9000-0061
52.216-3	9000-0068	52.247-43	9000-0061
52.216-4	9000-0068	52.247-51	9000-0061
52.216-5	9000-0071	52.247-53	9000-0057
52.216-6	9000-0071	52.247-13	9000-0055
52.216-7	9000-0069	52.247-57	9000-0061
52.216-10	9000-0067	52.247-63	9000-0054
52.216-13	9000-0068	52.247-64	9000-0054
52.216-15	9000-0069	52.248-1	9000-0027
52.216-16	9000-0067	52.248-2	9000-0027
52.216-17	9000-0067	52.248-3	9000-0027
52.219-9	9000-0006	52.249-2	9000-0028
52.219-10	9000-0006	52.249-3	9000-0028
52.222-2	9000-0065	52.249-5	9000-0028
52.222-4	1215-0119	52.249-6	9000-0028
52.222-21	1215-0072	52.249-11	9000-0028
52.222-22	1215-0072	52.250-1	9000-0029
52.222-23	1215-0072	SSF 24	9000-0045
52.222-25	1215-0072	SSF 25	9000-0045
52.222-26	1215-0072	SSF 25-A	9000-0045
52.222-27	1215-0072	SSF 25-B	9000-0045
52.222-35	1215-0072	SSF 28	9000-0001
52.222-36	1215-0072	SSF 34	9000-0045
52.222-46	9000-0066	SSF 35	9000-0045
52.223-1	9000-0021	SSF 119	9000-0003
52.225-1	9000-0024	SSF 129	9000-0002
52.225-6	9000-0023	SSF 254	9000-0004

FAR Segment	OMB Control No.
SSF 255	9000-0005
SSF 273	9000-0045
SSF 274	9000-0045
SSF 275	9000-0045
SSF 294	9000-0008
SSF 295	9000-0007
SSF 1403	9000-0011
SSF 1404	9000-0011
SSF 1405	9000-0011
SSF 1406	9000-0011
SSF 1407	9000-0011
SSF 1408	9000-0011
SSF 1411	9000-0013
SSF 1412	9000-0013
SSF 1413	9000-0014
SSF 1416	9000-0045
SSF 1417	9000-0037
SSF 1423	9000-0015
SSF 1424	9000-0015
SSF 1426	9000-0015
SSF 1427	9000-0015
SSF 1428	9000-0015
SSF 1429	9000-0015
SSF 1430	9000-0015
SSF 1431	9000-0015
SSF 1432	9000-0015
SSF 1433	9000-0015
SSF 1434	9000-0015
SSF 1435	9000-0012
SSF 1436	9000-0012
SSF 1437	9000-0012
SSF 1438	9000-0012
SSF 1439	9000-0012
SSF 1440	9000-0012
SSF 1443	9000-0010
All other requirements	9000-0063

PART 13—SMALL PURCHASE AND OTHER SIMPLIFIED PURCHASE PROCEDURES

13.501 [Amended]

3. Section 13.501 is amended by removing in the first sentence of paragraph (g) the reference "4.201" and inserting in its place the reference "4.101".

PART 14—SEALED BIDDING

4. Section 14.407-8 is revised to read as follows:

14.407-8 Protests against award.

See Subpart 33.1, Protests.

PART 15—CONTRACTING BY NEGOTIATION

15.412 [Amended]

5. Section 15.412 is amended by removing in paragraph (c) the introductory phrase "Except as authorized for NASA in its regulations," and by capitalizing the word "Proposals," to begin the paragraph.

15.502 [Amended]

6. Section 15.502 is amended by removing the second word in the first sentence, and inserting in its place the word "shall".

15.903 [Amended]

7. Section 15.903 is amended by adding in the second sentence of paragraph (d)(2), following the word

"However," the words "a deviation to"; and by removing in the second sentence the word "waived" and inserting in its place the word "authorized".

15.905-1 [Amended]

8. Section 15.905-1 is amended by removing in paragraph (b)(3) the word "terms" and inserting in its place the word "term".

15.1001 [Amended]

9. Section 15.1001 is amended by removing in the first sentence of paragraph (b)(1) the words "at over \$10,000" and inserting in their place the words "to exceed the small purchase limitation in Part 13"; by removing in the first sentence of paragraph (c)(1) the words "over \$10,000" and inserting in their place the words "exceeding the small purchase limitation in Part 13"; and by removing in paragraph (c)(3) the words of \$10,000 or less" and inserting in their place the words "not exceeding the small purchase limitation in Part 13".

PART 16—TYPES OF CONTRACTS

10. Section 16.307 is amended by adding three sentences at the end of paragraph (a) to read as follows:

16.307 Contract clauses.

(a) * * * If the contract is with an educational institution, modify the clause by deleting from paragraph (a) the words "Subpart 31.2" and substituting for them "Subpart 31.3." If the contract is with a State or local government, modify the clause by deleting from paragraph (a) the words "Subpart 31.2" and substituting for them "Subpart 31.6." If the contract is with a nonprofit organization other than an educational institution, a State or local government, or a nonprofit organization exempted under OMB Circular No. A-122, modify the clause by deleting from paragraph (a) the words "Subpart 31.2" and substituting for them "Subpart 31.7."

PART 22—APPLICATION OF LABOR LAWS TO GOVERNMENT ACQUISITIONS

11. Section 22.608-5 is amended by revising paragraph (b) to read as follows:

22.608-5 Award.

(b) Whenever Standard Form 279, Individual Contract Action Report, or its equivalent, is not submitted to the Federal Procurement Data System, furnish to the U.S. Department of Labor, Wage and Hour Division, Employment Standards Administration, Washington,

D.C. 20210 a completed original and one copy of Standard Form 99, Notice of Award of Contract.

22.810 [Amended]

12. Section 22.810 is amended by removing in paragraph (g) the words "(c), or (e)" and inserting in their place the words "(b), or (c)".

PART 25—FOREIGN ACQUISITION

13. Section 25.402 is amended by revising paragraph (a); and by removing from paragraph (c) the figure "\$161,000" and inserting in its place the words "the dollar threshold addressed in paragraph (a) above." to read as follows:

25.402 Policy.

(a) Executive Order 12260 requires the U.S. Trade Representative to determine from time to time the dollar threshold for use in implementing the Agreement on Government Procurement. The U.S. Trade Representative's dollar threshold determinations are published in the Federal Register and will be distributed through agency procedures on an expedited basis. Agencies shall evaluate offers at or over the dollar threshold for an eligible product without regard to the restrictions of the Buy American Act (see Subpart 25.1) or the Balance of Payments Program (see Subpart 25.3).

25.403 [Amended]

14. Section 25.403 is amended by removing in paragraph (a) the figure "\$161,000" and inserting in its place the words "the dollar threshold discussed in 25.402(a)".

15. Section 25.405 is amended by removing in the introductory text the words "\$161,000 or more" and inserting in their place the words "at or over the dollar threshold (see 25.402(a))"; and by revising paragraph (e) to read as follows:

25.405 Procedures

(e) Within seven working days after a contract award for an eligible product having a value equal to or exceeding the dollar threshold (see 25.402(a)), agencies shall give unsuccessful offerors from designated countries written notice that their offers were not accepted.

PART 31—CONTRACT COST PRINCIPLES AND PROCEDURES

16. Section 31.105 is amended by revising the first sentence of paragraph (a) to read as follows:

31.105 Construction and architect-engineer contracts.

(a) This category includes all contracts and contract modifications negotiated on the basis of cost with organizations other than educational institutions (see 31.104), State and local governments (see 31.107), and nonprofit organizations except those exempted under OMB Circular A-122 (see 31-108) for construction management or construction, alteration or repair of buildings, bridges, roads, or other kinds of real property. * * *

17. Section 31.205-19 is amended by inserting two sentences in paragraph (a)(3)(i), following the reference "(see 4 CFR 416.50(a)(2)(ii))"; and by removing from paragraph (f) the reference "(d)" and inserting in its place the reference "(a)(3)" to read as follows:

31.205-19 Insurance and indemnification.

- (a) * * *
- (3) * * *
- (i) * * * In those instances where an actual loss has occurred and the present value of the liability is determined under the provisions of CAS 416.50(a)(3)(ii), the allowable cost shall be limited to an amount computed using as a discount rate the interest rate determined by the Secretary of the Treasury pursuant to 50 U.S.C. App. 1215(b)(2) in effect at the time the loss is recognized. However, the full amount of a lump-sum settlement to be paid within a year of the date of settlement is allowable.
- * * *

PART 33—PROTESTS, DISPUTES, AND APPEALS**33.105 [Amended]**

18. Section 33.105 is amended by removing in the third sentence of paragraph (a)(1), the words "no later than one day after the protest is filed with GSBICA" and inserting in their place the words "on the same day the protest is filed with the GSBICA".

PART 44—SUBCONTRACTING POLICIES AND PROCEDURES**44.204 [Amended]**

19. Section 44.204 is amended by removing in paragraph (a)(1)(i) the word "Under" and inserting parentheses before "Fixed" and following "Contracts"; by removing in the first sentence of paragraph (b) the word "Under" and inserting parentheses before "Cost" and following "Contracts"; and by removing in the second sentence of paragraph (c) the word "Under" and inserting parentheses before "Time" and following "Contracts".

PART 52—SOLICITATION PROVISIONS AND CONTRACT CLAUSES**52-216-7 [Amended]**

20. Section 52.216-7 is amended by inserting a colon after the word "clause" in the first sentence of the introductory text and removing the remainder of the paragraph.

52.222-28 [Amended]

21. Section 52.222-28 is amended by removing the eighth word of the clause, i.e., "Subcontractors", and inserting in its place the word "Subcontracts".

52.225-9 [Amended]

22. Section 52.225-9 is amended by inserting a colon after the word "clause" in the introductory text and removing the remainder of the sentence; by removing in the title of the clause the date "1984" and inserting in its place the date "1985"; by removing from the third sentence of paragraph (b) of the clause the figure "\$161,000" and inserting in its place "\$. . . . [Contracting Officers shall insert the dollar threshold amount referenced in FAR 25.402(a)]"; and by removing both derivation lines following "(End of clause)".

52.244-1 [Amended]

23. Section 52.244-1 is amended by removing in the title of the section the word "under" by inserting a colon after the word "clause" in the first sentence of the introductory text and removing the remainder of the paragraph; by removing in the title of the clause the word "UNDER" and inserting parentheses before "FIXED" and following "CONTRACTS"; and by removing the date "1984" and inserting in its place the date "1985".

52.244-2 [Amended]

24. Section 52.244-2 is amended by inserting a colon after the word "clause" in the first sentence of the introductory text and removing the remainder of the paragraph; by removing in the title of the clause the word "UNDER" and inserting parentheses before "COST" and following "CONTRACTS"; by removing the date "1984" and inserting in its place the date "1985"; and by removing all derivation lines following "(End of clause)".

52.244-3 [Amended]

25. Section 52.244-3 is amended by inserting a colon after the word "clause" in the introductory text and removing the remainder of the sentence; by removing in the title of the clause the word "UNDER" and inserting parentheses before "TIME" and following "CONTRACTS"; and by removing the date "1984" and inserting in its place the date "1985"; and by removing the derivation line following "(End of clause)".

PART 53—FORMS**53.228 [Amended]**

26. Section 53.228 is amended by removing in paragraph (a) the date "(10/83)" and inserting in its place the date "(4/85)".

27. Section 53.301-24 (Standard Form 24) is revised to read as follows:

BILLING CODE 6820-61-M

53.301-24 Standard Form 24, Bid Bond.

OMB NO. 9000-0045																															
BID BOND <i>(See instructions on reverse)</i>			DATE BOND EXECUTED (Must not be later than bid opening date)																												
PRINCIPAL (Legal name and business address)			TYPE OF ORGANIZATION (X one) ☐ INDIVIDUAL ☐ PARTNERSHIP ☐ JOINT VENTURE ☐ CORPORATION STATE OF INCORPORATION																												
SURETY(IES) (Name and business address)																															
<table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <th colspan="4">PENAL SUM OF BOND</th> <th colspan="2">BID IDENTIFICATION</th> </tr> <tr> <th rowspan="2">PERCENT OF BID PRICE</th> <th colspan="3">AMOUNT NOT TO EXCEED</th> <th rowspan="2">BID DATE</th> <th rowspan="2">INVITATION NO.</th> </tr> <tr> <th>MILLION(S)</th> <th>THOUSAND(S)</th> <th>HUNDRED(S)</th> <th>CENTS</th> </tr> <tr> <td> </td> <td> </td> <td> </td> <td> </td> <td> </td> <td> </td> </tr> <tr> <td colspan="4"> </td> <td colspan="2">FOR (Construction, Supplies or Services)</td> </tr> </table>				PENAL SUM OF BOND				BID IDENTIFICATION		PERCENT OF BID PRICE	AMOUNT NOT TO EXCEED			BID DATE	INVITATION NO.	MILLION(S)	THOUSAND(S)	HUNDRED(S)	CENTS											FOR (Construction, Supplies or Services)	
PENAL SUM OF BOND				BID IDENTIFICATION																											
PERCENT OF BID PRICE	AMOUNT NOT TO EXCEED			BID DATE	INVITATION NO.																										
	MILLION(S)	THOUSAND(S)	HUNDRED(S)			CENTS																									
				FOR (Construction, Supplies or Services)																											
OBLIGATION: We, the Principal and Surety(ies) are firmly bound to the United States of America (hereinafter called the Government) in the above penal sum. For payment of the penal sum, we bind ourselves, our heirs, executors, administrators, and successors, jointly and severally. However, where the Sureties are corporations acting as co-sureties, we, the Sureties, bind ourselves in such sum "jointly and severally" as well as "severally" only for the purpose of allowing a joint action or actions against any or all of us. For all other purposes, each Surety binds itself, jointly and severally with the Principal, for the payment of the sum shown opposite the name of the Surety. If no limit of liability is indicated, the limit of liability is the full amount of the penal sum.																															
CONDITIONS: The Principal has submitted the bid identified above.																															
THEREFORE: The above obligation is void if the Principal - (a) upon acceptance by the Government of the bid identified above, within the period specified therein for acceptance (sixty (60) days if no period is specified), executes the further contractual documents and gives the bond(s) required by the terms of the bid as accepted within the time specified (ten (10) days if no period is specified) after receipt of the forms by the principal; or (b) in the event of failure so to execute such further contractual documents and give such bonds, pays the Government for any cost of procuring the work which exceeds the amount of the bid. Each Surety executing this instrument agrees that its obligation is not impaired by any extension(s) of the time for acceptance of the bid that the Principal may grant to the Government. Notice to the surety(ies) of extension(s) are waived. However, waiver of the notice applies only to extensions aggregating not more than sixty (60) calendar days in addition to the period originally allowed for acceptance of the bid.																															
WITNESS: The Principal and Surety(ies) executed this bid bond and affixed their seals on the above date.																															
PRINCIPAL																															
Signature(s)	1.		2.		Corporate Seal																										
	(Seal)		(Seal)																												
Name(s) & Title(s) (Typed)	1.		2.		Corporate Seal																										
INDIVIDUAL SURETIES																															
Signature(s)	1.		2.		(Seal)																										
	(Seal)		(Seal)																												
Name(s) (Typed)	1.		2.		(Seal)																										
CORPORATE SURETY(IES)																															
SURETY A	Name & Address			STATE OF INC.	LIABILITY LIMIT	Corporate Seal																									
	1.			\$	\$																										
	Signature(s)			2.																											
	Name(s) & Title(s) (Typed)			2.																											

CORPORATE SURETY(IES) (Continued)

	Name & Address	STATE OF INC.	LIABILITY LIMIT	
SURETY B	1. Signature(s)	2.	\$	Corporate Seal
	1. Name(s) & Title(s) (Typed)	2.		
SURETY C	1. Signature(s)	2.	\$	Corporate Seal
	1. Name(s) & Title(s) (Typed)	2.		
SURETY D	1. Signature(s)	2.	\$	Corporate Seal
	1. Name(s) & Title(s) (Typed)	2.		
SURETY E	1. Signature(s)	2.	\$	Corporate Seal
	1. Name(s) & Title(s) (Typed)	2.		
SURETY F	1. Signature(s)	2.	\$	Corporate Seal
	1. Name(s) & Title(s) (Typed)	2.		
SURETY G	1. Signature(s)	2.	\$	Corporate Seal
	1. Name(s) & Title(s) (Typed)	2.		

INSTRUCTIONS

1. This form is authorized for use when a bid guaranty is required. Any deviation from this form will require the written approval of the Administrator of General Services.

2. Insert the full legal name and business address of the Principal in the space designated "Principal" on the face of the form. An authorized person shall sign the bond. Any person signing in a representative capacity (e.g., an attorney-in-fact) must furnish evidence of authority if that representative is not a member of the firm, partnership, or joint venture, or an officer of the corporation involved.

3. The bond may express penal sum as a percentage of the bid price. In these cases, the bond may state a maximum dollar limitation (e.g., 20% of the bid price but the amount not to exceed _____ dollars).

4. (a) Corporations executing the bond as sureties must appear on the Department of the Treasury's list of approved sureties and must act within the limitation listed herein. Where more than one corporate surety is involved, their names and addresses shall appear

in the spaces (Surety A, Surety B, etc.) headed "CORPORATE SURETY(IES)". In the space designated "SURETY(IES)" on the face of the form, insert only the letter identification of the sureties.

(b) Where individual sureties are involved, two or more responsible persons shall execute the bond. A completed Affidavit of Individual Surety (Standard Form 28), for each individual surety, shall accompany the bond. The Government may require these sureties to furnish additional substantiating information concerning their financial capability.

5. Corporations executing the bond shall affix their corporate seals. Individuals shall execute the bond opposite the word "Corporate Seal"; and shall affix an adhesive seal if executed in Maine, New Hampshire, or any other jurisdiction requiring adhesive seals.

6. Type the name and title of each person signing this bond in the space provided.

7. In its application to negotiated contracts, the terms "bid" and "bidder" shall include "proposal" and "offeror".

STANDARD FORM 24 BACK (REV. 4-85)

Note.—The following appendix is included as an information item to contracting officers and will not appear in the Code of Federal Regulations.

Appendix A—Master List of Contractors for Negotiated Advance Agreements for Independent Research and Development and Bid and Proposal Costs

This Circular contains a revised master list for informational purposes of contractors requiring lead agency negotiation of advance agreements for Independent Research and Development and Bid Proposal costs (FAR SUBPART 42.10).

Questions as to assignments of negotiation cognizance and inclusion or exclusion of contractors on the master list should be directed to the agencies as follows:

Air Force: Headquarters, Air Force Systems Command, Attn: AFSC/PMO, Andrews Air Force Base, Maryland 20334.

Army: Commander Materiel Development and Readiness, Command, Department of the Army, Attn: DRCPP-SC, 5001 Eisenhower Avenue, Alexandria, Virginia 22333.

Navy: Headquarters, Naval Material Command, Attn: Director, Navy Triservice (NAVMAT 0224), Washington, D.C. 20360.

Contractor	Negotiating department ¹
AAI Corporation	Navy
ARO ENG	AF
Aerojet General Corporation	Navy
Applied Physics Lab (JHU/APL)	Navy
Atlantic Research Corporation	AF
Automation Industries, Inc.	Navy
AVCO	Army
Baird Atomic Inc.	AF
Ball Corporation	Navy

Contractor	Negotiating department ¹
Bendix Corporation	Navy
Bowling Company	AF
Burroughs Corporation, Federal & Special Systems Group	AF
CCI Marquardt Corporation	AF
Celco Industries Inc.	AF
Charles Stark Draper Laboratory, Inc.	Navy
Cincinnati Electronics	Army
Computer Sciences Corporation	Navy
Control Data Corporation	AF
Cubic Corporation	Navy
Curtiss-Wright Corporation	AF
DATATAPE	AF
Eastman Kodak	AF
E-Systems, Inc.	Navy
Eaton Corporation	Navy
Electrospan	AF
Emerson Electric Company	AF
FMC Corporation	Army
Except:	
Northern Ordnance Division	Navy
Fairchild Industries, Inc.	AF
Farrand Optical Company	AF
Ford Motor Company	Navy
GTE Products Corporation	Navy
Garrett Corporation	AF
General Dynamics Corporation	AF
Except:	
Land Systems	Army
General Electric Company	AF
General Motors Corporation	AF
Except:	
Transmission Operations	Army
Goodyear Tire & Rubber Company	Navy
Gould, Inc.	Navy
Grumman Aerospace Corporation	Navy
HARSCO/BMY	Army
Harris Corporation	Navy
Hazeltine	Army
Hercules	Navy
Honeywell, Inc.	AF
Hughes Aircraft Company	AF
IBM Corporation	AF
ITT Corporation	AF
Interstate Electronics Corporation	Navy
Itel Corporation	AF
Lear Siegler, Inc.	AF
Linkabit	AF
Liton Systems, Inc.	Navy
Lockheed Aircraft Corporation	AF

Contractor	Negotiating department ¹
Loral Corporation	AF
Magnavox Corporation	Navy
Martin Marietta Corporation	AF
McDonnell Douglas Corporation	AF
Except:	
Hughes Helicopter	Army
Morton Thiokol	AF
Motorola	Army
Northrop Corporation	AF
Page Communication Engineers	AF
Pan American World Airways, Inc.	AF
Perkin Elmer Corporation	AF
RCA Corporation	Navy
Raytheon	Army
Rockwell International Corporation	AF
Rosemount, Inc.	Navy
Sanders Associates, Inc.	Navy
Simmonds Precision	AF
Singer Company	AF
Sperry Corporation	AF
Stanford Research Institute	Army
Sundstrand Corporation	AF
Systems Development Corporation	AF
Teledyne, Inc.	AF
Except:	
Teledyne Systems Company	Navy
Teledyne Continental Motors	Army
Texas Instruments, Inc.	Navy
Textron	Army
Except:	
Bell Aerospace	AF
TRACOR	AF
TRW, Inc.	AF
Except:	
ESL, Inc.	Army
United Technologies Corporation	Navy
Except:	
Chemical Systems Division	AF
Varian Associates	AF
Vought Corporation	Navy
Western Electric/Bell Labs	Army
Westinghouse Electric Company	Navy
Williams Research Corporation	AF
Xerox Corporation	AF

¹ Negotiating Department for components of contractor operations except as noted.

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