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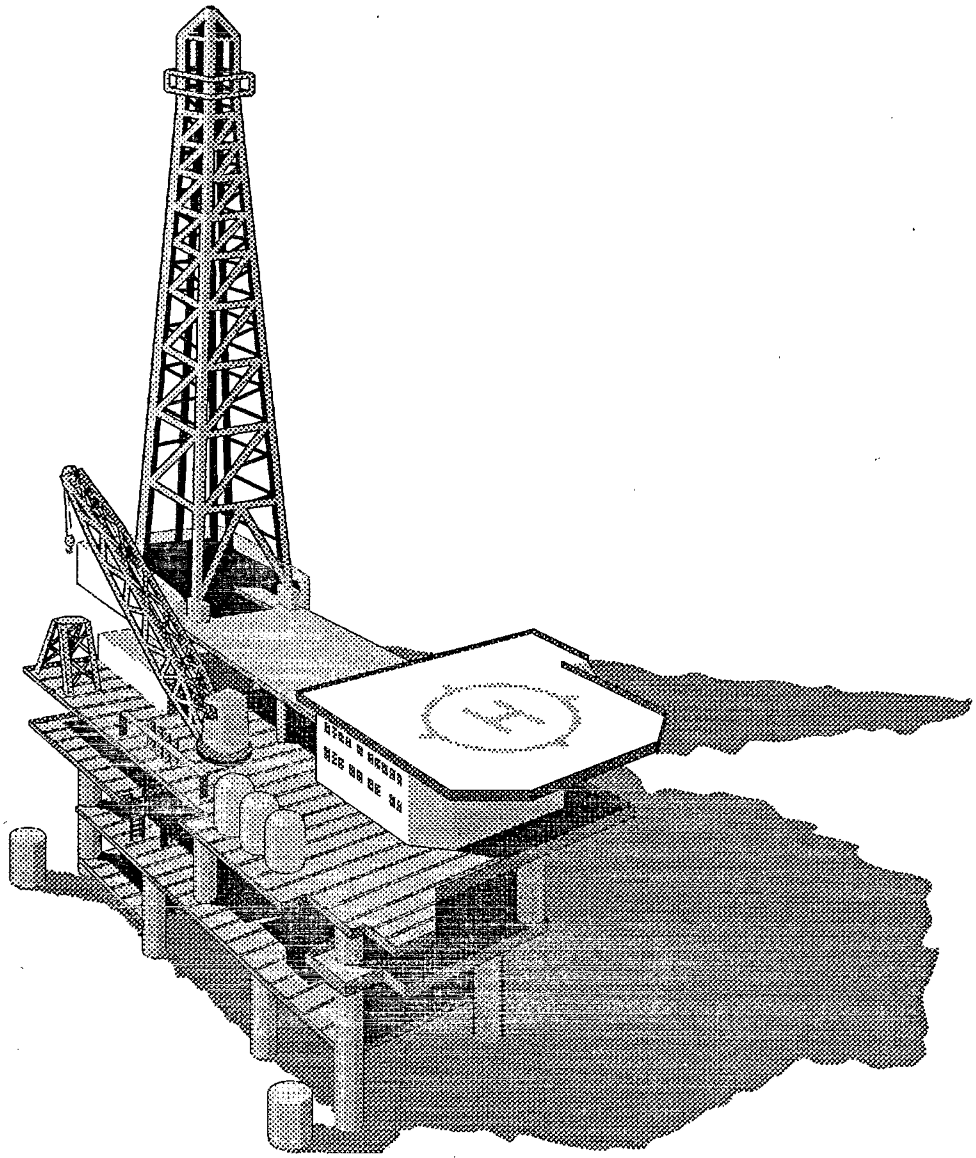
Development Document for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category



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CHAPTER I

INTRODUCTION

1.0 LEGAL AUTHORITY

The Environmental Protection Agency (EPA) is establishing these final Effluent Limitations Guidelines, New Source Performance and Pretreatment Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category (coastal guidelines) under the authority of Sections 301, 304, 306, 307, 308, and 501 of the Clean Water Act (CWA) (the Federal Water Pollution Control Act Amendments of 1972, as amended by the Clean Water Act of 1977 and the Water Quality Act of 1987); 33 U.S.C. 1311, 1314, 1315, 1317, and 1361. The requirements of the final regulation and supporting technical information are presented in the proceeding sections of this document. This chapter describes EPA's legal authority for issuing the coastal guidelines, as well as background information on prior regulations and litigation leading up to this regulation.

1.1 BACKGROUND

1.1.1 Clean Water Act

The CWA establishes a comprehensive program to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters" (Section 101(a)). To implement the CWA, EPA is to issue technology-based effluent limitations guidelines, new source performance standards and pretreatment standards for industrial dischargers. The levels of control associated with these effluent limitations guidelines and the new source performance standards for direct and indirect dischargers are summarized briefly below.

1. Best Practicable Control Technology Currently Available (BPT)

BPT effluent limitations guidelines are generally based on the average of the best existing performance by plants of various sizes, ages, and unit processes within the industrial category or subcategory.

In establishing BPT effluent limitations guidelines, EPA considers the following criteria: (1) total cost of achieving effluent reductions in relation to the effluent reduction benefits, (2) the age of equipment and facilities involved, (3) the processes employed, (4) the process changes required, (5) the engineering aspects of the control technologies, (6) the non-water quality environmental impacts (including energy requirements), and (7) other factors as the EPA Administrator deems appropriate (Section 304(b)(1)(B) of the CWA). EPA considers the category- or subcategory-wide cost of applying the technology in relation to the effluent reduction benefits. Where existing performance is uniformly inadequate, BPT may be transferred from a different subcategory or category.

2. *Best Available Technology Economically Achievable (BAT)*

BAT effluent limitations guidelines, in general, represent the best existing economically achievable performance of plants in the industrial subcategory or category. The CWA establishes BAT as a principal national means of controlling the direct discharge of toxic pollutants and nonconventional pollutants to navigable waters. The factors considered in assessing BAT include the following: (1) the age of the equipment and facilities involved, (2) the processes employed, (3) the engineering aspects of the control technologies, (4) potential process changes, (5) the costs and economic impact of achieving such effluent reduction, (6) non-water quality environmental impacts (including energy requirements) and (7) other factors as the EPA Administrator deems appropriate (Section 304(b)(2)(B) of the CWA). EPA retains considerable discretion in assigning the weight to be accorded these factors. As with BPT, where existing performance is uniformly inadequate, BAT may be transferred from a different subcategory or category. BAT may include process changes or internal controls, even when these technologies are not common industry practice.

3. *Best Conventional Pollutant Control Technology (BCT)*

The 1977 Amendments added Section 301(b)(2)(E) to the CWA establishing "best conventional pollutant control technology" (BCT) for the discharge of conventional pollutants from existing industrial point sources. Section 304(a)(4) designated the following as conventional pollutants: biochemical oxygen demand (BOD), total suspended solids (TSS), fecal coliform, pH, and any additional pollutants defined by the Administrator as conventional. The Administrator designated oil and grease as an additional conventional pollutant on July 30, 1979 (44 FR 44501).

BCT replaces BAT for the control of conventional pollutants. In addition to other factors specified in section 304(b)(4)(B), the CWA requires that BCT effluent limitations guidelines be established in light of a two-part "cost-reasonableness" test (American Paper Institute v. EPA, 660 F.2d 954 (4th Cir. 1981)). The methodology for establishing BCT effluent limitations guidelines became effective on August 22, 1986 (51 FR 24974, July 9, 1986).

4. New Source Performance Standards (NSPS)

NSPS are based on the performance of the best available demonstrated control technology (BADCT). Since new plants have the opportunity to install the best and most efficient production processes and wastewater treatment technologies, Congress directed EPA to consider the best demonstrated process changes, in-plant controls, and end-of-process control and treatment technologies that reduce pollution to the maximum extent feasible. As a result, NSPS should generally represent the most stringent numerical values attainable through the application of best available demonstrated control technology for all pollutants (i.e., conventional, nonconventional, and priority pollutants). In establishing NSPS, EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements.

5. Pretreatment Standards for Existing Sources (PSES)

Under Section 307(b) of the CWA, pretreatment standards for existing sources (PSES) are developed to prevent the discharge of pollutants that may interfere with or pass through to publicly-owned treatment works (POTWs). These discharges to POTWs are known as indirect discharges. Pretreatment standards are technology-based and analogous to BAT effluent limitations guidelines.

6. Pretreatment Standards for New Sources (PSNS)

Section 307(c) of the CWA authorizes EPA to promulgate pretreatment standards for new sources (PSNS) at the same time it promulgates (NSPS). PSNS are analogous to PSES in that PSNS limitations are developed to prevent discharges of pollutants to pass through or interfere with POTWs. New indirect dischargers have the opportunity to install the best available demonstrated technologies into their new plants similar to that of NSPS since the same factors are considered when promulgating both PSNS and NSPS limitations; and therefore EPA sets PSNS after considering the same criteria considered for NSPS.

1.1.2 Section 304(m) Requirements and Litigation

Section 304(m) of the CWA (33 U.S.C. 1314(m)), added by the Water Quality Act of 1987, requires EPA to establish schedules for (1) reviewing and revising existing effluent limitations guidelines and standards (effluent guidelines), and (2) promulgating new effluent guidelines. On January 2, 1990, EPA published an Effluent Guidelines Plan (55 FR 80), in which schedules were established for developing new and revised effluent guidelines for several industrial categories. One of the industries for which the Agency established a schedule was the Coastal Oil & Gas Extraction subcategory. Natural Resources Defense Council, Inc. (NRDC) and Public Citizen, Inc., challenged the Effluent Guidelines Plan in a suit filed in U.S. District Court for the District of Columbia (NRDC et al v. Reilly, Civ. No. 89-2980). On January 31, 1992, the Court entered a consent decree (the "304(m) Decree"), which establishes schedules for, among other things, EPA's proposal and promulgation of effluent guidelines for a number of point source categories, including the Coastal Oil and Gas Industry. The most recent Effluent Guidelines Plan was published in the Federal Register on October 7, 1996 (61 FR 52582).

1.1.3 Pollution Prevention Act

In the Pollution Prevention Act of 1990 (42 U.S.C. 13101 et seq., Pub. 1. 101-508, November 5, 1990), Congress declared pollution prevention the national policy of the United States. This act declares that pollution should be prevented or reduced whenever feasible; pollution that cannot be prevented should be recycled or reused in an environmentally safe manner wherever feasible; pollution that cannot be recycled should be treated; and disposal or release into the environment should be chosen only as a last resort.

1.1.4 Prior Regulation and Litigation for the Coastal Subcategory

EPA proposed coastal subcategory effluent limitations guidelines and standards on October 13, 1976 (41 FR 44943). On April 13, 1979 (44 FR 22069) EPA promulgated BPT effluent limitations guidelines for all subcategories under the oil and gas category, but deferred action on the BAT limitations, new source performance standards, and pretreatment standards. Table I-1 presents the 1979 BPT limitations.

On November 8, 1989, a notice of information and request for comments on the Coastal Oil and Gas subcategory effluent limitations guidelines development was published (54 FR 46919). The notice presented the Agency's approach to effluent limitations guidelines development for BAT, BCT, and NSPS. It also requested data available to develop such limitations. On February 17, 1995 (60 FR 9428), EPA proposed effluent limitations guidelines and standards for coastal discharges under BPT, BCT, BAT, NSPS, PSES and PSNS.

The definition of the coastal oil and gas industrial subcategory has been the subject of regulatory and litigation activity since 1979. The 1976 regulations had previously defined "coastal" on a geographic basis which specified boundaries in terms of longitude and latitude. Since then several changes were made or suggested regarding the definition of the coastal subcategory. These actions are summarized below:

TABLE I-1

COASTAL SUBCATEGORY BPT EFFLUENT LIMITATIONS

Waste Stream	Parameter	BPT Effluent Limitation
Produced Water	Oil and Grease	72 mg/l Daily Maximum 48 mg/l 30-Day Average
Drill Cuttings	Free Oil*	No Discharge
Drilling Fluids	Free Oil*	No Discharge
Well Treatment Fluids	Free Oil*	No Discharge
Deck Drainage	Free Oil*	No Discharge
Sanitary-M10	Residual Chlorine	1 mg/l (minimum)
Sanitary-M9IM	Floating Solids	No Discharge
Domestic Wastes	Floating Solids	No Discharge

* The free oil "no discharge" limitation is implemented by requiring no oil sheen to be present upon discharge.
Source: 40 CFR Part 435, Subpart D.

COASTAL DEFINITIONS

1976: Land and water areas landward of the inner boundary of the territorial seas and bounded inland by a series of longitude and latitude points in Louisiana and Texas (the Chapman line).

1979: The final BPT effluent guidelines defined coastal at 40 CFR, 435 as: (1) Any body of water landward of the inner boundary of the territorial (current) seas as defined in 40 CFR 125.1 (gg) or (2) any wetlands adjacent to such waters.

Wetlands are defined as surface areas which are saturated by surface or ground water at a frequency and duration sufficient to support a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas. (40 CFR Part 435.41 (f))

As part of the 1979 final rulemaking, EPA also attempted to reclassify approximately 1200 wells from the coastal subcategory to the onshore subcategory because these wells were located onshore but discharged to coastal waters. The American Petroleum Institute challenged this reclassification.

1981: American Petroleum Institute v. EPA, 661 F.2d 340, 354-57 (5th Cir. 1981), the Court held that EPA had failed to consider adequately the cost to the reclassified facilities of the 1979 regulatory change. As a result of the Court's decision, EPA suspended the applicability of the onshore subcategory guidelines to the reclassified wells and to any wells that came into existence in the affected area after the issuance of the 1979 redefinition. See 47 FR 31554 (July 21, 1982).

1989: EPA proposed to modify the 1979 definition to include only those facilities in saline water (greater than 0.5 parts per thousand) landward of the inner boundary of the territorial seas. (This would reclassify facilities located inland over saline and fresh water areas to the onshore or another subcategory). EPA never adopted this proposal.

1995: EPA proposed certain clarifications to the coastal definition to reflect the API decision and use the term of art "waters of the U.S." rather than body of water. EPA proposed revising the regulation to state that the coastal subcategory would consist of "any oil and gas facility located in or on a water of the United States landward of the territorial seas." The revised definition would make it clear that facilities located in or on isolated wetlands constituting a water of the U.S. would be considered coastal. The revised definition would no longer refer to 40 CFR Part 125.1(gg) since Part 125 was revised at 44 FR 32948 (June 7, 1979) and no longer exists in the CFR. Also, the proposed clarification explicitly included in the definition of "coastal" certain wells located in the area between the Chapman line and the inner boundary of the territorial seas that were determined to be coastal as a result of the 1981 decision of the U.S. Court of Appeals for the Fifth Circuit, API v. EPA, supra.

As described in Chapter III of this document, these final effluent guidelines modify the (1979) coastal definition as presented in the 1995 proposal.

Additional related rulemakings included a series of general National Pollutant Discharge Elimination System (NPDES) permits issued by EPA that set BPT, BCT and BAT limitations applicable to sources in the coastal subcategory on a Best Professional Judgment (BPJ) basis under Section 402(a)(1) of the CWA. These permits are described in Chapter III of this development document.

CHAPTER II

SUMMARY OF THE FINAL REGULATIONS

1.0 INTRODUCTION

The processes and operations which comprise the coastal oil and gas extraction subcategory (Standard Industrial Classification (SIC) Major Group 13) are regulated under 40 CFR 435, Subpart D. The effluent limitations guidelines in existence prior to the new regulations discussed in this document were issued on April 13, 1979 (44 FR 22069) and are based on BPT. This chapter summarizes the final effluent limitations guidelines, new source performance standards, and pretreatment standards for this subcategory based on BPT, BCT, BAT, BADCT.

1.1 BPT LIMITATIONS

In general, BPT represents the average of the best existing performances of well-known technologies and techniques for the control of pollutants. BPT for the coastal subcategory accomplishes the following: (1) limits the discharge of oil and grease in produced water to a daily maximum of 72 mg/l and a monthly average of 48 mg/l; (2) prohibits the discharge of free oil in deck drainage, drilling fluids, drill cuttings, and well treatment fluids; (3) requires a minimum residual chlorine content of 1 mg/l in sanitary discharges; and (4) prohibits the discharge of floating solids in sanitary and domestic wastes. Existing BPT effluent limitations guidelines are not being changed by this rule. A summary of the BPT effluent limitations guidelines is presented in Table I-1 in Chapter I Section 1.1.4.

Produced sand is the only wastestream for which BPT limits are being promulgated, as it is the only wastestream covered by the coastal guidelines for which BPT limits have not been previously promulgated.

1.2 SUMMARY OF THE FINAL RULE

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

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

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

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

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

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

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

These limitations are expected to reduce discharges of conventional pollutants by 2,780,000 pounds per year, non-conventional pollutants by 1,490,000 pounds per year, and priority toxic pollutants by 228,000 pounds per year.

1.3 PREVENTING THE CIRCUMVENTION OF EFFLUENT LIMITATIONS GUIDELINES AND STANDARDS

This rule includes a provision intended to prevent oil and gas facilities subject to 40 CFR Part 435 from circumventing the effluent limitations guidelines, new source performance standards and pretreatment standards applicable to those facilities by moving effluent from one subcategory to another subcategory in order to discharge with less stringent requirements. When EPA establishes effluent limitations guidelines and standards, it does so based on a determination, supported by analyses contained in the rulemaking record, that facilities in that subcategory, among other factors also considered under the CWA, can technologically and economically achieve the requirements of the rule. The purpose of the rule is not accomplished if facilities move effluent from a subcategory with more stringent requirements to a subcategory with less stringent requirements, or if facilities move effluent from a subcategory with less stringent requirements to a subcategory with more stringent requirements and discharge effluent at the less stringent limitations. EPA believes that it would enhance the enforcement of the effluent limitations guidelines and standards for the oil and gas industry to include a provision preventing such circumvention in the regulations at 40 CFR Part 435.

Accordingly, the rule prohibits oil and gas facilities from moving effluent from a subcategory with more stringent requirements to a subcategory with less stringent requirements, unless that effluent is discharged in compliance with the limitations imposed by the more stringent subcategory. For example, facilities could not move produced water generated from the onshore subcategory of the oil and gas industry (which is subject to zero discharge requirements) to the offshore subcategory of the oil and gas industry and dispose of the effluent at the offshore limitations and standards. Similarly, this rule prohibits facilities from moving produced water generated from the offshore subcategory to the coastal or onshore subcategory and discharging the produced water at the offshore limitations. (An offshore oil and gas facility could, however, pipe produced water to shore for treatment and return it to offshore waters for disposal in compliance with the offshore limitations. Disposal of such produced water onshore, however, would be subject to zero discharge.) EPA intends that these provisions would be applied prospectively in future NPDES permits (after the effective date of the coastal guidelines). Limitations for the Agricultural and Wildlife Water Use Subcategory and the reserved status of the Stripper Subcategory are not affected by these provisions.

1.4 THE EPA REGION VI COASTAL OIL AND GAS PRODUCTION NPDES GENERAL PERMITS

EPA's Region VI published final NPDES general permits regulating produced water and produced sand discharges to coastal waters in Louisiana and Texas (60 FR 2387, January 9, 1995). The permits prohibit the discharge of produced water and produced sand derived from the coastal subcategory to any water subject to EPA jurisdiction under the Clean Water Act. Under an Administrative Order issued by Region VI, operators are allowed until January 1, 1997 to cease discharges.

Much of the industry covered by this rulemaking is also covered by these general permits. However, one difference between the permits and this rule is that the permits do not cover produced water discharges derived from the Offshore subcategory wells into the main deltaic passes of the Mississippi River, or to the Atchafalaya River below Morgan City including Wax Lake Outlet. This rule-making covers these discharges (see the discussion in 1.3 above entitled "Preventing the Circumvention of Effluent Limitations Guidelines and Standards").

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

CHAPTER III

INDUSTRY DEFINITION AND WASTESTREAMS

1.0 INTRODUCTION

This section describes the coastal subcategory by (1) regulatory definition, (2) geographic locations, and (3) wastestreams regulated by the coastal guidelines.

2.0 REGULATORY DEFINITION

This rulemaking applies to coastal facilities included in the following SICs: 1311—Crude Petroleum and Natural Gas, 1381—Drilling Oil and Gas Wells, 1382—Oil and Gas Field Exploration Services, and 1389—Oil and Gas Field Services, not classified elsewhere.

The coastal subcategory of the oil and gas extraction point source category, as defined in 40 CFR 435.40, is comprised of those facilities involved in exploration, development, and production operations in waters of the United States landward of the inner boundary of the territorial seas (shoreline). The inner boundary of the territorial seas is defined in Section 502(8) of the CWA as "the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters." This includes inland bays and wetlands. The inner boundary of the territorial seas has been identified by EPA for areas where coastal oil and gas activity exists.[1]

Prior to this rulemaking, the coastal subcategory was defined as:

> "(1) any body of water landward of the territorial seas as defined in 40 CFR 125.1(gg) or (2) any wetlands adjacent to such waters." 40 CFR Section 435.41(e).

EPA has clarified the definition of the coastal subcategory in this rule. First, EPA revised the regulation to state that the coastal subcategory consists of "any oil and gas facility located in or on a water of the United States landward of the territorial seas." As suggested by the preamble to the 1979 guidelines stating that the coastal definition was intended to encompass "all facilities located over waters landward of the territorial seas, including wetlands adjacent to such waters"(44 FR 22017, April 13, 1979), EPA intended the subcategory to cover all facilities located over waters under CWA jurisdiction, including adjacent wetlands. Since 1979, courts have made it clear that isolated wetlands with an interstate commerce connection are waters of the United States subject to CWA jurisdiction. See, e.g., Hoffman Homes, Inc. v. Administrator 999 F.2d 256 (7th Cir. 1993). The revised definition makes it clear that facilities located in or on isolated wetlands that are waters of the U.S. are considered to be coastal. This application of the coastal definition is consistent with the Region 6 final general permit for coastal drilling operations (58 FR 49126, 49127, September 21, 1993). Also, the revised definition no longer refers to 40 CFR 125.1(gg) which no longer exists in the CFR (Part 125 was revised at 44 FR 32948, June 7, 1979). That regulatory provision, however, merely cited section 502(8) of the CWA which defines territorial seas as "the belt of seas measured from the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters, and extending seaward a distance of three miles." 40 CFR 125.1(gg) (July 1, 1978). That statutory definition is still in effect.

In addition, EPA has explicitly included in the definition of coastal certain wells located in the area between the Chapman line and the inner boundary of the territorial seas that were determined to be coastal as a result of decision of the U.S. Court of Appeals for the Fifth Circuit. American Petroleum Institute v. EPA, 661 F.2d 340 (5th Cir. 1981). To reflect this fact, the definition of coastal in 40 CFR 453.41(e) has been revised to include these wells.

This rule defines the coastal subcategory as follows:

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

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

Direction to West Longitude	Direction to North Latitude
West, 89°48'	North, 29°50'
West, 90°12'	North, 30°06'
West, 90°20'	South, 29°35'
West, 90°35'	South, 29°30'
West, 90°43'	South, 29°25'
West, 90°57'	North, 29°32'

Direction to West Longitude	Direction to North Latitude
West, 91°02'	North, 29°40'
West, 91°14'	South, 29°32'
West, 91°27'	North, 29°37'
West, 91°33'	North, 29°46'
West, 91°46'	North, 29°50'
West, 91°50'	North, 29°55'
West, 91°56'	South, 29°50'
West, 92°10'	South, 29°44'
West, 92°55'	North, 29°46'
West, 93°15'	North, 30°14'
West, 93°49'	South, 30°07'
West, 94°03'	South, 30°03'
West, 94°10'	South, 30°00'
West, 95°20'	South, 29°53'
West, 95°00'	South, 29°35'
West, 95°13'	South, 29°28'
East, 95°08'	South, 29°15'
West, 95°11'	South, 29°08'
West, 95°22'	South, 28°56'
West, 95°30'	South, 28°55'
West, 95°33'	South, 28°49'
West, 95°40'	South, 28°47'
West, 96°42'	South, 28°41'
East, 96°40'	South, 28°28'
West, 96°54'	South, 28°20'
West, 97°03'	South, 28°13'
West, 97°15'	South, 27°58'
West, 97°40'	South, 27°45'
West, 97°46'	South, 27°28'
West, 97°51'	South, 27°22'
East, 97°46'	South, 27°14'
East, 97°30'	South, 26°30'
East, 97°26'	South, 26°11'

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

2.1 NEW SOURCE DEFINITION

EPA is applying the definition of new source promulgated in the offshore guidelines to the coastal guidelines. The definition of "new source" was discussed at length in EPA's 1985 proposal for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, (50 FR 34617-34619, August 26, 1985). As discussed in that 1985 proposal, provisions in the NPDES regulations define new source (40 CFR 122.2) and establish criteria for a new source determination (40 CFR 122.29(b)). This rule includes special definitions which are consistent with 40 CFR 122.29 and which provide that 40 CFR 122.2 and 122.29(b) shall apply "except as otherwise provided in an applicable new source performance standard" (see 49 FR 38046, September 26, 1984).

The coastal guidelines apply to all mobile and fixed drilling (exploratory and development) and production operations. In 1985, EPA addressed the question of which of these facilities are new sources and which are existing sources under effluent guidelines for this point source category.

As discussed in 1985, Section 306(a)(2) of the Act defines "new source" to mean "any source, the construction of which is commenced after publication of the proposed NSPS if such standards are promulgated consistent with Section 306." The CWA defines "source" to mean any "facility . . . from which there is or may be a discharge of pollutants" and "construction" to mean "any placement, assembly, or installation of facilities or equipment . . . at the premises where such equipment will be used."

The regulations implementing this provision state, in part:

"*New Source* means any building structure, facility, or installation from which there is or may be a 'discharge of pollutants,' the construction of which is commenced:

(a) After promulgation of standards of performance under section 306 of the Act which are applicable to such source, or

(b) After proposal of standards of performance in accordance with section 306 of the Act which are applicable to such source, but only if the standards are promulgated in accordance with section 306 within 120 days of their proposal." 40 CFR § 122.2.

"(4) Construction of a new source as defined under § 122.2 has commenced if the owner or operator has:

(i) Begun, or caused to begin as part of a continuous on-site construction program;

(A) Any placement assembly, or installation of facilities or equipment; or

(B) *Significant site preparation work* including clearing, excavation or removal of existing buildings, structures or facilities which is necessary for the placement, assembly, or installation of new source facilities or equipment; or

(ii) Entered into a binding contractual obligation for the purchase of facilities or equipment which are intended to be used in its operation within a reasonable time. Options to purchase or contracts which can be terminated or modified without substantial loss, and contracts for feasibility engineering and design studies do not constitute a contractual obligation under the paragraph." 40 CFR § 122.29(b)(4) [emphasis added].

In 1985, EPA proposed to define, for purposes of the offshore guidelines, "significant site preparation work" as "the process of clearing and preparing an area of the ocean floor *for purposes of constructing or placing a development or production facility on or over the site.*" [emphasis added]. Thus, development and production wells would be new sources under the offshore guidelines. Further, with regard to 40 CFR 122.29(b)(4)(ii), EPA stated that although it was not "proposing a special definition of this provision believing it should appropriately be a decision for the permit writer," EPA suggested that the definition of new source include development or production sites even if the discharger entered into a contract for purchase of facilities or equipment prior to publication, if no specific site was specified in the contract. Conversely, EPA suggested that the definition of new source exclude development or production sites if the discharger entered into a contract prior to publication and a specific site was specified in the contract.

As a consequence of the definition of "significant site preparation work," if "clearing or preparation of an area for development or production has occurred at a site prior to the publication of the NSPS, then subsequent development and production activities at the site would not be considered a new source" (50 FR 34618). Also, exploration activities at a site would not be considered significant site preparation work, and therefore exploratory wells would not be new sources (50 FR 34618). The purposes of these distinctions were to "grandfather" as an existing source, any source if "significant site preparation work . . . evidencing an intent to establish full scale operations at a site, had been performed prior to NSPS becoming effective" (50 FR 34618). At the same time, if only exploratory drilling had occurred prior to NSPS becoming effective, then subsequent drilling and production wells would be considered to be new sources.

EPA also included a special definition for "site" in the phrase significant site preparation work used in 40 CFR 122.2 and 40 CFR 122.29(b). "Site" is defined in 40 CFR 122.2 as "the land or water area where any 'facility or activity' is physically located or conducted, including adjacent land used in connection with the facility or activity." The term "water area" means the "specific geographical location where the exploration, development, or production activity is conducted, including the water column and ocean floor beneath such activities. Thus, if a new platform is built at or moved from a different location, it will be considered a new source when placed at the new site where its oil and gas activities take place. Even if the platform is placed adjacent to an existing platform, the new platform will still be considered a 'new source,' occupying a new 'water area' and therefore a new site" (50 FR 34618, August 26, 1985).

EPA is using the same definition of "new source" in the coastal guidelines as was used in the offshore guidelines.

As a consequence of these distinctions, exploratory facilities would always be existing sources. Production and development facilities where significant site preparation has occurred prior to the effective date of the coastal guidelines would also be existing sources. These same production and development facilities, however, would become "new sources" under the regulatory definition if they move to a new water area to commence production or development activities. The definition, however, presents a problem because even though these facilities would be "new sources" subject to NSPS, they could not be covered by an NPDES permit in the period immediately following the issuance of these regulations. This is because no existing general or individual permits could have included NSPS until NSPS were promulgated. To resolve this problem, the rule will temporarily exclude from the definition of "new source" those facilities that as of the effective date of the coastal guidelines would be subject to an existing general permit pending EPA's issuance of a new source NPDES general permit. EPA believes this approach is reasonable because when Congress enacted Section 306 of the CWA it did not specifically address mobile activities of the sort common in this industry, as distinguished from activities at stationary facilities on land that had not yet been constructed prior to the effective date of applicable NSPS. Moreover, EPA believes that Congress did not intend that the promulgation of NSPS would result in stopping all oil and gas activities which would have been authorized under existing NPDES permits as soon as the NSPS are promulgated. EPA intends to issue as final, after opportunity for notice and comment, new source NPDES permits as soon as possible.

In summary, a drilling operation would be a new source if the drilling rig is drilling a development well (not an exploratory well) in a new water area. Exploratory drilling or drilling from an existing platform or rig that has not moved since it drilled a previously existing well would not be a new source. For production, a new source would be a facility discharging from a new site even if the discharge is piped to an existing facility at another site for ultimate treatment and/or disposal.

2.2 GEOGRAPHICAL LOCATIONS OF THE COASTAL INDUSTRY

As previously stated, coastal oil and gas activities are located on water bodies inland of the inner boundary of the territorial seas. These water bodies include inland lakes, bays and sounds, as well as saline, brackish, and freshwater wetlands. Although the definition includes inland waters of the U.S. in all U.S. states, EPA knows of no existing coastal operations other than those in certain states bordering the coast. Thus, although the rule applies to all areas defined as coastal, at this time the coastal industry is located only in coastal states.

Current coastal oil and gas activity exists along the Gulf Coast states of Texas, Louisiana, Alabama and Florida. The great majority of Gulf Coast activity resides in Texas and Louisiana. There, coastal oil and gas operations exist in a number of topographical situations including bays, sounds, lakes, or wetlands. Coastal oil and gas activity in Alabama is located in Mobile Bay. A small number of wells are also located on wetlands along the west coast of Florida.

Coastal oil and gas activity in California exists in Long Beach Harbor. There, four man-made islands have been constructed solely for the purpose of oil and gas extraction.

Roughly half of the coastal oil and gas activity exists in Alaska. Deep water platforms exist in the northern part of Cook Inlet. In addition, operations resembling onshore activities (as opposed to deep water platforms) are located on the tundra wetlands of Alaska's North Slope.

See Chapter IV for more details regarding the number of production wells, drilling activity, and production volumes located in these areas.

2.3 WASTESTREAMS REGULATED BY THE COASTAL GUIDELINES

The major wastestreams from drilling and production operations are those streams with the greatest volumes and amounts of pollutants. The wastestreams regulated by the coastal guidelines are drilling fluids, drill cuttings, dewatering effluent, produced water, produced sand, deck drainage, well treatment fluids, well completion fluids, workover fluids, domestic wastes, and sanitary wastes. The following sections present the regulatory definition for each of these wastestreams.

2.3.1 Drilling Fluids

The term "drilling fluids" refers to the circulating fluids (muds) used in the rotary drilling of wells to clean and condition the hole, to counter balance formation pressure, and to transport drill cuttings to the surface. A water-based drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspending medium for solids, whether or not oil is present. An oil-based drilling fluid has diesel, mineral, or some other oil as its continuous phase with water as the dispersed phase. A synthetic drilling fluid has as its continuous phase a synthetic-based material (such as poly(alpha)olefins, polyesters and vegetable esters) produced by the reaction of specific purified chemical feedstock, as opposed to physical separation processes to obtain materials from crude oil.

2.3.2 Drill Cuttings

The term "drill cuttings" refers to the particles generated by drilling into subsurface geologic formations and carried to the surface with the drilling fluid.

2.3.3 Dewatering Effluent

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

BAT and BCT limitations in the coastal guidelines for dewatering effluent are to be applicable prospectively. BAT and BCT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of the coastal guidelines no longer receive drilling fluids and/or drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority. Should an abandoned reserve pit receive drilling wastes after the effective date of the coastal guidelines, then discharges of wastes from within the reserve pit would be required to comply with the limitations of the guidelines.

2.3.4 Produced Water

The term "produced water" refers to the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

2.3.5 Produced Sand

The term "produced sand" refers to slurried particles used in hydraulic fracturing, the accumulated formation sands and scale particles generated during production. Produced sand also includes desander discharge from the produced water wastestream and blowdown of the water phase from the produced water treating system.

2.3.6 Well Treatment Fluids

The term "well treatment" fluids refers to any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled.

2.3.7 Well Completion Fluids

The term "well completion fluids" means salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production.

2.3.8 Workover Fluids

The term "workover fluids" means salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures.

2.3.9 Deck Drainage

The term "deck drainage" refers to any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas within facilities subject to this subpart. Within the definition of deck drainage for the purpose of this subpart, the term rainwater for those facilities located on land is limited to that precipitation runoff that reasonably has the potential to come into contact with process wastewaters. Runoff not included in the deck drainage definition would be subject to control as storm water under 40 CFR 122.26. For structures located over water, all runoff is included in the deck drainage definition.

2.3.10 Domestic Waste

The term "domestic waste" refers to materials discharged from sinks, showers, laundries, safety showers, eyewash stations, and galleys located within facilities subject to this subpart.

2.3.11 Sanitary Waste

The term "sanitary waste: refers to human body waste discharged from toilets and urinals located within facilities subject to this subpart.

2.4 MINOR WASTES

In addition to those specific wastes for which effluent limitations are being promulgated, coastal exploration and production facilities discharge other wastewaters. These wastes were investigated but are considered to be minor and, more appropriately controlled by NPDES permit limitations. Therefore, no controls for these wastes are proposed by this rule. These wastes are organized into the following 14 categories:

- *Blowout Preventer (BOP) Fluid*: hydraulic fluid used in blowout preventer stacks during well drilling.

- *Desalinization Unit Discharge*: wastewater associated with the process of creating fresh water from seawater.

- *Fire Control System Test Water*: sea water that is sometimes treated with biocide, used as test water for the fire control system on platforms and other facilities.

- *Non-Contact Cooling Water*: sea water that is sometimes treated with biocide, used for non-contact, once-through cooling of crude oil, produced water, power generators, and various other pieces of machinery.

- *Ballast and Storage Displacement Water*: tanker or platform ballast water, either local sea water or fresh water from the location where ballast was pumped into the vessel; may be contaminated with crude oil or platform oily slop water.

- *Bilge Water*: sea water that becomes contaminated with oil and grease and solids such as rust, when it collects at low points in the bilges.

- *Boiler Blowdown*: discharges from boilers necessary to minimize solids build-up in the boilers.

- *Test Fluids*: discharges that occur if hydrocarbons are located during exploratory drilling and tested for formation pressure and content.

- *Diatomaceous Earth Filter Media*: used to filter sea water or other authorized completion fluids and then washed from the filtration unit.

- *Bulk Transfer Operations Wastes*: bulk materials such as barite or cement that may be discharged during transfer operations.

- *Painting Operations Wastes*: discharges of sandblast sand, paint chips, and paint spay from painting operations.

- *Uncontaminated Fresh Water*: from wastes such as air conditioning condensate or potable water used during transfer or washing operations.

- *Waterflooding Discharges*: discharges associated with the treatment of sea water prior to its injection into a hydrocarbon-bearing formation to improve the flow of hydrocarbons from production wells. These discharges include the strainer and filter backwash water, and treated water in excess of that required for injection.

- *Laboratory Wastes*: material used for sample analysis and the material being analyzed.

- *Natural Gas Glycol Dehydration Wastes*: spent triethylene glycol or other desiccants used in the processing of natural gas.

3.0 CURRENT NPDES PERMIT STATUS

3.1 NPDES PERMITS

EPA has regulated discharges from coastal oil and gas operations in the Gulf of Mexico, California, and Alaska by general and individual National Pollutant Discharge Elimination System (NPDES) permits, issued under Section 402 of the CWA, based on BPT, State Water Quality Standards, and on Best Professional Judgment (BPJ) of BCT and BAT levels of control.

EPA's Region 6 has developed general NPDES permits for each phase of oil and gas operations (drilling and production). The drilling permit was published on September 21, 1993 (58 FR 49126). General permits regulating produced water and produced sand discharges to coastal waters in Louisiana and Texas were published on January 9, 1995 (60 FR 2387).

The existing general NPDES permit for oil and gas operations in the Upper Cook Inlet was published by EPA Region 10 on October 3, 1986 (51 FR 35460). Although expired, conditions of this general permit are still fully effective and enforceable until the permit is reissued. Region 10 published a new draft permit regulating discharges in Cook Inlet on September 20, 1995 (60 FR 48796). In addition to the general permit, the Region issued an individual permit regulating discharges from exploratory drilling operations in Upper Cook Inlet in May 1993.

The State of Alabama has been authorized to administer the NPDES program and has issued a final NPDES general permit covering facilities in State waters, including offshore and coastal facilities (including Mobile Bay) (Permit #ALG280000, May 25, 1994). This permit specifically prohibits the discharge of drilling fluids, drill cuttings, and produced water. The permit also does not allow the discharge of produced sands or treatment, workover and completion fluids.

In addition to technology pollutant removal performance, regional permit requirements are based on other factors, including water quality criteria. Table III-1 presents a summary of the requirements in these permits.

3.2 State Requirements

Louisiana

Two state agencies regulate oil and gas exploration and production (E&P) waste management activities in Louisiana: the Louisiana Department of Natural Resources, Office of Conservation (LDNR/OC) and the Louisiana Department of Environmental Quality (LDEQ). The LDNR has jurisdiction over most onsite and offsite E&P waste disposal activities, and implements the state's Underground Injection Control (UIC) program. The LDEQ has jurisdiction over surface discharge, and has authority to issue NPDES permits. LDEQ also regulates NORM-contaminated waste disposal and air emissions from waste disposal facilities.

Two state regulations govern most E&P waste management activities in Louisiana: Statewide Order 29-B[2] and Louisiana Administrative Code (LAC) 33, Part IX, Section 708.[3] Statewide Order 29-B covers the following activities:

- Onsite land treatment and burial of non-hazardous oilfield wastes (NOW), excluding drilling fluids, produced water, and completion and workover fluids;

- Onsite subsurface injection of produced water, drilling and workover waste fluids;
- Offsite storage, treatment, and disposal of NOW, including commercial land treatment and disposal well facilities.

LAC 33, Part IX, Section 708(c)(3) includes, in part, the following requirements:

- Surface discharges of drill cuttings, drilling fluids, and storm water runoff contaminated with these wastes, including the following requirements:
  - There shall be no discharge of oil-based drilling fluids,
  - There shall be no batch or bulk discharge of drilling fluids into water bodies inland of the territorial seas,
  - In fresh and intermediate marsh areas, only drill cuttings generated onsite and their adhering native mud drilling fluids may be discharged,
  - There shall be no discharge of drill cuttings generated in association with the use of oil-based drilling fluids, invert emulsion drilling fluids, or drilling fluids that contain diesel oil, waste engine oil, cooling oil, gear oil, or other oil-based lubricants;

LAC 33, Part IX, Section 708(c)(5) covers the following activities:

- Surface discharges of treated wastewater from drilling fluid reserve pits, abandoned or inactive production pits, ring levee borrow ditches, shale barges, and drilling fluid dewatering systems;

LAC 33, Part IX, Section 708(c)(2) includes, in part, the following requirements:

- Freshwater Areas
  - The discharge of produced water directly onto any vegetated area, soil, or intermittently exposed sediment surface is prohibited.
  - There shall be no discharge of produced water to lakes, rivers, streams, bayous, canals, or other surface waters of the state in areas regionally characterized as upland.
  - There shall be no discharge of produced water to freshwater swamp or freshwater marsh areas or to natural or manmade water bodies bounded by freshwater swamp or freshwater marsh vegetation unless the discharge has been specifically authorized in accordance with an approved schedule for discharge termination, or the discharge has been authorized by a valid LWDPS permit reflecting a discharge directed to a major deltaic pass of the Mississippi River or to the Atchafalaya River, including Wax Lake Outlet, below Morgan City.

- Intermediate, Brackish, and Saline Water Areas Inland of the Territorial Seas

  - The discharge of produced water directly onto any vegetated area, soil, or intermittently exposed sediment surface is prohibited.

  - There shall be no discharge of produced water to natural or man-made water bodies located in intermediate, brackish, or saline marsh areas after January 1, 1995, unless the discharge or discharges have been authorized in an approved schedule for elimination or effluent limitation compliance.

  - Operators discharging to the open waters and at least one mile from any shoreline in Chandeleur Sound, Breton Sound, Barataria Bay, Caminada Bay, Timbalier Bay, Terrebonne Bay, East Cote Blanche Bay, West Cote Blanche Bay, or Vermilion Bay from production originating in these areas will have until two years after the effective date of these regulations or one year after completion of the U.S. Department of Energy's (DOE) study concerning Louisiana coastal bays, whichever comes first, to show on a case-by-case basis that their particular discharge should be exempt from these regulations, if the DOE study, after scientific peer review, shows minimal acceptable environmental impacts.

Under the requirements of LAC 33, Part IX, Section 708(c)(2)b, requests for an extension of the compliance period beyond the January 1, 1995, deadline will be considered by the state if submitted with the original compliance schedule and if the following conditions are met:

- The operator establishes that surface discharge is the only immediately available and economically feasible alternative, that continued discharge does not represent gross potential for unacceptable environmental degradation, and that the produced water discharge termination schedule is limited in term to the period necessary to provide an alternate wastehandling method.

- The proposed extension would not extend the date of discharge termination or effluent limitation compliance beyond January 1, 1997.

Texas

The Railroad Commission of Texas (RRC), Oil and Gas Division, has regulated oil and gas field activities since 1917. The RRC oversees subsurface injection of produced water, as well as other oil and gas field wastes, through the state's UIC program. Requirements for the construction, use, and closure of pits is regulated via Statewide Rule 8.[4] The RRC will also oversee the state NPDES program, as delineated under a draft of Statewide Rule 77, although EPA has not yet authorized Texas to run the NPDES program. The RRC is also seeking primacy for the RCRA Subtitle C program for the management of hazardous oil and gas wastes.

Reserve pits, as well as many other types of pits, are authorized by Statewide Rule 8 and therefore do not require a permit. Only wastes specified in the Rule may be placed in these pits. Wastes authorized for placement in reserve and mud circulation pits are drilling fluids, cuttings, rig wash, drill stem test fluids, and blowout preventer test fluids. Rule 8 also lists pits that require permits, including those (other than reserve and mud circulation pits) used to store or dispose of drilling fluid. Pits used to store oil are specifically prohibited.

Two methods of landfarming oilfield wastes for disposal are authorized by the RRC: landspreading and land treatment. Landspreading is authorized by Rule 8 for the disposal of low-chloride ($\leq$ 3,000 mg/l) water based drilling fluids, drill cuttings, sands and silts associated with low-chloride water based drilling fluid, and rig wash. Land treatment involves adding nutrients or microbes to enhance degradation of oily Exploration and Production (E&P) wastes. This disposal method requires a permit and covers wastes such as oil based drilling fluids, cuttings associated with oil based drilling fluids, basic sediment, pit sludges, produced sand, and soil contaminated with produced water or oil. Drilling wastes that may be buried onsite under Rule B without a permit include:

- dewatered water base drilling fluid
- drill cuttings
- sands and silts associated with water base drilling fluid
- cuttings from oil base drilling fluid (but not oil base drilling fluid)
- solids from dewatered rig wash
- inert wastes
- basic sediment
- dewatered workover and completion solids.

A permit is required to bury any waste not specifically authorized by Rule 8.

Injection of drilling wastes to a non-productive formation is allowed by permit. Statewide Rule 9 covers permits for Class II injection wells under the Texas UIC program. All non-hazardous oil and gas wastes that are injectable are allowed to be injected to non-producing formations. Annular disposal of drilling waste also requires a permit, is not part of the state UIC program, and is limited to the drilling fluid used to drill the well. The type of drilling fluid is not restricted, and no waste analyses are required prior to disposal.[5]

Discharges of saline produced water to tidally influenced waters, and discharges of low-chloride produced water, gas plant effluent, or hydrostatic test water to the land surface or to surface waters are allowed by permit (under Rule 8(d)). Because Texas has not been authorized to administer the NPDES program, operators must apply for both a state and CWA/NPDES permit to discharge to state waters. As part of the state permit application process, produced water must be analyzed for 33 parameters including total organic compounds, benzene, naphthalene, oil and grease, metals, and chlorides. Discharges to tidally influenced waters are limited to 25 mg/l oil and grease.[5]

Produced water may be injected for disposal (Rule 9) or for enhanced recovery (Rule 46). Requirements include well construction specifications designed to protect usable water sources (e.g., casing depths, use of tubing and packer), and mechanical integrity tests are required at least every five years.

All commercial and centralized disposal facilities that accept oilfield waste must be permitted. The majority of E&P wastes disposed at commercial and centralized facilities are produced water and drilling fluids, which are mostly disposed in Class II injection wells.[5]

California

There are no discharges of produced water in the coastal subcategory off California. All produced water in this area is currently injected for use in waterflood operations to enhance hydrocarbon recovery. Regulations that would be applicable to discharges from coastal oil and gas facilities in California are included in the California State Water Resources Control Board's "Water Quality Control Plan for Ocean Waters of California." This "Plan" requires effluent limitations be met for oil and grease of 25 mg/l (30-day average), 75 mg/l (maximum at any time), settleable solids of 1 mg/l (30-day average), 3 mg/l (Maximum at any time), turbidity 75 NTU (30-day average), and pH of 6-9, for all discharges from POTWs and industrial point sources.[6] Total suspended solids are regulated by requiring that discharges shall, as a 30 day average, remove 75% of suspended solids from the wastestreams before discharging. In addition, discharge effluent limitations are specified for acute toxicity, metals, phenolic compounds and radioactivity.

Florida

There are no discharges of produced water in coastal waters of Florida. Florida's coastal oil and gas wastes are primarily regulated by Florida's Department of Environmental Protection (DEP). Regulations issued by the DEP prohibit the discharge of oil and gas wastestreams.[7]

TABLE III-1

NPDES PERMIT REQUIREMENTS[a]

REGIONAL PERMIT REQUIREMENTS						
Waste-stream	Region 10 (CI 1986 BPT Permit)	Region 10 Exploration Permit (1993)	Draft Cook Inlet Permit (1995)	Region 6 Drilling Permit (1993)	Region 6 Production Permit (1995)	Alabama Permit (1994)
Produced Water	1) Monitor daily flow rate 2) Oil & Grease: Phillips A Platform: 20mg/l daily max; 15 mg/l mo. avg. Other facilities: 48/72 mg/l pH = 6-9	Not Applicable	1) Flow rate: monitor daily 2) Oil and Grease: Phillips A/Tyonek: 20 mg/l daily max; 15 mg/l monthly avg Other facilities: 42/29 mg/l 3) pH: 6-9 4) Metals: (b) Cu: 58-244 daily max; 29-121 monthly avg As: 843-1780 daily max; 420-885 monthly avg Zn: 7980-16,500 daily max; 3980-8240 monthly avg 5) Total Aromatic Hydrocarbons (TAH):(b) 170-182,000 daily max 85-90,500 monthly avg 6) Total Aqueous Hydrocarbons (TaqH):(b) 255-272,000 daily max 127-136,000 monthly avg 7) Whole Effluent Toxicity:(b) 10-182 TUc daily max 7-124 TUc monthly avg 8) Metals: measure monthly for 1 year	Covered in Production Permit	No Discharge	No Discharge
Produced Sand	No free oil (Static Sheen)	Not Applicable	No Discharge	Not Applicable	No Discharge	No Discharge

TABLE III-1 (Continued)

NPDES PERMIT REQUIREMENTS[a]

REGIONAL PERMIT REQUIREMENTS						
Waste-stream	Region 10 (CI 1986 BPT Permit)	Region 10 Exploration Permit (1993)	Draft Cook Inlet Permit (1995)	Region 6 Drilling Permit (1993)	Region 6 Production Permit (1995)	Alabama Permit (1994)
Drilling Fluids and Cuttings	1) Toxicity: Discharge only approved generic muds 2) No free oil—static sheen 3) No discharge oil-based muds 4) 10 percent oil content for cuttings 5) No diesel oil 6) 1/3 mg/kg Hg/Cd in dry barite 7) Flow rate: >40 m = 1000 bbl/hr >20-40 m = 750 bbl/hr >5-20 m = 500 bbl/hr <5 m = No discharge	1) Flow rate = 750 bbl/hr 2) Use authorized muds only 3) Toxicity: 30,000 ppm in SPP 4) No free oil 5) No discharge of oil-based fluids 6) 5 percent (wt) oil content in cuttings 7) No discharge of diesel oil 8) 1 mg/kg Hg and 3 mg/kg Cd in stock barite	1) Flow Rate (Water Depth) >40m = 1,000 bbl/hr >20-40m = 780 bbl/hr 5-20m = 500 bbl/hr <5m =no discharge 2) Total Volume: monitor daily 3) Mud Plan: prior certification 4) Toxicity: 30,000 ppm SPP minimum 5) Free oil: no discharge 6) Oil-based fluids: no discharge 7) Oil content: monitor daily	No Discharge	Not Applicable	No Discharge
"Dewatering Effluent"	Not separately regulated	Not separately regulated	Not separately regulated	1) 2) 50 mg/l TSS 3) 5125 mg/l COD 4) pH = 6-9 5) 500 mg/l chlorides 6) 0.5 mg/l total Cr 7) 5.0 mg/l Zn 8) Monitor Volume	Not Applicable	Not separately regulated

TABLE III-1 (Continued)

NPDES PERMIT REQUIREMENTS[a]

REGIONAL PERMIT REQUIREMENTS						
Waste-stream	Region 10 (CI 1986 BPT Permit)	Region 10 Exploration Permit (1993)	Draft Cook Inlet Permit (1995)	Region 6 Drilling Permit (1993)	Region 6 Production Permit (1995)	Alabama Permit (1994)
Treatment, Completion, Workover Fluids	1) No free oil (Static Sheen) 2) No oil-based fluids 3) pH = 6–9 4) Oil and grease limits apply to combined discharge of any TWC commingled with produced water	1) No discharge of free oil or oil-based fluids 2) Monitor frequency of discharge and volume 3) pH = 6.5–8.5 4) Oil & grease = 72 daily max. & 48 mo. avg.	1) Discharge Frequency: report type and number of discharges 2) Flow Rate: monitor daily 3) Oil-based fluids: no discharge 4) Free oil: no free oil 5) Oil and grease: 42 mg/l daily max; 29 mg/l monthly avg 6) pH: 6.5-8.5 7) Metals: measure once per discharge	*Fresh Water*: No discharge ——— *Saline Water*: No toxics, No free oil (visual sheen), pH = 6–9	Not Applicable	No Discharge
Domestic Wastes	1) No free oil (no visible sheen) 2) No floating solids 3) Monitor flow rate	1) Monitor flow rate 2) No free oil (no visible sheen) 3) No floating solids 4) No visible foam	1) Flow rate: measure monthly 2) Floating solids: no discharge 3) Foam: no discharge	No discharge of solids ("garbage")	Not Applicable	See note below(c)
Deck Drainage	1) No free oil (visual sheen) 2) Monitor flow rate (mo. avg.)	1) Monitor flow rate (mo. avg.) 2) No free oil (visual sheen)	1) Flow rate: measure monthly 2) Free oil: no discharge 3) Whole effluent toxicity: measure twice per year	1) No free oil (visual sheen) 2) Monitor volume	Not Applicable	1) Monitor daily flow 2) No free oil (visual sheen)

TABLE III-1 (Continued)

NPDES PERMIT REQUIREMENTS[a]

REGIONAL PERMIT REQUIREMENTS						
Waste-stream	Region 10 (CI 1986 BPT Permit)	Region 10 Exploration Permit (1993)	Draft Cook Inlet Permit (1995)	Region 6 Drilling Permit (1993)	Region 6 Production Permit (1995)	Alabama Permit (1994)
Sanitary Wastes	1) No floating solids 2) Total residual chlorine: as close as possible to, but no less than, 1.0 mg/l 3) BOD & SS(d) 24 hr = 60 mg/l 7 day = 45 mg/l 30 day = 30 mg/l	1) No free oil (no visible sheen) 2) No floating solids 3) No visible foam 4) Total residual chlorine: as close as possible to, but no less than, 1 mg/l 5) BOD: 30 day: 30 mg/l 24 hr: 60 mg/l 6) TSS: 30 day: TSS intake + 30 mg/l 24 hr: TSS intake + 60 mg/l	1) Flow rate: measure monthly 2) Floating solids: no discharge 3) Total residual chlorine: as close as possible, but no less than 1 mg/l 4) BOD: 60 mg/l daily max 45 mg/l weekly avg 30 mg/l monthly avg 5) SS: SSintake + 60 mg/l SSintake + 45 mg/l SSintake + 30 mg/l 6) MSDs (FC, SS, TRC): Measure twice per month	1) No floating solids 2) BOD: 45 mg/l 3) TSS: 45 mg/l 4) Fecal coliforms: 200/ 100 mls 5) Monitor flow	Not Applicable	See note below(c)

[a] For a complete presentation of the effluent limitations and their basis in the permits see the following: Region 10 Final Permit for Cook Inlet (51 FR 35460; 10/3/86); Region 10 Exploration Permit (No. AK-005205-1; 5/24/93); Region 10 Draft Permit for Cook Inlet (60 FR 48796, 9/20/95); Region 6 Final General Permit for Drilling Operations (58 FR 49126; 9/21/93); Region 6 Final General Permits for Production Operations (60 FR 2387; 1/9/95); Alabama general permit (No. ALG280000; 5/25/94).

[b] Limitations are facility-specific; only range is presented.

[c] NOTE: The Alabama permit includes limitations for sanitary and domestic wastes that vary with the type of facility and whether the wastes are mixed.

[d] Limits apply only to discharges to state waters and separately for BOD and SS.

4.0 REFERENCES

1. *Avanti*, "Delineation of the Seaward Boundary of the Coastal Subcategory of the Oil & Gas Extraction Industry," May 3, 1993.

2. Louisiana Administrative Code, Volume 17, Title 43, Natural Resources, Part XIX. Office of Conservation - General Operations, Subpart 1. Statewide Order No. 29-B, 1990.

3. Smith, Michael, U.S. Court of Appeals (5th Circuit), facsimile transmitting Louisiana Administrative Code (LAC) 33, Part IX, Section 708 (Bureau of National Affairs, Inc., 1996), September 11, 1996.

4. Railroad Commission of Texas, Water Protection Manual, Appendix A; Summary of Statewide Rule 8, Statewide Rule 8, and Memorandum of Understanding, May 1992.

5. Interstate Oil and Gas Compact Commission, *IOGCC/EPA State Review of Oil and Gas Exploration & Production Waste Management Regulatory Programs, Texas State Review*, April 1993.

6. Wiedeman, A., Memorandum to file regarding "Coastal Oil and Gas Activity in CA, AL, MS, and FL," September 6, 1994.

7. Rules of the State of Florida Department of Environmental Protection, Florida Geological Survey, Oil and Gas Section, Conservation of Oil and Gas Chapters 16C-25 through 16C-30, Florida Administrative Code, Chapter 16C-28, Section 28.003.

CHAPTER IV

INDUSTRY DESCRIPTION

1.0 INTRODUCTION

This section describes the major processes associated with the oil and gas extraction and production industry located in the coastal regions of the United States, and presents the current and future production and drilling activities for this industry.

2.0 DRILLING ACTIVITIES

There are two types of operations associated with drilling for oil and gas: exploratory and development. Exploratory drilling includes those operations that involve the drilling of wells to determine potential hydrocarbon reserves. Development drilling includes those operations that involve the drilling of production wells, once a hydrocarbon reserve has been discovered and delineated. Although the rigs used in exploratory and development drilling sometimes differ, the drilling process is generally the same for both types of drilling operations. Drilling in coastal areas occurs on land (or wetland areas that are dry during certain parts of the year) as well as over water or wetlands. As described later in this section, the drill site location (over water or land) as well as water depth are influential when determining the type of drilling rig used.

2.1 EXPLORATORY DRILLING

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

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

2.1.1 Drilling Rigs

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

Bottom-supported drilling units are typically used in the Gulf of Mexico region when drilling occurs in shallow waters. Submersibles are barge-mounted drilling rigs that are towed to the drill site and sunk to the bottom. There are two common types of submersible rigs: posted barge and bottle-type. In shallow and inland waters, these units may be surrounded by barges to store and to transport materials and wastes to and from the site.

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

Land-based drilling rigs are also used in the coastal region of the Gulf of Mexico and on the North Slope. Land-based drilling rigs are different from water-based drilling rigs in that they are disassembled and transported from location to location by trucks. Land-based drilling rigs also take up more surface area than water-based drilling rigs. Land-based drilling rigs are usually surrounded by an earthen levee with a ditch to capture any runoff from the site. Materials and wastes are transported to and from the drill site by truck. Onsite living quarters are usually only provided for the supervisory personnel.

2.1.2 Formation Evaluation

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

2.2 DEVELOPMENT DRILLING

Development of the oil and gas reservoirs involves drilling of wells into the reservoirs to initiate hydrocarbon extraction, increase production or replace wells that are not producing on existing production sites. Development wells tend to be smaller in diameter than exploratory wells because, since the geological and geophysical properties of the producing formation are known, drilling difficulties can be anticipated and the number of workovers during drilling minimized. In the Gulf of Mexico coastal region, development wells average 8,500 feet in depth. In Alaska, development wells average 12,000 feet in depth.[2]

Different types of drilling rigs are used during development drilling, depending on the location of the producing reservoir. In the Gulf of Mexico region, mobile drilling units are used for development drilling as well as exploratory drilling. In the Cook Inlet region of Alaska, the two most commonly used types of drilling rigs are the platform rig and the mobile drilling units. Development wells are often drilled from fixed platforms in Cook Inlet because once the exploratory drilling has confirmed the existence of extractable quantities of hydrocarbons, a platform is constructed at that site for drilling and production operations. On the North Slope, development drilling is done from both dedicated and mobile drilling rigs. The drilling rig and all the associated equipment are housed and insulated to protect them from the harsh weather conditions.

To extract hydrocarbons from the reservoir effectively, several wells may be drilled into different parts of the formation. A special drilling technique, termed "directional drilling", has been developed to penetrate different portions of a reservoir from a fixed location directly below the rig. Directional drilling involves drilling the top part of the well straight and then directing the wellbore to the desired location in nonvertical directions. This requires special drilling tools and devices that measure the direction and angle of the hole. Directional drilling also requires the use of special drilling fluids that prevent temperature build up and stuck pipe incidents due to the increased stress on the drill bit and drill string. Directional drilling is commonly practiced in the Cook Inlet and on the North Slope. Although not commonly practiced in the Gulf of Mexico, some operators employ this drilling method to minimize environmental impacts (e. g., in protected wetlands) and to speed up the well permitting process by using existing drilling pads.[3]

Horizontal drilling is a specialized directional drilling technique that maximizes the length of penetration in the pay zone (hydrocarbon reservoir) by horizontally drilling through the pay zone, thus maximizing the fluid extraction from a single production string.[4] Horizontal drilling is also referred to as drilling under balance as there is no pressure equilibrium between the formation and the bore hole as in conventional drilling. The formation pressure is greater than the bore hole pressure (a blow out condition) but special surface equipment controls the down hole pressure differentials preventing a blow out.

Horizontal drilling is occasionally practiced in coastal environments when the geometry of the reservoir makes horizontal drilling the most economical method of extracting the hydrocarbon reserves.[4] It should be noted that horizontal drilling is not practiced as a means of minimizing impacts to the surface environment. Also, horizontal drilling is associated with greater volumes of waste than vertical drilling because the length of the borehole is greater and the drilling time is longer.

2.2.1 Well Drilling

The process of drilling the first few hundred feet of a well is referred to as "spudding." This process consists of extending a large diameter pipe, known as the conductor casing, from the drilling rig to a few hundred feet below the surface. The conductor casing, which is approximately two feet in diameter, is either hammered, jetted, or placed into the ground depending on the composition of the ground. If the composition of the ground is soft, the conductor casing can be hammered into place or lowered into a hole created by a high-pressure jet of water. In areas where the ground is composed of harder material, the casing is placed in a hole created by a large-diameter rotating drill bit.

Rotary drilling is the drilling process used to drill the well. The rotary drilling process consists of a drill bit attached to the end of a drill pipe, referred to as the "drill string," which makes a hole in the ground when rotated. Once the well is spudded and the conductor casing is in place, the drill string is lowered through the inside of the casing to the bottom of the hole. The bit rotates and is slowly lowered as the hole is formed. As the hole deepens, the walls of the hole tend to cave in and widen, so periodically the drill string is lifted out of the hole and casing is placed into the newly formed portion of the hole to protect the wellbore. Cement is pumped into the space between the casing and the hole wall to secure the casing in place. Each new casing string must be smaller in diameter than the previous string to allow for installation. This process of drilling and adding sections of casing is continued until final well depth is reached.

Rotary drilling utilizes a system of circulating drilling fluid to move drill cuttings away from the bit and out of the borehole. The drilling fluid, or mud, is a mixture of water, special clays, and certain minerals and chemicals. The drilling fluid is pumped downhole through the drill string and is ejected through the nozzles in the drill bit with great speed and pressure. The jets of fluid lift the cuttings off the bottom of the hole and away from the bit so that the cuttings do not interfere with the effectiveness of the drill bit. The drilling fluid is circulated to the surface through the space between the drill string and the casing, called the annulus, where cuttings, silt, sand, and any gases are removed before returning the fluid down-hole to the bit. The cuttings, sand, and silt are separated from the drilling fluid by a solids separation process which typically includes a shaleshaker, desilter, and desander and sometimes centrifuges. Figure IV-1 presents a schematic flow diagram of the fluid circulation system. Some of the drilling fluid remains with the cuttings after solids separation.[5,6]

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

Since the formation pressure varies at different depths, the density of the drilling fluid must be constantly monitored and adjusted to the downhole conditions during each phase of the drilling project.

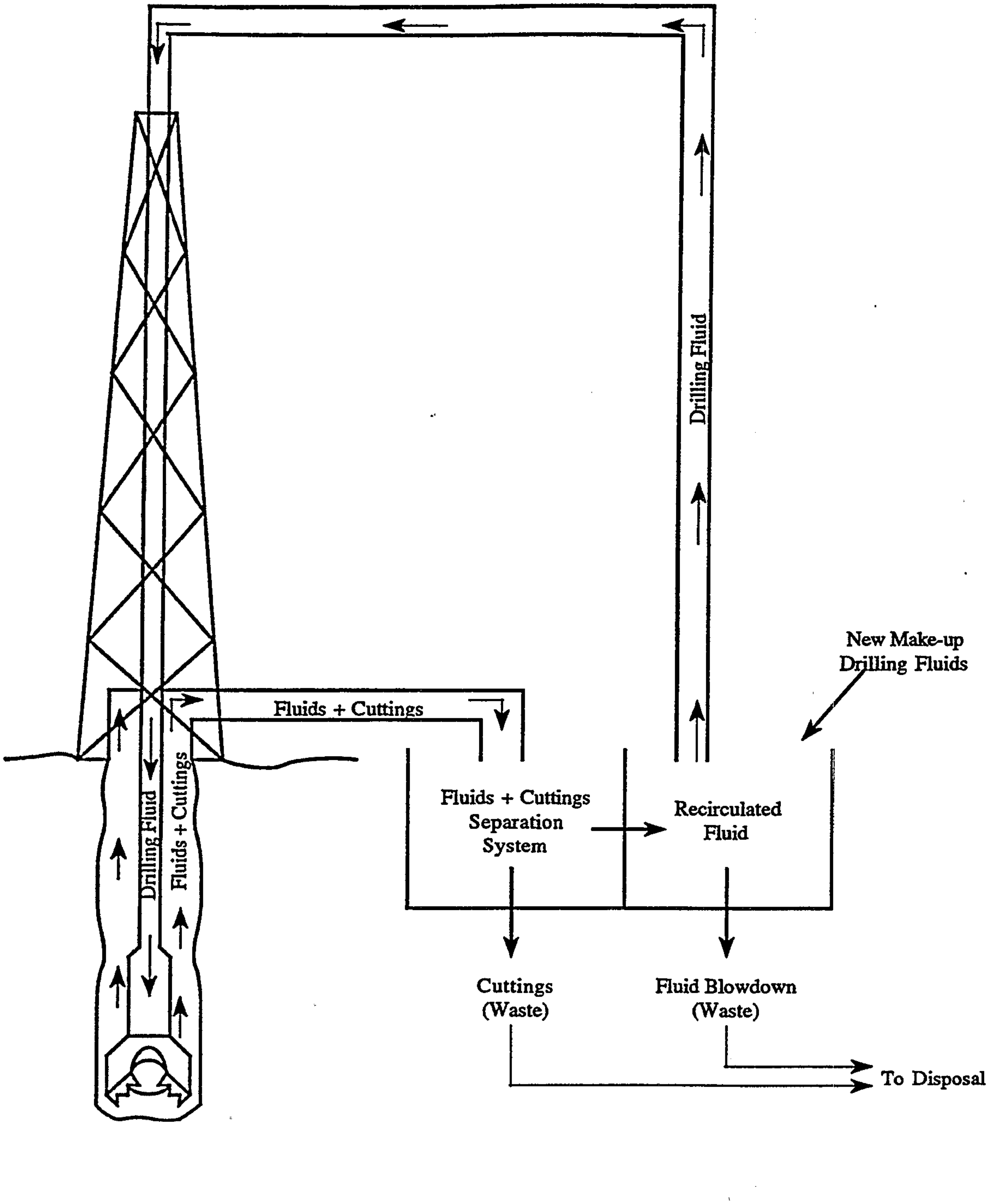


Figure IV-1
Typical Drilling Fluids Circulation System

One purpose of setting casing strings is to accommodate different fluid pressure requirements at different well depths. Other properties of the drilling fluid, such as lubricity, gel strength, and viscosity, must also be controlled to satisfy changing drilling conditions. The fluid must be replaced if the drilling fluid cannot be adjusted to meet the downhole drilling conditions. This is referred to as a "changeover."

The solids control system is necessary to maintain constant fluid properties and/or change them as required by the drilling conditions. The ability to remove drill solids from the drilling fluid, referred to as "solids removal efficiency," is dependent on the equipment used and the formation characteristics. High solids content in the drilling fluid, or a low solids removal efficiency, results in increased drilling torque and drag, increased tendency for stuck pipe, increased fluid costs, and reduced wellbore stability. More detailed discussion on solids control systems can be found in Chapter VII.

Operators control the solids content of the drilling fluid by adding fresh fluid to the circulating fluid system to reduce the percentage of solids and to rebuild the desired rheological properties of the fluid. A disadvantage of dilution is that the portion of the fluid removed, or displaced, from the circulating system must be stored or disposed. Also, greater quantities of fluid additives are required to formulate the replacement fluid. Both of these add expenses to the drilling project.

Most drilling fluid fluids are water-based, although oil-based systems are used for specialized drilling projects and more recently synthetic based drilling fluid systems are becoming more popular. In the 1970's, drilling fluids were mostly oil-based. The trend away from oil-based fluids is due to: 1) the BPT limitations which prohibit the discharge of drilling wastes if "free oil" is detected; and 2) advancements in water-based fluids technology. In the past, only oil-based fluids could achieve the temperature stability and lubricity properties required by special drilling conditions such as directional and deep well drilling. However, advancements in drilling fluid technology have enabled operators to formulate water-based fluids with similar properties to that of oil-based fluids through the use of small quantities of oil and/or synthetic additives. Small quantities of oil and/or synthetic additives are used to enhance the lubricity of a water-based fluid system and to aid in freeing stuck drill pipe. In the past, diesel oil was solely used to enhance lubricity and to free stuck pipe because of its properties and its availability at a drilling site. Mineral oil and synthetic lubricants now are used to replace diesel oil in many drilling situations. When oil or a synthetic spotting fluid is used as an aid in freeing stuck drill pipe, a standard technique is to pump a slug or "pill" of oil or oil-based fluid down the drill string and "spot" it in the annulus area where the pipe is stuck. Most of the pill can be removed from the bulk fluid system and disposed of separately. However, one hundred percent removal of the pill is not possible and a portion of the spotting fluid remains with the fluid system.[7]

The most significant waste streams, in terms of volume and constituents associated with drilling activities, are drilling fluids and drill cuttings. Drill cuttings are generated throughout the drilling project, although higher quantities of cuttings are generated during drilling of the first few thousand feet of the well because the borehole is the widest during this stage. The largest quantities of excess drilling fluids are generated as the project approaches final well depth. Fluids are generated during the drilling process because of displacement due to solids control, fluid changeover, and displacement by cement and casing. Fluid generation is the greatest at well completion because the entire fluid system must be removed from the hole and the fluid tanks. Some of the constituents in the drilling fluid can be recovered after completion of the drilling program, either at the rig or by the supplier of the drilling fluid. Where drilling is continuous, such as on multiple-well platforms, the fluid can be conditioned and reused from one well to another.[8]

3.0 PRODUCTION ACTIVITIES

This section describes the activities and processes associated with producing hydrocarbons from the formation and processing the production fluids. The activities and processes described in this section are well completion, fluid extraction, fluid separation, well treatment, and workover.

3.1 COMPLETION

After confirmation of a successfully producing formation, the well must be prepared for hydrocarbon extraction, or "completion." Completion operations include the setting and cementing of the production casing, packing the well and installing the production tubing. During the completion process equipment is installed in the well which allows hydrocarbons to be extracted from the reservoir. Completion methods are determined based on the type of producing formation, such as hard sand, loose sand, fine grain loose sand, and loose fine and coarse grain sands. Bridging agents are used to prevent fluid loss from the well to the formation.[9,10]

There are two types of completions: open hole and cased hole. Open hole completions are performed on consolidated formations. Cased hole completions are performed on unconsolidated formations. Figure IV-2 presents schematic diagrams of the four most common completion methods used

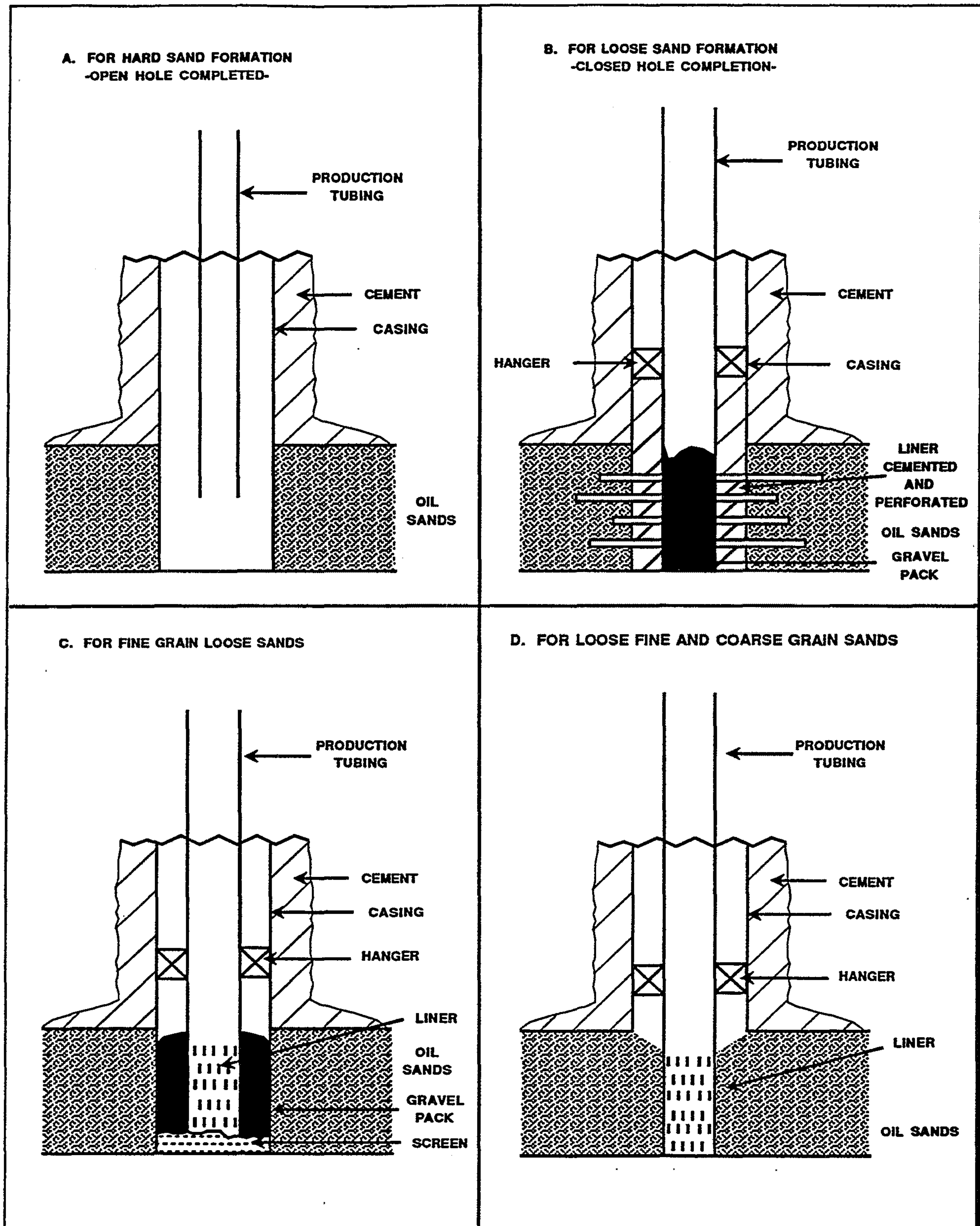


Figure IV-2
Typical Completion Methods

for different formation types. All completion methods consist of four steps: wellbore flush, production tubing installation, casing perforation, and wellhead installation.

Completion fluids are used during the completion phase to clean the wellbore or for pressure maintenance until production is initiated. The initial wellbore flush consists of a slug of water that is injected into the casing. These fluids are considered cleaning or pre-flush fluids and can be circulated and filtered many times to remove solids from the well and to minimize the potential of damage to the formation.[11] When the well has been cleaned, a second completion fluid termed a "weighing fluid" is injected. This fluid maintains sufficient pressure to prevent the formation fluids from migrating into the hole until the well completion is finished.

During the second step of well completion, production tubing is installed inside the casing using a packer which is placed at or near the end of the tubing. The packer, which consists of pipe, gripping elements, and sealing elements, is made of rubber. The purpose of the packer is to keep the tubing in place by expanding to form a pressure-tight seal between the production tubing and the well casing.[1,12] The packer seals off the annular space and forces the reservoir fluids to flow up through the tubing and not into the well annulus. Packer fluids are completion fluids that are trapped between the casing and the production tubing by the packer. These fluids are used to provide long-term protection against corrosion. Packer fluids are typically mixtures of a polymer viscosifier, a corrosion inhibitor, and a high concentration salt solution.[13] Packer fluids remain in place and may be removed during workover operations.[14]

After the production tubing is secured in place with packers, it must be perforated to allow the hydrocarbons to flow from the reservoir into the wellbore. Perforation may be accomplished with a special gun (usually lowered into the well by wireline) that fires steel bullets or shaped charges which penetrate the casing and cement. An additional means of perforation is achieved by suspending a small perforated pipe from the bottom of the casing.[1,12]

The final step in well completion is the installation of the "Christmas tree," a device that controls the flow of hydrocarbons from the well. When the valves of the Christmas tree are initially opened, the completion fluids remaining in the tubing are removed and flow of fluids from the formation begins.

3.2 FLUID EXTRACTION

The fluid produced from oil reservoirs consists of oil, natural gas (referred to hereafter as gas), and produced water. Gas wells may produce dry gas, but usually also produce varying quantities of light hydrocarbon liquids (known as natural gas liquids or condensate) and produced water. Produced water contains dissolved and suspended solids, hydrocarbons, metals, and may contain small amounts of radionuclides. Suspended solids consist of sands, clays, or other fines from the reservoir.

Crude oil can vary widely in its physical and chemical properties. Two important properties are its density and viscosity. Density usually is measured by the "API gravity" method which assigns a number to the oil according to its specific gravity. Oil can range from very light gasoline-like materials (called natural gasolines) to heavy, viscous asphalt-like materials.

Production fluids flow to the surface through tubing inserted within the cased borehole. For oil wells, the energy required to lift the fluids up the well is supplied by the natural pressure in the formation, known as natural drive. There are four kinds of natural drive mechanisms found with oil and gas production: dissolved-gas drive, gas-cap drive, water drive, and combination gas and water drive.

As hydrocarbons are produced, the natural pressure in the reservoir decreases and additional pressure must be added to the reservoir to continue production of the fluids. Additional pressure can be provided artificially to the reservoir by various mechanisms at the surface. The most common methods of artificial lift, or secondary recovery, are the following three: (1) gas lift, which is the injection of gas into the well in order to lighten the column of fluid in the borehole and assist in lifting the fluid from the reservoir as the gas expands while rising to the surface; (2) waterflooding, which is the injection of water into the reservoir to maintain formation pressure that would otherwise drop as the withdrawal of the formation fluids continue; and (3) employment of various types of pumps in the well itself. As the fluids in the well rise to the surface, they flow through a series of valves and flow control devices that make up the wellhead.

3.2.1 Enhanced Oil Recovery

When an oil field is depleted by primary and secondary methods (e.g., natural flow, artificial lift, waterflooding), as much as 50 percent of the original oil may remain in the formation. Enhanced oil recovery (EOR) processes have been developed to recover a portion of this remaining oil. The EOR processes can be divided into three general classes: (1) thermal, (2) chemical, and (3) miscible displacement.

Thermal: Thermal processes include steam stimulation, steam flooding, and *in situ* combustion. Steam stimulation and flooding processes differ primarily in the number of wells involved in a field. Steam stimulation uses an injection-wait-pump cycle in a single well, whereas the steam flooding process uses a continuous steam injection into a pattern of wells and continuous pumping from other wells within the same pattern. The *in situ* combustion process uses no other chemicals than the oxygen required to maintain the fire.

Chemical: Chemical EOR processes include surfactant-polymer injection, polymer flooding, and caustic flooding. In the first process, a slug of surfactant solution is pumped down the injection well followed by a slug of polymer solution to act as a drive fluid. The surfactant "washes" the oil from the formation, and the oil/surfactant emulsion is pushed toward the producing well by the polymer solution. In polymer flooding, a polymer solution is pumped continuously down the injection well to act as both a displacing compound and a drive fluid. Surfactant and polymer injection may require extensive treatment of the water used in solution make-up before the surfactant or polymer is added. Caustic flooding is used to drive oil through a formation toward producing wells. The caustic is delivered to the injection wells via a manifold system; the injection head is similar to that used in steam flooding.

Miscible displacement: These EOR processes use an injected slug of hydrocarbon (e.g., kerosene) or gas (e.g., carbon dioxide) followed by an immiscible slug (e.g., water). The miscible slug dissolves crude oil from the formation and the immiscible slug drives the lower viscosity solution toward the producing well. The injection head and manifold system are similar to those used for steam flooding.

3.3 FLUID SEPARATION

As they surface, the gas, oil, and water are separated for further processing and sale, and for treatment. The gas, oil, and water are separated in a single vessel or, more commonly practiced, in a series of vessels. Gas dissolved in oil is released from solution as the pressure of the fluid drops. Fluids from high-pressure reservoirs may be passed through a number of separating stages at successively lower pressures before oil is free of gas. The oil and brine do not separate as readily as the gas does. Usually, a quantity of oil and water is present as an emulsion. This emulsion may occur naturally in the reservoir or can be caused by the extraction process which tends to vigorously mix the oil and the water. The passage of the fluids into and up the well, through wellhead chokes, various pipes, headers, and control valves into separation chambers, and through any centrifugal pumps in the system, tends to increase emulsification. Moderate heat, chemical addition, quiescent settling, and/or electrical charges aid in the separation of emulsified liquids. The produced fluid separation system is a series of separation vessels arranged in a multistage separation process. Figure IV-3 presents a flow diagram of a typical produced fluid separation system.

The first stage of the produced fluids separation system consists of two-phase separators, or in some cases of three-phase separators. High-, intermediate-, and low-pressure separators are the most common arrangement, with the high-pressure liquids passing through each stage in series and gas being taken off at each stage. For gas wells the two-phase separators may generate light hydrocarbons that condense out as the pressure and temperature drop. These light hydrocarbons (known as gas liquids or condensate) can be processed and sold separately at a higher price than oil, or most commonly combined and processed with the oil. In a two-phase separator, the gas is separated from the liquid products. The separated gas is dehydrated in a glycol dehydrator and then used for electrical power generation, gas lift operations, or sold via pipeline. The liquid products free of gas are further treated in the oil treatment unit. A schematic of a two-phase separator is presented in Figure IV-4.

A three-phase separator, often referred to as bulk separator, is sometimes used instead of a two-phase separator to separate the produced fluids into gas, oil and water. The gas stream is drawn off the top of the vessel and further treated in a glycol dehydrator. The oil stream is drawn off the middle and piped to the oil treatment system for further processing. The water stream is drawn off the bottom and is piped to the water treatment system for further treatment. A schematic diagram of a bulk separator in presented in Figure IV-5.

Following the gas separation, the oil-water mixture is directed to the oil treatment system for separation. The oil treatment system consists of free-water knock out (FWKO) tanks, heater-treaters, and/or gun barrels. These types of oil-water separation systems may be used singly or in various combinations. FWKOs are often used to remove free water (water that is not in emulsion) from the influent to heater-treaters in order to reduce the amount of fluids to be heated, thus reducing the energy needed to heat the fluids.

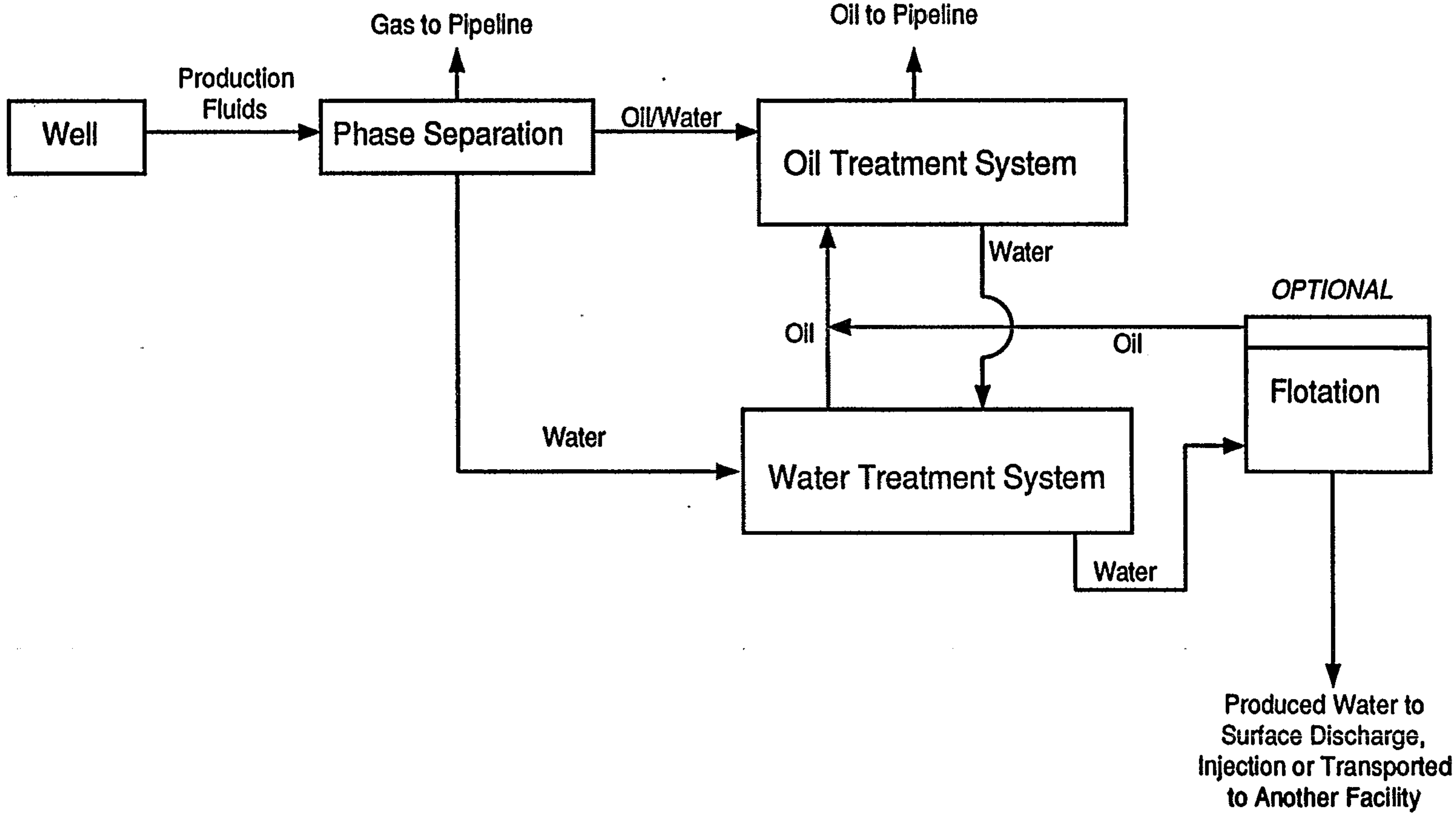
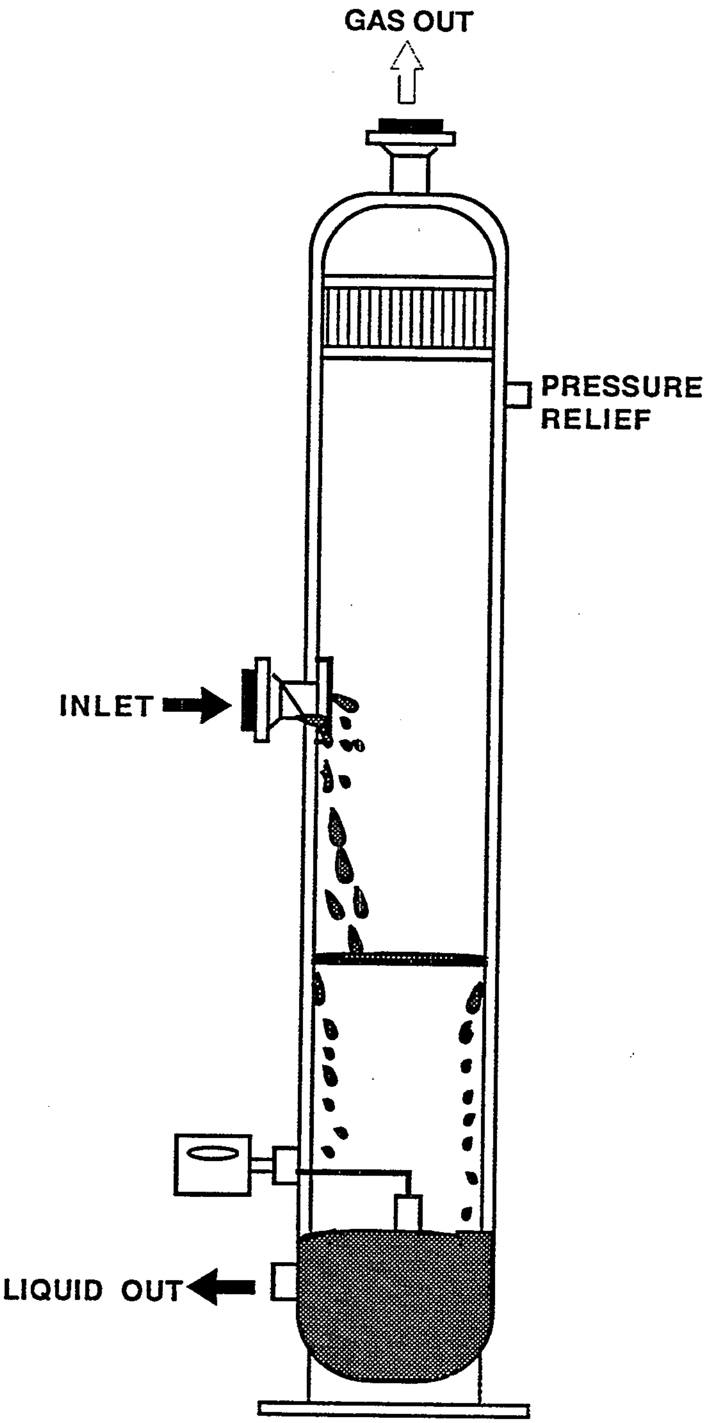


Figure IV-3
Produced Water Treatment System



Source: Smith Industries, Inc., 1980[15]

Figure IV-4
Two-Phase Separator

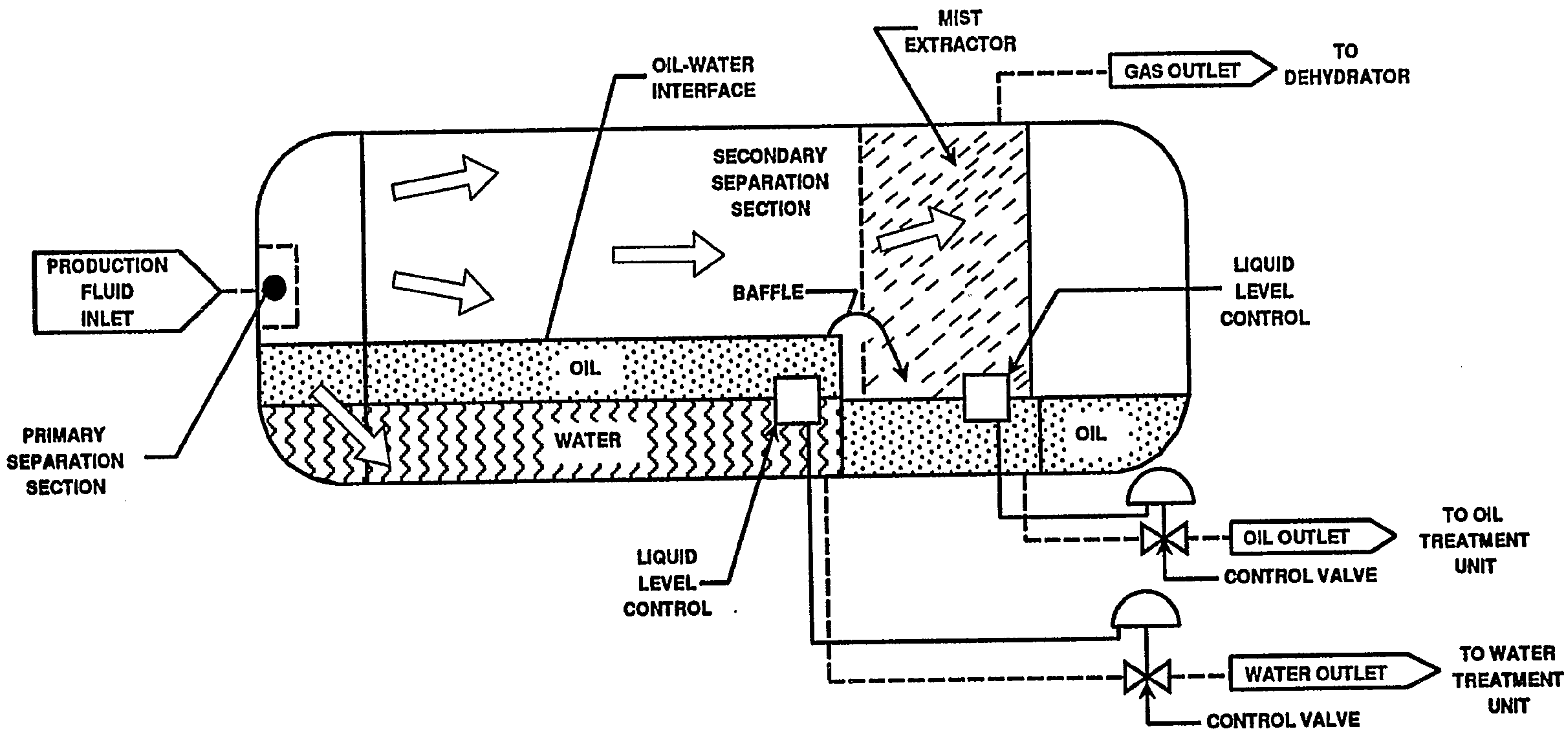


Figure IV-5
Three-Phase Separator

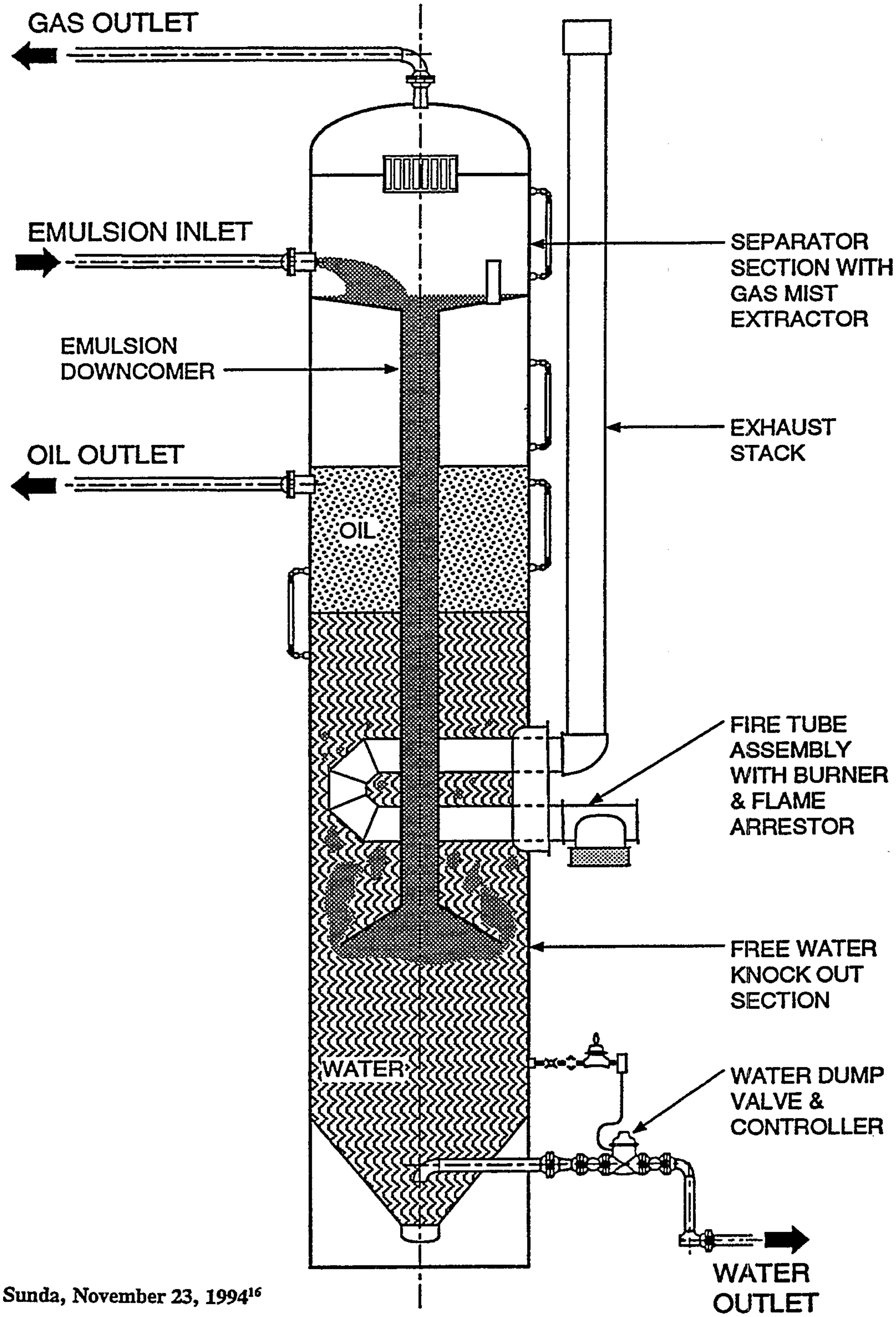
Whether or not a phase separator is used, if oil-water emulsions are present heater-treaters are required. Heat and/or emulsion-breaking chemicals are almost always necessary to break the oil-water emulsions to assure low water content in the oil product (most pipelines have water content limitations on the oil that can be transported). Heater-treaters are designed to remove emulsified water from the product oil through gravity separation aided by heat and/or the addition of chemicals to enhance and accelerate separation. Oil is drawn off the top of the heater/treater unit and sent to the oil product vessel for storage. Water is removed from the bottom of the heater/treater unit and is either piped to the gun barrel or the water treatment unit. A schematic diagram of a heater-treater is presented in Figure IV-6.

Gun barrels are sometimes used as a final oil-water separation process. The name refers to the fact that these units are usually configured as tall vertical tanks to allow for gravity flow of oil to the oil stock tanks. Figure IV-7 presents a schematic diagram of a gun barrel. A gun barrel is essentially a tall settling tank which utilizes gravity separation, sometimes assisted with heat and/or chemicals to further break the oil water emulsion. The water is piped to the water treatment unit.

The water treatment system receives produced water from the oil treatment unit. Water treatment usually consists of one or more large settling tanks, also called skim tanks, which utilize gravity to remove any residual suspended oil droplets from the produced water. This process is sometimes aided with the use of treatment chemicals such as surfactants.

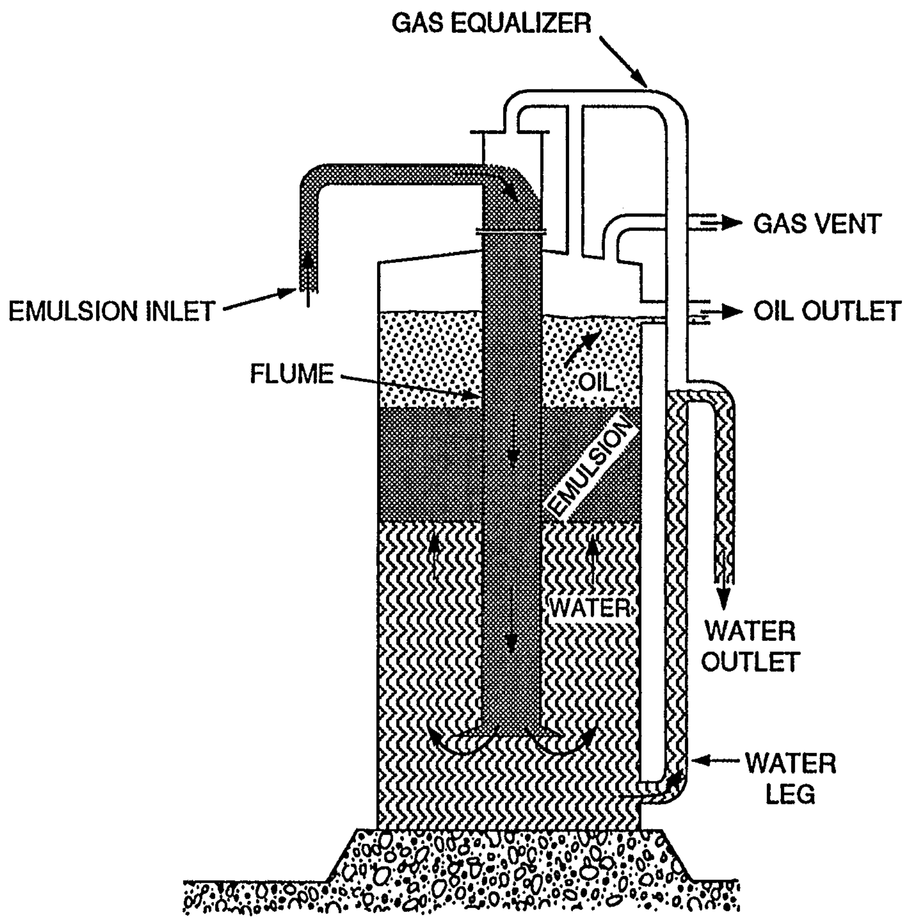
An oil layer accumulates in the top portion of the tank. Oil is periodically removed from the top of the tank and is piped back to the oil treatment unit. Water is drawn off the bottom of the vessel and is either discharged to surface waters if it meets the BPT oil and grease limitations, injected underground or transported to another site for disposal. In addition to the skim tank, the water treatment unit may include gas flotation and coalescers. A detailed discussion of these other produced water treatment technologies can be found Chapter VIII.

The major waste stream associated with production activities is the produced water stream. Produced sand or production solids is another waste stream of lesser volume. Both waste streams originate with the production fluids and are separated from the hydrocarbon products in the produced water treatment system.



Source: Sunda, November 23, 1994[16]

Figure IV-6
Verticle Heater - Treater



GUN BARREL

Source: API, 1983[17]

Figure IV-7

3.4 WELL TREATMENT

Well treatment is the process of stimulating a producing well to improve oil or gas productivity. There are two basic methods of well treatment: hydraulic fracturing and acid treatment. The specific method is chosen based on the characteristics of the reservoir, such as type of rock and water cut.[11] A well treatment job will enlarge the existing channels within the formation and increase the productivity of the formation. Typically, hydraulic fracturing is performed on sandstone formations, and acid treatment is performed on formations of limestone or dolomite.[10,12]

Hydraulic fracturing injects fluids into the well under high pressure, approximately 10,000 pounds per square inch gage (psig). This causes openings in the formation to crack open, increasing their size and creating new openings. The fracturing fluids contain inert materials referred to as "proppants," such as sand, ground walnut shells, aluminum spheres, and glass beads, that remain in the formation to prop the channels open after the fluid and pressure have been removed.[10,18] Hydraulic fracturing is rarely done in Gulf of Mexico operations because the unconsolidated sandstone formations in the region do not require fracturing.

Acid stimulation is performed by injecting acid solutions into the formation. The acid solution dissolves portions of the formation rock, thus enlarging the openings in the formation. The two most common types of acid treatment are acid fracturing and matrix acidizing. Acid fracturing utilizing high pressures results in additional fracturing of the formation. Matrix acidizing uses low pressures to avoid fracturing the formation. The acid solution must be water soluble, safe to handle, inhibited to minimize damage to the well casing and piping, and inexpensive.[10]

In addition to well treatment using hydraulic fracturing and acidizing, chemical treatment of a well may also be performed. Well treatment with an organic solvent like xylene or toluene will remove paraffins or asphalt blocks from the wellbore. These deposits of solid hydrocarbons occur due to the decrease in temperature and pressure when the liquid hydrocarbons are extracted from the well.[19]

3.5 WORKOVER

Workover operations are performed on a well to improve or restore productivity, repair or replace downhole equipment, evaluate the formation, or abandon a well. Loss of productivity can be the result of worn out equipment, restricted fluid flow due to sand in the well, corrosion, malfunctions of lift valves, etc. Workover operations include well pulling, stimulation (acidizing and fracturing), washout, reperforating, reconditioning, gravel packing, casing repair, and replacement of subsurface equipment.[10,20,21] Responses to EPA's 1993 survey of coastal oil and gas facilities (discussed in Section V) indicated that workovers or treatment jobs occur approximately once per year.[2] The EPA survey of coastal operators is described in detail in Chapter V.

The four general classifications of workover operations are pump, wireline, concentric, and conventional[22], Workovers can be performed using the original derrick if drilled from a drilling platform, a mobile workover rig, or by wireline. The operation is begun by using a workover fluid to force the production fluids back into the formation to prevent them from exiting the well during the operation. Then tools and devices can be attached to the wireline (a spool of strong fine wire) and lowered and pulled from the well to perform the required operations.

4.0 PRODUCTION AND DRILLING: CURRENT AND FUTURE

The industry profile is based on the information available at proposal revised to reflect changes in the production operations or in the regulatory requirements. For coastal production facilities in Texas and Louisiana, the issuance of EPA Region 6 General Permits has reduced the number of effected facilities significantly since proposal (60 FR 2387; January 9, 1995). In Cook Inlet, operational changes have resulted in revisions to the industry profile since proposal. The industry profile used in development of the final rule is described in Sections 4.1, and 4.2.

Subsequent to the issuance of the general permits requiring zero discharge in the Gulf Mexico region, EPA received individual permit applications seeking to discharge produced water. Additionally, the U.S. Department of Energy (DOE) has provided the State of Louisiana with comments and analyses in order to suggest a change in the Louisiana state law that currently requires zero discharge of produced water to open bays by January 1997. Because promulgation of this rule requiring zero discharge in these areas would preclude issuance of permits allowing discharge, EPA also calculated an alternative estimate of the costs, economic impacts, and pollutant removals under an "alternative requirements baseline." This "alternative requirements baseline" assumes that zero discharge under the general permits would no longer apply to Texas dischargers seeking individual permits and Louisiana open bay dischargers. The alternative requirements baseline industry profile is described in Section 4.3.

EPA updated the profile of Cook Inlet production facilities with current hydrocarbon and water production rates to address information submitted by industry in comments. The profile was also updated with current waterflood rates for use in estimating compliance costs under the produced water zero discharge option. The most notable changes to the Cook Inlet production profile include one platform which resumed oil production and ceased waterflooding; two platforms that resumed waterflooding; and one platform substantially reduced its waterflood rate. Production and waterflood levels for the remaining Cook Inlet facilities have not changed significantly since 1993. These profile changes are discussed in detail in Section 4.2 and in the technical support document for Cook Inlet.[23]

4.1 INDUSTRY PROFILE

Coastal oil and gas extraction activities currently exist in the Gulf of Mexico coastal regions of Texas, Louisiana, Alabama and Florida, in Long Beach Harbor, California, and in Cook Inlet and the North Slope, Alaska. Because of dramatic geological, topographical and climatological differences between these areas, production and drilling activities in these areas are equally as varied. In addition to the geographic location, several other factors affect the operations of this industry. These factors include whether oil, gas or both oil and gas are produced, whether the producing well(s) is located over water and wetlands or on land, the depth of water, whether it is a single producing well or a cluster of single wells, and whether it is a multi-well platform. The coastal oil and gas industry is described below in terms of production and drilling activity, as well as location and operational differences, where appropriate.

In general, the same factors that affect the operations of the producing wells will also affect the configuration of the separation/treatment facilities (production facilities) that service these wells. Production facilities consist of the treatment equipment and storage tanks that process the produced fluids to separate the hydrocarbons from the water and treat the water for discharge or injection. Production facilities may be configured to service one well, or as central facilities (also known as tank batteries or gathering centers) to service multiple satellite wells. Production facilities are also configured to service a single multi-well platform, or to service multiple platforms. A multiple-well producing platform is a fixed structure usually located in deep waters, with at least two producing wells that have the same surface location.[24]

Coastal production facilities can be located over water or on land. Production facilities located over water exist in generally two types of configurations: 1) individual deep water multi-well platforms or 2) central facilities supported on barges or wooden or concrete pilings that service multiple satellite wells in shallow water or wetlands. Production facilities on land may service satellite wells in any combination of locations.

Depending on operational preference or regulatory requirements, many of the coastal production facilities do not discharge produced water. Table IV-1 summarizes the number of producing wells and annual drilling activities for the coastal regions of the United States and the number of producing facilities that would incur costs due to this rulemaking, presented by geographic locations. The production facilities listed in Table IV-1 are discharging produced water into major deltaic passes of the Mississippi River, below Venice, Louisiana, and into the Cook Inlet in Alaska. This set of produced water dischargers is the current requirements baseline population, and represents only 1.6 percent of the population of production facilities accounted for in Table IV-1. The volumes and locations of discharges are discussed in more detail in Sections 4.2.1.1 and 4.2.4. All other Louisiana and Texas facilities are required to meet zero discharge of produced water under the requirements of NPDES permits (60 Fed. Reg. 2387; January 9, 1995). Along with the General permit, EPA issued a general administrative order providing until January 1997 to meet the zero discharge requirement. Other Gulf of Mexico production facilities, including those in Mississippi, Alabama, Florida, and those in Long Beach Harbor, California, and the North Slope of Alaska inject all of their produced water either for disposal or for waterflooding. Based on data provided by the 1993 Coastal Oil and Gas Questionnaire, 62 percent (528 out of 853 production facilities), were meeting zero discharge as of the 1992 time frame of the questionnaire.[25]

There are no discharges of drilling fluids or cuttings from coastal operators except for those in Cook Inlet, Alaska. The volumes and locations of discharges are discussed in more detail in Section 4.4.

4.2 CURRENT PRODUCTION OPERATIONS

4.2.1 Gulf of Mexico Current Requirements Baseline

4.2.1.1 Facilities

Multi-well platforms, such as those found in the Gulf of Mexico offshore area, are not commonly found in the Gulf coastal area. Based on an earlier mapping effort of all oil and gas wells, EPA determined that there are only four structures owned and operated by four different operators in the coastal Gulf of Mexico region that can be classified as multi-well platforms.[24] In addition, many single wellheads are located throughout coastal waters, serviced by gathering centers located on land or on platforms.

Production facilities in the Gulf of Mexico can be divided into two different types of structures: those located on land or fill material and those located over water or wetlands. Production facilities located

TABLE IV-1

PROFILE OF COASTAL OIL AND GAS INDUSTRY

Coastal Location	Region	No. of Producing Wells (1992)	No. of Production Facilities (1992)	No. of Produciton Facilities Discharging in 1992	No. of Operators (1992)	No. of Operators Discharging After January 1997	No. of Production Facilities Discharging After January 1997	No. New Wells Drilled per Year	
								All Well Types	New Development Wells Only
Gulf of Mexico	TX and LA	4,675(a)	853(a)	325(b)	270 - 435(a) (162 dischargers(b))	6(c)	6(c)	686(d)	187(d)
	AL and FL	56(e)	NE(f)	0(e)	NE(f)	0	0(e)	NE(f)	5-7(e)
Alaska	Cook Inlet	225(g)	8(g)	8(h)	3(g)	3(g)	8(g)	9(i)	6(i)
	North Slope	2,085(h)	11(j)	0(h)	3(k)	0	0(h)	161(l)	NE(f)
California	Long Beach Harbor	586(e)	4(e)	0(c)	1(e)	0	0(e)	NE(f)	6-7(e)
TOTALS	--	**7,639**	**876**	**333**	**277 - 442**	**9**	**14**	**856**	**204 - 207**

Notes and Ref.s:
(a) Jones, Sept. 26, 1994 (25)
(b) McIntyre, December 30, 1994 (26)
(c) See Table IV-2.
(d) SAIC, Jan. 31, 1995 (2)
(e) Wiedeman, Sept. 6, 1994 (27)
(f) NE = Not Estimated
(g) See Table IV-3.
(h) Wiedeman, Aug. 31, 1994 (28)
(i) Appendix X-1 (Worksheet 2). Includes only development and recompletion wells.
(j) See discussion in Section 4.2.5.
(k) SAIC, Jan. 6, 1995 (29)
(l) Erickson, Jan. 24, 1995 (30)

on land and fill material in wetlands and shallow water usually utilize earthen berms around storage tanks and equipment to contain spills. Production facilities located over water and protected wetlands can be located on diked concrete platforms supported on wooden or concrete pilings. In deeper waters such as in open bays, steel jacketed pilings or offshore type platforms may be necessary. Some of the older facilities have been constructed using wooden platforms or pilings. Another configuration for facilities over water is the use of barges to support equipment and for use as storage tanks. Although there are some exceptions, in most cases those located on land can be accessed by car or truck (land-access) while those facilities located over water must be accessed by boat or barge (water-access). Data from the 1993 Coastal Oil and Gas Questionnaire indicated that in most cases production facilities located on land could be accessed by car or truck (land-access), while those located over water must be accessed by boat or barge (water-access). This distinction was particularly important at proposal for estimating compliance costs and impacts. However, all of the facilities discharging into major deltaic passes of the Mississippi River have been determined subsequent to proposal to be water-access. The production facilities listed in Table IV-1 that are discharging produced water in coastal areas of Louisiana were each determined to be water-access facilities. Table IV-2 summarizes effluent production information for oil and gas production facilities for the current requirements baseline facilities located in coastal Louisiana.

4.2.1.2 Population

Based on the data available to EPA at proposal, EPA estimated that there would be 216 production facilities discharging in the Gulf of Mexico by July 1996 (the date scheduled for promulgating final Coastal Guidelines). Shortly before the proposal was published, EPA's Region 6 published final NPDES General Permits regulating produced water and produced sand discharges to coastal waters in Louisiana and Texas (60 Fed. Reg. 2387; January 9, 1995). These permits prohibited the discharge of any produced water derived from coastal waters of Louisiana and Texas. Because much of the industry covered by the proposed Coastal Guidelines is also covered by these General Permits, the industry profile used in the cost and economic analyses for the proposed rule overstates the number of facilities that would be incrementally affected by the final Coastal Guidelines. This possibility was noted at proposal. In the preamble for the proposed Coastal Guidelines, EPA stated that due to the close proximity (one month) of the timing of the publication of the Region 6 General Permits and the proposed guidelines, the costs and impacts of the proposed Coastal Guidelines were being presented in the preamble as if the General Permits were not final. EPA presented preliminary results of how the costs and impacts of the Coastal Guidelines would be reduced when the General Permits became effective and stated that the regulatory effects of the General Permits would be incorporated in the analysis conducted for the final guidelines.

TABLE IV-2

GULF OF MEXICO DISCHARGERS OF OFFSHORE PRODUCED WATER TO MISSISSIPPI RIVER PASSES [31]

Permit-Outfall Number	Operator	Field	Discharge Pass	Produced Water (bpd) Coastal Derived	Produced Water (bpd) Offshore Derived	Produced Water (bpd) Total
3229-001-3	Chevron Pipe Line Company	Main Pass Blk 69	North	0	18,920	18,920
2963-006	Warren Petroleum Company	Delta Gathering Station	Tante Phine	-	-	1,808
2071-004-1	Flores & Rucks, Inc.	South Pass Blk 24	Southwest	30,779	123,116	153,895
2400-001	Gulf South Operators, Inc.	Raphael Pass	Raphael	271	20	291
2184-002-2	North Central (formerly Forcenergy)	South Pass Blk 24	Southwest	0	1,910	1,910
2184-003-1	North Central (formerly Forcenergy)	South Pass Blk 24	Southwest	0	7,606	7,606
2184-001	North Central (formerly Forcenergy)	South Pass Blk 24	Southwest	0	572	572
3407-001	Amoco	Grand Bay	Emeline	0	6,290	6,290
TOTAL						**191,292**

The main difference between the general permits and the Coastal Guidelines is that the permits cover wastes generated by onshore Stripper Subcategory wells that are not covered under the Coastal Guidelines and the Louisiana permit does not cover produced water derived from Offshore Subcategory wells that is discharged into a major deltaic pass of the Mississippi River, or to the Atchafalaya River below Morgan City including Wax Lake Outlet. Since proposal, EPA has worked with industry sources and State regulatory authorities to identify those facilities whose discharges are covered by the Coastal Guidelines, but are not covered by the requirements of the General Permits. No facilities discharging Offshore Subcategory produced water into the Atchafalaya River were identified. Six production facilities with a total of eight outfalls were identified as discharging produced water derived from Offshore Subcategory wells into the major deltaic passes of the Mississippi River. These are presented in Table IV-2.

No new source facilities are expected in the main deltaic passes of the Mississippi River. Discharges at other coastal facilities are already required to comply with zero discharge under the Region 6 General Permits (60 FR 2387, January 9, 1995).

4.2.2 Mississippi, Alabama, Florida

According to the Mississippi State Oil and Gas Board, there are currently no coastal wells operating in the wetlands of Mississippi. None are planned in the foreseeable future. The only Mississippi oil and gas activity is onshore some 6 miles inland.[32]

Alabama coastal oil and gas activity consists of approximately 15 producing gas wells located in Mobile Bay.[33] Approximately 3-5 new wells are drilled in Mobile Bay each year.[34] All produced waters from the Bay's activities are injected for disposal in UIC Class II wells located onshore. All drilling fluids and cuttings are also transported to shore for disposal at onshore commercial disposal facilities.

In Florida, approximately 41 producing oil and gas wells currently exist in coastal subcategory areas on the western side of the state.[35] Average drilling rate is approximately two new wells per year. All produced water is injected in Class II UIC wells, primarily for disposal although some is also injected for waterflooding. All drilling fluids are either reused, annularly injected, or left in a dry wellbore. Drill cuttings are either disposed of in reserve pits or hauled off site to landfills.

4.2.3 California

The California coastal oil and gas industry currently exists on four man-made islands in Long Beach Harbor behind the barrier islands in San Pedro Bay. The facilities on these islands are operated by THUMS, a consortium of five oil and gas operating companies (Texaco, Humble (now Exxon), Union, Mobil and Shell). On these four islands operated by THUMS, approximately 586 wells are producing as of 1993.[36] Six to seven new wells are drilled each year. All produced waters from these operations are injected, primarily for waterflooding. No discharges occur from drilling fluids, drill cuttings, and dewatering effluent. Closed-loop solids control technology is employed by these operations. All dewatered solids are sent to an onshore landfill. The water from the solids dewatering equipment is allowed to settle (on-site) and the decant is directed to the on-site produced water treatment system. Plans are to begin using a grinding and injection operation in 1994 for drilling waste disposal. The ground wastes will be injected into a UIC well on site.

4.2.4 Cook Inlet

All the coastal oil and gas production is currently confined to the Upper portion of Cook Inlet. Oil and gas is produced from multi-well platforms that are similar in construction to offshore platforms. Table IV-3 presents information on existing oil and gas production facilities in Cook Inlet as of March 1996. There are three major operators in Cook Inlet: Unocal Corp., Phillips Petroleum Co., and Shell Western E&P Inc. In addition, ARCO and Phillips Petroleum are together developing a new discovery, the Sunfish field, which is located in the North Upper Cook Inlet. The total current oil production in Cook Inlet is about 37,400 barrels per day (bpd) and the total gas production is 385,000,000 cubic feet per day (cfd).

There are a total of 15 multi-well platforms in Cook Inlet, 13 of which were productive as of March 1996. Five of the thirteen platforms separate and treat the production fluids at the platform. Produced water from each of the five platforms is discharged directly overboard after treatment. The remaining eight platforms pipe the production fluids (oil, gas, and water) to three shore-based facilities for separation and treatment. Produced water from the three shore-based facilities is discharged to Cook Inlet after treatment. Of the three shore-based facilities, two discharge treated produced water from the facility, and the third sends its produced water back to one of the platforms for discharge. These three facilities treat and discharge 96% of the produced water generated from all platforms in Cook Inlet (see Table IV-3).

As of March 1996, Unocal owned and operated twelve platforms in the Trading Bay, Granite Point, and Middle Ground Shoal fields, which included a total of 163 oil producing wells, 55 service wells

TABLE IV-3

OIL AND GAS PRODUCTION FACILITIES IN COOK INLET REGION AS OF MARCH 1996[37]

Facility Name	Operator	Total No. Available Slots	No. Oil & Service Wells	No. Gas Wells	Oil Production (bpd)	Gas Production (cfd)	Seawater Waterflooding Vol. (bpd)	Avg. Produced Water Vol. (bpd)	PW Discharge Location
PLATFORMS									
King Salmon	Unocal	32	19 oil; 5 injection	1	3,864	Platform Use	40,067	40,540	Trading Bay
Monopod	Unocal	32	22 oil; 2 injection	0	1,981	Platform Use	5,608	6,230	Trading Bay
Grayling	Unocal	48	23 oil; 8 injection	1	5,207	Platform Use	52,387	45,180	Trading Bay
Granite Point	Unocal	48	11 oil; 7 injection	0	6,086	Platform Use	94	226	Granite Point
Dillon	Unocal	32	10 oil; 3 injection	0	841	0	0	3,116	Platform(a)
Bruce	Unocal	32	13 oil; 7 injection	0	865	Platform Use	0	199	Platform(a)
Anna	Unocal	32	23 oil; 7 injection	0	3,117	Platform Use	1,333	919	Platform(a)
Baker	Unocal	33	14 oil; 5 injection	2	1,301	Platform Use	5,863	924	Platform(a)
Dolly Varden	Unocal	48	24oil; 9 injection	1	4,983	Platform Use	38,890	31,510	Trading Bay
Spark	Unocal	12	5(shut-in)	9(shut-in)	0	0	0	0	Platform(a)
Steelhead	Unocal	48	4 oil; 2 injection	9	4,184	165,000,000	11,597	2,270	Trading Bay
Spurr	Unocal	12	6(shut-in)	1(shut-in)	0	0	0	0	Granite Point
SWEPI "A"	Shell Western	32	17	1	3,200	Platform Use	4,000	300	East Foreland
SWEPI "C"	Shell Western	24	17	0	1,800	Platform Use	4,200	1,400	East Foreland
Tyonek "A"	Phillips	--	0	13	0	220,000,000	0	30	Platform(a)
LAND-BASED TREATMENT FACILITIES									
Granite Point	Unocal	--	--	--	--	--	--	929	Spark Platform(a)
Trading Bay	Unocal	--	--	--	--	--	--	127,468	Outfall(a)
E. Foreland	Shell Western	--	--	--	--	--	--	1,700	Outfall(a)

[a] Metered outfall. Total produced water discharge is 135,285 bpd.

used to inject seawater, and 14 gas producing wells. On average, these platforms produced 32,400 bpd of oil in 1996. Only one Unocal-owned platform (Steelhead) produces enough gas to sell commercially. The Steelhead platform has 9 wells that produce an average of 165,000,000 cubic feet of gas per day. Most of the gas produced by Unocal-owned wells is not sold and is used to power equipment on platforms. Four of the platforms separate and treat the production fluids on the platform. Oil is piped to shore for sale, while the produced water, which totals an estimated 5,158 bpd from these four platforms, is discharged overboard. The remaining eight platforms pipe the production fluids to two shore-based facilities for separation and treatment. All produced water from these platforms, totaling an estimated 125,956 bpd, is discharged to Cook Inlet after treatment at the onshore facilities.

Shell Western E&P owns and operates two platforms in the Middle Ground Shoal field, including a total of 34 oil producing and service wells and one gas producing well. The gas produced is not sold and is only used to power equipment on platforms. The total produced water flow from the two platforms is 1,700 bpd. All production fluids are piped to the East Forelands shore-based facility for separation and treatment. Produced water is discharged to Cook Inlet after treatment.

Phillips Petroleum operates one platform in the North Cook Inlet field, including 13 wells producing 220,000,000 cubic feet of gas per day. All produced water generated is treated at the platform and discharged overboard.

4.2.5 North Slope

Table IV-4 summarizes information regarding oil and gas production on the North Slope. As can be seen from Table IV-4, there are a total of 2,085 oil, gas, and service wells on the North Slope. The Prudhoe Bay field is the largest production field on the North Slope, accounting for about 71% of the total oil production on the North Slope. The two major operators in Prudhoe Bay, ARCO and BP Exploration (BPX), which own and operate the east side and the west side, respectively.

Production fluids are piped to gathering centers for separation and treatment. All the produced water from the North Slope oil production operations is injected either for waterflooding or into regulated disposal wells. About 88% of all the produced water is injected for waterflooding. The remaining 12% is injected into Class II disposal wells.[28]

TABLE IV-4

OIL AND GAS PRODUCTION FACILITIES ON THE NORTH SLOPE[28]

Field Name	Operator	Number of Oil, Gas, and Service Wells	Oil Production[a] (bpd)	Average Produced Water (bpd)	Number of Gathering Centers
Prudhoe Bay	ARCO&BPX	1,159	1,126,000	1,233,000	6
Kuparuk	ARCO	663	300,000	300,000	3
Endicott[b]	BPX	85	115,000	80,000	1
Lisburne	ARCO	86	30,000	8,000	1
Milne Point	Conoco[c]	91	19,000	11,000	1
West Beach	ARCO	1	3,000	0	0
	Total	**2,085**	**1,593,000**	**1,632,000**	**12**

[a] Oil production data include natural gas liquid and condensate production, where applicable.
[b] Endicott field data also include production from BP's Sag Delta near Endicott.
[c] Conoco sold this field to BPX in December, 1993.

NOTE:
Point McIntyre, West Beach, and N. Prudhoe Bay production is handled in the Lisburne Production Center.

There are a total of 12 production facilities (gathering centers) on the North Slope, of which all but the Endicott gathering center are in the coastal region. The Endicott field is currently produced from two gravel islands constructed in the Beaufort Sea. The production facilities on these islands are permitted, by the Alaskan Department of Environmental Conservation, as offshore facilities. All the produced water from the Endicott field is injected for waterflooding.[28]

4.2.6 Alternative Requirements Baseline

Alternative requirements baseline facilities include, in addition to all Cook Inlet facilities, Texas facilities seeking individual permits allowing discharge and Louisiana open bay facilities as discussed in the Industry Profile. Separate efforts were conducted to determine the population of Texas and Louisiana alternative baseline facilities.

4.2.6.1 Texas Dischargers Seeking Individual Permits

The population of Texas dischargers seeking individual permits was obtained from the Railroad Commission of Texas (RRC) intake log of facilities currently under Region 6 NPDES general permits who are seeking individual permits or who have notified RRC of their intent to do so.[38] The original RRC intake log includes 91 outfalls, which were consolidated to 82 outfalls. The entire log was used, with updated volume information from the RRC, to characterize the Texas alternative baseline population. Revisions to the original RRC log included:

- Elimination of four facilities (RRC permits # 708, 731, 732, and 733). These facilities were located in the Gulf of Mexico (offshore) rather than in (coastal) open bay areas.[39]
- Revisions of produced water flow rates for four facilities, as noted.
- Combination of outfalls for identical permit numbers within the same field.
- Confirmation of zero produced water flow as logged by RRC, except for four new flow rates extracted from permit applications.[38]

The Texas alternative baseline population is presented in Table IV-5. Based on the data from the 1993 Coastal Questionnaire, these facilities are all considered land-access production facilities.

No new sources of produced water or drilling fluids are expected from the Texas alternative baseline population. If new sources were to occur, they would be subject to pre-existing zero discharge requirements and would not incur costs under this rule.

4.2.6.2 Louisiana Open Bay Dischargers

The inventory of Louisiana open bay dischargers was identified from the facilities listed in the U.S. Department of Energy (DOE) report: "Final Report: Risk Assessment for Produced Water Dischargers to Louisiana Open Bays."[40] Based on the DOE report, the Louisiana open bay population consists of 45 outfalls. The Louisiana open bay population is presented in Table IV-5. Based on the DOE report, the Louisiana open bay population consists of 45 outfalls.

Produced water flow rates were also obtained from the DOE study with certain exceptions. In the case of two permits, the operator provided EPA with updated produced water flow rates which varied substantially from the flow rates in the DOE report. In five other cases, produced water flow rates were omitted, intermittent, or listed as zero. EPA was reluctant to underestimate the population described in the DOE report, so the average produced water flow rate (4,621 bpd) was substituted for discharges from these five permits. (An underestimation could result in underestimated costs and impacts for these facilities.)

TABLE IV-5

TEXAS DISCHARGERS SEEKING INDIVIDUAL PERMITS AND LOUISIANA OPEN BAY DISCHARGERS[38]

TEXAS				LOUISIANA	
Permit Number	Current Volume (bbl/day)	Permit Number	Current Volume (bbl/day)	Permit Number	Current Volume (bbl/day)
04CCC	0.0	927	95.0	2,827	1.0
1	0.0	242	104.0	2,856	3.0
14	0.0	264	114.0	3,023	3.4
18	0.0	*	115.0	2,479	10.0
127	0.0	552	140.0	2,857	20.0
215	0.0	922	143.0	1,870	49.0
217	0.0	605	150.0	3,032	50.0
595	0.0	202	153.0	2,915	130.0
674	0.0	684	165.0	2,952	223.0
711	0.0	694	185.0	2,704	524.0
747	0.0	637	200.0	2,901	1,076.0
825	0.0	822	200.0	3,072	1,489.0
903	0.0	970	250.0	3,002	2,017.0
233	1.0	710	358.0	2,816	2,271.0
282	1.0	174	384.0	2,825	2,910.0
690	1.0	967	397.0	2,898	3,617.0
708	1.0	921	410.0	1,866	4,621.0
723	1.0	679	454.0	2,273	4,621.0
972	1.0	124	455.0	2,995	4,621.0
119	2.0	238	515.0	3,014	4,621.0
733	2.0	731	517.0	4,206	4,621.0
71	3.0	619	536.0	2,881	5,010.0
13	5.0	968	540.0	2,523	5,364.0
732	6.0	666	628.0	2,860	6,800.0
*	7.0	105	650.0	2,672	8,366.0
663	10.0	937	659.0	2,859	10,807.0
693	10.0	60	685.0	3,063	11,500.0
37	15.0	167	690.0	2,142	12,076.0
214	16.0	166	1,029.0	1,856	15,000.0
284	22.0	20	1,151.0	1,934	15,675.0
628	24.0	904	1,360.0	2,084	16,743.0
752	29.0	85	1,379.0	2,618	22,500.0
924	31.0	45	1,400.0	3,320	22,579.0
41	40.0	969	1,480.0	2,134	23,333.0
199	40.0	80	1,492.0	2,504	37,113.0
939	43.0	*	1,500.0	2,072	37,750.0
236	44.0	90	1,800.0	1,901	41,700.0
926	48.0	68	2,185.0		
104	49.0	81	3,090.0		
919	60.0	77	3,552.0		
925	69.0	164	4,353.0		
582	75.0	813	4,893.0		
905	86.0	952	4,980.0		
675	92.0	113	5,127.0		
*	93.0	954	7,384.0		
		953	9,316.0		
TOTAL PW VOLUME			**68,290.0**	**TOTAL PW VOLUME**	**329,814.4**
* **Railroad Commission Permit Pending.**					

4.3 FUTURE COASTAL OIL AND GAS ACTIVITY

4.3.1 Drilling

Coastal drilling efforts vary from year to year depending on such factors as the price and supply of oil, the amount of State and Federal leasing, and reservoir discoveries. EPA estimates that a total of 161 wells will be drilled in North Slope coastal areas, including development wells and recompletions.[30]

4.3.1.1 Cook Inlet

Based on drilling projections provided by the industry, EPA estimates future drilling in the Cook Inlet region to be a total of 61 wells (or 9 per year) over the 7-year period from 1996 through 2002.[41] The projected 61 wells include development wells and recompletions. Based on the data provided by industry, EPA estimates that 41 of the 61 wells are development and exploratory wells and 20 are recompletions. These estimates are based on industry-projected drilling activity estimates and on the number of unused slots on each platform. Projections were assumed to represent recompletions for those platforms where drilling was projected but no slots are available for new wells. Out of these 61 wells, none will be classified as "new sources" under EPA's NPDES program. This is because the projected wells will be drilled from existing platforms, or will be exploratory wells (classified as existing sources). See also Chapter III of this document.

4.3.1.2 Other Coastal Areas

EPA estimates that the current drilling rate experienced by other coastal states in 1992 (see Table IV-1) will be similar to future annual drilling rates, also. This is a conservative estimate based on projections where drilling rates are not expected to increase (due to the maturity of the Gulf coastal oil fields). Rather than project a decrease in drilling rates, EPA is estimating a linear projection.[42] Thus, out of the 686 well drilling operations performed per year in Texas and Louisiana, 187 of them will be for new production wells (as reported in the EPA's statistical analysis of the 1993 Coastal Oil and Gas Questionnaire.[2] (Note: The Questionnaire is discussed in detail in Chapter V).

These estimated 187 projected drilling operations per year are new sources because they are expected to be drilled over a new “water area”. The remaining 499, which are either recompletions, sidetracks of existing wells, exploration or service wells, are not new sources because they are drilled from existing operations.

4.3.2 New Production Activity

New production activity for Louisiana and Texas is estimated to include six new facilities or separation/treatment facilities per year, based on results of the 1993 Coastal Oil and Gas Questionnaire.[43] For Alabama and Florida, EPA estimates a maximum of one new production facility per year, based on a comparison of the number of producing wells in Alabama/Florida to the number of wells in Louisiana/Texas.

No new sources are expected in Alaska. Although exploration and development of new fields will continue on the North Slope, according to the operators there are no plans to build new production facilities.[44] For new discoveries, operators on the North Slope intend to take advantage of existing separation/treatment facilities as much as possible, assuming that these facilities have sufficient capacity to handle the increased load.[44] For Cook Inlet, no new source production facilities are expected to occur in the near future. This is because, even considering the Sunfish discovery, no new platforms construction is expected.[45]

EPA knows of no plans for new islands at the THUMS facility at Long Beach Harbor, California.

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CHAPTER V

DATA AND INFORMATION GATHERING

1.0 INTRODUCTION

The major studies presenting information on coastal oil and gas effluents and treatment technologies EPA used to develop the final rule are summarized in the following sections. These include: an investigation of the underground injection of produced water and associated produced water treatment technologies; an investigation of solids control technologies for drilling fluids; an investigation of the drilling fluids and cuttings waste generation, treatment, and disposal in coastal Alaska; and an investigation of commercial non-hazardous oil and gas waste disposal facilities and technologies. In addition, a comprehensive Clean Water Act Section 308 survey of the industry was conducted to gather information to help characterize the coastal oil and gas subcategory. The Questionnaire and a summary of results are described in this section. A listing is included of certain data obtained in previous studies, and used in the coastal rulemaking, conducted during the development of the offshore subcategory effluent guidelines development.

2.0 INFORMATION TRANSFERRED FROM THE OFFSHORE RULE

Due to the similarities in the technologies employed and wastes generated by the offshore and coastal subcategories of the oil and gas industry, certain data generated during the offshore rulemaking have been utilized in the development of this rule where appropriate. Those data most influential in the development of this rule, listed below, are described in more detail in the Offshore Development Document and will not be discussed further in this section.[1]

- Produced Water Characteristics for Cook Inlet

    The BPT-level produced water characteristics for Cook Inlet were used in calculating the pollutant reductions and the BCT cost test for the gas flotation and zero discharge options for Cook Inlet discharges. The data used included flow-weighted averages of the organics and zinc data in the Envirosphere report[2], BPT level effluent concentrations from the Gulf of Mexico data cited in Table XII-15 of the Offshore Development Document (where Cook Inlet data were missing for certain pollutant parameters, as discussed in Chapter VIII of this document), and radium data from the Alaska Oil and Gas Associations Comments submitted in response to the offshore rule, 56 FR 10664 March 13, 1991 and 56 FR 14049 April 5, 1991.[3]

- Produced Water Characteristics for Effluent from Improved Gas Flotation

  The difference between the pollutant concentrations for BPT-level effluent and the pollutant concentrations achieved using improved gas flotation (IGF) were used to calculate pollutant reductions for the IGF option. These data were reported in Table XII-15 of the Offshore Development Document.

- Drilling Fluids and Drill Cuttings Characteristics

  The concentrations of organic pollutants in mineral oil were used to calculate the pollutant loadings in drilling fluids and cuttings. The concentrations used were the averages of concentrations for three types of mineral oil presented in the Offshore Development Document, Table VII-9.

  The barium concentration used to calculate the barium loading of the discharged drilling fluid was calculated from the total pounds of barite in the drilling fluid. Based on the information provided in the Offshore Development Document, page XI-8, the barite was assumed to be pure barium sulfate (100% $BaSO_4$) and the barium sulfate was assumed to contain 58.8 percent (by weight) barium.

- Deck Drainage Characteristics

  The deck drainage characteristics from Chapter X of the Offshore Development Document were incorporated into the descriptive portions of this document and were not used in any analysis.

- Domestic Waste Characteristics

  The domestic waste characteristics from Chapter XVI of the Offshore Development Document were incorporated into the descriptive portions of this document and were not used in any analyses.

- Sanitary Waste Characteristics

  The sanitary waste characteristics from Section XVII of the Offshore Development Document were incorporated into the descriptive portions of this document and were not used in any analyses.

- Non-Water Quality Environmental Impacts

  The non-water quality environmental impacts data were used to estimate the non-water quality environmental impacts of this regulation. This includes the estimation of increases in air pollution emissions and safety. The data used are information from the offshore rulemaking and supplemented with information from sources described later in this Chapter. The data from the offshore rulemaking effort and the supplemental sources are listed below:

  - Equipment power and fuel requirements[4]
  - Equipment operating parameters[4]
  - Personnel casualty and injury data[5]

3.0 INDUSTRY SURVEY

A comprehensive questionnaire (comprising 99 pages) entitled the 1993 "Coastal Oil and Gas Questionnaire" was developed under the authority of Section 308 of the CWA. This Questionnaire was distributed to all known coastal oil and gas operators and requested detailed economic data and information on oil and gas waste generated, treatment and disposal methods, and disposal costs for these wastes.

Prior to this, a draft of the Questionnaire was reviewed by several industry trade associations, comments were considered and incorporated where appropriate. A pre-test Questionnaire was then sent to seven coastal operators in August 1992. After reviewing the pre-test results and consulting the operators, EPA made significant changes and improvements in the Questionnaire. In order to minimize the burden, the seven operators were not included in the final survey.

The 1993 Coastal Oil and Gas Questionnaire, hereafter referred to as the EPA Questionnaire, was divided into four sections. The first two sections requested information concerning the technical and financial contacts. Section 3 requested technical operating information in two parts: Section 3.1 "Production Operations," and Section 3.2 "Well Drilling Operations." Section 4 "Finances" requested financial information about the operator.

Section 3.1 "Production Operations" requested detailed information on: production data, treatment system wastewater disposal, outfall data, treatment technologies, treatment costs, injection costs, miscellaneous waste generation and disposal, miscellaneous waste disposal costs, and treatment chemical usage. Section 3.2 "Well Drilling Operations" requested detailed information on: type of well, well depth, drilling costs, type of drilling used, solids separation technologies, drilling fluid and cuttings disposal, waste handling and disposal costs, miscellaneous waste generation and disposal, miscellaneous waste disposal costs, reserve pit data, and drilling chemical usage.

The survey was designed to cover three interrelated populations. Population is a statistical term used to describe the set of all units of interest. The three populations are: (1) all operators of coastal oil and gas extraction facilities, (2) all coastal oil and gas wells, (3) all wastewater treatment facilities for coastal oil and gas extraction. There are two basic methods for conducting a survey: one is to perform a "census" which requests data on all identified units in a population, the second is to sample a subset of the population which is referred to as a "survey." The EPA Questionnaire was sent to all known coastal operators (a census) but only requested information on some of their wells (a survey).

EPA developed a list of coastal operators and their wells by combining information from several sources.[6] Three data sources were used to identify production wells and their locations. One source was the database maintained by the Petroleum Information Corporation. The database contains information on the wells completed or worked-over between 1980 and 1990. Worked-over wells were sometimes drilled decades prior to 1980. The second source was Tobin Survey Incorporated. Tobin compiles information on wells by geographic location. The third source was information supplied by the Alaska Oil and Gas Conservation Commission including wells that were active in 1991. As a result, the final list of operators to be surveyed contained 361 coastal operators and 3,623 wells.[6]

The operators were grouped into three categories; majors, large independents, and small independents. The wells were grouped into those completed before and after 1990 and those located in saline and freshwater environments. Table V-1 presents the breakdown of all 3,623 coastal wells into the categories described above. The survey was designed so that a census of all 361 operators (not including the seven pretest operators) was conducted. All operators were required to complete Section 4 "Finances." Information on all 3,623 wells was not requested. The 327 wells surveyed in the pre-test Questionnaire were excluded from responding to the Questionnaire. For 179 wells where particular situations existed that were limited in occurrence, EPA requested information on all of these wells. Such circumstances included wells located in marine wetlands (one well), wells located on platforms in the Gulf of Mexico (35 wells), and all wells owned by small independent operators (143 wells). The remaining 3,177 wells were surveyed using a stratified probability design (see Glossary), where a representative well population of 603 out of 3,177 wells were selected for purposes of responding to the Questionnaire. Operators were instructed to provide technical information only on the wells identified and the separation and treatment facility associated with each well.

Information was reported for all wells under Section 3.1 of the Questionnaire, entitled "Production Operations," but operators were not expected to retain drilling information associated with older wells. For Section 3.2 of the Questionnaire, entitled "Drilling Operations," EPA identified 191 wells that had been newly drilled or worked-over during the period of 1990 through 1992. Information on drilling operations was requested for only those identified wells. Of these, 167 were in the Gulf of Mexico and 24 were in Alaska. Data were received for 138 of the 191 wells surveyed for drilling operations.

TABLE V-1

TOTAL WELL COUNT SURVEYED FOR COASTAL OIL & GAS WELLS BY CATEGORY

Population		Prior to 1990		Including 1990 and After		Total Well Count	Actual Wells Surveyed
		Fresh	Saline	Fresh	Saline		
Alaska	Major	640	282	21	39	982	100
Gulf	Major	496	119	174	67	856	133
	Sm. Ind.	95	26	21	2	144	143
	Other	902	355	300	84	1,641	227
ALL		2,133	782	516	192	3,623	603

Of the 361 EPA Questionnaires that were sent out, 89 were out of scope because they were non-coastal operators or out of business. Of the remaining 272 surveyed operators that were in scope, 236 responded. Sufficient numbers of respondents were available to generate estimates for each of the survey strata, or analysis groups.

Upon their return, the EPA Questionnaires were reviewed for completeness and technical content and then were transcribed into a computer readable format using double key-entry procedures. Survey responses were used to generate statistical estimates describing that portion of the coastal oil and gas industry associated with wells completed or recompleted after 1980.

As described in the Economic Impact Analysis,[7] the well-specific data, statistical results, and an adjustment factor related to the number of producing wells that have not been recompleted since 1980 were then used in determining waste volumes, treatment and disposal methods and costs. The survey results were also used to estimate future industrial activity.

4.0 INVESTIGATION OF SOLIDS CONTROL TECHNOLOGIES FOR DRILLING FLUIDS

In 1993, EPA collected samples and gathered technical data at three drilling operations in the coastal region of Louisiana. The purpose of this effort was to gather operating and cost information regarding closed-loop solids control technology at active oil and gas well drilling operations and to collect samples of water generated from drilling waste dewatering operations. Samples were analyzed for a variety of analytes in the categories of organic chemicals, metals, conventional and non-conventional pollutants, radionuclides, and toxicity.

Three drilling operations were visited and samples were collected during drilling of three exploratory wells. The three wells were:

- The Gap Energy well (Sweetlake Land & Oil No.1) in Holmwood, spudded on May 24, 1993;[8]
- The Arco well (Miami Corporation No. 1) on the Black Bayou Prospect in Cameron Parish, spudded on June 22, 1993;[9] and
- The Unocal well (LA. FURS. C-16) at Freshwater Bayou in Vermilion Parish, spudded on August 7, 1993.[10]

The Gap and Arco wells were drilled using land-based rigs, while the Unocal well was drilled using a posted-barge. At the time of the sampling visits, all three wells were being drilled using water-base drilling fluids. However, for one well, oil-based fluids were used for the final section of the well. Table V-2 presents summary information obtained regarding drilling of these three wells.

Samples of dewatering centrifuge liquid were collected to determine the characteristics of this process stream. This process stream consisted mostly of the water phase of the drilling fluid. This dewatering effluent was not discharged at any of the sites visited. One solids control contractor suggested that further treatment with activated carbon would be necessary in order to meet applicable discharge criteria.[9]

One set of grab samples was collected on two consecutive days from the liquid discharge from the centrifuge processing the drilling fluids. The major difference between the solids control systems was that both Gap and Arco were using chemical treatment of the centrifuge influent with coagulant and polymer to enhance centrifugation during the time of sampling while Unocal was not. The result was that separation of the drilling fluid solids from the water was much more efficient at both the Gap and Arco sites. Both the Gap and Arco samples were relatively free of suspended solids (TSS ranged from 24 to 520 mg/l) while the Unocal samples were analyzed as a solids sample with total solids ranging from 23% to 24.7% and had the consistency of a drilling fluid.

TABLE V-2

TECHNICAL DATA FOR THE THREE WELL DRILLING OPERATIONS VISITED

Well Name	Total Depth	Depth at Sampling	Drilling Fluid Type	Solids Control Technologies	Reported Solids Control Efficiency[a]
Gap Energy Holmwood, LA	12,860 ft.	11,990 ft.	Water-base	Shale Shakers, Degasser, Desander, Desilter with Shaker, Barite Recovery Centrifuge, Chemically Enhanced Centrifugation	90%
Arco Black Bayou Prospect, LA	14,928 ft.	12,741 ft.	Water-base	Shale Shakers, Degasser, Desander, Desilter with Shaker, Barite Recovery Centrifuge, Chemically Enhanced Centrifugation	90%
Unocal Freshwater Bayou, LA	19,260 ft.	12,349 ft.	0-13,545 ft: Water-base >13,545 ft: Oil-base	Shale Shakers, Degasser, Desanders, Desilter with Shaker, Barite Recovery Centrifuge, Centrifuge (no chemical addition)	75%

[a] Estimate provided by solids control contractor for equipment configuration during day of sampling.

The combination chemical treatment and centrifugation, referred to as "chemically enhanced centrifugation," allows the water to be recycled back into the drilling fluid recirculation system without the build up of fine drill cuttings that is detrimental to the drilling fluid. This drilling technology is discussed in greater detail in Chapter VII.

In addition to the sampling activities, technical and cost information was collected on the following topics:

- drilling waste volumes and disposal methods
- solids control equipment design and performance
- drilling fluids
- well design and construction
- drilling operations
- annular injection
- miscellaneous waste volumes and disposal methods.

The results of this investigation were used to determine methods and costs of drilling waste disposal, and to provide information on miscellaneous waste volume, treatment and disposal.

5.0 SAMPLING VISITS TO 10 GULF OF MEXICO COASTAL PRODUCTION FACILITIES

From May 11 through November 13, 1992, EPA visited ten coastal oil and gas production facilities located in Texas and Louisiana. The purpose of this effort was to gather operating and cost information at active oil and gas production facilities and to collect samples of produced water and associated wastes. Samples were analyzed for a variety of analytes in the categories of organic chemicals, metals, conventional and non-conventional pollutants, and radionuclides. Sampling at each site was conducted for one day over a span of eight hours. Technical and cost data were collected in addition to the production waste samples. Table V-3 presents the operator name, field name, and location of the 10 facilities. A report was prepared, entitled "Coastal Oil and Gas Production Sampling Summary Report," that summarizes and describes the samples collected, treatment systems employed, and data generated.[21]

Below is a brief summary of the facilities, the samples collected and the types of pollutants analyzed in this study.[21]

TABLE V-3

PRODUCTION FACILITIES SAMPLED

Operator Name	Field Name	Location	Reference
Greenhill Petroleum	Bully Camp	La Fourche Parish, LA	11
Oryx Energy	Chacahoula	La Fourche Parish, LA	12
Exxon Corporation	Clam Lake	Jefferson County, TX	13
Oryx Energy	Caplen	Galveston County, TX	14
Texaco	Sour Lake	Hardin County, TX	15
Texaco	Port Neches	Orange County, TX	16
Arco	Bayou Sale	St. Mary Parish, LA	17
Texaco	Bayou Sale	St. Mary Parish, LA	18
Badger Oil Corporation	Larose	La Fourche Parish, LA	19
Texaco	Lake Salvador	St. Charles Parish, LA	20

- Of the ten facilities sampled, six were in southeastern Louisiana and four were in southeastern Texas.
- Five were accessible by car and five were accessible by boat.
- One site operator was a small independent company, one was a medium size company, and eight were major companies.
- Four facilities produced only oil and six produced both oil and gas.
- Produced water flowrates ranged from 2,500 bpd to 11,500 bpd.
- Nine facilities utilized injection wells for produced water disposal and one utilized surface discharge.
- Nine facilities utilized settling tanks as the primary step for removal of solids and trace quantities of oil from produced waters.
- One facility utilized a coalescer for removal of trace quantities of oil prior to settling.
- All of the four facilities that were accessible only by boat disposed of produced water using injection wells and utilized filtration as a final treatment step between settling and injection. Three of these facilities used cartridge filters and one used a 200 mesh screen.
- Aqueous samples were collected from settling tank effluent at all ten facilities.

- Aqueous samples were collected at the influent (settling effluent) and effluent of all four filtration systems.

- Aqueous samples were also collected at the influent and effluent of the coalescer, although the effluent samples were analyzed only for oil and grease and TSS.

- Two consecutive four-hour grab composite samples were collected at all aqueous sample locations. Each four-hour aqueous composite was analyzed for the following analytes:

  - Volatile Organics
  - Semi-volatile Organics
  - Metals
  - Conventional Parameters
  - Non-conventional Parameters
  - Radionuclides.

- Four consecutive two-hour grab composite samples were also collected at all aqueous sample locations. Each two hour composite was analyzed for the following:

  - Oil and Grease
  - TSS.

- Samples of cartridge filters were collected at all three facilities that utilized them. The samples were analyzed for radionuclides only.

- A grab sample of settling tank bottoms was collected at four facilities. Due to limited quantities available at two of these facilities, one of these samples was analyzed for radionuclides only and the other sample was analyzed for radionuclides and metals only.

- A grab sample of material that was cleaned out of a heater-treater (mostly sand and some oil) was collected at one facility.

- The remaining two settling tank bottoms samples and the heater-treater sample were analyzed for the following analytes:

  - Volatile Organics
  - Semi-volatile Organics
  - Metals
  - Conventional Parameter
  - Non-conventional Parameters
  - Radionuclides.

- One grab sample of coalescer tank bottoms was collected, and since the solids were dilute, the sample was analyzed as a liquid (aqueous) sample.

- One sample of sand generated during the workover of an oil producing well was collected and analyzed for radionuclides only.

Figure V-1 presents the location of the waste samples collected and also presents the five different treatment and disposal sequences observed at the 10 facilities.

In addition to the sampling activities, technical and cost information was collected on the following topics:

- separator and treatment system technologies and configuration
- equipment space requirements
- support structures
- miscellaneous waste volumes treatment and disposal methods
- produced water volumes and disposal methods
- energy requirements
- injection well remedial work requirements
- ancillary equipment requirements (besides the injection well) for injection
- injection well design and operation
- production data.

In response to comments on the proposed coastal oil and gas rulemaking, EPA excluded three facilities in the 10 Production Facility Study with settling effluent oil and grease concentrations greater than the BPT daily maximum discharge limit of 72 mg/l. These facilities were determined not to be representative of current BPT practices. The data from the remaining seven facilities were statistically evaluated to derive settling effluent average pollutant concentrations.[22] The results from the 10 Production Facility Study, together with data from the EPA Questionnaire, formed the basis for EPA's produced water treatment and disposal cost analyses discussed later in Chapter XI. The analytical data was used to characterize produced water effluent characteristics from BPT treatment system.

6.0 STATE DISCHARGE FILE INFORMATION

EPA obtained detailed information on produced water discharges, for operators in Texas and Louisiana, by reviewing state discharge permits. The Louisiana Department of Environmental Quality (LADEQ) and the Railroad Commission of Texas (RRC) supplied state permit data for all known dischargers in the coastal areas.[23] The state permit information identifies the operator, the name of the producing field, the location of the production facility, the volume of produced water discharged, the location and permit number of the outfall, and in Louisiana only, the compliance date by which the

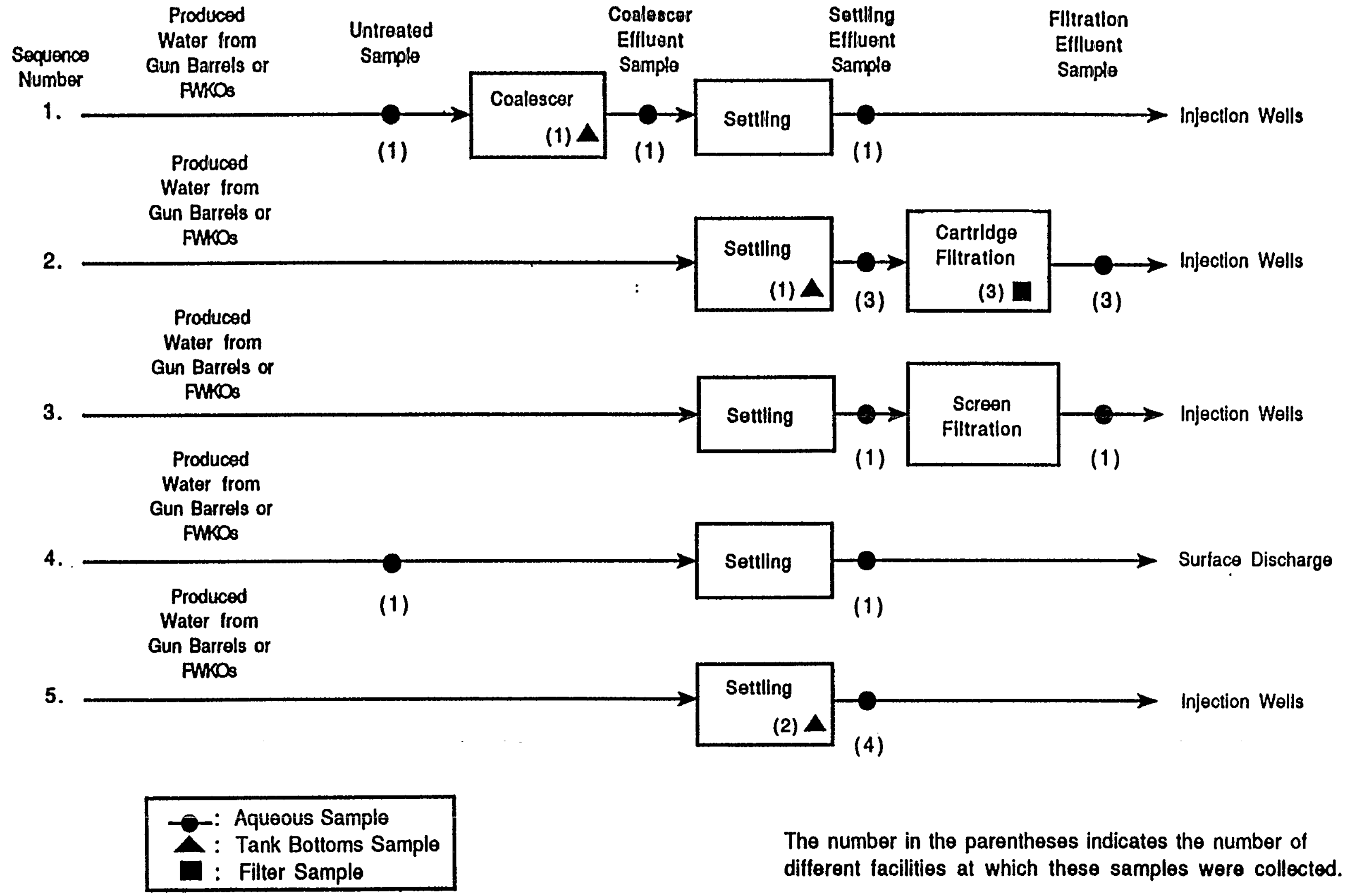

Figure V-1
Sample Locations and Treatment System Sequences at the 10 Coastal Production Facilities

discharge must cease. These data were used at proposal and during final rulemaking efforts to identify the discharging population affected by the regulations. For the alternative baseline requirements analysis (discussed in Chapter IV), EPA obtained from the RRC a list of produced water dischargers seeking individual permits. The inventory of Louisiana open bay dischargers was identified from the facilities listed in the U.S. Department of Energy (DOE) report entitled "Final Report: Risk Assessment for Produced Water Dischargers to Louisiana Open Bays."[24]

7.0 COMMERCIAL DISPOSAL OPERATIONS

7.1 COMMERCIAL DRILLING WASTE DISPOSAL SITE VISIT

In May 1992, EPA visited two non hazardous oil and gas waste land treatment facilities at Bourg and Bateman Island, Louisiana and also two waste transfer stations at Port Fourchon and Morgan City on Bayou Boeuf, Louisiana. Campbell Wells is the operator of these four facilities. The purpose of these visits was to investigate the transportation, handling, disposal methods employed and associated costs of these operations. Detailed information was gathered concerning the operation of the landfarm treatment process used for the disposal of non-hazardous oil field wastes, transportation equipment, transfer equipment, equipment fuel requirements and costs incurred by the facilities and costs charged to the customers. This information was summarized in the "Trip Report to Campbell Wells Landfarms and Transfer Stations in Louisiana."[25] The information was used in the development of compliance costs and the non-water quality impacts for the various regulatory options being considered.

7.2 SAMPLING VISITS TO TWO COMMERCIAL PRODUCED WATER INJECTION FACILITIES

On March 12, 1992, U. S. EPA visited two commercial produced water injection facilities to collect samples and technical data.[26,27] The purpose of the visits was to collect information regarding costs of produced water disposal and other operating costs as well as to collect samples of produced water, filter solids, used filters and tank bottoms solids for radioactivity analysis. The two facilities were Campbell Wells in Bourg, Louisiana and Houma Saltwater in Houma, Louisiana. Both facilities received produced water mostly by truck but also had the capability to receive produced water by barge. Both facilities utilized sedimentation and filtration as treatment processes for produced water followed by underground injection. The filtration systems differed slightly in that Houma Saltwater used bag and cartridge filters in series while Campbell Wells (Bourg) used only bag filters. At the Campbell Wells (Bourg) facility, water from the landfarming operation was combined with produced water received from offsite prior to treatment and injection.

At both facilities, samples of produced water from the influent and effluent of the filtration system were collected as well as solids from the bag filters, settling tank bottoms and at Houma Saltwater, a used cartridge filter. These samples were then analyzed for Ra-226, Ra-228, Gross Alpha, and Gross Beta. The technical information gathered at these sites was used in developing compliance costs and the non-water quality impacts for the various regulatory options being considered. The results of the radio- activity analyses were used in an evaluation of radioactivity concentrations in oil and gas wastes. This evaluation is described below.

8.0 NORM STUDY

EPA reviewed all known data regarding the presence of naturally occurring radioactive materials (NORM) found in discharges of produced water and associated with scales and sludges (produced sand) generated by production equipment from the coastal oil and gas industry. The oil and gas production process can extract naturally occurring radionuclides from within the geologic formation. The most common of these radionuclides found are radium-226, radium-228, and lead-210, which are soluble in the produced water. Radium-226 and radium-228 concentrations in ocean water may range from 0.024 to 0.182 pCi/l and 0.0001 to 0.1 pCi/l, respectively.[28]

EPA has prepared a report summarizing produced water radioactivity data from the 22 available studies EPA has reviewed, focusing on data from coastal sites.[29] Each of these 22 studies is summarized in that report according to the location of the sites, sampling plans, and analytical methods used to measure the radionuclides.

Tables V-4, V-5 and V-6 summarize the findings from this evaluation. This information was used in characterizing produced water effluents in the Gulf Coast.

9.0 ALASKA OPERATIONS

9.1 REGION 10 DISCHARGE MONITORING STUDY

In an effort to characterize discharges to Cook Inlet, EPA Region 10 conducted a comprehensive Discharge Monitoring Study of facilities that discharge produced water.[2] Produced water discharges from production facilities were sampled and analyzed for one year, from September 1988 through August 1989. Samples were collected and analyzed from two oil platforms, one natural gas platform and three shore-based treatment facilities, all of which discharge produced water to Cook Inlet. The results of this

TABLE V-4

SUMMARY STATISTICS OF RADIUM-226 (pCi/l) FROM COASTAL OIL AND GAS SITES[29]

Study	Source	No. of Sites	No. of Samples	Mean	Std	Min	Max
1	Formation Water	15	15	326.5	.	<0.1[a]	1580
2	Untreated Effluent	4	4	195.8	140.6	22	327
	Acidified/Filtered Effluent	6	6	238.8	140.8	16	393
	Acidified/Unfiltered Effluent	7	7	275.9	110.8	46	397
3	Produced Water (all sample pts)	1	14	20.3	9.5	10.6	42.4
	Produced Water Effluent	1	4	14.7	3.4	10.6	18.5
6	Produced Water Effluent (all methods)[b]	407	407	162.8	144.7	0.05	930
	Produced Water Effluent (Method 707E only)[b]	352	352	181.7	141.4	0.1	930
7	Produced Water Effluent	3	6	197.1	72.0	86.8	258.3
8	Produced Water Effluent[c]	1	4	539.0	145.3	448	756
9	Produced Water Effluent	6	8	2.7	2.2	1.1	4.2
10	Produced Water Effluent	4	4	497.0	96.1	355	567
11	Produced Water Eff. (MOGA)[b]	267	267	181.6	.	0.05	792
	Produced Water Eff. (DEQ)[b]	405	405	159.2	.	0.05	930
	Produced Water Eff. (CSA)	3	3	197.1	75.8	110.6	251.9
16	Produced Water Effluent	2	2	96.6	65.7	50.1	143
17	Produced Water Effluent (commercial facilities)[b]	2	2	50.3[d]	7.3[d]	33.9	66.2
	Produced Water Effluent (production facilities)[b]	10	20	172.19[d]	55.1[d]	4.5	420
20	Production Equipment Scale[e]	.	.	360.0[f]	.	.	.
	Production Equipment Sludge[e]	.	.	56.0[f]	.	.	.
	Disposal Wastes[e]	.	.	90.0[f]	.	.	.
21	Produced Water Effluent	25	25	.	.	.	.
22	Drilling Waste Effluent[b]	2	4	2.6[d]	1.2[d]	1.3	5.1

[a] Detection limit is 0.1 dpm/l.
[b] Samples below the minimum level of detection are set equal to the detection limit.
[c] Four samples analyzed by four different analytical methods.
[d] From SAIC, January 31, 1995[6]
[e] Combination of coastal, offshore, and onshore sites.
[f] Units are pCi/g for these samples.

TABLE V-5

SUMMARY STATISTICS OF RADIUM-228 (pCi/l) FROM COASTAL OIL AND GAS SITES[29]

Study	Source	No. of Sites	No. of Samples	Mean	Std	Min	Max
1	Formation Water	15	15	472.0	.	18.7	1248
3	Produced Water (all sample pts)	1	14	24.0	11.6	11.2	54.5
	Produced Water Effluent[a]	1	4	17.5	5.8	11.2	24.9
6	Produced Water Effluent[a]	407	407	184.5	375.9	0[b]	7090
7	Produced Water Effluent	3	6	294.1	69.4	233.6	386
8	Produced Water Effluent	1	1	460.0	.	.	.
9	Produced Water Effluent	6	8	7.5	3.1	5.3	9.7
11	Produced Water Eff. (MOGA)[a]	267	267	219.7	.	0[b]	928
	Produced Water Eff. (DEQ)[a]	405	405	164.5	.	0[b]	928
	Produced Water Eff. (CSA)	3	3	294.1	77.2	244.4	383.0
16	Produced Water Effluent	2	2	98.6	71.3	48.2	149
17	Produced Water Effluent (commercial facilities)[a]	2	2	34.9[c]	4.0[c]	17.5	49.0
	Produced Water Effluent (production facilities)[a]	10	20	228.4[d]	49.4	3.1	500
20	Production Equipment Scale[e]	.	.	120.0[a]	.	.	.
	Production Equipment Sludge[e]	.	.	19.0[a]	.	.	.
	Disposal Wastes[e]	.	.	30.0[a]	.	.	.
22	Drilling Waste Effluent[a]	2	4	7.3[c]	2.4[c]	5.7	10.5

[a] Samples below the minimum level of detection are set equal to the detection limit.
[b] One sample was reported with a detection limit of 0 pCi/l.
[c] Mean is arithmetic average of facility means; Standard deviation is pooled within-facility estimate.
[d] From SAIC, January 31, 1995[6]
[e] Combination of coastal, offshore, and onshore sites.

sampling effort are summarized in Table XII-15 in the Offshore Development Document[1] and are used in the coastal rulemaking to characterize Cook Inlet BPT produced water discharges.

9.2 EPA SITE VISITS AND INFORMATION GATHERING EFFORTS

In 1993, EPA visited drilling and production operations in both the Cook Inlet and the North Slope regions of Alaska. Information and data were obtained during these visits, as well as by contacting the

TABLE V-6

SUMMARY STATISTICS OF LEAD-210 (pCi/l) FROM COASTAL OIL AND GAS SITES[29]

Study	Source	No. of Sites	No. of Samples	Mean	Std	Min	Max
3	Produced Water (all sample pts)[a]	1	14	7.1	0.5	6.4	8.0
	Produced Water Effluent[a]	1	4	7.1	0.4	6.5	7.5
17	Produced Water Effluent (commercial facilities)[a]	2	2	47.4	0.9	42.5	50.5
	Produced Water Effluent (production facilities)[a]	10	20	75.2[b]	27.4[b]	40.1	221.0
20	Production Equipment Scale[c]	.	.	360.0[d]	.	.	.
	Production Equipment Sludge[c]	.	.	56.0[d]	.	.	.
	Disposal Wastes[c]	.	.	90.0[d]	.	.	.
22	Centrifuge Effluent[a]	2	4	12.1[d]	5.6	7.0	19.0

[a] Samples below the minimum level of detection are set equal to the detection limit.
[b] Mean is arithmetic average of facility means; Standard deviation is pooled within-facility estimate.
[c] Combination of coastal, offshore, and onshore sites.
[d] Units are pCi/g for these samples.

Alaska Oil and Gas Association (AOGA), state regulatory authorities, and individual operators. The EPA findings from the site visits are presented in a report on Cook Inlet and North Slope oil and gas facilities.[30]

AOGA and individual operators submitted, upon request from EPA, information on projects and technologies currently being developed and used in Cook Inlet and on the North Slope to handle drilling and production wastes, and the costs associated with these projects. The information regarding waste handling methods and technologies was incorporated into a report prepared for EPA.[31] This report reviews all past and current exploration and production waste handling methods in both Cook Inlet and on the North Slope, as well as the climate conditions and current state and Region 10 regulatory requirements.

The following sections summarize the information EPA has obtained through these efforts.

9.2.1 Drilling Operations on the North Slope

In their effort to achieve zero discharge, operators of oil and gas exploration facilities on the North Slope have developed a grinding and injection system for drilling fluids and cuttings as an alternative to land disposal. The grinding and injection system is a result of many years of investigation of technologies that can achieve zero discharge of drilling wastes.

As part of this program, operators investigated methods to reduce the volume of drilling fluids and cuttings that would require disposal. One such waste reduction method involved the separation of the surface cuttings from the drilling fluid, washing of the cuttings, and determining their potential reuse as construction material. Surface cuttings (cuttings generated from the first 3500 feet of drilled depth) account for approximately 50% of the total cuttings volume. On the North Slope, these cuttings are very similar to sand and gravel from the local pit mines which are used as construction material.[31]

The drill cuttings reclamation program established the potential of surface cuttings reclamation and reuse as construction gravel material. The next step in this program was to establish the technical achievability and costs of winterized, mobile cuttings processing units. In general, the study of the cuttings processing units consisted of processing surface hole cuttings through two separate, mobile, and winterized units. Processed sands and gravel were collected and analyzed at specific intervals to determine their reuse potential as construction materials. Coarse materials were recovered for reuse, while fines and fluids were disposed by injection.

As a result of this program, successful implementation of the use of grinding and injection for drilling fluids and cuttings disposal on the North Slope has been occurring for the past several years.[30]

9.2.2 Production Operations on the North Slope

All production waste handling methods on the North Slope are currently regulated by state agencies. Produced water, workover/treatment/completion (WTC) fluids, deck drainage, and produced sand are not discharged from the North Slope coastal facilities including Endicott Island. Only domestic and sanitary wastes may be discharged on the North Slope, after treatment. Produced water is injected for waterflooding and for disposal into Class II injection wells.[30]

9.2.3 Drilling Operations in Cook Inlet

Marathon Oil Co. and Unocal Corp. submitted to EPA a report on drilling waste disposal alternatives and their implementation costs based on projected drilling schedules.[32] Three alternatives were investigated in terms of technological achievability and costs: discharge to Cook Inlet, land-based disposal, and disposal by injection.

EPA evaluated the information presented in this report and utilized the relevant information in the development of regulatory options for drilling wastes in Cook Inlet. Costing information was used to estimate the regulatory compliance costs.

9.2.4 Production Operations in Cook Inlet

Marathon Oil Co. and Unocal Corp. submitted to EPA a report on the technological and economic feasibility of zero discharge of produced water from the Trading Bay onshore treatment facility.[33] This report presented the costs and technological achievability for three produced water injection alternatives.

EPA evaluated the information presented in this report and utilized the relevant information in the development of the zero discharge option for produced water in Cook Inlet by injection. Costing information was used to estimate the regulatory compliance costs.

10.0 REGION 10 DRILLING FLUID TOXICITY DATA STUDY

In order to determine the appropriate toxicity level for a more stringent toxicity option for drilling fluids and cuttings, EPA attempted to evaluate effluent toxicity test results for Cook Inlet drilling fluids and cutting discharges.[34] EPA reviewed permit compliance monitoring records, from EPA's Region 10, containing 161 sets of results for toxicity testing of drilling fluids and drill cuttings used in the Alaska offshore and coastal regions between 1985 and 1994. (The measure of toxicity is a 96 hour test that estimates the concentration of drilling fluids suspended particulate phase (SPP) that is lethal to 50 percent of the test organisms.) The records were summarized into a database which was evaluated on the basis of the toxicity of drilling fluids and drill cuttings used in Alaska as a whole and Cook Inlet in particular.

These evaluations utilized an available database obtained from EPA's Region 10, which provides an account of the relationship between toxicity and drilling fluids currently being discharged. The toxicity values are identified in the available database by operator, permit number, well name, date and base fluids system (mud). In addition, some of the values are related to an identified volume of muds discharged. However, many of the values in the summary do not have either a volume identified or whether the drilling fluids were discharged. The findings of these evaluations were incorporated into the descriptive portions of this document and were not used in any analysis.

11.0 CALIFORNIA OPERATIONS

EPA visited coastal oil and gas operations in Long Beach Harbor, California in February of 1992.[35] Four man-made islands have been constructed in the Harbor for the purpose of oil and gas extraction, and the facilities on these islands are operated by THUMS. EPA met with state regulatory officials and was given a tour of one of the islands by THUMS personnel. Both drilling and production were occurring at the time of the visit.

Information regarding waste generation, treatment, disposal, and costs were obtained during the visit. The information provided EPA with specific waste disposal technology and cost information which has, where appropriate, been incorporated into cost analyses, and enabled EPA to characterize California coastal oil and gas operations.

12.0 OSW SAMPLING PROGRAM

EPA's Office of Solid Waste conducted a sampling program of various oil and gas wastes in 1992.[36,37] As part of this effort, samples were obtained for completion, workover, and treatment fluids. EPA has used this database to characterize the effluent for these fluids. Treatment, workover and completion fluids were collected from operations in Texas, New Mexico, and Oklahoma. Treatment, workover and completion operations at onshore and coastal sites are identical, thus these data are valid for characterizing discharges of these fluids at coastal operations. The samples were analyzed for conventional, nonconventional and priority pollutants.

13.0 ESTIMATION OF INNER BOUNDARY OF THE TERRITORIAL SEAS

EPA specifically estimated the location of the outer boundary of the coastal subcategory (which is the inner boundary of the Territorial Seas)[38] by estimating the latitude and longitude coordinates covering that part of the inner boundary of the Territorial Seas along Alaska's North Slope and Cook Inlet, Texas, Louisiana, Alabama, and Southern California.

Much of this boundary has been delineated on nautical charts published by the National Ocean Service of the National Oceanic and Atmospheric Administration (NOAA). In some locations, however, this boundary has not previously been delineated by NOAA, and EPA completed the coordinates using established procedures described in the Convention of the Territorial Seas and the Contiguous Zone, Articles 3-13. This boundary was used by EPA to determine the number of coastal oil and gas wells that exist in this subcategory.

14.0 OTHER INFORMATION SOURCES

EPA utilized specific information submitted with public comments on the proposed rule. Commenters provided information that EPA included, where applicable, in the compliance cost, pollutant removal, and non-water quality environmental impact (NWQI) analyses presented in this Development Document. The information provided in the comments was augmented with additional data and information as needed to update the corresponding sections of this document. The Construction Cost Index (CCI) reported in the Engineering News Record was used to convert to 1995 dollars otherwise unmodified compliance cost estimates as well as equipment or service costs from other years.[39] In addition, EPA contacted individual operators to confirm current drilling plans, oil and gas production facility locations, current produced water discharging volumes, and produced water outfall configurations. The specific sources of this information are cited throughout the chapters of this document.

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CHAPTER VI

SELECTION OF POLLUTANT PARAMETERS

1.0 INTRODUCTION

This section presents information concerning the selection of the pollutants to be limited for the Coastal Effluent Guidelines. The discussion is presented by wastestream.

2.0 DRILLING FLUIDS, DRILL CUTTINGS, AND DEWATERING EFFLUENT

EPA is establishing BAT, BCT, NSPS, PSES, and PSNS limitations that would require zero discharge of drilling fluids, drill cuttings, and dewatering effluent, except for BAT, BCT, and NSPS in Cook Inlet, Alaska.

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

The toxic metals identified in drilling fluids and cuttings include zinc, beryllium, cadmium, chromium, copper, nickel, lead, mercury, silver, arsenic, selenium, and antimony. Toxic organic compounds in drilling fluids and cuttings include naphthalene, fluorene, and phenanthrene. Also included are the alkylated forms of the toxic organics along with total oil, TSS and other metals including iron, tin, and titanium. The pollutant data is summarized in Chapter VII of this document. Where zero discharge is required, EPA will be controlling all pollutants in the wastestream.

For Cook Inlet, EPA has determined that it is not technically feasible to regulate separately each toxic or nonconventional pollutant found in drilling fluids and drill cuttings discharges. The control of diesel oil and free oil will control toxic and nonconventional pollutants found in these discharges; and thus, diesel oil and free oil serve as indicator pollutants for these toxic and nonconventional pollutants, including those that are not otherwise controlled by the diesel and free oil prohibitions. Limitations on toxicity and cadmium and mercury content in barite control toxic and nonconventional pollutants in drilling waste discharges, as discussed in the following sections.

With respect to EPA's BCT and NSPS limits prohibiting discharge of free oil, free oil would serve as a surrogate pollutant for oil and grease in recognition of the complex nature of the oil present in drilling fluids.

2.1 DIESEL OIL

Diesel oil may contain 20 to 60 percent by volume poly aromatic hydrocarbons (PAH's) which constitute most of the toxic components of petroleum products. Diesel oil also contains a number of non-conventional pollutants, including PAHs such as methylnaphthalene, methylphenanthrene, and other alkylated forms of the listed organic priority pollutants. Prohibiting the discharge of diesel oil would eliminate the discharge of the constituents of diesel oil listed in Table VI-1. Diesel oil is considered an indicator of specific toxic pollutants present in the complex hydrocarbon mixtures used in drilling fluid systems (see Section 2.2).

The use of mineral oil instead of diesel oil as an additive in water-based drilling fluids reduces the quantity of toxic and nonconventional organic pollutants that are present in drilling fluids, as compared to the quantity of these pollutants present when using diesel oil as an additive (See Table VI-1). Mineral oils contain lower concentrations of some of the same pollutants than diesel oil due to their lower aromatic hydrocarbon content and lower toxicity.

2.2 FREE OIL

The basis for a prohibition on discharges of free oil in drilling fluids and cuttings is substitution of water-based fluids for oil-based fluids, use of non-petroleum oil containing additives and minimization of the use of mineral oil. An additional technology basis for compliance with the prohibition on the discharge of free oil is transporting the drilling wastes to shore facilities for treatment, disposal or reuse. Transporting the drilling wastes to shore facilities would be done instead of product substitution when the used drilling fluids are contaminated by crude oil due to the contribution of the oil from the formation being drilled. In these situations, toxic and nonconventional pollutants contained in crude oil are eliminated from discharge.

Free oil would be used as an indicator pollutant for the control of toxic pollutants. Free oil would also be used as a surrogate for oil and grease in BCT options in recognition of the complex nature of the oils present in drilling fluids including crude oil from the formation being drilled. Both free oil and diesel

TABLE VI-1

ORGANIC CONSTITUENTS OF DIESEL AND MINERAL OILS[1]

Concentration in mg/ml unless noted otherwise

Organic Constituents	Gulf of Mexico Diesel	Calif. Diesel	Alaska Diesel	EPA/API Ref. Fuel Oil	Mineral Oil A	Mineral Oil B	Mineral Oil C
Benzene	ND	0.02	0.02	0.08	ND	ND	ND
Ethylbenzene	ND	0.47	0.26	2.01	ND	ND	ND
Naphthalene	1.43	0.66	0.48	0.86	0.05	ND	ND
Fluorene	0.78	0.18	0.68	0.45	ND	0.15	0.01
Phenanthrene	1.85	0.36	1.61	1.06	ND	0.20	0.04
Phenol (μg/g)	6.0	ND	1.2	ND	ND	ND	ND
Alkylated benzenes[(a)]	8.05	10.56	1.08	34.33	30.0	ND	ND
Alkylated naphthalenes[(b)]	75.68	18.02	25.18	38.73	0.28	0.69	ND
Alkylated fluorenes[(b)]	9.11	1.60	5.42	7.26	ND	1.74	ND
Alkylated phenanthrenes[(b)]	11.51	1.41	4.27	10.18	ND	0.14	ND
Alkylated phenols (μg/g)[(c)]	52.9	106.3	6.60	12.8	ND	ND	ND
Alkylated biphenyls[(b)]	14.96	4.03	6.51	13.46	0.23	5.57	0.02
Total dibenzothiophenes (μg/g)	760	1200	900	2100	ND	370	ND
Aromatic content (%)	23.8	15.9	11.7	35.6	10.7	2.1	3.2

Note: The study characterized six diesel oils and three mineral oils. For the purpose of the general comparison and summary presented above, the Alaska, California, and Gulf of Mexico diesels are assumed to be representative of those used in coastal drilling operations.

ND = Not Detectable
(a) Includes C1 through C6 alkyl homologues
(b) Includes C1 through C5 alkyl homologues
(c) Includes cresol and C2 through C4 alkyl homologues

oil are considered to be indicators and to control specific toxic pollutants present in the complex hydrocarbon mixtures used in drilling fluid systems. These pollutants include benzene, toluene, ethylbenzene, naphthalene, phenanthrene, and phenol. As an illustration of the relationships between oils and drilling fluids, Table VI-2 shows an increase in oil and grease concentrations from water based fluids to water-based fluids with mineral oil additives. This table is from Chapter VII, Section 4.3 of the 1993

TABLE VI-2

POLLUTANT ANALYSIS OF GENERIC DRILLING FLUIDS[2]

Generic Mud No.	Type of Mud	pH	Specific Gravity	% Weight Loss (103°C) (b)	BOD_5 ACT in SOW (b)	BOD_5 POLY in SOW (b)	UOD_{20} ACT in SOW (b)	UOD_{20} POLY in SOW (b)	TOC (c)	COD (b)	O&G Sonication (b)	O&G Soxhlet Extract. (a)
1	KCl Polymer	8.05	1.74	34.1	1,813	2,037	4,223	3,407	3,040	8,000	532	4,860
2	Seawater Lignosulfonate	10.10	2.15	26.6	1,483	1,373	2,717	2,330	15,000	39,900	1,270	2,750
3	Lime	11.92	1.73	44.0	1,657	2,743	3,207	3,963	15,000	41,200	796	1,240
4	Nondispersed	8.60	1.44	659.6	< 50	10	136	286	1,220	4,200	520	1,820
5	Spud	8.10	1.09	90.1	< 50	9	160	124	100	420	597	140
6	Seawater/Freshwater	7.95	1.09	88.0	181	216	130	285	686	1,800	661	672
7	Lightly Treated Lignosulfonate	8.50	1.44	56.2	1,470	1,386	2,187	1,733	5,650	15,200	1,710	572
8	Lignosulfonate Freshwater	8.60	2.12	27.1	1,530	1,393	2,413	1,980	14,200	34,900	1,400	7,380
2-01	Mud 2 + 1% (Vol.) Mineral Oil	10.95	2.15	26.4	1,416	2,223	4,073	5,803	15,900	46,100	2,730	2,400
2-05	Mud 2 + 5% (Vol.) Mineral Oil	9.75	2.07	27.2	3,416	2,157	8,340	7,473	26,300	98,300	11,700	23,400
2-10	Mud 2 + 10% (Vol.) Mineral Oil	8.55	2.04	25.7	1,558	1,877	9,273	6,190	36,500	144,000	14,800	40,400
8-01	Mud 8 + 1% (Vol.) Mineral Oil	8.00	2.21	27.0	1,373	2,383	4,423	4,297	13,400	53,800	1,990	2,560
8-05	Mud 8 + 5% (Vol.) Mineral Oil	9.22	2.23	26.3	2,207	2,023	9,773	6,940	20,800	75,300	7,080	7,670
8-10	Mud 8 + 10% (Vol.) Mineral Oil	8.50	2.25	25.6	1,423	1,633	7,863	6,497	24,200	99,600	12,300	2,800

All Data on Dry Weight Basis
(a) - Average of duplicates; (b) - Average of triplicates; (c) - Average of three triplicates

Offshore Development Document where characteristics of eight generic drilling fluids, representing water-based drilling fluids commonly used in the drilling industry, were presented.[3]

The relationship between oils and toxic organic constituents can be illustrated by noting, as an example, the concentrations of the toxic organic, phenanthrene, in drilling fluids. Table VI-3 shows an increase in organic constituent concentrations from water-based fluids to water-based fluids with mineral additives. Note a particular increase in phenanthrene from "not detected" in water-based fluids, to a range of 1,060 to 19,300 μg/kg in water-based fluids with mineral oil additives. Furthermore, Table VI-1 shows a general trend toward increases in organic concentrations from mineral oils to diesel oils. Note, for phenanthrene in particular, a concentration in the range of not detected to 0.04 mg/ml in mineral oil to a range of 0.36 to 1.85 mg/ml in diesel oil.

Prohibiting the discharge of free oil reduces the level of oil and grease present in the drilling fluids and drill cuttings allowed to be discharged and eliminates the pollutants listed above to the extent that these are present to a lesser degree in substitute fluids and additives.

2.3 TOXICITY

Acute toxicity is a measurement used to determine levels of pollutant concentrations which can cause lethal effects to a certain percentage of organisms exposed to the suspended particulate phase (SPP) of the drilling fluids and drill cuttings (for more details on the acute toxicity test see the final Offshore Guidelines 58 FR 12507, March 4, 1993—Appendix 2 to Subpart A of Part 435). Toxicity of drilling fluids, drill cuttings, and dewatering effluent is being regulated as a nonconventional pollutant that controls certain toxic and nonconventional pollutants. The technology basis for the toxicity limitation is product substitution, i.e., substitution using less toxic drilling fluids, or if the toxicity limitation cannot be met, transporting the drilling fluids and cuttings to shore for disposal.

Additives such as oils and some of the numerous specialty additives, especially biocides, may greatly increase the toxicity of the drilling fluid and drill cuttings (due to the adherence of drilling fluid to the drill cuttings). The toxicity is, in part, caused by the presence and concentration of toxic pollutants. However, control of free oil and diesel oil, in some cases, may not be an effective means of regulating these additives since they are neither diesel oil nor do they contain constituents with a free oil component. A toxicity limitation requires that operators must also consider toxicity in selecting additives and select the less toxic alternatives. Thus, the toxicity limitation will also serve to reduce discharges of toxic and non-

TABLE VI-3

ORGANIC POLLUTANTS DETECTED IN GENERIC DRILLING FLUIDS[2]

Generic Mud No.	Type of Mud	Phenanthrene	Dibenzofuran	N-Dodecane (C_{12})	Diphenylamine	Biphenyl
1	KCl Polymer	-	-	899	-	-
2	Seawater Lignosulfonate	-	-	-	-	-
3	Lime	-	-	809	-	-
4	Nondispersed	-	-	819	-	-
5	Spud	-	-	854 (822)	-	-
6	Seawater/Freshwater Gel	-	-	847 (802)	-	-
7	Lightly Treated Lignosulfonate	-	-	736	-	-
8	Lignosulfonate Freshwater	-	-	780	-	-
2-01	Mud 2 + 1% (Vol.) Mineral Oil	1,060	-	726	-	-
2-05	Mud 2 + 5% (Vol.) Mineral Oil	8,270	827	6,540	-	867
2-10	Mud 2 + 10% (Vol.) Mineral Oil	19,300	1,040	13,300	4,280	2,290
8-01	Mud 8 + 1% (Vol.) Mineral Oil	-	-	-	-	-
8-05	Mud 8 + 5% (Vol.) Mineral Oil	5,580	-	9,380	-	-
8-10	Mud 8 + 10% (Vol.) Mineral Oil	11,100	933	8,270	5,200	1,120

Note: Concentrations are in $\mu g/kg$

conventional pollutants. The limitation would encourage the use of the lowest toxicity generic water-based drilling fluids or newer drilling fluid compositions with lower toxicity than the generic fluids, and the use of low-toxicity drilling fluid additives.

By regulating the toxicity of drilling fluids and cuttings, certain toxic and nonconventional pollutants are controlled. It has been demonstrated, during EPA's development of the Offshore limitations (discussed in Chapter V of the Offshore Development Document),[2] that toxicity directly controls the type and amount of mineral oil that can be added to a drilling fluid and pollutants such as PAHs identified as constituents of mineral oil. Drilling fluids and drilling fluid additives with low toxicity would be encouraged by a toxicity limitation.

2.4 CADMIUM AND MERCURY

By limiting cadmium and mercury content in the stock barite, toxic and nonconventional pollutants in drilling fluids and cuttings can be controlled. EPA has determined that it is not technically feasible to specifically control the toxic pollutants controlled by the mercury and cadmium limits. Limitations on cadmium and mercury content in the stock barite would control toxic and nonconventional pollutants in drilling fluids and cuttings discharges. This limitation directly controls the levels of cadmium and mercury, and indirectly controls the levels of other toxic pollutant metals. Control of other toxic pollutant metals occurs because cleaner barite that meets the mercury and cadmium limits has been shown to have reduced concentrations of other metals.

Barite is an additive used in drilling operations to increase the weight of the drilling fluid necessary when drilling "deep" formations. Barite is mined from either bedded or veined deposits. Research has shown that bedded deposits are characterized by substantially lower concentration of heavy metal contaminants including mercury and cadmium (See Table VI-4). Thus, use of barite from bedded deposits will result in less toxic drilling fluids.

Table VI-5 presents metal concentrations in barite. Comparing the concentrations of metals for "dirty" (vein deposits) versus "clean" (bedded deposits) barite clearly indicate that for some metals, the concentrations decrease when using "clean" barite and others stay virtually the same. Limiting cadmium and mercury to 3 mg/l and 1 mg/l respectively in stock barite indirectly controls the levels of toxic pollutant metals by using cleaner barite because of reduced concentrations these metals have in clean barite.

TABLE VI-4

ANALYSIS OF TRACE METALS IN BARITE SAMPLES[4]

Source	Trace Metals Concentration on Dry Weight Basis (mg/kg)									
	Fe	Pb	Zn	Hg	As	Ca	Cd	Ni	Cu	Co
Literature Values:										
Vein Deposits	8-22,000	4-1,220	10-4,100	0.06-14	7*	2-26	<0.2-19	19**	2-97	ND
Bedded Deposits	100-3,000	<10	<200***	0.06-0.19	<500***	1-11	<50***	<5	3-20	<5-60
Kramer, et. al.:										
Vein Deposits	200-59,000	<2-3,370	<0.2-9,020	0.8-28	0.008-170					
Bedded Deposits	2,500-6,000	1-1.8	6-10	0.13-0.26	1.4-1.8		0.5-0.7	0.4-5.7	5.4-7.6	1-2.2
Reference Data:										
Crust Average	50,000	15	65	0.1	2	2	0.2	80	45	23
Ocean Sediment	50,000	110	40	0.3	8	8	1	240	350	100

* - One Sample
** - Mean of 83 Samples
*** - Semiquantitative Emission Spectrographic Method
ND - Not detected

Evaluation of the relationship between cadmium and mercury and the trace metals in barite shows a correlation between the concentration of mercury with the concentration of arsenic, chromium, copper, lead, molybdenum, sodium, tin, titanium, and zinc; and the concentration of cadmium with the concentrations of arsenic, boron, calcium, sodium, tin, titanium, and zinc.[5]

2.5 POLLUTANTS NOT REGULATED

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

EPA has determined that certain of the toxic and nonconventional pollutants are not controlled by the limitations on diesel oil, free oil, toxicity, and mercury and cadmium in stock barite. EPA exercised its discretion not to regulate these pollutants because EPA did not detect these pollutants in more than a

TABLE VI-5

METALS CONCENTRATION IN BARITE[5]

Metal	"Dirty" Barite Concentration (mg/kg)	"Clean" Barite Concentration (mg/kg)
Priority Pollutants		
Cadmium	2.3	1.1
Mercury	0.7	0.1
Antimony	5.7	5.7[a]
Arsenic	12.0	7.1
Beryllium	0.7	0.7[a]
Chromium	561.4	240.0
Copper	39.9	18.7
Lead	66.7	35.1
Nickel	13.5	13.5[a]
Selenium	1.1	1.1[a]
Silver	0.7	0.7[a]
Thallium	1.2	1.2[a]
Zinc	200.5	200.5[a]
Nonconventional Pollutants		
Barium[b]	120,000.0	120,000.0[a]
Iron	15,344.3	15,344.3[a]
Tin	14.6	14.6[a]
Titanium	87.5	87.5[a]

[a] Value substituted from "dirty" barite dataset where not available in "clean" barite dataset.[2]
[b] Source: SAIC, June 6, 1994.[5]

very few of the samples from EPA's field sampling program and does not believe them to be found through out the industry; the pollutants when found are present in trace amounts not likely to cause toxic effects; and due to the large number and variation in additives or specialty chemicals that are only used intermittently and at a wide variety of drilling locations, it is not feasible to set limitations on specific compounds contained in additives or specialty chemicals.

3.0 PRODUCED WATER

EPA is establishing BAT and NSPS limitations for produced water requiring zero discharge everywhere except for Cook Inlet, Alaska where oil and grease would be limited to a 29 mg/l monthly average and a 42 mg/l daily maximum. BCT establishes limitations on the concentration of oil and grease in produced water equal to current BPT limits (48 mg/l monthly average, 72 mg/l daily maximum). These limitations represent the appropriate levels of control under BAT, BCT and NSPS.

3.1 POLLUTANTS REGULATED

Where zero discharge is required, all pollutants found in produced water discharges are controlled. In Cook Inlet, EPA is regulating oil and grease under BAT as an indicator pollutant controlling the discharge of toxic and nonconventional pollutants. Oil and grease is limited for produced water under BCT as a conventional pollutant. Oil and grease is limited under NSPS as both a conventional pollutant and as an indicator pollutant controlling the discharge of toxic and nonconventional pollutants.

As previously denoted in the Offshore Technical Development Document (Chapter VI), oil and grease serves as an indicator for toxic pollutants in the produced water wastestream which include phenol, naphthalene, ethylbenzene, and toluene. Also see Table VIII-3 of Chapter VIII which lists organic pollutants detected in EPA's sampling programs.

The technology basis for the oil and grease limitations is improved gas flotation. In addition to oil and grease, gas flotation technology with chemical addition removes both metals and organic compounds. The insoluble metal hydroxide particle formation and adsorption by the chemical (polymer) floc of oil and the action of the gas bubbles forces both the oil (oil and grease) containing floc and metal hydroxide floc to the surface for removal (skimming), thus resulting in lower concentration levels in the discharge of oil and grease for the above priority pollutants. (See Chapter VIII for discussions of gas flotation technology.)

During the Offshore Guideline development, EPA determined the characteristics of produced water both after the BPT level of control and after gas flotation technology. Table VI-6 demonstrates that as oil and grease is removed, so too are the organic pollutants. (Note, this table is taken from the Offshore Guidelines and presents data that may be different from that used in the development of the Coastal Guidelines presented throughout the proceeding sections of this document).

3.2 POLLUTANTS NOT REGULATED

Where EPA requires zero discharge, all pollutants found in produced water would be regulated. Thus, this discussion pertains only to EPA's BAT and NSPS limits for Cook Inlet and the BCT limitations.

TABLE VI-6

POLLUTANT LOADING CHARACTERIZATION—PRODUCED WATER[2]

Pollutant Parameter	BPT-Level Effluent	Improved Gas Flotation Effluent
	Concentrations mg/l	
Oil & Grease	25.0	23.5
TSS	67.5	30.0[a]
	Concentrations μg/l	
Priority and Non-conventional Organic Pollutants:		
2-Butanone	1028.96	411.58
2,4-Dimethylphenol	317.13	250.00
Anthracene	18.51	7.40
Benzene	2978.69	1225.91
Benzo(a)pyrene	11.61	4.65
Chlorobenzene	19.47	7.79
Di-n-butylphthalate	16.08	6.43
Ethylbenzene	323.62	62.18
n-Alkanes	1641.50	656.60
Naphthalene	243.58	92.02
p-Chloro-m-cresol	25.24	10.10
Phenol	1538.28	536.00
Steranes	77.50	31.00
Toluene	1897.11	827.80
Triterpanes	78.00	31.20
Total xylenes	695.03	378.01
Priority and Non-conventional Metal Pollutants:		
Aluminum	78.01	49.93
Arsenic	114.19	73.08
Barium	55563.80	35560.83
Boron	25740.25	16473.76
Cadmium	22.62	14.47
Copper	444.66	284.58
Iron	4915.87	3146.15
Lead	195.09	124.86
Manganese	115.87	74.16
Nickel	1705.46	1091.49
Titanium	7.00	4.48
Zinc	1190.13	133.85

[a] Source: SAIC, January 13, 1993.[8]

Note: This table is taken from the Offshore Development Document and used here for illustrative purposes. It may not be the same as data presented for the coastal produced waters presented later in Chapter VIII.

The feasibility of regulating separately each of the constituents of produced water determined to be present was evaluated during the development of the Offshore Guidelines (See Chapter VI of the Offshore Technical Development Document).[2] EPA determined that it is not feasible to regulate each pollutant individually for reasons that include the following: 1) the variable nature of the number of constituents in the produced water, 2) the impracticality of measuring a large number of analytes, many of them at or just above trace levels, 3) use of technologies for removal of oil which are effective in removing many of the specific pollutants, and 4) many of the organic pollutants are directly associated with oil and grease because they are constituents of oil, and thus, are directly controlled by the oil and grease limitation. These reasons apply to the Coastal Guidelines.

While the oil and grease limitations limit the discharge of toxic pollutants, EPA determined during the Offshore Guidelines rulemaking that certain of the toxic priority pollutants, such as pentachlorophenol, 1,1-dichloroethane, and bis(2-chloroethyl) ether, would not be controlled by the limitations on oil and grease in produced water. EPA is not regulating these pollutants in this rule because EPA did not detect them in the samples within the coastal oil and gas data base. (See the Offshore Development Document, Chapter VI, page VI-7).

Naturally occurring radioactive materials (NORM), mainly consisting of radium 226 and radium 228, in produced water were found in concentrations averaging 400 pCi/l (for both Radium 226 and Radium 228 combined, sometimes referred to as total radium) in the coastal areas of the Gulf of Mexico.[6] This pollutant would be eliminated by a zero discharge requirement.

Existing data for radium 226 and radium 228 in Cook Inlet produced water show that radium is detected either at levels of detection or not at all. Data presented in Chapter VIII show radium 226 was not detected in six out of eight produced water samples, and radium 228 also was not detected in six out of eight samples. Where these analytes were detected, they were found at low concentrations only slightly above levels of detection. Under the CWA, EPA has discretion to determine what pollutants to regulate. EPA has determined that radium is not a pollutant of concern in Cook Inlet because it is either not detectable or, when present, is present only in trace amounts not likely to cause toxic effects.

Produced water treatment technology, other than subsurface injection, has not been shown to remove NORM. According to data submitted for the offshore record, removals of radium 226 and radium 228 by granular filtration and improved gas flotation, if any, are believed to be minimal.[7] The Offshore Development

Document also presents the membrane filtration performance on pollutant removals (summarized on Table IX-17 of that document), which shows insignificant radium removals.

4.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

EPA is establishing BAT and NSPS limitations for well treatment, completion and workover fluids requiring zero discharge for all coastal areas except for Cook Inlet, where BAT and NSPS establish oil and grease limitations (29 mg/l 30-day average; 42 mg/l daily maximum). EPA is also establishing a no discharge of free oil limitation for BCT as determined by the static sheen test and a zero discharge requirement for all coastal areas under PSES and PSNS. These limitations represent the appropriate level of control under BAT, BCT, PSES, PSNS and NSPS.

Where zero discharge is required, all pollutants found in well treatment, workover and completion fluids are controlled. As with produced water, oil and grease serves as an indicator for toxic pollutants in well treatment, workover and completion fluids including, phenol, naphthalene, ethylbenzene, toluene, and zinc. EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitations on oil and grease reflect control of these toxic pollutants at the BAT and NSPS levels. BCT limits for treatment, workover and completion fluids prohibit the discharge of "free oil" as a surrogate for control over the conventional pollutant "oil and grease." No discharge of "free oil" is determined by the static sheen test. EPA is prohibiting discharge of "free oil" as a surrogate for control over the conventional pollutant "oil and grease" in recognition of the complex nature of the oils present in drilling fluids, including crude oil from the formation being drilled. Oil and grease is limited under NSPS as both a conventional pollutant and as an indicator pollutant controlling the discharge of toxic and nonconventional pollutants.

EPA has determined, moreover, that it is not feasible to regulate separately each of the constituents in well treatment, completion and workover fluids because these fluids in most instances become part of the produced water wastestream and take on the same characteristics as produced water. Due to the variation of types of fluids used, the volumes used and the intermittent nature of their use, EPA believes it is impractical to measure and control each parameter. However, because of the similar nature and commingling with produced water, the limitations on oil and grease and/or free oil in the Coastal Guidelines will control levels of certain toxic priority and nonconventional pollutants for the same reason as stated in the previous discussion on produced water.

4.1 POLLUTANTS NOT REGULATED

While the oil and grease and, in certain instances, the no free oil limitations limit the discharges of toxic and nonconventional pollutants found in well treatment, completion and workover fluids, certain other pollutants are not controlled. These pollutants are the same as those listed in produced waters as not being controlled by an oil and grease limitation. EPA exercised its discretion not to regulate these pollutants because EPA did not detect them in more than a very few of the samples within the subcategory and does not believe them to be found throughout the coastal subcategory; and the pollutants when found are present in trace amounts not likely to cause toxic effects.

5.0 PRODUCED SAND

EPA is establishing BPT, BCT, BAT, NSPS, PSES and PSNS limitations for produced sand equal to zero discharge, which will control all pollutants present in the produced sand wastestream. This limitation represents the appropriate level of control under BAT, BCT, NSPS, PSES and PSNS.

6.0 DECK DRAINAGE

EPA is controlling pollutants found in deck drainage by the prohibition on the discharge of free oil. This limitation is the current BPT level of control and represents the appropriate level of control under BCT, BAT and NSPS.

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

The specific conventional, toxic and nonconventional pollutants controlled by the prohibition on the discharges of free oil are the conventional pollutant oil and grease and the constituents of oil that are toxic and nonconventional pollutants (see previous discussion in Section 2.2 of this chapter describing the chemical constituents of oil). EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitation on free oil in deck drainage reflects control of these toxic pollutants at the BAT and NSPS level.

Additional controls on deck drainage were rejected based on the technical infeasibility of deck drainage add-on systems to existing sump and skim pile systems currently being used. Deck drainage discharges are not continuous, vary significantly in volume, and contain a wide range of chemical constituents and concentration levels of the constituents, many of which are at or near trace levels. At times of platform washdowns, the discharges are of relatively low volume and anticipated; during rainfall events, very large, unanticipated volumes may be generated.

7.0 REFERENCES

1. Batelle New England Marine Research Laboratory, "Final Report for Research Program on Organic Chemical Characterization of Diesel and Mineral Oils Used as Drilling Mud Additives" prepared for the Offshore Operators Committee—December 31, 1984 (*Offshore Rulemaking Record, Volume 13*).

2. CENTEC Analytical Services Inc., "Results of Laboratory Analysis and Findings Performed on Drilling Fluids and Cuttings - Draft," submitted to Effluent Guidelines Division, U.S. EPA, April 3, 1984 (*Offshore Rulemaking Record Volume 13*).

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

4. Kramer, J.R., H.D. Grundy, and L.G. Hammer, "Occurrence and Solubility of Trace Metals in Barite for Ocean Drilling Operations," Symposium—Research on Environmental Fate and Effects of Drilling Fluids and Cuttings, Sponsored by API, Lake Buena Vista, Florida, January 1980. (*Offshore Rulemaking Record 26*).

5. SAIC, "Descriptive Statistics and Distributional Analysis of Cadmium and Mercury Concentrations in Barite, Drilling Fluids, and Drill Cuttings from the API/USEPA Metals Database," prepared for Industrial Technology Division, U.S. Environmental Protection Agency, February 1991. (*Offshore Rulemaking Record Volume 120*).

6. SAIC, "Statistical Analysis of Effluent from Coastal Oil and Gas Extraction Facilities (Final Report)," September 30, 1994.

7. Jordan, R., Engineering and Analysis Division, U.S. EPA, Memorandum to Record. "Offshore Oil and Gas—Characterization of BPT- and BAT- Level Produced Water Effluent," December 10, 1992.

8. SAIC, "Analysis of Oil and Grease Data Associated with Treatment of Produced Water by Gas Flotation Technology," prepared for the Engineering and Analysis Division, U.S. EPA, January 13, 1993. (*Offshore Rulemaking Record Volume 169*).

CHAPTER VII

DRILLING WASTES
CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

The first three parts of this section describe the sources, volumes, and characteristics of drilling wastes generated from coastal oil and gas exploration and development activities. The last part of this section describes the control and treatment technologies currently available to reduce the volume of drilling wastes and the quantities of pollutants discharged to surface waters.

2.0 DRILLING WASTE SOURCES

This section focuses on three wastes generated during drilling: spent drilling fluid, drill cuttings, and dewatering liquid. Drilling fluid and drill cuttings are both major wastes streams of concern because they are generated in significant volumes. Dewatering liquid is a process stream that sometimes becomes a waste stream. EPA has found that coastal facilities either recycle or send dewatering liquid offsite with waste drilling fluids and cuttings to commercial disposal facilities.

2.1 DRILLING FLUID SOURCES

Drilling fluids, also referred to as drilling muds, are suspensions of solids, chemicals, and other materials in a base of water, oil, or synthetic-based material which is specifically formulated to lubricate and cool the drill bit, carry drill cuttings from the hole to the surface, and maintain downhole hydrostatic pressure. Drilling fluids typically contain a variety of specialty chemicals (called "additives" in this report) to control density (weight) and viscosity, reduce fluid loss to the formation, inhibit corrosion, and control or impart other properties to the drilling fluid.

Drilling fluids are formulated at the drill site according to the drilling conditions. Once formulated, the fluid is pumped down the drill pipe and ejected to the borehole through jets in the drill bit. The drilling fluid returns to the surface through the annulus (space between the casing and the drill pipe). As the fluid travels up the annulus, it carries the drill cuttings in suspension. The fluid then passes through the solids control equipment (shale shaker screens, hydrocyclones, etc.) to remove the cuttings, and is returned to the mud tank for recirculation. The design and use of solids control equipment are discussed in detail in Section 5.5, "Waste Minimization-Enhanced Solids Control."

Excess drilling fluids are removed from the fluid circulation system during the drilling operation and at the end of the drilling program for various reasons. Excess drilling fluids are generated during drilling when:

- cement, casing, drill pipe or packer fluid are placed downhole,
- the fluid is diluted to maintain constant rheological properties, and
- the entire drilling fluid system is periodically changed over in response to changing drilling conditions.

At the end of the drilling program, the remaining fluid left over in the circulation system and the storage tanks is either considered waste or recycled and/or regenerated for future use.

2.2 Drill Cuttings Sources

Drill cuttings are small pieces of formation rock that are generated by the crushing action of the drill bit. Additional hole material can slough off the drill hole wall, which is commonly referred to as "washout." Drill cuttings are carried out of the borehole with the drilling fluids. Drill cuttings can disperse as fine drill solids into the drilling fluids and can significantly effect the fluid's rheological (flow) properties. Solids control is the process of maintaining the concentration of drill solids in the drilling fluid at an acceptable level. The most common solids control methods are mechanical removal, dilution, and displacement.

Dilution and displacement are usually practiced together because each method is dependent on the other. As the level of fine drill solids increases in the drilling fluid, the viscosity also increases. For a drilling fluid to remain effective, the viscosity must be maintained at a specific level. Diluting the drilling fluid with make-up water has been the traditional method of viscosity control. In order to maintain other properties of the drilling fluid after dilution, additives must be mixed into the fluid in correct proportions. Therefore, the dilution method of viscosity control increases the total volume of drilling fluid in the system and requires the purchase of additional drilling fluid materials. Since the drilling fluid circulation system can hold only a limited volume of fluid at any time, the excess volume generated as a result of dilution must be removed from the active system. Thus, the major waste generated from the use of dilution/displacement is spent drilling fluid. The disposition of the displaced drilling fluid depends on several factors including, but not limited to, site location, applicable regulations, and the operator's waste management budget. Detailed discussions regarding the management and disposal of waste drilling fluid are provided in later sections.

Viscosity can also be maintained by mechanically separating undesirable solids (drill cuttings) from the drilling fluid (see also Section 5.5). It is important to note that dilution/displacement is often practiced in combination with mechanical solids control as a means of maintaining desired drilling fluid properties, although the amount of excess drilling fluid is minimized in this application. The major waste resulting from mechanical solids control is drill cuttings with adhering drilling fluid. The disposition of the waste drill cuttings depends on the same factors listed above for waste drilling fluid. These factors are discussed in detail in later sections.

2.3 DEWATERING LIQUID SOURCES

Dewatering liquid may come from one of two sources: the dewatering of a waste drilling fluids and/or cuttings storage vessel or pit, or from a dewatering centrifuge used as part of the solids control system. EPA does not consider this as a separate waste stream because it is often recycled back into the drilling fluid circulation system as make up water or mixed with waste drilling fluids and cuttings that are sent to offsite commercial disposal facilities.

EPA investigated this particular potential waste source because it has been regulated separately in the Region 6 general NPDES permit (58 FR 49126; September 21, 1993). Dewatering liquid was the focus of an EPA sampling program at three active drill sites in southern Louisiana.[1,2,3] These sampling efforts are described in Section V.4.0, "Investigation of Solids Control Technologies for Drilling Fluids." These data were not used for regulatory purposes because EPA later determined through contacts with industry and onsite visits, that this waste stream is rarely, if ever, discharged as a separate waste. BAT and BCT limitations in the coastal guidelines for dewatering effluent are to be applicable prospectively. BAT and BCT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of the coastal guidelines no longer receive drilling fluids and/or drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority. Should an abandoned reserve pit receive drilling wastes after the effective date of the coastal guidelines, then discharges of wastes from within the reserve pit would be required to comply with the zero discharge limitations of the rule.

The technical aspects of dewatering liquid generation are discussed in greater detail in Sections 5.5.5 and 5.5.6.

3.0 DRILLING WASTE VOLUMES

Approximately 89,000 bbls per year of drilling fluids and cuttings are being discharged by the coastal oil and gas industry, all of which is occurring in Cook Inlet. All other coastal areas are prohibited from discharging drilling wastes. Thus, approximately 626,000 barrels of drilling fluids and cuttings will be discharged from all of the Cook Inlet drilling projects currently planned by industry extending until the year 2002. The following sections discuss the factors affecting the volumes of drilling waste generated and numerical estimates of these volumes.

3.1 FACTORS AFFECTING DRILLING WASTE VOLUMES

Drilling fluids discharges are typically in bulk form and occur intermittently during well drilling and at final well depth. Low volume bulk discharges are the most frequent and are associated with fluid dilution, the process of maintaining the required level of solids in the fluid system. High volume bulk discharges occur less frequently during a well drilling operation, and are associated with drilling fluid system changeover and/or emptying of the mud tank at the end of the drilling program.

The volume of drilling fluid generated and the volume of drill cuttings recovered at the surface will depend on the following:

- Size and type of drill bit
- Hole enlargement
- Type of formation drilled
- Efficiency of solids control equipment
- Type of drilling fluid
- Density of drilling fluid.

The EPA Offshore Oil and Gas Development Document describes the effect of each of these factors on drilling fluid volume.[4]

The volume of drill cuttings generated depends primarily on the dimensions (depth and diameter) of the well drilled and on the percent washout. Washout is the enlargement of a drilled hole due to the sloughing of material from the walls of the hole. Drill solids are continuously removed via the solids control equipment during drilling. The greatest volumes of drill cuttings are generated during the initial stages of drilling when the borehole diameter is large and washout tends to be higher. Continuous and intermittent discharges are normal occurrences in the operation of solids control equipment. Such discharges occur for periods from less than one hour to 24 hours per day, depending on the type of operation and well conditions.

The volume of drill cuttings generated also depends on the type of formation being drilled, the type of bit, and the type of drilling fluid. Soft formations are more susceptible to borehole washout than hard formations. The type of drilling fluid used can affect the amount of borehole washout and shale sloughing. The type of drill bit determines the characteristics of the cuttings (particle size). Depending on the formation and the drilling characteristics, the total volume of drill solids generated will be at least equal to the borehole volume, but is most often greater due to the breaking up of the compacted formation material.

Additional information regarding hole enlargement due to washout is listed in Table VII-1. These data were provided to EPA by drill site operators during visits to three coastal sites in southern Louisiana.[1,2,3] Because the volume of washout varies depending on the type of formation being drilled, no single set of numbers can be applied as a rule of thumb to all drilling situations. However, Table VII-1 indicates that the percent washout generally decreases with hole depth. It should be noted that the values in Table VII-1 were estimates obtained from industry operators during EPA's drilling site study and were not directly measured.

3.2 ESTIMATES OF DRILLING WASTE VOLUMES

In order to compare waste volumes generated during various drilling projects, a normalized waste volume can be determined by dividing the total reported waste discharged from the active drilling fluid circulation system by the total volume of hole drilled. The volume of hole drilled is calculated from the bit sizes used for specific depth intervals, and from estimated washout volumes. The volume of waste

TABLE VII-1

PERCENT WASHOUT FACTORS

Reference	Depth Interval (feet)	Percent Washout
SAIC, May 25, 1994[1]	0 - 3,000	100
	3,000 - 11,500	25-50
	> 11,500	10
SAIC, Aug. 8, 1994[2]	0 - 4,000	75
	4,000 - 11,000	40
	11,000 - 13,000	20
	> 13,000	10
SAIC, Aug. 5, 1994[3]	0 - 3,000	100
	3,000 - 10,000	50
	> 10,000	25-50

discharged is typically available from waste transport reports or other records maintained at the drill site, and are often estimated based on the volume of the vessel used to store and/or transport the waste. Once calculated, the ratio of waste-to-hole volume can then be compared between drilling projects. For drill cuttings, this ratio is called the "expansion factor" because it indicates how much a given volume of cuttings increased after it was drilled out of the hole. No such distinctive name is used for the ratio of waste drilling fluid to calculated hole volume. For both drilling fluids and cuttings, the waste-to-hole volume ratio should always be greater than one, although in some cases it is less than one due to the disposal of fine cuttings with the waste fluid, or to inaccurate waste volume tracking procedures or records. Table VII-2 lists the hole volumes, waste volumes, and the calculated waste-to-hole volume ratios for eight different drilling projects in the coastal Gulf of Mexico region. The first three projects were created based on a "model well" as part of EPA Region 6's development of two general NPDES permits for coastal Louisiana and Texas (55 FR 23348), and were not actual wells drilled. The characteristics of the model well (e.g., depth intervals, hole volume, percent washout, etc.) and the solids control system parameters were designed to represent typical coastal drilling projects. The remaining five projects in Table VII-2 were actual wells, including two offshore and three coastal.

TABLE VII-2

WASTE DRILL CUTTINGS AND DRILLING FLUID VOLUMES

Reference	Closed-Loop Solids Control Equipment Efficiency	Well Depth (ft)	Calculated Hole Volume[a] (bbls)	Waste Drilling Fluids Volume[b] (bbls)	Drilling Fluids-to-Hole Ratio (bbls/bbls)	Waste Cuttings Volume[b] (bbls)	Cuttings Expansion Factor[c] (bbls/bbls)
55 FR 23348 (EPA Region 6 general NPDES permit)	<u>Scenario 1</u>: 36%	15,000	1,881	21,220	11.2	2,264	1.20
	<u>Scenario 2</u>: 62%			12,938	6.88	3,301	1.75
	<u>Scenario 3</u>: 90%			3,405	1.81	3,889	2.07
Offshore Operators Committee, 1981[5] (Data for two offshore wells)	50%	10,000	2,453	5,349	2.18	1,430	0.58
		18,000	4,619	10,486	2.27	2,781	0.60
SAIC, May 25, 1994[1] (Data obtained during EPA site visit)	90%	12,860	2,126	2,690	1.27	3,256	1.53
SAIC, August 8, 1994[2] (Data obtained during EPA site visit)	90%	14,928	3,689	5,850	1.59	10,070	2.73
SAIC, August 5, 1994[3] (Data obtained during EPA site visit)	75%	19,260	7,510	8,198	1.09	8,130	1.08
Average	70%	15,000	3,173	8,767	3.54	4,390	1.44

[a] "Hole Volume" was calculated from drilled hole diameter and depth data provided in the references. The data have been adjusted to compensate for hole enlargement due to erosion (washout).

[b] "Discharged Cuttings/Mud Volume" includes the total volume of cuttings or spent drilling fluids that were either discharged or hauled-off by the end of drilling, as reported in the references. These values may be derived estimates or actual data, depending on the reference document.

[c] "Expansion Factor" = Discharged Cuttings Volume (bbls) / Calculated Hole Volume (bbls).

A number of observations can be made from the data in Table VII-2. Referring to the EPA Region 6 data only, it is apparent that as solids control system efficiency increases, the fluid-to-hole volume ratio decreases and the cuttings expansion factor increases. A low efficiency solids control system will allow a significant volume of drill cuttings to remain in the circulating drilling fluid, thus requiring greater dilution of the drilling fluid and hence increasing the volume to be disposed. A higher efficiency solids control system will remove a greater volume of cuttings from the circulating drilling fluid, thus decreasing the need for dilution as well as the volume of waste drilling fluid. In addition, if chemically enhanced centrifugation (CEC) is part of the solids control system, the volume of waste solids should be slightly higher than systems not using CEC because the flocculated solids add to the volume discharged by the centrifuge.

These trends are to be expected, but are not always observed in practice due to site-specific conditions, inaccuracies in hole volume estimation, and in waste volume tracking and reporting. Data from the five actual drilling projects listed in Table VII-2 illustrate this point. The cuttings expansion factors for the two offshore drilling projects are both less than one, suggesting that washout volumes may have been overestimated and that a significant volume of cuttings may have been included with the discharged mud volume. Also, the 8,130 barrels of cuttings reported for the last drilling project in this table is known to include 591 barrels of spent drilling fluid and is believed to include more, particularly because the cuttings were collected in a barge and there was no other holding vessel dedicated to spent drilling fluid at the site. Such uncertainties about what is included in a load of drilling waste and its volume occur because there are no requirements for keeping waste drilling fluid and cuttings volumes separate when they are being hauled offsite.

Volumes of waste drilling muds and cuttings generated by operators located in Cook Inlet, Alaska were reported in responses to the 1993 EPA Coastal Oil and Gas Questionnaire.[6] From the data submitted in the survey and information obtained directly from the operators, an average volume of muds and cuttings generated was calculated to be 14,354 barrels from an average well of 11,765 feet in depth. Table VII-3 lists the data used to calculate these averages.[5]

Based on this estimation and on projected drilling schedules provided by operators in Cook Inlet, the total volume of drilling wastes generated from drilling activities in Cook Inlet is a total of 632,000 bbls over the seven years following promulgation of this rule, or 90,000 bbls per year (see Chapter X for details).

TABLE VII-3

COOK INLET DRILLING WASTE VOLUMES

Operator ID	Depth Interval #1 (feet)	Depth Interval #2 (feet)	Depth Interval #3 (feet)	Total Well Depth (feet)	Muds and Cuttings Volume Int. #1 (bbls)	Muds and Cuttings Volume Int. #2 (bbls)	Muds and Cuttings Volume Int. #3 (bbls)	Total Muds and Cuttings Volume (bbls)
A	1,389	8,477	2,029	11,895	1,528	9,325	2,232	13,085
A	1,256	8,368	2,176	11,800	1,213	8,081	2,101	11,395
A	1,155	8,642	2,343	12,140	1,361	10,180	2,760	14,300
B	2,110	7,999	860	10,969	3,313	7,334	1,334	11,981
B	4,120	5,962	1,478	11,560	Not Available	9,558	1,583	Not Available
B	4,017	5,745	2,068	11,830	6,065	7,606	2,326	15,997
B	3,823	6,240	2,100	12,163	7,504	8,838	3,024	19,366
AVERAGE	**2,553**	**7,348**	**1,865**	**11,765**	**3,497**	**8,703**	**2,194**	**14,354**

Source: EPA, July 1993[6]

3.3 DEWATERING LIQUID VOLUMES

Estimates of dewatering liquid volumes were obtained from two of the three drilling operations visited by EPA in 1993.[1,2] Referring to Table VII-2, the wells drilled to depths of 12,860 and 14,928 feet generated estimated volumes of 4,800 and 2,423 barrels of dewatering liquid, respectively. Although a larger hole volume is generally associated with larger volumes of waste fluids and cuttings, there is no apparent relationship between well depth and dewatering liquid volume. As explained in Sections 5.5.5 and 5.5.6, factors affecting the volume and quality of the liquid effluent from a dewatering process are related to the selected dewatering method and the efficiency of the upstream solids separation equipment rather than the well depth. The dewatering liquid from these two drilling operations was either recycled into the active fluid system or hauled off-site for disposal; no dewatering liquid was discharged.

4.0 DRILLING WASTE CHARACTERISTICS

4.1 DRILLING FLUID CHARACTERISTICS

Several broad categories of drilling fluids exist such as water-based fluids (fresh or salt water), low solids polymer fluids, oil-based fluids, and oil emulsion fluids. This section discusses only water- and oil-based fluids because they represent the traditional and most widely used drilling fluids. A newer class of drilling fluids using synthetic materials is discussed later in this chapter (see Section 5.11).

Oil-based drilling fluids are only used for specific drilling conditions because they cannot be discharged and are more expensive to use than water-based drilling fluids. The discharge of oil-based drilling fluids and associated cuttings is prohibited under the BPT limitations of "no discharge of free oil." Industry has indicated that oil-based drilling fluids continue to be the material of choice for certain drilling conditions.[7] These conditions include the need for thermal stability when drilling high-temperature wells, specific lubricating characteristics when drilling deviated wells, and the ability to reduce stuck pipe or hole washout problems when drilling thick, water-sensitive shales. A primary concern when using conventional, oil-based fluid systems is their potential for adverse environmental impact in the event of a spill. Because of the relatively high toxicity of diesel oil, some mineral oil-based fluid systems have replaced diesel oil-based fluids, and as discussed in Section 5.11, synthetic-based drilling fluids are being used in applications previously reliant upon oil-based systems.

Water-based drilling fluids are dense colloidal slurries in a water phase of either fresh or saturated salt mixtures. Salt water-based drilling fluids may be comprised of seawater, sodium chloride (NaCl), potassium chloride (KCl), magnesium chloride ($MgCl_2$), calcium chloride/bromide ($CaCl_2/CaBr_2$), or zinc chloride/bromide ($ZnCl_2/ZnBr_2$). All freshwater fluids contain bentonite (sodium montmorillonite clay) and caustic soda (NaOH), while saltwater fluids may contain attapulgite clay instead of bentonite. Clays are a basic component of drilling fluids used to enhance the fluid viscosity. The most common required drilling fluid properties and the additives used to enhance these properties are discussed below.

Several different formulations of drilling fluids and additives can be created to achieve the required downhole conditions. The most common properties of the drilling fluid that the mud engineer controls are:

- Rheology (flow properties)
- Density
- Fluid loss control
- Lubricity
- Lost circulation
- Corrosion and scale control
- Solvents
- Low solids polymer fluids
- Bactericides.

Each of these properties can be tailored to specific well and drilling conditions through the addition of active solids, inactive solids, and chemicals to the base drilling fluid. The EPA Offshore Development Document discusses each of the above-listed properties, and describes the individual components of drilling fluids as well as typical drilling fluid compositions.[4] A comprehensive list of drilling fluid components and their applications is provided in Appendix VII-1.[8]

Barite, which is used to control the density of drilling fluids, is the primary source of toxic metal pollutants. The characteristics of raw barite will determine the concentrations of metals found in the spent drilling fluid system. A statistical analysis of metals concentrations in spent drilling fluids showed a higher concentration of toxic metal pollutants in drilling fluids formulated with "dirty" barite than in those formulated with "clean" barite.[9]

Based on the results of this analysis, EPA developed a profile of metals concentrations in drilling fluids formulated with "clean" barite as part of the development of Offshore Guidelines. "Clean" barite is defined as stock barite that meets the maximum limitations of cadmium of 3 mg/l and for mercury of 1 mg/l.[4] Table VII-4 presents the estimated characteristics of drilling fluids and cuttings tailored specifically for Cook Inlet since drilling wastes are discharged in this area only. Table VII-4 includes the offshore metals concentration profile developed from the statistical analysis for "clean" barite. The only difference to be noted is the concentration of barium, which was reevaluated in this rulemaking effort because the average weight of drilling fluid (10 lb/gal) reported by Cook Inlet operators in the 1993 EPA Coastal Questionnaire was lower than the average offshore model fluid weight of 11.0 lb/gal. The revised barium concentration for coastal regulations was calculated to be 120,000 mg/kg as compared to the calculated concentration of 359,747 mg/kg estimated for the offshore model well.[10]

Mineral oil, which is used in Cook Inlet drilling operations mostly to free stuck pipe, is a drilling fluid additive that contributes toxic organic pollutants to the drilling fluid system. An operator in Cook Inlet, Alaska estimated that the amount of mineral oil typically used in water-based drilling fluids is approximately 0.02 percent.[6] The concentrations of organic compounds listed in Table VII-4 were calculated based on this estimate,[14] and on the average concentrations of organics in mineral oil as listed in Table VII-9 in the Offshore Development Document.[4]

The TSS attributable to drilling fluids is estimated based on two physical properties of the waste drilling fluids: the estimated percentage of the fluid that is dry solids (11%), and the estimated density of the dry solids (1,025 lbs/bbl).[10] The dry solids content of the drilling fluid was estimated from mud reports provided by the operator of one of the drill sites visited by EPA.[1] The density of dry solids was estimated based on the mud weight of 10.1 lbs/gal obtained from the mud reports,[1] and calculated by subtracting the density of water (in lbs/gal) from the mud weight.[10] Finally, the TSS concentration in drilling fluid was calculated as follows:

$$(0.11 \text{ bbl dry solids/bbl drilling fluid}) \times (1{,}025 \text{ lbs dry solids/bbl dry solids})$$
$$= 113 \text{ lbs dry solids/bbl drilling fluid}$$

TABLE VII-4

COOK INLET DRILLING WASTE CHARACTERISTICS

Waste Characteristics	Value	Reference
Percent of cuttings in waste drilling fluid	19%	1993 EPA Coastal Oil and Gas Questionnaire[6]
Percent of drilling fluid adhering to cuttings	5%	Ray, 1979[11]
Average density of dry cuttings	980 pounds per barrel	Estimated[12]
Average density of waste drilling fluid	420 pounds per barrel	1993 EPA Coastal Oil and Gas Questionnaire[6] and Calculations[13]
Percent of dry solids in waste drilling fluid, by volume	11%	Calculations[10]
Average density of dry solids in waste drilling fluids	1,025 pounds per barrel	Calculations[10]
Drilling Fluid Pollutant Concentration Data		
Conventionals	lbs/bbl of drilling fluid	Reference
Total Oil	0.0596	Estimated[14]
Total Suspended Solids	113.0	Estimated[10]
Priority Metals	mg/kg dry drilling fluid	Reference
Cadmium	1.1	Offshore Development Document, Table XI-6[4]
Mercury	0.1	
Antimony	5.7	
Arsenic	7.1	
Beryllium	0.7	
Chromium	240.0	
Copper	18.7	
Lead	35.1	
Nickel	13.5	
Selenium	1.1	
Silver	0.7	
Thallium	1.2	
Zinc	200.5	
Priority Organics	lbs/bbl of drilling fluid	Reference
Naphthalene	0.0000035	Calculated[14] from concentrations in Offshore Development Document, Table VII-9[4]
Fluorene	0.0000563	
Phenanthrene	0.0000084	
Non-Conventional Metals	mg/kg dry drilling fluid	Reference
Aluminum	9,069.9	Offshore Development Document, Table XI-6[4]; except for barium, which was estimated.[10]
Barium	120,000.0	
Iron	15,344.3	
Tin	14.6	
Titanium	87.5	
Non-Conventional Organics	lbs/bbl of drilling fluid	Reference
Alkylated benzenes	0.0021017	Calculated[14] from concentrations in Offshore Development Document, Table VII-9[4]
Alkylated naphthalenes	0.0000344	
Alkylated fluorenes	0.0001218	
Alkylated phenanthrenes	0.0000143	
Total biphenyls	0.0001360	
Total dibenzothiophenes	0.0000004	

4.2 DRILL CUTTINGS CHARACTERISTICS

Drill cuttings themselves are inert solids from the formation. However, drill cuttings discharges also contain drilling fluids that have adhered to the cuttings. The composition of drill cuttings discharges is directly dependent upon the fluid used. Cuttings associated with oil-based drilling fluids or from petroleum bearing formations will contain hydrocarbons which adsorb on the surface of drill solid particles and resist removal by washing operations. The volume of the fluid adhering to the discharged cuttings can vary considerably depending on the formation being drilled, the type of drilling fluid being used, the particle size distribution of the cuttings, and the efficiency of the solids control equipment. A general rule of thumb is that five percent (5%) drilling fluid by volume is associated with the cuttings.[11] Data from a drilling project in the Outer Continental Shelf off southern California indicate that the cuttings discharges from the solids control equipment were comprised of 96 percent cuttings and four percent adhered drilling fluids.[15]

For the purpose of estimating pollutant reductions, the total suspended solids (TSS) concentration attributable to drill cuttings is equivalent to the density of the dry weight of cuttings (980 lbs/bbl).[12] This density was estimated from Cook Inlet geologic information provided by the industry,[16] and the specific gravities of low- and high-gravity solids,[17] as follows:

- The first 500 feet of depth consists of high-gravity solids[13] with a specific gravity of 4.5.[17]
- The depth from 500 to 10,000 feet consists of low-gravity solids[13] with a specific gravity of 2.6.[17]
- 50% of the total cuttings volume is generated during the first 3,000 feet.[6]
- The average specific gravity for the first 3,000 feet (50% of the total volume) =
  $$[(4.5 \times 500 \text{ ft}) + (2.6 \times 2{,}500 \text{ ft})] / 3{,}000 \text{ ft} = 2.92$$
- The average specific gravity for the remaining depth = 2.6
- The overall specific gravity for drilling cuttings =
  $$(2.92 + 2.6) / 2 = 2.8$$
- The average density of dry cuttings (using water at standard temperature and pressure as a reference) =
  $$2.8 \times 350 \text{ lbs water/bbl} = 980 \text{ lbs/bbl}$$

4.3 DEWATERING LIQUID CHARACTERISTICS

During site visits to three southern Louisiana drilling operations, EPA collected samples of dewatering centrifuge liquid to determine the quality of this process stream.[1,2,3] This process stream consisted mostly of the water phase of the drilling fluid.

At each drill site, one set of grab samples was collected on two consecutive days from the liquid discharge from a decanting centrifuge that was part of the solids control system (see also Section 5.5.5). The major difference between the three solids control systems was that two of them included chemical treatment of the centrifuge influent to enhance liquid\solid separation, also referred to as chemically enhanced centrifugation (CEC--see Section 5.5.6). The third system used no additional chemicals upstream of the centrifuge. The result was that separation of the colloidal solids from the liquid phase was much more efficient at the two sites using CEC. These samples were relatively free of suspended solids (TSS ranged from 24 to 520 mg/l), while the untreated sample had to be analyzed as a solid due to its solids content (23% to 24.7%), and had the consistency of a drilling fluid.

Table VII-5 compares data obtained from the two sites that used CEC to effluent limits established for this waste stream in a general permit covering drilling waste discharges in the coastal Gulf of Mexico region (58 FR 49126). The dewatering liquid at these sites was being treated for recycle and not for surface discharge. In fact, the majority of these waste volumes was hauled to commercial disposal.[1,2] The solids control contractor at one of these sites suggested that further treatment with activated carbon would produce discharge-quality effluent.[2]

4.4 COOK INLET DRILLING WASTE CHARACTERISTICS

For the purpose of developing compliance cost and pollutant reduction estimates, particular characteristics of drilling wastes in Cook Inlet, Alaska were identified. The sources for these data include the 1993 Coastal Oil and Gas Questionnaire, the EPA Offshore Development Document, direct correspondence with the operators, and calculations and estimates based on the data from these sources. Table VII-4 lists the characteristics of interest, including densities of cuttings and drilling fluid, percentage of solids in drilling fluid, and pollutant concentration data.

TABLE VII-5

COMPARISON OF ANALYTICAL CHARACTERISTICS OF CENTRIFUGE WATER EFFLUENT FROM THE GAP ENERGY AND ARCO DRILLING SAMPLING EPISODES TO THE EPA REGION VI GENERAL PERMIT POLLUTANT LIMITATIONS FOR DRILLING OPERATIONS

Pollutant	Units	General Permit Limitations[a]		GAP Energy[1]		ARCO[2]	
		Texas	Louisiana	6/16/93	6/17/93	7/21/93	7/22/93
Oil & Grease	mg/l	15	15	ND(1.0)	1.0	8.0	3.0
TSS	mg/l	50	50	24	35	**520***	**440***
TDS	mg/l	3,000	--	**7,600***	**6,420***	**14,000***	**15,200***
COD	mg/l	200	125	**1,040***	**735***	**5,370***	**4,630***
pH	S.U.	6 - 9	6 - 9	6.27	8.95	7.48	7.4
Chloride	mg/l	500	500	317	**866***	**2,050***	**2,150***
Arsenic	mg/l	0.1	--	0.310	ND(0.018)	0.0766	0.0679
Barium	mg/l	1.0	--	ND(0.018)	2.32	0.667	0.696
Cadmium	mg/l	0.05-0.1	--	ND(0.004)	ND(0.002)	ND(0.005)	ND(0.005)
Chromium	mg/l	0.5	0.5	**1.26***	0.069	**4.59***	**4.42***
Copper	mg/l	0.5	--	ND(0.012)	ND(0.006)	0.23	0.141
Lead	mg/l	0.5	--	ND(0.044)	ND(0.022)	ND(0.047)	ND(0.047)
Manganese	mg/l	1.0	--	3.84	ND(0.003)	0.442	0.762
Mercury	mg/l	0.005	--	ND(0.0002)	ND(0.0002)	0.00115	0.00075
Nickel	mg/l	1.0	--	ND(0.026)	ND(0.013)	0.0279	0.0273
Selenium	mg/l	0.05-0.1	--	0.044	ND(0.0258)	ND(0.02)	ND(0.02)
Silver	mg/l	0.05	--	ND(0.010)	ND(0.005)	ND(0.004)	ND(0.004)
Zinc	mg/l	1.0	5.0	0.006	0.501	0.083	0.198

[a] 58 FR 49126

* Samples that exceed General Permit Limitations

5.0 CONTROL AND TREATMENT TECHNOLOGIES

This section includes discussions of drilling waste treatment technologies currently employed in the coastal oil and gas industry. The technologies include the following:

- product substitution to minimize pollutant content
- closed-loop solids control systems to minimize waste stream volume
- reserve pits
- conservation and reuse/recycling.

In addition, EPA investigated the following disposal methods:

- land treatment/disposal
- subsurface injection of drilling fluids
- grinding and subsurface injection of drill cuttings.

5.1 BPT TECHNOLOGY

EPA has developed effluent limitations guidelines for the Coastal subcategory based on Best Practicable Control Technology Currently Available (BPT), which represented the average of the best existing technologies at the time of investigation. These standards were published on April 13, 1979 (44 FR 22069). At that time, EPA determined that drilling product substitution, or the use of more environmentally benign products, combined with onshore disposal was the best practicable control method available. An example of product substitution is the use of water-based drilling fluid in place of oil-based drilling fluid such that the drilling fluid (and cuttings) discharged would pass the no-free-oil limit. Effluent limitations based on this technology allow no discharge of free oil in drilling fluids and drill cuttings. This limitation was implemented by requiring no oil sheen to be present upon discharge.

5.2 PRODUCT SUBSTITUTION - ACUTE TOXICITY LIMITATIONS

It has been shown that low toxicities can be achieved through the use of water-based drilling fluids and low toxicity specialty additives.[4] Thus, limitations based on acute toxicity would encourage operators to substitute low toxicity additives in place of high toxicity additives. One BAT/NSPS control option evaluated for the final rule includes the current offshore limitation of 30,000 ppm in the suspended particulate phase (SPP) (see Chapters X and XIII). At proposal, EPA considered an option that would have established a toxicity limitation in the range of 100,000 ppm to 1,000,000 ppm in the suspended particulate phase (SPP). EPA subsequently determined that the data available were not sufficient for establishing a toxicity limit more stringent than 30,000 ppm (see Chapters X and XIV).

5.3 PRODUCT SUBSTITUTION - CLEAN BARITE

Barite is a major component of drilling fluids which can represent as much as 70 percent of the weight of a high-density drilling fluid. Barite has been shown to contain varying concentrations of metals of toxic concern, particularly cadmium and mercury. Barium sulfate, the natural source of barite, has also been shown to contain varying concentrations of metals depending on the characteristics of the deposit from where the barite was mined. During the development of the Offshore Guidelines, a statistical analysis of the API/USEPA Metals Database indicated that there is some correlation between cadmium and mercury and other trace metals in the barium.[9] Thus, regulating the concentration of cadmium and mercury in barite would indirectly regulate other metals present in barite (see Section VI.2.4). The Offshore Development Document includes a detailed discussion of the findings of this analysis.[4]

5.4 PRODUCT SUBSTITUTION - MINERAL OIL

In addition to using low toxicity drilling fluids, low toxicity lubrication additives can reduce the overall toxicity of the drilling fluid. For many years, diesel oil was the preferred additive for lubrication purposes and for spotting jobs. EPA has evaluated other lubricants that have similar properties to diesel but are less toxic. Mineral oil has become a common substitute for diesel oil as it can be used as a torque-reducing agent and a spotting fluid.[4]

An OOC sponsored analysis of organic chemical characterization of diesel and mineral oils used as drilling fluid additives indicated that there are similar constituents in both diesel and mineral oils but at significantly higher concentrations in the diesel.[18] The analysis revealed quantitative differences in the total aromatic, total sulfur and organic sulfur contents, as well as in the concentrations of individual polyaromatic hydrocarbons (PAHs, including benzene, naphthalene, biphenyl, fluorene and phenanthrene alkyl homologue series) and sulfur- and nitrogen-polycyclic aromatic compounds (PAC) (debenxothiophene and carbazole alkyl homologue series, respectively). Thus, the differences in amounts of these compounds in mineral and diesel oils accounts for the lower toxicity of mineral oil.

In 1984, industry representatives acknowledged that mineral oil is an adequate substitute for diesel as a torque-reducing lubricity agent.[18] Several industry studies investigated the effectiveness of using diesel oil versus mineral oil in freeing stuck pipe. The data gathered from these studies indicated that: mineral oil was commonly used by operations in the Gulf of Mexico, mineral oil is an available alternative to the use of diesel oil, and success rates comparable to those with diesel oil can be achieved with mineral oil.

5.5 ENHANCED SOLIDS CONTROL: WASTE MINIMIZATION/POLLUTION PREVENTION

A widely recognized method of minimizing drilling waste volumes is the use of high-efficiency solids control systems, sometimes referred to as "closed-loop" solids control systems or CLSs. The term "closed-loop" is somewhat misleading in that it implies a closed system from which only waste cuttings are removed. The system is not truly closed because, regardless of the system's level of efficiency, some cuttings are always retained in the drilling fluid and some drilling fluid is always discarded with the cuttings.[19] While no single definition of the term "closed-loop" is available, definitions throughout current literature generally describe closed-loop technology as the process of minimizing both the amount of waste produced from an active drilling fluid circulation system and the amount of dilution required by the drilling fluid.[19,20,21] In practice, then, a CLS returns as much drilling fluid to the circulation system as is economically and practically possible. The drill cuttings removed from the circulation system are consequently reduced in liquid content and overall volume. While the practical application of solids control systems cannot be 100 percent "closed," the CLSs currently in use in the coastal oil and gas industry are measurably more efficient than conventional systems that utilize reserve pits and little or no waste minimizing technology.

Following is a list of advantages to using CLS technology compiled from current literature:[20,21,22]

- Reduced dilution and associated displacement of drilling fluid, resulting in reduced drilling fluid maintenance costs
- Reduced waste volume and disposal cost
- Reduced disposal costs offset increased costs for improved solids control
- Reduced total drilling location waste management costs
- Reduction or elimination of the need for an earthen pit and avoidance of significant site closure costs at land-based sites
- Increased rate of penetration

- Increased drilling efficiency through optimization of drilling fluid solids content and rheological properties
- Reduced trouble costs
- Minimal environmental impact
- Reduced waste transportation and disposal liability.

It is apparent in both industry literature and industry practices (as observed directly by EPA) that closed-loop solids control technology is achievable using currently available equipment.[1,2,3,20] A typical CLS consists of at least some of the following equipment, depending on the drilling program: shale shakers, a sand trap, a degasser, hydrocyclones (desanders, desilters, microclones), a flocculation chemical addition manifold, a dewatering centrifuge, and a barite recovery centrifuge if weighted drilling fluid is used. Closed-loop solids control systems can provide greater than 90 percent solids removal efficiency when flocculation enhancing chemicals are used.[23] Without chemical addition, CLS efficiency ranges between 72-75 percent.[23] The following sections describe these unit processes as they are currently utilized in closed-loop solids control systems.

5.5.1 Shale Shakers

Shale shakers, also called vibrating screens, are usually the first step in a solids control system. The function of a shale shaker is to remove the largest drill cuttings from the active drilling fluid system and to protect downstream equipment from unnecessary wear and damage from abrasion. Variables involved in shale shaker design include screen cloth characteristics, type of motion, position of screen, and arrangement of multiple screens.

Screen characteristics are expressed as mesh size (the number of openings in a linear inch), opening size, percent open area, and wire diameter. Typical mesh sizes range from 30 to 250.[24] The type of screen motion is determined by the eccentric weight or reciprocator (the vibrating device) and the suspension system. Motion can be circular, elliptical, or straight-line. Screen position depends on the effectiveness of the vibrating motion to move solids. Ideally, balanced circular or elliptical motion should move the solids across the screen regardless of screen position. Tilting the screen might be necessary to overcome problems brought on by unbalanced elliptical motion. Such tilting can cause an increase in drilling fluid loss with the cuttings. Multiple screens are used when the solids load is too great for a single screen (or under other problematic drilling conditions), and are used in one of two arrangements: series or parallel.

Staged (or "cascaded") screens in series are arranged so that the underflow of the first screen is the feed to the second, and so that the coarser mesh screen comes first. Parallel arrangements can include multiple screens on a single deck or side-by-side pairs of shale shakers. Some operators use two sets of shale shakers in series, wherein the first shakers, referred to as "scalp" shakers, contain coarser mesh to remove sticks and the largest particles, and the second set of shakers contain finer mesh.[23]

A term that is used to quantify the portion of solids that remain in the discharge as compared to the solids that leave with the liquid underflow is the "median cut." This term is used to describe the performance of all solids separation equipment in addition to shale shakers. The median cut-size particle for a shale shaker screen is that of which half pass through and half remain on the screen. For a given shale shaker (or any solids separation unit), a smaller median cut particle size indicates better separation than a larger median cut particle size. The range of acceptable median cut particle size depends on multiple factors for any particular unit. Factors that determine what the median cut will be for a given shale shaker include the screen mesh size, screen opening shape (square or rectangular), the amplitude (or distance) of the vibration, and the particle shapes. Not all particles smaller than the screen mesh get through, and likewise, some oversize particles pass through due to their shape.

Common shale shaker problems include solids overloading and screen plugging (called "blinding"). Both problems cause the screen to be bypassed and thus reduce the liquid throughput. Solids overloading, which may occur at times of increased drilling rate, can be overcome by adding a screen, either in series or in parallel. Blinding may be due either to a film of small particles that adheres to the screen and reduces the effective open area or to near-size particles plugging the screen. The former case may be corrected with a coarser mesh screen, and the latter might require a smaller mesh. Some shale shakers are equipped with a spray bar that showers water over the cuttings on the screen to enhance mud/cuttings separation. However, one source recommends that only temporary spray bars be used to apply a "mist" to sticky clay cuttings and other problematic solids.[25]

Current innovative screening device designs include fine mesh (up to 400) screens capable of processing drilling fluid through an effective area of up to 600 square feet per second under a slight vacuum. Advantages of such designs include improved degassing capability and reduced free liquid on the discarded solids.[26]

5.5.2 Sand Traps

A sand trap is a settling tank positioned to receive the liquid underflow from the shale shakers. This tank serves to "trap" sand and other large particles that bypass the shale shaker screens, either by design or due to a problem with the shakers (e.g., torn screen, blinded screen, solids overload). This settling protects the downstream equipment from wear due to abrasion. A properly designed sand trap is not stirred (as are other tanks in the active fluid system), removes solids only through a bottom-opening dump valve, and discharges mud over a retaining weir. Because large amounts of barite could settle out in this quiescent tank, weighted fluids should bypass the sand trap, unless there are problems with the shakers.[27,28]

5.5.3 Degassers

The purpose of a degasser is to remove gas and air from the drilling fluid which, due to its compressibility, can have detrimental effects on the drilling fluid. In addition, centrifugal pumps used to feed downstream equipment, as well as hydrocyclones, do not operate efficiently with gas-cut fluid. Therefore, in a well designed system, a degasser is positioned after the sand trap and before the hydrocyclone pumps.

Two basic designs of degassers include atmospheric and vacuum. Atmospheric degassers use turbulence to separate bubbles from the drilling fluid, and vacuum degassers use a combination of turbulence, thin film, and vacuum to perform the necessary separation. Available degasser performance data indicate that atmospheric degassers work satisfactorily on lower-weight, lower-viscosity water-based fluids as well as oil-based fluids.[29] Vacuum degassers perform better than atmospheric degassers on heavier fluids. However, when the yield point (a rheological property) of the drilling fluid is below 10 lb/100 ft^2, shale shakers can remove enough of the gas to make degassing equipment unnecessary.[27]

5.5.4 Hydrocyclones

The hydrocyclones used in drilling fluid circulation systems are static units that have no moving internal parts. Drilling fluid is fed tangentially into a hydrocyclone under pressure. Separation of the solid particles from the liquid occurs in these units by means of centrifugal forces imposed on the influent as it spirals down the inside of the cone, which causes the heavier particles to move radially to the outer edge of the stream. The underflow solid particles exit through the bottom of the conical housing and the liquid overflow passes upward near the center and out through the top. Figure VII-1 illustrates the flow patterns

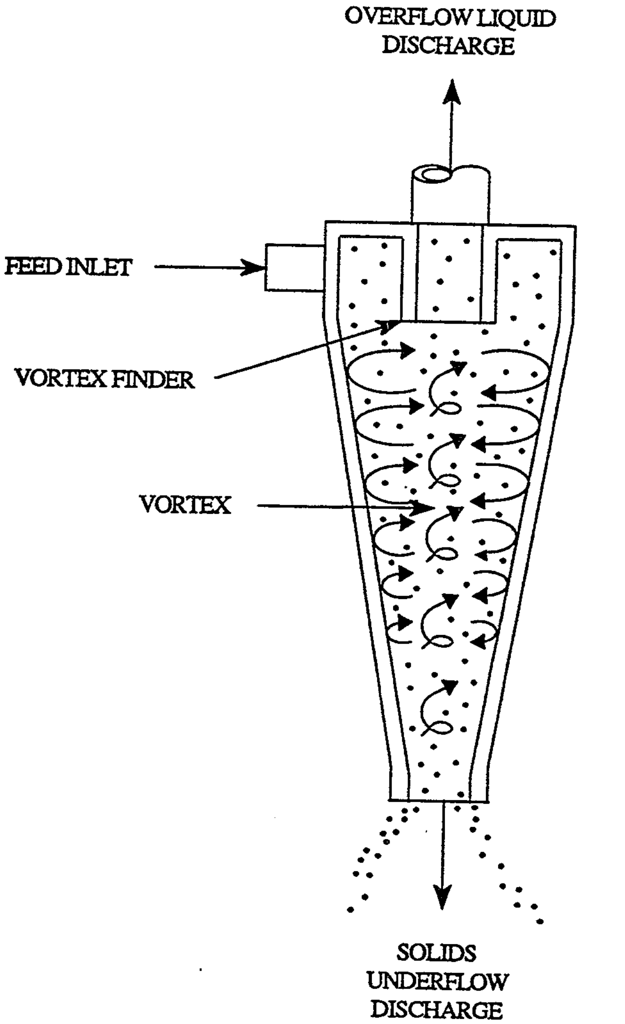

Figure VII-1
Hydrocyclone Flow Patterns

within a properly operating hydrocyclone, as well as the nomenclature associated with hydrocyclone technology.

Hydrocyclones are typically referred to as "desanders" and "desilters," depending on the size particle they are intended to remove from the drilling fluid. Desanders are designed to remove particles down to 40 microns in size, desilters remove down to 20 microns, and specially designed "microclones" remove down to 10 microns (55 FR 23348). As a point of reference, human hair ranges in size from 30 to 200 microns. Particles less than two microns are referred to as "clay," particles from two to 74 microns are "silt," and particles greater than 74 microns are "sand."[27] While there is no industry standard for the distinction, desander cones generally range in size from six to 12 inches in diameter, and desilter cones range from two to five inches.[30] The two-inch desilters are referred to as "microclones."

The cones of a desander are often arranged in two parallel rows of three each, for a total of six cones. The liquid overflow from each cone enters a header which returns the combined overflows to the next tank in the active drilling fluid system. Desilters often consist of two rows of six cones each. The number of cones required depends on the size of each cone and the type of solids being handled. Cones can also be arranged in a circle around a common header.

The problems experienced by hydrocyclones include clogged inlet or exit flow holes and improper flow adjustment. When the underflow opening is blocked, solids will exit the cone through the top with the liquid overflow and return to the active drilling fluid system. When the feed stream is blocked, the absence of the upward liquid flow can cause liquid overflow from adjacent cones to enter the cone from the overflow header and be lost through the underflow opening. If the flow rate is improperly adjusted, the hydrocyclone can become overloaded with solids, thus causing solid particles to exit with the overflow.

“Mud cleaners" were initially developed for weighted fluid systems for the purpose of capturing solids that exit through the hydrocyclone underflow, thus allowing the weighting agents existing with the solids to be returned to the system. A mud cleaner is a combination hydrocyclone-shale shaker designed to remove sand-sized particles while returning medium and fine silt as well as clay-sized material to theactive drilling fluid system. One source states that the purpose of this separation step is to reduce the amount of barite make-up required by returning some solids that would otherwise be discarded by the hydrocyclone.[27] However, the return of the clay-bearing liquid should be stopped if viscosity becomes a problem. Another source states that the purpose of the mud cleaner is to remove any API sand (between

74 and 178 microns) that is not removed by the primary shale shakers, and offers guidelines for proper operation.[29] With recent improvements in shale shaker screens and hydrocyclone performance, the need for mud cleaners must be determined on a case-by-case basis.

5.5.5 Centrifuges

Centrifuges are used in solids separation systems to enhance the solids removal efficiency. For example, use of centrifuges with standard rig equipment only, can boost a system's removal efficiency from 30 to 40 percent.[31] Two centrifuge designs are currently in use in the solids separation systems: decanting centrifuges and perforated rotor centrifuges (also called "RMS" for rotary mud separator).

Both the decanting centrifuge and the RMS can be used as "barite-recovery" units from which the barite-laden solids are returned to the active drilling fluid system while the liquid (dewatering effluent) is discharged or disposed. However, only the decanting centrifuge is used as a solids dewatering device, from which relatively dry solids (fine cuttings) exit to a waste pile and the liquid may be returned to the active drilling fluid system. The RMS is not capable of removing enough liquid from the solids fraction to be used as a dewatering step in a closed-loop solids control system.[23] Additional discussion regarding the applications of these units is included in the next section.

The decanting centrifuge, illustrated in Figure VII-2, is equipped with a spiral conveyor housed within a conical- or cylindrical-shaped bowl, both of which rotate in the same direction. The conveyor rotates at a slower speed than that of the bowl and the relative rotation between the two dictates the solids conveying speed. Bowl rotation speeds range from 1,500 to 3,500 rpm, and the conveyor speed is determined by the gear ratio, which may be controlled.

A typical gear ratio is 80:1 where the conveyor loses one revolution per 80 revolutions of the bowl, such that a bowl speed of 1,500 rpm will correspond to a conveyor speed of 1,481 rpm and a relative conveying speed of 18.75 rpm. Retention time within the unit ranges between 10 and 80 seconds.[26]

The performance of a decanting centrifuge is measured by the feed rate capacity, the solids discharge capacity, and the liquid discharge capacity. The feed rate depends on the solids content of the feed, such that a feed with a high solids content will be limited by the solids discharge capacity, and a feed with a low solids content will be limited by the liquid discharge capacity. The solids discharge capacity depends on the rates at which solids are conveyed and discharged through the openings. The liquid

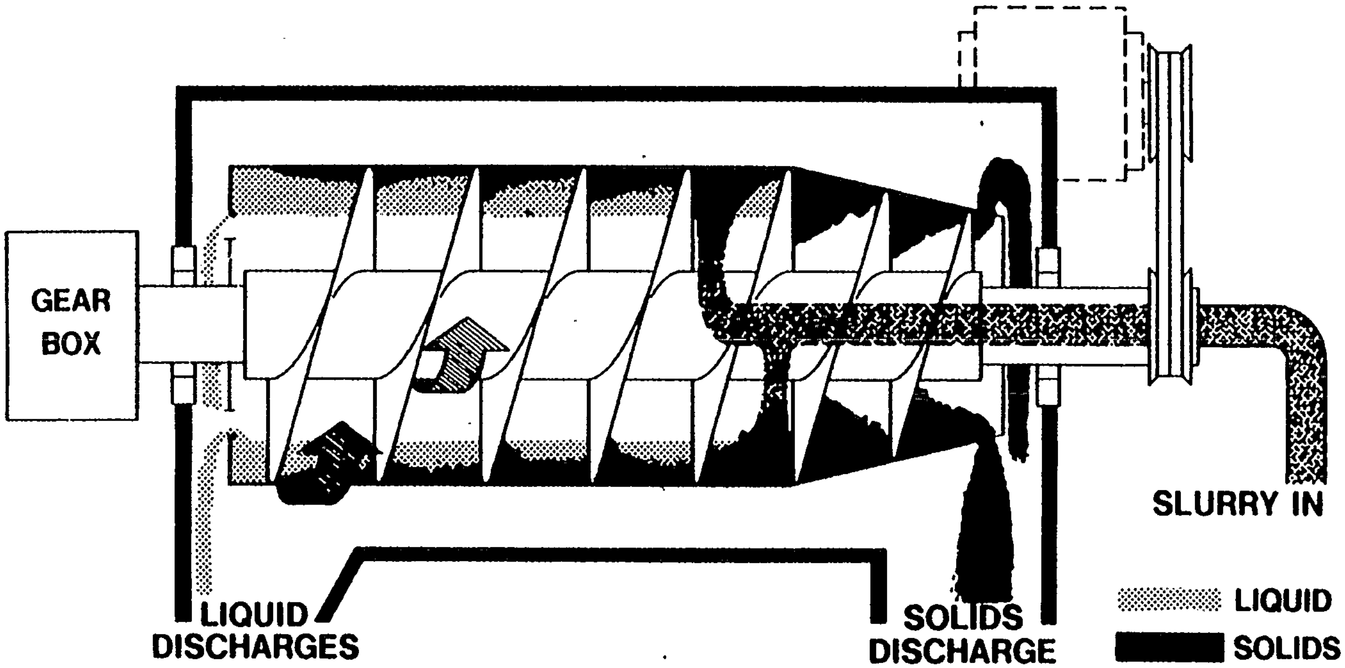

Figure VII-2
Decanting Centrifuge[24]

discharge capacity depends on the capacity of the openings to discharge liquid of a certain depth within the bowl. A major development in decanter bowl design occurred in the early 1970's when a cylindrical or "contour" bowl was introduced. With this design, the increased bowl volume allows for a higher feed rate with the same separation achieved by a conical design. Due to their additional cost, contour bowl decanting centrifuges are typically used to dewater waste solids and recycle liquid back to the active system, rather than for barite recovery.[27]

The advantage of the RMS over the decanting centrifuge is that of portability. Because the solids-laden underflow is liquid, it exits the unit through a pipe, thus allowing the unit to be positioned anywhere in relation to the mud tanks. In contrast, a decanting centrifuge must be placed so that the solids fall directly into the receiving vessel (either the mud tanks or a waste container) or onto a solids conveyor.

Figure VII-3 illustrates the operation of a RMS. The feed enters the unit through an opening in the outer housing. The perforated rotor is the only part that rotates, causing the heavier particles to move radially toward the wall of the outer housing. The liquid overflow enters the rotor through the perforations and exits the unit through a pipe attached to the end of the rotor. The solids-laden underflow exits through a pipe located in the outer housing located at the opposite end from the feed inlet. The rate at which the underflow discharges is regulated by a choke valve in the discharge pipe. This choke also controls the amount of liquid exiting through the overflow discharge. Normal operation with a water-based fluid requires a dilution of ten parts feed mud to seven parts dilution water. This water must be compatible with the active drilling fluid. Disadvantages to the RMS, as compared to a decanting centrifuge, include a slightly higher barite loss, a high demand for dilution water, and a high rate of overflow discharge requiring disposal.[26] However, the smaller RMS is applicable in situations over water where there is no room to move a decanter around the mud tanks.

5.5.6 Chemically Enhanced Centrifugation

Chemically enhanced centrifugation (CEC) is a term used to describe the addition of coagulation and flocculation chemicals to enhance the effectiveness of a decanting centrifuge. CEC is also referred to as "dewatering" because its purpose is to remove as much of the liquid phase from the feed to a decanting centrifuge as is economically practical. The use of CEC systems is cited throughout current literature[21,32,33] and has been observed recently by EPA.[1,2] The CEC step is typically located where it can process the discharge from other solids separation equipment such as desilters, desanders, and barite-recovery

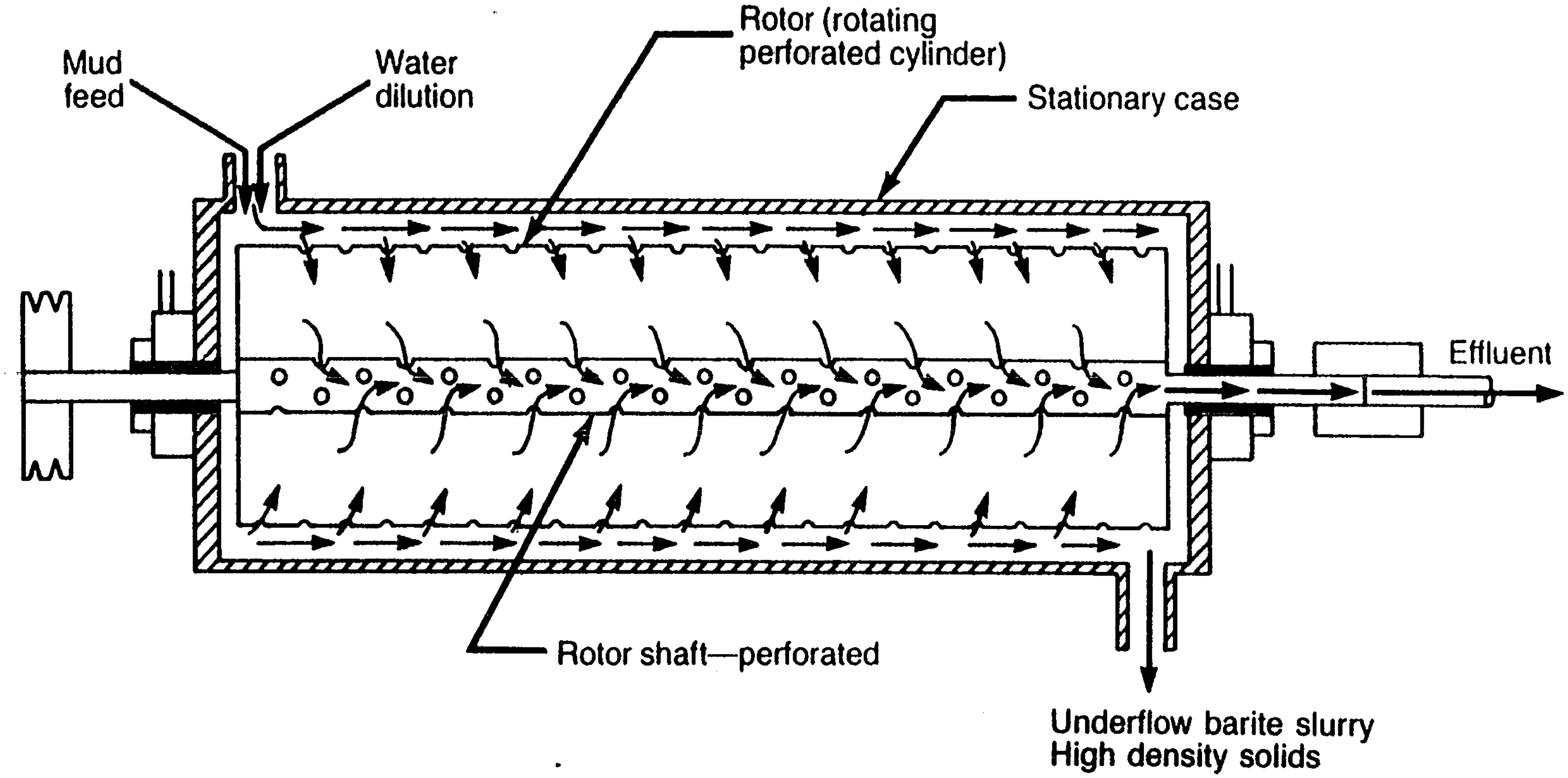

Figure VII-3
Rotary Mud Separator (RMS) Centrifuge[24]

centrifuges. The products of this dewatering step are a damp solid discharge and a clarified liquid discharge.

A CEC step is included in a CLS when it is necessary to remove colloidal particles (less than 5 microns) from the active drilling fluid system. If excess drill solids are not removed from a CLS, each pass through the system causes the particles to degrade to smaller sizes making them increasingly difficult to remove. The mechanical action of centrifugal pumps and shale shakers contribute to particle degradation. An undesirable increase in drilling fluid weight and viscosity can occur when drill solids degrade, due to the increased surface area of the smaller particles.[33] Increased surface area causes increased water consumption. Drill solids degradation can be controlled through the choice of drilling fluid and additives, which can consequently increase the efficiency of the mechanical solids control equipment. Additionally, removing colloidal solids with a CEC step prevents returning detrimental particles to the active drilling fluid system.

Chemical treatment is needed to remove low-gravity particles (below 5 microns in size) which are not removed by centrifugation alone.[33] These small particles must first be treated with coagulant to reduce the radius of their electric charge (called "zeta potential") which repels them from particles of like charge. Flocculent is then added to allow the coagulated particles to come together (or "bridge") into larger groups of particles that can be removed by a decanting centrifuge. High molecular weight polyacrylamides are commonly used for flocculation.[34]

The degree to which the discharged liquid is clarified depends on its intended disposition, either as recycle back to the active drilling fluid system, or as waste to be disposed in some manner (including annular injection, surface discharge, or off-site disposal). The solids discharged from a CEC unit are typically 35 to 75 percent water by volume.[21] If the discharged liquid is to be returned to the active drilling fluid system, it must be compatible with the drilling fluid.

Finally, it is important to note that onsite dewatering of spent drilling fluid is typically practiced only when an economical onsite method of disposal or reuse is available for either the dewatering liquid or the dewatered solids. Such methods include onsite land disposal of the solids and injection of the liquid into either the annulus of the well being drilled or an available disposal well. When an economical means of disposing or reusing the products of dewatering is not available, the least expensive method of handling these wastes is to remove the dewatering step and haul the spent drilling fluid to an offsite disposal facility.

5.5.7 Closed-Loop Solids Control System Design

To better understand the design of a closed-loop solids control system, it is important to discuss the basic applications of each unit in relation to the active drilling fluid circulation system. Table VII-6 describes various applications of solids separation equipment used with unweighted and weighted drilling fluid systems.[27] The distinction between whether a separation step is primary or secondary is determined by the origin of the feed stream to a particular unit: a primary separation step is fed directly from the active drilling fluid circulation system, and a secondary step is fed from a primary step. Also of concern is whether a separation unit is designed to handle a flow rate equal to the total drilling fluid circulation rate ("full" flow) or a fraction thereof ("partial" flow).

As shown in Table VII-6, the location of a centrifuge within a solids control system varies depending on its application. Both decanting and RMS centrifuges can be located as primary separation units when used to recover barite from a weighted drilling fluid. In this primary application, the centrifuge processes the entire volume of recycled drilling fluid. A decanting centrifuge, the only centrifuge useful for dewatering purposes, may be located in a secondary position to receive either desilter underflow or barite recovery centrifuge overflow. This secondary separation step processes only a fraction of the total drilling fluids system volume.

Figure VII-4 illustrates a system in which the shale shakers, degasser, desander, and desilter, are operated in primary full-flow, and the decanting centrifuge is operated as secondary separation of the hydrocyclone underflow. This example is an unweighted drilling fluid application. The system arrangement illustrated in this figure is typical of CLSs used to minimize solid waste volume and to recycle water back into the active drilling fluid system. Table VII-6 demonstrates that there is often more than one piece of equipment capable of performing a given separation task. The choice of equipment is usually the result of an analysis weighing the drilling program operating parameters and conditions against overall cost. Current literature cites the fact that poor choices of solids separation equipment were prevalent in the 1980s due to a general misunderstanding of the operating principles of each unit.[25,27] However, it is apparent that more operators are taking a closer and more careful look at solids separation technology as a means of reducing drilling fluid make up costs as well as drilling waste generation and costs.

CLS systems change with operating conditions, even during the same drilling operation. For example, a CLS might consist of multiple shale shakers, hydrocyclones, and a dewatering centrifuge during the drilling of the surface interval of the hole where an unweighted water-base fluid is used and the rate

TABLE VII-6

SOLIDS SEPARATION EQUIPMENT APPLICATIONS[a]

Item	Type of Equipment	Separation	Type of Flow	Character of the Discard	Application(s)
1	Shale shaker screens	Primary	Full	Wet to damp	Remove coarsest particles (cuttings) and protect downstream separation units. Use with both unweighted and weighted fluids.
2	Desanding hydrocyclones	Primary	Full	Wet	Remove sand-size particles (down to approx. 40 microns). Use with both unweighted and weighted fluids. With oil-base fluids, use only when followed by items 7 or 8.
3	Desilting hydrocyclones	Primary	Full	Very wet	Remove silt-size particles (down to approx. 20 microns). Use with both unweighted and weighted fluids.
4	Decanting centrifuges	Primary	Partial	Low-volume liquid	Remove clays and soluble materials (in free liquid overflow) for viscosity control in a weighted water-base fluid. This application is often called a "barite-recovery" centrifuge. Mis-application if used on unweighted fluid or on oil-based fluids.[b]
5	Perforated rotor centrifuges	Primary	Partial	Medium-volume liquid	Remove clays and soluble materials (in free liquid overflow) for viscosity control in a weighted water-base fluid. This application is often called a "barite-recovery" centrifuge. Mis-application if used on unweighted fluid or on oil-based fluid.[b]
6	Special barite cyclones	Primary	Partial	High volume liquid	Remove clays and soluble materials (in free liquid overflow) for viscosity control in a weighted fluid. With oil-base fluids, use only when followed by items 7 or 8. Mis-application if used on unweighted fluid.
7	Decanting centrifuges	Secondary	(Desilter underflow)	Damp	Dewater solids from hydrocyclone underflow and return free liquid overflow to the drilling fluid system. Useful in areas where 1) water is expensive, or 2) solid waste minimization is necessary. Mis-application if used on weighted fluid.
8	Decanting centrifuges	Secondary	(Barite recovery overflow)	Damp	Dewater solids from barite recovery overflow and return free liquid overflow to the drilling fluid system. Useful in areas where 1) water is expensive, or 2) solid waste minimization is necessary.
9	Special screens	Secondary	(Desilter underflow)	Wet to damp	Remove selective solids from hydrocyclone underflow and return free liquid overflow to the fluid system.. This application is called a "mud cleaner" when used on a weighted fluid, and is intended to reduce barite usage. Usually a mis-application if used on an unweighted fluid.

[a] Adapted from Ormsby, 1983.[27]

[b] Another industry source reports using barite-recovery centrifuges on weighted mud regardless of whether it is water base or oil base.[35]

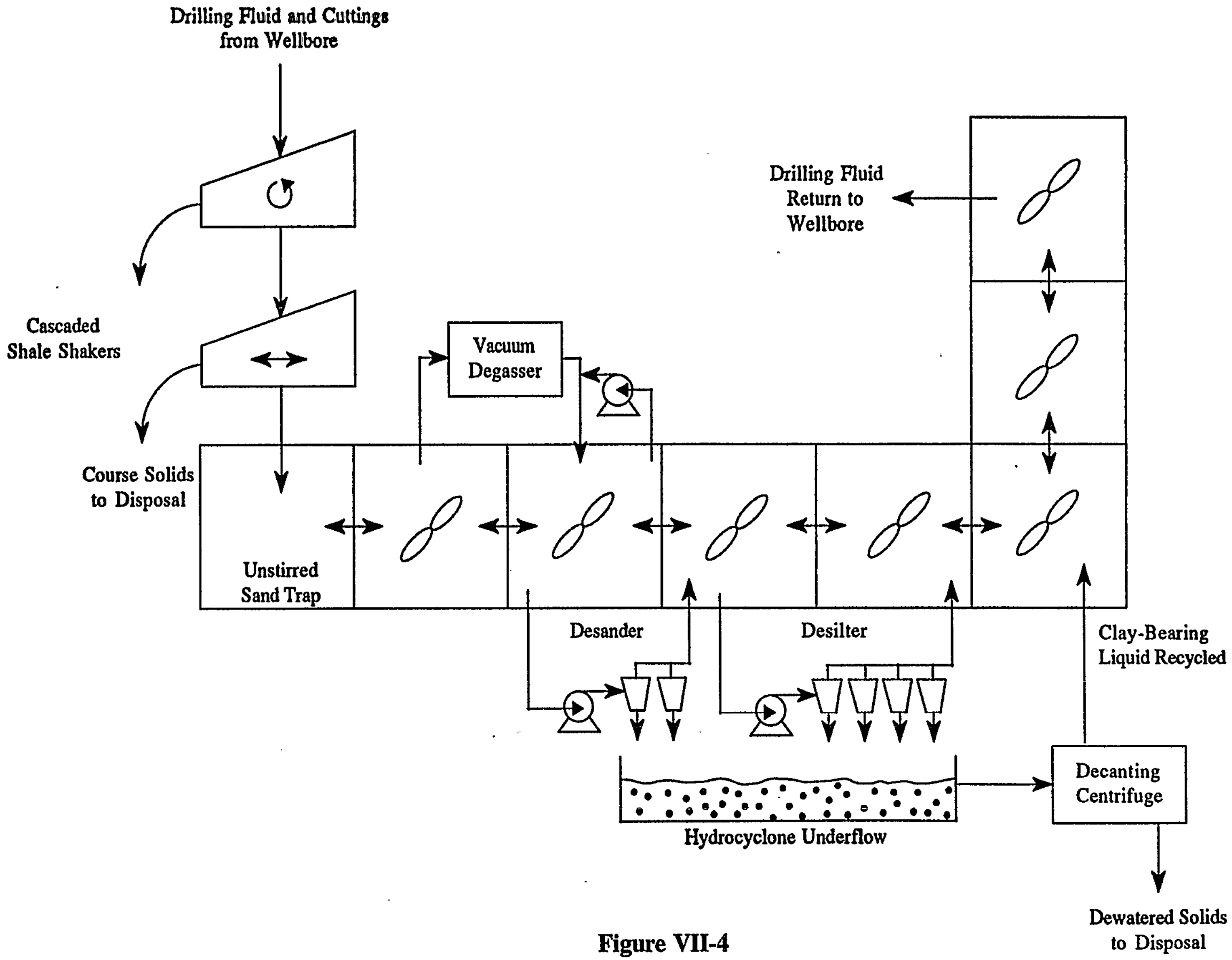

Figure VII-4
Example Closed-Loop Solids Control System
(Unweighted Drilling Fluid Application)

of drill cuttings production is greatest. Then as the fluid is weighted up and the rate of penetration decreases, one of the shale shakers might be removed and a barite-recovery centrifuge might replace the desilter. If a formation of reactive clay is reached, flocculation chemicals and associated equipment might be added at that point. Examples of these and other CLS design considerations are cited in current literature.[36]

As part of the Costal guidelines development, EPA visited three drill sites in southern Louisiana, each of which utilized closed-loop solids control technology.[1,2,3] Figures VII-5, VII-6, and VII-7 depict the solids control systems used at the three sites.

The CLS used at the GAP Energy drill site (Figure VII-5) included a CEC step to separate water from spent drilling fluid for recycle back into the active drilling fluid system. A unique feature of the GAP site is that in addition to the solids control equipment provided with the drilling rig, another suite of solids control equipment was brought onsite by the solids control contractor. Depending on the requirements of the drilling program, it is not uncommon for the solids control contractor to substitute part or all of the rig-supplied equipment. The ARCO drill site (Figure VII-6) included a barite recovery centrifuge and a CEC step to separate and recycle water from the barite recovery centrifuge overflow. Chemical addition was minimized at ARCO to keep fluid treatment chemicals in the recycle water. Thus, the water samples obtained from the dewatering centrifuge at the ARCO site were significantly darker than the water samples obtained at the GAP site. Based on visual inspection, samples from both sites were free of settleable solids. The CLS system used at the UNOCAL site (Figure VII-7) was similar to the ARCO system, except that no chemicals were added to the feed to the dewatering centrifuge. By comparison, then, the water sample from the UNOCAL site was considerably more turbid than the samples obtained at the other sites, containing total solids ranging from 23% to 24.7%.[3]

5.5.8 Solids Control System Efficiency

Table VII-7 lists solids control system efficiencies from various literature sources. These numbers are not statistically comparable due to the lack of information available regarding the methods by which they were calculated. However, it is interesting to observe that efficiency increases dramatically for systems using chemically enhanced centrifugation over those relying only on mechanical means.

The difference in CLS efficiencies with and without chemical addition was apparent from the systems observed during EPA's three drill site visits. All efficiencies reported by the solids control

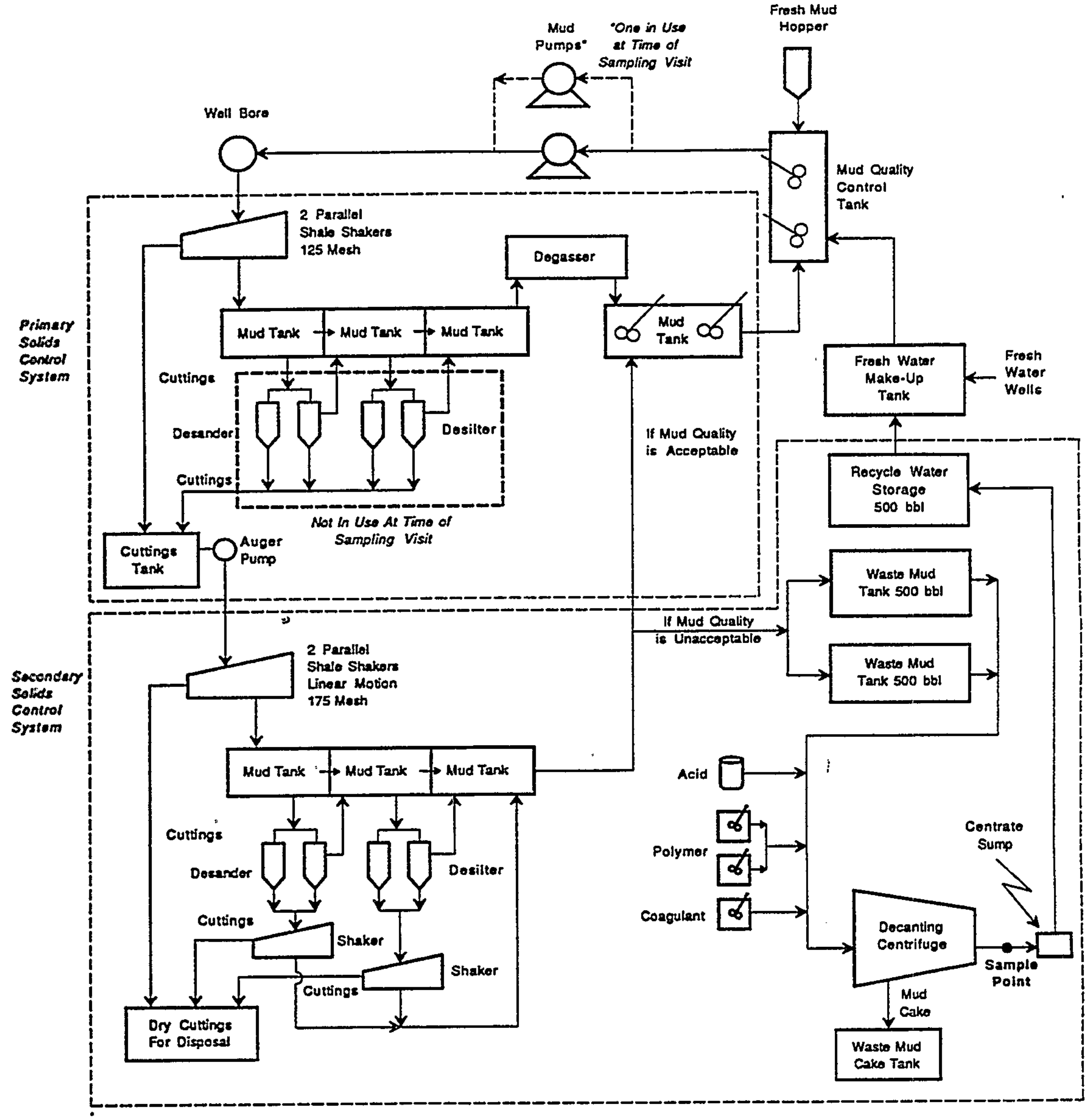

Figure VII-5
GAP Energy Mud Recirculation and Solids Control System

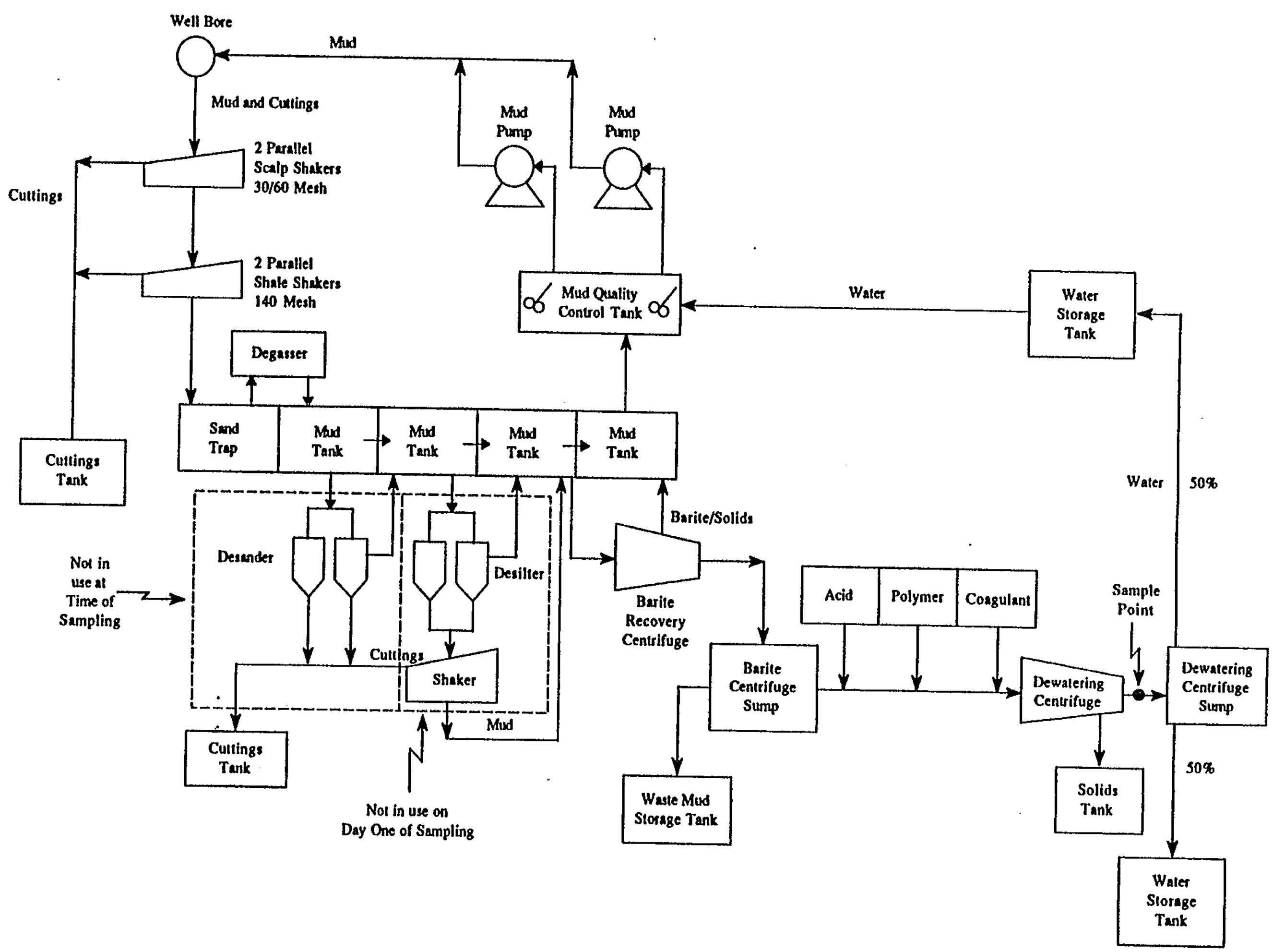

Figure VII-6
ARCO Mud Recirculation and Solids Control System

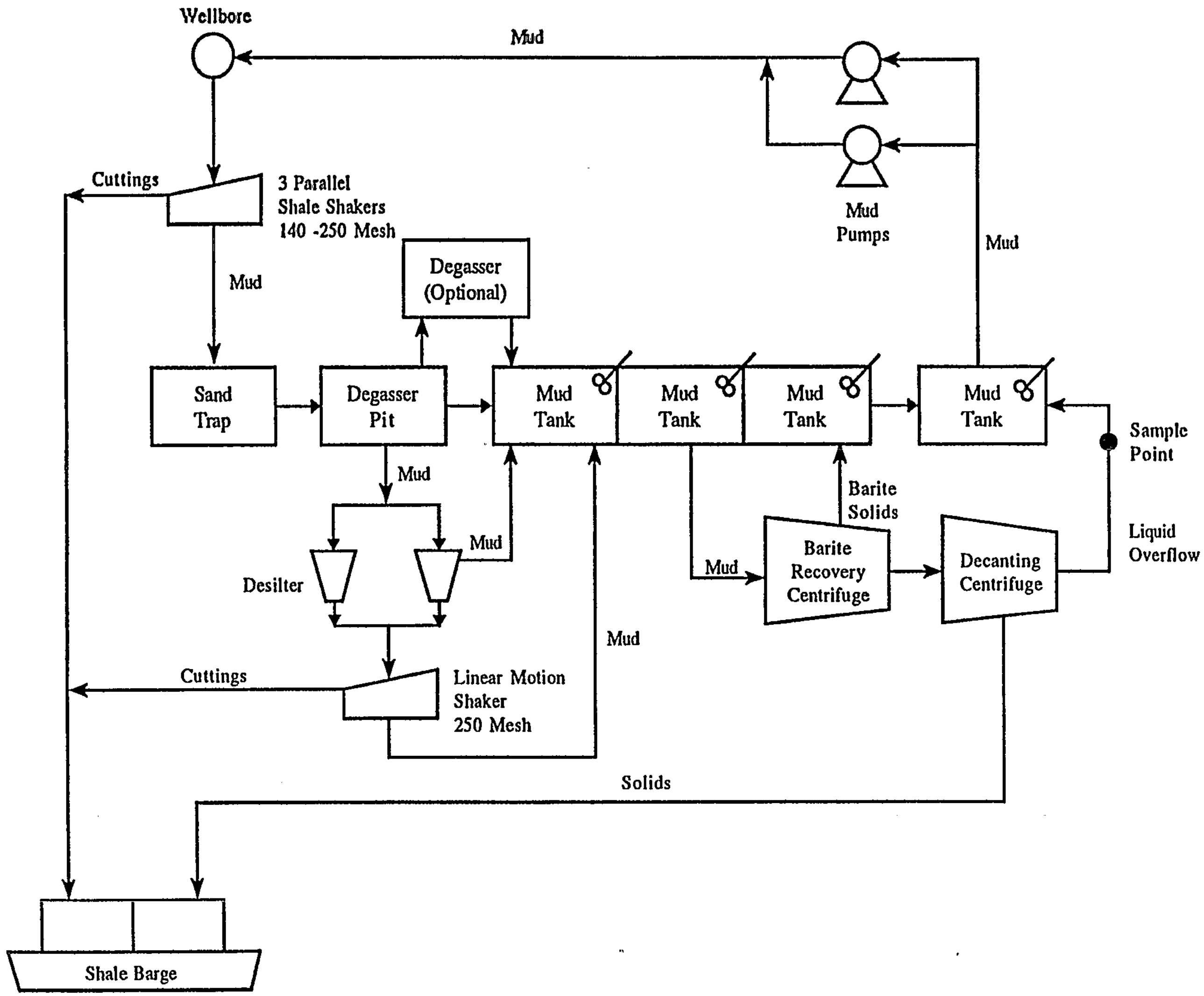

Figure VII-7
UNOCAL Mud Recirculation and Solids Contol
for 11,700 ft to 13,500 ft

TABLE VII-7

CLOSED-LOOP SOLIDS CONTROL SYSTEM EFFICIENCIES

Source	Equipment Used[a]	Reported Efficiency (vol. %)
Walters, 1991[33]	1	31.13
Walters, 1991[33]	2	37.58
Walters, 1991[33]	1	30.40
Walters, 1991[33]	3	88.31
Walters, 1991[33]	3	87.97
Walters, 1991[33]	1	21.73
Walters, 1991[33]	2	45.53
Finke, Aug. 18, 1993[25]	4	72-75
Finke, Aug. 18, 1993[25]	5	>90
Wojtanowicz, 1988[37]	6	99.967[b]
Wojtanowicz, 1988[37]	6	99.945[b]

a Classes of equipment:

1: Rig shale shakers, desander, and desilter only.
2: Rig equipment plus rental mud cleaner and centrifuge.
3: Unitized system: 2-4 parallel shale shakers, desander mud cleaner, desilter mud cleaner, microclone, low-speed centrifuge, and high-speed centrifuge.
4: Unitized system: two sets of shale shakers (in series), desander mud cleaner, desilter mud cleaner, and dewatering centrifuge.
5: Same as 4 plus flocculation chemicals and finer hydrocyclones.
6: Dewatering centrifuge and flocculation chemical addition only

b Wojtanowicz studied different sizes of dewatering centrifuges with flocculation chemical addition and reported the best two efficiencies observed as measured by weight % of the solids in the centrifuge liquid effluent compared to the centrifuge feed.

contractors at these sites are general values for the equipment used, as illustrated in Figures VII-5, VII-6, and VII-7. None of the efficiencies were directly measured on-site. The solids control contractors at both the GAP and ARCO sites reported efficiencies of approximately 90% when chemical flocculation was used.[1,2] The contractor at the ARCO site estimated efficiencies of 72-75% for the same equipment when chemicals are not added.[2] Similarly, an efficiency of 75% was reported for the system used at the UNOCAL site, where chemical flocculation was waived due to the availability of annular injection of the decanting centrifuge overflow.[2] By comparison, Cook Inlet operators reported in the 1993 Coastal Oil and Gas Questionnaire an average efficiency of 69 percent for the closed-loop solids control systems.[6]

5.6 RESERVE PITS

Although their use has been phased out in Alaska and is being phased out in much of the coastal Gulf of Mexico region, reserve pits are still employed within the coastal subcategory. A reserve pit is an earthen pit (lined or unlined) that is used to contain drilling fluids and wastes such as drill cuttings, discharges from solids control equipment, location drainage, drilling fluid, excess cement, equipment wash-down water, and completion/workover fluids. In addition, the pit contents can be used as reserve fluids in the event that the drilling fluids in the active system are lost to the formation.[21,38] Different types of earthen pits (lined or unlined) are used at land-based drilling sites to manage both solid and liquid materials and wastes.

Pit construction is based on the volume of waste to be placed in the pit. Industry sources suggest that, when sizing the pit, the smallest practical volume be used.[39] This minimizes the size of a land-based drilling location. In addition to drilling wastes, the reserve pit also accumulates precipitation, thus a smaller pit will accumulate less over the course of drilling operations. An industry source indicated that the pit should be designed using the assumption that two barrels of drilling waste will be generated for every foot of hole drilled.[39]

Reserve pits are designed to prevent migration of pit contents. This is achieved through the use of adequate berm (levee) height to maintain freeboard in the pit to prevent overflow of pit contents. Louisiana regulations specify that a minimum two feet of freeboard be maintained in the pit at all times (Louisiana Administrative Code, Statewide Order 29-B). In addition, low-permeability soils or synthetic liners are used to prevent the pit contents from leaching during the course of drilling operations.

In terms of site layout, two types of approaches to reserve pit construction are documented in current literature. The following sections discuss conventional reserve pits, which are the historically traditional approach to land-based drilling waste management, and "managed" reserve pit systems, which reflect current industry efforts to segregate and minimize wastes at the drill site.

5.6.1 Conventional Reserve Pits

In a conventional reserve pit system, one pit is used to contain all of the drilling wastes at the drilling location. These wastes may include drill cuttings, spent drilling fluid, location drainage, excess cement, equipment wash water, and completion/workover fluids. A footprint area of 200 feet by 300 feet would normally be required for a conventional reserve pit at a drilling location with an approximate well depth of 14,000 to 18,000 feet.[40] Assuming a levee ten feet wide encloses the pit, the actual surface dimensions of the pit would be 180 feet by 280 feet. Pit construction companies indicate that the average conventional reserve pit is 200 feet by 200 feet.[41,42] The pit is generally five to six feet deep but depths of eight and ten feet are also used.[42] The depth is limited by the height of the water table. Figure VII-8 is a layout of a typical drilling location where a conventional reserve pit has been used to manage drilling fluids and wastes. Pit construction companies also indicate that they are frequently asked to segment or partition the conventional reserve pits.[41,42]

5.6.2 Managed Reserve Pits

The following text is adapted from a paper presented by EPA at the SPE/EPA Exploration and Production Environmental Conference held in San Antonio, Texas in March 1993.[43]

A managed reserve pit is a waste segregation system that uses two or more pits to prevent contaminated wastes from coming in contact with uncontaminated materials. This can occur when using a conventional reserve pit while drilling into salt formations, if the well experiences a salt-water kick, or if oil-based fluid or fluid containing barite is used for drilling.[44] The number and size of the individual pits or cells depend on the number and volume of distinct waste streams expected to be generated during drilling operations. For instance, one cell would be sized and constructed as the reserve pit to accommodate the volume of drilling fluid required for the operation plus an adequate freeboard. A second cell would be constructed to manage cuttings, a third cell for rainwater runoff which may also be used for rig wash and drilling fluid make-up water. An important design consideration of the managed reserve pit system is to ensure that natural communication between the cells is prevented. The transfer of material between pits is handled using a dragline or manually controlled pumps.

The entire managed reserve pit system can be constructed in an area that would be occupied by a conventional reserve pit.[40] Thus, while the overall footprint of the managed pit system is comparable to that of a conventional reserve pit, a benefit is derived from keeping contaminated waste separated from waste that might be recycled, reused, or disposed of at a lower cost.

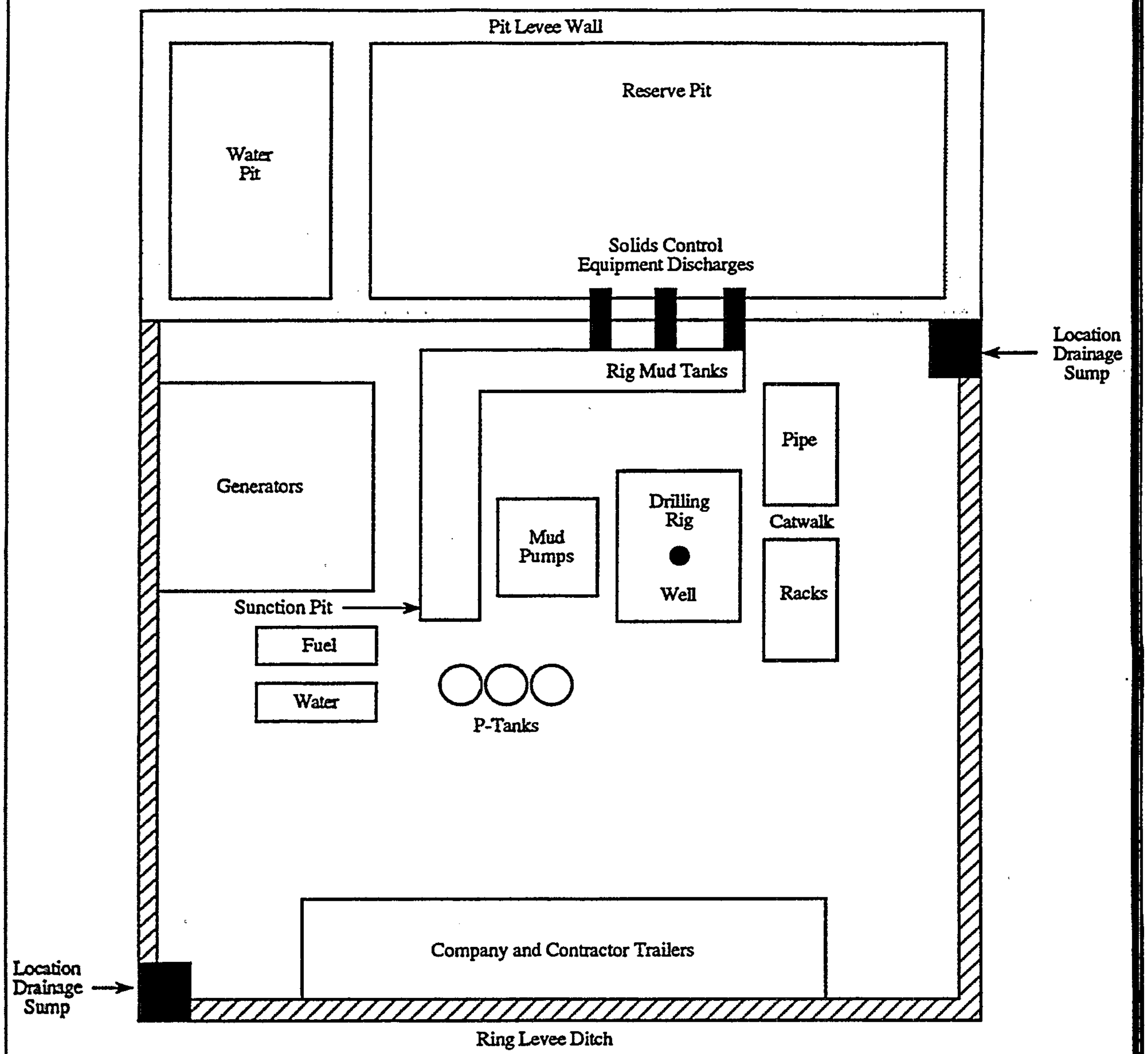

Figure VII-8
Layout of a Drilling Location Utilizing a Conventional Reserve Pit

The operation of a managed reserve pit system is summarized as follows.[40] Solids and residual drilling fluids are discharged to the shaker pit from the solids control equipment. Solids from the shaker pit are transferred to the storage pit and fluids are transferred to the settling pit along with rain water and equipment wash water. Following settling, the water is transferred to the treatment pit. Reserve pit treatment often includes lime addition to raise the pH, followed by aeration by mixing the pit contents. Such treatment clarifies the water by causing the solids to settle out. From the treatment pit, water is recycled for continued use in the drilling operations or discarded as waste. The status of the managed pit system is evaluated on a daily basis and consists of assessing the volume of wastes in the system and the distribution of these wastes among the pits in the system.

5.6.3 Pit Closure and Site Restoration

The regulations in the States of Louisiana and Texas specify requirements for pit closure and approved disposal methods for pit contents (Louisiana Statewide Rule 29-B; Texas Statewide Rule 8). The closure and disposal requirements (applicable to conventional and managed reserve pits) include:

- Dewatering and backfilling
- Solidification
- Landfarming and backfilling
- Injection (liquids)
- Burial on-site (solids)
- Treatment and discharge (liquids)
- Off-site commercial disposal.

In locations where discharge is prohibited, disposal of drilling wastes can be accomplished via on-site annular injection, on-site landfarming or burial,[21,41] injection into a dedicated UIC Class II disposal well (either on- or off-site) or hauling off-site for land application at either a centralized commercial facility or a non-commercial site.

Following disposal of pit contents by any of the methods mentioned above, the reserve pit(s) is backfilled with the earthen levee material and/or stockpiled soil from initial excavation of the pit(s). The area may then be graded and restored to predrilling conditions.[40,45]

5.6.4 Reserve Pits on the North Slope

Reserve pits were initially the drilling fluids and cuttings disposal method of choice on the North Slope. A discussion of the use of reserve pits and other land disposal methods unique to Alaska is included in the document entitled "Oil and Gas Exploration and Production Wastes Handling Methods in Coastal Alaska".[46] However, the North Slope operators have ceased using reserve pits and now rely on a grinding and injection system for drilling waste, described in detail in Section 5.10. The unused reserve pits are in the process of being closed out in accordance with requirements issued by the state of Alaska.[47] See also Section 2.3 for a discussion of the applicability of reserve pit wastes to the final coastal guidelines.

5.7 CONSERVATION AND REUSE/RECYCLING

The emergence of the closed-loop solids control system has provided operators with one of the best means of reducing wastes generated and increasing recycling opportunities. Additionally, reuse and recycle is particularly desirable for fluids that have a hydrocarbon (diesel or mineral oil) liquid base or synthetic-based material because they cannot be discharged or are expensive. Economically attractive reuse practices for spent oil-based and synthetic-based drilling fluids are:

- Drilling fluid company buys back the used drilling fluid which is hauled to shore, processed, and reused.
- The spent drilling fluid is treated with additional solids-suspending agents and used as a packer fluid.

5.8 LAND TREATMENT AND DISPOSAL

This section discusses land-based treatment and disposal methods for drilling wastes at onsite and centralized commercial land treatment and disposal facilities. In addition, this section discusses current land disposal methods in Cook Inlet, Alaska.

5.8.1 Onsite Landfarming

Onsite landfarming of drilling wastes is a potential option in cases where there is adequate space, the soil conditions are suitable, and the oil company is the land owner or has permission from the land owner to landfarm.

The landfarming process consists of spreading a thin layer of the drilling waste over the landfarm area. After spreading the drilling waste, the top soil and humus layer that was stripped in the preparation phase of the drill site is spread over the drilling waste with a nitrogen fertilizer. The drilling waste, topsoil, and fertilizer are mixed through cultivation with a set of disks or a tractor-mounted tiller. The cultivation/fertilizer cycle is repeated about twice a year for two or three years. The time period is dependent on the quantity and the concentration of the drilling waste applied to the soil and the size of the application area.[48] The area can be successfully re-vegetated once the hydrocarbon content in the soil is less than one percent and the chloride content in the soil is less than 1,000 ppm.[48] Seed germination studies have revealed that landfarming operations can be re-vegetated within 180 days.[49]

Microbial decomposition is the major cause of hydrocarbon reduction in landfarming, although evaporation and volatilization of the light-end hydrocarbons is probably significant.[49] To maximize microbial decomposition, the most important aspects of landfarming are to maximize the surface contact between the drilling waste and soil bacteria, to aerate the soil/drilling waste mix to promote aerobic decomposition, and to boost the soil microbe count by providing additional nutrients in the form of high nitrogen fertilizer. The two commonly used fertilizers are 34-0-0 and 11-51-0 (nitrogen-phosphorous-potassium ratio). Fertilizer application rates are typically on the order of 1,000 pounds per acre.[48]

In one study, metals were analyzed in samples of waste/soil mixtures treated by landfarming and in leachate collected from under plots of treated mixture.[49] The total metals measured in the treated waste/soil mixture did not exceed guidelines for limiting constituents for land application. In the leachate, lead was measured at levels exceeding drinking water standards, and selenium was measured equal to drinking water standards. While the study made no general conclusions regarding the effectiveness of landfarming on metals, it was observed that[49]:

- flyash is more effective than native soil in reducing the rate of leaching of soluble salts,
- adsorption of barium on clay particles may remove it from solution,
- the presence of high levels of chlorides can increase the solubility of barium,
- arsenic in drilling fluids is not an environmental threat if the pH is maintained between 3 and 12.

EPA's costing analysis of drilling waste disposal (Chapter X) did not include onsite landfarming, but rather assumed that all wastes would be either injected onsite (see Section 5.10) or sent to commercial disposal facilities (see below).

5.8.2 Centralized Commercial Land Treatment and Disposal Facilities

Centralized commercial facilities are treatment and disposal and/or processing facilities that are located offsite from the drilling operation and are generally not operated by an oil and gas operator. In Louisiana, the Department of Natural Resources permits non-hazardous oil field wastes (NOW) facilities, and in Texas, the Railroad Commission of Texas permits NOW facilities.

Centralized commercial treatment facilities receive drilling wastes in vacuum trucks, dump trucks, cuttings boxes or barges. In Louisiana, the transportation of drilling wastes in barges is common because of the high frequency of drilling projects occurring in coastal waters. Coastal treatment facilities also receive barged drilling wastes from offshore drilling operations. One major commercial waste treatment facility in Louisiana has treatment facilities with barge access and several transfer stations with barge access.[50]

Most of these facilities employ a landfarming technique whereby the wastes are spread over small areas and are allowed to biodegrade until they become claylike substances that can be stockpiled outside of the landfarming area. Another common practice at centralized commercial facilities is the processing of drilling waste into a reusable construction material. This process consists of dewatering the drilling waste and mixing the solids with binding and solidification agents. The oil and metals are stabilized within the solids matrix and cannot leach from the solids. The resulting solids are then used as daily cover at a Class I municipal landfill. Other potential uses for the stabilized material include use as a sub-base for road construction and levee maintenance.[51]

The treatment process most often employed at land treatment facilities consists of a cycle which includes application, treatment, certification, and excavation. The treatment phase is designed to address heavy metals, sodium imbalances in the waste, chloride concentrations in excess of the state regulatory limits, oil and grease concentrations in excess of the regulatory limits and moisture contents. Commercial landfarming facilities typically treat waste in cells designed for a particular amount of waste. When the maximum amount of waste has been applied to a cell, the treatment process begins.[52]

The landfarming treatment process for one commercial NOW facility located in southeast Louisiana is described in the following paragraphs.[50,52]

The treatment cells at this facility range in size from 1.5 to 6 acres and consist of above-ground-level structures surrounded by berms built up to a height of 6 to 8 feet. Topsoil is removed prior to cell construction. Clay deposits under the topsoil serve as natural barriers to groundwater contamination. The clay acts to prevent cell leachate drainage to groundwater and to prevent groundwater infiltration into cells where there is a high natural water table.

The application phase of treatment consists of filling the cell with incoming drilling waste. The maximum application that the state of Louisiana allows is 15,000 barrels per acre over a three month period. Approximately 20 tons per acre of gypsum or calcium sulfate is spread and mechanically mixed with the waste. Through a classic ion exchange chemical reaction, the calcium from gypsum or calcium sulfate replaces the sodium on the soil particles. This step is necessary in reducing the exchangeable sodium percentage (ESP) of the soil. The ESP is a measure of the number of exchange sites on the soil particles which are occupied by sodium ions. The Louisiana regulations for landfarming limit the ESP concentration to 25 percent.

The next step of the treatment phase is flooding of the cell to remove the soluble salts from the soil-waste matrix. Approximately 6 to 12 inches of water is pumped onto the cell and mixed with the waste with mechanical equipment. The higher salt concentrations in the waste drive the concentrations up in the fresh water, thereby lowering the concentrations in the waste. Once the chloride concentrations reach an equilibrium and the water ceases to absorb more salts (at approximately 1,500-2,000 ppm), the solids are allowed to settle out of the water and the water is pumped out of the cell into a surface impoundment prior to injection. The salt removal step is an important step in maximizing the biodegradation process because many microorganisms do not function well in a high salt environment. The treatment process has taken about four to six months at this point.

The next step of the landfarming process consists of treatment of the oil and grease content of the waste. The oil and grease content is lowered by mixing the waste with the soil and through biodegradation. This treatment step consists of cultivation of the soil/waste mixture to improve exposure to the sun and air which maximizes biodegradation. The matrix in the cell is cultivated twice a month for a period of six to eight months.

Once all the material in the cell is treated and all the analyses are below the state-required limitations, the "cleaned" clay-like product is transferred from the cell to a stockpile area onsite. This material is used to maintain or construct new berms around the cells.

EPA determined that existing land disposal facilities in the areas accessible to the Gulf of Mexico offshore and coastal oil and gas subcategories have 5.5 million barrels annual capacity available for oil and gas field wastes.[4] Land disposal facilities accessible to California oil and gas operations in the offshore and coastal subcategories are estimated to have 19.4 million barrels annual capacity.[4]

5.8.3 Cook Inlet Land Disposal

There are currently no commercial land disposal facilities permitted in Cook Inlet. There are, however, two non-commercial land disposal facilities in Cook Inlet. These are: Marathon/UNOCAL Landfill at Kustatan (west side of Cook Inlet), and UNOCAL Beaver Creek Landfill on the Kenai Peninsula. Marathon and UNOCAL jointly operate the disposal site at Kustatan, located 3 miles north of the Trading Bay facility. The Beaver Creek landfill is limited to accepting drilling wastes generated only at the Beaver Creek Production facility.[53] Other operators do not have access to land disposal facilities in the Cook Inlet region and would have to transport drilling wastes to land disposal facilities located in other states. One operator responding to the 1993 Coastal Oil and Gas Questionnaire reported transporting drilling wastes to a landfill located in Idaho.[6] Another available landfill is located in Oregon (see Chapter X).

The site at Kustatan is a landfill that has been used for the disposal of a limited volume of drilling wastes and tank bottoms. This facility is authorized to receive wastes from the same platforms as do Trading Bay and Granite Point facilities.[53] The landfill consists of lined cells into which wastes are placed and stabilized. The size of the landfill is 16 modules, each module containing 4 lined cells, for a total size of 64 cells. Each cell can hold approximately 2,000 cubic yards or 9,620 bbl of material, for a total capacity of 615,680 bbl. Once a cell has reached full capacity, it is covered and closed. When one module reaches capacity, a new module is developed.[53] To date, only 19,240 bbl of wastes have been disposed at Kustatan.[54] This facility is only accessible and operated in the summer months because of its location and the harsh climate conditions in Cook Inlet. Due to the shallow waters on the west side of Cook Inlet, only barges can be used to transport the wastes to the west side of Cook Inlet for disposal.

5.9 SUBSURFACE INJECTION OF DRILLING FLUIDS

Subsurface injection of spent drilling fluids is an established oil field practice, although its availability is limited to those areas with access to viable receiving formations. If the solids control system at a well includes a dewatering step, the resulting liquid stream may also be injected if it is not being recycled into the drilling fluid system. Subsurface injection can be either through the annulus of an existing casing system, as shown in Figure VII-9, or into a UIC Class II injection well. The process consists of pumping the fluid down hole into a receiving formation. Prior to injection, drilling fluids are typically screened using a shale shaker to remove any large particles. The typical drilling fluid injection system consists of a shale shaker, mud tank, and pump. Triplex (three-plunger) pumps are commonly used as injection pumps. Maintenance of all flow rates, pressures, and injection zones is the responsibility of the oil company in accordance with the requirements of the permit.

5.10 GRINDING AND SUBSURFACE INJECTION OF DRILLING WASTE

The process of grinding and injection of drilling muds and cuttings was developed by operators on the North Slope Alaska in mid-1980's. This process is currently being used on the North Slope for the injection of spent drilling fluids and cuttings. EPA has learned that several similar projects have also occurred or are planned in coastal areas in the Gulf of Mexico and California,[55] and in the North Sea[56] for the injection of drilling fluids and cuttings. The following sections discuss these projects.

The critical parameters that affect the performance of any grinding and injection system are: drilled solids particle size, the injectable fluid density and viscosity, percent solids in the injectable fluid, injection pressure, and the characteristics of the receiving formation. These parameters and their effect on the design of the grinding and injection system are discussed in detail in the following sections.

5.10.1 Cuttings Processing System and Injection

The cuttings grinding system consists of three separate unit processes: screening, grinding, and slurrification. On the North Slope, cuttings are first conveyed to a large triple-deck classifier where the cuttings are washed with high pressure water to remove residual drilling fluid and are sorted according to size. The underflow from the classifier, which contains particles smaller than 74 microns, and the washwater are sent to the injection slurry pit. The overflow, which contains particles larger than 74 microns, are further processed in a ball mill grinding unit.[57]

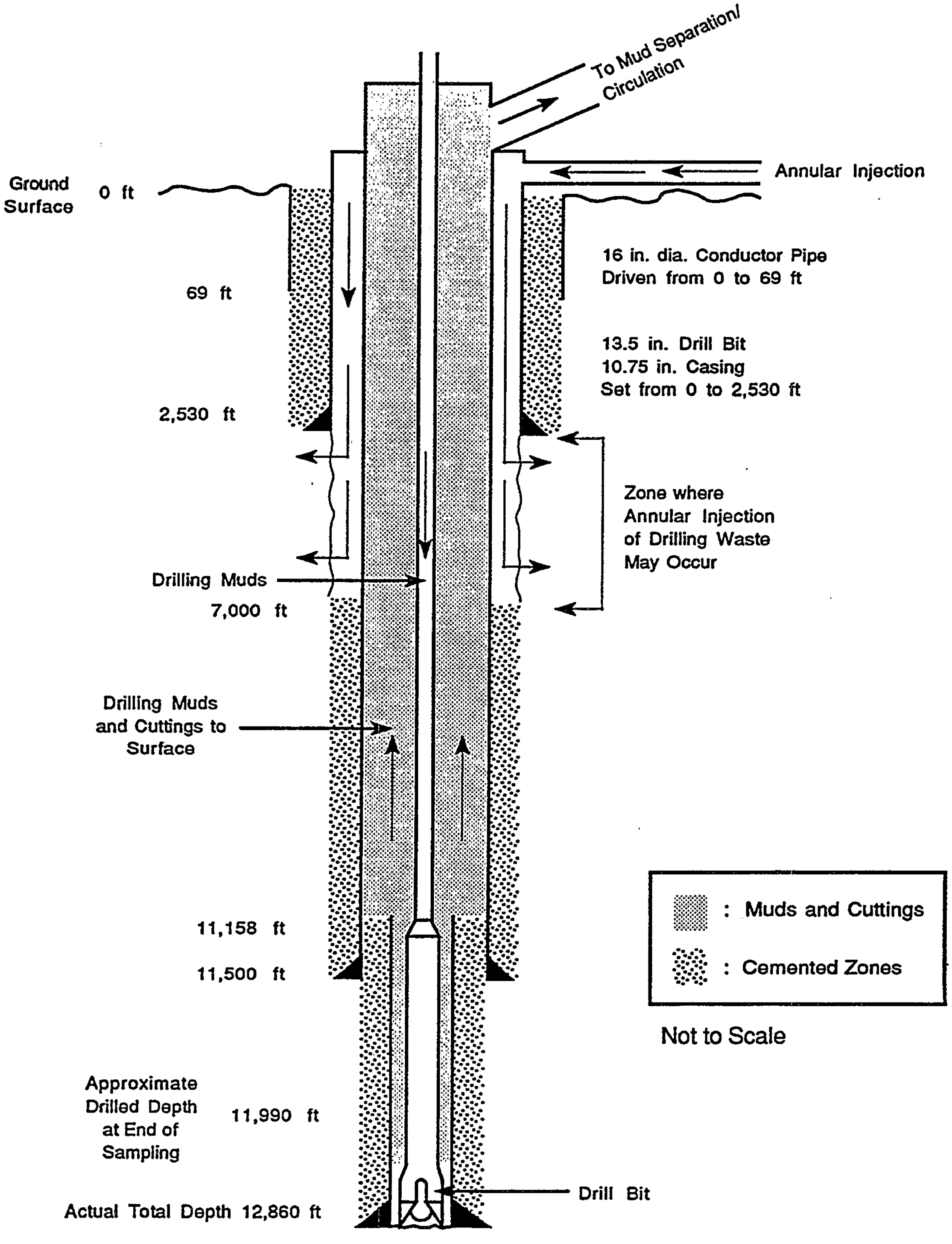

Figure VII-9
Annular Injection During Drilling

The grinding unit is a 30-inch by 34 inch chamber that contains 3,000 lb of 1.5-inch forged steel balls. The cuttings are fed into this chamber for size reduction. In order to achieve the required particle size, the chamber is vibrated at 1,200 cycles with an amplitude of 3/4 inch.[57] After size reduction in the ball mill, cuttings are pumped to a hydrocyclone for further classification. Particles larger than 74 microns are returned to the ball mill for repeated grinding, while particles smaller than 74 microns are sent to the injection pit.

The injection pit has a capacity of 500 barrels and is mechanically agitated to maintain a homogeneous slurry. Chemicals such as bentonite and extenders are added to the pit to increase the solids carrying property, or viscosity of the injection fluid. The injection fluid is typically maintained at a funnel viscosity of 100 seconds per quart.[57]

The final step of this process is the injection system. Ground and slurried cuttings are pumped from the injection pit to the injection pump(s) by hard chrome-lined centrifugal pumps.[57] The centrifugal pumps have a pumping capacity of 500 gallons per minute (gpm). One operator uses a pair of positive displacement piston injection pumps, each with a pumping capacity of 210 gpm. These are 165-horsepower (hp) triplex pumps driven by a 150 hp electric motor through a four-speed gearbox. The injection pressure varies between 600 to 1,000 psi depending on the weight of the fluid being injected. Typically, the density of the injection fluid is maintained within 10 to 11 pounds per gallon (ppg) with a solids content of 25 to 30%.[57]

Successful grinding and injection projects in the Gulf of Mexico coastal region were cited by one company licensed to perform this technology.[58] Drill cuttings generated from drilling operations in the coastal Gulf of Mexico region often consist of bentonitic shale formations which break up easily when hydrated and subjected to high shear pressures. Because of these cuttings properties, the grinding and injection systems employed in the Gulf of Mexico coastal projects take advantage of the transfer pumps' shear force for size reduction.[59] Freshwater or seawater are added to the cuttings stream before and after size reduction. After size reduction, the cuttings slurry is further mixed with freshwater or seawater so that the injectable fluid has a funnel viscosity of 70 to 90 seconds per quart and a density of 11 to 12 ppg.[58]

Similar grinding and injection processes were successfully tested on other drilling fluid systems, mainly on oil-based fluids and cuttings.[56,60,61] With the new grinding and injection technology available and proven on oil-based fluids and cuttings, the use of oil-based fluids followed by grinding and injection may prove in some cases to be more economical than land disposal, thus further reducing the overall well cost. The cuttings processing systems employed on these projects are similar to the system used on the North Slope. Variations of this process consist of the type of screens used, elimination of cuttings washing systems, and the type of grinding equipment used. Rotating ball mills instead of vibrating ball mills have been successfully used on offshore platforms. Although rotating ball mills are high maintenance pieces of equipment, they are usually employed on offshore platforms for grinding large and relatively high density material. Vibrating ball mills are not typically used on offshore platforms because of the possible structural impact of the weight and of vibration.[16,56]

5.10.2 Receiving Formation Evaluation--North Slope Operations

The injection mechanism for solids-laden fluids differs from that used for solids-free liquids such as produced water. Produced water is injected at a pressure that does not fracture the receiving formation. On the North Slope, successful cuttings injection operations demand that a fracture be created in the receiving formation before injection of the cuttings slurry can occur. Without a fracture, the solids in the slurry would quickly plug up the pore spaces in the formation.[62]

Therefore, the success of the grinding and injection technology depends on the proper selection of the receiving formation. In general, the desired characteristics of the receiving formation are to be unconsolidated, of high porosity (typically 20%), high permeability (typically 0.5 Darcy) material of sufficient thickness (typically 33 feet) and at a sufficient depth not to affect the surrounding environment. The specific values, however, change for different drilling locations.[63]

Injection of a homogeneous cuttings slurry can be achieved through a dedicated wellbore or through the annular space between a string of casing and the exposed formation. The slurry is pumped at a specified rate into the wellbore or the annulus. When the downhole pressure of the fluid exceeds the formation pressure, the formation fractures and the cuttings slurry flows into the fissure. The pumping operation continues until all slurry is injected into the formation.

The optimum injection pressure depends on the characteristics of the receiving formation, and should be continuously monitored. The mechanisms of inducing a fissure in the formation, such as its mode of propagation, its size, its containment, and its impact on nearby wellbores, should be well understood before injecting the cuttings slurry. Fracture modeling can be used to estimate the size and shape of the injection fracture. A new 3-dimensional model has been developed to optimize the design of hydraulic fractures and to simulate drill cuttings injection.[64]

Subsurface geology of the North Slope is uniform throughout the area, making disposal of drilling wastes by injection an attractive alternative to land disposal. North Slope geologic stratification is more suited to injection because of the shale and sandstone formations, and because of the permafrost which underlies most of the North Slope.

Shale, which is composed entirely of clays, is a relatively plastic and low permeability rock. These properties make it a good confining zone. The fracture gradient for shale ranges from 0.8-0.9 psi/ft. For comparison purposes, sandstone (a rock composed of sand sized rock and mineral fragments) has a fracture gradient of 0.55-0.65 psi/ft.[65] The lower the fracture gradient, the easier the formation will fracture. Therefore, sandstone is a better receiving formation than shale because it fractures more easily, while shale is a better confining formation.

Of importance to the oil and gas operations on the North Slope is the continuous permafrost which descends from the surface to depths between 1,000 and 2,000 ft.[57] The permafrost provides a low permeability barrier so that the injected wastes do not migrate upward towards the surface.

5.10.3 Availability of Subsurface Injection

As stated above, the uniformity of the underlying geology of the North Slope makes injection of drilling wastes a viable disposal method throughout in that area. In the coastal Gulf of Mexico area, a statistical analysis of the responses to the 1993 Coastal Oil and Gas Questionnaire indicates that 122 new production drilling projects, or 65% of the 187 new production wells drilled in 1992,[6] utilized annular injection for disposal of drilling wastes.[66]

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

Drilling fluids and drill cuttings can not be injected into producing formations, as is sometimes the case for produced water, because they would interfere with hydrocarbon recovery. Thus, operators must have available different formation zones with appropriate characteristics (e.g., porosity and permeability) for injection of drilling fluids and drill cuttings. Unlike the coastal region along the Gulf of Mexico or the North Slope of Alaska, where the subsurface geology is relatively porous and formations for injection are readily available, the geology in Cook Inlet is highly fragmented and information in the record indicates that formations amenable to injection may not be available throughout Cook Inlet. EPA reviewed information where attempts to grind and inject drilling fluids and drill cuttings failed in the Cook Inlet area.[68] For example, one operator attempted to operate a grinding and injection well in the Kenai gas field that failed due to downhole mechanical failure of the injection well (1992/1993). There, the well experienced abnormal pressure on the well annulus, necessitating shutdown of the disposal operation.[46] The operator also attempted annular pumping of drilling fluids and drill cuttings in two production wells in the Ivan River Field (onshore on the west side of Cook Inlet) where the annuli of both wells plugged during injection. Another operator, attempting to pump drilling waste into the annuli of exploration wells, lost the integrity of the well.[16] In view of these difficulties encountered in injecting drilling wastes and the limited data available to date, EPA is unable to estimate the degree to which injection would be available in Cook Inlet and believes that the information in the record indicates that certain sites in Cook Inlet may not be able to inject sufficient volumes of drilling wastes to enable compliance with zero discharge.

5.10.4 Cuttings Washing and Reuse on the North Slope

On Alaska's North Slope, while all drilling fluids and most drill cuttings are injected, some cuttings are cleaned and used as fill material in the construction of drill pads.[57] These fill materials require a fill permit issued pursuant to section 404 of the Clean Water Act. According to the North Slope operators, shallow drill cuttings generated from the first 3,500 feet of drilling are very similar in composition to gravel that is used as a foundation material for roads and oil field facilities. Based on an agreement with the Alaska Department of Environmental Conservation (ADEC), North Slope operators are allowed to clean and reuse these cuttings as gravel as long as the cuttings meet certain criteria. The operators developed the "Drill Cuttings Reclamation Program" to minimize the volume of larger cuttings requiring grinding and injection and to reduce the need for gravel mining.[67]

The CC2A facility, located in the Prudhoe Bay oil field, processes all drilling wastes generated in the Prudhoe Bay area oil fields. This facility contains impactors to handle larger gravels, ball mills for further particle-size reduction as needed, and pumps for injection into the CC2A Class II disposal well.

As of June, 1995, the CC2A facility has disposed of about 70,000 cubic yards of solids from drilling wastes.[68] At this facility, the gravel is washed and classified utilizing a shale shaker, water spray bars, mixing tanks and pumps. Cuttings are sprayed with high-pressure water to remove drilling muds and fine clay-sized particles. Washed cuttings larger than 1/8 of an inch in diameter are stored pending chemical analysis and approval for reuse.[69]

Approval for reuse is contingent on meeting a set of reuse criteria established by ADEC. The reclaimed gravel must be greater than 1/8 inches in diameter, generated within the first 3,500 feet, and be drilled with water-based mud systems (lists of drilling mud additives must be supplied to and approved by ADEC prior to reuse should these conditions not be met), and must meet the following standards:

Arsenic	22 mg/kg
Barium	790 mg/kg
Lead	20 mg/kg
Total Petroleum Hydrocarbons (Diesel Range Organics - EPA method 8100M)	200 mg/kg
Particle Sizes 74μ or less	<5%

If the arsenic standard is violated, a secondary analytical procedure may be performed. In this case, a sample of the gravel is subjected to a leachability test, and the extract may contain no more than 0.016 mg/L arsenic.[70]

5.11 SYNTHETIC-BASED DRILLING FLUIDS

Synthetic-based drilling fluids or synthetic-based muds (SBM) represent a new technology which was developed in response to the oil-based drilling fluids discharge ban in the North Sea. They were first used in the North Sea in 1990, and the first well drilled in the Gulf of Mexico using SBM was completed in June 1992.[71] Compared to the discharge of water-based muds (WBM) and cuttings and barging/hauling of cuttings from oil-based muds (OBM), the use of the synthetics and on-site discharge of associated cuttings is claimed to present a pollution prevention opportunity. From 1992 to mid-1996, roughly 250 to 300 wells in the Gulf of Mexico had been drilled with SBM, and for the most part the cuttings have been discharged on site. The cuttings are typically coated with 7-12 percent synthetic material.[72,73]

An SBM has a synthetic material as its continuous phase and water as the dispersed phase. The types of synthetic material which have been used include vegetable esters, poly (alpha olefins), linear alpha olefins, internal olefins, and ethers. Of the 250-300 estimated SBM wells drilled in the Gulf of Mexico, approximately 47 percent were internal olefin-based, 34 percent were poly (alpha olefin)-based, and 19 percent were vegetable ester-based. More recently internal olefin-based SBMs have been almost exclusively used. The synthetic materials are produced by the reaction of specific chemical feedstock, resulting in products of defined and narrow molecular composition and structure. They are differentiated from the traditional oil base fluids such as diesel and mineral oil which are derived from crude oil solely through physical separation processes and minor chemical reactions such as cracking and hydroprocessing. This physical separation results in products having a broad range of hydrocarbons as opposed to the specific products resulting from the chemical synthesis reactions to form the synthetic materials.

Since the cuttings wastestream from SBM was nonexistent during the start of this Coastal rulemaking, no specific limitations for SBM have been set and they are covered by the same set of requirements as the other drilling fluids in this rule. EPA recognizes the potential pollution prevention opportunities presented by this new technology. EPA is encouraging their further development and use by providing definitions for "synthetic-based drilling fluid" and the "synthetic material" which comprises the SBM, and is providing interim guidance for current SBM discharges in areas not covered by a zero discharge of drilling fluids and cuttings. Because of concerns over the appropriateness of the sheen and toxicity tests as applied to the discharge of cuttings associated with SBM, EPA is suggesting the use of additional tests to allow discharge where zero discharge requirements are not in effect and for possible use in evaluating environmental impacts. Tests of interest include determining impacts of the synthetic-contaminated cuttings pile on the seafloor through the evaluation of benthic toxicity, bioaccumulation potential, and rate of recovery of the seafloor by measurement of biodegradation rate. Such tests are already applied for SBM cuttings discharges in the North Sea.[72] Impacts due to the discharge of WBM and associated cuttings fall into two main categories: water column and seafloor. The 30,000 mysid shrimp LC_{50} toxicity limitation as it is applied to WBM can measure effects on both the water column and seafloor since the discharged material does disperse into the aqueous phase during testing. However, for SBM a much more distinct separation occurs during toxicity testing and very little if any of the synthetic material is present in the aqueous phase. Consequently, in order to properly compare the discharge of muds and cuttings of WBM versus SBM the seafloor effects should be considered as well as the water column effects.

SBMs are reported to perform as well as or better than OBMs in terms of rate of penetration, borehole stability, and shale inhibition. Due to decreased washout (erosion), drilling of narrower gage holes, and lack of dispersion of the cuttings in the SBM, compared to WBM the quantities of muds and cuttings waste generated is reduced, reportedly in some cases by as much as 70 percent.[74,75] The greatest reduction seen is for the drilling fluids. The SBM offer the opportunity for high recycle rates because unlike the WBM the cuttings do not disperse in the fluid and so less dilution and additives are required to keep the necessary mud characteristics. In general the only SBM discharged is the amount adhered to the cuttings, which ranges from 7 to 12 percent based on dry cuttings weight.[73] When WBM is used, the mud discharged is often 5 or 6 times greater than that discharged when drilling a similar hole with SBM. If the engineering aspects of the effectiveness of a drilling fluid are considered as a technology to reduce the levels of pollution, then SBM may be viewed as a control technology for conventional pollutants.[75]

When WBM and cuttings are discharged they disperse in the water and create muddy-looking water, and the particles settle according to size and density. Conversely, since the synthetic materials are hydrophobic and the mud is weighted, when cuttings coated with SBM are discharged minimal dispersion in the water column is observed, the water in general stays clear, and the cuttings rapidly sink to the seafloor. Thus water column effects are greatly reduced and the seafloor effects are of a different nature due to the adhered synthetic material loading.

Concerning the water column effects, comparisons can be made between the mysid shrimp LC_{50} suspended particulate phase (SPP) for the WBMs versus the SBMs. The toxicity of WBMs is dependent on their formulation and addition of toxic components added for drilling performance. Acute toxicity tests of eight generic WBM gave LC_{50} values ranging from 27,000 ppm to over 1,000,000 ppm.[4] Data collected in 1985 and 1986, before the 30,000 parts per million LC_{50} limitation was promulgated, found that approximately 42 percent of the used drilling fluids tested for toxicity were below (more toxic than) the 30,000 ppm value.[4] In choosing the 30,000 ppm limitation EPA considered the many available formulation possibilities and determined that the toxicity limitation of 30,000 ppm was achievable and would significantly reduce the discharges of toxic muds without significantly affecting drilling activity. Thus the WBMs are typically formulated to meet the 30,000 ppm limitation plus a safety factor. The SBMs, on the other hand, typically report mysid shrimp LC_{50} values of greater than 1,000,000 ppm, in other words, greater than 50 percent survival in 100 percent suspended particulate phase. In addition, unlike with the use of WBMs, toxic additives are not generally needed in SBMs to enhance performance. However, when compared to WBM, this reduction in aquatic toxicity may be due to the lack of the synthetic material dispersion and dissolution in the aqueous or SPP phase which reduces exposure to the mysid shrimp, as well as decreased inherent toxicity.[76] In general, evidence shows that use of SBM in place of WBM will reduce adverse environmental impact in the water column because of a) reduction in volume discharged, b) less dispersion in water, and c) lower aquatic toxicity.

Seafloor effects can be separated into two types: short-term burial effects and long-term toxic effects.[76] The adverse impact caused by burial can be assumed to be directly proportional to the quantity of solids discharged, and will also depend on the dispersion of the settling solids. As discussed earlier the use of SBMs has shown to create a lower volume of drilling wastes. Also, the cuttings which are coated with 7-12 percent of the synthetic material, tend to sink without drifting in the water column unlike the particulate matter of the WBM which tends to disperse and stay suspended longer. Therefore as compared to WBM the burial footprint from SBM cuttings discharge is expected to be smaller and have less solids. This diminished dispersion of the SBM has been shown by relating barium concentrations on the seafloor.[71,77]

Therefore, compared to WBM the SBM are believed to have lower aquatic toxicity and cause less seafloor burial. The other impact of concern is the toxic effect of the cuttings pile as indicated by the rate of recovery of the benthic organisms in the pile. One research article details the history of a cuttings pile generated with a poly (alpha olefin) SBM and compared the recovery with a cuttings pile associated with an oil-based mud (OBM).[71] The organic loading from the oil based mud caused alterations in the benthic community, and the area of contamination was observed to remain nearly constant since discharge during the five year test period. Meanwhile the zone of contamination of the SBM was observed to reduce about 86 percent during the first eight months after discharge, but then remained constant during the next 16 months. The zone of impact to the benthic community for the OBM was described as encompassing 98,178 square meters after five years, whereas that for the SBM was said to be affecting an area of only 589 square meters after just two years. Thus this study shows that changing the toxicity, degradability, and bioaccumulation of the oily or hydrophobic constituent of the cuttings can have a large affect on the recovery of the benthic community. Each synthetic material is expected to exhibit a unique set of benthic toxicity, biodegradation, and water column toxicity, and there are likely to be tradeoffs. For instance, compared to the poly (alpha olefin) of the referenced study, internal olefins are reported to exhibit higher toxicity, but they degrade faster.[73] Thus the rate of recovery with the internal olefins may be faster than that found for the poly (alpha olefin), and may be more comparable to recovery with WBM.

A separate investigation in the North Sea sampled the seafloor two days after and one year after the discharge of 749 tons of cuttings contaminated with 97 tons of a vegetable ester.[78] The presence of the polychaete (worm) *Capitella capitata* in the cuttings pile two days after drilling ceased was cited as an indication that the recolonization process had started. Reportedly, the recolonization of OBM cuttings piles starts only several weeks after discharge. In one year the vegetable ester cuttings pile was found to be in a natural state with a normal diversity and number of benthic organisms, except at one station where there was a dominant population of the opportunistic polychaete *Capitella capitata*. The vegetable ester concentrations had been greatly reduced, and the sediment grain size distribution had returned to normal. A conclusion of the study was that the seafloor environmental impact due to discharge of the vegetable ester contaminated cuttings was of comparable magnitude to that of benign water based muds.

A study performed in the Gulf of Mexico at well sites where WBMs and cuttings were discharged found that due to the drilling activity concentrations of metals in the area were of such concentrations to potentially cause long-term adverse effects.[79] Since there is a great reduction in the muds and cuttings discharged with SBMs, one can infer that there would also be a reduction in metals discharged and so this adverse impact would be reduced.

Most germane is a comparison of the recolonization of WBM cuttings piles compared to that of SBM cuttings piles. While WBM cuttings piles are said to recover "quickly" in the literature, data have not been found in any source which defines just how quickly to compare with the SBM recovery, which itself has only been detailed in the two above mentioned instances. Just recently detailed monitoring at several sites in the North Sea has begun to evaluate several different mud systems and to compare the actual seafloor determinations with the laboratory determinations.[72] While evaluations in the Gulf of Mexico may prove to be different from those in the North Sea due to the differences in physical parameters and sea life, EPA will be following these seafloor evaluations closely for early indications of appropriate laboratory and field evaluation methods.

In summary, there is conclusive evidence showing that discharge of SBM cuttings, as compared to discharge of WBM spent mud and cuttings, reduces adverse water column effects and seafloor physical burial effects. At the same time, within the smaller footprint on the seafloor, adverse toxic or chemical effects may or may not be increased due to the organic loading of the synthetic materials and concurrently decreased due to reduced toxic metals loading. Site specific factors of ocean currents, water and sediment physical parameters, and local benthic species, may also affect the predominance and extent of any short term or long term toxic effect. Investigations are now under way in the North Sea, and the EPA recommends similar investigations in the Gulf of Mexico, to quantify the difference in the rate of benthic recovery between WBMs and the various viable SBMs. In this way the environmental benefits of SBM can be appropriately weighed against purported environmental liabilities.

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CHAPTER VIII

PRODUCED WATER—CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

The first three parts of this section describe the sources, volumes, and characteristics of produced water from coastal oil and gas production activities. The final part of this section describes the treatment technologies available to reduce the quantities of pollutants in produced water discharged to surface water.

2.0 PRODUCED WATER SOURCES

Produced water is the water (brine) brought up from the hydrocarbon-bearing strata during the production of oil and gas. Produced water includes: the formation water brought to surface with the oil and gas, the injection water used for secondary oil recovery that has broken through the formation, and various well treatment chemicals added during production and the oil/water separation process.

Formation water, which comprises the bulk of produced water, is found in the same rock formation as is the crude oil and gas. Formation water is classified as meteoric, connate, or mixed. Meteoric water comes from rainwater that percolates through bedding planes and permeable layers. Connate water (seawater in which marine sediments were originally deposited) contains chlorides, mainly sodium chloride (NaCl), and dissolved solids in concentrations many times greater than common seawater. Mixed water is characterized by both a high chloride and sulfate-carbonate-bicarbonate content, which suggests multiple origins.

3.0 PRODUCED WATER VOLUMES

Produced water is the highest volume waste source in the coastal oil and gas industry. The total volume of produced water being discharged by the coastal oil and gas industry is 119.2 million bpy (or 326,577 bpd). The volume of wastewater generated by the oil and gas industry is somewhat unique in comparison with industries in which wastewater generation is directly related to the quantity or quality of raw materials processed. By contrast, produced water can constitute from 2 percent to 98 percent of the gross hydrocarbon fluid production at a given well or production facility. In general, the percent of produced water volume to oil and gas is small during the initial production phase when hydrocarbon production is the greatest, and increases as the formation approaches hydrocarbon depletion. Produced water volumes are generally greater for facilities producing oil or a combination of both oil and gas as compared to gas-only facilities. The volume of produced water at a given facility is a site-specific phenomenon. In some instances, no formation water is encountered while in others there is an excessive amount of formation water encountered at the start of production.

As discussed in Chapter IV, the entire volume of produced water generated in the North Slope region of Alaska and the coastal region of California is injected for waterflooding, and therefore will not be discussed in this chapter. In addition, in the Gulf of Mexico states of Florida and Alabama, all coastal facilities inject their produced water, primarily for disposal, and therefore, are not discussed in this chapter. Also, a significant number of facilities in Texas and Louisiana coastal areas are currently injecting their produced water, or are required to do so by January 1997. Produced water characteristics for those coastal areas discharging it (i.e., Cook Inlet, Alaska and Texas and Louisiana) are discussed below.

3.1 GULF OF MEXICO

For the Gulf of Mexico region, the three sources of data that are available for produced water volumes are: the 1993 Coastal Oil and Gas Questionnaire database, the Gulf of Mexico state discharge file information and the 1992 EPA 10 production facility data. These three data sources are discussed in detail in Chapter V. Because the Coastal 308 Questionnaire was not a census, the data concerning produced water volumes and other parameters from the survey were statistically extrapolated as estimated industry-wide averages. The Gulf of Mexico state discharge file information contains comprehensive facility-specific data, but only includes facilities that are discharging. The 1992 EPA 10 production facility study contains data from 10 selected facilities that primarily inject produced water. The following is a summary of the produced water flow data from these three sources.

According to the statistical analysis of the EPA 1993 Coastal Oil and Gas Questionnaire, hereafter referred to as the coastal questionnaire statistical results, the average produced water generation rate from a coastal facility was 1,923 barrels per day (bpd) for facilities that inject produced water and 2,069 bpd for facilities that surface discharge produced water.[1]

Table VIII-1 presents the produced water volumes, treatment systems information, and hydrocarbon production from the production facilities sampled in EPA's 10-facility study. Details of this

TABLE VIII-1

CHARACTERISTICS OF THE 10 PRODUCTION FACILITIES SAMPLED BY EPA[3]

Operator Name	Field Name	Oil/Condensate (bpd)	Gas (MMcf/d)	Brine (bpd)	Treatment Technologies Prior to Injection
Greenhill Petroleum	Bully Camp	1,050	11	8,000	Settling Tanks, Cartridge Filters
Oryx Energy	Chacahoula	213	24	3,000	Settling Tanks
Exxon Corporation	Clam Lake	518	0	7,500	Settling Tanks
Oryx Energy	Caplen	186	35-50	3,559	Settling Tanks
Texaco	Sour Lake	300	0	11,500	Settling Tanks
Texaco	Port Neches	210	0	4,000	Settling Tanks
Arco	Bayou Sale	1,485	62.2	6,150	Settling Tanks, Parallel Plate Coalescer
Texaco	Bayou Sale	2,381	29.4	6,462	Settling Tanks, Cartridge Filters
Badger Oil Corp.	Larose	200	0	2,500	Settling Tank, Screen Filter
Texaco	Lake Salvador	950	25	7,000	Setting Tanks, Cartridge Filters
Average	-	749	19.4	5,967	-

[a] No injection at this site.

study are discussed in Chapter V. All of these facilities, except for Texaco Port Neches, disposed of their produced water via subsurface injection. As can be seen from this table, no correlation is apparent between oil or gas production and produced water volumes.

Table IV-2 in Chapter IV presents the list of coastal discharging facilities in the Gulf of Mexico current requirements baseline. As can be seen from these data, produced water volumes for discharging facilities range from 291 bpd to 153,895 bpd. The average produced water volume for discharging facilities is 23,912 bpd. The total volume of produced water discharged in the Gulf of Mexico is 191,292 bpd.

3.2 ALASKA

Table VIII-2 presents the produced water volume and treatment data for Cook Inlet. As noted in Chapter IV, there are five platforms that discharge directly into Cook Inlet while the remaining nine pipe their combined production fluids (hydrocarbon and water) to one of three shore-based separation/treatment facilities. The total volume of produced water discharged from platforms in Cook Inlet is 5,188 bpd, and the overall total including the three shore-based facilities is 135,285 bpd. The three shore-based facilities discharge approximately 96 percent of the Cook Inlet produced water, not including the Dillon platform discharges.

3.3 ALTERNATIVE BASELINE FACILITIES

As discussed in Chapter IV, the Alternative Baseline includes Gulf of Mexico facilities that are additional to those in the baseline Gulf of Mexico analysis. The total produced water volume contributed by these additional facilities is 397,578 barrels per day (see Section XI.5 for details regarding these facilities). The total produced water volume for the Alternative Baseline population (which is the sum of the baseline Gulf of Mexico facilities, Cook Inlet facilities, and additional Gulf of Mexico facilities) is 724,155 barrels per day or 264.3 million barrels per year.

4.0 PRODUCED WATER COMPOSITION

Since the 1979 promulgation of the Coastal Oil and Gas BPT Effluent Limitations Guidelines, EPA has conducted several produced water characterization studies. A number of these studies were used in the development of the 1993 Offshore Guidelines. These studies are the 30 Platform Study, the California Sampling Program, and the Alaska Sampling Program, and are described in detail in the Offshore

TABLE VIII-2

PRODUCED WATER VOLUMES FOR OIL AND GAS PRODUCTION FACILITIES IN COOK INLET REGION[4]

Facility Name	Operator	Avg. Prod. Water Vol. (bpd)	PW Disch. Location	Treatment Technologies
DISCHARGING PLATFORMS				
Dillon	Unocal	3,116	Platform	Skim Tanks
Bruce	Unocal	199	Platform	Skim Tanks
Anna	Unocal	919	Platform	Skim Tanks
Baker	Unocal	924	Platform	Skim Tanks
Tyonek "A"	Phillips	30	Platform	Skim Tanks, Gas Flotation
SHORE BASED TREATMENT/DISPOSAL FACILITIES				
Granite Point	Unocal	929	Spark Platform	Skim Tanks
Trading Bay	Marathon	127,468	Outfall	Skim Tanks, Gas Flotation, Settling Pits
E. Foreland	Shell Western	1,700	Outfall	Skim Tanks, Corrugated Separators
TOTAL		**135,285**	-	-

Development Document.[2] Therefore, data from these studies will not be presented individually in this document. In some cases, data summarized in the Offshore Development Document have been used in the tables presented in this section, particularly with respect to certain treatment system performance data and the composition of produced water in Cook Inlet. For the Gulf of Mexico region, the EPA 10 Production Facility Study is the source of produced water composition data. Separate discussions on the characteristics of produced water and the databases used are presented for both the Gulf of Mexico and Cook Inlet regions.

4.1 COMPOSITION OF PRODUCED WATER FOR THE GULF OF MEXICO

The 1992 EPA 10 Production Facility Study characterizes BPT-level produced water effluent for the coastal region of the Gulf of Mexico. EPA excluded data from three facilities that were not meeting

BPT limits. Although samples were collected at a number of locations within each facility, samples collected at the effluent of the settling tanks were most representative of BPT level treatment.

Table VIII-3 presents the overall summary of occurrence of the organic pollutants detected in at least 25 percent of the 14 samples of settling tank effluents that were collected. As can be seen from this table, only benzene and toluene were detected in 100 percent of the samples. An additional 18 organic pollutants were detected in greater than 25 percent of the samples. Out of a total of 232 priority and non-conventional organics analyzed, 212 were either not detected, detected in less than 25 percent of the samples, or were removed from consideration because they are not expected to be characteristic of wastewater pollutants discharged in produced water.[5]

Table VIII-4 presents summary analytical data of the settling tank effluents from the 1992 EPA 10 Production Facility Study. Only pollutants that were detected in at least 25 percent of samples are listed. Any non-detected sample results were given the value of one-half the detection limit value in the derivation of the overall mean values. These data were used as BPT-level effluent concentrations for the Gulf of Mexico region in the development of the Coastal Guidelines.

4.2 COMPOSITION OF PRODUCED WATER FOR COOK INLET

Table VIII-5 presents the summary data obtained from several sampling programs that are considered to be representative of the composition of produced water in Cook Inlet. The primary source, a comprehensive Cook Inlet Discharge Monitoring Study was conducted by EPA Region 10 to investigate oil and gas extraction point source discharges.[8] In this study, produced water discharges from production facilities in Cook Inlet (coastal subcategory) were sampled and analyzed for one year, from September 1988 through August 1989. Samples were collected from two oil platforms and one natural gas platform, all of which discharge to the surface waters, and also from three shore-based central treatment facilities. Flow-weighted averages were then calculated using the mean concentrations from each discharge in this study. This study, however, only provided data for 10 organic pollutants and zinc. Concentrations for the other pollutants included in Table VIII-5 were taken from the BPT-level effluent data from the Offshore Development Document.[2] EPA determined it appropriate to apply effluent data for offshore platforms to these in Cook Inlet because of the similarities in operation. The data for radium 226 and 228 presented in Table VIII-6 are from the Alaska Oil and Gas Association's comments on the offshore rulemaking.[9]

TABLE VIII-3

PERCENT OCCURRENCE OF ORGANICS FOR BPT LEVEL TREATMENT EFFLUENT SAMPLES FROM THE 1992 EPA 10 PRODUCTION FACILITY STUDY[6]

Pollutant	Number of Independent Samples	Number of Independent Samples w/ Detects	Percent Detects
Benzene	14	14	100.0
Toluene	14	14	100.0
o+p Xylene	14	12	85.7
Ethylbenzene	14	9	64.3
Benzoic Acid	14	9	64.3
m-Xylene	14	8	57.1
Phenol	14	8	57.1
n-Hexadecane	14	7	50.0
Naphthalene	14	8	57.1
o-Cresol	14	8	57.1
Hexanoic Acid	14	8	57.1
n-Tetradecane	14	6	42.9
p-Cresol	14	7	50.0
n-Decane	14	6	42.9
n-Dodecane	14	7	50.0
2,4-Dimethylphenol	14	8	57.1
n-Octadecane	14	6	42.9
n-Eicosane	14	6	42.9
2-Hexanone	14	4	28.6
2-Methylnaphthalene	14	6	42.9

5.0 CONTROL AND TREATMENT TECHNOLOGIES

Treatment processes for produced water are primarily designed to control oil and grease, priority pollutants, and total suspended solids. Currently, most state and NPDES permits that allow the discharge of coastal produced water to surface water bodies with limits only for the oil and grease content (BPT limitation) in the produced water.

5.1 BPT TECHNOLOGY

BPT effluent limitations restrict the oil and grease concentrations of produced water to a maximum of 72 mg/l for any one day, and to a thirty-day average of 48 mg/l. BPT end-of-pipe treatment that can achieve this level of effluent quality consists of some, or all of the following technologies:

- Equalization (surge tank, skimmer tank)
- Chemical addition (feed pumps)

TABLE VIII-4

SUMMARY POLLUTANT CONCENTRATIONS FOR BPT LEVEL EFFLUENT FROM THE 1992 EPA 10 PRODUCTION FACILITY STUDY[6]

Pollutant	Settling Effluent Concentration ($\mu g/l$)	Pollutant	Settling Effluent Concentration ($\mu g/l$)
CONVENTIONAL AND NON-CONVENTIONAL POLLUTANTS		**PRIORITY POLLUTANT VOLATILE ORGANICS**	
Total Recoverable Oil and Grease	26,600	Benzene	5,200
Total Suspended Solids	141,000	Ethylbenzene	110
Ammonia	41,900	Toluene	4,310
Chlorides	57,400,000		
Total Dissolved Solids	77,500,000	**OTHER VOLATILE ORGANICS**	
Total Phenols	2,430	m-Xylene	147
PRIORITY POLLUTANT METALS		o+p Xylene	110
Cadmium	31.50	2-Hexanone	34.50
Chromium	180	**PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS**	
Copper	236	Naphthalene	184
Lead	726	Phenol	723
Nickel	151	**OTHER SEMI-VOLATILE ORGANICS**	
Silver	359	Benzoic Acid	5,360
Zinc	462	Hexanoic Acid	1,110
OTHER METALS		n-Decane	152
Aluminum	1,410	n-Dodecane	288
Barium	52,800	n-Eicosane	78.80
Boron	22,800	n-Hexadecane	316
Calcium	2,490,000	n-Octadecane	78.80
Cobalt	117	n-Tetradecane	119
Iron	17,000	o-Cresol	152
Magnesium	601,000	p-Cresol	164
Manganese	1,680	2-Methylnaphthalene	77.70
Molybdenum	121	2,4-Dimethylphenol	148
Strontium	287,000	**RADIONUCLIDES**	
Sulfur	12,200	Gross alpha (pCi/l)	675
Tin	430	Gross beta (pCi/l)	367
Titanium	43.80	Lead 210 (pCi/l)	41.30
Vanadium	135	Radium 226 (pCi/l)	189
Yttrium	35.30	Radium 228 (pCi/l)	264

- Oil and/or solids removal
- Gravity separators
- Flotation
- Filters
- Plate coalescers
- Filtration (used prior to subsurface disposal)
- Subsurface disposal (injection).

TABLE VIII-5

PRODUCED WATER POLLUTANT CHARACTERIZATION FOR COOK INLET, ALASKA

Pollutant Parameter	Concentration (μg/l)
CONVENTIONALS	
Oil & Grease)	35,400[a]
TSS	67,500[b]
PRIORITY METALS	
Cadmium	22.62[b]
Copper	444.66[b]
Lead	195.09[b]
Nickel	1,705.46[b]
Zinc	44.77[a]
PRIORITY ORGANICS	
2,4-Dimethyl phenol	514.70[a]
Anthracene	25.25[a]
Benzene	3,386.12[a]
Benzo(a)pyrene	10.56[a]
Ethyl benzene	157.73[a]
Naphthalene	933.54[a]
Phenol	431.49[a]
Toluene	1,507.43[a]
NON-CONVENTIONALS	
n-Alkanes	1,641.5[b]
Steranes	77.5[b]
Triterpanes	78[b]
Total Xylenes	542.47[a]
Aluminum	78.01[b]
Barium	55,563.80[b]
Boron	25,740.25[b]
Iron	4,915.87[b]
Manganese	115.87[b]
Titanium	7.00[b]
Radium 226	2.65e-06[c]
Radium 228	3.0e-08[c]

a Source - Envirosphere, 1989[8]

b Source - EPA, January 1993[2]

c Source - AOGA, 1991; The values shown were converted from pCi/l to μg/l using the conversion factors 1×10^{-6} μg/pCi for radium 226 and 3.7×10^{-9} μg/pCi for radium 228[7]

Oil is present in produced water in a range of particle sizes from molecular to droplet. Reducing the oil content of produced water involves removing three basic forms of oil: (1) large droplets of coalesceble oil, (2) small droplets of emulsified oil, and (3) dissolved oil. The removal efficiency and resultant effluent quality achieved by the treatment unit is a function of, among other factors, the influent flow, the influent concentrations of oil and grease and suspended solids, and the other types of compounds in the produced water.

TABLE VIII-6

COOK INLET PRODUCED WATER RADIOACTIVITY DATA[9]

PARAMETER/SAMPLE	RADIOACTIVITY (pCi/l)	
	PRODUCED WATER SAMPLE	COOK INLET SAMPLE
RADIUM 226		
Sample 1 (SWEPI East Foreland)	1.1±0.9	1.2±0.9
Sample 1 (Unocal Anna)	ND (1.9)	--
Sample 2 (Unocal Baker)	ND (1.9)	--
Sample 3 (Unocal Bruce)	ND (1.9)	--
Sample 4 (Unocal Dillon)	4.2±1.9	--
Sample 1 (Marathon Trading Bay)	ND (0.4)	--
Sample 2 (Marathon Trading Bay)	ND (0.4)	--
Sample 3 (Marathon Trading Bay)	ND (0.4)	--
RADIUM 228		
Sample 1 (SWEPI East Foreland)	ND (3.9)	ND (3.9)
Sample 1 (Unocal Anna)	ND (2.9)	--
Sample 2 (Unocal Baker)	ND (2.9)	--
Sample 3 (Unocal Bruce)	9.7±2.1	--
Sample 4 (Unocal Dillon)	ND (2.9)	--
Sample 1 (Marathon Trading Bay)	ND (2.9)	--
Sample 2 (Marathon Trading Bay)	5.3±2.0	--
Sample 3 (Marathon Trading Bay)	ND (2.9)	--

ND = Not Detected (value in parentheses is the lower limit of detection).

Smaller oil droplets are formed by the shear forces encountered in pumps, chokes, valves, and high flow rate pipelines. These droplets are stabilized (maintained as small droplets) by surface active agents, fine solids, and high static charges on the droplets.[10] Any operational change that promotes the formation of smaller droplets or the stabilization of small droplets can make oil and water separation more difficult. Operational changes affecting the performance of the produced water treatment system, referred to as upset conditions, can be caused by detergent washdowns in deck drainage entering the treatment unit, high flow volumes caused by heavy rainfall (where deck drainage is commingled and treated with produced water), and equipment failures.

End-of-pipe control technology for treating produced water from coastal oil and gas production consists of physical and/or chemical methods. The type of treatment system selected for a particular facility is dependent upon availability of space, waste characteristics, volumes, existing discharge limitations, and other site specific factors. Oil skimming with gravity separation and/or chemical treatment using settling tanks historically has been widely used in the coastal industry to meet BPT effluent limitations because the support structure is relatively inexpensive (compared to offshore platforms where more compact technologies are installed) and maintenance costs are low compared to more sophisticated technologies. A description of the unit processes that may be used in the treatment scheme for produced water is presented in the following sections.

5.1.1 Equalization

Equalization dampens flow and pollutant concentration variation of wastewater prior to subsequent downstream treatment. By reducing the variability of the raw waste loading, equalization can significantly improve the performance of downstream unit processes by providing uniform hydraulic, organic, and solids loading rates. Increased treatment efficiency reduces effluent variability associated with slug raw waste loadings. Equalization is accomplished in a holding tank. To be effective, the tank should be designed with sufficient retention time to dilute the effects of variable flow and concentrations on the treatment plant performance. Some oil and water separation will also take place in the equalization tank.

5.1.2 Solids Removal

The fluids produced with oil and gas may contain small amounts of sand or scale particles from the piping which must be removed from lines and vessels. Removal of these solids can be accomplished by blowdown, by cyclone separators (desanders), or during equipment cleanout. Desanders are not typically used in coastal operations to remove sand (and other particles) from produced water. The most common method of removing produced solids from the process equipment is during cleanout of the gravity separators which accumulate solids. Equipment cleanouts typically occur every three to five years. Additional information on produced sand generation rates and disposal practices is presented in Chapter IX.

5.1.3 Gravity Separation

The simplest form of produced water treatment is gravity separation in horizontally or vertically configured tanks or pressure vessels. Gravity separators are sometimes called skim tanks, skim vessels, or water clarifiers. Gravity separators are designed with enough storage capacity to provide sufficient residence time for the oil and water to separate. Performance of these systems depends upon the characteristics of the oil and produced water, flow rates, and retention time. Gravity separation systems with large residence times are typical for coastal operations, however on the Cook Inlet platforms that do not pipe produced water to onshore facilities, gravity separation systems have limited residence times because of space and weight limitations. While a treatment system relying exclusively on gravity separation requires large tanks with long retention times, any treatment can benefit from even short periods of quiescent retention to allow for some oil and water separation and dampen surges in flow rate and oil loadings. Many coastal operations configure two or more gravity separators in series with the first separator acting as both an equalization tank and as a gravity separator.

Offshore type platforms such as those in Cook Inlet, Alaska use a device called a skim pile as the final gravity separation treatment step. A skim pile is a large diameter pipe attached to the platform extending below the surface of the water. Skim piles are vertical gravity separators that remove the portion of oil which quickly and easily separates from water. Figure VIII-1 presents a diagram of a skim pile.

During the period of no flow, oil will rise to the quiescent areas below the underside of inclined baffle plates where it coalesces. Due to the difference in specific gravity, oil floats upward through oil risers from baffle to baffle. The oil is collected at the surface and removed by a submerged pump. The pump operates intermittently and removes the separated liquid to a skimming vessel for further treatment.

5.1.4 Parallel Plate Coalescers

Parallel plate coalescers are gravity separators which contain a pack of parallel, tilted plates arranged so that oil droplets passing through the pack need only rise a short distance before striking the underside of the plates. Guided by the tilted plate, the droplet then rises, coalescing with other droplets until it reaches the top of the pack where channels are provided to carry the oil away. In their overall operation, parallel plate coalescers are similar to API gravity oil-water separators. The pack of parallel plates reduces the distance that oil droplets must rise in order to be separated; thus the unit is much more compact than an API separator. Suspended particles, which tend to sink, move down a short distance when they strike the upper surface of the plate; then they move down along the plate to the bottom of the unit

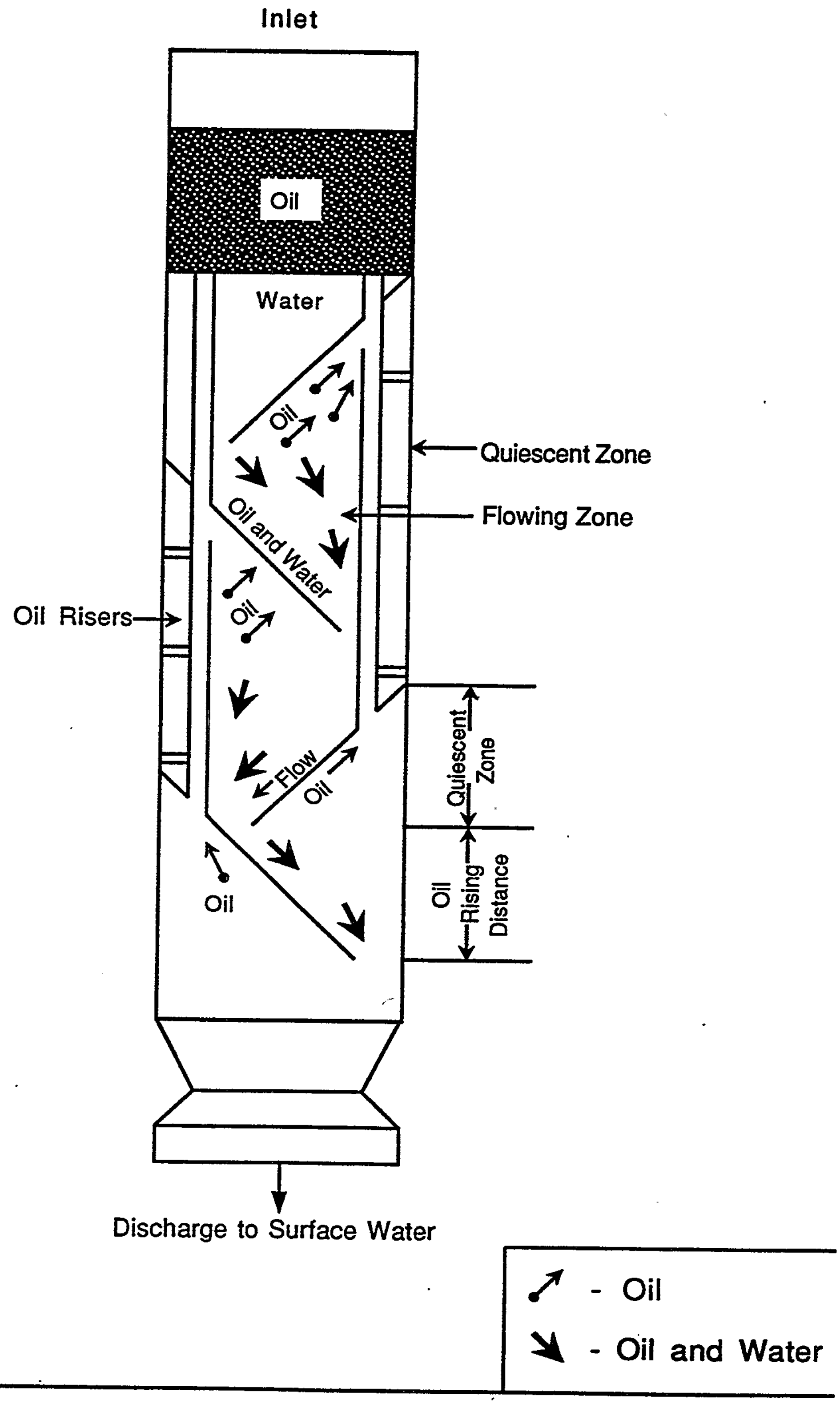


Figure VIII-1
Typical Skim Pile

where they are deposited as sludge and can be periodically removed. Particles may become attached (scale) to the plates' surfaces requiring periodic removal and cleaning of the plate pack.

5.1.5 Gas Flotation

Although gas flotation may be used for BPT treatment (and served as the technology basis for BPT limitations established in 1979), it is currently used at only a small proportion of coastal facilities in the Gulf of Mexico and Cook Inlet, Alaska regions. Results of the 1993 Coastal Oil and Gas Questionnaire show that the majority of coastal operators are using gravity separation instead of gas flotation to comply with current BPT limitations. The questionnaire results showed that only 20 facilities out of the 224 that were surveyed in the coastal Gulf of Mexico area reported using gas flotation.[1] Only two of the eight Cook Inlet locations that treat produced water currently have gas flotation units in place (see Chapter XI for details regarding current Cook Inlet produced water management practices). However, improved gas flotation was investigated as a BAT technology for the coastal subcategory and is discussed as such in Section 5.2.1.

Gas flotation units introduce small gas bubbles into the body of wastewater to be treated. As the bubbles rise through the liquid, they attach themselves to any particle (e.g., oil droplet) in their path, and the gas and oil rise to the surface where they are skimmed off as a froth. Gas flotation may also aid in the removal of oil-wet solids, finely divided solids and solids with low specific gravity. These solids become entrained in, and exit the system with the oily froth.

The gas flotation methods currently available are generally divided into two groups: (1) dissolved-gas flotation (DGF) and (2) induced-gas flotation (IGF). The major difference between these methods are the techniques used to generate the gas bubbles and the size of the gas bubbles produced. In dissolved-gas flotation, the gas bubbles are generated by the precipitation of air (gas) from a super-saturated solution. In induced-gas flotation, gas bubbles are generated by mechanical shear or propellers, diffusion of gas through a porous media, or homogenization of a gas and liquid stream.[11]

Dissolved-gas flotation processes were at one time extensively used for the final treatment of produced oil field water in offshore operations.[12] Currently, the majority of the offshore oil production facilities use induced-gas flotation systems for treating their produced water prior to discharge. Induced-gas flotation requires less space than dissolved gas systems, and thus IGF is the system of choice in the offshore industry. However, space requirements at most coastal facilities are not as limited and therefore coastal operators may elect to install DGF.

5.1.5.1 Dissolved-gas Flotation

In dissolved-gas flotation, the produced wastewater is first saturated with air (gas) either under atmospheric or elevated pressures, then air is evolved from the solution by either applying a vacuum (referred to as vacuum flotation) or an instantaneous reduction in system pressure (referred to as pressure flotation). Under the reduced air pressure, the air evolves in the form of air bubbles which interact with the dispersed material (oil and solid particles) and carry them to the surface of the liquid. Often the oil and solid particles act as nuclei for the growing gas bubbles. Mechanical flight scrapers are then used to remove the floated material.

Since the solubility of air at atmospheric conditions is low and efficiency of the flotation process is a function of the volume of gas released from solution within the flotation cell, the use of vacuum flotation is extremely limited. With the pressure flotation method, higher gas solubilities are possible because of the higher system pressures involved. As a result, larger volumes of gas are released within the flotation units following a drop in the system pressure resulting in greater overall process efficiency. In the following discussion, the term "gas flotation" refers to the process of pressure flotation.[11,13]

The major components of a conventional gas flotation unit include a centrifugal pump, a retention tank, and a flotation cell.[12,14] As the first step in the gas flotation process, gas is introduced into the influent stream at the suction end of a centrifugal pump discharging into a small pressurized retention tank. During this process, the gas is sheared into finely dispersed bubbles which remain in the solution for a short period of time (1 to 3 minutes retention time) in the retention tank. At this point the excess gas (undissolved air) is purged from the tank. From the retention tank, the pressurized saturated water passes through a backpressure regulator before entering the flotation unit. This regulator facilitates the necessary instant pressure drop in the system and creates turbulence for proper dispersion of super-saturated water. Floc, which forms as air bubbles and particles in the fluid interact, is lifted to the surface of the flotation cell, where it is removed by mechanical skimmers. Higher density suspended material which is not amenable to flotation is settled, concentrated and removed from the bottom of the flotation cell. Effluent is discharged from the lower part of the cell where there is less turbulence.

5.1.5.2 Induced-gas Flotation

In a basic induced-gas flotation system (also referred to as dispersed-gas flotation), gas is drawn into the flotation cell either mechanically (mechanical-type) by an impeller or hydraulically (hydraulic-type) by an eductor into a cell containing the water. The introduced gas is then sheared into finely dispersed bubbles by a disperser or a rotating impeller. The dispersed gas interacts with the suspended solid and oil particles and floats them to the surface as an oily froth which is removed by a skimmer system.

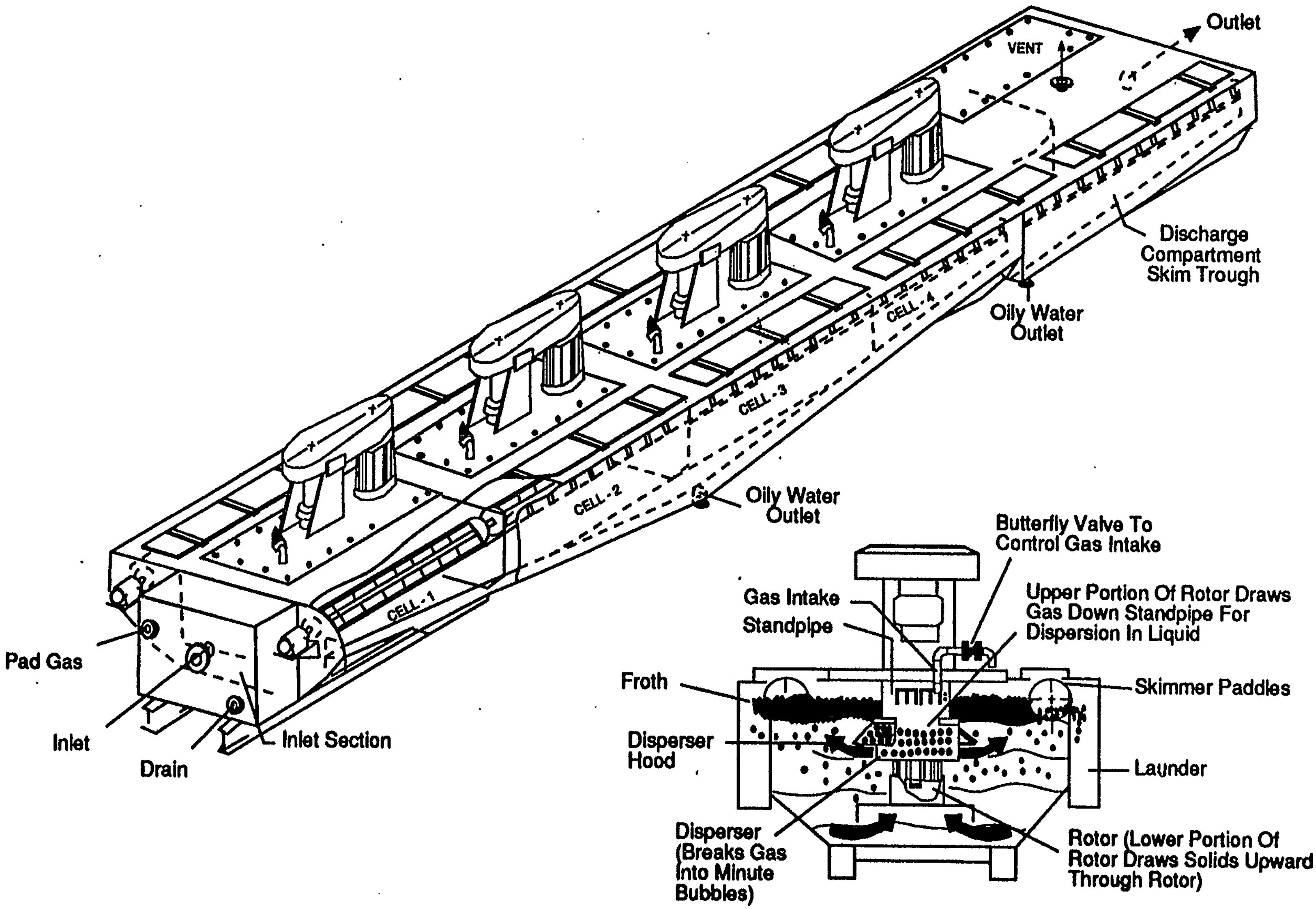
The more advanced induced-gas flotation units are generally multi-cell in design. This feature provides these systems with improved hydraulic characteristics due to reduced short-circuiting (as compared to a single-cell design) and sequential contaminant removal. For example, if each cell in a four-cell unit removes 60 percent of its receiving waste load, the overall removal performance is 97.5 percent; at 70 percent per unit, the overall efficiency of greater than 99 percent is achieved.[11]

Studies have shown that induced-gas systems produce bubbles that can reach 1,000 microns (1mm) in diameter. Bubbles from dissolved-gas flotation average between 70 to 90 microns in diameter and can get as small as 30 microns.[15] Larger gas bubbles can cause turbulence in the solution which could lead to breakdown of the floc, thus reducing the overall system efficiency. This type of problem can be remedied by proper modifications to existing systems or consideration in the new designs. Such consideration may include repositioning the diffuser nozzles so that the air is released in the vertical direction for maximum efficiency and minimum turbulence in the flotation tank.[13,15]

Some of the main advantages of IGF include: less stringent operation and maintenance requirements, lower comparative power requirements, and less costly adaptability to existing facilities. In addition, because of the larger bubbles produced in this type of unit, interactions are much faster resulting in shorter required retention time and smaller units. Hence, less capital cost and space are required.[11,13,14]

Figure VIII-2 presents a schematic drawing of a mechanical-type induced-air gas flotation unit.[16]

Mechanical-Type Induced Gas Flotation Systems - In this type of gas flotation system, a rotor with several blades rotates in the produced water creating a vortex. This creates a negative pressure which draws gas from the freeboard down a standpipe for dispersion in liquid. The gas is then sheared into minute bubbles as it passes through a disperser and therefore creates a mixture of liquid and bubbles. The



Source: Arnold, 1987 [16]

Figure VIII-2
Dispersed Gas Floatation Unit

rotating action of the rotors also causes liquid and solids to circulate upward from the bottom of the cell and allows it to mix with the incoming waste stream and gas bubbles. The interaction of oil droplets and gas bubbles occurs in the flotation region of the tank.

A dispenser hood provides a baffling effect which maintains the skim region in a quiescent state. The rising of bubbles creates a surface flow towards the cell walls, where skimmer paddles are located. Skim rate is generally a function of foam characteristics and unit size. Suspended solids that are amendable to flotation are also removed along with the oil.[13,16]

The action of the rotor and dispenser generates relatively large bubbles (up to about 1000 microns in diameter). Since the size of the bubbles is larger than in dissolved-gas flotation units, greater gas flow is required by this type of unit to maintain a sufficient bubble population.[13]

Hydraulic-Type Induced Gas Flotation Systems - Hydraulic-type induced gas flotation units consist of a feedbox, a series of cells separated by underflow baffles, and a discharge box. A gas eductor is installed in each cell in a standpipe through which part of the cleaned discharge water is recycled back to the unit. Gas is drawn into this stand pipe as the result of the venturi effect created by the flow of the recycled water. The mixing of gas with the recycled water generates small bubbles which diffuse and interact with the dispersed oil droplets in the water. Eductors are often installed at an angle to create a surface flow to the side where the skimmers and the skim trough are located. The flotation and skimming processes are similar to those in mechanical-type systems.[13]

The rate at which gas flows into an eductor is a function of recycle rate (eductor pressure), gas inlet orifice size, and any valve that may have been installed in the gas feed pipe. The gas flow rate and energy dissipation are the major factors in determining the size of bubbles produced. The recycle flow rate is generally controlled manually through control valves installed in the recycle line and between the recycle header and each eductor. The recycle rate is the most important control parameter for optimizing the performance of hydraulic-type systems. For example, as recycle rate increases, the gas rate increases, resulting in a decrease in the initial residence time. This allows for only partial treatment of the influent water and could result in short circuiting of the system.[13]

Hydraulic type units are generally less expensive, are lower in overall operating cost, and experience less downtime than other types of gas flotation systems. However, because the gas transfer per unit volume of water in this type of unit is significantly lower than in mechanical-type units, hydraulic-type units typically achieve lower removal efficiency than mechanical-type units.[13,17]

5.1.6 Chemical Treatment

The addition of chemicals to the wastewater stream is an effective means of increasing the efficiency of treatment systems. Chemicals are used to improve removal efficiencies in gravity separation systems, plate coalescers, and flotation units. The three basic types of chemicals that are used to enhance equipment removal efficiencies in wastewater treatment are:

Surfactants: Surfactants, also known as surface-active agents or foaming agents, are large organic molecules that are slightly soluble in water and cause foaming in wastewater treatment plants and in the surface waters into which the waste effluent is discharged. Surfactants are sometimes used to treat oil-wet solids. Oil-wet solids tend to settle poorly because the combined lower density of the oil and higher density of the solids results in particles that have neutral buoyancy in water. Surfactants break apart the oil and solids so that they can more readily separate from the water.

Coagulants: Coagulating agents assist the formation of a floc and improve the settling characteristics of the suspended matter. The most common coagulating agents are aluminum sulfate (alum) and ferrous sulfate.

Polyelectrolytes: These chemicals are long chain, high molecular weight polymers used to bring about particle aggregation. Polyelectrolytes act as coagulants to lower the charge of the wastewater particles, and aid in the formation of interparticle bridging and aggregation of particles. Depending on whether their charge, when placed in water, is negative, positive, or neutral, these polyelectrolytes are classified as anionic, cationic, and nonionic, respectively.

Surface active agents and polyelectrolytes are the most commonly used chemicals in wastewater treatment processes. The chemicals are usually injected into the wastewater in the piping upstream of the treatment unit without pre-mixing. Serpentine pipes, existing piping arrangements, etc., induce enough turbulence to disperse these chemicals into the water stream.

5.1.7 Subsurface Injection and Filtration

Subsurface disposal is sometimes used to comply with BPT limits and is the technology used in coastal areas to comply with zero discharge limits in NPDES permits. Injection is also used for waterflooding to enhance production. At some facilities injection is preceded by a filtration process to protect the formation face from becoming fouled with solids. Subsurface injection in combination with filtration is the BAT technology basis for complying with zero discharge for produced water and is discussed in detail in Section 5.2.2.

5.2 ADDITIONAL TECHNOLOGIES EVALUATED FOR BAT AND NSPS CONTROL

Several produced water treatment technologies were considered as add-on technologies to the existing BPT technologies to achieve BAT and NSPS limitations. In particular, EPA evaluated the following technologies for BAT and NSPS level of control: gas flotation, subsurface injection, cartridge filtration, granular filtration, crossflow membrane filtration, and activated carbon adsorption. The following sections describe these technologies in detail.

5.2.1 Improved Performance of Gas Flotation Technology

During the development of the offshore rule, EPA evaluated the costs and feasibility of improved performance of gas flotation treatment systems to determine whether more stringent effluent limitations based on improved performance of gas flotation would be appropriate. Specific mechanisms to improve the performance of gas flotation systems include proper sizing of the gas flotation unit to improve hydraulic loading (water flow rate through the equipment), adjustment and closer monitoring of engineering parameters such as recycle rate and shear forces that can affect oil droplet size (the larger the oil droplet, the easier the removal), additional maintenance of process equipment, and the addition of chemicals to the gas flotation unit to enhance pollutant removals. Since most coastal facilities do not currently use this technology, it is reasonable to conclude that for most coastal facilities the improvements can be designed into any newly installed systems. The performance data for this technology has been adopted from the offshore rule. Table VIII-7 presents summary data for improved gas flotation effluent as compared to settling effluent data which characterize BPT-level treatment.

The performance of a gas flotation process is highly dependent on the bubble-particle interaction. The mechanisms of this interaction include: (1) precipitation of the bubbles on the particle surface, (2) collision between a bubble and a particle, (3) agglomeration of individual particles or a floc structure

TABLE VIII-7

PRODUCED WATER EFFLUENT CONCENTRATIONS FOR THE GULF OF MEXICO

Pollutant Parameter	Concentration (μg/l)	
	Settling Effluent[a]	Improved Gas Flotation Effluent[b]
Oil and Grease	26,600	23,500
TSS	141,000	30,000
Priority Organic Pollutants		
2,4-Dimethylphenol	148	148 [c]
Benzene	5,200	1,226
Ethylbenzene	110	62.18
Naphthalene	184	92.02
Phenol	723	536
Toluene	4,310	827.80
Priority Metal Pollutants		
Cadmium	31.50	14.47
Chromium	180	180 [c]
Copper	236	236 [c]
Lead	726	124.86
Nickel	151	151 [c]
Silver	359	359 [c]
Zinc	462	133.85
Non-Conventional Pollutants		
Aluminum	1,410	49.93
Ammonia	41,900	41,900 [c]
Barium	52,800	35,561
Benzoic acid	5,360	5,360 [c]
Boron	22,800	16,473
Calcium	2,490,000	2,490,000 [c]
Chlorides	57,400,000	57,400,000 [c]
Cobalt	117	117 [c]
Hexanoic Acid	1,110	1,110 [c]
2-Hexanone	34.50	34.50 [c]
Iron	17,000	3,146
Magnesium	601,000	601,000 [c]
Manganese	1,680	74.16
2-Methylnaphthalene	77.70	77.70 [c]
Molybdenum	121	121 [c]
n-Decane	152	152 [c]
n-Dodecane	288	288 [c]
n-Eicosane	78.80	78.80 [c]
n-Hexadecane	316	316 [c]
n-Octadecane	78.80	78.80 [c]
n-Tetradecane	119	119 [c]
o-Cresol	152	152 [c]
p-Cresol	164	164 [c]
Strontium	287,000	287,000 [c]
Sulfur	12,200	12,200 [c]
Tin	430	430 [c]
Titanium	43.80	4.48
m-Xylene	147	147 [c]
o+p-Xylene	110	110 [c]
Vanadium	135	135 [c]
Yttrium	35.30	35.30 [c]
Lead 210	5.49e-07	5.49e-07 [c]
Radium 226	1.91e-04	1. 91e-04
Radium 228	9.77e-07	9. 77e-07 [c]

a Source: SAIC, 1996.[18]

b Concentrations in this column are from the Offshore Development Document unless otherwise noted.[2]

c For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no data were available in the Offshore Development Document or because the offshore gas flotation value was greater than the settling effluent value.

as the bubbles rise, and (4) absorption of the bubbles into a floc structure as it forms. These mechanisms indicate that surface chemistry aspects of flotation play a critical role in improving the performance of gas flotation. Chemicals that enhance the bubble-particle interaction will increase pollutant removal. In fact, chemicals have been an integral part of the flotation process for some time.[11]

Chemicals are commonly used to aid the flotation process. Chemicals function to create a surface or a structure that can easily absorb or entrap air bubbles. Three basic types of chemicals, which are previously discussed in Section 5.1.6, are generally utilized to improve the efficiency of the gas flotation units used for treatment of produced water; these chemicals are surface active agents, coagulating agents, and polyelectrolytes. Polyelectrolytes and coagulants increase pollutant reductions for gas flotation systems by facilitating interparticle bridging or aggregation of particles. This "particle growth" results in structures (flocs) that more easily entrap other particles (even at the molecular level) and the gas bubbles in the produced water (through absorption or adsorption). Surfactants and polyelectrolytes enhance the particle interaction by altering surface tension or particle eletrical charge, thus increasing the chance the gas bubble will interact with the pollutant and float it to the surface for removal. Inorganic chemicals, such as the aluminum or ferric salts and activated silica, can be used as coagulating agents to bind the particulate matter and to create a structure that can easily entrap air bubbles. Various surface active organic chemicals can be used to change the nature of either the air-liquid interface or the solid-liquid interface, or both. These compounds usually collect on the interface to bring about the desired changes.

Researchers have demonstrated that the addition of chemicals to the water stream is an effective means of increasing the efficiencies of gas flotation treatment systems.[10,13,19,20,21,22,23] Pearson, 1976, reported that the use of coagulants can drastically increase the oil removal efficiency of dissolved-gas flotation units.[14] The addition of alum plus polyelectrolyte to a flotation cell treating refinery wastewater increased the unit efficiency from 40 percent to 90 percent. Luthy, et al., 1978, also demonstrated the effectiveness of polyelectrolytes for improving the effluent quality of dissolved-gas flotation units treating refinery wastewater.[24]

Factors related to engineering or mechanical design aspects of the gas flotation systems which could also affect process performance include:

- Type of gas available or used
- Pressure supplied and temperature (DGF)
- Type and condition of eductor (IGF)

- Rotor speed and submergence (IGF)
- Percent recycle (DGF) or rate of recycle (IGF)
- Influent characteristics, concentration, and fluctuations
- Hydraulic and mass loadings
- Chemical conditioning
- Type and operation of skimmer
- Air-to-solids ratio
- Hydraulic retention time
- pH
- Chemical addition (i.e., frequency and dosage rate)
- Surface area of unit
- Retention time of floated material.

A review of the design parameters for 32 gas flotation units surveyed by EPA in 1975 revealed that these units were designed for maximum expected hydraulic loadings. However, none were designed to handle mass overload conditions which may occur during start-up, process malfunctions, or poor operating practices. The survey also indicated that those systems that were properly designed, maintained, and operated had excellent performance. Produced water effluent oil concentrations from these systems averaged less than 25 mg/l.[21]

For those few coastal facilities that already have gas flotation in place most modifications to improve gas flotation are simple and could be done by using the existing tankage and equipment with minimal costs. For example, according to a case study conducted by Rochford, 1986, an inadequately designed induced gas flotation system operating in North Sea was successfully modified to operate as a dissolved gas flotation with minimal capital cost.[25] The IGF unit was not designed to treat produced water with very small oil droplets (5 to 40 microns), thus achieving only 30 percent removal efficiency. The modified system simplified the equipment required for conventional DGF systems by utilizing the existing tanks and the dissolved gas already present in the produced water. The new system efficiency ranged between 70 to 80 percent.

In general, gas flotation systems may have oil and grease removal efficiencies of 90 to 95 percent.[15] With proper operation, chemical addition, and low suspended solids concentration, a mechanical-type IGF system can consistently achieve oil removal efficiencies greater than 90 percent, even when operating at capacities beyond the design flowrates. Some older and larger size hydraulic-type IGF systems using one eductor per cell have not demonstrated the capability to consistently exceed 90 percent oil removal efficiency at one minute residence time per cell. However, the newer designs which have employed multiple eductors in each cell, more cells for the same volume, a means of ensuring smaller bubbles, and superior baffle design give comparable performance to mechanical-type units. As a general design rule, gas flotation units used for treating oily water should have a large drain piping system, at least 4-inches in diameter, to prevent foam plugging. Also, adequate surge capacity is necessary upstream of IGF units to protect the system from oil "slugs," eliminate flowrate surges, and to remove suspended solids.[13]

5.2.2 Subsurface Injection

Disposal of produced water by injection into a subsurface geological formation can serve the following purposes:

- Provide zero discharge of wastewater pollutants to surface waters.
- Increase hydrocarbon recovery by flooding or pressurizing the oil bearing strata (waterflooding).
- Stabilize (support) geologic formations which settle during oil and gas extraction (a significant problem for older, i.e onshore and coastal, more depleted reserves).

Coastal and onshore produced water injection is a well-established practice for disposal of produced water. With the exception of Cook Inlet, injection of produced water is widely practiced by facilities in the coastal subcategory. Independent of this rule, all coastal facilities in Alabama, California, Florida, and the North Slope of Alaska are currently practicing zero discharge. EPA estimates that at least 80% to 99.9% of all coastal facilities in Louisiana and Texas will be practicing zero discharge by January 1, 1997. The 80% estimate is based on subtracting the sum of the 6 facilities discharging into a major deltaic pass of the Mississippi, the 82 facilities discharging to Louisiana open bays, and the 82 facilities associated with individual permit applicants in Texas from the 853 total coastal facilities estimated to exist in Louisiana and Texas. The 99.9% estimate is based on subtracting the number of facilities discharging into a major deltaic pass of the Mississippi from the total number of coastal facilities in Louisiana and Texas. Additionally, using data from the Coastal Oil and Gas Questionnaire and other information regarding facilities known to be discharging in 1992, EPA estimated that 62% of coastal facilities along the Gulf of Mexico were practicing zero discharge in 1992. For the onshore subcategory, injection is the predominant technology used to comply with the zero discharge BPT limitation promulgated in 1979. Additionally, some facilities have been subject to consent decrees requiring zero discharge in citizen suits filed by environmental groups. For the onshore subcategory, injection is the predominant technology used to comply with the zero discharge BPT limitation promulgated in 1979.

As part of the offshore rulemaking process, and in response to industry concerns about the feasibility of injection due to the receiving formation characteristics, EPA evaluated the technical feasibility of implementing this technology at both existing and new offshore facilities.[26] The study showed that injection is generally technologically feasible in all offshore areas, i.e., suitable formations and conditions are available for disposal operations. The same is generally true for the coastal regions in that the geologies of the North Slope and the Gulf Coast consist of formations which can readily accept injected produced water. EPA has no information in the record that would indicate that other coastal regions, other than Cook Inlet, Alaska, would be unable to inject produced water.

The following sections present information on the injection technology as a means to control produced water discharges.

5.2.2.1 Industrial Practices by Location

Most of the produced water generated in the coastal and offshore areas of California is presently injected for waterflooding to enable recovery of the heavy crude oil that is typically produced in that part of the country. Coastal facilities in Florida, Alabama, and Mississippi are currently practicing zero discharge of produced water. In the western Gulf of Mexico, produced water generated in the coastal region has been either treated to the BPT limitations and discharged to the surface waters or it is injected for disposal under the Region 6 general permits (60 FR 2387) published January 9, 1995. Coastal injection experiences in Texas and Louisiana have shown that the characteristics of the regional geology make it possible to inject produced water in the Gulf Coast region.[27] However, in Cook Inlet, because of the highly fractured and compartment geology present, there are no formations onshore directly beneath the treatment facilities to accept the large volumes of produced waters treated, making injection onsite infeasible.[28]

The data in Table IV-1 show that EPA estimates that there were 853 production facilities in Texas and Louisiana in 1992 and of those, 325 were discharging produced water to surface waters. The Coastal Oil and Gas Questionnaire Summary Statistics showed that of the production facilities in the Gulf of Mexico, an estimated 62 percent were injecting produced water in 1992.[1] The majority of the 528 production facilities not discharging in 1992 were disposing of produced water by subsurface injection. As shown in Table IV-1, EPA estimates that by January 1, 1997, only 6 coastal facilities in the Gulf of Mexico will be discharging produced water (see Chapter III for details regarding current regulatory requirements).

All of the coastal operations in the North Slope region of Alaska inject all of their produced water, primarily for waterflooding. In Cook Inlet, Alaska, produced water is surface discharged after BPT treatment. However, waterflooding is being performed using seawater.

5.2.2.2 Well Selection and Availability

There are a number of considerations in the planning, design, and operation of a produced water injection system. These include important design considerations such as selection of a receiving formation, preparation of an injection well, and choice of equipment and materials. Significant operational parameters include scaling, corrosion, incompatibility with the receiving stratum, and bacterial fouling.

5.2.2.2.1 Formation Characteristics

Selection of the receiving formation should be based on geologic as well as hydrologic factors. These factors determine the injection capacity of the formation and the chemical compatibility of the injected produced water with the water within the formation. The most important regional geologic characteristics of a disposal formation are areal extent and thickness, continuity, and lithological character. This information can be obtained or estimated from core analysis, examination of bit cuttings, drill stem test data, well logs, driller's logs, and injection tests.

The desirable characteristics for a produced water injection formation are: an injection zone with adequate permeability, porosity, and thickness; an areal extent sufficient to provide liquid-storage at safe injection pressures; and an injection zone that is confined by an overlying consolidated layer which is essentially impermeable to water. There are two common types of intraformation openings: (1) intergranular and (2) solution vugs and fracture channels. Formations with intergranular openings are usually made up of sandstone, limestone, and dolomite formations and often have vugulur or cavity-type porosity. Limestone, dolomite, and shale formations may be naturally fractured. Formations with fracture channels are often preferable for produced water disposal because fracture channels are relatively large in comparison to intergranular openings. These larger channels may allow for fluids with higher concentrations of suspended solids to be injected into the receiving formation under minimum pumping pressure and minimal pretreatment.

A formation with a large areal extent is desirable for disposal purposes because the fluids within the disposal formation must be displaced to make room for the incoming fluids. An estimate of the areal extent of a formation is best made through a subsurface geological study of the area. If it is possible to inject water into the aquifer of some oil- or gas-producing formation, the size of the disposal formation is not critically important. Under these circumstances, the injected water would displace water from the aquifer into the producing reservoir from which fluids are being produced. Thus, the pressure in the aquifer would only increase in proportion to the amount that water injection exceeds fluid withdrawals. Pressure-depleted aquifers of older producing reservoirs are highly desirable as disposal formations, provided the disposal practice will not adversely affect the producing reservoir.

Formations capped or sandwiched by impervious strata generally will assure that fluids pumped into the formation will remain in place and not migrate to another location.[29] Abandoned producing formations are ideal for disposal because the original fluids were trapped in the formation. Fluids injected into those formations also will be trapped and will not migrate into other areas.

5.2.2.2.2 Proper Location of Disposal Wells

Faulting in an area should be evaluated critically before locating a disposal well, particularly if the disposal formation is other than an active or abandoned oil or gas producing formation.[26] Depending upon local stratigraphy and the type and amount of fault displacement, one of three possible conditions can occur. Displacement along the fault may either: (1) limit the area available for disposal; (2) place a different permeable formation opposite the disposal formation which could allow fluids to migrate to unintended locations; or (3) the fault itself may act as a conduit, allowing injected fluids to flow along the fault plane either back to the surface or to permeable formations at a shallower depth than the disposal formation.

Another concern associated with faulting is that fluids entering the fault or fault zone may cause a reduction in friction along the fault plane, thus allowing additional, and perhaps unwanted, displacement to occur.[26] Such movement can create seismic activity in the area. The city of Denver, Colorado placed a disposal well near the Rocky Mountain Arsenal and pumped city waste water down the well. The well bottom was in the vicinity of a fault. Subsequent analysis showed a direct correlation between the number of microseisms in the Denver area and well pumping times and rates. Increased pumping caused a corresponding increase in the number of microseisms.

5.2.2.2.3 New Versus Converted Wells

Whether the objective is enhanced ("secondary") recovery or disposal, a primary requirement for the proper design of a injection well is that the produced water be delivered to the receiving formation without leaking or contaminating fresh water or other mineral bearing formations. The injection well may be installed by either drilling a new hole or by converting an existing well. The types of existing wells which may be converted include: marginal oil producing wells, plugged and abandoned wells, and wells that were never completed (dry holes). If an existing well is not available for conversion, a new well must be drilled. Moreover, for injection from platforms supported on pilings, adequate equipment and storage space must be provided at the facilities.

The drilling of a new injection well is very similar in practice to the drilling of production wells except that injection wells may not need to be drilled as deep as the production wells they serve, if shallower disposal formations are available. The advantages of drilling a new well specifically for produced water injection include the following:

- Location can be selected to minimize surface piping.
- Location can be selected to utilize optimal geologic formations.
- Casing and long string can be sized to handle designed produced water flowrates.
- Casing can be properly cemented to meet regulatory requirements.
- Desired casing grades and weights may be used.

The disadvantages of drilling new injection wells are:

- Costs are higher than converting an existing well.
- Geology and downhole conditions may not be known prior to drilling.

Figure VIII-3 presents a schematic of a typical well drilled for subsurface injection. EPA's field investigations found that the conversion of existing production wells to injection wells is the most common practice in the coastal Gulf of Mexico region primarily due to availability and costs.[3] Conversions are most commonly performed on depleted production wells using wells whose hydrocarbon production rates have or soon will diminish to the point where they are no longer economical to operate as production wells (i.e., depleted wells). Such depleted wells are included in the bases for the Gulf of Mexico compliance cost estimates presented in Chapter XI. Wells that were never completed (dry holes) and old plugged and abandoned wells may also be used, but may require more work at greater expense.[30]

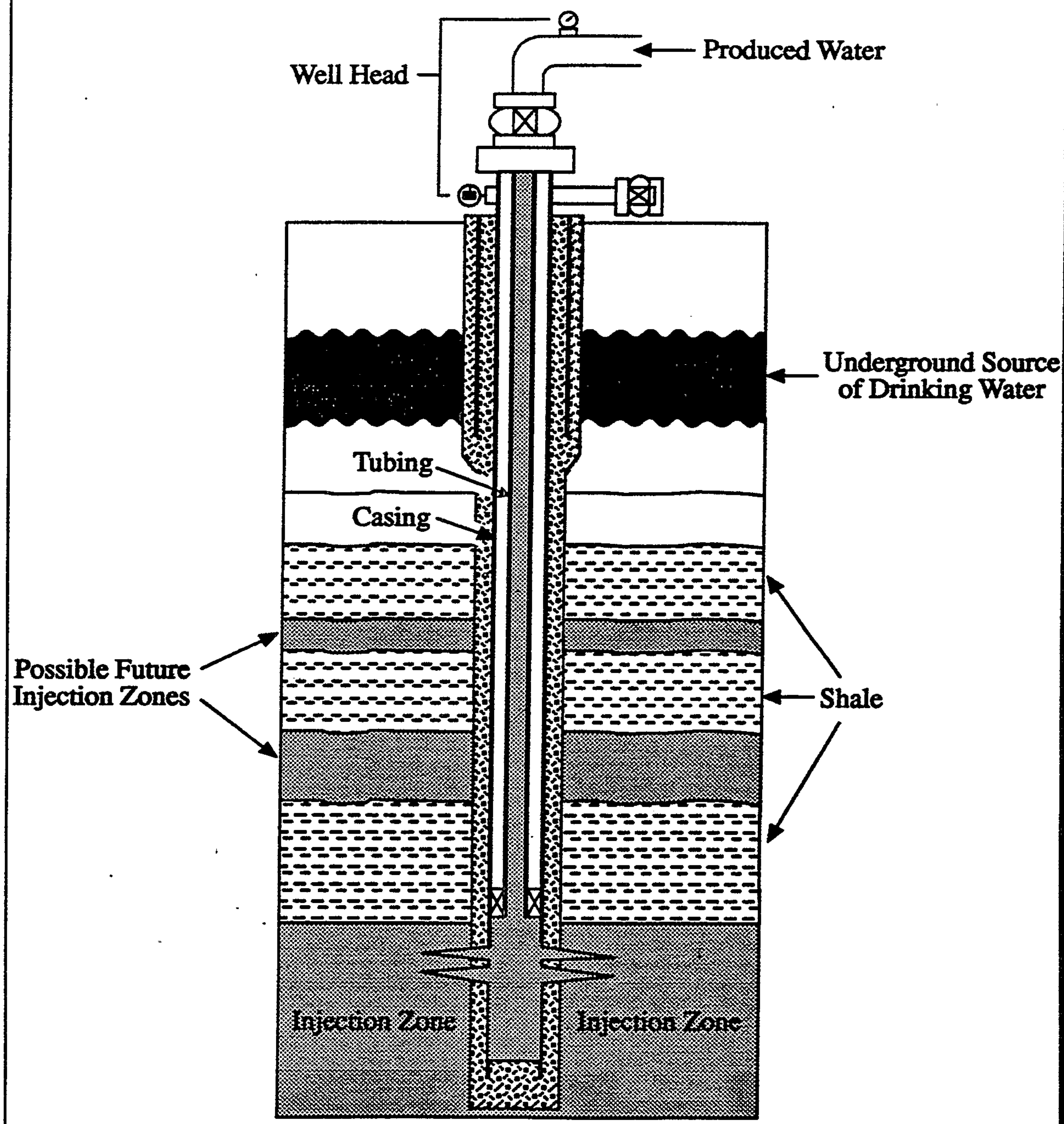


Figure VIII-3
Typical Subsurface Injection Well

The most common method of conversion involves recompletion of the well at a shallower depth into a non-hydrocarbon producing formation.[3] In such a case the lower portion of the well is cemented. Conversion operations may include:

- Pulling/fishing of old tubing and equipment.
- Squeeze cementing if casing was not cemented to the lowest underground source of drinking water.
- Cementing of lower portion of the long string.
- Perforation into injection zone.
- Setting of new tubing and packer.
- Stimulation of the well.
- Installation of surface piping valves and gauges.

The advantages of converting an existing well rather than drilling a new well include the following:

- Lower cost since drilling is not required.
- Formation depths, porosity, thickness, and approximate permeabilities are already known.
- Casing and cement is often in satisfactory condition.

The disadvantages of converting an existing well include the following:

- Casing or long string may be too narrow to allow tubing of sufficient size to handle desired produced water flow rate.
- Location may not be satisfactory.
- Casing may be in poor mechanical condition.
- Casing or long string may not be properly cemented.

Despite these advantages, most facilities will choose to use converted injection wells rather than drill new ones due to the savings in cost.[31]

The report entitled "Evaluation of Class II Regulatory Impacts" estimates that approximately 90 percent of newly installed injection wells will be converted wells and 10 percent will be newly drilled wells.[32] This estimate is based upon API data for existing permits and should be representative of both the Gulf Coast and California. This estimate corresponds well with information gathered during the 1992 Coastal Oil and Gas sampling effort where eleven injection facilities were visited with two of them being offsite commercial operations.[3] Both of the offsite commercial operations had newly drilled injection wells because they were not located over an oil field and thus did not own or have access to existing wells. Out of the remaining nine injection facilities visited by EPA, eight installed converted wells and one installed a newly drilled well, or 11.1 percent of the facilities drilled new wells and 88.9 percent converted existing wells. The total overall number of operating disposal wells for the nine onsite injection facilities consisted of one newly drilled well and twenty-two converted wells or 4.3 percent newly drilled wells and 95.7 percent converted wells.

5.2.2.2.4 Regional Geological Considerations

California

There is little question about the technical feasibility of injecting produced water at the existing facilities in the coastal region of California because the current practice of this technology is common. In the coastal and offshore subcategories for California, most of the produced water is injected for the sole purpose of enhanced recovery by waterflooding. In fact, at the THUMS facilities in Long Beach Harbor, additional brine to that of the produced water must be injected to provide sufficient pressure maintenance. Injection of produced water is not practiced in areas where there is potential to increase seismic activity.[33] The coastal geological conditions and engineering requirements for the injection of brines from new sources in areas expected to be open for oil and gas development and production, i.e., free of seismic activity, are expected to be essentially the same as for existing sources. Consistent with the past and present industry practices, suitable disposal formations with adequate permeability, porosity, thickness, and areal extent are expected to be available. Similarly, constructability and trouble-free operation of injection wells, availability of coastal pretreatment technologies, and the transport and onshore disposal of solids and sludges from new sources pose no additional technical problems beyond those currently encountered due to the injection of brines from existing sources.

Gulf of Mexico

In the Gulf of Mexico, injection of produced water from existing coastal sources is common (see Sections 5.2.2 and 5.2.2.1). The two most common disposal practices are either to pretreat and inject or to treat the produced water to the BPT effluent limitations and discharge. While they do exist, waterflood projects are not common in the Gulf of Mexico; it is estimated that less than ten facilities in the Gulf of Mexico inject produced water for pressure maintenance.[34] The primary reason that waterflooding is not common is because, unlike California, extraction of the formation fluids from the reservoirs in the Gulf of Mexico does not necessarily require the additional water drive provided by waterflooding. An effective waterflood program requires several wells, since waterflooding operations often push the oil zone up and horizontally direct the movement of the zone to the production well.

Injection of brines for disposal from existing and new sources in the coastal Gulf of Mexico region depends on the availability of an adequate number of suitable disposal formations. In the early stages of production, there is little need for injection fluids to enhance recovery and, therefore, the produced water would be injected only for disposal purposes. The coastal injection experience in Texas and Louisiana has shown that injection of produced water is possible. Throughout most of the coastal region of Louisiana and Texas, the oil and gas producing formations are overlaid with alternating sequences of sand and shale sediments formed by ancient rivers and oceans and make up a considerable part of the stratigraphic column.[24] The advantages of using these formations for disposal include:

- Formation thicknesses, depths, porosities and permeabilities are usually available from logs of the production wells and past experience.

- Shallower depths require less drilling and tubing, thereby reducing construction and future remedial well work costs.

- Production wells can be converted to disposal wells without affecting producing reservoir dynamics.

Eight of the ten coastal production facilities in the Gulf of Mexico region investigated by EPA in 1992 were injecting produced water into sand formations shallower than the producing formations.[3] Several facilities indicated that additional shallower sand formations existed that could be used in the future by recompleting the disposal wells at a shallower depth. The only disadvantage of using shallower formations is that the maximum allowable injection pressure will be reduced. This can result in lower injection pressures and more frequent remedial well work.

Alaska

In the North Slope region of Alaska, all produced water generated is injected with the major portion being used for waterflooding. Waterflooding is also practiced in Cook Inlet, however, seawater is used rather than the produced water. The waterflooding occurring in Cook Inlet has reached "parity" which means that the volume of seawater injected is essentially equal to the combined volume of oil and produced water that is brought to the surface.

An industry study of the technological feasibility and the economic analysis of subsurface disposal in Cook Inlet was performed for produced water from the Trading Bay Production Facility.[28] In this report, three injection alternatives were considered and evaluated: 1) treatment and injection for waterflooding at the platform; 2) piping produced water to an onshore facility for treatment and return to the platform for injection for waterflooding; and 3) piping produced water to an onshore facility for treatment and injection for disposal. In this study, alternatives 1 and 2 were reported to be technically feasible, however, several operational problems were identified that could affect the system. These problems, along with preventative remedial measures are discussed below.

For the third alternative, the study suggests that the available Tyonek sands injection formations directly beneath the Trading Bay Facility (which discharges 94% of the Cook Inlet produced waters) are not suitable to accept the large amounts of produced water generated at this facility. Although significant in gross pore volume, these formations are broken up into numerous smaller reservoirs. Continuous injection into any one reservoir could cause the reservoir to become overpressurized, threatening to cause fracturing and migration to shallower potable water aquifers and, according to the study, possibly triggering seismic activity. In addition, the Tyonek formations contain significant amounts of water-sensitive clays which, when injected with the relatively fresh produced water from the Trading Bay Facility, could result in severely or completely restricted permeability.[28]

5.2.2.3 Technical Issues

Some of the technical issues that may be associated with subsurface injection of produced water are described below. In general, these issues can be avoided or remedied through engineering and operational applications such as the use of treatment chemicals. Possible solutions for each are also discussed.

Formation Plugging and Scaling - Scales and sludges that are commonly found in produced water disposal systems include: calcium carbonate, magnesium carbonate, calcium sulfate, barium sulfate, strontium sulfate, iron sulfide, iron oxide, and sulfur. These scales and sludges can form in collection and distribution lines, treating equipment, well tubulars and at the injection formation.[35]

Scale and sludge differ in that scale is a deposit formed in place on surfaces in contact with water, while sludge may be formed in one place and deposited in another. Sludges may collect in low flow rate areas of a system such as tanks and vessels, in the bends of lines and on filter surfaces.[35]

Scales and sludges are formed from water as the waters adjust to changes in equilibrium. Changes in equilibrium are caused by temperature changes, pressure changes, chemical changes, changes in pH, impurities, additives, gas evaporation, and the mixing of two or more stable but incompatible waters.[36,37] Scale may form as a result of a chemical reaction between the water, or some impurity in the water, and the pipe. Corrosion products, such as iron oxide or iron sulfide, may be scales of this type. Other precipitates, such as sulfur, may form when water with hydrogen sulfide is mixed with water with a high dissolved oxygen content.[35]

The solubility of calcium carbonate (a common component of groundwater) is influenced by the concentration of dissolved carbon dioxide in water. If calcium carbonate is present in an underground formation and the concentration of dissolved carbon dioxide in the formation water is increased, the amount of dissolved calcium carbonate will increase. When the dissolved carbon dioxide concentration is reduced, such as when carbon dioxide-rich produced water comes to the surface where the pressure is lower and it comes into contact with air, the reverse occurs, and the carbon dioxide is released and calcium carbonate will precipitate.[36] Also, the solubility of most scales decreases with decreasing temperatures.

All of the produced water operations in the 1992 EPA 10 Production Facility Study sampling effort maintained closed systems that exclude air using gas blankets. When the produced water samples were cooled and exposed to air, a noticeable increase in turbidity and a color change occurred for most samples. The turbidity was probably the result of calcium carbonate precipitation and the color change was probably the result of the oxidation of dissolved iron.

Scale Prevention - Scale formation is normally preventable. Once formed, however, scale removal is expensive and may cause some permanent damage. Individual waters or mixtures of waters should be tested prior to the design of the produced water disposal system to determine if scale deposition will be a problem. The waters that are to be added to an existing system should also be tested prior to hookup.[35]

Scale deposition of waters can be predicted with moderate accuracy using conventional water analysis and the Stiff-Davis method of predicting the approximate solubility of calcium carbonate and calcium sulfate in produced waters. Compatibility tests will also indicate if scale formation is to be expected.[35]

Depending on the type of scale involved, methods of preventing or removing scale prior to injection include: maintaining a closed system using gas blankets; use of scale inhibiting chemicals; use of acid treatment; use of solvents; use of settling tanks with chemical addition; filtration; mechanical scraping or reaming; and prevention of mixing incompatible waters.[37]

Properly-operated gas blanketing, in combination with the addition of scale-inhibiting treatment chemicals is effective in preventing scale formation in produced water. In the report "Coastal Oil And Gas Production Sampling Summary Report,"[3] field observations of aqueous samples were reported for produced water samples collected from ten oil and gas facilities. Observations were recorded for freshly taken samples (before prolonged air contact) and after prolonged contact with air (i.e., one hour or greater exposure). Produced water samples from four facilities exhibited an increase in turbidity after exposure to air. The report stated that this increase in turbidity may have resulted from precipitates of calcium carbonate, calcium sulfate, and/or other scale-forming materials. As a result, preventing exposure to air would have likely reduced or eliminated the formation of these materials and the observed increase in sample turbidity.

According to the API publication "Subsurface Saltwater Injection Disposal,"[38] the presence of oxygen in produced water is an important driver for the formation of scale materials. The publication states that "systems are designed to prevent the introduction of oxygen into the system, thereby minimizing the amount of oxygen available for scale formation or corrosion reactions."

In the case of calcium carbonate precipitation, a closed system will reduce the loss of dissolved carbon dioxide and/or hydrogen sulfide from the produced water.[39] The calcium carbonate scaling tendency and the likelihood of precipitating iron compounds from the produced water increases as these gases escape from solution. Gas blanketing should therefore substantially alleviate this problem.

In Cook Inlet, Alaska, the operators have expressed concern that the produced water contains a significant amount of scale-forming ions, primarily calcium carbonate, and that the use of treated produced water for waterflooding will result in the rapid plugging of the injection wells. One problem associated with this is that the onshore produced water treatment systems at Trading Bay, Granite Point and East Forelands do not maintain closed systems with gas blankets throughout the system. Therefore, there is a greater potential for produced water from these systems to develop calcium carbonate scale. However, the use of the remedies discussed above such as gas blankets and chemical treatment should substantially alleviate this problem.

In addition to scales and sludges, production formation solids such as sands are commonly found in produced water disposal systems. This is especially true for produced waters from unconsolidated sand formations which are common in the Gulf Coast region. Formation solids referred to as produced sand in this report are most commonly removed using settling tanks and filters in the coastal areas of the Gulf of Mexico.

Formation Swelling - The injection of water with a lower total dissolved solids or salt content than the injection formation water can cause clay particles embedded in the formation to swell. However, this is generally not a problem for produced water injection in the Gulf Coast region because produced water in the Gulf Coast region generally has a total dissolved solids or salt content which is several times that of seawater. This swelling in turn increases the necessary injection pressure and may decrease the injection capacity of the injection well. This phenomenon was reported by the Campbell Wells facility at Bourg, Louisiana which injected a high proportion of relatively fresh washwater (about 73 percent) from their land treatment operation along with produced water from commercial clients (about 27 percent).[40] The result was that higher injection pressures were necessary but injection was not prevented. In Cook Inlet, the use of seawater for waterflooding does not appear to have created a swelling problem. This problem can also occur at facilities that combine a significant quantity of contaminated stormwater with produced water for disposal.

Corrosion - A more common problem encountered in combining fresh water, such as stormwater, with produced water for injection is corrosion caused by dissolved oxygen. The corrosion of metals in a produced water disposal system is usually caused by electrochemical reactions. In this type of reaction an anode (electron donor) and cathode (electron acceptor) must exist in the presence of an electrolyte (ionic solution) and an external circuit. Anodes and cathodes can exist at different points on the steel surfaces with the steel providing the external circuit. A brine solution provides an excellent electrolyte. Thus, an electric circuit can be set up in the unprotected, produced water-handling pipelines with iron being oxidized at one portion of the system (cathode) and iron being reduced and corroded away in another portion (anode).

Corrosion damage can occur uniformly as a gradual thinning of the anode portion, or it can occur in the form of pitting where localized electrolytic cells are set up. It can also occur as galvanic corrosion when two different metals come into contact and form an electrolytic cell.

Dissolved oxygen is a major producer of corrosion. Oxygen-induced corrosion is the result of an electrochemical reaction between a metal, such as iron, and the oxygen where the oxygen accepts electrons and the metal donates electrons. While oxygen is normally absent in formation waters, it is unavoidably absorbed by contact with air in open produced liquid handling systems and can also be introduced with the addition of contaminated stormwater.

Corrosion Prevention - At three of the ten production facilities that EPA sampled, contaminated stormwater was periodically added to the produced water for treatment and disposal.[3] The dissolved oxygen in the stormwater can be removed using a chemical (oxygen scavenger) which combines with the oxygen. In addition, the use of closed systems with gas blankets can prevent the introduction of oxygen to the system. According to the report "Technical Feasibility of Brine Reinjection for the Offshore Oil and Gas Industry,"[35] a major utility of gas blankets is corrosion inhibition. While oxygen is normally absent in formation waters, it is unavoidably absorbed by contact with air in open produced water handling systems. As a result, gas blanket-producing equipment will minimize produced water contact with air, and consequently minimize the formation of corroded metal particles.

Incompatibility of Injected Produced Waters with Receiving Formation Fluids - In the design and operation of a produced water injection system, the compatibility of injected produced waters with the fluids already in the receiving formation is an important consideration. Incompatibility occurs when one or more of the chemicals in the produced water reacts with chemicals in the existing reservoir fluid to cause an undesirable effect, such as precipitation of scale. This condition could also occur if incompatible waters from different reservoirs or surface sources are to be mixed prior to injection. Precipitates that may be associated with incompatible fluids include calcium carbonate, magnesium carbonate, calcium sulfate, barium sulfate, and strontium sulfate. Both barium sulfate and strontium sulfate are highly insoluble in water and are extremely difficult to remove.

It is interesting to note that injection well plugging due to incompatibility between the injected water and the formation water is considered extremely unlikely.[39] However, severe scale formation can occur after injection water breakthrough (i.e., simultaneous production of the injected water with the formation water). While this may not be a problem in a dedicated produced water disposal well, incompatibility can cause problems in a producing well from which injected and formation waters are produced simultaneously.

Incompatibility Prevention - Treating produced water to prevent incompatibility consists of reducing the strength of or removing the reactive element or otherwise altering the nature of the injected fluid using treatment chemicals. Because scale formation is the primary concern when incompatible waters are mixed, the scale prevention measures described above are applicable. Also, a buffer zone of a third water which is compatible with both the injection water and the formation water may be injected to avoid permeability reduction.[39]

Bacteria - The presence of bacteria in a system may present a corrosion or plugging problem. Bacteria in oil field waters may be aerobic (active in presence of oxygen), or anaerobic (active in the absence of oxygen).

Iron bacteria are aerobic and are active in removing iron from water and depositing it in the form of hydrated ferric hydroxide. They are commonly active in fresh waters but are occasionally found in produced waters containing oxygen. The removal of oxygen by the bacteria causes an anaerobic condition to exist under the ferric hydroxide iron deposits on vessel walls where sulfate reducing bacteria can grow and corrode the vessel walls. Both types of bacteria are easily controlled with bactericides.[35]

Aerobic bacteria, or slime formers, can grow in sufficient numbers to cause significant well plugging. Aerobes are indicators of excessive bacterial activity in oxygen-bearing waters and if present in a closed system indicate that air contamination exists. The slimes that are formed shield the metal surfaces from oxygen and provide an environment for the growth of sulfate reducing bacteria. Control of aerobic bacteria is generally accomplished by treatment with an organic biocide.[35]

Anaerobes are active in the absence of oxygen but are not killed by the presence of oxygen. Anaerobes, except sulfate reducers, multiply slowly and normally are found under slime deposits. They are effectively killed with bactericides. Although chlorine could be used, in a closed system chlorine is not used because it is an oxidizing agent.[35]

Sulfate reducing bacteria are the most common and economically significant of the bacteria found in salt water disposal and injection systems. Sulfate bacteria are economically significant due to the corrosion problems associated with them. Sulfate reducing bacteria are anaerobic and have the ability to convert sulfate to sulfide. Sulfate reducers are most active in neutral to mildly acidic waters, are frequently found under slime deposits, and are most prolific under corrosion products, tank bottoms, filters, oil water interfaces, and dead water areas, such as joints, crevices, and cracks in cement linings. Sulfate reducers may also exist naturally in some oil and water producing strata.[35]

In addition to being corrosive, hydrogen sulfide is highly toxic and can cause embrittlement of steel. Hydrogen sulfide is sometimes present in significant quantities in the hydrocarbon producing formations where it was created in the past by sulfate reducing bacteria that were present in the formation. When brought to the surface, it separates out with the gas phase. This type of natural gas is referred to as "sour gas" and is a potential health problem for operators. Thus, its presence requires safety training of operators and the use of special safety equipment and preventive measures. In addition, the corrosion and embrittlement problem may require the use of special steel alloys or coatings in the production equipment. The sour gas must be treated to remove hydrogen sulfide prior to delivery to the pipeline.[41]

Operators in Cook Inlet have expressed concern that the replacement of seawater with treated produced water for use in waterflooding will result in the growth of sulfate reducing bacteria.[28] If so, the bacteria will plug the formation and will generate hydrogen sulfide which will return to the surface with the produced fluids creating corrosion and safety hazards. The reason that this does not currently occur is that the seawater does not contain the nutrients necessary to promote bacterial growth. However, the operators claim that the standard treatment chemicals used in processing the produced water contain nutrients that will promote bacterial growth and that the previous use of seawater for waterflooding has introduced a substantial quantity of sulfate to the formations.

Bacteria Prevention and Treatment - As noted above, the prevention of bacterial growth is primarily remedied with the use of bactericides which are injected into the produced water treatment system influent. In addition, if process treatment chemicals are the source of nutrients that are conducive to bacterial growth, the substitution of these chemicals with ones that do not contain the nutrients can be an effective preventive measure.[42] Chemical treatment can be continuous, although batch treatment is often more cost-effective than continuous treatment. One source states that chemical addition should be as near the water source as possible, and should be added where good mixing is possible.[39] Addition of the chemical to the water intake line, down the annulus of the supply well, or downstream of the supply pump are common locations.

Pigging facilities installed in systems with large diameter pipelines that run for several miles remove deposits and part of the biofilm built up in the pipe.[39] If a batch of biocide follows the line scraper (or "pig"), the effectiveness of the biocide is increased because the chemical can readily contact the remaining biofilm. This can result in substantial savings in chemical treatment costs.[39]

Injection Into Producing Formations - Injection into producing formations is not extensively practiced in the coastal region of the Gulf of Mexico because of potential problems that waterflooding can cause by adversely changing the field pressure.[26] These pressure changes can cause a production loss from nearby production wells either by coning at the injection wellbore or, if there is directional permeability within the reservoir, the rapid return of injected water back to the production wellbore. Increased pressure can also cause movement of the formation fluid containing the oil and gas away from the production wellbore. These movements may result in reduced production. Because each production area has its own unique set of conditions, each site must be individually evaluated for potential problems that may arise from injection into a producing formation. Despite these potential problems, waterflooding is practiced in some locations of the coastal Gulf of Mexico, and extensively in coastal California and Cook Inlet (see Chapter IV for details regarding the coastal industry profile).

5.2.2.4 Down-Hole Remedial Measures

The text in this subsection is excerpted from the publication entitled "Subsurface Saltwater Injection and Disposal."[38] The information provided in this publication is a generalized overview of injection operations provided by the largest oil and gas industry association in the United States, the American Petroleum Institute.

During the life of an injection system, formation capacity may decrease significantly due to formation plugging (from suspended solids, precipitation, hydrocarbons, or bacteria) or fouling of flowlines from scale or biological growth. Should these problems develop, the following remedial measures have been used to increase and prolong capacity.[38]

Acidizing - In many cases the receptivity of a formation may be improved or restored by acid treatments. In carbonate formations, acid will dissolve or etch fluid passageways through the treated area of the formation, creating an enlarged effective well bore. In all formations, foreign materials introduced while drilling, completing, or injecting into a well may block or plug the formation. Acid cleanup treatments may dissolve, loosen, shrink, or affect these foreign materials so that they may be removed by swabbing, or dispersed by flushing. A well should never be left shut-in following acid treatments. The spent acid and residual products should be removed from the well bore immediately after the reaction time of the acid.[38]

One of the commercial facilities in the 1992 EPA coastal sampling effort reported that they routinely added acid to their first equalization tank prior to injection. This was most likely done to reduce the quantity of scales and sludges present in the incoming water shipments as well as those that may form as a result of the mixing of water from different sources. Scales and sludges that are effectively treated with acid include calcium carbonate, magnesium carbonate, iron oxide, and iron sulfide.[38]

Sand Jetting or Under Reaming - An injection well completed in open hole (without casing) may cease to take water because of damage or plugging at the formation face. The formation can be reconditioned by removing the face of the formation with a high velocity jet of sand-laden fluid, or by cutting away the face of the formation using an underreamer. In cases of insoluble scale damage, these methods could be more effective than acid treating.[38] None of the nine onsite or two commercial offsite injection facilities in the 1992 EPA Coastal sampling effort reported performing a sand jetting or underreaming operation on an injection well.[31]

Backwashing - Periodically, wells can be backflowed to clean the formation face. Backwashing is performed by sparging gas, usually nitrogen, near the bottom of the injection tubing which creates an upward flow of injection/formation fluid and solids that are plugging the formation face. This operation is similar in principal to backwashing a filter. The fluids and solids are captured in tanks and are hauled offsite for treatment and disposal. In some cases the fluids and solids are treated onsite, and the treated fluids are injected. Special strings of tubing are used to facilitate this operation. One practice that is becoming increasingly more common is the use of coil tubing. Coil tubing refers to a long flexible metal tube that is stored on a large spool. The tube is inserted down the well production tubing to perform the backwash. The method is replacing the old method of using rigid threaded pipe sections which takes more time and manpower to utilize. This operation was the most commonly cited remedial measure conducted by the facilities in the 1992 EPA Coastal sampling effort.[31]

Treating with Solvents, Dispersants, and Other Chemicals - In special cases where injection wells have suffered loss of receptivity from known or identifiable causes, chemical treatments for the specific cause may be appropriate. Treatments of this type include solvents to remove asphaltines or paraffins, converter type treatments for the relatively acid-insoluble scales such as calcium sulfate or barium sulfate, fresh water for the removal of salt blocks, and emulsion breakers for an emulsion problem.[38]

5.2.2.5 Pretreatment of Produced Water Prior to Injection

Pretreatment of produced water may be necessary to prevent scaling, corrosion, precipitation, and fouling from solids and bacterial slimes. Corrosion and scale deposits lead to decreased equipment performance and to plugging in the underground formation. One method to overcome this problem is to increase injection pressures. However, excessive injection pressure may fracture the receiving formation causing the escape of produced water into freshwater or other mineral bearing formations. Injection well permits specifically identify the maximum allowable injection pressure which is based on an estimation of the injection formation fracture pressure. Also, additional energy (fuel) is necessary to obtain the higher discharge pressures and consequently results in increased air emissions.

Most coastal treatment systems are classified as closed systems which operate in the absence of air. As stated earlier, all of the production facilities visited by EPA in 1992 used closed systems.[31] This alleviates the problems arising from oxygen induced corrosion, scaling, and chemical precipitation. In a closed system, a blanket of natural gas is maintained over the produced water in pipelines and tanks.

Pretreatment for injection can include gravity separation, gas flotation, and/or filtration. At coastal facilities in the Gulf of Mexico region, the most common form of pretreatment used is gravity separation (settling) and filtration using cartridge or bag filters. These technologies can be used as treatment prior to discharge or injection, and are described in detail in Section 5.2.3.1. The settling tanks are usually part of the existing BPT treatment system, whereas the filters are usually installed with the injection system to prevent the plugging of the injection formation. Filters are used especially at facilities located in water to minimize the frequency of performing well workovers. Facilities located over land may opt to delete the filtration step and conduct periodic well workovers instead. Well workovers in water areas are more expensive (see Section XI.3.2.1.2). Filtration is discussed in more detail in the following section.

5.2.3 Filtration

Filtration is widely used for produced water treatment as a polishing step for the removal of suspended solids following the oil separation processes. Filtration is generally utilized to improve the injection characteristics of produced water.[35] Cartridge filtration is commonly used at coastal facilities in the Gulf of Mexico as a pretreatment step prior to injection to prevent plugging of the injection formation, and was included in the compliance cost estimates for subsurface injection of produced water in the coastal Gulf of Mexico region (see Chapter XI). Filtration can also be used as a treatment step prior to surface discharge.

Crossflow membrane filtration was investigated in detail during the development of the Offshore Effluent Guidelines where it was determined that widespread use is hampered by operational problems. Therefore, this technology was not selected for consideration in any options for the coastal subcategory.

5.2.3.1 Cartridge Filtration

Cartridge filtration involves the passage of water through disposable filter elements (cartridges) to remove solids. The cartridges are housed in a filter chamber that can hold from several, and up to 27 or more cartridges, depending on the flow capacity of the unit. Figure VIII-4 presents a schematic diagram of a typical cartridge filtration system. The filter element consists of a hollow cylinder of tightly wrapped twine that is several inches in diameter. The cartridges come in various grades ranging from five micrometers (μ) nominal pore size to 50μ or greater. The chamber is arranged so that water is forced tangentially through the fibers of the cartridge to the center and out one end of the cartridge. As solids build up on the cartridges, the pressure drop across the filter increases. The pressure drop is monitored by the operator and when the pressure drop exceeds a specified amount, usually between 10 psi and 20 psi, the filter chamber is taken out of service and the cartridges are replaced. The frequency of filter changeout is dependant on the quality and flowrate of the influent and was observed in the field to range from several days to a week or more.

A typical arrangement is two sets of filters arranged in parallel, with each set capable of processing the entire flow so that the flow can be alternated from one set to the other to allow for continuous operation during filter changeout. In some arrangements, each set of filters consist of two filters in series with finer grade filters in the downstream position. This arrangement extends the life of the finer filter which will clog up more quickly without prefiltration.

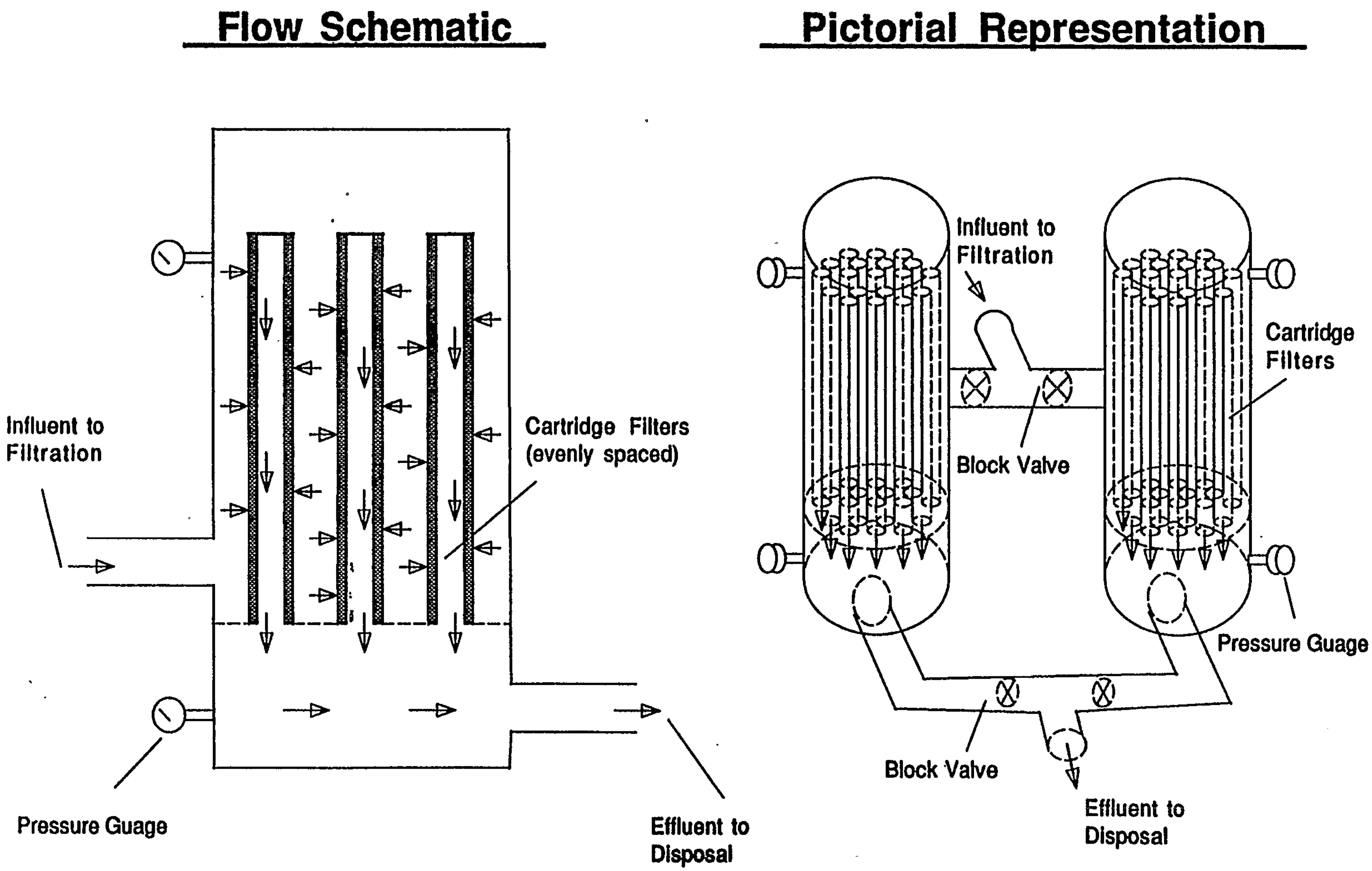


Figure VIII-4
Cartridge Filter

At the ten production facilities investigated by EPA in 1992, cartridge filtration was used by three of the four facilities that utilized filtration as a pretreatment step prior to injection (the fourth facility uses a 200 mesh screen).[3] Table VIII-8 presents a summary of the produced water influent and effluent data from these three facilities. The cartridge filtration systems used at the three production facilities consisted of the following: Greenhill Petroleum at Bully Camp used a single stage 40μ filter; Texaco at Bayou Sale and Texaco at Lake Salvador used a two-stage filtration system with 25μ filters followed by 10μ filters. It should be noted that each of these facilities used gas blanket systems to prevent air from coming into contact with the produced water. When the samples were collected, the samples developed an increase in turbidity after contact with air. This turbidity increase was the result of the precipitation of scale particles such as calcium carbonate that formed when the samples came in contact with air. This resulted in an increase in TSS. Therefore, the observed TSS concentrations in Table VIII-8 may not be representative of the actual concentrations as they existed in the closed systems.

Oil and grease reduction averaged 28% across the filters from these three sites. However, one site realized an 8% increase in oil and grease concentrations. Of these three sites, only one site employed chemical addition during water separation and this was a surfactant. Oil and grease reduction across this filter averaged 30%, however, oil and grease effluent concentrations averaged 78.5 mg/l (the highest average oil and grease level of all 3 sites).[43]

A review of other pollutant reductions across the filters for these three sites does not show notable reductions. Other parameters including TOC, total phenols, aluminum, lead, benzene, and toluene showed increases of 1 to 5%.

A preliminary estimate of oil and grease effluent limitations using these data resulted in a daily maximum of 65 mg/l and a monthly average of 40 mg/l.[43] The long term average was estimated to be 24 mg/l. As a result of this information, EPA does not consider cartridge filtration as a candidate technology for BAT or NSPS because not only do pollutant concentrations sometimes increase, but for the pollutants that are removed, the removal is not as effective as improved gas flotation.

5.2.3.2 Granular Filtration

Granular media filtration involves the passage of water through a bed of filter media to remove solids. The filter media can be single, dual, or multi-media beds. When the ability of the bed to remove suspended solids becomes impaired, cleaning through backwashing is necessary to restore operating head

TABLE VIII-8

INFLUENT AND EFFLUENT POLLUTANT CONCENTRATION MEANS FROM CARTRIDGE FILTRATION[6]

Pollutant	Influent Mean ($\mu g/l$)	Effluent Mean ($\mu g/l$)	Pollutant	Influent Mean ($\mu g/l$)	Effluent Mean ($\mu g/l$)
CONVENTIONAL AND NON-CONVENTIONAL POLLUTANTS			**PRIORITY POLLUTANT VOLATILE ORGANICS**		
Total Recoverable Oil and Grease	49,904	31,426	Benzene	6,689	6,721
Total Suspended Solids	139,917	136,792	Ethylbenzene	63	63
Ammonia as Nitrogen	75,947	73,937	Toluene	5,191	5,227
Chloride	70,753,000	71,423,083	**OTHER VOLATILE ORGANICS**		
Total Dissolved Solids	115,377,667	117,719,167	m-Xylene	193	184
Total Phenols	2,363	2,407	o+p Xylene	118	112
			2-Hexanone	55	53
			PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS		
PRIORITY POLLUTANT METALS			Naphthalene	222	215
Cadmium	61	61	Phenol	947	937
Chromium	140	135	**OTHER SEMI-VOLATILE ORGANICS**		
Copper	146	145	Benzoic Acid	7,638	7,356
Lead	430	422	Hexanoic Acid	1,762	2,064
Nickel	281	274	n-Decane	210	109
Silver	560	590	n-Dodecane	156	253
Zinc	652	395	n-Eicosane	55	50
OTHER METALS			n-Hexadecane	222	201
Aluminum	1,403	1,426	n-Octadecane	53	49
Barium	50,338	51,124	n-Tetradecane	73	73
Boron	28,059	28,751	o-Cresol	107	147
Calcium	2,411,483	2,413,592	p-Cresol	313	258
Cobalt	228	224	2Methylnaphthalene	76	73
Iron	15,935	15,994	2,4-Dimethylphenol	184	185
Magnesium	485,158	490,460			
Manganese	1,431	1,444			
Molybdenum	155	154			
Sulfur	2,150	2,195			
Tin	300	312			
Titanium	24	31			
Vanadium	324	322			
Yttrium	21	44			

and effluent quality. There are a number of variations in filter design systems. These include: (1) the direction of flow: downflow, upflow, or biflow; (2) types of filter beds: single, dual, or multi-media; (3) the driving force: gravity or pressure; and (4) the method of flow rate control: constant-rate or variable-declining-rate.[35] Figure VIII-5 shows the schematic of a multi-media granular filter.

The Offshore Guidelines three-facility study evaluated granular filtration systems designed to pretreat produced water following oil separation and prior to injection.[44] These particular operations inject produced water either because of a zero discharge permit requirement or for enhanced oil recovery. The

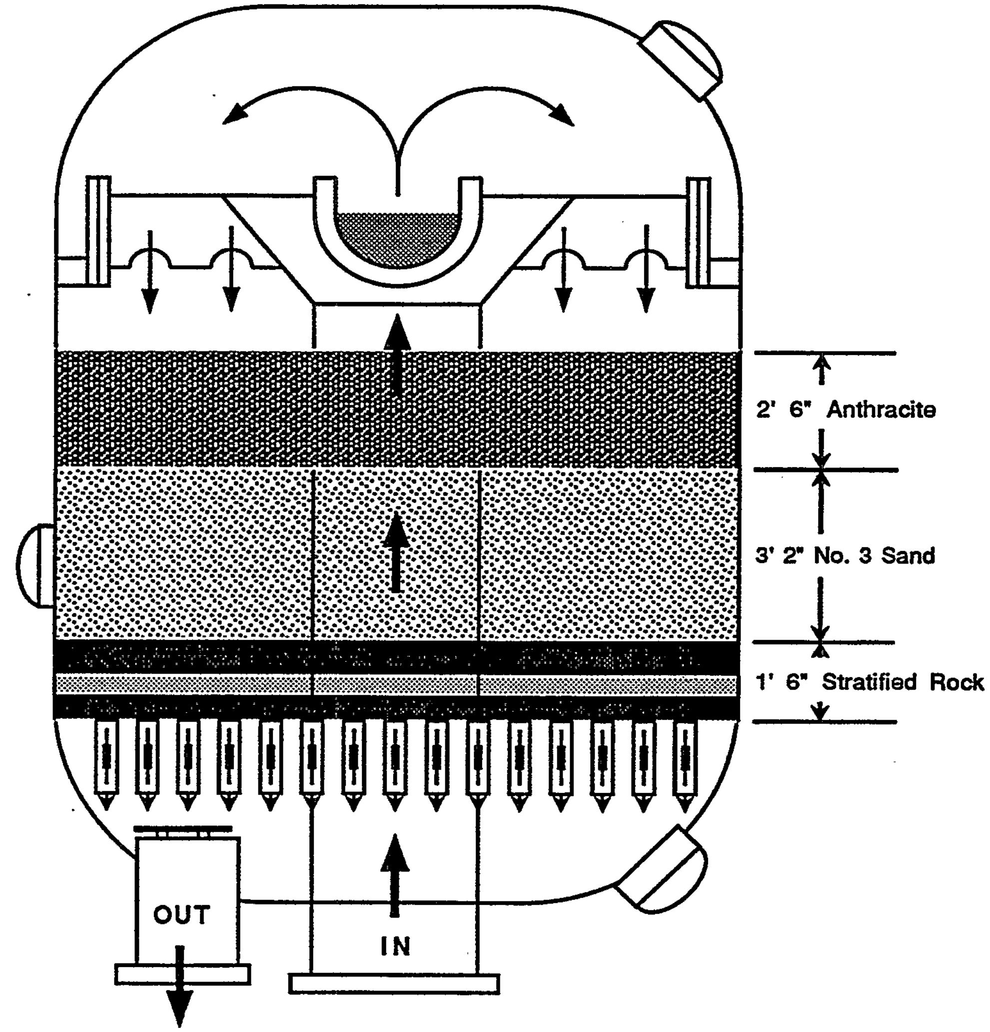


Figure VIII-5
Multi-Media Granular Filter

three facilities evaluated were: Conoco's Maljamar Oil Field near Hobbs, New Mexico; Shell Western E&P, Inc. - Beta Complex off Long Beach, California; and the Long Beach Unit -Island Grissom which is owned by the City of Long Beach, California, and operated by THUMS Long Beach Company.

EPA statistically analyzed the data from these facilities to determine effluent levels achievable from add-on granular media filtration technology. Table VIII-9 presents the performance of granular media filtration for oil and grease and TSS, based on calculated daily composites. Granular filtration has demonstrated good removals of TSS and oil and grease at the two facilities using chemical coagulants and flocculants to enhance separation, thus improving filtration performance.

TABLE VIII-9

GRANULAR MEDIA FILTRATION PERFORMANCE[44]

	TSS (mg/l)[a]	Oil and Grease (mg/l)[b]
Thums Long Beach (With Chemical Addition)		
Filter Influent	43.27	20.75
Filter Effluent	25.65	11.22
% Removal	40.7%	46%
Conoco, Hobbs (With Chemical Addition)		
Filter Influent	102.84	34.54
Filter Effluent	48.77	10.90
% Removal	53%	68%

[a] TSS concentrations represent flow weighted averages of paired samples for each day of sampling.
[b] Composite sample concentrations estimated by the arithmetic average of sample concentrations within a day.

5.2.3.3 Crossflow Membrane Filtration

Crossflow membrane filtration is an ultrafiltration process. The process operates at low pressures, less than 100 pounds per square inch (psi). The membrane pore sizes range from 0.03 to 0.8 micrometers. Crossflow filtration minimizes the accumulation of particulates on the surface of the membrane by flowing the feed stream over the surface of the membrane to sweep away part of the accumulated layer on the membrane. Figure VIII-6 presents the flow dynamics of a crossflow filter. Crossflow filtration requires recirculation of the process stream that may be several orders of magnitude greater than the rate of filtration. The advantage of crossflow filtration is that the membrane's life and periods between cleaning cycles are extended through constant membrane scouring by the particulates in the produced water.[45] In addition to the high velocities of produced water across the membrane surface to prevent membrane fouling, some systems utilize a backflow of permeate (i.e., filter effluent) through the membrane to dislodge any oil or solid particles embedded within the pores of the membrane.

Several types of crossflow membrane filters have been pilot or field tested for the treatment of produced water. The two common types of membrane materials are an inorganic ceramic material and an organic polymeric material. Membrane module designs include hollow fiber, spiral wound, and tubular. Many systems require either pre-filtration or chemical treatment to prevent rapid membrane fouling and flux degradation. For flux restoration, some systems utilize on-line membrane cleaning, such as backpulsing, while others require system shutdown and physical cleaning of the membrane. This technology was investigated during the development of the Offshore Guidelines.

One type of crossflow membrane filtration system is currently being operated on two different platforms located in the Gulf of Mexico. One is a 5,000 barrel per day full scale unit processing a partial stream (slip stream) of the produced water for waterflood injection purposes.[46] The ceramic membranes used in these filtration modules are made of porous alumina. The alumina membranes have a pore size of 0.8 micrometers. The produced water stream is chemically pretreated with ferric chloride. Through a hydrolysis reaction between the produced water and ferric chloride, a ferric hydroxide floc is formed. The ferric hydroxide floc develops a precoat layer on the surface of the membrane and serves as a "dynamic membrane." This "dynamic membrane" is unique to this system and allows water to permeate through the ceramic membrane while reducing the rate of accumulation of oil and oil wet solids on the membrane surface. A backpulse cycle serves to constantly replace the "dynamic membrane" with a fresh ferric hydroxide floc precoat. However, the "dynamic membrane" does not completely prevent the membrane from fouling. When backpulsing does not restore the permeate flux rates, shutdown of the system is necessary for chemical cleaning.[47]

In 1991, EPA conducted a week long sampling episode of the full scale unit described in the preceding paragraphs. Data obtained from this sampling effort indicate that the total oil and grease of the

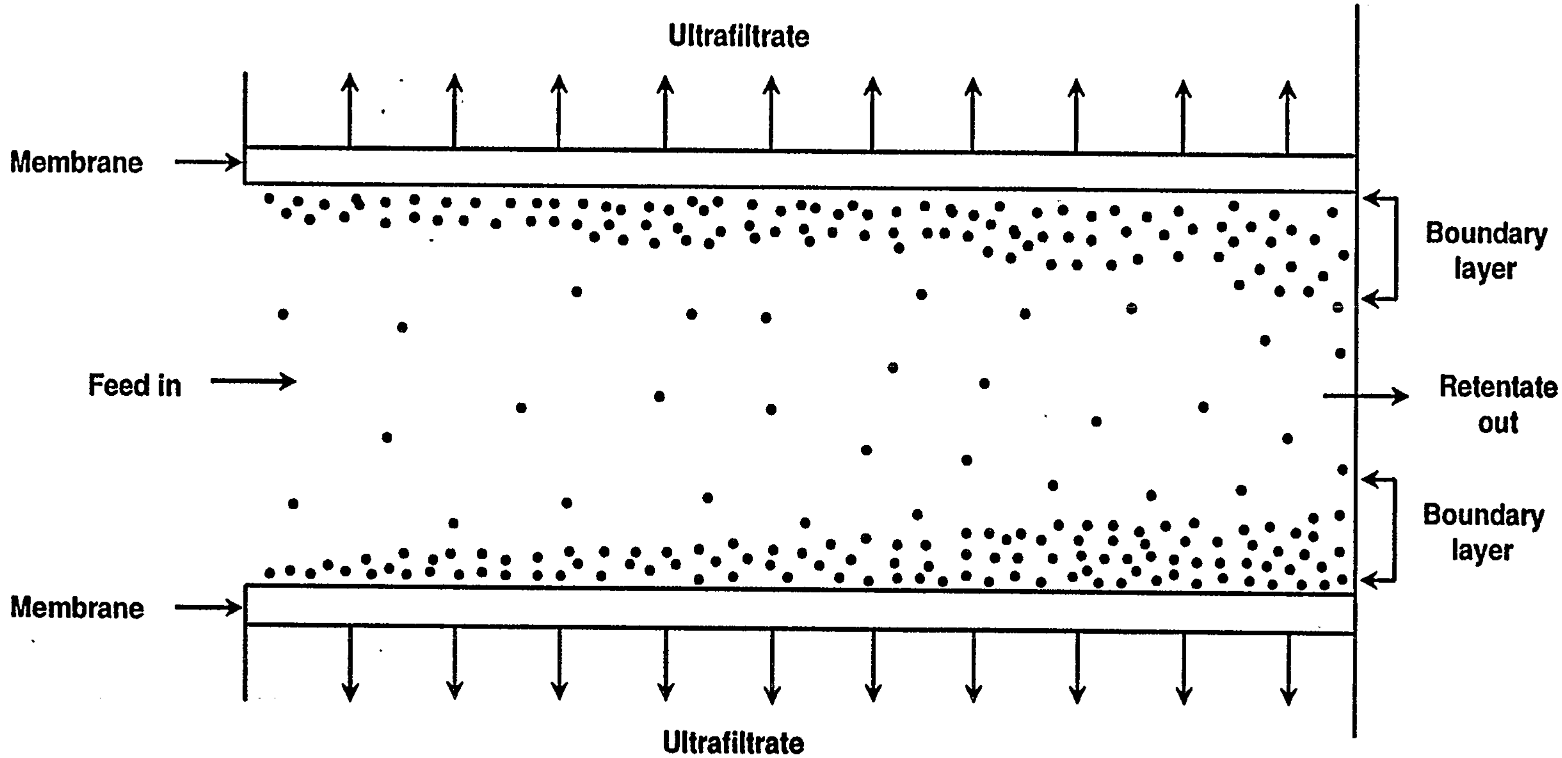


Figure VIII-6
Flow Dynamics of a Crossflow Filter

effluent can be as low as 3.5 mg/l with an influent oil and grease concentration of 22 mg/l. The sampling program also analyzed the filtration process for removal efficiencies and potential concentration of TSS, organic compounds, metals, and radionuclides. Table VIII-10 presents data obtained from the sampling program.

Despite the potential of high pollutant removal efficiencies, use of crossflow membrane filtration for the treatment of produced water has been hampered by operational problems, due to membrane fouling, experienced by several of the pilot and full scale units, including the unit studied in the 1991 EPA sampling program. The unit evaluated was being operated at 20 percent of the design capacity due to a barium sulfate scale build-up on the membrane surface.

The filtration unit was also bypassed several times during the sampling program due to upsets in the produced water treatment system. The unit was bypassed as a preventative measure to avoid sending water with a relatively high oil and solids content to the filter. The membrane pores can be easily plugged during high loadings of oil and solids. If the membrane pores become oil wet or plugged with solids, significant flux reduction results and shutdown of the filter is necessary for chemical cleaning. The operator was also experiencing problems with the waste streams generated from the filtration process. The major waste streams generated by the unit include: the oily float skimmed at the feed tank surface, the solids concentrate blowdown stream, and the spent acid and caustic used for filter cleaning. The wastes were being recycled into the produced water treatment system or neutralized and discharged overboard. The wastes being recycled into the produced water treatment system were creating upsets in the chemical equilibrium of the system. The operator indicated that a larger filtration unit would generate greater volumes of waste which would be difficult to recycle into the produced water treatment system without causing significant upsets and be costly to dispose of onshore.[48] A more detailed description of this technology can be found in the Offshore Development Document.[2]

No additional data were submitted or gathered as part of this rulemaking on the operation of crossflow membrane filtration for treatment of produced water at full scale facilities. However, EPA has maintained an interest in the potential for this technology through work by EPA's Treatment Research Division, Risk Reduction Engineering Laboratory in Cincinatti, Ohio. This work is being performed by the University of Colorado and consists of laboratory scale tests performed on oily wastewaters, including a synthetic produced water, using a novel membrane process which employs rapid backpulsing to reduce

TABLE VIII-10

MEMBRANE FILTRATION PERFORMANCE DATA FROM THE MEMBRANE FILTRATION STUDY[48]

Pollutant Parameter	Influent (μg except where noted)			Effluent (μg except where noted)		
	MIN*	MAX*	MED*	MIN*	MAX*	MED*
Oil & Grease						
Freon (mg/l)	16.33	42.67	19.67	3	7.67	4.67
Hexane (mg/l)	8.0	21.67	11.0	3.0	6.33	3.33
Total Petroleum Hydrocarbon (mg/l)	16.33	42.67	19.67	3.0	7.67	4.67
TSS (mg/l)	67.0	86.0	82.0	86.0	97	97
Priority and Non-conventional Organic Pollutants:						
Benzene	738.38	1,050.32	925.35	441.5	958.9	860.0
Benzoic acid	51	84.83	67.82	50.0	50.4	50.0
Biphenyl	10	557.41	10	10	10	10
Chlorobentene	10	16.5	11.78	10	15	10
Ethylbenzene	62.6	114.3	90.1	10	77.2	61.8
Hexanoic Acid	10	14.4	10	10	47.2	10
Methylene Chloride	10	148.3	83.2	10	138.7	10
Naphabene	10	29.6	17.8	10	21.5	13.1
o,p-Xylene	34.15	83.4	53.7	31.0	47.3	35.4
Phenol	10	53.4	10	10	66.1	10
Toluene	438.4	650.5	556.7	445.9	607.1	517.5
2-Butanone	180.4	1,206.0	282.0	182.1	2,610.2	305.8
2-Propanone	50	1,901.1	1,004.3	50	2,686.1	1,215.2
Priority and Non-conventional Metal Pollutants:						
Aluminum	875	2,270	1,660	343	1,351	1,100
Antimony	3	617	30	30	4,200	264
Arsenic	165	211	187	127	256	160
Barium	92,150	135,220	130,000	90,250	142,000	128,000
Boron	6,950	8,050	7,620	6,790	7,830	7,570
Copper	30	31	30	30	30	30
Iron	24,300	28,800	27,500	26,100	28,450	26,900
Lead	150	530	150	150	314	212
Magnesium (mg/l)	2,280	2,495	2,450	2,280	2,495	2,460
Manganese	1,440	1,965	1,960	1,910	2,325	2,265
Strontium (mg/l)	181	224	218	202	226	216.5
Titanium	9	12	9	9	17	9
Yttrium	9	14	9	9	17	9
Zinc	24	38	25	24	45	28
Radionuclides:						
Gross Beta (pCi/l)	296.0	442.5	328.0	296.0	390.5	304
Radium 226 (pCi/l)	381.0	643.0	484.0	521.0	616	583.0
Radium 228 (pCi/l)	511.8	863.6	604.3	130.4	868.3	579.7

* Pollutant Concentration "Minimum Level" Values were Substituted for Non-detect Samples

NR=Not Reported

fouling. Results of these tests were very promising with excellent removals of oil while maintaining high flux rates.[49,50]

5.2.4 Activated Carbon Adsorption

Activated carbon is a material which selectively removes organic contaminants from wastewater by adsorption. Activated carbon can be used both as an in-plant process for the recovery of organics and as an end-of-pipe treatment for the removal of dilute concentrations of organics from wastewater prior to discharge or recycle. Key design parameters for an activated carbon unit include the quantity and quality of wastewater to be treated, the required effluent quality, type and quantity of activated carbon, the empty bed contact time, and the breakthrough capacity before regeneration is necessary.

Generally, activated carbon systems are preceded by treatment systems such as chemical treatment or filtration to remove the suspended solids and any other materials which might be present in the wastewater and which interfere with the adsorption phenomenon. Presently, activated carbon is not generally used in the treatment of produced water from oil and gas wells.

EPA determined that carbon adsorption is not technologically available to implement as a basis for BAT or NSPS limitations for the treatment of produced water from coastal oil and gas production. This is because of the lack of treatability information related to the effects of treating large volumes of the brine-like nature of produced water on the adsorption process, either from literature or from pilot or full-scale studies.

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CHAPTER IX

MISCELLANEOUS WASTE—
CHARACTERIZATION, CONTROL AND TREATMENT TECHNOLOGIES

1.0 INTRODUCTION

This section describes the sources, volumes, and characteristics of miscellaneous waste streams from coastal oil and gas exploration, development, and production activities. The miscellaneous waste streams considered for regulation are:

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

This section also includes a brief description of the minor waste streams associated with coastal oil and gas drilling and production and a description of the treatment technologies currently available to reduce the quantities of pollutants associated with these wastes.

2.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

The definitions for well treatment, workover, and completion fluids (TWC fluids) are as follows:[1]

- **Well Treatment Fluids** are "any fluids used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled."

- **Workover Fluids** are "salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures."

- **Completion Fluids** are "salt solutions, weighted brines, polymers and various additives used to prevent damage to the wellbore during operations which prepare the drilled well for hydrocarbon production."

Table IX-1 lists the data used in the compliance cost analysis for TWC fluids, presented in Chapter XII. These data include the number of wells discharging TWC fluids, the average volume discharged per job, and the total annual discharge volumes. The sources and derivation of these data are described in the following section.

TABLE IX-1

DATA USED IN TWC FLUID COMPLIANCE COST ANALYSIS[a]

Fluid	Number of Discharging Wells (1992)	Average Volume Discharged per Well (bbls/job)	Total Volume Discharged per Year (bbls/yr)
Workover/Treatment	350	587	205,450
Completion	334	209	69,806
TOTAL	**684**	---	**275,256**

[a] Values are for coastal Gulf of Mexico operations only. Since Cook Inlet operators commingle TWC fluids with produced water for treatment, compliance costs for Cook Inlet TWC fluids are included in the Cook Inlet produced water cost analysis (see Chapter XII for details regarding the cost analysis).

2.1 WELL TREATMENT, WORKOVER, AND COMPLETION FLUID VOLUMES

The volume of well treatment, workover, and completion fluids generated will vary depending on the type of well and the specific operation to be performed. Normally, workover and completion operations require at least one well volume of fluid since the fluids are contained within the well bore. For example, a 10,000 foot well with 3.5 inch diameter tubing contains a volume of less than 100 barrels.[2] The volume of workover and completion fluids will generally be the same before and after usage. More than one well volume (usually no more than three) are necessary for well treatment because the fluids may be lost to the formation. Treatment fluids can react with the formation and the volumes before and after use are not the same.

Typically, small volume discharges of fluids occur during the course of workover and completion operations in the same manner as drilling fluid discharges. Most completion and workover fluid discharges occur as small volume discharges several times during the completion or workover operations (normally lasting seven to thirty days).[3] Workover and completion fluids that return to the surface as a discrete slug represent only a small portion of the fluids discharged during workover and completion operations.[1] Discharge volumes for specific workover, completion and well treatment activities are presented in Table IX-2. This information indicates that discharges can range from 100 to 1,000 barrels.[4]

TABLE IX-2

TYPICAL VOLUMES FROM WELL TREATMENT, WORKOVER, AND COMPLETION OPERATIONS[4]

Operation	Type of Material	Volume Discharges (barrels)
Completion and Workover	Packer Fluids	100 to 1000
	Formation Sand	1 to 50
	Metal Cuttings	<1
	Completion/Workover Fluids	100 to 1000
	Filtration Solids	10 to 50
	Excess Cement	<10
Well Treatment	Neutralized spent Acids	10 to 500
	Completion/Workover Fluids	10 to 200

A statistical analysis of the results of the 1993 Coastal Oil and Gas Questionnaire shows that in 1992, workover, treatment, and completion operations in the coastal Gulf of Mexico region discharged an average of 587 barrels of waste workover/treatment fluids and 209 barrels of waste completion fluids.[5] Workover and treatment fluids are presented in this document together because they are both used during production. Completion fluids are generated separately during completion just prior to production. For the purpose of developing compliance cost estimates, these volumes (presented in the survey as volume per year) are assumed to be average discharges per job because the survey results also indicate a workover/treatment fluid discharge frequency of between 0.78 and 1.87 times per year.[5] The numbers of wells discharging TWC fluids were derived from survey results and state Discharge Monitoring Report (DMR) data. The survey results indicate that in 1992, 219 wells discharged workover/treatment fluids and 209 wells discharged completion fluids.[5] A comparison of the number of wells in the survey to the number of wells for which DMR data are available revealed that the survey count of wells must be increased by a factor of 1.6 for an accurate count of existing wells.[6] Thus, the estimates of 219 wells discharging workover/treatment fluids and 209 wells discharging completion fluids were increased to 350 and 334, respectively. These well counts were then used to estimate the total annual volume of TWC fluids currently discharged: 205,450 barrels of workover/treatment fluid and 69,806 barrels of completion fluid, for a total of 275,256 barrels of TWC fluids discharged per year in the Gulf of Mexico.

Volumes of fluids used for workover, completion, and well treatment operations were collected for a Cook Inlet Discharge Monitoring Study. Table IX-3 presents the volumes discharged during specific operations. Volume information was collected for a one year period. Ten discharge events were sampled during the course of the year. Each of the discharge events was from a single operation (either well treatment, workover, or completion) but discharges of the fluids may have occurred at several times during the course of the operations.[7] Average discharge of TWC fluids ranged from 80 to 647 barrels per job.

TABLE IX-3

VOLUMES DISCHARGED PER JOB DURING WORKOVER, COMPLETION, AND WELL TREATMENT OPERATIONS FROM THE COOK INLET DISCHARGE MONITORING STUDY[7]

Type of Job	Workover	Completion	Well Treatment	Acid	Clean Out Tubing
Volumes Discharged (barrels)	600 600 400 100 1,111 492 1,200 670	390 75 310 303 50 50 25 75 25 1,295 740 50	178.6 238.1 35.7 71.4 20 93	10.8 320.8 25 173	12 148
Minimum	100	25	20	10.8	12
Maximum	1,200	1,295	238.1	320.8	148
Average	647	282	106	132	80

The 1993 Coastal Oil and Gas Questionnaire also provided data regarding volumes of TWC fluids discharged in Cook Inlet, Alaska.[8] Volumes of workover/treatment fluids reported in the survey as discharged ranged from 300 to 18,000 barrels per well per year. These volumes were reported by two of the 13 active platforms in Cook Inlet. The 18,000-bbl discharge volume was a total of three discharges throughout the year, so the average per-job discharge volume is 3,150 bbls of workover/treatment fluid. Discharged completion fluid volumes ranged from 360 to 2,720 barrels per well for the year, and were reported for four wells on two different platforms. The average per-job discharge volume is 2,243 bbls of completion fluids. A total annual TWC discharge volume for all platforms in Cook Inlet was calculated to be 60,496 barrels per year, based on the above per-job volumes and a seven-year schedule for drilling new wells and recompletions provided by Cook Inlet operators.[9] All discharges of TWC fluids to Cook Inlet reported in the survey were commingled with produced water for treatment prior to discharge.

2.2 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS CHARACTERISTICS

2.2.1 Well Treatment Fluids

In general, well treatment fluids are acid solutions. Acids used include: hydrochloric acid (HCl), hydrofluoric acid (HF) and acetic acid ($C_2H_4O_2$). Concentrations of HCl in water range from 15 to 28 percent. A mixture of hydrochloric and hydrofluoric acid is also used and is referred to as "mud acid."[2] Mud acid mixtures are 12 percent HCl and 3 percent HF in water. Acids are selected based on formation solubility, reaction time, and reaction products. The acid reactions are temperature dependent and temperature increases can decrease the depth of acid penetration.[10]

A well treatment job involves a series of several solutions to be pumped down hole: a pre-flush solution, the acid solution, and a post-flush or "chaser" solution. The pre-flush solution is generally 3-5 percent ammonium chloride (NH_4Cl) and forces the hydrocarbons back into the formation to prepare for stimulation. The acid solution is then pumped downhole. Following the acid solution is a post-flush of ammonium chloride that forces the acid further into the formation.[11] The solutions remain in the formation for 12 to 24 hours and are then pumped back to the surface.[2]

Common well treatment fluids include: hydrofluoric acid, hydrochloric acid, ethylene diaminetetracetic acid (EDTA), ammonium chloride, nitrogen, methanol, xylene, toluene. Well treatment fluids may include additives such as corrosion inhibitors, demulsifiers, acid neutralizers, diverters, sequestering agents, and anti-sludging agents.[4] Additives include: iron sequestering agents, corrosion inhibitors, surfactants, viscosifiers, and fluid diverters.[12] The purpose of the additives can be for: reducing the leak-off rate, increasing the propping agents carried by the fluid, reducing friction, and preventing the aggregation and deposition of solid particles.[11] A corrosion inhibitor is always used during an acid stimulation job because the acids used are extremely corrosive to the steel piping and equipment.[2,13] Table IX-4 lists some of the typical chemicals used during well treatment.

TABLE IX-4

WELL TREATMENT CHEMICALS[14]

Type of Fluid or Purpose	Constituents	Dose
Fracture or matrix acidizing agent	Acrylamide polymer	0.1 to 1.5% by weight
	Gelling agent	0.5 to 30% by weight of polymer used
	Reducing agent	200% of stoichiometric amount of gelling agent used
	Acid	10% by weight
Acid stimulation agent	Vinyl pyrolidine copolymer	1% by weight
	HCl	8% by weight
	Water	91% by weight
Acidizing fluid	Oxyalkylated acrylamidoalkane-sulfonic acid polymer	1% by weight in 15% HCl
Acid fracturing agent	Dialkyldimethyl-ammonium chloride polymers in acid solution	0.1 to 1% by weight polymer, 5 to 15% HCl solution
Self breaking acidizing emulsion	C_6-C_{18} primary amine	0.01 to 0.5% by weight
	Diethanolamide of C_8-C_{18} fatty acid	0.02 to 1.0% by weight
	Kerosene	25 to 35% by volume
	Acid solution	25 to 38% HCl solution
Acid precursor	Carbon tetrachloride	10% CCl_4
		90% water
Acidizing of siliceous strata	Ammonium fluoride	1 to 10% by weight fluoride ion concentration
Sequestering additive for iron and aluminum in acid stimulation	Levulinic acid	10 to 400 lb/1000 gallon
	Citric acid	10 to 400 lb/1000 gallon
	HCl solution	15% HCl solution
Fracturing agent	Hydroxypropyl cellulose	1%
	Poly (maleic anhydride) alkyl vinyl ether	3%
High temperature fracturing agent	Aluminum salt of phosphate ester in kerosene	1% by weight in kerosene
Acid stimulation	Acetic acid	20 to 30%
Acid fracturing	Acid in oil emulsion	10 to 28%

2.2.2 Workover and Completion Fluids

Workover and completion fluids are similar in nature and are typically a variety of clear brine. Packer fluids are workover or completion fluids which are left in the annulus between the well casing and tubing at the conclusion of the operation.[3] Specific fluids are used during completion and workover operations to seal off the producing formation to prevent fluids and solids loss to the formation. The formation is sealed by the disposition of a thin film of solids over the surface of the formation. These solids are called bridging agents.[14] The bridging agents are oil or acid soluble and dissolve at the cessation of workover or completion operations to enable oil or gas to be produced from the well.[15] Commonly used bridging agents are: ground calcium carbonate, sodium chloride, oil soluble resins, and calcium lignosulfonates.[16] The fluids are selected to be compatible with the formation to minimize damage to the formation and should perform the following functions:[4,16,17]

- Control subsurface pressures
- Maintain hole stability
- Transport solids to the surface
- Installation of packer fluids
- Keep solids in suspension
- Minimize corrosion
- Remain stable at elevated temperatures.

Workover and completion fluids can be divided into two broad classifications: water-based and oil-based fluids. There are three types of water-based fluids: brine water solutions, modified drilling fluids, and specially designed drilling fluids.

Brine fluids are comprised of inorganic salts dissolved in water. This combination yields a solids-free fluid with sufficient density to control sub-surface pressures.[16] Brine solutions have a density ranging from 8.5 pounds per gallon (ppg) for seawater to 19.2 ppg for zinc bromide/calcium bromide fluids.[17] Table IX-5 lists some of the more common brine solutions and their densities. Disadvantages of brine fluids are: expense (which can reach $800/barrel), the generation of precipitates in the formation at high pH or when contaminants are present, loss of large volumes of fluid to the formation, limited lifting capacities, poor suspension properties, and temperature sensitivity.[16]

Modified drilling fluids contain the necessary additives to achieve the basic functions of a completion or workover fluid. These fluids are economical to use since they are usually readily available. The disadvantages of modified drilling fluids is their high solids content (both compressible and incompressible solids). The high solids content can result in: hydration and/or migration of formation clays and silts, emulsion or water blocking, and permanent formation damage.

Specially designed fluids consist of inorganic brines with the addition of: polymers, acids, water, or oil-soluble materials needed to formulate a fluid with the proper viscosity, weight support, and fluid loss

TABLE IX-5
COMMON BRINE SOLUTIONS USED IN WORKOVER AND COMPLETION OPERATIONS[16]

Brine Solution	Density (lb/gallon)[a]
Potassium Chloride	9.7
Sodium Chloride	10.0
Sodium Bromide	12.5
Calcium Chloride	11.6
Calcium Bromide	11.6 to 14.2
Calcium Chloride-Calcium Bromide	11.6 to 15.1
Zinc Bromide-Calcium Bromide-Calcium Chloride	15.1 to 19.2

[a] Densities given are the maximum density except where a range is provided.

control. These fluids are used where additional clay inhibition is required. Two of the available polymers used are hydroxyethyl cellulose (HEC) and xanthan gum. Problems associated with specially designed systems include poor temperature stability, foaming, and corrosivity.[16]

There are two types of oil-based fluids: true oil fluids and invert emulsion fluids. The advantages of oil-based fluids include: temperature stability, density range, maximum inhibition, minimum filtrate invasion, and non-corrosive. Disadvantages include toxicity and the potential to damage environmentally sensitive areas, change the wettability of the formation, cause emulsion blocks, or damage dry gas sands.[16]

The drilling fluid tanks are used to mix and circulate workover and completion fluids. The fluids are circulated to remove unwanted materials and to maintain pressure.[2] Solids control must be maintained in workover and completion fluids so that the formation is not irreversibly plugged in the vicinity of the wellbore.

World Oil publishes a yearly guide of commercially available drilling, completion and workover fluids. The guide lists specific additives to the basic fluid and includes the product name, tradename, description of material, recommended uses, product function and the company from which they may be obtained. The primary functions of additives in completion and workover fluids are listed in the guide as corrosion inhibitors, viscosifiers, and filtration reducers. The corrosion inhibitors such as hydrated lime and amine salts are added to the fluid to control corrosion. The viscosifiers are added to increase the viscosity. The filtration reducers are added to reduce fluid loss to the formation and can include bentonite clays, sodium carboxymethylcellulose, and pregelatinized starch.[18] Table IX-6 identifies specific additives to completion and workover fluids.

TABLE IX-6
ADDITIVES TO COMPLETION AND WORKOVER FLUIDS[4]

Type of Additive	Specific Additives
Viscosifiers	Guar Gum Starch Xanthan Gum Hydroxyethyl Cellulose Carboxymethyl Cellulose
Fluid Loss Control	Calcium Carbonate Graded Salt Oil Soluble Resins
Corrosion Inhibitors	Amines Quaternary Ammonia Compounds

Several sources indicate that well completion and workover fluids may include hydroxyethyl cellulose, xanthan gum, hydroxypropyl guar, sodium polyacrylate, filtered seawater, calcium carbonate, calcium chloride, potassium chloride, and various corrosion inhibitors and biocides, zinc bromide, calcium bromide, calcium chloride, hydrochloric acid, and hydrofluoric acids.[12]

2.2.3 Chemical Characterization of Well Treatment, Workover, and Completion Fluids

A comprehensive source of analytical data for TWC fluids is a study of "associated wastes" conducted by the EPA Office of Solid Waste (OSW), Waste Management Division.[19,20] The term "associated wastes" is used in the OSW study to describe miscellaneous and minor wastes associated with the exploration, development, and production of oil and gas resources. This study includes data from samples of TWC fluids collected in Texas, New Mexico, and Oklahoma during sampling efforts in 1992. Table IX-7 provides the average concentrations of pollutants found in selected TWC fluid samples from the OSW study.[21] In general, the pollutant characteristics of TWC fluids vary considerably from job to job. Therefore, the data in Table IX-7 are listed as ranges as well as averages.

Table IX-7
POLLUTANT CONCENTRATIONS IN TREATMENT, WORKOVER, AND COMPLETION FLUIDS[19]

Pollutant Parameter	Pollutant Concentration (μg/l)	
	Range	Average
Conventionals		
Oil & Grease	15,000.0 - 722,000.0	231,688.00
Solids, Total Suspended	65,500.0 - 1,620,000.0	520,375.00
Priority Pollutant Organics		
Benzene	477.0 - 2,204.0	1,341.00
Ethylbenzene	154.0 - 2,144.0	1,149.00
Methyl Chloride (Chloromethane)	0.0 - 57.0	29.00
Toluene	298.0 - 1,484	891.00
Fluorene	0.0 - 123.0	62.00
Naphthalene	0.0 - 1,050.0	525.00
Phenanthrene	0.0 - 128.0	64.00
Phenol	255.0 - 271.0	263.00
Priority Pollutant Metals		
Antimony	0.0 - 148.0	29.60
Arsenic	0.0 - 693.0	166.00
Beryllium	0.0 - 25.1	8.64
Cadmium	7.6 - 82.3	26.08
Chromium	48.0 - 1,320.0	616.82
Copper	0.0 - 1,780.0	277.20
Lead	0.0 - 6,880.0	1,376.00
Nickel	0.0 - 467.0	115.52
Selenium	0.0 - 139.0	42.94
Silver	0.0 - 8.0	1.60
Thallium	0.0 - 67.3	13.46
Zinc	0.0 - 1,330	362.94
Other Non-Conventionals		
Aluminum	0.0 - 13,100.0	6,468.40
Barium	66.5 - 3,360.0	498.10
Boron	4,840.0 - 45,200.0	15,042.00
Calcium	1,070,000.0 - 28,000,000.0	10,284,000.00
Cobalt	0.0 - 40.9	8.18
Cyanide, Total	0.0 - 52.0	52.00
Iron	7,190.0 - 906,000.0	384,412.00
Manganese	187.0 - 18,800.0	5,146.00
Magnesium	10,400.0 - 13,500,000.0	5,052,280.00
Molybdenum	0.0 - 167.0	63.00
Sodium	7,170,000.0 - 45,200,000.0	18,886,000.00
Strontium	21,100.0 - 343,000.0	142,720.00
Sulfur	72,600.0 - 646,000.0	245,300.00
Tin	0.0 - 135.0	27.00
Titanium	0.0 - 283.0	74.58
Vanadium	0.0 - 4,850.0	1,156.00
Yttrium	0.0 - 131.0	41.92
Acetone	908.0 - 13,508.0	7,205.00
Methyl Ethyl Ketone (2-Butanone)	0.0 - 115.0	58.00
M-Xylene	335.0 - 3,235.0	1,785.00
O-+P-Xylene	161.0 - 1,619.0	890.00
4-Methyl-2-Pentanone	198.0 - 5,862.0	3,028.00
Dibenzofuran	136.0 - 138.0	137.00
Dibenzothiophene	0.0 - 222.0	111.00
N-Decane (N-C10)	0.0 - 550.0	275.00
N-Docosane (N-C22)	237.0 - 1,304.0	771.00
N-Dodecane (N-C12)	0.0 - 1,152.0	576.00
N-Eicosane (N-C20)	0.0 - 451.0	226.00
N-Hexacosane (N-C26)	173.0 - 789.0	481.00
N-Hexadecane (N-C16)	0.0 - 808.0	404.00
N-Octacosane (N-C28)	0.0 - 422.0	211.00
N-Octadecane (N-C18)	281.0 - 1,868.0	1,075.00
N-Tetracosane (N-C24)	312.0 - 1,289.0	801.00
N-Tetradecane (N-C14)	513.0 - 1,961.0	1,237.00
P-Cymene	0.0 - 144.0	72.00
Pentamethylbenzene	0.0 - 108.0	54.00
1-Methylfluorene	0.0 - 163.0	82.00
2-Methylnaphthalene	0.0 - 1,634.0	817.00

Samples of workover, completion and well treatment fluids were collected and analyzed for the Cook Inlet Discharge Monitoring Study conducted in 1987. The study was a cooperative effort between the U.S. EPA Region 10 and seven oil and gas companies. The specific objective of the study was to determine the type, composition and volume of discharges from workover, completion, and well treatment operations. Samples were collected of fluids during five workover operations (one using weak acid, EDTA), two completion operations, and three well treatments using acid.[7]

The samples collected during the Cook Inlet Discharge Monitoring Study were analyzed for pH, oil and grease, dissolved oxygen, BOD, COD, TOC, salinity, zinc, cadmium, chromium, copper, mercury, and lead. Table IX-8 summarizes the analytical results from the Cook Inlet Discharge Monitoring Study.

2.3 WELL TREATMENT, COMPLETION, AND WORKOVER FLUIDS CONTROL AND TREATMENT TECHNOLOGIES

2.3.1 BPT Technology

The current BPT requirement for TWC fluids is "no discharge of free oil" to receiving waters. EPA's general permit limiting the discharges from coastal oil and gas drilling operations in Texas and Louisiana further prohibits discharges of TWC fluids to freshwater areas (58 FR 49126; September 21, 1993). Methods for treatment and disposal include:

- Treatment and disposal along with the produced water
- Neutralization for pH control and discharge to surface waters
- Reuse
- Onshore disposal and/or treatment.

Treatment and disposal of well treatment, workover, and completion fluids with the produced water varies depending on how the fluids resurface, their reusability, and their volume in relation to produced waters they may be commingled with. The fluids are often commingled with the produced water, especially where the proportion of produced water to TWC fluids is high enough to overcome the interference the TWC fluids may have on the produced water treatment system. According to one industry report, TWC fluids can be effectively treated in the produced water treatment system if commingling is performed in such a manner that the treatment system is not subjected to large concentrated slugs of TWC fluids.[11] Operators in Alaska also treat and dispose of these fluids with their produced water.[8,22,23] In California, facilities commingle the workover, completion and well treatment fluids with the produced water and dispose of the wastes in injection wells.[2]

TABLE IX-8

ANALYTICAL RESULTS FROM THE COOK INLET DISCHARGE MONITORING STUDY[7]

	Lab pH	Field pH	O&G	Field D.O.	BOD	COD	TOC	Salinity	Zn	Cd	Cr	Cu	Hg	Pb
Units	SU*	SU*	mg/l	ppm	mg/l	mg/l	mg/l	ppt	mg/l	mg/l	mg/l	mg/l	mg/l	mg/l
Workover Fluids	6.3	6.5	36	1	690	1,170	306	16.7	NA	NA	NA	NA	NA	NA
	4.1	4.1	. 74	0.2	460	1,820	1,700	16.2	NA	NA	NA	NA	NA	NA
	NA	NA	47	NA	NA	NA	NA	NA	2.2	0.21	3.3	1.3	0.0019	0.3
	7.9	7.2	21	0.4	660	1,130	249	22.78	0.13	ND*	0.12	ND*	ND**	ND*
	6.6	6.9	21	0.3	680	1,270	321	21	0.16	ND*	ND*	ND*	ND**	ND*
	6.7	7.1	0.34	2.6	3.4	236	23	17.65	NA	NA	NA	NA	NA	NA
	7.2	7	9.4	0.4	400	>1,500	203	27.81	NA	NA	NA	NA	NA	NA
	6.7	6.9	21	2.8	51	408	61	24.16	NA	NA	NA	NA	NA	NA
	NA	1.4	66	NA	NA	NA	NA	NA	0.68	0.142	ND*	2.8	0.00044	0.35
	7.5	7.6	12	0.1	660	1010	289	30.63	0.015	ND***	ND*	ND*	ND**	ND*
	7.5	7.5	14	0.2	630	965	294	30.63	0.01	ND***	ND*	ND*	ND**	ND*
	7.4	7.4	16	0.2	720	1,410	302	29	0.036	ND***	ND*	ND*	ND**	ND*
	NA	1.6	23	NA	NA	NA	NA	NA	0.175	0.0063	0.04	0.18	0.00074	0.05
	6.8	7.2	13	0.2	600	1,080	350	27.36	0.017	ND***	ND*	ND*	ND**	ND*
	6.7	7.3	11	0.1	600	1,035	304	25.72	0.02	ND***	ND*	ND*	ND**	ND*
	6.7	7.3	8.1	0.1	560	1080	307	25.72	0.012	ND***	ND*	ND*	ND**	ND*
	7.2	7.2	5.6	0.4	570	1,230	115	30.01	NA	NA	NA	NA	NA	NA
	7.2	7	2.2	0.1	865	980	70	29.51	NA	NA	NA	NA	NA	NA
	7	7.1	1.9	0.5	645	1,000	119	29.18	NA	NA	NA	NA	NA	NA
Completion Fluids	7.1	7.1	6.1	4.7	108	590	90	25.76	NA	NA	NA	NA	NA	NA
	8.6	8.5	0.23	6.2	6	865	4	2.14	NA	NA	NA	NA	NA	NA

*pH reported in standard units
NA = Not analyzed
ND* = Not detected (detection limit at 0.01)
ND** = Not detected (detection limit at 0.0002)
ND*** = Not detected (detection limit at 0.002)

TWC fluids may be treated separately from the production fluid stream if they resurface as a discrete slug. It is especially advantageous to separately collect them if they are heavily weighted and can be reused. Workover and completion fluids can be reused 2 to 3 times depending on the amount of oil and grease build-up. Inexpensive workover and completion fluids consisting primarily of filtered seawater are typically not reused. However, treatment fluids are not reused because they react with the formation and lose their treatment ability.[2]

2.3.2 Additional Technologies Considered

Additional controls considered for this rulemaking are limitations on oil and grease or zero discharge. The technology basis for these other controls on TWC fluids is commingling and treating with produced water or sending the fluids separately to commercial disposal facilities. A detailed discussion of produced water treatment technology is presented in Chapter VIII.

A new technology tested for the treatment of TWC fluids is a granular filtration media formulated to absorb crude oil contamination from wastewater streams at pH levels less than one.[24] After phase separation, the hydrocarbon contaminated fluids are pumped through a vessel loaded with the formulated media to remove hydrocarbons and additives detected as oil and grease. The cost of the treatment is $30.00 per barrel of fluids based on an average volume of 587 bbl per well treatment (acid) job. Vendor data indicate that for a given acid job, the oil and grease removal efficiencies range from 98.25% to 98.97%.[24]

3.0 DECK DRAINAGE

For coastal operations in the Gulf of Mexico, EPA investigated the deck drainage generated from drilling operations and production operations separately. Generally, deck drainage generated during drilling may vary in volume, characteristics, and its method of collection from that generated during production. Deck drainage from production operations occurs over a long period of time while drilling operations occur only for a relatively short and finite period of time. However, this distinction can not be made in Cook Inlet, since both drilling and production operations occur simultaneously on the same platform.

3.1 Deck Drainage Sources

Deck drainage includes wastes resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas. Within the definition of deck drainage for the coastal guidelines, the term rainwater for those facilities located on land is limited to that precipitation runoff that reasonably has the potential to come into contact with process wastewaters. Runoff not included in the deck drainage definition is subject to control as storm water under 40 CFR 122.26. For structures located over water, all runoff is included in the deck drainage definition.

The final rule clarifies the definition of deck drainage to limit its applicability to precipitation runoff to that runoff which reasonably has the potential to come into contact with process wastewaters associated with production, field exploration, drilling, well completion, well treatment, or well workover operations. This clarification to the definition will allow that precipitation runoff which does not come into contact with process wastewaters to more appropriately be regulated under the provisions for storm water at 40 CFR 122.26. Coastal subcategory structures located on land have greater areal extent than structures located over water and generally are able to segregate and separately discharge runoff within a facility which has not become contaminated with (or have a reasonable potential to come into contact with) process wastewaters and spillage from process equipment. This physical segregation is generally accomplished through the use of devices such as berms, curbs, and gutters. Another means for accomplishing this segregation includes enclosing process operations in structures which allow the uncontaminated runoff to be channelled away from process wastewaters to prevent possibility of contact. On Alaska's North Slope, the harsh climatelogical conditions have led operators to enclose most process equipment (e.g., production and injection wellheads, separation equipment, and wastewater treatment systems) in buildings. In this instance, all wastes from washings and spillage within the building would be included within the definition of deck drainage. Runoff outside the buildings, if not contaminated with process wastewaters, would be excluded from the deck drainage definition and would instead be subject to control as storm water under 40 CFR 122.26. For structures located over water, due to the nature of these structures, all runoff is considered to be contaminated and therefore included in the deck drainage definition.

3.2 Deck Drainage Volumes

3.2.1 Total Volumes

Table IX-9 presents the overall total volume of deck drainage disposed by both drilling and production operations in the Gulf of Mexico and Cook Inlet.

TABLE IX-9

ANNUAL VOLUME OF DECK DRAINAGE DISPOSED

Region	Drilling Operations (bpy)	Production Operations (bpy)	Total (bpy)
Gulf of Mexico	937,286	9,932,332	10,869,618
Cook Inlet	628,475		628,475
Total			**11,498,093**

3.2.2 Gulf of Mexico-Production Operations

The predominant source of deck drainage at production facilities in the Gulf coastal region is from rain falling within bermed and diked areas. During the 1992 EPA 10 Production Facility Sampling Programs, it was observed that deck drainage collection systems can cover areas ranging from several hundred square feet for small satellite tank batteries to much larger areas covering tens of thousands of square feet. The New Orleans area receives an average annual rainfall of 53.7 inches of rain compared to 14.7 inches in Anchorage, Alaska.[25] The statistical analysis of the 1993 Coastal Oil and Gas Questionnaire data estimated that the average volume of deck drainage from production facilities is 11,644 bpy.[5] By multiplying this value with the estimated 853 total number of production facilities,[6] the result is an estimated total annual deck drainage volume of 9,932,332 bbls for all production facilities in the Gulf coastal region. Using the average deck drainage volume of 11,644 bpy and the rainfall reported for the New Orleans area in 1992 of 60 inches[26] the area covered by the average production facility is estimated to be 9,806 square feet.

EPA estimates that 7,995,527 bbls (80.5%) of the total estimated volume generated by production operations is being discharged to surface waters. Although no one reported that they injected deck drainage in Question A42b of the Coastal Oil and Gas Questionnaire, the summary statistics indicate that, based on the response to Questions A39b, 19.5% of the facilities that reported deck drainage data do not discharge produced water and at the same time commingle deck drainage along with the produced water for disposal.

3.2.3 Gulf of Mexico-Drilling Operations

Because of the significant differences in the deck drainage collection area covered and the deck drainage handling equipment, EPA investigated deck drainage from land-based and water-based drilling operations as separate sources. The two data sources that were investigated to obtain estimates of the average volumes of deck drainage generated for disposal from land-based and water-based drilling operations were the 1993 Coastal Oil and Gas Questionnaire data and the three coastal drilling site visits conducted by EPA in 1992. After a review of the Coastal Oil and Gas Questionnaire and the trip reports, it was determined that a different method for estimating deck drainage volumes would be necessary for land-based versus water-based operations. These methods are discussed below.

3.2.3.1 Total Deck Drainage Volumes

Table IX-10 presents the per well and overall total volumes of deck drainage generated by water-based drilling operations in the Gulf of Mexico region. Tables IX-11 and IX-12 present the per well and overall total volumes of deck drainage generated by drilling operations in the Gulf of Mexico region based on the data and assumptions presented below.

3.2.3.2 Estimation of the Proportion of Land-based Versus Water-based Drilling Operations

It is important to distinguish between land- and water-based drilling operations because land-based systems cover a larger area. Such systems utilize ring levees which tend to collect more rainwater. Answers to three questions in the 1993 Coastal Oil and Gas Questionnaire were used to estimate the proportions of land- and water-based drilling rigs. One is the reported type of drilling rig used for the injection wells in Question A18. Although these are injection wells and not production wells, it is reasonable to assume that the location of injection wells is likely to be proportionately the same as most of the production wells at a typical injection facility. The second and third sources come from two questions in Table B-7 requesting information on the number of wells that reported using either trucks or barges for hauling drilling waste. Question B27 requests the transport capacity, and Question B28 requests the number of vessels. In both cases, only barge and truck responses were counted since tugs are used to move the barges. Table IX-13 shows the number of facilities or drilled wells in the survey that indicated truck- or barge-based operations in each of these questions. The percentages of land-based versus water-based responses for all three sources were then averaged together to estimate the overall proportion of each type of well in the region.

TABLE IX-10

ANNUAL DECK DRAINAGE VOLUMES CURRENTLY DISCHARGED FROM WATER-BASED DRILLING OPERATIONS IN THE COASTAL GULF OF MEXICO REGION

Type of Well	Total Number of Wells[a]	Volume Discharged per Well (bbl)[b]	Total Volume Discharged (bbl)
New and Exploratory	152.2	516	78,535
Recompletions and Sidetracks	182.4	567	103,421
Total	334.6	--	181,956

[a] See Section 3.2.3.3

[b] See Section 3.2.3.4

TABLE IX-11
LAND-BASED DRILLING OPERATIONS DECK DRAINAGE PER WELL VOLUMES

Type of Well	Drilling Days	Volume Generated (bbl)	Volume Disposed (bbl)	Volume Reused (bbl)
New and Exploratory[a]	30	7,876	5,901	1,975
Recompletion and Sidetracks[b]	15	3,938	2,766	1,172

[a] See Section 3.2.3.5

[b] See Section 3.2.3.6

TABLE IX-12
LAND-BASED DRILLING OPERATIONS
DECK DRAINAGE TOTAL VOLUMES ALL WELLS

Type of Well	Total Number of Wells[a]	Volume Generated[b] (bbl)	Volume Disposed[b] (bbl)	Volume Reused[b] (bbl)
New and Exploratory	79.8	628,505	470,900	157,605
Recompletion and Sidetracks	95.6	376,473	264,430	112,043
Total	**175.4**	**1,004,978**	**755,330**	**269,648**

[a] See Section 3.2.3.3

[b] (Number of Wells) x (Per Well Volumes in Table IX-11)

TABLE IX-13
PROPORTION OF LAND-BASED VERSUS BARGE-BASED OPERATIONS REPORTED IN THE COASTAL SURVEY

Type of Response	Number of Responses to Question A18[a]	% of Total	Number of Responses to Question B27[b]	% of Total	Number of Responses to Question B28[c]	% of Total	Average %
Truck	26	37.7%	9	34.6%	8	30.8%	34.4%
Barge	43	62.3%	17	65.4%	18	69.2%	65.6%
Total	**69**	**100%**	**26**	**100%**	**26**	**100%**	**100%**

a Question A18: What was the rig configuration for your injection well? Land-based, barge-based, or other?
b Question B27: What was the chosen mode of transporting drilling waste and its capacity? Barge, truck, tug, or other?
c Question B28: How many vessels or vehicles were required to dispose of drilling waste?

3.2.3.3 Numbers of Wells

Using the information reported in Question B2 in the Coastal Oil and Gas Questionnaire, the well-type data were divided into six categories; "exploratory," "new production," "new and exploratory," "recompletion," "sidetrack of existing well," and "other and service". The estimated total wells for the Gulf of Mexico coastal area that belong in each of these categories are provided in Table IX-14. Since the sample size was small for "exploratory" and "sidetrack of existing well" (only four for each), these two categories were combined with "new production" and "recompletion," respectively. In addition, the "other and service" wells were predominantly "rig workovers" and some "through-tubing plug backs". Since "other and service" wells mostly were not drilling operations, they are not included in this analysis. These numbers are used to calculate estimated annual deck drainage volumes for each type of drilling operation. Table IX-15 presents the estimated number of wells in these categories that are land-based and barge-based using the percentage split described in Table IX-13. For the purposes of estimating the olumes of deck drainage generated, EPA assumed that new production and exploratory wells are similar in nature and thus are grouped together. EPA also assumed the same is true for recompletions and sidetracks of existing wells.

3.2.3.4 Volumes Generated Per Well

The data in Table IX-13 show that, based on a review of the Coastal Oil and Gas Questionnaire, the majority of the responses were from water-based operations. The one water-based drilling operation

TABLE IX-14
ESTIMATED NUMBER OF WELLS
DRILLED IN 1992 IN COASTAL GULF OF MEXICO AND
DURATION OF DRILLING[5]

Type	Number	Days To Drill
Exploratory	45	9.8
New production	187	21.4
New and Exploratory	232	19.3
Recompletion	241	8.5
Sidetrack of existing	37	10.6
Recompletion and Sidetrack	278	-
Other and service	177	19[a]

[a] Only one well reported days drilling because most of these wells were "rig workovers" and thus were not drilled.

TABLE IX-15

NUMBER OF WELLS BY LOCATION AND WELL TYPE CATEGORIES

Access	Well Type	Total Wells Each Type	Land vs. Water Proportions	Number of Wells
Land	New & Exploratory	232	34.4%	79.8
Land	Recompletion & Sidetracks	278	34.4%	95.6
Water	New & Exploratory	232	65.6%	152.2
Water	Recompletion & Sidetracks	278	65.6%	182.4

visited by EPA was an unusually deep well and did not report the deck drainage volume because it was combined with and included in the total volume reported for waste drilling fluid and wash water.[27] Therefore, the average volume surface discharged from water-based drilling operations for exploratory and new production wells, which is 516, was selected for use in this analysis based on responses to the Coastal Oil and Gas Questionnaire database.

A review of a printout of the Coastal Oil and Gas Questionnaire database shows that the majority of the deck drainage reported in Table B-9 was from water-based drilling operations.[8] The average volume of deck drainage discharged to surface waters from water-based operations, including all exploratory and new production wells except the one land-based well, was 516 bbls per drilling job. The volumes ranged from 60 bbls to 2,318 bbls. In general, the higher volumes were for deeper wells which take longer to drill and therefore generate more deck drainage.

For water-based recompletions and sidetracks of existing wells, the estimated average deck drainage volumes discharged for these categories are 824 bbls and 310 bbls respectively.[5] These volumes were averaged together to get the volume of 567 bbls discharged because of the low number of survey responses for each category; two and three, respectively. The values reported in the questionnaire database are the volumes disposed and thus already take into account any reduction in volume due to reuse of deck drainage as mud make-up water. This may explain why the recompletion volume is greater even though the drilling time is lower for recompletions.

A review of the site visit data in Table IX-16 shows that both of the land-based drilling operations were deeper wells and longer in duration than the estimated average well in the Coastal Oil and Gas Questionnaire.[5] In the survey, the estimated average well depth was 8,429 ft for exploratory wells and 8,487 ft for new production wells, and the estimated average drilling duration was 10 days and 21 days, respectively. Because the site visit data appear to represent greater than average values, a methodology was developed for estimating the average volume of deck drainage generated by land-based drilling operations rather than use the site visit data directly. The methodology utilized the drill site dimensions, annual rainfall data, estimated mud make-up water volume and average drilling operation duration. Based on this methodology, EPA estimates that land-based drilling operations dispose of 5,901 bbls of deck drainage per well.[28] The assumptions used are described below.

3.2.3.5 Assumptions for New and Exploratory Wells

- Deck drainage and area runoff are collected in the cellar and ring levee ditch.
- The drilling pad area will be 350 ft x 350 ft with a total surface area of 122,500 sq ft. These were the dimensions of the ARCO drilling operation in the Sabine Wildlife Refuge and represent the minimum area requirements.[29]

TABLE IX-16

SUMMARY OF DECK DRAINAGE INFORMATION FROM THE THREE COASTAL DRILLING SAMPLING SITE VISITS IN LOUISIANA[27,29,31]

Operator/ Type of Operation	Waste Type	Mud Type/ Drilling Interval	Treatment and Disposal	Surface Area (sq ft)	Volume Generated (bbls)	Days of Drilling
UNOCAL/ Posted Barge	Deck Drainage	Water base/ 0-13,555 ft	Drains to shale barge	7,236	Commingled with water based mud. Total mud + water = 2,515 bbls	57
		Oil base/ 13,555- 19260 ft	Drains to shale barge then annularly injected	7,236	4,199 bbls of wash water was injected	123
	Rainwater	Both intervals	Drains to a sump	7,236	Not reported	180
ARCO/ Land Rig	Deck Drainage and Rainwater	Water base/ 0-TD(14,928 ft)	Contained in levee and trucked to commercial facility	122,500 sq ft	12,440	63
GAP Energy/ Land Rig	Deck Drainage and Rainwater	Water base/ 0-TD(12,860 ft)	Contained in levee and trucked to commercial facility; 8000 bbls were surface discharged during heavy rain	164,025 sq ft	7,060 (commercial) 8,000 (surface)	96

- Drilling time will be 30 days. The estimated average drilling time from the Coastal Oil and Gas Questionnaire was approximately 20 days (see Table IX-14), however this did not include time to test the well and to plug and abandon or complete the well. The additional 10 days accounts for these activities.

- The amount of rainfall is based on the average 30-day rainfall for New Orleans Louisiana using the 1993 annual rainfall amount of 52.7 inches.[30] The 30-day average rainfall total is 4.33 inches.

- Rainwater will be used as make up-water for drilling fluids.[31] The amount used will be equal to the volume of waste mud generated minus the solids content of the mud. The estimated average volume of mud disposed as reported in the Statistical Analysis of the Coastal Oil and Gas Questionnaire was 3,038.5 bbls.[5] The drilling fluid solids content ranged from below 10% to around 35% by volume at the three sampled drilling operations.[27,29,31] A solids content of 35% will be used as a conservative estimate since it will result in a lower volume of deck drainage that is recycled. This results in a deck drainage reuse volume of 1,975 bbls.

3.2.3.6 Assumptions For Recompletion and Sidetrack of Existing Land-based Well

- Table IX-14 shows that for recompletions and sidetracks, the average days to drill were 8.5 and 10.5 or roughly one half the time to drill a new well. Therefore, the amount of rainwater generated is assumed to be one-half that of newly drilled wells (i.e., one-half the average 30-day rainfall; 15 days duration). Although recompletions may use smaller equipment and smaller pads, there is not sufficient information available to estimate the size of the reduction in volume. The 15-day average rainfall total is 2.16 inches and is based on the New Orleans annual 1993 rainfall data.[30]

- Rainwater will be used as make-up water for drilling fluids.[31] The amount used will be equal to the volume of waste mud generated minus the solids content of the mud. The estimated average volume of mud disposed as reported in the Statistical Analysis of the Coastal Oil and Gas Questionnaire was 1,803 bbls (Note that this volume is close to half the volume reported for newly drilled wells).[5] The drilling fluid solids content ranged from the low 20's to around 35% by volume at the three sampled drilling operations. A solids content of 35% will be used as a conservative estimate. This results in a deck drainage reuse volume of 1,172 bbls.

3.2.4 Cook Inlet Alaska

Table IX-17 presents the Cook Inlet deck drainage volumes obtained from the Coastal Oil and Gas Questionnaire and an EPA site visit. Of the 10 platforms in Cook Inlet that transfer produced fluids to shore for separation, only four treat and discharge their deck drainage at the platform. The remaining six commingle deck drainage with production fluids and transfer the combined stream to shore-based facilities for separation and disposal of the deck drainage along with the produced water. At the five platforms that separate produced fluids on the platform, deck drainage is treated along with the produced water and discharged through the skim pile. The arithmetic average of four reported discharge volumes (44,891 bpy)

TABLE IX-17
ANNUAL DECK DRAINAGE VOLUMES DISPOSED IN COOK INLET, ALASKA

Facility	Platform	Deck Drainage Volume (bbl/yr)	
		Reported	Average[c]
Trading Bay	King Salmon	--	44,891
	Dolly Varden	4,000[a]	--
	Steelhead	--	44,891
	Monopod	--	44,891
	Grayling[d]	--	44,891
Granite Point	Spark	--	44,891
	Spurr	--	0
	Granite Point[d]	--	44,891
E. Foreland	SWEPI "A"[d]	65,000[a]	--
	SWEPI "C"[d]	81,000[a]	--
Dillon	Dillon[e]	--	44,891
Bruce	Bruce[e]	29,565 (max. 95,630)[b]	--
Anna	Anna[e]	--	44,891
Baker	Baker[e]	--	44,891
Tyonek "A"	Tyonek "A"[e]	--	44,891
Total			**628,475**

[a] Source: 1993 Coastal Oil and Gas Survey (Operators did not claim confidentiality of information for deck drainage data)
[b] Source: Wiedeman, May 1, 1993
[c] Average Volume = (4,000 + 65,000 + 81,000 + 29,565)/4 = 44,891 bbl/yr
[d] These platforms do not commingle deck drainage with produced fluids. Deck drainage is treated and discharged at the platforms.
[e] These platforms commingle deck drainage with produced water and discharge both at the platform after treatment.

was used by EPA in studying costs and impacts of deck drainage options. By adding the reported volumes to the calculated volumes reported in Table IX-17, the total volume disposed from Cook Inlet platforms is estimated to be 628,475 bpy.

3.3 DECK DRAINAGE CHARACTERISTICS

Oil and grease are the primary pollutants identified in the deck drainage waste stream. In addition to oil, various other chemicals used in drilling and production operations may be present in deck drainages.

EPA's analytical data for deck drainage comes from the data acquired during the Offshore Oil and Gas rulemaking effort. As part of this effort, EPA evaluated Discharge Monitoring Reports (DMRs) for deck drainage discharges from 32 oil companies located in the Gulf of Mexico.[32] The DMR data spans two years from May 1, 1981 through April 30, 1983 and consists of deck drainage monitoring data from oil and gas production facilities. The data do not indicate the location of where the samples were taken, the treatment of the waste stream prior to sampling, or the analytical method of determining oil and grease. The DMR data included oil and grease concentrations of deck drainage discharges. Table IX-18 presents the monthly averages of deck drainage oil and grease concentrations for the two years evaluated. The DMR data reports monthly samples taken by the operators. The data do not indicate the location of where the samples were taken, the treatment of the waste stream prior to sampling, or the analytical method of determining oil and grease.

Also, as part of the Offshore Oil and Gas rulemaking effort, EPA conducted a comprehensive 4-day sampling program at three oil and gas production facilities in June of 1989, to evaluate the performance of granular filtration technology and to characterize produced water and other miscellaneous discharges such as produced sand, well treatment fluids and deck drainage. EPA selected facilities for the three facility study based on: (1) their use of granular filtration, and (2) the oil and grease level being comparable to the BPT level prior to filtration. The facilities selected were from three separate oil and gas subcategories. The three facilities selected for this study were: Thums Long Beach Island Grissom (coastal subcategory), Shell Western, E & P, Inc. - Beta Complex (offshore subcategory), and Conoco's Maljamar Oil Field (onshore subcategory).[33,34,35]

Samples of treated and untreated (pre-BPT) deck drainage were collected at two of the facilities; the THUMS facility and the Shell Beta Complex. The range of pollutant concentrations in untreated deck drainage are presented in Table IX-19. As can be seen from the data in Tables IX-18 and IX-19, the pollutant concentrations can vary widely between locations and over time. In these samples, eight toxic metals were detected, most notably lead (ranging in concentration from 25 - 325 ug/l) and zinc (ranging in concentration from 2,970 - 6,980 ug/l). The presence of lead, copper and zinc may be related to the presence of these metals in standard drill pipe thread compound. Organics were also present including benzene, toluene, xylene and naphthalene. These organic pollutants are commonly found in oil.

The content and concentrations of contaminants in deck drainage can also depend on chemicals used and stored at the oil and gas facilities. An additional study on deck drainage in Cook Inlet reviewed during the development of the Offshore Guidelines showed that discharges from this wastestream may also contain paraffins, sodium hydroxide, ethylene glycol methanol and isopropanol.[36]

TABLE IX-18
CHARACTERISTICS OF DECK DRAINAGE FROM OFFSHORE GULF OF MEXICO PLATFORMS[32]

	Oil and Grease in Deck Drainage (mg/l)			
	Monthly Average		Daily Maximum	
	Range	Average	Range	Average
1981-82 (19 Sites)	5-47	22	19-72	51
1982-83 (117 Sites)	2-183	28	5-1363	75

3.4 DECK DRAINAGE CONTROL AND TREATMENT TECHNOLOGIES

3.4.1 BPT Technology

BPT limitations for deck drainage prohibit the discharge of free oil. Typical BPT technology for compliance with this limitation is a sump, skim tank or skim pile which facilitates gravity separation of any floating oil prior to discharge of the deck drainage. Deck drainage treatment systems typically use gravity to convey the flow, and the skim tanks generally do not require a constant power source for operation. Thus, deck drainage generated at facilities located in powerless remote locations (such as satellite tank batteries) can be effectively treated.

3.4.1.1 Cook Inlet

Typical platforms such as those in Cook Inlet are equipped with drip pans and gutters to collect deck drainage. The drainage flows by gravity to a sump where the water and oil are separated by a gravity separation process. Oil in the sump tank is recovered and transferred to the oil treater of the produced water treatment system. Figure IX-1 is a schematic of a generic production platform flow system. The water from the sump is discharged to the surface via a submerged outfall or a skim pile. Skim piles which are common only to relatively deep water platforms, such as in Cook Inlet, remove that portion of oil which quickly and easily separates from water (see Figure VIII-1). They are constructed of large diameter pipes containing internal baffled sections and an outlet at the bottom. During the period of no flow, oil will rise to the quiescent areas below the underside of inclined baffled plates where it coalesces. Due to the differences in specific gravity, oil floats upward through oil risers from baffle to baffle. The oil is collected at the surface and removed by a submerged pump. These pumps operate intermittently and will move the separated oil to a sump tank. Oil recovered in the sump is combined with production oil. At some

TABLE IX-19

POLLUTANT CONCENTRATIONS IN UNTREATED DECK DRAINAGE[33,34]

Pollutant	Range of Concentration[a]	Pollutant	Range of Concentration[a]
Temperature (°C)	20-32		
Conventionals (mg/l)			
pH	6.6-6.8		
BOD	<18-550		
TSS	37.2-220.4		
Oil & Grease	12-1,310		
Nonconventionals			
TOC (mg/l)	21-137		
Aluminum (μg/l)	176-23,100		
Barium	2,420-20,500		
Boron	3,110-19,300		
Calcium	98,200-341,000		
Cobalt	<20		
Iron	830-81,300		
Magnesium	50,400-219,000		
Manganese	133-919		
Molybdenum	<10-20 $151x10^4$-		
Sodium	$568x10^4$		
Tin	<30		
Titanium	4-2,030		
Vanadium	<15-92		
Yttrium	<2-17		
Priority Metals (μg/l)		**Priority Organics (μg/l)**	
Antimony	<4-<40	Acetone	ND-852
Arsenic	<2-<20	Benzene	ND-205
Beryllium	<1-1	m-Xylene	ND-47
Cadmium	<4-25	Methylene chloride	ND-874
Chromium	<10-83	N-octadecane	ND-106
Copper	14-219	Naphthalene	392-3,144
Lead	<50-352	o,p-Xylene	105-195
Mercury	<4	Toluene	ND-260
Nickel	<30-75	1,1-Dichloroethene	ND-26
Selenium	<3-47.5		
Silver	<7		
Thallium	<20		
Zinc	2,970-6,980		

[a] Ranges of four samples, two each, at two of the three facilities in the Three-Facility Study.

facilities deck drainage contaminated with oil is commingled with produced water and is treated in the produced water treatment system.

One of the platforms examined in the Cook Inlet Discharge Monitoring Study was the Phillips Petroleum Company's Platform Tyonek. On this platform all produced water and deck drainage water are

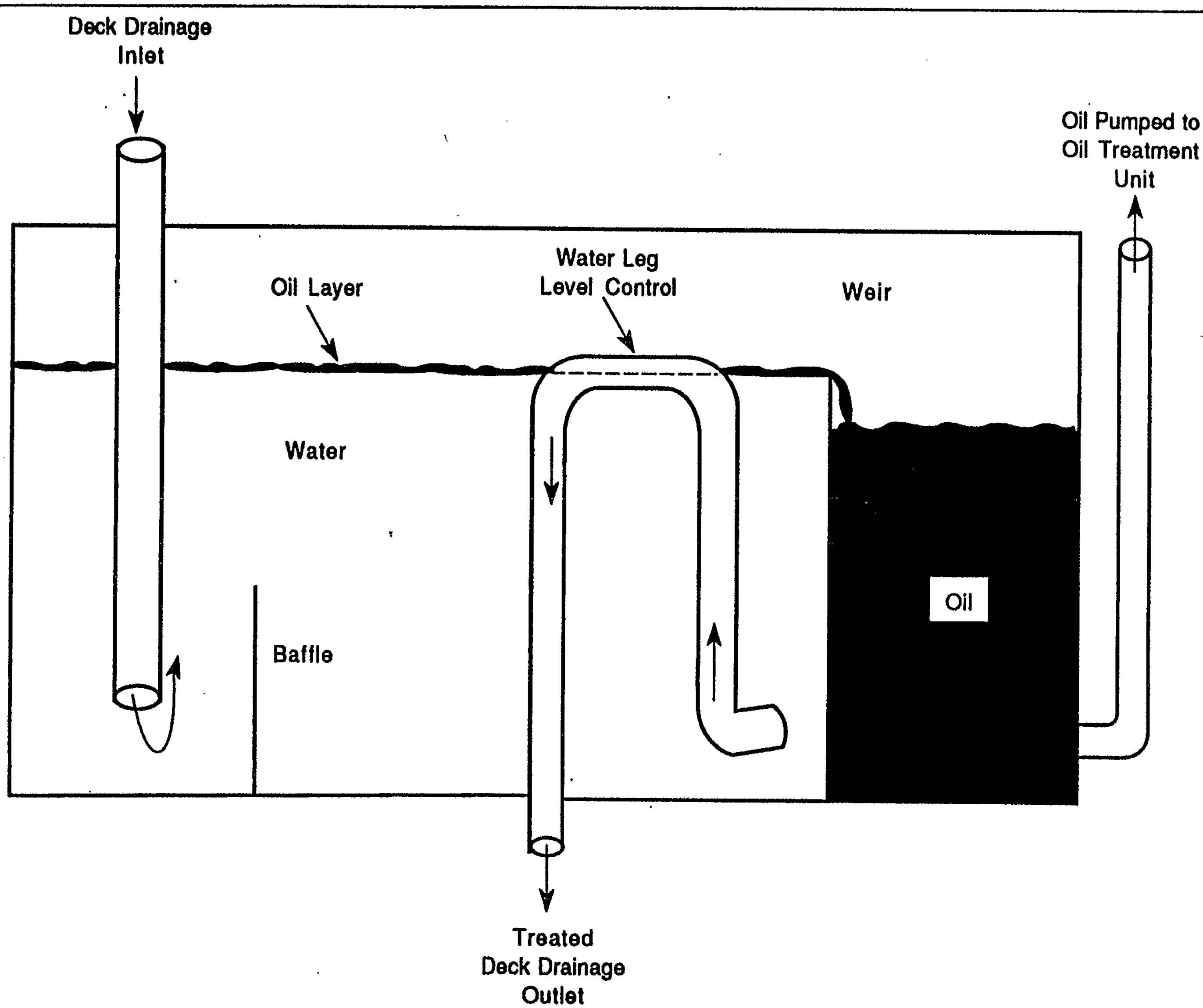

Figure IX-1
Deck Drainage Sump

commingled in a slop tank. Waters from the slop tank are pumped to the balance tank in batches. Chemicals are added and circulated to extract the hydrocarbon from the water. The mixture is retained in the tank for a period of time to allow the oil and water to separate by gravity. The water is discharged to the sea. The remaining liquid is transferred to another slop tank for holding and reprocessing. Sampling results indicated a mean average oil and grease content of 3.8 milligrams per liter.[36]

Some platforms in Cook Inlet collect crankcase oil separately and oil-based muds are diverted from the platform drain systems for onshore separation and treatment. Deck drainage is either piped to shore with the produced water waste stream and treated by gas flotation or gravity separated on the platform and treated by gas flotation to an average of 25 mg/l oil and grease.[36]

At the Bruce Platform in Cook Inlet, deck drainage from diked areas flows to a 300-bbl skim tank where oil is skimmed off and pumped to the oil processing system. The effluent from the skim tank is then commingled with produced water in two 600-bbl settling tanks. The combined effluent is discharged 10 feet below the water surface.[22]

On the jackup drilling rig, Adriatic 8, contaminated deck drainage is retained in the drilling deck area using four inch collars. The deck drainage is collected in a 20-bbl skim tank that can hold approximately one week's worth of deck drainage. The water then passes through a 7-ft high by 2-ft diameter separator and is then discharged.[22]

3.4.1.2 North Slope

Drilling and production facilities on the North Slope of Alaska are typically constructed on gravel pads to insulate the permafrost from melting and from the consequential subsidence due to oil and gas operations.[22] According to industry responses to the Coastal Oil and Gas Questionnaire, 2 percent of deck drainage or area runoff is recycled with produced water, while the remaining 98 percent is injected for disposal.[8] All facilities in the North Slope inject produced water either for enhanced oil recovery or into Class II disposal wells.[37]

An example of deck drainage waste management on the North Slope is found at the Endicott Field. The Endicott Field consists of two gravel islands constructed in the Beaufort Sea. A 40' x 40' wastewater settling tank collects miscellaneous wastes including area runoff and treatment, workover or completion fluids. After settling, the fluids are injected into a Class II disposal well located on site.[22]

3.4.1.3 *Gulf of Mexico-Production Operations*

Typical production operations in the Gulf area that use elevated platforms are equipped with drip pans and gutters to collect deck drainage and direct it to a sump where oil skimming occurs prior to discharge below the water surface. Skim piles are not used because of the generally shallow water which preclude installation of skim piles (see Chapter VIII for a discussion of skim piles). Figure IX-2 presents a schematic diagram of a sump/skim tank. In this tank, deck drainage enters near the bottom at one end and passes over a baffle into a quiescent zone where oil floats to the surface. The separated oil passes over a weir and is pumped to an oil-water treatment unit such as a gun barrel. Treated deck drainage exits the skim tank from a port near the bottom of the tank and passes through an inverted "U" shaped pipe and is discharged below the water surface. The inverted "U" shaped pipe controls the liquid depth in the tank and is referred to as the water leg. These tanks are usually installed below the deck near the water surface to take advantage of using gravity flow in the deck drainage collection system.

Operations that are located on land or fill are usually equipped with earthen or concrete beams with a depression in one area that acts as a sump to collect drainage. The collected water may be either sent to a treatment system, commingled with produced water for treatment and disposal (where feasible), or discharged without treatment. Three of the 10 coastal facilities sampled by EPA in 1992 commingled deck drainage with produced water prior to treatment and subsurface injection.[38] Three facilities used skim tanks prior to surface discharge and the remaining five discharged deck drainage without treatment, if no sheen was visible.

3.4.1.4 *Gulf of Mexico-Drilling Operations*

Deck drainage is periodically pumped from the ring levee ditch or collection sump and is disposed by one or more of the following four methods: (1) hauled offsite in vacuum trucks or barges for disposal, (2) reused as make-up water in drilling fluids, (3) subsurface injection through the annulus of the intermediate casing of the well being drilled or (4) surface discharge.

Deck drainage from the drilling deck contains a considerable amount of drilling fluid and is almost always collected, treated, and disposed in the same manner as waste drilling fluids. For many land-based drilling operations in the Gulf region, at least a portion of the deck drainage, particularly site runoff, is used as make-up water for drilling fluid. For deck drainage that is not reused in this manner and does not meet the state discharge limitations, the treatment and disposal method is either annular injection or

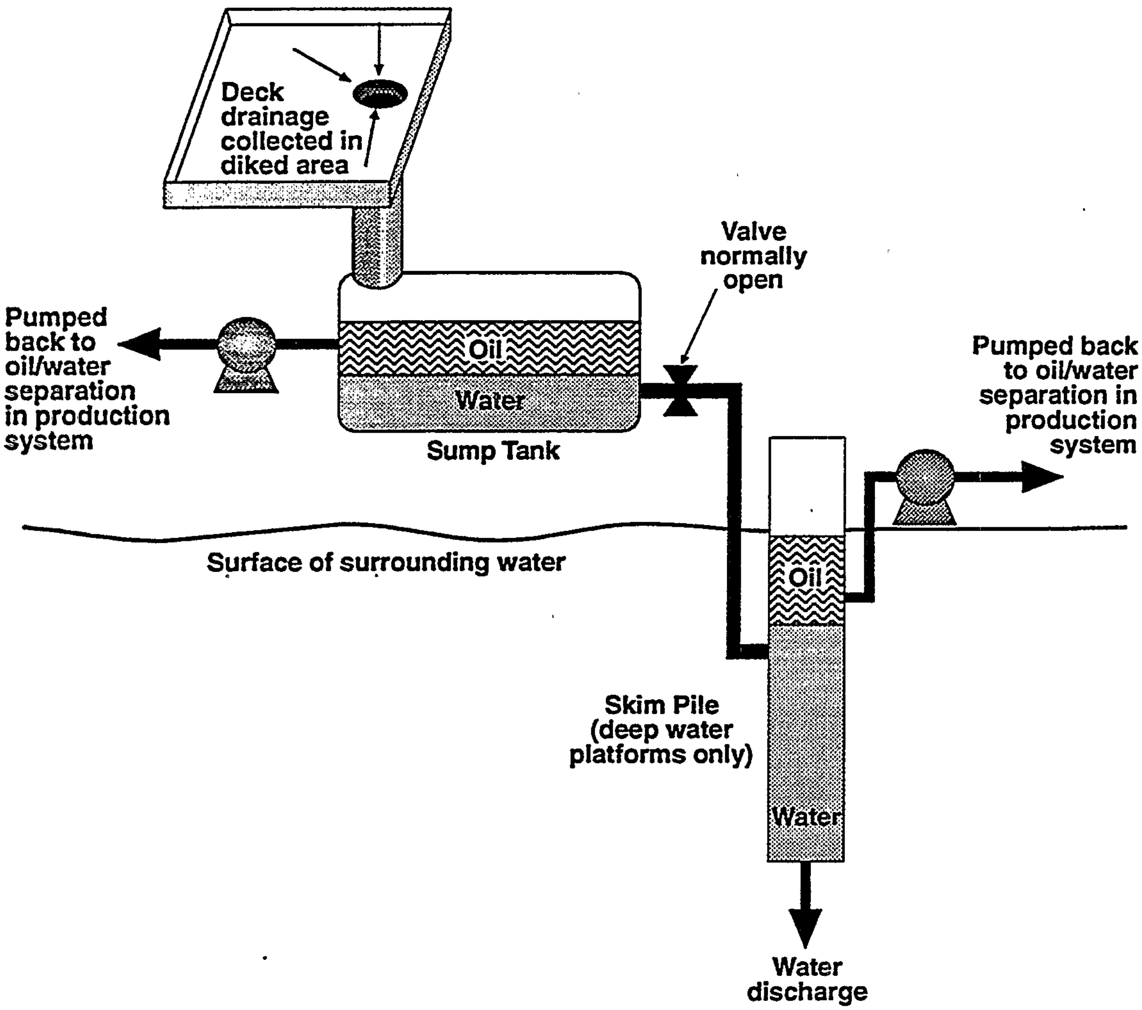

Figure IX-2
Deck Drainage Treatment System

transportation to and disposal at an offsite commercial facility. For water-based drilling operations, deck drainage is collected in a sump tank and can be combined with waste mud for offsite disposal. Although deck drainage from oil-base drilling operations can be treated using gravity separation, EPA observed that because of the relatively small deck drainage volumes contaminated with oil-based drilling fluids, the common practice is to dispose of the untreated water by injection or transport it to a commercial disposal facility.[27,29,31]

3.4.2 Additional Deck Drainage Technologies

At proposal, EPA considered BAT and NSPS limitations based on commingling deck drainage with produced water or drilling fluids and requiring best management practices. Under such requirements, deck drainage would be commingled with either produced water or drill fluids and thus become subject to the limitations imposed on these major waste streams. EPA also considered requiring best management practices (BMPs) on either a site-specific basis or as part of the Coastal Guidelines. However, as discussed below and in Chapter XVI, these additional requirements were rejected in the final rule (see Chapters IX and XIII of the Development Document for the proposed rule for additional discussions).

An example of commingling can be found on Shell Western's "SWEPI A" platform in Cook Inlet. All deck drainage is collected and drained to the production surge tank where it combines with produced fluids and is also shipped to shore. It was found, through a telephone conversation with a senior process engineer in Cook Inlet, that mixing of the deck drainage and produced water is only conducted when the deck drainage stream fails the visual sheen test, while some operators diverted deck drainage to a sump tank to be treated and discharged.[39] As noted earlier, three of the ten Gulf coastal production facilities visited by EPA in 1992 commingled deck drainage with produced water prior to treatment and disposal by subsurface injection.

Difficulties encountered in commingling the whole deck drainage waste stream with the produced waste water stream include:[12]

- The resulting flow variations could seriously upset the produced water treatment facility.
- Deck drainage water, saturated with oxygen, when combined with the salt content of the produced water could result in higher corrosion rates in the equipment. Also, the oxygen may combine with iron and sulfide in the produced water can causing the formation of solids which foul treatment equipment;

- Detergents, used for washing oil off the decks, cause emulsification of oil and seriously upset the produced water treatment processes.

While the total volume of deck drainage is less than the total volume of produced water generated annually, the deck drainage sent to the produced water treatment system could create hydraulic overloading of the equipment because of the highly variable nature of the flow rate. An add-on treatment specifically designed to capture and treat deck drainage, other than the type of sump/skim pile systems typically used, is not technologically feasible. Deck drainage discharges are not continuous discharges and they vary significantly in volume. At times of platform washdowns, the discharges are of relatively low volume and are anticipated. During rainfall events, very large volumes of deck drainage may be discharged in a very short period of time. A wastewater treatment system installed to treat only deck drainage would have to have a large treatment capacity, be idle at most times, and have rapid startup capability.

Since zero discharge for all deck drainage poses problems with storage and handling capacity during severe storm events, EPA considered the capturing of only the first 500 bbls (first flush) and commingling it with produced water for disposal at production operations and commingling it with drilling wastes for disposal at drilling operations. Rainfall in excess of the 500 bbl volume would be subject to BPT limitations. The volume of 500 bbls was selected because it is a standard storage tank volume and would capture approximately 3.5 inches of rainfall at an average production operation (see Section XIII.3.2 of the Development Document for the proposed coastal guidelines).[40] The installation of larger tanks was considered to be too costly.

The current BPT limitations allows for use of non-powered systems that utilize gravity to collect and treat deck drainage. The commingling of the first flush volume has several technical problems including:

- Above-deck storage tanks would require the installation of a sump and high capacity pumps (e.g.,two 200-gpm pumps) to handle sudden surges in flow.
- Many coastal facilities are unmanned and have no power source available to them. Generators or fuel powered pumps would be required at these locations that otherwise would not need them.
- Facilities that do not have a power source capable of driving high capacity pumps would need to use gravity to direct the first flush volume to the storage tank. This would require the installation of the tank below the deck which may not be feasible in many instances.

- Control systems that would prevent the overflow of an already full tank, during severe or back-to-back storms would be required.

- The storage tanks would require additional deck space that would add significant costs, especially for water-based facilities.

- Isolating the first flush at land-based drilling operations, that use ring levees, would be difficult because the first flush volume could become mixed with deck drainage already in the ring levee at the time of a storm event. The installation of a separate collection system, including pumps and tanks, would add significant cost.

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

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

While costs are significant, the technological difficulties involved with adequately capturing deck drainage at coastal facilities are the principal reason why additional requirements were rejected for the final rule.

The volume of contaminated deck drainage can be reduced by segregating the clean area of the site from the potentially contaminated area.[41] This involves using a segregation berm to separate the office trailer and parking/truck maneuvering areas which generate relatively little pollution from the drilling equipment, pipe racks, production and treatment areas, and waste storage areas. Such a set up which also recycled the dirty water into the mud system was reported to result in a 40% savings to location and waste management costs.[41] The storm water from the non-contaminated side of a drilling or production site would be subject to NPDES requirements for storm water and may require the operator to develop and implement a site-specific storm water pollution prevention plan consisting of a set of BMPs, depending on specific sources of pollutants at each site. A discussion of best management practices is presented in Chapter XVI of this document.

4.0 PRODUCED SAND

Produced sand consists of the accumulated formation sands and other particles (including scale) generated during production as well as the slurried particles used in hydraulic fracturing. This waste stream also includes sludges generated by chemical flocculation used in solids separation processes for produced water such as filtration or sedimentation. The following sections describe the sources, volumes, characteristics, and treatment methods for produced sand.

4.1 PRODUCED SAND SOURCES

Produced sand is generated during oil and gas production by the movement of sand particles in producing reservoirs into the wellbore, by silica material spilling off the face of the producing formation and by the precipitation of scale and other solid particles. The generation of produced sand usually occurs in reservoirs comprised of young, unconsolidated sand formations.[42] Produced sand is considered a solid and consists primarily of sand and clay with varying amounts of mineral scale (epsom salts, magnesite, gypsum, calcite, barite, and celestite) and corrosion products (ferrous carbonate and ferrous sulfide).[43]

Produced sand is carried from the reservoir to the surface by the fluids produced from the well. The well fluids stream consists of hydrocarbons (oil and/or gas), water, and sand. At the surface, the production fluids are processed to segregate the specific components. The produced sand drops out of the well fluids stream during the separation process due to the force of gravity as the velocity of the stream is decreased during passage through the treatment vessels. The sand accumulates at low points in the equipment and is removed periodically through sand drains, manually during equipment shut-downs for cleaning, or by periodic blowdowns as a wet sludge containing both water and oil.[44,45] One source indicates that desanders or desilters (hydrocyclones) are used to remove sand if the volume produced is high.[43] However, observations during the EPA 1992 Production Sampling Program indicate that for lower production volumes more typical of coastal situations, sand removal is primarily achieved by tank cleanouts and that desanders are seldom used.[38] Equipment is typically cleaned on a three to five year cycle. At some locations, sand is collected on a yearly basis because large volumes of sand are being generated due to failure of downhole sand control measures.[45]

4.2 PRODUCED SAND VOLUMES

The generation rate of produced sand will vary between wells and is a function of the amount of total fluid produced, location of the well, type of formation, production rate and completion methods.[43,44] Oil producing reservoirs will typically generate more produced sand than gas producing reservoirs. This is because oil reservoirs generate more liquids (both oil and water) which are more viscous than gas and thus the liquids will remove and carry the sand more easily to the surface than gas. Also, the greater water volumes associated with oil reservoirs will create more scale particles. Another reason is because gas producing wells have sensors that detect sand flowing with the gas stream to prevent erosion on the production equipment due to sand flowing with the gas at high velocities.[46] Table IX-20 presents a summary of the produced sand volumes data.

4.2.1 Gulf of Mexico

224 production separation facilities in the Gulf of Mexico provided produced sand data in the 1993 Coastal Oil and Gas Questionnaire.[8] Of these 224, a total of 37 facilities reported produced sand generation volumes. The average volume generated was 74 bbls. Since produced sand is not collected from process equipment every year, the survey only represents a snapshot of produced sand collection for the year of 1992. The average frequency of generation of produced sand for these 37 facilities ranged between 2.2 times per year and once every 2.9 years. Although only 16.5% of the facilities reported produced sand volume data, this does not indicate that 83.5% of the facilities did not generate any produced sand that year. It indicates that either these facilities did not generate any produced sand, or no produced sand was collected from the process equipment for that year, or that the volume was unknown.

The annual sand generation rates obtained during EPA's 1992 10 production facility study ranged from 106 to 400 bbls for facilities with produced water flowrates of 6,462 and 7,000 bpd respectively.[38] In addition, one of the two commercial produced water injection facilities sampled by EPA in 1992

TABLE IX-20
PRODUCED SAND VOLUMES GENERATED

	Gulf of Mexico		Cook Inlet	
Source	Produced Sand Generated	Frequency	Produced Sand Generated	Frequency
Oil & Gas Questionnaire	74 bbls[a]	1/2.9 yr[a]	365 bbl[8] 1 bbl[8] 1 bbl[8] 1 bbl[8]	--
Trip Reports	106 bbls[38] 400 bbls[38]	1/1 yr[38] 1/1 yr[38]	600 bbl[22]	½+yr[22]

[a] Estimated average from SAIC, September 30, 1994.[5]

reported an annual sand generation rate of 50 bbls with an average produced water flowrate of 5,000 bpd.[47] It is likely that some of the produced sand in the produced water received by the commercial facility would have settled out in the production equipment and produced water storage tanks prior to being sent to commercial disposal.

The Coastal Oil and Gas Questionnaire indicates that only one of the operators surveyed discharged produced sand at three of its facilities in 1992. The operator indicated that this practice would be discontinued in the near future.[48] All other operators dispose of produced sands via landfarming, underground injection, landfilling, or onsite storage. The total sand production from the three sites discharging sand was 144 bbls which is a small proportion of produced sand generated in the region.

4.2.2 Cook Inlet

Four of the platforms in Cook Inlet reported produced sand generation volumes in the 1993 Coastal Oil and Gas Questionnaire.[8] One reported generating 365 bbls in 1992 while the remaining three reported only one bbl for 1992. Operators of the Bruce Platform in Cook Inlet reported that they had removed 600-bbls of produced sand for disposal from their two 600-bbl produced water settling tanks two years prior to EPA's visit in August 1993.[22] Therefore, the amount generated per platform can vary greatly. The current produced sand disposal practice in Cook Inlet is zero discharge via land disposal and storage for future land disposal.[49,50] In the past, produced sand from the Bruce Platform had been sent to the Kenai

Gas Field for storage. This produced sand has recently been ground and injected as part of a pilot project to grind and inject stored wastes and the contents of old reserve pits.[23]

4.3 PRODUCED SAND CHARACTERIZATION

Produced sand is generally contaminated with crude oil from oil production or condensate from gas production. The primary contaminant associated with produced sand is oil.[12] The oil content of unwashed produced sand can range from a trace (expected in sand from blowdown) to as much as 19 percent by volume.

During the EPA 1992 Production Sampling effort, samples of settling tank bottoms were collected at four facilities and analyzed for conventional, non-conventional, organic pollutants and metals and radionuclides.[38] These samples are considered representative of produced sand. Table IX-21 presents the maximum and minimum observed concentrations detected in these samples. In cases of a single detect for a particular pollutant, the detected concentration value is reported in Table IX-21 as the maximum observed concentration. Due to a limited volume available at some of these sites, not all analytes were analyzed for all of the samples. For the two samples that were analyzed for oil content, the concentration ranged from 12.7 to 19 percent. All toxic metals were present except silver, with most notable contributions from copper (32.15 mg/kg) and lead (171.94 mg/kg).[51] The toxic organic pollutants present were similar to those found in produced water including benzene, ethylbenzene, toluene, xylene, propanone, and phenanthrene.

4.4 PRODUCED SAND CONTROL AND TREATMENT TECHNOLOGIES

The primary control and treatment technology for produced sand is preventing the sand from exiting the formation. Sand control is determined by the type of well completion. A specialized completion can prevent sand from being brought into the production line with the fluids.[46] The most up-to-date completion technology will prevent production solids from entering the production tubing, even in loose and unconsolidated formations.

The most common type of completion that prevents solids from entering the production tubing is a gravel pack completion. A gravel pack completion is a perforated cased hole completion that includes the placement of gravel, glass beads, or some other packing material between the production tubing and the casing. A screen or mesh is also placed between the production tubing and the casing. The gravel pack and screen serve as a filter to prevent solids from entering the production tubing. Older wells are

TABLE IX-21

RANGE OF POLLUTANT CONCENTRATIONS IN PRODUCED SAND FROM THE 1992 COASTAL PRODUCTION SAMPLING PROGRAM[51]

Pollutant	Units	Number of Samples	Number of Detects	Minimum Value	Maximum Value
CONVENTIONAL AND NON-CONVENTIONAL					
Total Recoverable Oil & Grease	μg/kg	3	3	84,000.00	328,562.87
Oil Content	%	2	2	12.70	19.00
Total Solids	μg/kg	3	3	76.00	1,052,084.21
BOD 5-day (Carbonaceous)	μg/kg	3	3	16,000.00	161,413.51
Total Organic Carbon (TOC)	μg/kg	3	3	20,000.00	285,693.11
Ph	Ph	3	3	6.70	10.50
Chloride	μg/kg	3	3	1,360.78	25,000.00
Fluoride	μg/kg	3	3	1.30	368.25
Nitrate/Nitrite	μg/kg	3	1	(a)	19.00
Total Releasable Sulfide	μg/kg	3	1	(a)	200.00
Total Sulfide (Isometric)	μg/kg	3	2	26.14	2,000.00
PRIORITY POLLUTANT METALS					
Antimony	mg/kg	4	1	(a)	4.50
Arsenic	mg/kg	4	2	8.30	34.00
Beryllium	mg/kg	4	3	0.10	0.20
Cadmium	mg/kg	4	2	0.93	2.20
Chromium	mg/kg	4	4	3.70	26.60
Copper	mg/kg	4	4	6.50	72.00
Lead	mg/kg	4	4	25.70	510.00
Mercury	mg/kg	4	1	(a)	0.20
Nickel	mg/kg	4	4	4.90	12.50
Selenium	mg/kg	4	1	(a)	4.00
Thallium	mg/kg	4	1	(a)	2.70
Zinc	mg/kg	4	4	63.80	11,700.00
NON-PRIORITY POLLUTANT METALS					
Aluminum	mg/kg	4	4	879.00	71,100.00
Barium	mg/kg	4	4	201.00	3,680.00
Boron	mg/kg	4	4	26.80	328.00
Calcium	mg/kg	4	4	6,020.00	23,500.00
Cobalt	mg/kg	4	4	1.70	3.50
Iron	mg/kg	4	4	4,650.00	14,300.00
Magnesium	mg/kg	4	4	602.00	3,030.00
Manganese	mg/kg	4	4	54.50	121.00
Molybdenum	mg/kg	4	2	1.60	15.70
Sodium	mg/kg	4	4	13,300.00	32,800.00
Strontium	mg/kg	2	2	131.00	256.00
Sulfur	mg/kg	4	4	1,570.00	5,890.00
Tin	mg/kg	4	3	3.80	349.00
Titanium	mg/kg	4	4	14.60	60.80
Vanadium	mg/kg	4	4	2.90	18.60
Yttrium	mg/kg	4	4	2.30	5.80
PRIORITY POLLUTANT VOLATILE ORGANICS					
Benzene	μg/kg	3	3	55,352.86	283,445.00
Ethylbenzene	μg/kg	3	3	33,170.00	296,995.00
Methylene Chloride	μg/kg	3	2	193.37	54,140.35

TABLE IX-21 - *Continued*

RANGE OF POLLUTANT CONCENTRATIONS IN PRODUCED SAND FROM THE 1992 COASTAL PRODUCTION SAMPLING PROGRAM[51]

Pollutant	Units	Number of Samples	Number of Detects	Minimum Value	Maximum Value
CONVENTIONAL AND NON-CONVENTIONAL					
Toluene	μg/kg	3	3	89,417.14	355,835.00
Trichlorofluoromethane	μg/kg	3	2	30,707.14	250,754.39
NON-PRIORITY POLLUTANT VOLATILE ORGANICS					
M-Xylene	μg/kg	3	3	18,827.14	161,610.00
O+P Xylene	μg/kg	3	2	70,039.68	116,645.00
2-Propanone	μg/kg	3	1	(a)	222,183.05
PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS					
Acenaphthene	μg/kg	3	1	(a)	8,511.33
Anthracene	μg/kg	3	1	(a)	10,442.33
Fluorene	μg/kg	3	2	12,115.33	19,521.00
Naphthalene	μg/kg	3	3	46,547.00	57,003.33
Phenanthrene	μg/kg	3	2	19,739.00	26,779.67
2,4,6-Trichlorophenol	μg/kg	3	1	(a)	139,153.33
NON-PRIORITY POLLUTANT SEMI-VOLATILE ORGANICS					
Acetophenone	μg/kg	3	1	(a)	50,996.67
Biphenyl	μg/kg	3	2	25,620.33	50,769.33
Dibenzofuran	μg/kg	3	1	(a)	15,397.00
Dibenzothiophene	μg/kg	3	2	4,873.33	6,826.33
n-Decane	μg/kg	3	3	7,302.67	169,263.33
n-Docosane	μg/kg	3	3	53,659.33	199,183.33
n-Dodecane	μg/kg	3	3	50,642.33	716,843.33
n-Eicosane	μg/kg	3	3	139,153.33	333,090.00
n-Hexacosane	μg/kg	3	3	20,380.00	123,716.67
n-Hexadecane	μg/kg	3	3	250,070.00	554,033.33
n-Octacosane	μg/kg	3	3	5,543.67	150,746.67
n-Octadecane	μg/kg	3	3	225,183.33	463,686.67
n-Tetracosane	μg/kg	3	3	64,200.00	187,440.00
n-Tetradecane	μg/kg	3	3	253,220.00	439,433.33
n-Triacontane	μg/kg	3	3	16,789.00	393,873.33
1-Methylfluorene	μg/kg	3	3	31,473.33	88,670.00
1-Methylphenanthrene	μg/kg	3	2	10,717.33	38,270.00
1-Phenylnaphthalene	μg/kg	3	1	(a)	5,124.00
2-Isopropylnaphthalene	μg/kg	3	1	(a)	39,190.00
2-Methylnaphthalene	μg/kg	3	2	96,533.33	155,923.33
2-Phenylnaphthalene	μg/kg	3	2	6,012.00	6,871.33
3,6-Dimethylphenanthrene	μg/kg	3	1	(a)	62,333.33
4-Aminobiphenyl	μg/kg	3	1	(a)	31,025.67
RADIONUCLIDES					
Gross Alpha	pCi/g	4	1	(a)	872.00
Gross Beta	pCi/g	4	4	12.00	668.00
Lead 210	pCi/g	4	3	4.20	11.70
Radium 226	pCi/g	5	4	2.60	6.90
Radium 228	pCi/g	5	3	2.70	6.50

(a) Analyte detected in only one sample; the detected value is reported as the maximum.

typically open holed perforated completions in which nothing prevents solids from entering the production tubing with the fluid. Figure IX-3 presents a schematic diagram of a closed hole perforated completion with gravel packing.

Gas producing wells are typically equipped with sand sensors which indicate the presence of sand in the gas stream. Sand sensors are commonly used in gas producing wells because sand flowing at high velocities with the produced gas will erode tubing, valves, and other process equipment. A sand sensor is a simple device that detects the sand particles hitting its surface. If sand is detected, an electrical signal will trigger an alarm to notify the operator. The operator can either alleviate the sand generation problem at the source or reduce the gas velocities to prevent the sensor from detecting the sand flow. The sand probes do not work in liquid streams and thus are not used on oil producing wells.[46] In addition, produced sand contained in liquids such as oil and water do not pose as great a physical erosion problem due to the lower velocities of these fluids and the lubricating properties of the liquids.

4.4.1 BPT Technology

The management of produced sand wastes involves either treating the sand to meet the no free oil limitations and discharge to the surface waters, land application, or hauling the sand to a commercial facility for final disposal.

Of the 10 coastal production facilities in the Gulf of Mexico region visited by EPA in 1992, only one reported onsite disposal of produced sand. At this facility located in Texas, produced sand is removed from the produced water treatment tanks and deposited on the ground within the diked area. Samples are collected for oil and grease analysis and if the concentration is below 1.0 percent, they are allowed to dispose of the produced sand by spreading it on their sand and gravel roads.[52] The remaining nine production facilities reported that they transport produced sand to commercial disposal facilities.

Data from the 1993 Coastal Oil and Gas Questionnaire indicate that 4.6 percent of the coastal facilities in the Gulf of Mexico inject produced sand and that the remainder is either landfilled, stored onsite for future disposal, hauled offsite for disposal or is encapsulated and disposed in abandoned wells.[5]

Since only one operator in the Gulf of Mexico reported discharge of produced sand and that operator reported its intention to discontinue this practice, this information indicates that the current practice of the industry is zero discharge. The one operator that reported discharge of produced sand

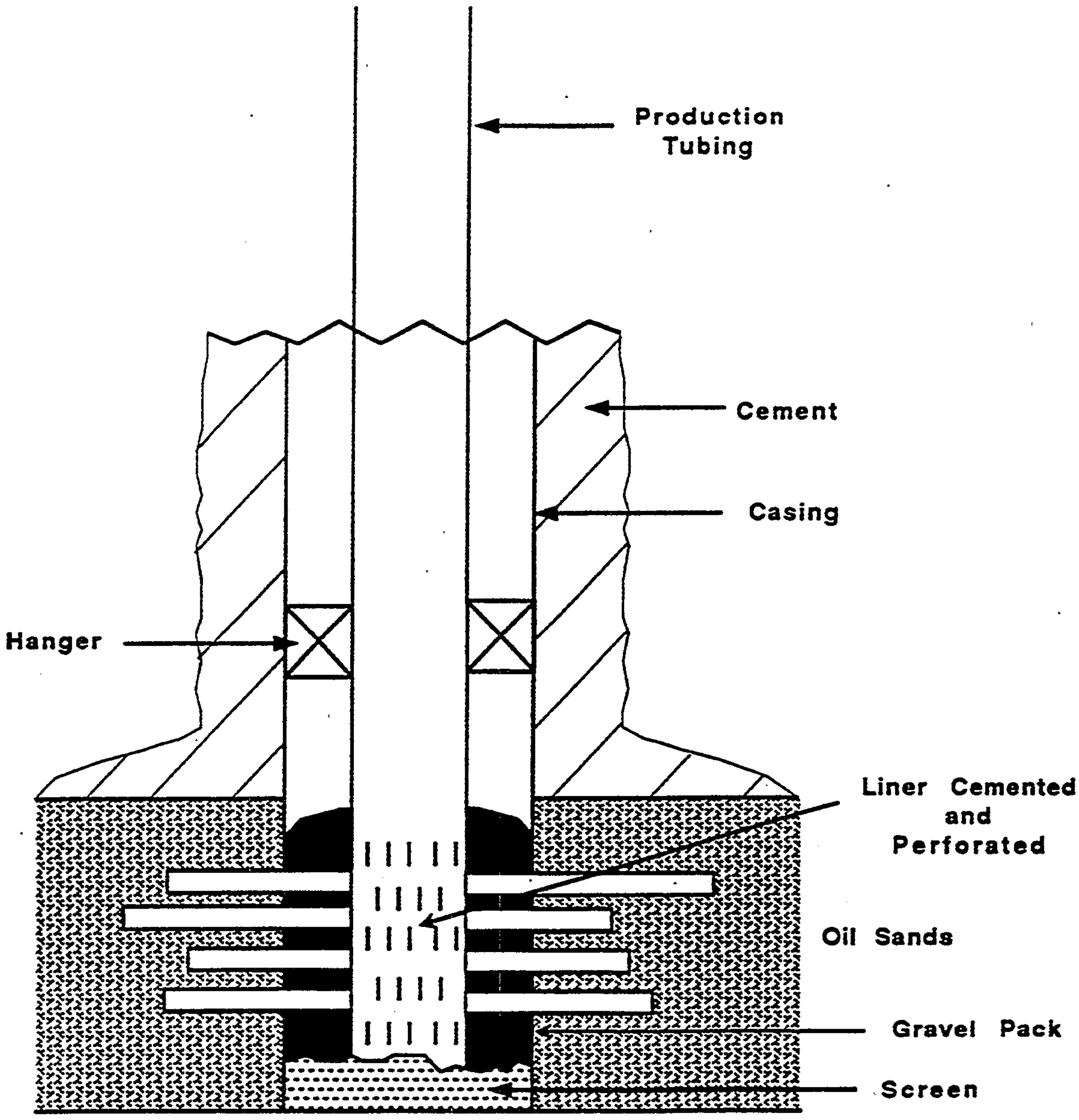

Figure IX-3
Closed Hole Perforated Completion (With Gravel Pack)

indicated that the sand was first treated by sand washing prior to disposal.[48] A detailed discussion of sand washing technology and its capabilities is presented below.

4.4.2 Additional Technologies

Several methods other than zero discharge via land disposal were identified in the literature for treatment of produced sand and are included in this section. The treatment methods include: washing the material with water and detergents, mechanical separation, separation with solvents, thermal treatment and air flotation. Most of the sources consulted did not provide data or cleaning efficiencies for the treatment of produced sand.

Data submitted from an industry supported study for the offshore subcategory demonstrate the variability of oil content in washed sand. In the study, produced sand was washed using detergents and the resultant oil content ranged from 0.99 to 4.6 percent by weight.[53] Information recently reached regarding current sand washing technology indicates that oil can be removed without the use of detergents or other chemicals.[54,55] Data provided by vendors submitted in comments to the proposed rule demonstrate that the oil content of washed sand can be below 1 percent by weight but can vary from 0.2 percent to 3.9 percent. Another sand washing system demonstrated at offshore sites generates sand capable of meeting a no-free-oil limitation, although residual liquids and solids (by-products from washing) remain which are unable to meet the no-free-oil limitation and must be disposed in a manner other than surface discharge.[56]

Several other treatment systems have been identified in the literature:

- A sand washer system that mechanically removes oil from produced sand consisting of a bank of cyclone separators, a classifier vessel, and another cyclone. Following treatment the sand is reported to have no trace of oil.[57] Actual data were not presented.
- A sand cleaning system consisting of two vertical two-phase separators. The initial separator is baffled and sand falls through to the second separator. The second separator contains a solvent layer to absorb oil from the sand grains.[57] Data were not presented.
- A produced sand disposal system consisting of a conventional cyclone and a cyclone with chemical and air injection that removes the oil by air flotation.[58]

Treatment of produced sand via mechanical washing has several drawbacks. The capital costs necessary to install a complete sand washing unit on a platform preclude the widespread installation of systems on platforms which only need to wash sand every 3 to 5 years. In addition to the equipment costs, current existing platform space is limited or not available for such equipment and therefore the addition of extra platform space would be required. Sand washing does not always guarantee one-hundred percent discharge of the sand. Sands containing heavy oils cannot always be washed thoroughly enough to meet the permit discharge prohibition on free oil. In these cases, the sand cannot be discharged and must be transported offsite for disposal. Since sand washing is designed to only reduce the oil content, produced sand that contains certain levels of Naturally Occurring Radioactive Material (NORM) must be transported to shore for disposal depending on state requirements. In addition, sand washing can generate additional wastes, such as oily solids and oily water, which require further treatment and disposal.

5.0 DOMESTIC WASTES

5.1 DOMESTIC WASTE SOURCES

Domestic wastes (gray water) originate from sinks, showers, laundry, food preparation areas, and galleys on the larger facilities. Domestic wastes also include solid materials such as paper, boxes, etc.

5.2 DOMESTIC WASTE VOLUME AND CHARACTERISTICS

The volume of domestic waste discharged has been estimated to range from 50 to 100 gallons per person per day, with a BOD of 0.2 pound per day per person.[36,59] For drilling rigs, rather than require flow measurement, the State of Louisiana requires operators to report the estimated domestic waste volume as equal to 0.7 bbs/day (30 gal/day) per person occupying the rig.[27] The 1993 Coastal Oil and Gas Questionnaire statistics estimate that 76 percent of production facilities discharge domestic/sanitary wastes with an average volume of 2,049 bpy (282 bpd).[5] It often is necessary to utilize macerators with domestic wastes to prevent the release of floating solids. Chlorination is not necessary since these wastes do not contain coliforms. Tables IX-22 and IX-23 summarize the volume and characteristics of domestic wastes for offshore platforms which would reflect domestic waste in Cook Inlet.

5.3 DOMESTIC WASTE CONTROL AND TREATMENT TECHNOLOGIES

Because domestic wastes do not contain fecal coliform, no chlorination is required. Domestic wastes must only be ground up so as to comply with the NPDES permit prohibitions on discharges of floating solids. Maceration by comminutor should be sufficient treatment. Treatment such as macerators will guarantee that this discharge will not result in any floating solids. In addition, many existing NPDES and State permits prohibit discharges of foam (as no visible foam). Where existing discharges may be experiencing discharges of foam, measures taken to remediate the situation can include the relocation of

TABLE IX-22

TYPICAL UNTREATED COMBINED SANITARY AND DOMESTIC WASTES FROM OFFSHORE FACILITIES[60]

Number of Persons	Flow (gal/day)	BOD (mg/l)		Suspended Solids (mg/l)		
		Average	Range	Average	Range	Total Coliforms (x 10)
76	5,500	460	270-770	195	14-543	10-180
66	1,060	875		1,025	1,025	
67	1,875	460		620	620	
42	2,155	225		220	220	
10-40	2,900	920				

TABLE IX-23

TYPICAL OFFSHORE SANITARY AND DOMESTIC WASTE CHARACTERISTICS[61]

Waste Type	Discharge Rate (m^3/cap/day)	Loading		Concentration		
		BOD (kg/cap/day)	S.S (kg/cap/day)	BOD (mg/l)	S.S (mg/l)	Residual Chlorine (mg/l)
Sanitary Waste (treated)	0.075	0.002	0.003	30	40	1.7
Domestic Waste (direct discharge)	0.110	0.022	0.016	195	140	0

the discharge to a standpipe with a subsurface discharge location and careful selection and use of detergents.

5.3.1 Additional Technologies

EPA is incorporating Annex V of the Convention to Prevent Pollution from Ships (MARPOL), Part 151 of Title 33 Code of Federal Regulations, and the Act to Prevent Pollution from Ships, 33, U.S.C. 1901 et seq., in the BCT and NSPS limitations on domestic waste.

EPA compiled U.S. and international regulations governing the discharge of domestic wastes into ocean waters from ships and fixed or floating platforms. Although these Coast Guard regulations are primarily intended for offshore and international waters, EPA Region VI has adopted them as part of the domestic wastes limitations in the General Permit for coastal drilling operations (58 FR 49126). International waters are governed by MARPOL 73/78 (the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto). The Coast Guard implemented MARPOL 73/78 as part of its pollution regulations (33 CFR-Part 151) governing U.S. waters.

Disposal from drilling rigs are dealt with in Regulation 4 of Annex V of MARPOL. It states that:

(1) Fixed or floating platforms engaged in the exploration, exploitation, and associated offshore processing of sea-bed mineral resources, and all other ships alongside such platforms or within 500 meters of such platforms, are forbidden to dispose of any materials regulated by this Annex, except as permitted by paragraph (2) of this Regulation.

(2) The disposal into the sea of food wastes when passed through a comminutor or grinder from such fixed or floating drilling rigs located more than 12 nautical miles from land and all other ships when positioned as above. Such comminuted or ground food wastes shall be capable of passing through a screen with openings no greater than 25 mm.

Table IX-24 summarizes the garbage discharge restrictions from fixed or floating platforms.

In summary, under the Coast Guard Regulations, discharges of garbage, including plastics, from fixed and floating platforms engaged in the exploration, exploitation and associated offshore processing of seabed mineral resources are prohibited with the exception that food wastes may be discharged from fixed and floating platforms located beyond 12 nautical miles from the nearest land (33 CFR 151.75).

6.0 SANITARY WASTES

6.1 SANITARY WASTE SOURCES, VOLUMES AND CHARACTERISTICS

The sanitary wastes from oil and gas facilities are comprised of human body wastes from toilets and urinals. The volume and concentration of these wastes vary widely with time, occupancy, platform characteristics, and operational situation.

TABLE IX-24
GARBAGE DISCHARGE RESTRICTIONS

Garbage Type	Fixed or Floating Platforms & Associated Vessels[a] (33 CFR 151.73)
Plastics - includes synthetic ropes and fishing nets and plastics bags.	Disposal prohibited (33 CFR 151.67)
Dunnage, lining and packing materials that float.	Disposal prohibited
Paper, rags, glass, metal bottles, crockery and similar refuse.	Disposal prohibited
Paper, rags, glass, etc. comminuted or ground.[b]	Disposal prohibited
Victual waste not comminuted or ground.	Disposal prohibited
Victual waste comminuted or ground.[b]	Disposal prohibited less than 12 miles from nearest land and in navigable waters of the U.S.
Mixed garbage types.[c]	See note c.

[a] Fixed or floating platforms and associated vessels include all fixed or floating platforms engaged in exploration, exploitation, or associated offshore processing of seabed mineral resources, and all ships within 500m of such platforms.
[b] Comminuted or ground garbage must be able to pass through a screen with a mesh size no larger than 25 mm (1 inch) (33 CFR 151.75).
[c] When garbage is mixed with other harmful substances having different disposal requirements, the more stringent disposal restrictions shall apply.

EPA compiled U.S. and international regulations governing the discharge of sanitary waste into ocean waters from manned ships and manned fixed or floating platforms. International waters are governed by MARPOL 73/78, Annex IV which deals specifically with the disposal of sewage from ships. The Federal Water Pollution Control Act (FWPCA) §312 (33 U.S.C. 1322) administered/implemented by U.S.EPA, provides the regulations and the standards to eliminate the discharge of untreated sewage from vessels into waters of the U.S. and the territorial seas. The U.S. Coast Guard has established regulations governing the design and construction of marine sanitation devices and procedures for certifying that marine sanitation devices meet the regulations of the FWPCA (33 CFR Part 159 and 40 CFR Part 140).

Combined sanitary and domestic waste discharge rates of 3,000 to 13,000 gallons per day have been reported.[62] Monthly average sanitary waste flow from Gulf Coast platforms was 35 gallons per day based on discharge monitoring reports.[63] For drilling rigs, rather than require flow measurement, the State of Louisiana requires operators to report the estimated sanitary waste volume as equal to 0.00006 MGD/day (60 gal/day) per person occupying the rig.[27] The EPA 1993 Coastal Oil and Gas Questionnaire statistics estimate that 76 percent of production facilities discharge domestic/sanitary wastes with an average volume of 2,049 bpy (282 bpd).[5]

6.2 SANITARY WASTE CONTROL AND TREATMENT TECHNOLOGIES

There are two alternatives to handling of sanitary wastes from coastal facilities. The wastes can be treated at the facility, or they can be retained and transported to shore facilities for treatment. However, due to storage limitations on platforms, water-access facilities usually treat and discharge sanitary waste at the source. The treatment systems presently in use may be categorized as physical/chemical and biological.

Physical/chemical treatment may consist of evaporation-incineration, maceration-chlorination, and chemical addition. With the exception of maceration-chlorination, these types of units are often used to treat wastes on facilities with small numbers of men or which are intermittently manned. The incineration units may be either gas fired or electric. The electric units have been difficult to maintain because of saltwater corrosion and heating coil failure. The gas units are not subject to these problems, but create a potential source of ignition which could result in safety hazards. Some facilities have chemical toilets which require hauling of waste and create odor and maintenance problems. Macerators-chlorinators would be applicable to provide minimal treatment for small and intermittently manned facilities.

The most common biological system applied to manned water-access operations is aerobic digestion or extended aeration processes. These systems usually include a comminutor which grinds the solids into fine particles, an aeration tank with air diffusers, a gravity clarifier return sludge system, and a chlorination tank. These biological waste treatment systems have proven to be technically and economically feasible means of waste treatment at offshore facilities which have more than 10 occupants and are continuously manned.

BPT for sanitary wastes from coastal facilities continuously manned by 10 or more persons requires a residual chlorine content of 1 milligram per liter (and maintained as close to the limit as possible). Facilities continuously manned by fewer than 10 persons or intermittently manned by any number of persons are prohibited from discharging floating solids. These standards are based on end-of-pipe technology consisting of biological waste treatment systems (extended aeration). The system may include a comminutor, aeration tank, clarifier, return sludge system, and disinfection contact chamber. Studies of treatability, operational performance, and flow fluctuations are required prior to application of a specific treatment system to an individual facility. EPA has not identified any additional control beyond BPT appropriate for this wastestream.

7.0 MINOR DISCHARGES

The term "minor" discharges is used here to describe all point sources originating from coastal oil and gas drilling and production operations, other than produced water, drilling fluids, drill cuttings, deck drainage, produced sand, well treatment, completion and workover fluids, and sanitary and domestic wastes. The following sections identify these discharges followed by a brief description.

7.1 BLOWOUT PREVENTER (BOP) FLUID

An oil (vegetable or mineral) or antifreeze solution (glycol) is used as hydraulic fluid in blowout preventer (BOP) stacks during drilling of a well. The blowout preventer is designed to maintain the pressure in the well that cannot be controlled by the drilling mud. Small quantities of BOP fluid are discharged periodically to the sea floor during testing of the blowout preventer device. Such discharges are limited to deep water operations such as in Cook Inlet. BOP fluid released from above water applications would be captured, treated and disposed accordingly.

7.2 DESALINATION UNIT DISCHARGE

This is the residual high-concentration brine discharged from distillation or reverse osmosis units used for producing potable water and high quality process water. The concentrate is similar to sea water in chemical composition. However, as the name implies, anion and cation concentrations are higher. This waste is discharged directly to the surface as a separate waste stream.

7.3 FIRE CONTROL SYSTEM TEST WATER

The local water source, which may be treated with a biocide, is used as test water for the fire control system on platforms and other facilities. This test water is discharged directly as a separate waste stream.

7.4 NON-CONTACT COOLING WATER

Non-contact, once-through water is used to cool crude oil, produced water, power generators, and various other pieces of machinery at production and drilling operations. Biocides can be used to control biofouling in heat exchanger units. Non-contact cooling waters are discharged directly to the surface as a separate waste stream.

7.5 BALLAST AND STORAGE DISPLACEMENT WATER

Two types of ballast water are found in production and drilling operations: tanker and platform ballast. Tanker ballast water can be either salt/brackish water or fresh water from the area where ballast was pumped into the vessel. It may be contaminated with crude oil (or possibly some other cargo such as fuel oil), if the vessel is not equipped for segregated cargo and does not have segregated ballast tanks.

Unlike tank ballast water, which may be from multiple sources and may contain added contaminants, platform stabilization (ballast) water is taken on from the waters adjacent to the platform and will, at worst, be contaminated with stored crude oil and platform oily slop water. Newly designed and constructed floating storage platforms use permanent ballast tanks that become contaminated with oil only in emergency situations when excess ballast must be taken on. Oily water can be treated through the oil/water separation process prior to discharge.

7.6 BILGE WATER

Bilge water is a minor waste for floating platforms. Bilge water is seawater that becomes contaminated with oil and grease and with solids such as rust, when it collects at low points in the bilges. This bilge water is usually directed to the oil/water separator system used for the treatment of ballast or produced water, or is discharged intermittently.

7.7 BOILER BLOWDOWN

Purges from boilers circulation waters necessary to minimize solids build-up are intermittently discharged to the surface.

7.8 TEST FLUIDS

Test fluids are discharges that would occur if hydrocarbons are located during exploratory drilling and tested for formation pressure and content.

7.9 Diatomaceous Earth Filter Media

Diatomaceous earth filter media are used to filter seawater or authorized completion fluids and then washed from the filtration unit.

7.10 Bulk Transfer Operations

The transport and handling of bulk materials can result in discharges of barite or cement.

7.11 Painting Operations

Sandblasting and painting operations can result in discharges of sandblast sand, paint chips, and paint spray.

7.12 Uncontaminated Freshwater

Uncontaminated freshwater discharges come from wastes such as air conditioning condensate or potable water during transfer or washing operations.

7.13 Waterflooding Discharges

Oil fields that have been produced to depletion and have become economically marginal may be restored to production, with recoverable reserves substantially increased, by secondary recovery methods. The most widely used secondary recovery method is waterflooding. A grid pattern of wells is established, which usually requires downhole repairs of old wells or drilling of new wells. By injecting water into the reservoir at high rates, a front or wall of water moves horizontally from the injection wells toward the producing wells, building up the reservoir pressure and sweeping oil in a flood pattern.

Waterflooding can substantially improve oil recovery from reservoirs that have little or no remaining reservoir pressure. Treated seawater typically is used in Cook Inlet for injection purposes. Waterflooding is also used in California and to a lesser degree in the Gulf of Mexico region. Treatment consists of filtration to remove solids that would plug the formation, and dearation. Dissolved oxygen is removed to protect the injection pipeline system from corrosion. A variety of chemicals can be added to water flooding systems such as flocculants, scale inhibitors, and oxygen scavengers. Biocides are also used to prevent the growth of anaerobic sulfate-reducing bacteria, which can produce corrosive hydrogen sulfide in the injection system. Discharges from water flooding operations will include excess injection water and backwash from filtering systems.

7.14 LABORATORY WASTES

Laboratory wastes contain material used for sample analysis and the material being analyzed. The volume of this waste stream is relatively small and is not expected to pose significant environmental problems. Freon may be present in laboratory waste. Because freon is highly volatile, it will not remain in aqueous state for very long. The Agency is discouraging the discharge of chlorofluorocarbon to air or water media.

7.15 NATURAL GAS GLYCOL DEHYDRATION WASTES

A common step in processing natural gas is dehydration using a desiccant such as triethylene glycol. In this process natural gas is brought into contact with a glycol stream which has an affinity for and adsorbs water vapor. The glycol is then passed through a reboiler where the water is distilled out of the solution. This vaporized water is then condensed into a liquid waste stream. This waste stream may be returned to the produced water treatment and disposal system or it may be surface discharged. Sometimes impurities will build up in the glycol solution requiring that it be replaced. Spent glycol can be regenerated onsite through distillation or it is hauled offsite for regeneration or disposal.

7.16 MINOR WASTES VOLUMES AND CHARACTERISTICS

Information concerning the characteristics, discharge volumes, and the frequency of discharge of these minor waste streams is limited. Table IX-25 provides a range of discharge volumes for the minor waste streams that were identified for the offshore category. Data concerning the characteristics and volumes of test fluids, diatomaceous earth filter media, bulk transfer operations, and painting operations are not available.

TABLE IX-25
MINOR WASTE DISCHARGE VOLUMES[15]

Waste	Discharge Volume
BOP fluid	10 - 500 gal/day
Boiler blowdown	0 - 5 bbl/day
Desalination waste	typically <238 bbl/day
Fire system test water	24 bbl/test
Noncontact cooling water	7 - 124,000 bbl/day
Uncontaminated ballast/bilge water	70 - 620 bbl/day
Water flooding	up to 4,030 lb solids/month
Test fluids	Unknown
Diatomaceous earth filter media	Unknown
Bulk transfer operations	Unknown
Painting operations	Unknown
Uncontaminated fresh water	Unknown
Glycol dehydration condensate	Unknown

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CHAPTER X

COST AND POLLUTANT REMOVAL DETERMINATION OF DRILLING FLUIDS AND DRILL CUTTINGS

1.0 INTRODUCTION

This section presents incremental costs and pollutant removals for the regulatory options considered for control of drilling fluids, drill cuttings and dewatering fluids. Incremental compliance costs beyond current industry practices and NPDES permit requirements were developed for each control option for Cook Inlet, Alaska only. Compliance costs were not developed for the other coastal regions where oil and gas activity exists or is expected, because, as is discussed in earlier chapters of this document, discharges of drilling fluids and drill cuttings do not occur in these areas.[a]

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

2.0 OPTIONS CONSIDERED AND SUMMARY COSTS

Two disposal options were considered for control and treatment of drilling fluids, drill cuttings, and dewatering effluent for this rule. These options are:

- Option 1: Zero discharge for all areas except Cook Inlet, where discharge limitations require toxicity of no less than 30,000 ppm in the suspended particulate phase (SPP), no discharge of free oil and diesel oil, and no more than 1 mg/l mercury and 3 mg/l cadmium in the stock barite

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[a] Based on an agreement with the Alaska Department of Environmental Conservation (ADEC), operators in Alaska's North Slope are allowed to clean and reuse drill cuttings as gravel as long as the cuttings meet certain criteria. The operators developed the "Drill Cuttings Reclamation Program" whose goals are to minimize the volume of larger cuttings requiring grinding and injection and to reduce the need for gravel mining. Details regarding this program are provided in the rulemaking record.[1]

(these limitations are reflective of current practice in Cook Inlet and are similar to the offshore limitations).

- Option 2: Zero discharge for all areas.

Costs for these options are applicable only to Cook Inlet operators since zero discharge represents current practice in all other coastal areas. Since Option 1 is reflective of current practice in Cook Inlet, no costs or pollutant removals are attributed to this option. (See Section 2.1 for a discussion of current practice.) Thus, only costs and pollutant removals that are incremental to current practice were determined for Option 2.

Options 1 and 2 apply to the drill cuttings as well as to drilling fluids since drilling fluid adheres to cuttings and is discharged along with the drill cuttings.[2] The same pollutants found in drilling fluids are thus found on the wet drill cuttings. Section discusses the constituents in drilling wastes as part of the pollutant removal analysis.

One option considered at proposal would have retained the limitation of Option 1 above, but required a more stringent toxicity limit in the range of 100,000 ppm (SPP) to 1 million ppm (SPP). At proposal, EPA based the more stringent toxicity limitations, in part, on the volume of drilling wastes that could be injected or disposed of onshore without interfering with ongoing drilling operations. The more stringent toxicity limit would have been based on (1) the volume of drilling wastes that could be subjected to zero discharge without interfering with ongoing drilling operations and (2) a specified level of toxicity selected such that no more than this volume of waste, determined in the previous step, would exceed the specified level of toxicity. However, as pointed out in comments on the proposal and confirmed with further investigation, there are a number of problems with the database making it insufficient for establishing a more stringent toxicity limitation. Many of the records in the database do not have either a waste volume identified or indicate whether the drilling fluids were discharged. Where waste volumes are reported, the methods used to determine these volumes are not consistent and they are not documented. It is also unclear whether the volumes and fluid systems reported for any given well represent a complete record of the drilling activity associated with the well. For these reasons, EPA rejected the option of developing a more stringent toxicity limitation for the final rule.

Another wastestream resulting from drilling activities is the wastewater derived from dewatering drill cuttings, called dewatering effluent. This wastestream is typically created only where drill cuttings and drilling fluid may not be discharged, and there is incentive to reduce the volume of these wastes prior to disposal. Also, cuttings must be dewatered to the extent landfills limit the amount of liquid in the solids they accept for disposal. Depending on the availability of fresh water, dewatering effluent may also be recycled within the active drilling fluid system, thus never becoming a separate wastestream.

In the Gulf Coast region where discharges of drill cuttings and drilling fluids are prohibited, the EPA Region 6 general permits for drilling operations for Texas and Louisiana (58 FR 49126, September 21, 1993) include limitations for the discharge of dewatering effluent. However, the 1993 Coastal Oil and Gas Questionnaire results showed that few operators discharge dewatering effluent as a separate wastestream.[3] Additionally, contacts with industry indicate that the volume of dewatering effluent from reserve pits is small and growing smaller since the use of pits is phasing out due to state permit conditions, environmental or landowner concerns, and the expanding use of closed-loop systems in the Gulf Coast region. EPA site visits to drilling operations where closed-loop solids control systems were in place showed that none of the dewatering effluent was discharged.[4,5,6] Instead, it was either recycled or sent with other drilling wastes to commercial disposal. Operators at theses facilities explained that it is less expensive to send this waste stream along with drilling fluids and drill cuttings for onshore disposal rather than to treat for discharge. Therefore, EPA has concluded that any costs attributable to zero discharge of dewatering effluent are negligible in comparison to the costs of treating and discharging this waste.

In Cook Inlet where drill cuttings may be discharged under current NPDES requirements,[7] there is no incentive to dewater the cuttings and create a separate dewatering effluent wastestream. The compliance costs and pollutant removals presented in this document are based on the total volume of drill cuttings (including the drilling fluid adhering to the cuttings) and drilling fluids generated by Cook Inlet operators. Since dewatering effluent is derived from separating the solids in the drill cuttings wastestream from the liquid (drilling fluid) adhering to the cuttings, and EPA's compliance cost estimates for Cook Inlet are based on the total volume of drilling wastes generated, EPA's analyses include any costs that may be attributable to dewatering effluent in Cook Inlet.

The purpose of the toxicity limitation in Option 1 is to encourage the use of water-based or other low toxicity drilling fluids and the use of low-toxicity drilling fluid additives. The toxicity limitation in Option 1 (30,000 ppm) represents current industry practice.[8] The toxicity limitation applies to any periodic blowdown of drilling fluid as well as to bulk discharges of drilling fluid systems and cuttings. The term "drilling fluid systems" refers to particular types of drilling fluids used during the drilling of a single well. As an example, the drilling of a particular well may use a spud mud for the first 200 feet, a seawater gel mud to a depth of 1,000 feet, a lightly treated lignosulfonate mud to 5,000 feet, and finally a freshwater lignosulfonate mud system to a bottom hole depth of 15,000 feet. Typically, bulk discharges of spent drilling fluids occur when such systems are changed during the drilling of a well or at the completion of a well.

For the purpose of self monitoring and reporting requirements in NPDES permits, it is intended that only samples of the spent drilling fluid system discharges be analyzed in accordance with the proposed bioassay method. These bulk discharges are the highest volume mud discharges and will contain all the specialty additives included in each mud system. Thus, spent drilling fluid system discharges are the most appropriate discharges for which compliance with the toxicity limitation should be demonstrated. In the above example well, four such determinations at each of the depth intervals (i.e., 200, 1,000, 5,000, and 15,000 feet) would be necessary.

For determining the toxicity of the bulk discharge of mud used at maximum well depth, samples may be obtained at any time after 80 percent of actual well footage (not total vertical depth) has been drilled and up to and including the time of discharge. This would allow time for a sample to be collected and analyzed by bioassay and for the operator to evaluate the bioassay results so that the operator will have adequate time to plan for the final disposition of the spent drilling fluid system. For example, if the bioassay test is failed, the operator could then anticipate and plan for either land disposal or injection of the spent drilling fluid system to comply with the effluent limitations. However, the operator is not precluded from discharging a spent mud system prior to receiving analytical results, although the operation would be subject to compliance with the effluent limitations regardless of when self monitoring analyses are performed. The prohibition on discharges of free oil and diesel oil would apply to all discharges of drilling fluid and cuttings at any time. These requirements described above represent existing NPDES permit requirements.

For Option 1, diesel oil and free oil would serve as "indicators" of toxic pollutants, and thus these discharges would be prohibited by this rule. The discharge of diesel oil, either as a component in an oil-based drilling fluid or as an additive to a water-based (or synthetic-based or enhanced mineral oil) drilling fluid, would be prohibited under these limitations. Diesel oil would be regulated as a toxic pollutant because it contains such toxic organic pollutants as benzene, toluene, ethylbenzene, naphthalene, and phenanthrene. The method of compliance with this prohibition is to:

- use mineral oil instead of diesel oil for lubricity and spotting purposes;
- transport to shore for recovery of the oil, reconditioning of the drilling fluid for reuse, and land disposal of the drill cuttings; or
- grind and inject the drilling wastes.

EPA believes that in most cases substitution of mineral oil or other lubricity additive or the use of newer synthetic material based fluids such as those comprised of linear or poly(alpha)olefins, vegetable esters, or polyesters will be the method of compliance with the diesel oil discharge prohibition. Mineral oil is a less toxic alternative to diesel oil and is available to serve the same operational requirements. Low toxicity mineral oils and other drilling fluid systems, such as linear or polyolefins, vegetable oil and other synthetic hydrocarbon-based fluids, are available as substitutes for diesel oil and continue to be developed for use in drilling systems. Free oil is being used as an "indicator" pollutant for control of priority pollutants, including benzene, toluene, ethylbenzene, and naphthalene.

Cadmium and mercury would be regulated at a level of 3 and 1 mg/kg, respectively, in the stock barite. This limit pertains to the barite used in the drilling fluid compositions and is not an effluent limit measured at the point of discharge. These two toxic metals would be regulated to control the metals content of the barite component of any drilling fluid discharges. Control of other toxic pollutant metals occurs because cleaner barite that meets the mercury and cadmium limits has been shown to have reduced concentrations of other metals. Evaluation of the relationship between cadmium and mercury and the trace metals in barite shows a correlation between the concentration of mercury with the concentration of arsenic, chromium, copper, lead, molybdenum, sodium, tin, and zinc, and the concentration of cadmium with the concentration of arsenic, boron, calcium, sodium, tin, titanium, and zinc (see Section VI.2.4). Compliance with this requirement would involve use of barite from sources that either do not contain these metals or contain the metals at levels below the limitation.

Option 2 would prohibit the discharge of drilling fluids and cuttings from all coastal oil and gas drilling operations. This option utilizes grinding and injection and onshore disposal as a basis for complying with zero discharge of drilling fluids and cuttings. The technology option alternatives for Cook Inlet have been developed taking into consideration that Cook Inlet operations are unique to the industry due to a combination of climate, transportation logistics, and structural and space limitations (see Chapter XIV).

Four different scenarios were investigated as possible technology bases for achieving zero discharge under Option 2. These scenarios included:

- Landfill without CLS: Landfill disposal without closed-loop solids control technology (CLS).
- Landfill with CLS: Waste minimization using closed-loop solids control followed by disposal via transporting wastes to a landfill.
- Injection without CLS: Grinding followed by onsite injection.
- Injection with CLS: Waste minimization using closed-loop solids control technology followed by grinding and injection. This alternative is presented for comparison with the injection-without-solids control alternative.

Table X-1 presents the total coastal Cook Inlet compliance costs and pollutant removals calculated for each option. The total costs are based on the drilling activity plans or schedules as provided by the industry and cover a seven-year period from 1996 through 2002. The pollutant removals are based on typical volumes and characteristics of drilling wastes. The derivation of these costs and removals are described in detail in the remainder of this chapter.

TABLE X-1

INCREMENTAL COMPLIANCE COSTS AND POLLUTANT REMOVALS FOR DRILLING FLUIDS AND DRILL CUTTINGS BAT OPTIONS[a]

BAT Option		Total Costs (1995 $)		Pollutant Removals (lbs)	
Option 1:	Zero discharge except Cook Inlet = no free oil or diesel, and limits of 30,000 ppm SPP toxicity, 1 mg/l Hg and 3 mg/l Cd	$0		Conventionals Priority Organics Priority Metals Non-Conventionals Total	0 0 0 0 0
Option 2:	Zero discharge all	Landfill Without CLS[b]	$66,167,388	Conventionals Priority Organics Priority Metals Others Total	168,624,108 35 30,399 8,361,216 177,015,758
		Landfill With CLS	$57,337,369		
		Injection Without CLS	$35,625,501		
		Injection With CLS	$47,307,372		

[a] Costs and pollutant removals are totals for seven years following promulgation (1996–2002), based on drilling activity schedules as provided by the industry.
[b] CLS = Closed-loop solids control equipment.

2.1 CURRENT PRACTICE

BPT effluent limitations for coastal drilling fluids and cuttings prohibit the discharge of free oil (using the visual sheen test). However, because of either EPA general permits, state requirements, or operational preference, no discharges of drilling fluids, drill cuttings, or dewatering effluent are occurring in the North Slope, the Gulf coast states, or California. The only coastal operators discharging drilling fluids and cuttings are located in Cook Inlet. In Cook Inlet, neither diesel nor mineral-oil-based drilling fluids or resultant cuttings may be discharged to surface waters because they have been shown to cause a visible sheen upon the receiving waters. Compliance with the BPT limitations may be achieved either by product substitution (substituting a water-based or synthetic material-based fluid for an oil-based fluid), recycle and/or reuse of the drilling fluid, grinding and injection, or by onshore disposal of the drilling fluids and cuttings at an approved facility.

NPDES permits issued by EPA for Cook Inlet drilling operations have also included BAT limitations on "best professional judgement" (BPJ). The permit requirements allow discharges of drilling fluids and drill cuttings provided certain limitations are met including a prohibition on the discharges of free oil, diesel oil, and oil-based drilling fluids, as well as limitations on mercury, cadmium, and oil content (see Chapter III for a summary of the permits). The toxicity of drilling fluids is controlled by "preapproval" requirements that limit drilling fluid constituents to "generic" drilling fluids and authorized additives only. Operators may employ any number of the following waste management practices to meet those permit limitations:

- Product substitution - to meet prohibitions on free oil and diesel oil discharges, as well as the toxicity requirements and clean barite limitations,
- Onshore treatment and/or disposal of drilling fluids and drill cuttings that do not meet the permit requirements,
- Waste minimization - enhanced solids control to reduce the overall volume of drilling fluids and drill cuttings,
- Conservation and recycling/reuse of drilling fluids, and
- Grinding and injection.

3.0 OVERVIEW OF METHODOLOGY

A set of detailed spreadsheets was developed for predicting industry-wide compliance costs and pollutant removals for each regulatory option considered (see Appendix X-1). All costs are for BAT or BCT, and no costs are attributed to NSPS since there are no plans for construction of any new development wells from new platforms in Cook Inlet. (All well drilling will be from existing platforms and is therefore defined as existing sources.) In characterizing the coastal Alaska drilling industry, EPA used the drilling activity plans or schedules as provided by the industry which actually covered only a 7-year period, from 1996 through 2002, because no information on drilling beyond this time was available.[9] The typical volumes of drilling fluids and cuttings generated during a drilling event were estimated based on information provided by the industry in the 1993 Coastal Oil and Gas Questionnaire (see Worksheet 1 in Appendix X-1). The disposal costs were estimated based on the cost and operation information provided by the industry (see Worksheets 2 to 4A in Appendix X-1).

EPA also considered the logistical difficulties of transporting drilling wastes in Cook Inlet as part of its costing analysis of the options. To accomplish zero discharge via landfill, operators would have to transport drill wastes to a staging location on the eastern side of Cook Inlet by supply boat. During the summer months, the one operator with access to an existing Cook Inlet landfill would then transfer the wastes to barges for transport to the landfill which is located on the west side of the Inlet. During ice conditions, the wastes would have to remain stored at the transfer station until they could be transported by barge. Other operators would transport wastes via truck from the east side of Cook Inlet to a landfill located in Arlington, Oregon. Details of waste transport information and data are discussed below.

Details of the methodology used to develop the compliance costs and pollutant removals presented in Table X-1 are discussed in Sections 4.0 and 5.0, respectively. Although the zero discharge scenarios are not considered to be feasible for all facilities in Cook Inlet, the analyses of costs and pollutant reductions are included here to provide an indication of the magnitude of costs that would be faced by a given facility. While not considered feasible throughout Cook Inlet, it is conceivable that site-specific data may be developed that would indicate that zero discharge may be available at some locations. In such instances, it is possible that water quality considerations may warrant imposition of zero discharge limitations on a site-specific basis where feasible.

4.0 COMPLIANCE COST METHODOLOGY

The following sections detail the methodology used to develop compliance cost estimates for the four Option 2 (zero discharge) scenarios. The compliance costs for these four scenarios are presented in Table X-2. Option 1 is reflective of current industry practice and would not incur incremental compliance costs.

4.1 GENERAL ASSUMPTIONS AND INPUT DATA

All four zero discharge cost scenarios are based on the total volume of drilling waste (including drilling fluids and drill cuttings) estimated for currently planned drilling activity in Cook Inlet. This total volume was calculated based on the numbers of new wells and recompletions planned by the Cook Inlet operators, and the estimated volume of waste generated by a "model" Cook Inlet drilling project. The following sections discuss the bases of these estimates. Additional sections discuss the means of achieving zero discharge, namely transportation and landfilling, grinding and injection.

4.1.1 Drilling Activity

The compliance cost analysis is based on the most current drilling plans available from the Cook Inlet operators. The total volume of fluids and cuttings generated was estimated from the projection of the number of wells to be drilled by the industry and the average volume of waste generated from each well. Table X-3 presents the numbers of platforms, new wells and recompletions included for each operator based on information provided by industry. EPA estimates that the total amount of drilling fluids and cuttings annually generated from the drilling activities listed in Table X-3 is 89,438 barrels per year, or 626,070 barrels over the next seven years.

One operator that was included in the proposed analysis has no further plans to drill in Cook Inlet and is therefore not included in the analysis presented in this document. In the proposal analysis, this operator was designated as Operator C. In the current analysis, Operator C represents a different company.

4.1.2 Model Well Characteristics and Costs

The drilling waste compliance cost analysis was based on the total estimated volume of drilling fluids and drill cuttings generated from a typical or "model" Cook Inlet well. Various characteristics of

TABLE X-2

DRILLING WASTE COMPLIANCE COSTS FOR FOUR ZERO-DISCHARGE SCENARIOS[a] (1995 $)

Waste Management Scenario	Total Drilling Waste Volume Disposed (bbls)	Total Compliance Cost	Cost per Barrel of Waste Disposed	Cost per Platform	Cost per Drilling Event	Cost per New Well	Cost per Recompletion
Landfill Without CLS[b]	626,070	$66,167,388	$106	$6,015,217	$1,084,711	$1,501,859	$229,558
Landfill With CLS	431,988	$57,337,369	$133	$5,212,488	$939,957	$1,301,436	$198,924
Injection Without CLS	626,070	$35,625,501	$57	$3,238,682	$584,025	$808,623	$123,598
Injection With CLS	431,988	$47,307,372	$110	$4,300,670	$775,531	$1,073,777	$164,126

[a] Costs in this table are from Worksheets 2, 3, 4, and 4A in Appendix X-1. Total costs represent costs incurred over the seven-year period following promulgation, from 1996 through 2002.

[b] CLS = Closed-loop solids control equipment.

TABLE X-3

SCHEDULE OF DRILLING ACTIVITY BY OPERATOR IN COOK INLET, ALASKA FOR SEVEN YEARS AFTER PROMULGATION

Operator	Number of Platforms With Planned Drilling Program	Number of New Wells to be Drilled	Number of Existing Wells to be Recompleted
A	1	3	1
B	9	28	19
C	1	10	0
TOTALS	**11**	**41**	**20**

Note: The identity of the operators is confidential. Sources of this information are listed in a memorandum filed as confidential business information.[9]

the model well, such as depth, waste volumes, and cost of drilling, were incorporated into the four Option 2 waste management scenarios discussed in Section 2.0.

The model Cook Inlet well was developed from industry data submitted to EPA in the 1993 Questionnaire for Coastal Oil and Gas Operators.[3] Worksheet 1 in Appendix X-1 presents the detailed calculations involving the model well data, as well as the cost of drilling an injection well based on these data. All wells considered in this estimation were drilled in three intervals to an average total depth of 11,765 feet. The volume of drilling waste (drilling fluids and drill cuttings) generated from an average 11,765-foot well was estimated to be 14,354 barrels with an average cuttings content of 19 percent by volume. This volume compares well with the 13,500 bbl per well provided by industry.[9] Since no information was available on the volumes of drilling waste generated during recompletion of existing wells, EPA assumed that the volume of drilling fluids and drill cuttings generated during an average recompletion is equal to the average volume of wastes generated during the last drilling interval of a new well. This volume was estimated to be 2,194 barrels and was assumed to contain 19 percent cuttings by volume. This volume is a conservative estimate when compared to the volumes estimated for recompletions in the Gulf of Mexico: 1,803 barrels of drilling fluid and 72 barrels of drill cuttings per job.[10]

The estimated drilling waste generation rate and the percent cuttings were used to estimate the total volumes of waste drilling fluids and drill cuttings generated for each operator. The estimated total industry-wide volume of waste drilling fluids and drill cuttings generated is the sum of all volumes estimated for each operator. An industry source stated that under current NPDES permit requirements, the volume of non-complying drilling waste is generally less than one percent (1%) of the total generated waste volume.[11] Therefore, EPA estimates that one percent of all generated drilling waste in Cook Inlet is currently not meeting the existing permit requirements and limitations in this region and therefore cannot be discharged.[11] Since all disposal costs are directly proportional to the amount of drilling fluids and drill cuttings that are currently generated, all estimated total disposal volumes were reduced by one percent to reflect current practice. Thus, the amount of drilling fluids and drill cuttings discharged is estimated to be one percent less than the amount generated.

Hence, for the two compliance cost scenarios without closed-loop solids control equipment, the waste volume for each new well drilled is 99 percent of the total average 14,354 bbls of waste calculated for the model well, or 14,210 bbls. The waste volume per recompletion comprises 99 percent of the 2,194 bbls generated in the third interval (from 9,901 to 11,765 feet) of the model well, or 2,172 bbls.

For the two scenarios with closed-loop solids control equipment, the per-well waste volume was reduced 31 percent in addition to the one percent reduction due to current practice. The additional volume reduction is attributed to the application of high-efficiency closed-loop solids control. A detailed description of the closed-loop systems is presented in Chapter VII of this document. The per-well waste volumes used in these scenarios are 9,805 bbls and 1,499 bbls for new wells and recompletions, respectively.

In the scenarios involving injection of drilling wastes, the cost of drilling an injection well was derived from 1993 Questionnaire data, as shown in Worksheet 1 in Appendix X-1. The $1,313,897 (1995 dollars) cost of this injection well was adjusted from 1992 dollars to 1995 dollars using the Engineering News Record Construction Cost Index (ENR-CCI) ratio of 5471/4985 (1.0975).[12] This cost appears in Worksheets 4 and 4A, as described in Section 4.3.3.

4.1.3 Transportation and Onshore Disposal Costs of Drilling Wastes

For Cook Inlet operators, on-land disposal sites in Alaska are available only to Operator B. This operator owns an oil and gas landfill disposal site on the west side of the Inlet. EPA has determined that there is sufficient on-land disposal capacity to accept all of the drilling fluids and cuttings generated by this operator at this disposal facility.[13] EPA investigated the logistical difficulties of storing and transporting drilling wastes in Cook Inlet due to the extensive tidal fluctuations, strong currents, and ice formation during winter months. Based on operational difficulties in conjunction with the long distances that the wastes must be hauled by most operators to disposal sites outside of Cook Inlet, EPA found that zero discharge was not technologically available to Cook Inlet operators. EPA nevertheless did an analysis of the costs of zero discharge assuming that zero discharge could be attained in order to assess the economic impacts of zero discharge. EPA has taken into consideration supplementary costs incurred by additional winter transportation and storage of drilling wastes in its cost evaluation of this option. However, the feasibility of this option throughout Cook Inlet is questionable.

EPA costed the zero discharge option assuming that all operators would use supply boats to transport generated drilling fluid and drill cuttings to location on the east side of Cook Inlet. Operator B would transfer the drilling wastes into barges during the summer months, or temporarily store the wastes at an east-side facility during winter months when barge traffic is not possible due to sea ice conditions. For example, the upper Cook Inlet would be covered by solid ice in winter if it were not for large tidal ranges (frequently in excess of 30 feet). Because these large tidal ranges produce very strong currents, moving broken ice is a common occurrence in Cook Inlet.[14] Ice typically covers upper Cook Inlet for about four months during the year and portions of the lower Cook Inlet for about three months during the year.[14] Therefore, during ice conditions, only V-hulled vessels can be used to transport drilling wastes. Because of tidal fluctuations in the summer and ice conditions in winter, EPA costed this option assuming V-hulled supply vessels rather than barges would be used for transporting supplies to and wastes from platforms.

EPA costed zero discharge by assuming barges would be used by Operator B to transport wastes to the west side of Cook Inlet because during low tide the water depth prohibits access by V-hulled vessels.[15] EPA further assumed that since no docking facility is available on the west side of the Inlet, the offloading of barges would have to be done by building earthen ramps onto the beach to provide access to the barge. Barges would then have to be maneuvered to the earthen ramps during the high tide. When the tide recedes, the barges would be beached near the ramps and unloading resumes.

For all other operators, EPA costed this option assuming that drilling wastes would be transported from the east side of Cook Inlet by truck to a landfill in Arlington, Oregon. There is also capacity for the waste volumes generated over the seven year period at a disposal site in Idaho. The Idaho facility information was used in the proposal analysis and was based on responses to the 1993 Coastal Oil and Gas

Questionnaire. However, costs for the final rule were based on the transportation and disposal costs at the Oregon facility.

4.1.4 Grinding and Injection

To meet the zero discharge requirements of Option 2, Cook Inlet operators could elect to grind and inject the drilling waste if suitable geology were found to be available. Disposal of drilling wastes by injection requires: (1) installation of processing equipment to grind the solids into a slurry liquid with fine particles; (2) installation of injection equipment for delivery of the processed wastes into a subsurface formation; and (3) installation of injection wells to allow injection into suitable subsurface formations.

Grinding and injection is a relatively contemporary technology that has been successfully demonstrated on the North Slope, and has been used to a limited extent on the Gulf Coast. While it was evaluated as a disposal scenario, grinding and injection is not used in the cost basis for Cook Inlet because geology amenable to grinding and injection does not appear to be available throughout Cook Inlet and transportation of such wastes to where it could be reinjected is further not available due to operational difficulties faced by operators. Nonetheless, EPA did calculate the compliance costs for such an option with the following assumptions. EPA assumed that all platforms in question require retrofitting for installation of processing and injection equipment. According to industry, operators with multiple platforms do not need to purchase or lease injection equipment for each platform since such equipment could be shared between platforms.[16] Processing and injection equipment for use on platforms can be constructed in package units in such a way that the entire unit could be transported and placed on a platform when needed, provided that adequate space is available on that platform and that the formations are suitable for accepting the waste.

Operators in Cook Inlet have the option of either purchasing or leasing the processing and injection equipment. EPA evaluated both the costs of leasing and purchasing of this equipment for the purpose of compliance cost calculations. According to industry sources, the 1992 unit cost of purchasing processing and injection equipment was approximately $1,000,000 and the unit rental cost of the same equipment was approximately $1,500 per day.[13] The total equipment purchase and rental costs for each operator were indexed to 1995 dollars and presented in Worksheets 4 and 4A in Appendix X-1. The calculated total purchasing costs of grinding and injection equipment were greater than total rental costs for all operators included in this compliance cost analysis.

Injection of processed drilling waste also requires access to a suitable subsurface formation. EPA based injection costs on drilling injection wells to a depth of 4,000 feet.

4.2 OPTION 2: ZERO DISCHARGE

The methodologies used to develop the four zero-discharge cost scenarios are described in the following sections. Worksheets 2, 3, 4 and 4A in Appendix X-1 present the detailed cost calculations.

4.2.1 Landfill Without Closed-Loop Solids Control

Worksheet 2, located in Appendix X-1, presents the detailed calculation of the compliance cost for achieving zero discharge via landfill without the use of incremental closed-loop solids control equipment.

An onshore disposal cost of $103 per barrel was calculated for Operator B. This unit cost takes into account the costs of all transportation, purchasing waste containers, temporary storage, and landfill gate fees. This unit cost was calculated based on the following assumptions:

- Eight-barrel fluid/cuttings boxes (4 feet x 4 feet x 4 feet) are used to store the drilling waste prior to landfill disposal, with a purchase cost of $125 per box.[13,15]
- Supply boats are used to transport the drilling waste from the platforms to a temporary onshore storage facility on the east side of the inlet at the rate of $5,000 per day per boat, including loading and unloading costs.[9]
- Supply boats currently make two regularly scheduled trips per week to each platform.[9]
- Supply boats have a capacity of 300 tons on deck (for cuttings boxes) and 170 tons below deck (for bulk drilling fluids).[17]
- Platform capacity for storing waste cuttings is 12 boxes.[9]
- Transportation for one supply boat load of drilling waste to the east-side temporary storage area includes: one day for loading boxes onto the supply boat and transporting to the east Cook Inlet docking area, and one day for unloading boxes and transporting by truck to the temporary storage area.[15]
- Trucks that are used to transport drilling waste to the temporary onshore storage area have a capacity of 12 boxes per load, and cost $300 per load.[13]
- Barges that are used to transport drilling waste from the east Cook Inlet docking area to the existing landfill facility on the west side of the inlet have a capacity of 240 boxes, and cost $6,000 per day.[9,18]

- Transportation from temporary storage to the west side Cook Inlet landfill includes: one day to truck the wastes from the storage area to the docking facility and load the barges, one day to barge the wastes to the west side unloading area, and one day to unload boxes and truck them to the landfill.[15]

- Additional costs were included to address industry comments regarding specific fees associated with disposal at the Kustatan landfill, as follows:[9]

  - Platform waste handling cost: $ 6.90/bbl
  - Waste stabilization cost: $12.47/bbl
  - Landfill usage fee: $45.38/bbl
  - Fill cell cost: $ 8.28/bbl

Operators A and C were assigned costs associated with the use of a landfill located in Arlington, Oregon. The unit landfill cost applied to these operators was $112/bbl, as per the following assumptions:

- Transportation of the drilling wastes includes the use of supply boats from the platform to an east Cook Inlet docking facility followed by the use of trucks from the docking facility to Arlington, Oregon.[19]
- Supply boats are assumed to have the same capacity, frequency, and cost as described above (see also Appendix X-2).
- Trucks transporting drilling wastes from the east-side docking facility to Arlington, Oregon have a 22-ton capacity and cost $1,800 per load.[20]
- The Arlington, Oregon disposal facility cost is $500 per eight-barrel cuttings box.[19]

Other assumptions established for Operator B, including the cost of cuttings boxes and platform storage capacity, are also applied to the costs for Operators A and C. The detailed calculation of the unit landfill costs for these operators is presented in Appendix X-2.

4.2.2 Landfill With Closed-Loop Solids Control

The land disposal with the closed-loop systems scenario assumes installation of high efficiency solids separation units to minimize the volume of drill waste generated. The components of a closed-loop system considered by EPA include high efficiency shale shakers, mud cleaners, chemically enhanced centrifugation (CEC), waste storage tanks, and transfer equipment. Installation of closed-loop systems reduces the overall landfill and transportation costs but will incur additional costs of retrofitting the platform, purchasing or leasing of high efficiency separation equipment, and operating the equipment.

Installation of closed-loop systems will enable the operator to reuse the same drilling fluid for a longer period of time and therefore reduce the need to introduce fresh drilling fluid into the system. However, a platform may not have adequate deck space for installation of additional solids separation systems and may require retrofitting. The Agency estimated an average retrofitting cost of $270,000 and assumed that all platforms need retrofitting. This retrofitting cost was estimated based on the need for 450 square feet of additional deck space at the rate of $600 per square foot.[16,21]

Based on information obtained from Gulf of Mexico industry sources, EPA estimated an average cost of $2,085 per day for leasing high efficiency solids separation systems.[21] The estimated $2,085 per day costs include all maintenance costs. However, the Agency added an additional cost of $1,098 per day for any additional operating costs that may be needed in Cook Inlet. The $1,098 per day operating cost was reported by Cook Inlet industry sources for operation of waste processing and injecting equipment.[22] Since a closed-loop system is comparable to a processing and injecting system in terms of labor requirements, the Agency assumed the unit operating cost determined for operation of injection systems as the unit operating cost for operation of closed-loop systems. The total equipment and operating costs of a closed-loop system were calculated from the total number of drilling events for each operator, the average drilling period estimated for each drilling event, the unit equipment cost, and the unit operating cost. These costs were adjusted from 1992 dollars to 1995 dollars using the ENR-CCI of 5471/4985 (1.0975).[12] The same $103 per barrel and $112 per barrel land disposal unit costs specified for Worksheet 2 were also used for this disposal method.

4.2.3 Subsurface Injection Through Dedicated Wells

Subsurface injection of drilling waste through a dedicated injection well involves the installation of dedicated injection wells to a suitable underground formation, grinding of the drilling fluid and drill cuttings solids into a slurry liquid with fine particles, and injection of processed waste into the subsurface formation.

The total industry-wide disposal cost for this method includes the costs of dedicated injection wells, platform retrofitting, injection equipment, and injection equipment operation. The unit cost of installing a 4,000-foot injection well was estimated to be $1,313,897 per well in Worksheet 1. For the zero discharge option (Option 2), the number of dedicated wells was estimated for each operator based on the assumption that one injection well is needed for every 4 new drillings[23] and one for every 16 recompletions. The assumption for one injection well for every 16 recompletions was based on the approximate ratio of

4:1 between the estimated volumes of drilling waste generated from a new well and a recompletion which was shown in the 1993 Coastal Oil and Gas Questionnaire data.[3]

The cost of retrofitting platforms was assumed to be $750,000 per platform based on information provided by the industry.[13] The Agency assumes that all platforms would need retrofitting. Based on information obtained from industry, it was further assumed that operators with multiple platforms do not need to install injection equipment at each platform, because injection equipment could be shared as long as space is available at each platform.[13] Based on information provided by industry, it was assumed that 4 injection units would be adequate for Operator B which operates 12 platforms in Cook Inlet. For the other operators with only one platform, one injection unit was assumed for each platform.

The costs of acquiring injection equipment were estimated for both purchasing and leasing of the equipment based on $1,097,500 per system for purchasing or $1,537 per day for leasing.[13] These costs were indexed from 1992 dollars to 1995 dollars using the ENR-CCI of 5471/4985 (1.0975).[12] All operators were assigned the lesser cost of leasing equipment in this analysis.

The last scenario investigated for achieving zero discharge was the use of closed-loop solids control technology followed by grinding and injection. Worksheet 4A in Appendix X-1 presents the detailed calculations for this scenario. The costs and assumptions developed for Worksheets 3 and 4 were combined in this scenario. Specifically, the total waste volume (431,988 bbls) is the same as the waste volume in Worksheet 3, reflecting the waste-minimizing effect of closed-loop solids control equipment. Itemized costs include both solids control equipment and grinding and injection equipment. The purpose of this analysis was to determine whether minimizing the waste volume would reduce the overall compliance cost. The analysis showed that the additional equipment costs override the savings earned through waste minimization, resulting in a total cost that was 33 percent greater than the cost of grinding and injecting without waste minimization (see Table X-1).

5.0 POLLUTANT REMOVALS

The following sections describe in detail the methodology used in determining pollutant removals associated with Option 2 (zero discharge). There are no incremental pollutant removals associated with Option 1 because it represents current industry practice in Cook Inlet, Alaska.

5.1 GENERAL ASSUMPTIONS AND INPUT DATA

The following sections describe the assumptions and input data used to develop pollutant removals for drilling wastes in the Cook Inlet region. These sections include the following topics:

- Drilling fluid characteristics
- Drill cuttings characteristics
- Mineral oil content
- Barite characteristics.

5.1.1 Drilling Fluid Characteristics

Since the drilling fluid characteristics change as drilling proceeds to greater depths, an average mud density was assumed for the purposes of determining the pollutant loadings. Based on the information provided by the industry in the 1993 Coastal Oil and Gas Questionnaire and information obtained through sampling trips, EPA assumed a 10 pound per gallon mud with 11 percent solids by volume to have the average characteristics (density) of the mud system used over the entire drilling project.[24] Using the same bases of information, the density of dry solids and concentration of barite in this mud were estimated to be 1,025 pounds per gallon and 24 pounds per gallon, respectively.[25] The drilling fluid characteristics are also discussed in Chapter VII of this document.

5.1.2 Drill Cuttings Characteristics

In order to calculate the total suspended solids (TSS) loading due to spent drill cuttings, the density of dry drill cuttings was estimated. Based on a geological stratigraphic profile provided by the industry, dry drill cuttings were estimated to have a density of 980 pounds per barrel on a dry weight basis.[26] For the purpose of the pollutant loading analysis for this rule, the volume of wet cuttings was estimated to be 19 percent of the total volume of drilling wastes.[3] The volume of dry drill cuttings was determined by subtracting the amount of drilling fluid (estimated to be 5 percent by volume[2]) that adheres to the cuttings discarded from the solids separation equipment. Since dry cuttings are generally comprised of inert material, no hydrocarbons or metals were assumed to be present in the dry drill cuttings. Drill cuttings characteristics are also discussed in Chapter VII of this document.

5.1.3 Mineral Oil Content

Based on information obtained from the 1993 Coastal Oil and Gas Questionnaires, EPA assumed a mineral oil content of 0.02 percent by volume in the entire volume of drilling waste generated from drilling operations in Cook Inlet.[27] Since there are generally no significant sources of organic pollutants in the drilling waste other than any oil based lubricant added to the drilling fluid system, it is assumed that the mineral oil is the only source of organic pollutants in the spent drilling fluid and drill cuttings. Table X-4 presents the organic constituents in the mineral oil used to calculate the pollutant loadings for this rulemaking. The concentrations in Table X-4 are averages of concentrations for three types of mineral oil presented in the Offshore Development Document.[8]

5.1.4 Barite Characteristics

Barite is the primary source of metals (cadmium, mercury, and other priority pollutants of concern) in drilling fluids. The characteristics of the raw barite used will determine the concentrations of metals in the drilling fluid and thus, provide EPA with the bases to determine pollutant reductions for each technology option. The concentrations of metals in drilling fluids containing barite have been shown to be directly related to the concentrations of cadmium and mercury in the stock barite.[26] The current NPDES permits in Cook Inlet have limitations on the concentrations of cadmium and mercury in the stock barite. Stock barite that meets regulated metals limitations is referred to in this document as "clean" barite. For the purposes of calculating the BAT metals concentrations in drilling fluids, the metals concentrations of clean barite was used.

The mean metals concentrations for clean barite are presented in Table X-5. The metals concentrations represent averages of data from Region 10 Discharge Monitoring Report Data.[26] The metals concentrations from Region 10 are considered to represent those of clean barite. Where no concentration data were given for an analyte in the Region 10 data, the concentration of the analyte from the 15 Rig Study from the Gulf of Mexico was incorporated.[26] The barium concentration reported in Table X-5 was calculated from the total pounds of barite in the drilling fluid.[25] The barite was assumed to be pure barium sulfate (100% $BaSO_4$) and the barium sulfate was assumed to contain 58.8 percent (by weight) barium.[8] For the purposes of calculating the pollutant loadings for the BAT option, use of clean barite was assumed for drilling operations in Cook Inlet, Alaska.

TABLE X-4

ORGANIC CONSTITUENTS IN MINERAL OIL
(mg/ml, unless noted otherwise)

Organic Constituent	Concentration (mg/ml)
Benzene	ND
Ethylbenzene	ND
Naphthalene	0.05
Fluorene	0.08
Phenanthrene	0.12
Phenol (ug/l)	ND
Alkylated benzenes[a]	30.0
Alkylated naphthalene[b]	0.49
Alkylated fluorenes[b]	1.74
Alkylated phenanthrenes[b]	0.14
Alkylated phenols[c]	ND
Total biphenyls[b]	1.94
Total dibenzothiophenes (ug/g)	370

Notes: The above data are averages of data presented in Table VII-9 of the 1993 Offshore Development Document for three types of mineral oil.[8] Averages include only detected values.
ND = Not Detected for all three types of mineral oil
[a] Includes C_1 through C_6 alkyl homologues
[b] Includes C_1 through C_5 alkyl homologues
[c] Includes cresol and C_2 through C_4 alkyl homologues

5.2 INCREMENTAL POLLUTANT REMOVALS

The total industry-wide incremental pollutant removals were estimated for Option 2 based on the total incremental volume and pollutant concentrations in the generated drilling fluids and drill cuttings. Table X-6 presents the pollutant loadings and removals for Option 2. Loadings are the product of the pollutant concentrations and the waste volume discharged following a particular treatment. The loadings resulting from zero-discharge are all 0 barrels per year because no discharge would be allowed. The

TABLE X-5

METALS CONCENTRATIONS IN BARITE

Metal	"Clean" Barite Concentration (mg/kg)
Cadmium	1.1[a]
Mercury	0.1[a]
Aluminum	9,069.9[b]
Antimony	5.7[b]
Arsenic	7.1[a]
Barium	33,000.0[25]
Beryllium	0.7[b]
Chromium	240.0[a]
Copper	18.7[a]
Iron	15,344.3[b]
Lead	35.1[a]
Nickel	13.5[a]
Selenium	1.1[b]
Silver	0.7[b]
Thallium	1.2[b]
Tin	14.6[b]
Titanium	87.5[b]
Zinc	200.5[b]

[a] Region 10 DMR Data[26]
[b] 15 Rig Study[26]

pollutant reductions, also presented in Table X-6, are the difference between the loadings from current practice and the loadings resulting from zero discharge. Therefore, the overall reductions for this option are equal to the total loadings calculated for current discharges because the application of zero discharge essentially removes all pollutants currently being discharged. Detailed calculations for the removals analysis are presented in Worksheet 10, Appendix X-3.

EPA used the drilling waste volume of 626,070 bbls (over the seven-year period following promulgation) to calculate the pollutant removals. EPA used this non-closed-loop solids control volume

TABLE X-6

COOK INLET DRILLING WASTE POLLUTANT LOADINGS AND REMOVALS BASED ON ZERO DISCHARGE[a]

Pollutant	Annual Loadings Based on Current Practices[b] (lbs/yr)	Annual Loadings Based on Zero Discharge (Option 2)[c] (lbs/yr)	Annual Removals[d] (lbs/yr)	Cumulative Removals[e] (lbs)
Conventionals				
TSS (Total)	24,084,790	0	24,084,790	168,593,529
Oil Content (Total)	4,368	0	4,368	30,579
Total Conventionals	24,089,158	0	24,089,158	168,624,108
Priority Pollutant Organics				
Naphthalene	0.3	0	0.3	1.8
Fluorene	4.1	0	4.1	28.9
Phenanthrene	0.6	0	0.6	4.3
Total P.P. Organics	5.0	0	5.0	35.0
Priority Pollutant Metals				
Cadmium	9.1	0	9.1	63.6
Mercury	0.8	0	0.8	5.8
Antimony	47.1	0	47.1	329.7
Arsenic	58.7	0	58.7	410.7
Beryllium	5.8	0	5.8	40.5
Chromium	1,983.4	0	1,983.4	13,883.5
Copper	154.5	0	154.5	1,081.8
Lead	290.1	0	290.1	2,030.5
Nickel	111.6	0	111.6	780.9
Selenium	9.1	0	9.1	63.6
Silver	5.8	0	5.8	40.5
Thallium	9.9	0	9.9	69.4
Zinc	1,656.9	0	1,656.9	11,598.5
Total P.P. Metals	4,342.7	0	4,342.7	30,399.1
Non-Conventionals				
Aluminum	74,953.7	0	74,953.7	524,675.6
Barium	991,680.1	0	991,680.1	6,941,760.9
Iron	126,805.3	0	126,805.3	887,637.2
Tin	120.7	0	120.7	844.6
Titanium	723.1	0	723.1	5,061.7
Alkylated benzenes[f]	154.0	0	154.0	1,078.3
Alkylated napthalenes[f]	2.5	0	2.5	17.6
Alkylated fluorenes[f]	8.9	0	8.9	62.5
Alkylated phenanthrenes	1.0	0	1.0	7.3
Total biphenyls[f]	10.0	0	10.0	69.8
Total dibenzothiophenes	0.03	0	0.03	0.2
Total Non-Conventionals	1,194,459	0	1,194,459	8,361,216
Total Loadings	25,287,965	0	25,287,965	177,015,758

a Source: Appendix X-3
b Values are from Column 4 of Worksheet 10, divided by 7 years (See Appendix X-3)
c Values are from Column 6 of Worksheet 10, divided by 7 years (See Appendix X-3)
d Values are from Column 7 of Worksheet 10, divided by 7 years (See Appendix X-3)
e Total cumulative reductions cover the 7-year period from 1996 through 2002.
f These analyte groups contain both priority pollutants and non-conventional pollutants, but were not distinguished in the source document.

because in the absence of a zero-discharge requirement, Cook Inlet operators would not use closed-loop technology since they are already accomplishing a fairly high level of solids control.

The values in Column 3 of Worksheet 10 (page 2), "Amount of Total Drilling Waste Currently Discharged," are calculated on page 1 of the worksheet. The value by which heavy metal concentrations are multiplied (57,848,007 lbs) is the dry weight of the total volume of drilling fluids expected to be discharged over the next seven years. This value is used in Column 3 because the metals concentrations are given on a dry weight basis, and because it is assumed that metal contaminants are associated only with barite in the drilling fluid (see Section 5.1.4.). The value by which organic and total oil concentrations are multiplied (513,064 bbls) is the volume of drilling fluids expected to be discharged over the next seven years. The concentrations of these pollutants are given on a volumetric basis.

Column 5 of Worksheet 10 presents the percentage of the amounts reported in Column 3 that will be discharged following application of each option. Worksheet 10 shows 0% discharged following the zero-discharge option.

Page 1 of Worksheet 10 provides calculations for the total suspended solids (TSS) values in the drill cuttings and the drilling fluids. The TSS value for the drill cuttings is equal to the total weight of dry cuttings, calculated as the product of the estimated volume of dry cuttings discharged (i.e., 95 percent of the wet cuttings volume) and the density of the dry cuttings. The TSS value for the drilling fluids is the product of the estimated volume of drilling fluids discharged (comprised of 81 percent of the drilling waste volume plus 5 percent of the wet cuttings volume as adhering drilling fluid), the percent of dry solids in the mud by volume (11 percent), and the density of dry solids in drilling fluid. The TSS value for drilling fluids in Column 4 of Worksheet 10 (57,848,007 pounds) is also the value of the dry-basis weight of waste discharged, listed in Column 3.

6.0 BCT COMPLIANCE COSTS AND POLLUTANT REMOVALS DEVELOPMENT

6.1 BCT METHODOLOGY

The methodology for determining "cost reasonableness" was proposed by EPA on October 29, 1982 (47 FR 49176) and became effective on August 22, 1986 (51 FR 24974). These rules set forth a procedure which includes two tests to determine the reasonableness of costs incurred to comply with candidate BCT technology options. If all candidate options fail any of the tests, or if no candidate technologies more stringent than BPT are identified, then BCT effluent limitations guidelines must be set at a level equal to BPT effluent limitations. The cost reasonableness methodology compares the cost of conventional pollutant removal under the BCT options considered to be the cost of conventional pollutant removal at publicly owned treatment works (POTWs).

BCT limitations for conventional pollutants that are more stringent than BPT limitations are appropriate in instances where the cost of such limitations meet the following criteria:

- The POTW Test: The POTW test compares the cost per pound of conventional pollutants removed by industrial dischargers in upgrading from BPT to BCT candidate technologies with the cost per pound of removing conventional pollutants in upgrading POTWs from secondary treatment to advanced secondary treatment. The upgrade cost to industry must be less than the POTW benchmark of $0.586 per pound ($0.25 per pound in 1976 dollars indexed to 1995 dollars).

- The Industry Cost-Effectiveness Test: This test computes the ratio of two incremental costs. The ratio is also referred to as the industry cost test. The numerator is the cost per pound of conventional pollutants removed in upgrading from BPT to the BCT candidate technology; the denominator is the cost per pound of conventional pollutants removed by BPT relative to no treatment (i.e., this value compares raw wasteload to pollutant load after application of BPT). The industry cost test is a measure of the candidate technology's cost-effectiveness. This ratio is compared to an industry cost benchmark, which is based on POTW cost and pollutant removal data. The benchmark is a ratio of two incremental costs: the cost per pound to upgrade a POTW from secondary treatment to advanced secondary treatment divided by the cost per pound to initially achieve secondary treatment from raw wasteload. The result of the industry cost test is compared to the industry Tier I benchmark of 1.29. If the industry cost test result for a considered BCT technology is less than the benchmark, the candidate technology passes the industry cost-effectiveness test. In calculating the industry cost test, any BCT cost per pound less than $0.01 is considered to be the equivalent of de minimis or zero costs. In such an instance, the numerator of the industry cost test and therefore the entire ratio are taken to be zero and the result passes the industry cost test.

These two criteria represent the two-part BCT cost reasonableness test. Each of the regulatory options was analyzed according to this cost test to determine if BCT limitations are appropriate.

6.2 BPT BASELINE

In order to estimate the incremental costs and the incremental conventional pollutant removals for the BCT options, BPT baseline compliance costs and pollutant removals for drilling fluids and drill cuttings were determined. BPT limitations prohibit the discharge of drilling fluids and drill cuttings containing free oil, as determined by the visual sheen test. The estimated costs incurred by industry to comply with the

BPT limitations consist of transportation and onshore disposal costs for all non-compliant drilling fluids and drill cuttings.

For the purpose of developing BPT compliance costs, EPA applied current waste management costs to the amount of drilling waste that currently does not meet BPT limitations. The following information was used to develop the BPT drilling costs and conventional pollutant removals:

- Based on information provided by the industry,[11] EPA estimates that approximately one (1) percent of the drilling waste currently generated in Cook Inlet cannot be discharged due to existing discharge requirements (see Chapter III, Section 3.0 for a review of current Region 10 NPDES regulations).

- Using the total drilling waste volume calculated for the seven-year period of anticipated drilling activity (626,070 bbl of drilling fluids and drill cuttings, from Appendix X-1), the total volume of waste estimated to incur BPT compliance costs is 6,261 bbl.

- Drilling waste composition and property data utilized in the pollutant removal analysis presented in Appendix X-1 are applied to this analysis as follows:

  - Combined drilling waste consists of 19 percent wet cuttings and 81 percent drilling fluids, by volume.[3]

  - Wet drill cuttings contain 5 percent by volume adhering drilling fluid.[2]

  - Drilling fluids contain 11 percent by volume dry solids.[25]

  - Average density of dry cuttings is 980 lbs/bbl.[28]

  - Average density of dry solids in drilling fluids is 1,025 lbs/bbl.[25]

  - Specific gravity of mineral oil is 0.85.[8] This converts to a density of 297.74 lbs/bbl (0.85 x 350 lbs water/bbl).

- The drilling fluid in the non-compliant drilling waste volume is estimated to contain 60 percent by volume mineral oil.[8]

- The unit cost of disposing drilling wastes at landfills is $106 per bbl (Worksheet 2, Appendix X-1).

Table X-7 presents the calculations for the BPT baseline disposal costs and conventional pollutant removals based on the above information. Table X-8 presents the results of the unit BPT costs for drilling fluids, drill cuttings, and for the drilling wastes combined. The values used in the Table X-8 calculations are the results of the calculations presented in Table X-7.

TABLE X-7

COOK INLET BPT DRILLING WASTE DISPOSAL COST AND CONVENTIONAL POLLUTANT REMOVAL CALCULATIONS

DISPOSAL COSTS
a) Drilling waste disposal cost is $106/bbl (Worksheet 2, Appendix X-1).
b) Total drill cuttings disposal cost: (0.19) x (6,261 bbls) x (106 $/bbl) = $126,097
c) Total drilling fluids disposal cost: (0.81) x (6,261 bbls) x (106 $/bbl) = $537,569
CONVENTIONAL POLLUTANT REMOVALS
a) TSS in drilling fluid disposed: (5,071 bbl drilling fluid) x (0.11) x (1,025 lbs/bbl) = 571,801 lbs TSS
b) Oil in drilling fluid disposed: (5,071 bbl drilling fluid) x (0.60) x (297.74 lbs/bbl) = 905,977 lbs Oil
c) TSS in cuttings disposed: (1,190 bbl wet cuttings) x (0.95) x (980 lbs/bbl) = 1,107,508 lbs TSS
d) Oil in cuttings disposed: (1,190 bbl wet cuttings) x (0.05) x (0.60) x (297.74 lbs/bbl) = 10,626 lbs Oil

TABLE X-8

COOK INLET DRILLING WASTE UNIT BPT COSTS

Waste Stream	Unit BPT Costs
Drilling Fluids	$\frac{\$571,801}{(571,801 + 905,977)} = \$0.364/lb$
Cuttings	$\frac{\$124,022}{(1,107,508 + 10,626)} = \$0.113/lb$
Drilling Fluids + Cuttings	$\frac{\$126,097 + \$537,569}{(571,801 + 905,977 + 1,107,508 + 10,626)} = \$0.256/lb$

6.3 BCT Compliance Costs, Pollutant Removals, and Cost Reasonableness Test

Only one BCT option was considered in the analysis: zero discharge of waste drilling fluids and drill cuttings. The BCT compliance costs and pollutant removals were based on the scenarios previously described in Section 4.2: 1) zero discharge via landfill and 2) zero discharge via injection. Although zero discharge was determined to be not available in Cook Inlet, the results of the BCT cost test calculations are presented to show whether such a limitation would pass the cost tests.

The conventional pollutant removals (for TSS and oil) are identical to those developed for the BAT options analysis. Table X-9 presents the TSS and oil removals calculated in Worksheet 10 of Appendix X-1 and used in the BCT cost reasonableness test. These removals are based on the total volume of drilling waste estimated to be disposed in the seven-year period following promulgation, 626,070 barrels of drilling fluid and drill cuttings (see Section 4.1).

TABLE X-9

CONVENTIONAL POLLUTANT REMOVALS[a]

Wastestream	Total Suspended Solids (TSS) (lbs)	Total Oil (lbs)	Total Conventional Pollutants (lbs)
Drilling Fluids	57,848,007	30,579	57,878,586
Dry Drill Cuttings	110,745,522	NA	110,745,522
Fluids + Cuttings	168,593,529	30,579	168,624,108

[a] Pollutant removals for conventional analytes (TSS and oil) are derived in Worksheet 10, Appendix X-1.

As stated above, the BCT costs were calculated for two zero discharge scenarios. The cost for the zero discharge via landfill scenario comes from Worksheet 3 in Appendix X-1 which includes costs for applying closed-loop solids control equipment. The total cost for this scenario is $57,337,369. To distinguish the cost of disposing drilling fluids from the cost of disposing drill cuttings in the BCT cost analysis, the total cost was multiplied by the percentage that each waste volume represents. Worksheet 1 in Appendix X-1 shows that 19 percent of the total wastestream is cuttings. Therefore, the cost of disposing cuttings was calculated to be $10,894,100 (0.19 x $57,337,369). Likewise, the cost of disposing drilling fluids was calculated to be $57,337,369 (0.81 x $57,337,369). Table X-10 presents these costs based on disposal via landfill, as well as the pollutant removals, the unit POTW cost, and the results of the BCT cost reasonableness test. As discussed elsewhere in this document, a zero discharge limitation for drilling fluids, drill cuttings and dewatering effluent was rejected for Cook Inlet because it was found to be unavailable (see Chapter XIV).

Table X-11 presents the BCT cost analysis for the second zero-discharge scenario, disposal via subsurface injection. The total cost for this scenario, from Worksheet 4 in Appendix X-1, is $35,624,501. The cost of disposing cuttings was calculated to be $6,768,845 (0.19 x $35,624,501), and the cost of disposing drilling fluids was calculated to be $28,856,656 (0.81 x $35,624,501).

TABLE X-10

BCT COST TEST RESULTS FOR DRILLING FLUIDS AND DRILL CUTTINGS BASED ON DISPOSAL COSTS FOR CLOSED-LOOP SOLIDS CONTROL AND LANDFILL

Wastestream	Total Conv.s Removed (lbs)	Total Costs[a] (1995$)	POTW Cost ($/lb)	Pass POTW? (<$0.586/lb)	BPT Cost ($/lb)	ICR Ratio	Pass ICR? (<1.29)
Drilling Fluid	57,878,586	46,443,269	0.802	N	0.364	NA	N
Dry Drill Cuttings	110,745,522	10,894,100	0.098	Y	0.113	0.87	Y
Fluids + Cuttings	168,624,108	57,337,369	0.340	Y	0.256	1.33	N

[a] Total cost for fluids+cuttings comes from Worksheet 3, Appendix X-1 (zero discharge via landfill). Total cost for fluids = 0.81 x $57,337,369; total cost for cuttings = 0.19 x $57,337,369.

TABLE X-11

BCT COST TEST RESULTS FOR DRILLING FLUIDS AND DRILL CUTTINGS BASED ON DISPOSAL COSTS FOR SUBSURFACE INJECTION

Wastestream	Total Conv.s Removed (lbs)	Total Costs[a] (1995$)	POTW Cost ($/lb)	Pass POTW? (<$0.586/lb)	BPT Cost ($/lb)	ICR Ratio	Pass ICR? (<1.29)
Drilling Fluid	57,878,586	28,856,656	0.499	Y	0.364	1.37	N
Dry Drill Cuttings	110,745,522	6,768,845	0.061	Y	0.113	0.54	Y
Fluids + Cuttings	168,624,108	35,625,501	0.211	Y	0.256	0.83	Y

[a] Total cost for fluids+cuttings comes from Worksheet 4, Appendix X-1 (zero discharge via subsurface injection). Total cost for fluids = 0.81 x $35,625,501; total cost for cuttings = 0.19 x $35,625,501.

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CHAPTER XI

COMPLIANCE COST AND POLLUTANT REMOVAL DETERMINATION-PRODUCED WATER

1.0 INTRODUCTION

This section presents the estimated compliance costs and reductions in pollutants discharged as a result of the treatment options developed for control of produced water. Currently, discharges of produced water in the coastal subcategory are occurring only in the Gulf of Mexico and Cook Inlet, Alaska. The technology costs represent additional investment required beyond those costs associated with BPT technologies. The methods used to develop compliance costs for the control options are presented in Sections 4 and 5. Pollutant reductions are presented in Section 6.

Treatment technology costs were estimated on a facility-specific basis. For operators in coastal areas of the Gulf of Mexico, regulatory compliance costs and pollutant removals are based on mathematical cost model equations applied to each production facility that is projected to be discharging produced water after January 1997. For operators in Cook Inlet, compliance costs and pollutant removals were estimated for each production facility that currently discharges produced water, based on the current level of treatment at each facility.

2.0 OPTIONS CONSIDERED AND SUMMARY COSTS

Three BAT options for produced water effluent limitations guidelines for existing coastal sources were considered in this estimate of compliance costs and pollutant removals:

- Option 1: Zero discharge except: (a) facilities discharging produced water derived from offshore subcategory wells into main [major] deltaic passes of the Mississippi River must meet a monthly average oil and grease content of 29 mg/l and a daily maximum of 42 mg/l; and (b) Cook Inlet facilities allowed to discharge must meet a monthly average oil and grease content of 29 mg/l and a daily maximum of 42 mg/l.
- Option 2: Zero discharge for all coastal facilities except in Cook Inlet, where discharges must meet the 29/42 mg/l oil and grease limitations.
- Option 3: Zero discharge for all coastal facilities.

2.1 OPTION 1

The technology basis for meeting the 29/42 mg/l limitations contained in Option 1 (and for Cook Inlet in Option 2) is improved operating performance of gas flotation. This technology consists of improved operation and maintenance of gas flotation treatment systems, more operator attention to treatment systems operations, chemical pretreatment to enhance system effectiveness, and possible re-sizing of certain treatment system components for increased treatment efficiency. The improved performance gas flotation technology basis was developed as part of the Offshore Oil and Gas rulemaking effort, and is described more fully in the 1993 Offshore Development Document.[1] Improved operation of gas flotation can result in additional removal of oil and grease from the produced water relative to BPT-level treatment systems. The discharge limitations on oil and grease as described in the regulatory options are more stringent than the current BPT limitations of 48 mg/l monthly average, 72 mg/l daily maximum. For those platforms or facilities that do not have gas flotation units, the installation of new flotation units was assumed necessary in the analysis to achieve compliance with the new limitations. For Cook Inlet, the compliance costs and pollutant removals calculated for Options 1 and 2 are identical since both options are based on improved operation of gas flotation.

2.2 OPTIONS 2 AND 3

For coastal Gulf of Mexico facilities, compliance costs and pollutant removals for Options 2 and 3 are identical since both options are based on subsurface injection of produced water. Subsurface injection is the predominant technology used for zero discharge compliance in the Onshore Subcategory. It consists of filtration followed by injection of produced water into a compatible geologic formation, either for disposal or for enhanced oil recovery or waterflooding. For operators in the Gulf of Mexico, the injection option includes cartridge filtration as pretreatment followed by injection for disposal. (For Cook Inlet operators, the injection option includes granular media filtration and gas flotation as pretreatment followed by injection either for waterflooding or for disposal. Injection may take place for enhanced oil recovery or for disposal, or for a combination of purposes.) Injection of produced water for enhanced oil recovery generates an economic benefit for the facility that has not been credited against zero discharge compliance costs.

In order to generate estimates of costs and pollutant removals for each option, EPA used the coastal Gulf of Mexico. The industry profile information was obtained from studies described in Chapter V, and includes state discharge monitoring data, EPA site visits and sampling reports, and direct contacts with the operators. This information consists of the following elements:

- Identification of currently discharging production facilities including name of the operator, state discharge permit number, location of the producing field, produced water discharge volumes, and date of compliance with state requirements for no discharge where applicable.

- Contaminant levels in produced water from BPT treatment.

All options considered for this regulation beyond the BPT level of control for the coastal region are based on two treatment technologies:

- Improved operating performance of gas flotation followed by discharge to surface water.

- Subsurface injection.

In referring to the options considered for control of produced water discharges, the Gulf of Mexico and Cook Inlet are presented separately in the option descriptions and accompanying discussion. All other coastal areas are practicing zero discharge of oil and gas production wastes, and will be subject to this rule, even though not mentioned specifically.

2.3 SUMMARY COSTS AND REDUCTIONS

Table XI-1 presents summary compliance costs for Options 1, 2, and 3 using the Region 6 General Permit to define regulatory baseline. Operating and maintenance (O&M) costs are estimated for the first year after implementation. These first year O&M costs may rise in subsequent years as produced water flow rates increase. This increase in O&M costs is addressed in the "Economic Impact Analysis for Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category."[2]

Table XI-2 presents summary compliance costs for Options 1, 2, and 3 using the alternative baseline. Compliance costs for Cook Inlet are identical to the baseline costs presented in Table XI-1. Operating and maintenance (O&M) costs are estimated for the first year after implementation, which may rise as produced water flow rates increase in the future.[2]

No new source facilities are expected to occur in facilities discharging produced water derived from offshore subcategory wells into main [major] deltaic passes of the Mississippi River. Discharges at other coastal facilities would already be required to comply with zero discharge under the Region 6 General Permits (60 FR 2387, January 9, 1995).[3] No new source production facilities are expected to occur in Cook

TABLE XI-1

TOTAL COMPLIANCE COSTS AND POLLUTANT REMOVALS FOR PRODUCED WATER BAT OPTIONS (BASELINE)

Options	Compliance Costs		Pollutant Removals (pounds)
	Capital Costs (1995 $)	O&M Costs (1995 $/yr)	
Option 1: Zero discharge except (a) major pass facilities and (b) Cook Inlet facilities = 29/42 mg/l oil and grease	11,051,065	1,455,085	2,281,305
Option 2: Zero discharge except Cook Inlet facilities = 29/42 mg/l oil and grease	30,512,598	10,774,115	1,494,100,361
Option 3: Zero discharge, all facilities	118,236,230	30,566,255	2,549,142,381

Inlet in the near future. Therefore, no NSPS costs or pollutant reductions are anticipated as a result of this rulemaking. However, due to frequent changes in the oil and gas industry, costs for a model new source facility in Cook Inlet have been estimated for purposes of analysis and are discussed in Section 4.3.

3.0 GULF OF MEXICO BASELINE COMPLIANCE COST METHODOLOGY

EPA determined that six production facilities will be discharging produced water from eight outfalls as of January 1997.[4] The produced water population consists of production facilities in Louisiana with medium to high produced water flow rates (referred to hereafter as medium/large facilities) that will treat or inject onsite. These facilities treat offshore-derived produced water prior to discharge into major deltaic passes of the Mississippi River. The treatment/disposal technologies evaluated and costed for disposal of produced water from these facilities are based on: 1) effluent limitations based on improved operating performance of gas flotation (IGF), and 2) zero discharge by subsurface injection in dedicated disposal wells. In the proposed rule, EPA assumed that a production facility with more than one outfall would consolidate produced water into a single flow for treatment or for injection. While generally true, site-specific information on the eight outfalls in the coastal Gulf of Mexico population indicates it would not

TABLE XI-2

TOTAL COMPLIANCE COSTS AND POLLUTANT REMOVALS FOR PRODUCED WATER BAT OPTIONS (ALTERNATIVE BASELINE)

Options	Compliance Costs		Pollutant Removals (pounds)
	Capital Costs (1995 $)	O&M Costs (1995 $/yr)	
Option 1: Zero discharge except (a) major pass facilities and (b) Cook Inlet facilities = 29/42 mg/l oil and grease	36,197,804	5,067,546	10,585,607
Option 2: Zero discharge except Cook Inlet facilities = 29/42 mg/l oil and grease	92,756,848	36,147,868	4,602,978,833
Option 3: Zero discharge, all facilities	180,480,480	55,940,008	5,658,020,853

be practical for these particular outfalls to be consolidated. For example, two of North Central's outfalls are separated by the Southwest Pass of the Mississippi River, while the third is over five miles away.[5] These features are prohibitive to consolidation at North Central, thus EPA estimated compliance costs assuming produced water from each outfall would be injected separately.

This section describes the development of compliance costs in terms of capital and operating and maintenance (O&M) costs for production facilities in the coastal Gulf of Mexico region. For the purpose of clarity, terminology used in this section is defined as follows:

> Design cost data: Produced water flow rates and capital and O&M costs developed from actual equipment design and cost data obtained from oil and gas operators and equipment vendors. The term "design cost data" refers to both the "design costs" and the "design flows" (each defined below). For the zero discharge option and flows above 5,000 bpd in the improved gas flotation option, the design cost data were used to develop mathematical models to best represent the relationship between cost and flow in order to predict facility-specific compliance costs.
>
> Design flows: Produced water flow rates specifically selected using available treatment equipment sizes and best engineering judgement.

Design costs: Capital and O&M costs calculated from actual equipment cost data obtained from oil and gas operators and equipment vendors. Design costs were calculated for each selected design flow.

Step costs: Discrete capital and O&M design costs calculated for specific produced water flows were applied to produced water flow rates under 5,000 bpd. (Refer to following discussion.)

Figure XI-1 is a flow chart showing the development of the capital and O&M costs for the Gulf of Mexico production facilities, based on discharge option, facility size and produced water volumes generated. Information and data obtained from EPA site visits, oil and gas production operators, vendor quotes, cost data developed by the Energy Information Administration (Department of Energy), and engineering analyses were used to estimate design costs based on selected design flow rates.[6,7,8,9] The design cost data were then used to develop mathematical models that best represented the relationship between the design costs and the design produced water flow. When the cost equation development methodology was used, actual facility-specific discharge flows were inserted into the equations to calculate capital and O&M compliance costs.

One exception to the cost equation methodology applies to lower flows (70.5 to 5,000 bpd) for the improved gas flotation option. In this case, continuous mathematical models did not adequately represent the engineering relationship between design costs and lower flow rates. Equipment costs are steady across a low flow range until a threshold is reached which requires equipment sizes to "step up" to the next available size. To more precisely portray costs at low flow ranges (70.5 to 5,000 bpd), step costs were applied to three flow rate ranges:

- 200 bpd step cost: The capital and O&M costs calculated for 200 bpd design flows were applicable to the 70.5 to 200 bpd flow range.
- 2,000 bpd step cost: The capital and O&M costs calculated for 2,000 bpd were applicable to the 201 to 2,000 bpd flow range.
- 5,000 bpd step cost: The capital and O&M costs calculated for 5,000 bpd were applicable to the 2,001 to 5,000 bpd flow range.

When the step cost methodology was used, actual facility-specific discharge future flow rates were compared to the defined flow ranges and the corresponding cost was applied. Capital and O&M compliance costs were derived for each of the eight production facilities based on individual flow. Current produced water flows for the eight facilities reportedly range from 291 bpd to 153,895 bpd.

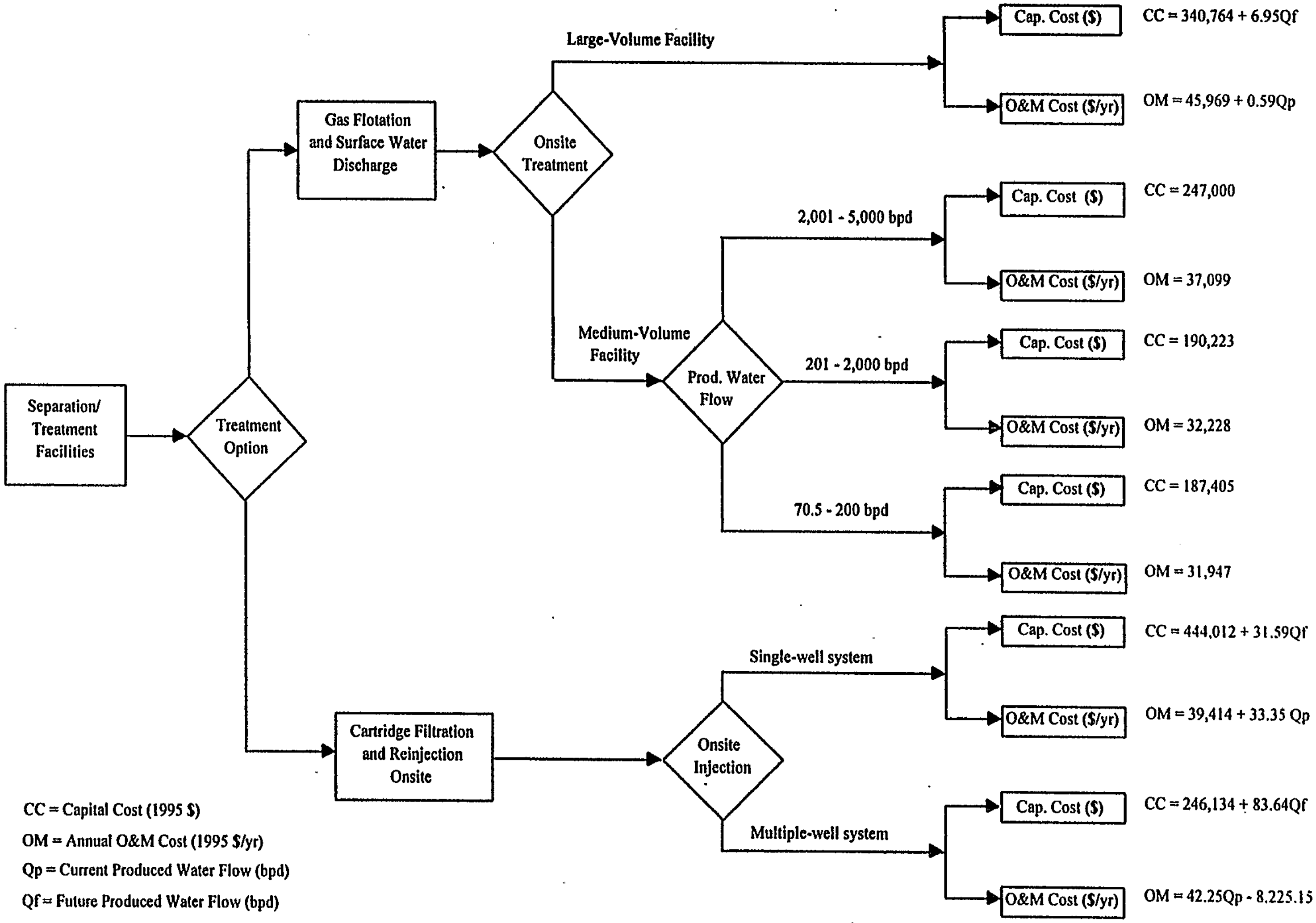

Figure XI-1
Produced Water Cost Determination Flow Chart For Gulf of Mexico

Regulatory compliance costs were estimated for all options based on estimated future produced water volumes. Future produced water volumes were required when sizing and costing the treatment equipment. EPA based its estimate of future flow rates based on the following assumptions:

- Future produced water volume increases by the same rate for both oil and natural gas producing wells. While produced water volumes from gas producing wells is not expected to increase by the same rate as from oil producing wells, EPA made a conservatively higher cost assumption in the absence of data.

- Capital costs for facilities currently discharging produced water were estimated by assuming a future produced water flow 1.5 times the current flow. The use of this factor, which is a standard engineering design practice, has resulted in an overall conservative (i.e., high) capital cost estimate. Many operators have indicated a factor of 1.2 to 1.25 is typically used when sizing and costing produced water treatment equipment.[7]

- Production facility location, either land- or water-access, was considered in the proposed rule as an important factor in determining cost. In the final rule, all facilities are assumed to be water-access due to their locations on major deltaic passes and supported by telecons with each operator.[4]

3.1 GULF OF MEXICO OPTION 1 BASELINE CAPITAL AND O&M COSTS (IMPROVED OPERATING PERFORMANCE OF GAS FLOTATION)

As previously stated, costs for medium/large-volume facilities (including all Gulf of Mexico facilities) to achieve improved gas flotation treatment were developed by first estimating design costs based on selected design flows, and then either performing a regression analysis with these data points to derive the cost equations or applying discrete step costs to the appropriate flow rates. Section 3.1.1 discusses the design parameters used as the basis for the cost equation and step cost derivations. Section 3.1.2 presents the basis for O&M cost estimates.

3.1.1 Development of Gulf of Mexico Option 1 Baseline Capital Costs (Improved Operating Performance of Gas Flotation)

Under Option 1, EPA would establish effluent limitations based on the operating performance of gas flotation technology, improved over the performance noted in the development of BPT limitations. This technology would consist of improved operation and maintenance of gas flotation treatment systems, more operator attention to treatment system optimization, chemical pretreatment to enhance system effectiveness, and possible resizing of certain treatment system components for increased treatment efficiency. The costs for this option were developed for new improved gas flotation systems for the facilities not having existing improved gas flotation systems. Design capital and O&M costs for medium/

large-volume facilities include the costs of the gas flotation unit, and a natural gas driven generator for systems that require more than 25 hp to operate. Costs for natural gas generators were derived based on information developed by Energy Information Administration (Department of Energy).[8]

One Gulf of Mexico facility, Flores & Rucks, currently operates an improved gas flotation system. EPA has reviewed discharge data on Flores & Rucks' treated produced water effluent to determine the level of effluent treatment. This data consisted of historical DMRs from LDEQ and other information submitted directly to EPA.[10,11,12] This information demonstrates effluent treatment performance within the effluent limits of 29 mg/l monthly average and 42 mg/l daily maximum. A single exceedance of these limits was reported between January 1993 and September 1995.[11] In view of comments made by Flores & Rucks and the fact that this facility is currently only required to meet BPT limits, it may have allowed effluent levels to fluctuate somewhat. Thus, this lone exceedance is viewed as an anomaly. For these reasons Flores & Rucks incurs no capital or O&M costs under Option 1.

Another facility, North Central, currently operates a gas flotation system at one outfall. The effluent data from this facility do not represent oil and grease levels attainable with improved operation of gas flotation technology. Therefore, EPA has included costs to upgrade the gas flotation unit at that outfall to improved gas flotation operational levels. These upgrade costs are included as O&M costs and represent costs for chemical addition, labor (for closer monitoring of operating parameters), and other costs associated with achieving IGF treatment levels.

3.1.1.1 Design Capital Costs for Improved Operating Performance of Gas Flotation Treatment

Table XI-3 presents the capital costs for improved gas flotation for the selected design flows. Design equipment capital costs for gas flotation in coastal areas were obtained from supporting documentation for the Offshore Development Document in 1986 dollars.[1] These figures were adjusted to 1995 dollars by the ratio of Engineering News Record-Construction Indices (ENR-CCI) of 5471 (for 1995) to 4295 (for 1986).[13]

The following list summarizes the information and methodology used to develop the design capital costs.

- **Equipment Purchase Cost:** The equipment purchase cost for all production facilities includes: gas flotation unit and feed pump, and natural gas generator for systems that require more than

TABLE XI-3

DESIGN CAPITAL COSTS (1995 DOLLARS) FOR IMPROVED GAS FLOTATION AT MEDIUM/LARGE FACILITIES

Component	Medium Design Flow (bpd)				Large Design flow (bpd)				
	200	1,000	2,000	5,000	10,000	15,000	25,000	40,000	80,000
Gas Flotation	89,369	89,369	89,369	114,577	126,034	135,201	143,220	160,407	206,238
Generator	0	0	0	0	65,850	65,850	80,448	101,580	176,896
Feed Pumps	4,032	5,518	5,518	5,997	10,317	13,398	19,476	26,764	36,125
Total Equipment Purchase Cost:	93,401	94,887	94,887	120,574	202,201	214,449	243,144	288,751	419,259
Piping and Instrumentation	14,010	14,233	14,233	18,086	30,330	32,167	36,472	43,313	62,889
Installation	29,888	30,364	30,364	38,584	64,704	68,624	77,806	92,400	134,163
Equipment Installed Cost:	137,299,	139,484	139,484	177,244	297,235	315,240	357,422	424,464	616,311
Engineering	13,730	13,948	13,948	17,724	29,724	31,524	35,742	42,446	61,631
Contingency	20,595	20,923	20,923	26,587	44,585	47,286	53,613	63,670	92,447
Insurance/Bonding	5,492	5,579	5,579	7,090	11,889	12,610	14,297	16,979	24,652
Total Equipment Installed Cost:	177,116	179,934	179,934	228,644	383,434	406,660	461,074	547,559	795,041
Platform Retrofit	10,289	10,289	10,289	18,356	34,818	38,522	48,894	62,640	105,854
TOTAL CAPITAL COST:	**187,405**	**190,223**	**190,223**	**247,000**	**418,252**	**445,182**	**509,968**	**610,199**	**900,895**

25 hp to operate. A regression analysis was performed to determine the relationship between the horsepower demand and the produced water flow. 25 hp power requirements corresponded to a produced water flow of 5,000 bpd. Flows greater than 5,000 bpd require more than 25 hp to operate and the electric power is supplied by natural-gas driven generators.[8] Gas flotation equipment cost includes: gas flotation skid-mounted, complete electrical systems, oil and water outlets brought to the edge of the skid, and sufficient instrumentation for proper operation. All gas flotation systems are equipped with electric motors.[8]

- **Installed Costs:** Equipment installation costs include the piping cost (15% of the purchase cost), and installation labor cost (32% of the purchase cost). No transportation costs were separately included because the equipment costs already take this into account by being based on costs of equipment delivered to the Gulf of Mexico area.[6]

- **Additional Costs (Engineering, Contingency, and Insurance/Bonding Fees):** These fees were added to the equipment purchase and installation costs to develop actual capital costs. These fees include all engineering design costs (10%), administrative costs (4%), and any incidental costs incurred in the process of purchasing and installing the equipment (15%).[7]

- **Platform/Concrete Pad Retrofit Costs:** Equipment space requirements were estimated to be twice the footprint. The retrofit costs were $82/ft^2 (1995 dollars).[6]

3.1.1.2 Model Cost Equations for Improved Operation of Gas Flotation

Two separate capital cost methodologies were developed for Option 1. For future produced water flow rates exceeding 5,000 bpd, cost relationships were predicted using equations developed from actual data. These calculations are described in Large Flow Cost Determination, below. For facilities projected to have produced flow rates below 5,000 bpd, EPA developed a methodology to more closely model costs for these medium-size facilities. This methodology is presented in Medium Flow Cost Determination, below.

Large Flow Cost Determination

For Option 1, two independent cost equations were developed for medium/large-volume facilities with predicted future flows greater than 5,000 bpd: one capital cost equation and one O&M cost equation. Table XI-4 lists the two cost equations developed and used to predict costs for treatment by improved gas flotation of high produced water flow facilities in the Gulf of Mexico (i.e., Chevron Pipe Line Company, Flores & Rucks, North Central Outfall 003-1, and Amoco).

For production facilities with future flows projected to exceed 5,000 bpd, the best-fit mathematical model is a linear function of the general form:

TABLE XI-4

CAPITAL AND O&M STEP COSTS AND COST EQUATIONS FOR IMPROVED GAS FLOTATION

Medium-Volume Gas Flotation Systems				
Design Flow Ranges (bpd)	Capital Cost (1995 $)		O&M Cost (1995 $/yr)	
	Design	Step Cost	Design	Step Cost
70.5 - 200	187,405	187,405	31,947	31,947
201 - 2,000	190,223	190,223	32,228	32,228
2,001 - 5,000	247,000	247,000	37,099	37,099

Large-Volume Gas Flotation Systems						
Design Flow (bpd)	Capital Cost (1995 $)			O&M Cost (1995 $/yr)		
	Design	Calculated	% Error	Design	Calculated	% Error
10,000	418,252	410,215	-1.92%	52,578	51,893	-1.30%
15,000	445,182	444,941	-0.05%	54,901	54,855	-0.08%
25,000	509,968	514,393	0.87%	60,342	60,779	0.72%
40,000	610,199	618,570	1.37%	68,991	69,665	0.98%
80,000	900,895	896,376	-0.50%	93,739	93,360	-0.40%
Cost Equation	340,764 + 6.95 x (flow, bpd)			45,969 + 0.59 x (flow, bpd)		

$$Y = mX + b$$

where:

Y = design cost (either capital or O&M cost)

m = slope (X-coefficient)

X = design flow (in barrels per day)

b = Y-intercept (constant)

The X-coefficient and constant for each of the two equations were determined using regression analyses with the design costs.[14] Note that in Table XI-4, "calculated" costs are those generated by the model cost equations for each design flow listed. The comparison of design to calculated costs shows an error of no greater than $\pm 2\%$ for all IGF.[14]

Medium Flow Cost Determination

The proposed rule had represented the relationship between medium design flows and design costs as a binomial function of the form: $Y = a + bX + cX^2$. EPA re-evaluated costs predicted by the binomial model for facilities with medium produced water flows (i.e., between 70.5 and 5,000 bpd) and determined that modeling for capital costs and O&M costs could be improved with a different modeling approach. Within the medium flow range, costs change at discrete yet small intervals which were distorted when applied to the continuous mathematical models in the proposal Development Document. In this case, continuous mathematical models did not adequately represent the engineering relationship between design costs and lower flow rates. Equipment costs are steady across a low flow range until a threshold is reached which requires equipment sizes to "step up" to the next available size. To more precisely portray costs at low flow ranges (70.5 to 5,000 bpd), step costs were applied to three flow rate ranges. Table XI-3 lists the flow ranges and the corresponding design costs.

State DMR data for the Gulf of Mexico facilities were used to establish current flow rates. Current flow rates were escalated to future flow rates by a factor of 1.5.[7] Facilities with future flow rates predicted at less than 5,000 bpd included Warren Petroleum, Gulf South Operators, North Central outfall 002-2 and North Central outfall 001 (see Table XI-5). These future flow rates were compared to one of the three flow ranges and assigned the corresponding design cost to estimate each facility's compliance cost. Table XI-5 presents the facility-specific compliance estimates based on either the step cost determination or the model capital and O&M cost equations.

TABLE XI-5

GULF OF MEXICO FACILITIES CAPITAL AND O&M COSTS PRODUCED WATER TREATMENT VIA IMPROVED GAS FLOTATION (1995 DOLLARS)

Permit-Outfall Number	Operator	Current Average Volume (bpd)	Future Average Volume (bpd)	Capital Cost ($)	O&M Cost ($/yr)
3229-001-3	Chevron Pipe Line Company	18,920	28,380.0	537,867	57,177
2963-006	Warren Petroleum Company	1,808	2,712.0	247,000	32,228
2071-004-1	Flores & Rucks, Inc.	153,895	230,842.5	0	0
2400-001	Gulf South Operators, Inc.	291	436.5	190,223	32,228
2184-002-2	North Central	1,910	2,865.0	247,000	32,228
2184-003-1	North Central	7,606	11,409.0	0	50,475
2184-001	North Central	572	858.0	190,223	32,228
3407-001	Amoco	6,290	9435.0	406,291	49,695
TOTALS		**191,292**		**$1,818,604**	**$286,259**

3.1.2 Development of Gulf of Mexico Option 1 O&M Costs (Improved Operating Performance of Gas Flotation)

Estimated design O&M costs for IGF treatment are presented in Table XI-6. Standard operating and maintenance cost was estimated to be 10% of the total capital equipment cost.[8] In addition, labor costs were estimated based on one person-hour per day at a rate of $39.00 per hour (in 1995 dollars).[15] Typical operating and maintenance costs, other than increased labor, include: polymer and/or flocculation enhancement chemicals, fuel cost, and feed pump and agitator maintenance and replacement costs. As discussed in Section 3.0, EPA based capital costs on assuming future produced water flow 1.5 times the current flow. O&M costs estimate first year expenditures, which may be expected to rise as produced water flow rates increase. This future escalation in O&M costs due to produced water flow increases is addressed in the economic impact model.[2]

3.2 GULF OF MEXICO OPTIONS 2 AND 3 BASELINE CAPITAL AND O&M COSTS (ZERO DISCHARGE BY SUBSURFACE INJECTION)

Capital and O&M costs for zero discharge by subsurface injection at medium/large-volume facilities include the costs of pretreatment by cartridge filtration, the costs of injection pumps and wells, and the costs of well installation and maintenance. Produced water injection costs are the same whether or not the subsurface formation is utilized for disposal or for enhanced oil recovery (waterflood). However, potential production benefits from the use of produced water injection as waterflood support could reasonably been credited against compliance costs. Since little data is available to quantify this benefit, and to help ensure conservatively higher cost estimates, this credit is not reflected in the following analyses.

Since the completion of the Development Document for the proposal, capital costs have been adjusted to 1995 dollars, and certain other costs have been revised as a result of EPA's evaluation of information submitted by commenters. O&M costs have been added since proposal for replacement filters, additional treatment chemicals, and increased well backwash frequency. These costs are detailed in following sections and in the technical support document.[14]

3.2.1 Design Capital Costs for Subsurface Injection

Design capital costs are based on direct quotes from equipment vendors, summary statistics from the EPA 1993 Coastal Oil and Gas Questionnaire,[16] and standard engineering cost estimating factors. The following list summarizes the bases for the design capital costs:

TABLE XI-6

DESIGN O&M COSTS FOR IMPROVED GAS FLOTATION AT MEDIUM/LARGE FACILITIES

Component	Design Flow (bpd)								
	200	1,000	2,000	5,000	10,000	15,000	25,000	40,000	80,000
Standard Operation & Maintenance	17,712	17,993	17,993	22,864	38,343	40,666	46,107	54,756	79,504
Labor	14,235	14,235	14,235	14,235	14,235	14,235	14,235	14,235	14,235
TOTAL O&M COST (1995 $ per year):	**31,947**	**32,228**	**32,228**	**37,099**	**52,578**	**54,901**	**60,342**	**68,991**	**93,739**

- **Pretreatment:** EPA conservatively assumed facilities would include cartridge filtration as pretreatment to injection.

- **Cartridge Filters and Feed Pumps:** Cartridge filters and feed pumps were sized based on the design flows and the manufacturer recommended volumetric loads as follows:[17]
  10" cartridge - 7 gpm/cartridge (240 bpd)
  20" cartridge - 14 gpm/cartridge (480 bpd)
  30" cartridge - 21 gpm/cartridge (720 bpd)

  One module contains 4 cartridges. Where design flow exceeds 84 gpm (2,880 bpd), multiple modules were costed. The cartridge filters are rated for a maximum pressure of 150 psig. Filter feed pumps were sized for the required flow and a discharge pressure of 50 psig.

- **Feed Pumps:** Feed pumps are electrically driven from existing power (either diesel or natural gas) for single-well injection systems or flows up to 5,000 bpd.[18] For multiple well injection systems, the filter feed pumps have natural gas driven motors.

- **Injection Pump Feed Tank:** After filtration, the produced water goes into an injection pump feed tank. The capacity of the feed tank is flow dependent. For facilities processing less than or equal to 1,000 bpd of produced water, a surge tank of 150 bbl capacity was included. This translates into a minimum of 3.6 hrs of surge capacity for the design flow of 1,000 bpd. For facilities processing more than 1,000 bpd but less than or equal to 5,000 bpd of produced water, a surge tank of 1,000 bbl capacity was included. This translates into a minimum of 4.8 hrs of surge capacity for the design flow of 5,000 bpd. For facilities processing more than 5,000 bpd of produced water, a surge tank of 1,500 bbl capacity was included. This translates into 51 minutes of surge capacity for the design flow of 42,000 bpd [(1,500 bbl/42,000 bpd) x (24 hr/day x 60 min/hr)]. This assumption is consistent with the Walk-Haydel analysis in which the minimum capacity for the surge tank was assumed to be 3 minutes.[19]

- **Injection Pumps:** Injection pumps are positive displacement pumps capable of delivering the required flow at 1,500 psig. Costs include the pump plus the motor, both skid mounted. Spare pumps are not included because the results of the statistical analysis of the 1993 Survey show that the majority of injection facilities in the coastal region (i.e., 58%) do not use spare pumps.[16]

- **Spare Wells:** According to studies of producing areas of Louisiana and other areas in the U.S. where injection wells are used to dispose of produced water, operators rarely go to the expense of drilling a "spare" well to handle produced water when the primary disposal well is shut in for servicing.[6,20] Instead, it is more typical for operators to respond by temporarily incurring the costs associated with hauling produced water to commercial disposal facilities, or shutting in the producing well(s) until the disposal well is brought back into service. If the production facility is serving multiple wells, those with the highest water cut are more likely to be shut in for the duration of the injection well workover. Therefore, this analysis assumes that no spare wells are needed.[20]

- **Pump Engines:** Injection pumps with capacities up to 500 bpd, or 12 hp, have electric motors. For flows greater than 500 bpd, natural gas engines are used.[18]

- **Power Generation:** For electric pumps and instrumentation, no additional power generation equipment is required. It is assumed that existing onsite power generation equipment can handle the excess load of up to 25 hp. A regression analysis was performed to determine the mathematical relationship between horsepower demand and produced water flow. The cutoff produced water flow corresponding to 25 hp power requirement was 603 bpd, above which additional power generation is necessary.

- **Injection Well Capacity:** The average capacity for Gulf of Mexico injection wells, new or converted, is 5,000 bpd. For flows greater than 5,000 bpd, the number of injection wells and pumps was determined based on one injection well and one pump with a capacity of 5,000 bpd for each 5,000 bpd of flow or portion thereof. For these cost estimates, an average injection well capacity of 5,000 bpd has been selected based on information obtained from the 1993 survey of coastal oil and gas industry.[16,21] Average injection well capacity is based on the statistical analysis of the produced water flow data from facilities that currently inject produced water. The statistical analysis, which took into account the effect of under utilization by spare wells, showed that a typical injection well in the Gulf of Mexico has an average capacity of 5,000 bpd. The cost to drill an injection well is dependent on the required drilled depth, the location of the well and to a lesser extent on the capacity of the well. Other information in the record also supports a 5,000 bpd average injection flow rate.[22,23]

- **Average Injection Well Cost:** EPA estimated, based on data obtained directly from operators, that 90% of injection wells will be converted from previously producing wells and abandoned wells. Ten percent will be newly drilled injection wells.[24]

  The cost of a new well at facilities in the Gulf of Mexico region was escalated to 1995 dollars using the ratio of 5471 (for 1995) to 4985 (for 1992) from the Construction Cost Index.[13] The 1995 cost is estimated to be $329,250 for a new dedicated injection well. It has been noted that the cost of drilling injection wells in the coastal Gulf of Mexico region does not appear to vary significantly with well capacity for wells having the same depth.[20] The cost of converting an existing well to an injection well at facilities in the coastal Gulf of Mexico region was estimated to be $263,400 (1995 dollars).[6] Again, the well conversion cost does not appear to be affected significantly by the injection capacity of the well.[20]

  The average injection well cost was determined as follows:

  Injection Well Cost = 0.9 x $263,400 + 0.1 x $329,250 = $270,000

  The average injection well cost (i.e., average weighted cost of new and converted wells) is $270,000 (adjusted to 1995 dollars).[13]

- **Platform/Concrete Pad Retrofit Cost:** Platform costs were escalated to 1995 dollars using the ratio of 5471 (for 1995) to 4985 (for 1992) from the Construction Cost Index equipment area requirements. The retrofit costs were $82/ft (in 1995 dollars).[25]

- **Pipeline Cost:** Pipeline costs are based on $12.74/in. of pipe diameter/ft. Although the same Walk-Haydel report continues to be the source of the cost estimate factor, pipeline costs have been escalated according to the appropriate year span of Construction Cost Indices.[13,19] The piping diameters used for calculating piping costs are as recommended in the Walk-Haydel report and in engineering standards literature[26] as follows:

Flows	Pipe Diameter
up to 5,000 bpd	3-inch
5,001 up to 14,000 bpd	4-inch
14,001 up to 31,900 bpd	6-inch
31,901 up to 58,300 bpd	8-inch
58,301 up to 85,700 bpd	10-inch
85,701 up to 192,000 bpd	12-inch

- **Average Pipeline Distance:** The average pipeline distance from the separation/treatment facility to the injection well is assumed to be 3,438 feet. This distance is five feet longer than that listed in the Development Document for the proposed rule since it is based on the final statistical analysis of the 1993 Coastal Oil and Gas Questionnaire as opposed to the preliminary analysis.[16,21,27]

- **Installed Costs:** Equipment installation costs include the piping cost (15% of the purchase cost), installation labor cost (32% of the purchase cost), and transportation cost (5% of the purchase cost).[6]

- **Additional Costs (Engineering, Contingency, and Insurance/Bonding Fees):** These fees were added to the equipment purchase and installation costs to develop actual capital costs. These fees include all engineering design costs (10% of installed equipment cost), administrative costs (4% of installed equipment cost), and any incidental costs incurred in the process of purchasing and installing the equipment (15% of equipment installed cost).[8]

Table XI-7 presents the design capital costs for the selected design flows for production facilities in the Gulf of Mexico coastal region.

3.2.2 Model Capital Cost Equations for Subsurface Injection

For the zero discharge via injection option, four independent linear cost equations were developed for medium/large-volume facilities: two for single well injection systems (one capital cost equation and one O&M cost equation) and two for multiple injection well systems. Again, single injection well systems are assumed for operations with flows less than or equal to 5,000 bpd. Multiple injection well systems are assumed for flows greater than 5,000 bpd. Table XI-8 lists the four cost equations.

The mathematical model best representing the relationship between design flow and design cost for injection was found to be a line of the general form:

TABLE XI-7

CAPITAL AND O&M COST EQUATIONS FOR INJECTION OF PRODUCED WATER AT MEDIUM/LARGE-VOLUME FACILITIES

Single - Well Injection Systems						
Design Flow (bpd)	Capital Cost ($)			O&M Cost ($)		
	Design	Calculated	% Error	Design	Calculated	% Error
200	453,789	450,330	-0.76%	45,988	46,085	0.21%
500	456,032	459,808	0.83%	53,983	56,090	3.90%
1,000	475,701	475,603	-0.02%	75,252	72,765	-3.30%
5,000	602,186	601,967	-0.04%	205,885	206,168	0.14%
Cost Equation	444,012 + 31.59 x (flow)			39,414 + 33.35 x (flow)		
Multiple - Well Injection Systems						
Design Flow (bpd)	Capital Cost ($)			O&M Cost ($)		
	Design	Calculated	% Error	Design	Calculated	% Error
10,000	1,025,405	1,082,505	5.57%	411,029	414,322	0.80%
18,000	1,881,955	1,751,602	-6.93%	768,651	752,359	-2.12%
30,000	2,646,805	2,755,246	4.10%	1,235,611	1,259,415	1.93%
42,000	3,794,079	3,758,891	-0.93%	1,777,276	1,766,471	-0.61%
Cost Equation	246,134 + 83.64 x (flow)			42.25 x (flow) - 8,225		

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TABLE XI-8

DESIGN CAPITAL COSTS (1995 DOLLARS) FOR PRODUCED WATER INJECTION AT GULF OF MEXICO PRODUCTION FACILITIES

Component	Design Flow Rate (bpd)							
	200	500	1,000	5,000	10,000	18,000	30,000	42,000
Injection Pumps	5,158	5,912	15,259	47,543	95,086	190,172	285,258	427,887
Feed Tank	13,719	13,719	13,719	14,816	14,816	19,975	19,975	19,975
Filters and Feed Pumps	2,927	3,296	3,813	6,209	12,420	24,840	40,328	63,560
Total Equipment Purchase Cost	21,804	22,927	32,791	68,568	122,322	234,987	345,561	511,422
Piping and Instrumentation (15%)	3,271	3,439	4,919	10,285	18,348	35,248	51,834	76,713
Labor (32%)	6,977	7,337	10,493	21,942	39,143	75,196	110,580	163,655
Transportation (5%)	1,090	1,146	1,640	3,428	6,116	11,749	17,278	25,571
Equipment Installed Cost	33,142	34,849	49,842	104,223	185,929	357,180	525,253	777,361
Engineering (10%)	3,314	3,485	4,984	10,422	18,593	35,718	52,525	77,736
Contingency (15%)	4,971	5,227	7,476	15,634	27,889	53,577	78,788	116,604
Insurance/Bonding (4%)	1,326	1,394	1,994	4,169	7,437	14,287	21,010	31,094
Total Equipment Installed Cost	42,753	44,955	64,297	134,448	239,849	460,763	677,576	1,002,796
Platform Retrofit (pumps, tanks, filters)	9,635	9,676	10,004	66,338	70,356	78,392	86,428	98,482
Pipeline Cost	131,400	131,400	131,400	131,400	175,200	262,801	262,801	262,801
Injection Well Cost	270,000	270,000	270,000	270,000	540,000	1,080,000	1,620,000	2,430,000
TOTAL CAPITAL COST:	**453,788**	**456,031**	**475,701**	**602,186**	**1,025,405**	**1,881,956**	**2,646,805**	**3,794,079**

$$Y = mX + b$$

where: Y = design cost (either capital or O&M cost)

m = slope (X-coefficient)

X = design flow (in barrels per day)

b = Y-intercept (constant)

The constants (Y-intercept) and X-coefficients for each of the four equations were determined using regression analysis with the "design" costs, and "calculated" costs are those generated by the model cost equations for each design flow listed.[14] The comparison of "design" to "calculated" costs shows an error of no greater than $\pm 7.0\%$ for all systems.

Once the model capital and O&M cost equations were developed for all medium/large-volume facilities, future flow rates were used to calculate facility-specific compliance cost estimates. The results of these calculations are presented in Table XI-9.

3.2.2.1 Compliance Cost Methodology for Flores & Rucks, Inc.

A separate methodology was developed to estimate zero discharge compliance costs for Flores & Rucks, Inc. Flores & Rucks submitted information in its comments on the proposed effluent limitations which suggested its compliance costs might be significantly different than compliance costs for other existing Gulf of Mexico operators due to size and other factors.[12] These factors included operation of an existing improved gas flotation system treating all Flores & Rucks' produced water, the presence of source water[a] production and waterflooding operations, and its offshore/coastal production configuration. The Flores & Rucks production configuration straddles the offshore and coastal subcategories. To support its arguments that it should not be subject to zero discharge, Flores & Rucks provided EPA with highly detailed technical and cost information regarding its production and produced water treatment operations.[28] EPA also conducted a site visit to Flores & Rucks' East Bay field in December 1995.[29]

Description of Current Flores & Rucks' Operations

Flores & Rucks is a large and complex facility. Of the set of Gulf of Mexico facilities affected

[a] "Source water" is the term used for subsurface waters produced from non-hydrocarbon bearing formations for waterflooding purposes.

TABLE XI-9

GULF OF MEXICO FACILITIES CAPITAL AND O&M COSTS PRODUCED WATER ZERO DISCHARGE VIA INJECTION (1995 DOLLARS)

Permit-Outfall Number	Operator	Current Average Volume (bpd)	Future Average Volume (bpd)	Capital Cost ($)	O&M Cost ($/yr)
3229-001-3	Chevron Pipe Line Company	18,920	28,380.0	2,619,754	791,233
2963-006	Warren Petroleum Company	1,808	2,712.0	529,687	99,712
2071-004-1	Flores & Rucks, Inc. (a)	153,895	230,842.5	14,431,657	7,932,898
2400-001	Gulf South Operators, Inc.	291	436.5	457,802	49,120
2184-002-2	North Central	1,910	2,865.0	534,520	103,114
2184-003-1	North Central	7,606	11,409.0	1,200,350	313,164
2184-001	North Central	572	858.0	471,117	58,491
3407-001	Amoco	6,290	9435.0	1,035,250	257,557
TOTALS		**191,292**		**$21,280,137**	**$9,605,289**

(a) Flores & Rucks costed at Case 2. Costs for Flores & Rucks may be considerably lower (see Section 3.2.2.2).

by the coastal guidelines, eighty percent (80%) of the produced water is discharged from the Flores & Rucks oil and gas production operation located in the East Bay area of the Mississippi River delta (see Table XI-9). Flores & Rucks' production operations encompass both offshore and coastal subcategories, extending about 40 square miles.[12] Production (and therefore produced water) is predominately from offshore subcategory wells, with some coastal subcategory production.[30] Flores & Rucks currently discharges to coastal waters, the Southwest Pass of the Mississippi River.

The Flores & Rucks production system gathers wellhead fluids (including liquid and gaseous hydrocarbons and produced water) generated from wells in both subcategories into four centralized points, as shown in Table XI-10. Production fluids from all of the coastal wells (with a single exception) are piped directly to the Central Processing facility for initial hydrocarbon/produced water separation.

The three offshore FWKO[b] platforms listed in Table XI-10 handle production fluids from offshore subcategory wells and one coastal subcategory well. Initial hydrocarbon/produced water separation takes place offshore on the FWKO platforms. Following the initial hydrocarbon/produced water separation, all four produced water streams are commingled prior to IGF treatment and discharge into the Southwest Pass of the Mississippi River.

The East Bay field is waterflooded via a system of source water wells and injection wells. Source water is produced, filtered, and injected into producing horizons for secondary hydrocarbon recovery. The company does not currently utilize produced water from petroleum-bearing formations for waterflooding.[12] All onshore subcategory facilities are required to comply with zero discharge. As early in the regulatory process as the 1993 Survey, produced water was already utilized for secondary recovery in some Gulf coastal operations.[16,31] Flores & Rucks states its concern of technical difficulties (such as well plugging, increased maintenance, and potential shortened disposal well life) which might be encountered if Flores & Rucks attempted to inject untreated produced water.[12] However, since Flores & Rucks already treats all produced water with IGF, it may reasonably be expected that the treated produced water filtered and given additional chemical treatments could be used in lieu of source water for waterflooding. In point of fact, Flores & Rucks costed this scenario in its comments. The cost of mitigating potential technical difficulties with injection of produced water (for disposal or for waterflooding) has been incorporated into cost estimates by increasing expected compliance costs to include additional filtration, higher chemical

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[b] FWKO: Free Water Knock-Out.

TABLE XI-10

FLORES & RUCKS OIL/WATER/GAS PROCESSING LOCATIONS

Produced Water Facility	Production Subcategory	Function
Central Processing	Coastal	Oil/water/gas separation and processing; produced water IGF treatment
FWKO #1 Platform	Offshore and Coastal	Oil/water/gas separation and processing
FWKO #2 Platform	Offshore (except 1 coastal well)	Oil/water/gas separation and processing
FWKO #3 Platform	Offshore	Oil/water/gas separation and processing

costs, increased well backwash frequency, and doubled workover rates for all facilities (see Section 3.2). Potential production benefits from the use of produced water injection as waterflood support has not been credited against Flores & Rucks' compliance costs. Cost savings generated from shutting in source water production (such as fuel costs, well maintenance, and filter replacement) have also not been credited against compliance costs for Flores & Rucks. Thus, these cost estimates are higher than might be experienced.

Potential Flores & Rucks Zero Discharge Compliance Strategies

Information acquired through the 1993 Coastal Oil and Gas Questionnaire and extensive industry contacts indicate that Gulf of Mexico operators have used a variety of strategies to meet the zero discharge requirement of the General Permits. In several cases, operators have combined outfalls and drilled/converted wells for produced water injection for disposal.[5,16,25,32,33,34,35,36] The 1993 Coastal Oil and Gas Questionaire results indicate injection zones for produced water disposal are generally attainable in the Mississippi delta region at 2,500 to 3,500 feet, with an average disposal flow rate of 5,000 bpd produced water.[16] Information received since proposal regarding coastal Louisiana production fields (Coquille Bay, Bayou de Fleur and Morgan City fields) demonstrate an average depth of 2,785 feet for injection wells disposing an average of 5,812 bpd produced water.[23] Operators of these fields indicated that locating disposal zones able to accept 5,000 bpd produced water is not difficult in the Gulf of Mexico area. This information is strongly corroborative of the cost basis used in development of proposed limitations. Further, this information suggests that the final rulemaking costs may be exaggerated by the incremental cost to drill and complete deeper injection wells and because 16 percent more produced water disposal capacity may be available per well than was used in zero discharge compliance cost estimates.

The availability of zero discharge of produced water for Flores & Rucks and other major pass dischargers is demonstrated by the numerous facilities injecting produced water near the Mississippi River delta.[37]

In anticipation of a possible zero discharge limitation, some Louisiana companies have minimized produced water volumes by segregating offshore-derived produced water. Where this occurs, offshore-derived produced water is treated on offshore platforms and discharged under permit limits incorporating Louisiana state water quality standards or the offshore guidelines.[33,36]

EPA has considered the range of available compliance strategies in development of the following four zero discharge compliance scenarios for Flores & Rucks:

Case 1: All produced water (coastal- plus offshore-derived) is injected in dedicated disposal wells.

Case 2: Some produced water is injected for waterflood; the remainder is injected in dedicated disposal wells.

Case 3: Coastal subcategory produced water is disposed by injection in dedicated disposal wells; Offshore-derived produced water is treated offshore and discharged offshore in compliance with state water quality standards and Offshore Guidelines.

Case 4: Coastal subcategory produced water is disposed entirely by waterflood injection; Offshore-derived produced water is treated and discharged offshore in compliance with state water quality standards and Offshore Guidelines.

In its comments on the proposed rule, Flores & Rucks suggested (and rejected as infeasible due to high costs and possible strategic difficulties) an additional compliance strategy: treating the produced water at the central facility IGF before pipelining the produced water into the offshore subcategory for discharge in compliance with state water quality standards and the offshore guidelines.[12] EPA estimated costs for each Gulf of Mexico facility on the basis of this strategy. The cost estimation was performed to determine whether the strategy might be a cost effective approach to compliance. EPA's analysis showed that, except for Flores & Rucks, this strategy was more expensive than other alternatives and presented other compliance difficulties. The capital cost estimates and discussion for the pipeline scenario are presented in the technical support document.[14]

EPA selected Case 2 as the primary basis for its economic analyses because it is a reasonable compliance scenario which is technically feasible economically comparable to Case 1, and which realizes lower non-water quality environmental impacts than Case 1 (see Chapter XIII). Case 2 is based on replacing source water as the waterflood fluid with treated produced water. Produced water is extensively used for waterflooding at Alaska's North Slope, California and other onshore and coastal locations.[16,21,31] Even in its own comments, Flores & Rucks presented a similar scenario costing injection of produced water for waterflooding. Thus, it is reasonable to believe Case 2 is technically feasible.

3.2.2.2 Flores & Rucks Estimated Compliance Costs

Capital costs for each Flores & Rucks zero discharge case are the same as those developed for other major pass dischargers presented previously in Section 3.2.2, except where different equipment was required to fit the compliance strategy. Itemized costs showing the list of capital equipment are presented in Tables XI-11 and XI-12. Distinctions between these costs and those used for other coastal Gulf of Mexico facilities are described in detail in the Technical Support Document.[14]

Capital costs are based on actual equipment design and cost data obtained from oil and gas operators and equipment vendors. A cost analysis was developed for each produced water gathering facility at Flores & Rucks (Table XI-12) before summing to arrive at its total East Bay costs. Flores & Rucks' produced water flow rates are averages of LDEQ Discharge Monitoring Reports from calendar years 1993, 1994 and partial year 1995.[11] Equipment design flow is based on an assumed "future flow," calculated as 1.5 times the current average flow rate.[7] Based on industry data, Case 1 assumes that 90 percent of the disposal wells would be converted idle production wells and 10 percent would be newly drilled injection wells.[3,16,21,24,38] Site-specific data from Flores & Rucks at the time cost estimates were developed indicated that ample wells are available for conversion, thus this is considered a conservative estimate.[14,39]

Cases 3 and 4 offer significant cost savings compared to Case 2 and indicate that Flores and Rucks' true costs for complying with zero discharge limitations may be much lower. Because of these cost savings, Cases 3 and 4 are more likely to be implemented for compliance with zero discharge. However, Cases 3 and 4 have uncertainties in the cost estimating with regard to specific platforms and what would actually be required to structurally modify them for installing treatment equipment used to comply with offshore BAT requirements. By basing costs on a higher cost compliance scenario, EPA has based its decision-making on a conservative cost estimate.

TABLE XI-11

FLORES & RUCKS PRODUCED WATER COMPLIANCE COST SCENARIOS (1995 dollars)

COASTAL INJECTION Capital Costs	Case 1	Case 2
Produced Water New Injection Well Volume (bpd)[a]	230,843	184,670
Injection Pumps	2,234,521	1,759,091
Surge Tank	0	0
Filters and Feed Pumps	363,968	363,968
Total Equipment Cost:	2,598,489	2,123,059
Piping (15%)	389,773	318,459
Labor (32%)	831,516	679,379
Transportation (5%)	129,924	106,153
Subtotal:	3,949,703	3,227,050
Engineering (10%)	394,970	322,705
Contingency (15%)	592,455	484,057
Insurance/Bonding(4%)	157,988	129,082
Subtotal:	5,095,117	4,162,892
Platform Space:		
Pumps	150,306	118,326
Filters	38,540	38,540
Pipeline Cost:		
Disposal Well Pipe	1,576,804	1,314,004
Waterflood Well Pipe	0	4,678,128
Subtotal	6,860,768	10,311,892
Injection Well Number	47	37
Injection Well Cost	12,690,000	9,990,000
COASTAL CAPITAL COST	$19,550,768	$20,301,892
Offshore volume (bpd)	0	0
OFFSHORE CAPITAL COST	0	0
TOTAL CAPITAL COST	**$19,550,768**	**$20,301,892**
COASTAL INJECTION O & M Costs		
Labor	1,619,089	1,274,602
Pump Fuel Cost	1,163,625	941,000
Maintenance	129,924	106,153
Cartridge Filter Replacement	421,288	421,288
Produced Water Treatment Chemicals	5,687,394	5,687,394
Injection Well Backwash	523,345	935,340
COASTAL O & M COST	$9,544,666	$9,365,778
OFFSHORE GAS FLOTATION O&M Costs		
Offshore labor	0	0
Standard O & M (10%)	0	0
OFFSHORE O & M COST	$0	$0
TOTAL O&M COST	**$9,544,666**	**$9,365,778**

a) Future produced water volumes are used for equipment design. Future flow equals 1.5 times current flow.

TABLE XI-12

FLORES & RUCKS PRODUCED WATER COMPLIANCE COST SCENARIOS (1995 dollars)

COASTAL INJECTION **Capital Costs**	**Case 3**			**Case 4**		
Coastal Inj. PW Volume (bpd),(a)	45,057			45,057		
Injection Pumps	427,077			0		
Surge Tank	0			0		
Filters and Feed Pumps	69,696			69,696		
Total Equipment Cost:	496,773			69,696		
Piping (15%)	74,516			10,454		
Labor (32%)	158,967			22,303		
Transportation (5%)	24,839			3,485		
Subtotal:	755,095			105,938		
Engineering (10%)	75,509			10,594		
Contingency (15%)	113,264			15,891		
Insurance/Bonding(4%)	30,204			4,238		
Subtotal:	974,072			136,660		
Platform Space:						
Pumps	31,980			31,980		
Filters	7,380			7,380		
Pipeline Cost						
Disposal Well Pipe	525,601			0		
Waterflood Well Pipe	0			4,678,128		
Segregation Cost (b)	780,000			780,000		
Subtotal	2,319,034			5,634,148		
Injection Well Number	9			0		
Injection Well Cost	2,430,000			0		
COASTAL CAPITAL COST	$4,749,034			$5,634,148		
OFFSHORE GAS FLOTATION **Capital Costs**	**FWKO #1 Platform**	**FWKO #2 Platform**	**FWKO #3 Platform**	**FWKO #1 Platform**	**FWKO #2 Platform**	**FWKO #3 Platform**
Average PW Volume (bpd),(a)	68,576	24,878	92,332	68,576	24,878	92,332
Gas Flotation	206,238	143,220	341,439	206,238	143,220	341,439
Generator	176,896	80,448	242,746	176,896	80,448	242,746
Feed Pumps	36,125	19,476	49,523	36,125	19,476	49,523
Total Equipment Purchase Cost	419,259	243,144	633,708	419,259	243,144	633,708
Piping & Instrumentation (15%)	62,889	36,472	95,056	62,889	36,472	95,056
Discharge Piping	72,557	0	90,862	72,557	0	90,862
Installation (32%)	134,163	77,806	202,787	134,163	77,806	202,787
Equipment Installed Cost	688,868	357,422	1,022,413	688,868	357,422	1,022,413
Engineering (10%)	68,887	35,742	102,241	68,887	35,742	102,241
Contingency (15%)	103,330	53,613	153,362	103,330	53,613	153,362
Insurance/Bonding (4%)	27,555	14,297	40,897	27,555	14,297	40,897
Total Equipment Installed Cost	888,639	461,074	1,318,912	888,639	461,074	1,318,912
Satellite Platform	122,229	296,730	892,545	122,229	296,730	892,545
OFFSHORE CAPITAL COST	$1,010,868	$757,804	$2,211,457	$1,010,868	$757,804	$2,211,457
TOTAL CAPITAL COST	**$8,729,164**			**$9,614,278**		
COASTAL INJECTION **O & M Costs**						
Labor	310,038			0		
Pump Fuel Cost	222,825			22,475		
Maintenance	24,839			0		
Segregation O & M	78,000			78,000		
Cartridge Filter Replacement	82,229			82,229		
Produced Water Treatment Chemicals	1,110,092			1,110,092		
Injection Well Backwash	100,215			512,210		
COASTAL O & M COST	$1,928,238			$1,805,006		
OFFSHORE GAS FLOTATION **O & M Costs**	**FWKO #1 Platform**	**FWKO #2 Platform**	**FWKO #3 Platform**	**FWKO #1 Platform**	**FWKO #2 Platform**	**FWKO #3 Platform**
Standard O & M (10%)	88,864	46,107	131,891	88,864	46,107	131,891
Offshore labor	42,705	42,705	42,705	42,705	42,705	42,705
OFFSHORE O & M COST	$131,569	$88,812	$174,596	$131,569	$88,812	$174,596
TOTAL O & M COST	**$2,323,215**			**$2,199,983**		

(a) Future produced water volumes are used for equipment design. Future flow equals 1.5 times current flow.
(b) Coastally generated fluids costed for segregated oil/water separation at FWKO #1. After separation the produced water fraction goes through existing pipeline to the Central Facility for treatment and injection.

As discussed above, by developing compliance costs using the total produced water flow at the facility, EPA has unnecessarily included compliance costs for that 20 percent of produced water derived from coastal subcategory wells. Since this produced water is required to comply with EPA Region 6 zero discharge requirements by January 1, 1997, it is reasonable to reduce the total facility costs developed by EPA by 20 percent. In doing so, the capital costs for Case 2 are reduced from $20.3 million to $16.2 million, and the O&M costs are reduced from $9.4 million per year to $7.5 million per year. Since the volume of coastally-derived produced water is equal to that volume assumed under Case 2 to be injected into waterflood wells, the cost for waterflood pipeline is appropriately due to existing permit requirements and not the coastal guidelines. A review of the Case 2 capital costs shows that by eliminating the waterflood well pipeline cost, a savings of more than 20 percent of the total costs is achieved. In addition, since filtration system costs and produced water treatment chemical costs are based on total facility flow, these costs should also be reduced by 20 percent, thus realizing more than 20 percent reduction in total costs by excluding costs attributable to existing permit requirements for the coastally-derived produced water. The other cases for FRI are similarly over-estimated because they include costs attributable to coastally-derived produced water.

Subsequent to development of compliance cost estimates, on August 5, 1996, EPA received comments and information from Flores & Rucks that presented additional cost information.[40] This information was submitted very late in the regulatory process, over 14 months after the close of the comment period (initially established as May 1995 in the Federal Register notice, later extended to June 1995). These late comments are discussed in the Response to Comments document.[42]

3.2.3 Gulf of Mexico Baseline Options 2 and 3 O&M Cost (Zero Discharge by Subsurface Injection)

Design O&M costs for produced water injection are presented in Table XI-9, with Flores & Rucks under compliance Case 2. The bases for the design O&M costs for injection are presented in Table XI-13, as follows:

- **Labor:** Labor costs are based on an hourly rate of $39.00 per hour (1995 dollars). This is an increase from $20 per hour which was used in the proposal compliance cost estimates. Bureau of Labor Statistics data and information from commenters and other operators support the increase to $39.00 per hour.[15] Labor is estimated at 2 person-hours per day for the operation of single-well injection systems. Labor costs for multiple-well injection systems are based on 2.42 person-hours per day.[16]

TABLE XI-13

DESIGN O&M COSTS (1995 DOLLARS PER YEAR) FOR PRODUCED WATER INJECTION AT GULF OF MEXICO PRODUCTION FACILITIES

O&M Component	Design Flow (bpd)							
	200	500	1,000	5,000	10,000	18,000	30,000	42,000
Labor	28,470	28,470	28,470	28,470	56,940	113,880	170,820	256,230
Pump Fuel Cost	0	0	7,545	30,539	61,078	122,157	186,828	283,835
Maintenance Materials (5%)	1,090	1,146	1,640	3,428	6,116	11,749	17,278	25,571
Cartridge Filter Replacement	365	913	1,825	9,125	18,250	32,850	54,750	76,650
Produced Water Treatment Chemicals	4,928	12,319	24,638	123,188	246,375	443,475	739,125	1,034,775
Injection Well Backwash	11,135	11,135	11,135	11,135	22,270	44,540	66,810	100,215
TOTAL O&M COST:	**45,988**	**53,983**	**75,253**	**205,885**	**411,029**	**768,651**	**1,235,611**	**1,777,276**

- **Fuel:** Fuel cost was calculated based on the maximum pumping horsepower required above 25 hp, continuous operation (365 days per year), and a natural gas unit cost of $2.50 per 1,000 cubic feet.[6,16] Information obtained from the Department of Energy confirms gas unit costs have dropped and recovered since proposal.[43] Thus, proposal natural gas costs are used herein.

- **Maintenance Materials:** Maintenance materials represent 5% of the equipment purchase cost.

- **Cartridge Filter Replacement:** The cost to replace filters within the cartridge filtration system were not included in the 1995 Coastal Development Document and were added to the current list of O&M costs as $0.005/bpd.[44] Cost of replacement was based on vendor quotes and industry comments on frequency of replacement as a function of produced water flow.[44]

- **Chemicals:** Total chemical cost for treating produced water for injection is $24.6375/yr (in 1995 dollars) multiplied by the daily flow rate in barrels.[44]

- **Well Backwash:** The well backwash unit cost rate was based on the results of the statistical analysis of the 1993 Coastal Oil and Gas Questionnaire. Well backwash cost is $11,135 (adjusted to 1995 dollars) per job.[16] In response to comments received on the proposed rulemaking, the backwash frequency has been increased from bi-annually in the proposal (based on the statistical analysis of the 1993 EPA Coastal Oil and Gas Questionnaire),[16] to once per year in this analysis.

As discussed in Section 3.0, EPA based capital costs on assuming future produced water flow 1.5 times the current flow. O&M costs estimate first year expenditures, which may be expected to rise as produced water flow rates increase. This future escalation in O&M costs due to produced water flow increases is addressed in the economic impact model.[2]

4.0 COOK INLET COMPLIANCE COST METHODOLOGY

EPA determined that oil and gas are produced from 13 of 15 existing platforms in Cook Inlet. Two platforms are shut in. Eight platforms pipe the production fluids (oil, gas, and water) to three shore-based facilities for separation and treatment. Produced water from the three shore-based facilities is discharged to Cook Inlet after treatment. The remaining five platforms separate and treat the production fluids at the platform. Produced water from each of the five platforms is discharged directly overboard after treatment. Facility-specific information such as the average daily produced water flow and current treatment technology employed was evaluated for each facility and compared to the treatment technology required for complaince with each of the regulatory options. Incremental capital and O&M costs were estimated specifically for each discharging facility.

Costs for each option were developed separately for the three shore-based facilities and for the five platforms that discharge overboard, as presented in Table XI-14. The following sections present the

TABLE XI-14

SUMMARY CAPITAL AND O&M COSTS FOR COOK INLET PRODUCED WATER BAT OPTIONS

Facility or Platform	Options 1 and 2 Improved Operation of Gas Platform		Option 3 Subsurface Injection	
	Capital Costs (1995 $)	O&M Costs (1995 $/yr)	Capital Costs (1995 $)	O&M Costs (1995 $/yr)
Trading Bay Production Facility	0	245,579	51,117,826	15,183,281
Granite Point Treatment Facility	1,297,003	129,700	5,603,072	556,615
East Foreland Treatment Facility	1,297,003	129,700	24,045,167	2,742,016
Anna	1,713,256	171,326	2,195,407	393,459
Dillon	1,914,317	191,432	2,396,472	693,719
Bruce	1,297,626	129,763	4,592,766	445,857
Baker	1,713,256	171,326	2,195,407	644,658
Tyonek	0	0	4,809,976	301,363
TOTAL	**9,232,461**	**1,168,826**	**96,956,093**	**20,960,966**

detailed methodologies used to calculate the produced water regulatory compliance costs based on improved gas flotation (Options 1 and 2) and subsurface injection (Option 3).

Table XI-15 lists the produced water treatment equipment known or assumed to be currently present at the Cook Inlet operations. In the cost analysis, no costs were added for the equipment listed in Table XI-15. Capital costs were incurred only for the incremental equipment required to treat and/or inject produced water according to the options described in Section 2.0. Table XI-15 lists only the platforms for which costs were incurred. Monopod, Steelhead, Granite Point, Spurr, and SWEPI "A" are projected to incur no costs due to the final rule. Produced water from Monopod and Steelhead goes to the Trading Bay Production Facility (TBPF) and is not returned to those platforms for injection (see Table IV-3) for the current locations of produced water discharge). Granite Point pipes produced water to Granite Point Treatment Facility and does not treat or inject produced water onsite. Spurr platform is currently shut in. Because the volume of treated produced water from the East Foreland treatment facility is less than the waterflooding demand at both SWEPI "A" and "C" platforms, only SWEPI "C" incurred injection costs. The following sections present lists of incremental equipment that was included in the capital cost analysis as needed for each platform and treatment facility.

4.1 COOK INLET OPTIONS 1 AND 2 COMPLIANCE COSTS (IMPROVED OPERATION OF GAS FLOTATION)

The technology basis for Options 1 and 2 is treatment of produced water with gas flotation under improved operating conditions. For those platforms or facilities that do not have gas flotation units, the installation of new flotation units was assumed necessary in the analysis to achieve compliance with the limitations of Options 1 and 2.

Of the three onshore treatment facilities, Granite Point and East Foreland were assumed to require additional gas flotation equipment. No capital costs were assigned to the Trading Bay Production Facility due to the presence of existing gas flotation equipment, although such costs were estimated in order to calculate O&M costs for operating a gas flotation unit at this facility, since O&M costs are based on capital costs.

Of the five platforms that currently discharge produced water, only Tyonek platform is equipped with gas flotation units. For Options 1 and 2, the Tyonek platform did not incur any compliance costs. The other four dischargers (Dillon, Bruce, Anna, and Baker) were assumed to require gas flotation units.

TABLE XI-15

EXISTING EQUIPMENT AT SELECTED COOK INLET TREATMENT FACILITIES AND PLATFORMS[45]

Facility or Platform	Basic Gravity Separation Equipment	Return Pipeline from Facility to Platform	Gas Flotation	Granular Filtration	Injection Wells and Associated Equipment
Trading Bay Production Facility	✓		✓		
Granite Point Treatment Facility	✓	✓			
East Foreland Treatment Facility	✓[a]				
King Salmon	✓			✓	
Grayling	✓			✓	
Dolly Varden	✓			✓	
Spark	✓			✓	
SWEPI "C"	✓			✓	✓
Dillon	✓			✓	✓
Bruce	✓			✓	
Anna	✓			✓	✓
Baker	✓			✓	✓
Tyonek "A"	✓		✓		

[a] The current treatment equipment at East Foreland Treatment Facility consists of basic separation, skim tanks, and a corrugated plate interceptor.[46]

4.1.1 Cook Inlet Options 1 and 2 Capital Cost Estimates

Tables Y through EE in Appendix XI-1 present the detailed capital costs developed for Options 1 and 2 for each discharging Cook Inlet facility and platform. Capital costs were adjusted from 1992 dollars to 1995 dollars using the Engineering-News Record Construction Cost Index (ENR-CCI) ratio of

5471/4985 (1.0975).[13] It is important to note that because O&M costs for Options 1 and 2 are calculated as 10 percent of the capital costs, and because the Trading Bay Production Facility has existing gas flotation equipment, the capital costs for the Trading Bay Production Facility in Table Y were developed only to determine the incremental O&M costs due to operating improved gas flotation. Table XI-16 lists the summary capital and O&M costs for all facilities and platforms included in this analysis.

The following bases were applied to the capital cost analysis for the three onshore treatment facilities and the four platforms included in the gas flotation compliance cost analysis (see Appendix XI-1 for details):

- **Materials and Equipment:** The equipment purchase cost for all production facilities includes: gas flotation skid-mounted, complete electrical systems, oil and water outlets brought to the edge fo the skid, and sufficient instrumentation for proper operation. Available gas flotation unit sizes include 1,000 bpd, 5,000 bpd, 10,000 bpd, and 40,000 bpd.[1] The size of the equipment varies with flow.

  Most gas flotation units were sized assuming a peak produced water flow of 2.3 times the average produced water flow of each production facility.[47,48]

- **Piping and Instrumentation:** Piping and instrumentation costs were assumed to be 15% of the equipment purchase cost. This cost includes any additional valves, fittings, piping, cables, conduits, instrumentation, and instrumentation wiring (see Section 3.1.1.1).

- **Geographic Area Multiplier:** Total equipment costs were multiplied by a "geographic area multiplier" of 2.0.[1] This factor is the ratio of the equipment installation costs in a particular region compared to the costs for the same equipment installation in the Gulf of Mexico region.

- **Installation Costs:** Installation costs added to the three onshore facilities are equal to the total materials and equipment (M&E) costs. Installation costs added to the platforms are 2.5 times the M&E costs.[9]

- **Main Equipment Building:** The main equipment building was added to Granite Point and East Foreland treatment facilities to house the additional gas flotation and associated equipment. This cost was not added to the TBPF for Options 1 and 2 because TBPF's capital costs were used only to estimate O&M costs associated with the use of gas flotation equipment. The cost for this building was estimated by Cook Inlet operators.[49] The cost was $325,532 in 1995 dollars.[48]

- **Platform Modification Cost:** Platform modification costs were added to the four platforms to accommodate space requirements for the gas flotation equipment. The square footage required is: 112 square feet for a 1,000 bpd unit; 210 square feet for a 5,000 bpd unit; 266 square feet for a 10,000 bpd unit.[1] The cost for additional platform space[50] was adjusted to $658.5 per square foot in 1995 dollars using the ENR-CCI ratio of 5471/4985 (1.0975).[13]

TABLE XI-16

CAPITAL AND O&M COSTS FOR GAS FLOTATION (OPTIONS 1 AND 2) PER COOK INLET FACILITY/PLATFORM

Category	Name of Discharging Facilities or Platforms								Grand Total
	Trading Bay[a]	Granite Pt.[a]	E. Foreland[a]	Anna[b]	Dillon[b]	Bruce[b]	Baker[b]	Tyonek[b]	
1. Capital Cost ($)									
Installed Equipment	0	679,897	679,897	1,189,820	1,308,807	932,159	1,189,820	0	5,980,400
Main Equipment Bldg.	0	325,532	325,532	0	0	0	0	0	651,064
Engineering (10%)	0	100,543	100,543	132,811	148,396	100,591	132,811	0	715,695
Contingency (15%)	0	150,814	150,814	199,216	222,595	150,887	199,216	0	1,073,542
Ins.-Bonding (4%)	0	40,217	40,217	53,124	59,358	40,237	53,124	0	286,277
Platform Modifications	0	0	0	138,285	175,161	73,752	138,285	0	525,483
Total Capital Cost	0	1,297,003	1,297,003	1,713,256	1,914,317	1,297,626	1,713,256	0	9,232,461
2. O&M Cost ($/yr)	245,579	129,700	129,700	171,326	191,432	129,763	171,326	0	1,168,826

[a] Shore-based treatment facility
[b] Platform

- **Additional Costs (Engineering, Contingency, and Insurance/Bonding):** These fees were added to the equipment costs to develop actual capital costs. These fees include all engineering design costs, administrative costs, and any incidental costs incurred in the process of purchasing and installing equipment.[1]

4.1.2 Cook Inlet Options 1 and 2 Operating and Maintenance Costs

All O&M costs for Options 1 and 2 were calculated as 10 percent of the capital costs. This percentage is commonly used for estimating O&M costs in process industries, and is within the range of two to 11 percent cited in the literature.[51] These O&M costs include labor, maintenance, spare parts, and standard treatment chemicals.[9] Table XI-16 lists the O&M costs calculated for all facilities and platforms included in this analysis.

4.2 COOK INLET OPTION 3 COMPLIANCE COSTS (ZERO DISCHARGE BY SUBSURFACE INJECTION)

This option is based on the injection of produced water into available subsurface formations. For Cook Inlet facilities, if zero discharge were required, the least costly basis for compliance would be to inject produced water into production zones as part of the ongoing waterflood operations or into dedicated disposal wells where waterflooding operations do not exist. The substitution of produced water for the seawater that is currently used in Cook Inlet waterflood operations was included in EPA's analysis for two reasons: 1) using existing injection technology results in significant cost savings over the purchase of new equipment, and 2) concerns regarding limited available geologic formations for produced water disposal.[49,52] In particular, injection of produced water at the onshore treatment facilities is not technically possible because the geology of the underlying formations cannot accept the large volumes of produced water that must be disposed.[49,53] In Cook Inlet, unlike states along the Gulf Coast, only the production formation is generally available for injection. For platforms that pipe produced fluids to shore for separation and treatment, Option 3 assumes that the produced water is piped back to selected platforms for injection as part of the waterflood operations. This assumption is based on information provided in the Marathon/Unocal report which asserts that piping produced water back to the platforms "is considered the most viable" injection scenario.[49] For platforms that separate and treat at the platform, Option 3 assumes that the produced water is injected into production zones as part of the waterflood operations or requires that disposal wells be installed. Two platforms, Bruce and Tyonek, do not have waterflooding operations and therefore incurred costs for disposal wells and injection equipment under this option. In addition, Spark has waterflooding equipment that is not currently in use, and so incurred costs for the recompletion of service wells for produced water disposal.

Table XI-17 presents an inventory of the incremental equipment added and modifications made to the treatment facilities and platforms as needed to comply with Option 3. These are general equipment categories; specific items and capital costs are detailed in the technical support document.[48]

To allow for the continuance of waterflooding and to prevent long-term damage to the injection wells and reservoirs, produced water must be treated for removal of oil and grease and total suspended solids (TSS). Compliance costs were estimated assuming that gas flotation and multi-media filtration is the treatment train necessary to pretreat produced water for injection.[48]

EPA reviewed the effects of produced water injection and concluded that downhole problems such as calcium carbonate scale precipitation and bacterial growth can be mitigated through the use of proper operating procedures.[46] These procedures consist of pretreatment of the produced water for oil and grease and TSS, and continued chemical treatment of the injection stream. The proper usage of scale inhibitors can minimize scale deposits in the injection equipment, tubing flow lines, and injectors. The usage of biocides can minimize bacterial growth, thus reducing the formation of hydrogen sulfide. In addition to chemical treatment, annual well workovers can minimize scale build-up. Therefore, the cost analysis presented herein includes separate O&M costs for standard O&M activities (i.e., 10 percent of capital costs for standard labor, maintenance, spare parts, and treatment chemicals) as well as "additional" treatment chemicals and well workovers (see Section 4.2.2).

To manage the increase in filter backwash due to the pretreatment of produced water prior to subsurface injection, a centrifuge was added to every location that filters produced water, as well as additional O&M costs for the transport and disposal of the dewatered backwash sludge. These costs are presented in Sections 4.2.1 and 4.2.2.

4.2.1 Cook Inlet Option 3 Capital Cost Estimates (Subsurface Injection)

Tables A through K in Appendix XI-2 present the detailed capital costs developed for Option 3 for each of the three onshore treatment facilities and the 10 platforms included in the zero discharge compliance cost analysis. Table XI-18 presents the summary capital and O&M costs for all facilities and platforms included in this analysis. Assumptions regarding standard equipment and costs, including the geographic area multiplier, installation, main equipment building, and fees for engineering, contingency, and insurance/bonding were also included in the capital cost analysis for Option 3. These assumptions are

TABLE XI-17

SUMMARY OF EQUIPMENT AND MODIFICATIONS ASSUMED NECESSARY FOR COMPLIANCE WITH OPTION 3: ZERO DISCHARGE VIA INJECTION

Facility or Platform	Return Pipeline from Facility to Platform	Connecting Return Pipeline at Platform	Gas Flotation	Granular Filtration	Filtration Backwash Centrifuge	Injection Wells and Associated Equipment
Trading Bay Production Facility	✓					
Granite Point Treatment Facility			✓	✓	✓	
East Foreland Treatment Facility	✓		✓			
King Salmon		✓			✓	
Grayling		✓			✓	
Dolly Varden		✓			✓	
Spark		✓				✓
SWEPI "C"		✓			✓	
Dillon			✓		✓	
Bruce			✓		✓	✓
Anna			✓		✓	
Baker			✓		✓	
Tyonek "A"				✓	✓	✓

TABLE XI-18

CAPITAL AND O&M COSTS FOR OPTION 3
PER COOK INLET FACILITY/PLATFORM

Category	Trading Bay Production Fac. [a]	Granite Point Treat. Fac. [b]	E. Foreland [c]	Anna	Dillon	Bruce	Baker	Tyonek	TOTAL
CAPITAL COSTS									
Installed Equip.	9,862,859	1,993,878	5,416,656	1,563,581	1,682,569	1,305,920	1,563,581	1,284,652	24,673,696
Main Building	325,532	325,532	325,532	0	0	0	0	0	976,596
Engineering (10%)	1,018,839	231,941	574,219	156,358	168,257	130,592	156,358	128,465	2,565,029
Contingency (15%)	1,528,259	347,911	861,328	234,537	252,385	195,888	234,537	192,698	3,847,543
Ins. + Bonding (4%)	407,536	92,776	229,687	62,543	67,303	52,237	62,543	51,386	1,026,011
Pipeline	33,143,900	0	15,297,055	0	0	0	0	0	48,440,955
Platform Modification	4,830,901	1,058,958	1,340,690	178,388	225,958	95,140	178,388	339,786	8,248,209
Injection Equipment	0	70,451	0	0	0	185,194	0	185,194	440,839
Injection Well	0	1,481,625	0	0	0	2,627,795	0	2,627,795	6,737,215
Total Capital Cost	**51,117,826**	**5,603,072**	**24,045,167**	**2,195,407**	**2,396,472**	**4,592,766**	**2,195,407**	**4,809,976**	**96,956,093**
O&M COSTS									
Standard O&M	5,111,783	405,100	2,404,517	219,541	239,647	177,978	219,541	199,699	8,977,804
Well Workover	2,400,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	3,100,000
Treatment Chemicals	4,611,467	30,966	140,000	44,433	103,867	3,966	195,433	1,000	5,131,132
Filtration O&M	3,060,031	20,549	97,499	29,485	250,205	163,913	129,684	664	3,752,030
Total O&M Costs	**15,183,281**	**556,615**	**2,742,016**	**393,459**	**693,719**	**445,857**	**644,658**	**301,363**	**20,960,966**

a) Costs in this column includes combined capital and O&M costs for TBPF, King Salmon, Grayling, and Dolly Varden platforms.
b) Costs in this column includes combined capital and O&M costs for Granite Point treatment facility and Spark platform.
c) Costs in this column includes combined capital and O&M costs for East Foreland treatment facility and SWEPI "C" platform.

presented in Section 3.1.1 under the gas flotation capital costs analysis. Additional assumptions developed specifically for the Option 3 analysis are as follows.

4.2.1.1 Return Pipeline from Facility to Platform

Of the three onshore treatment facilities, Trading Bay and East Foreland incurred costs for pipelines to return produced water to selected platforms for injection. The Granite Point facility has an existing return pipeline to Spark platform where all the facility's produced water is currently discharged. Thus, no capital costs related to a return pipeline were incurred by the Granite Point facility. As presented in the Marathon/Unocal report, Trading Bay is assumed to return treated produced water to King Salmon, Grayling, and Dolly Varden platforms.[c] Based on industry information, each of the three 8-inch pipelines is determined to be 6.5 miles long.[49] The Marathon/Unocal pipeline cost estimates, also used in this analysis, include pipeline and riser material costs, pipe laying costs, mobilization/demobilization costs, and project management costs. The specific total pipeline cost cited in the Marathon/Unocal report was $31,562,519 (1993 $). The cost per foot of pipeline is $306.55 (1993 $). The pipeline cost in 1995 dollars for TBPF is $33,143,900 or $321.91 per foot using an ENR-CCI ratio of 5471/5210. Applying this cost per foot to the nine miles of pipeline assumed to connect the East Foreland facility to the SWEPI "C" platform, a pipeline cost of $15,297,055 (1995 $) was incurred.

In addition to pipelines, TBPF and East Foreland incurred costs for equipment associated with the pipeline, as presented in the Marathon/Unocal report.[49] The assumptions used to develop these costs are as follows:

- Shipping pumps were included, one per pipeline plus one spare. For TBPF, four pumps were included; for East Foreland, two pumps were included. Each pump is rated for 1460 gpm at 700 psig with a 1000 hp motor.[49] The pump costs which were originally presented in 1993 dollars were adjusted to 1995 dollars using the ENR-CCI ratio of 5471/5210.

- One booster pump was included for each pipeline: three pumps for TBPF and one pump for East Foreland. Booster pumps are required to pump the water from storage tanks to 150 psig to satisfy the net positive suction head of the shipping pumps. Each pump is rated for 2120 gpm at 150 psig with a 300 hp motor.[49] The pump costs which were originally presented in 1993 dollars were adjusted to 1995 dollars using the ENR-CCI ratio of 5471/5210.

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[c] The Marathon/Unocal report presented three zero-discharge compliance cost scenarios, including 1) piping treated produced water from TBPF to three Cook Inlet platforms for waterflooding operations, 2) installing hydrocyclones at the platforms for onsite treatment prior to injection, and 3) installing injection wells at TBPF.[49] The report stated that the first scenario was "the most technically viable re-injection alternative," citing technical limitations of the other two alternatives. EPA selected the first scenario as the basis for its analysis.

- All motors are electric. Electricity for these motors is supplied by a natural gas driven generator. The cost of the power generation equipment is included, as provided by Marathon/ Unocal.[49]

- Two 15,000-barrel storage tanks were included for TBPF; one 15,000-barrel tank was included for East Foreland.[49] The storage tanks which were originally presented in 1993 dollars were adjusted to 1995 dollars using the ENR-CCI ratio of 5471/5210.

- One pig launcher was included for each pipeline: three for TBPF and one for East Foreland. Each pig launcher is an eight-inch standard 600 ANSI.[49] The pig launcher costs which were originally presented in 1993 dollars were adjusted to 1995 dollars using the ENR-CCI ratio of 5471/5210.

- Piping and instrumentation costs were assumed to be 15 percent of the equipment purchase cost. This cost includes any additional valves, fittings, piping, cables, conduits, instrumentation, and instrumentation wiring.[9]

4.2.1.2 Connecting Return Pipeline at the Platform

The five platforms assumed to receive produced water from onshore treatment facilities are King Salmon, Grayling and Dolly Varden (associated with TBPF), Spark (associated with Granite Point), and SWEPI "C" (associated with East Foreland). These platforms incur costs for equipment and services related to retrofitting the platforms to accommodate the return pipeline to the existing produced water injection systems. These costs primarily consist of pipeline installation and replumbing existing piping to the injection system. The basis for these costs is the Marathon/Unocal report, which states that the costs were developed using engineering data from other platform modification projects.[49] The specific items included in these modifications are listed in Tables D, E, and F in Appendix XI-2. The only difference between the platforms with regard to return pipeline modifications is that Spark does not incur the cost of a pig receiver, because the existing pipeline would be equipped with one.

4.2.1.3 Improved Gas Flotation

The assumptions developed for incremental gas flotation equipment costs are the same as those presented in Section 4.1.1 for Options 1 and 2. Table XI-17 indicates which facilities and platforms incur these costs, and Tables B, C, and G through J in Appendix XI-2 list the specific equipment sizes and costs incurred.

4.2.1.4 Granular Filtration

As shown in Table XI-17, granular media filtration equipment was added to only two operations: Granite Point treatment facility and Tyonek platform. All other facilities and platforms at which produced water is treated have existing granular filtration units.[45] The assumptions regarding the size and cost of granular filters were adopted from the Offshore rulemaking effort, as follows:

- Available granular filtration unit sizes include 200 bpd, 1,000 bpd, 5,000 bpd, 10,000 bpd, and 40,000 bpd. These sizes and their capital costs were originally developed for the Offshore rulemaking effort.[9]
- Granular filtration units were sized assuming a peak produced water flow of 2.3 times the facility's average produced water flow.[47,48]
- Platform modification costs were added to Tyonek platform to accommodate space requirements for the filtration (and additional injection) equipment. The square footage required is 400 square feet.[9] The cost for additional platform space was $658.5 per square foot in 1995 dollars.[13]
- All capital costs were adjusted from 1992 dollars to 1995 dollars using the ENR-CCI ratio of 5471/4985 (1.0975).[13]

4.2.1.5 Filtration Backwash Centrifuge

With one exception, a centrifuge for dewatering filtration backwash solids was added to all platforms that were assumed to inject produced water in the Option 3 zero discharge cost analysis. Spark platform did not receive a centrifuge in this analysis because all the treatment equipment is located at the Granite Point facility. Centrifuges would concentrate the solids removed from the filtered produced water, thus allowing the liquid portion of the backwash to be injected. The dewatered solids would be disposed of by transport to a landfill, as is reflected in the operating and maintenance costs in Section 4.2.2. The assumptions regarding the size and cost of centrifuges were adopted from the Offshore rulemaking effort, as follows:[1]

- Centrifuge costs are based on a centrifuge sized to process 75 barrels of filtration backwash concentrate for all the platforms. The Offshore development document presents the assumptions behind calculated volumes of concentrated backwash ranging from 1 bpd (for a 200 bpd produced water flow) to 200 bpd (for a 40,000 bpd produced water flow).[1] Two centrifuges were assumed adequate for systems treating more than 40,000 bpd of produced water. Thus, King Salmon, Grayling, and Dolly Varden each received two centrifuges while all other operations received only one.
- The centrifuge cost was adjusted from its 1981 price of $30,000 to $46,430 in 1995 dollars using the ENR-CCI ratio of 5471/3535 (1.548).[13]

4.2.1.6 *Injection Wells and Associated Equipment*

For this costing effort, new injection wells were added to Bruce and Tyonek platforms, and recompletion of two existing service wells were assumed for Spark platform. The existing injection wells and supporting equipment at all other platforms are assumed to be adequate to meet the requirements of Option 3. This assumption is based on the use of existing injection equipment and wells in the Marathon/Unocal "zero discharge analysis."[49] The following assumptions were developed for incremental injection requirements:

- Two injection wells were assumed to be added to each of Bruce and Tyonek platforms. One well is necessary as a spare. Each injection well has a capacity of 6,000 bpd.[9]
- The cost to drill an injection well is $1,313,897. This cost was adjusted from its original cost in 1992 dollars[46] to 1995 dollars using the ENR-CCI ratio of 5471/4985 (1.0975).[13]
- Two 1,000 bpd injection pumps were assumed for each of Bruce and Tyonek, with one pump acting as a spare. The selected pump is a Meyers model C35-20 rated for 1800 psia. The motor for this pump is a 42 hp model VSG-413, 4 cylinder, 79 CID, natural gas drive. The total cost of the pump and motor is $14,600 in 1995 dollars adjusted from their cost in 1992 dollars[44] using the ENR-CCI ratio of 5471/4985 (1.0975).[13]
- Two former waterflood wells were assumed to be recompleted for use as produced water disposal wells on Spark platform, with one well as a spare.
- The cost to recomplete each well was assumed to be $740,813. This cost was adjusted from its original cost in 1992 dollars[44] to 1995 dollars using the ENR-CCI ratio of 5471/4985 (1.0975).[13]
- Two 3,000 bpd injection pumps were assumed for Spark platform, with one pump acting as a spare. The pump selected is a Meyers model DP90-18AB, 1700 psia. The motor for the pump is a 100 hp model CSG-649, 6 cylinder, 300 CID, natural gas drive. The cost of the pump and motor is $32,023 in 1995 dollars adjusted from their cost in 1992 dollars[46] using the ENR-CCI ratio of 5471/4985 (1.0975).[13]

4.2.2 Cook Inlet Option 3 Operating and Maintenance Costs

Operating and maintenance costs for Option 3 consist of four parts: standard O&M, well workovers, additional treatment chemicals, and filtration O&M. Table XI-18 lists the O&M costs calculated for all facilities and platforms included in this analysis. Standard O&M costs were calculated as 10 percent of the capital costs. Standard O&M costs include the necessary labor, maintenance, spare parts, and treatment chemicals to manage the incremental equipment required under this option.[9] Annual well workover costs were $100,000 per workover.[44,48,54]

As stated earlier in Section 4.2, additional O&M costs were included to address the increased need for chemicals to treat produced water for injection. For this analysis, additional chemical costs include the biocide, corrosion inhibitor, and scale inhibitor needed to treat produced water prior to injection. The cost for these chemicals is derived from information submitted by Cook Inlet operators. At an estimated cost of $5 million per year and an annual produced water discharge rate of 54,750,000 bpy (150,000 bpd x 365), the unit cost for these chemicals is $0.0913/bbl.[48,49] All locations that treat the produced water prior to injection in this analysis incur additional treatment chemical costs.

The filtration O&M costs consist of labor to operate the filtration unit(s), maintenance costs, and dewatered backwash sludge disposal. Combinations of these costs were applied to the locations that have granular filtration, depending on whether equipment is existing or new, and whether a platform is waterflooding. Table XI-19 presents the various costs assigned to the platforms and treatment facility that require filtration O&M costs. Only Dillon and Bruce incur filtration labor and maintenance costs because the existing filtration equipment on these platforms is not currently in use. Labor and maintenance costs for platforms acquiring new filtration equipment are incurred as part of the standard O&M costs associated with the capital cost of new equipment. All filtration systems in this analysis incur O&M costs for dewatered sludge disposal. Filtration enhancing polymers are not included in these costs because they are either accounted for in standard O&M costs for new equipment or are already in use at existing filtration units. The following assumptions apply to the filtration O&M costs presented in Table XI-19:

- Labor is based on two man-hours per day,[1] at a rate of $78 per hour, calculated as twice the Gulf of Mexico labor rate.[15]
- Maintenance costs are 10 percent of the capital costs, and include energy, unit clean out, inspection and replacement of filter media.[1]
- Sludge disposal costs are based on the estimated backwash sludge volume of 0.06 percent of the total volume filtered.[1] The unit disposal costs (in $/bbl) were developed for the drilling waste compliance cost analysis in which wastes are transported from the platforms to a landfill.[55]

4.3 COOK INLET MODEL NEW SOURCE COMPLIANCE COST ANALYSIS

EPA performed an analysis for a model new source platform to estimate compliance costs for potential new sources in Cook Inlet. The platform profile was modeled after the Steelhead Platform, the most recently constructed platform. The model platform profile was based on information from the Offshore Economic Impact Assessment which states that Steelhead had 36 wells that had been drilled as of 1988.[56] (Current information shows only 15 wells in use. See Table IV-3 for current status of Cook Inlet platforms.) The two injection wells currently used for waterflooding on Steelhead were subtracted from the baseline of 36 wells in order to determine the numbers of producing oil and gas wells expected

TABLE XI-19

COOK INLET FILTRATION O&M COSTS
(1995 $/YR)

Facility/Platform	Labor	Maintenance	Sludge Disposal	Total
Granite Point Treatment Facility	---	---	20,549	20,549
King Salmon	---	---	1,018,956	1,018,956
Grayling	---	---	1,180,867	1,180,867
Dolly Varden	---	---	860,208	860,208
SWEPI "C"	---	---	97,499	97,499
Dillon	56,940	124,342	68,923	250,205
Bruce	56,940	104,341	2,632	163,913
Anna	---	---	29,485	29,485
Baker	---	---	129,684	129,684
Tyonek	---	---	664	664
Totals	**113,880**	**228,683**	**3,409,467**	**3,752,030**

to be present on the model platform after five years of development. Based on the proportion of 30 percent oil wells to 70 percent gas wells currently on Steelhead, the remaining 34 wells were designated as 10 oil wells and 24 gas wells. Using the profile and current oil, gas, and water production data for all active Cook Inlet platforms (see Table IV-3), an average daily produced water flow rate of 7,353 bpd was estimated for the model platform. Table A in Appendix XI-3 presents the details of this calculation.

Capital and O&M costs for the treatment and injection of produced water at the model platform were then calculated based on the estimated daily produced water flow rate. The costs and methodologies presented in Section 4.2 for the zero-discharge via injection option were used in the model platform analysis. The items included in the capital cost calculations are the incremental equipment required to meet zero discharge by injection, as follows:

- one 10,000 bpd granular filtration unit
- one 75 bpd centrifuge for dewatering filtration backwash
- three 6,000 bpd injection wells
- two injection pumps.

No gas flotation unit was added in the analysis because it was assumed to be part of the baseline equipment installed on the new platform. That is, gas flotation units are already commonly in use to treat produced water prior to discharge, so this does not represent incremental treatment. The total capital cost for the above treatment and injection system was estimated to be $8,098,375 in 1995 dollars. Table B in Appendix XI-3 presents the detailed calculations for this estimate.

Total operating and maintenance costs are the sum of standard O&M costs, annual injection well workovers, additional treatment chemicals, and sludge disposal costs, based on the information presented in Section 4.2.2. These costs total $1,517,578 annually (1995 dollars) as shown in Appendix XI-3, Table B.

5.0 GULF OF MEXICO ALTERNATIVE BASELINE COMPLIANCE COST METHODOLOGY

The Alternative Baseline introduces additional oil and gas production facilities in the Gulf of Mexico region to the Baseline industry profile (see Chapter IV - Industry Description). These additional facilities include operations seeking individual permits from EPA as well as Louisiana facilities identified in "Risk Assessment for Produced Water Discharges to Louisiana Open Bays" by the U.S. Department of Energy.[57,58] Compliance costs associated with the additional facilities have been estimated separately as described below, then added to the Baseline compliance costs and Cook Inlet compliance costs. The Cook Inlet industry profile, cost estimates and pollutant reductions are not affected by the Alternative Baseline.

Some distinctions between the cost bases for the Alternative Baseline and Baseline analyses should be noted. In the absence of facility-specific information (as was available for Baseline facilities), Alternative Baseline facilities with multiple outfalls were assumed to combine produced water volumes to acheive compliance. This assumption was used at proposal and was not criticized by commenters. Other differences in the cost estimating process included addressing uncertainties with regard to some Louisiana facilities' produced water flow rates. Louisiana produced water flow rates that were omitted or were reported to the Louisiana Department of Environmental Quality (LDEQ) as zero or intermittent, have been provided with the average Louisiana produced water flow rate (4,621 bpd) as an estimating tool. As in the proposal analysis, Louisiana Alternative Baseline facilities were consided to be water-access for cost estimating purposes.

Those Texas produced water flow rates that were reported as zero or omitted have been confirmed by the Railroad Commission of Texas as having no produced water.[59,60,61] Thus, these particular Texas Alternative Baseline facilities incur no compliance costs or O&M costs for facilities having reported zero flow. As in the proposal analysis, Texas Alternative Baseline facilities were assumed to be land-access for cost estimating purposes.

5.1 GULF OF MEXICO ALTERNATIVE BASELINE OPTION 1 CAPITAL COSTS

Option 1 Capital costs for Alternative Baseline facilities were determined using the same methodology presented in Section 3.1. For Louisiana Alternative Baseline facilities with future produced water flow rates below 70.5 bpd, barging costs were incurred in addition to commercial IGF treatment costs. The 70.5 bpd cutoff rate was determined by cost parity between barging/commercial treatment and on-site IGF treatment at water-access facilities. For Texas Alternative Baseline facilities with furture flow rates below 76.5 bpd, trucking costs were incurred in addition to commercial IGF treatment costs. The 76.5 bpd cutoff rate was determined by cost parity between trucking/commercial treatment and on-site IGF treatment at land-access facilities.

For Alternative Baseline facilities with future produced water flows between 70.5 and 5,000 bpd, the step cost method was used to determine the captital costs as described in Section 3.1.1.2. The flow rate was used to determine capital costs from Table XI-4. For future produced water flow rates above 5,000 bpd, the capital cost equation in Table XI-4 was used. Tables XI-20 and XI-21 present capital costs estimated for Alternative Baseline facilities. Table XI-22 presents total capital costs for Option 1 including Alternative Baseline facilities, Baseline facilities and Cook Inlet facilities.

5.2 GULF OF MEXICO ALTERNATIVE BASELINE OPTION 1 O&M COSTS

Estimated design O&M costs for IGF treatment are presented in Tables XI-20, XI-21 and XI-22, alongside capital costs. Standard operating and maintenance costs were estimated to be ten percent of the total capital equipment cost.[8] In addition, labor costs were estimated based on one person-hour per day at a rate of $39.00 per hour (in 1995 dollars).[15] Typical operating and maintenance costs, other than increased labor, include: polymer and/or flocculation enhancement chemicals, fuel cost, and feed pump

TABLE XI-20

LOUISIANA OPEN BAY DISCHARGERS COSTS[a]

Permit Number	Current Volume (bbl/day)[b,c]	Future Volume (bbl/day)[d]	Gas Flotation[e]		Zero Discharge[f]	
			Cap Cost ($)	O&M Cost ($/yr)	Cap Cost ($)	O&M Cost ($/yr)
2827	1.0	1.5	$35,131	$980	$35,131	$980
2856	3.0	4.5	$35,131	$2,940	$35,131	$2,940
3023	3.4	5.1	$35,131	$3,332	$35,131	$3,332
2479	10.0	15.0	$35,131	$9,800	$35,131	$9,800
2857	20.0	30.0	$44,566	$19,601	$44,566	$19,601
1870	49.0	73.5	$187,405	$31,947	$91,609	$48,021
3032	50.0	75.0	$187,405	$31,947	$91,609	$49,001
2915	130.0	195.0	$187,405	$31,947	$450,172	$45,918
2952	223.0	334.5	$190,223	$32,228	$454,579	$50,570
2704	524.0	786.0	$190,223	$32,228	$468,843	$65,628
2901	1,076.0	1,614.0	$190,223	$32,228	$495,000	$93,242
3072	1,489.0	2,233.5	$247,000	$37,099	$514,570	$113,903
3002	2,017.0	3,025.5	$247,000	$37,099	$539,590	$140,317
2816	2,271.0	3,406.5	$247,000	$37,099	$551,627	$153,023
2825	2,910.0	4,365.0	$247,000	$37,099	$581,907	$184,990
2898	3,617.0	5,425.5	$378,445	$49,183	$699,907	$221,027
1866	4,621.0	6,931.5	$388,904	$50,075	$825,865	$284,663
2273	4,621.0	6,931.5	$388,904	$50,075	$825,865	$284,663
2995	4,621.0	6,931.5	$388,904	$50,075	$825,865	$284,663
3014	4,621.0	6,931.5	$388,904	$50,075	$825,865	$284,663
4206	4,621.0	6,931.5	$388,904	$50,075	$825,865	$284,663
2881	5,010.0	7,515.0	$392,957	$50,421	$874,667	$309,319
2523	5,364.0	8,046.0	$396,645	$50,735	$919,078	$331,756
2860	6,800.0	10,200.0	$411,604	$52,011	$1,099,232	$422,772
2672	8,366.0	12,549.0	$427,919	$53,403	$1,295,696	$522,029
2859	10,807.0	16,210.5	$453,348	$55,572	$1,601,933	$676,744
3063	11,500.0	17,250.0	$460,568	$56,188	$1,688,874	$720,668
2142	12,076.0	18,114.0	$466,568	$56,700	$1,761,136	$757,176
1856	15,000.0	22,500.0	$497,030	$59,298	$2,127,968	$942,505
1934[g]	15,675.0	23,512.5	$504,062	$59,898	$2,212,651	$985,288
2084	16,743.0	25,114.5	$515,188	$60,847	$2,346,638	$1,052,980
2618	22,500.0	33,750.0	$575,163	$65,962	$3,068,885	$1,417,870
3320	22,579.0	33,868.5	$575,986	$66,032	$3,078,796	$1,422,877
2134[g]	23,333.0	34,999.5	$583,841	$66,702	$3,173,390	$1,470,667
2504	37,113.0	55,669.5	$727,397	$78,947	$4,902,168	$2,344,072
2072	37,750.0	56,625.0	$734,033	$79,513	$4,982,083	$2,384,446
1901	41,700.0	62,550.0	$775,183	$83,023	$5,477,633	$2,634,805
TOTAL	**329,814.4**	**494,721.6**	**$13,126,433**	**$1,672,383**	**$49,864,657**	**$21,021,582**

[a] For outfalls indicated in Meinhold, et. al., "Final Report: Risk Assessment for Produced Water Discharges to Louisiana Open Bays," March 1996.[58]

[b] For permit numbers with multiple outfalls, volumes were combined.

[c] Average Louisiana PW flow rate (4,621 bpd) was used for outfalls with zero, intermittent, or omitted discharge rates.

[d] Future Volume = 1.5 x Current Volume

[e] Small Volume facilities will barge their produced water to a commercial facility for injection. The cut-off volume between barging and on-site gas flotation is 70.5 bbl/day.

[f] The cut-off volume between barging to a commercial facility for injection and on-site injection is 108.4 bbl/day.

[g] Produced water flow rates for permits 1934 and 2134 provided by Carl Sayer, Callon Petroleum, to Kerri Kennedy, *Avanti*, on June 20, 1996.[62]

TABLE XI-21

TEXAS DISCHARGERS SEEKING INDIVIDUAL PERMITS COSTS[a]

Permit Number	Current Volume (bbl/day)[b,c]	Future Volume (bbl/day)[d]	Gas Flotation[e]		Zero Discharge[f]	
			Cap Cost ($)	O&M Cost ($/yr)	Cap Cost ($)	O&M Cost ($/yr)
04CCC	0.0	0.0	$0	$0	$0	$0
1	0.0	0.0	$0	$0	$0	$0
14	0.0	0.0	$0	$0	$0	$0
18	0.0	0.0	$0	$0	$0	$0
127	0.0	0.0	$0	$0	$0	$0
215	0.0	0.0	$0	$0	$0	$0
217	0.0	0.0	$0	$0	$0	$0
595	0.0	0.0	$0	$0	$0	$0
674	0.0	0.0	$0	$0	$0	$0
711	0.0	0.0	$0	$0	$0	$0
747	0.0	0.0	$0	$0	$0	$0
825	0.0	0.0	$0	$0	$0	$0
903[g]	0.0	0.0	$0	$0	$0	$0
233	1.0	1.5	$31,290	$996	$31,290	$996
282	1.0	1.5	$31,290	$996	$31,290	$996
690	1.0	1.5	$31,290	$996	$31,290	$996
723	1.0	1.5	$31,290	$996	$31,290	$996
972	1.0	1.5	$31,290	$996	$31,290	$996
119	2.0	3.0	$31,290	$1,993	$31,290	$1,993
71	3.0	4.5	$31,290	$2,989	$31,290	$2,989
13	5.0	7.5	$31,290	$4,982	$31,290	$4,982
*	7.0	10.5	$31,290	$6,975	$31,290	$6,975
663	10.0	15.0	$31,290	$9,965	$31,290	$9,965
693	10.0	15.0	$31,290	$9,965	$31,290	$9,965
37	15.0	22.5	$31,290	$14,947	$31,290	$14,947
214	16.0	24.0	$31,290	$15,943	$31,290	$15,943
284	22.0	33.0	$31,290	$21,922	$31,290	$21,922
628	24.0	36.0	$31,290	$23,915	$31,290	$23,915
752	29.0	43.5	$31,290	$28,897	$31,290	$28,897
924	31.0	46.5	$31,290	$30,890	$31,290	$30,890
41	40.0	60.0	$31,290	$39,858	$31,290	$39,858
199	40.0	60.0	$31,290	$39,858	$31,290	$39,858
939	43.0	64.5	$31,290	$42,847	$31,290	$42,847
236	44.0	66.0	$31,290	$43,844	$31,290	$43,844
926	48.0	72.0	$31,290	$47,830	$165,750	$24,907
104	49.0	73.5	$31,290	$48,826	$165,787	$24,947
919	60.0	90.0	$182,605	$25,723	$166,188	$25,395
925	69.0	103.5	$182,605	$25,723	$166,517	$25,761
582	75.0	112.5	$182,605	$25,723	$166,736	$26,005
905	86.0	129.0	$182,605	$25,723	$167,137	$26,453
675	92.0	138.0	$182,605	$25,723	$167,356	$26,697
*	93.0	139.5	$182,605	$25,723	$167,393	$26,738
927	95.0	142.5	$182,605	$25,723	$167,466	$26,819
242	104.0	156.0	$182,605	$25,723	$167,794	$27,185
264	114.0	171.0	$182,605	$25,723	$168,159	$27,592
*	115.0	172.5	$182,605	$25,723	$168,196	$27,633
552	140.0	210.0	$185,423	$26,005	$169,108	$28,650
922	143.0	214.5	$185,423	$26,005	$169,218	$28,772
605	150.0	225.0	$185,423	$26,005	$169,473	$29,057
202	153.0	229.5	$185,423	$26,005	$169,583	$29,179
684	165.0	247.5	$185,423	$26,005	$170,021	$29,667

TABLE XI-21
TEXAS DISCHARGERS SEEKING INDIVIDUAL PERMITS COSTS[a] (Continued)

Permit Number	Current Volume (bbl/day)[b,c]	Future Volume (bbl/day)[d]	Gas Flotation[e]		Zero Discharge[f]	
			Cap Cost ($)	O&M Cost ($/yr)	Cap Cost ($)	O&M Cost ($/yr)
694	185.0	277.5	$185,423	$26,005	$170,751	$30,480
637	200.0	300.0	$185,423	$26,005	$171,299	$31,091
822	200.0	300.0	$185,423	$26,005	$171,299	$31,091
970	250.0	375.0	$185,423	$26,005	$173,124	$33,125
710	358.0	537.0	$185,423	$26,005	$177,066	$37,519
174	384.0	576.0	$185,423	$26,005	$178,015	$38,577
967	397.0	595.5	$185,423	$26,005	$178,490	$39,105
921	410.0	615.0	$185,423	$26,005	$178,964	$39,634
679	454.0	681.0	$185,423	$26,005	$180,570	$41,424
124	455.0	682.5	$185,423	$26,005	$180,607	$41,465
238	515.0	772.5	$185,423	$26,005	$182,797	$43,906
619	536.0	804.0	$185,423	$26,005	$183,563	$44,761
968	540.0	810.0	$185,423	$26,005	$183,709	$44,923
666	628.0	942.0	$185,423	$26,005	$186,922	$48,503
105	650.0	975.0	$185,423	$26,005	$187,725	$49,398
937	659.0	988.5	$185,423	$26,005	$188,053	$49,765
60	685.0	1,027.5	$185,423	$26,005	$189,002	$50,822
167	690.0	1,035.0	$185,423	$26,005	$189,185	$51,026
166	1,029.0	1,543.5	$185,423	$26,005	$201,559	$64,818
20	1,151.0	1,726.5	$185,423	$26,005	$206,012	$69,781
904	1,360.0	2,040.0	$238,433	$30,876	$213,641	$78,284
85	1,379.0	2,068.5	$238,433	$30,876	$214,335	$79,057
45	1,400.0	2,100.0	$238,433	$30,876	$215,101	$79,911
969	1,480.0	2,220.0	$238,433	$30,876	$218,022	$83,166
80	1,492.0	2,238.0	$238,433	$30,876	$218,460	$83,654
*	1,500.0	2,250.0	$238,433	$30,876	$218,752	$83,980
90	1,800.0	2,700.0	$238,433	$30,876	$229,702	$96,185
68	2,185.0	3,277.5	$238,433	$30,876	$243,756	$111,848
81	3,090.0	4,635.0	$238,433	$30,876	$276,790	$148,667
77	3,552.0	5,328.0	$364,298	$42,902	$307,814	$167,859
164	4,353.0	6,529.5	$372,070	$43,614	$362,622	$202,905
813	4,893.0	7,339.5	$377,309	$44,093	$399,572	$226,532
952	4,980.0	7,470.0	$378,153	$44,171	$405,525	$230,338
113	5,127.0	7,690.5	$379,580	$44,301	$415,583	$236,770
954	7,384.0	11,076.0	$401,479	$46,307	$570,019	$335,521
953	9,316.0	13,974.0	$420,225	$48,024	$702,216	$420,052
TOTAL	**67,764.0**	**101,646.0**	**$12,020,306**	**$1,940,078**	**$12,379,593**	**$4,352,171**

* RRC Permit Pending.

a Railroad Commission of Texas Individual Permit Application Intake Log, May 15, 1996. (Information for Permit Numbers 903, 919, 921, 927, 937, 970 updated per fax from Kevin McClary, Railroad Commission of Texas, May 31, 1996.)[60] Permit numbers 708, 731, 732, 733 were deleted from this profile because they are located in the Offshore Subcategory in the Gulf of Mexico. (Memorandum to the Record, R. Montgomery, June 7, 1996)[61]

b For permit numbers with multiple outfalls, volumes were combined.

c RRC confirms that permits reporting zero barrels per day are not discharging (Kerri Kennedy telecons with Carlos Villamarin and Kevin McClary of RRC, May 31, 1996.)[60]

d Future Volume = 1.5 x Current Volume

e Small Volume facilities will truck their produced water to a commercial facility for injection. The cut-off value between trucking to a commercial facility for injection and on-site gas flotation is 76.5 bbl/day.

f The cut-off volume between trucking to a commercial facility for injection and on-site injection is 70.5 bbl/day.

g Permit Number 903 was canceled at the request of the applicant. (Telecon with Kevin McClary, Railroad Commission of Texas, May 31, 1996.)[60]

TABLE XI-22

TOTAL CAPITAL AND O&M COSTS FOR PRODUCED WATER BAT OPTIONS ALTERNATIVE BASELINE

Options	Alternative Baseline Facilities				Baseline Facilities				Totals	
	LA Open Bay Dischargers		TX Dischargers Seeking Indiv. Permits		Gulf of Mexico[a]		Cook Inlet[b]			
	Capital ($)	O&M ($/yr)	Captial ($)	O&M ($/yr)	Capital ($)	O&M ($/yr)	Captial ($)	O&M ($/yr)	Capital ($)	O&M ($/yr)
1	13,126,433	1,672,383	12,020,306	1,940,078	1,818,604	286,259	9,232,461	1,168,826	36,197,804	5,067,546
2	49,864,657	21,021,582	12,379,593	4,352,171	21,280,137	9,605,289	9,232,461	1,168,826	92,756,848	36,147,868
3	49,864,657	21,021,582	12,379,593	4,352,171	21,280,137	9,605,289	96,956,093	20,960,966	180,480,480	55,940,008

[a]Costs for Gulf of Mexico Baseline Facilities are from Tables XI-5 and XI-9.
[b]Costs for Cook Inlet Baseline Facilities are from Table XI-14.

and agitator maintenance and replacement costs. Alternative Baseline O&M costs were calculated in the same way Baseline O&M costs were estimated, as presented in Section 3.1.2. O&M costs estimate first year expenditures, which may be expected to rise as produced water flow rates increase.

5.3 GULF OF MEXICO ALTERNATIVE BASELINE OPTIONS 2 AND 3 CAPITAL COSTS

Capital costs for Options 2 and 3 for Alternative Baseline facilities were determined using the same methodology presented in Section 3.2. For Louisiana Alternative Baseline facilities with future flow rates below 108.4 bpd, barging costs were incurred in addition to commercial subsurface injection costs. The 108.4 bpd cutoff rate was determined by cost parity between barging/commercial injection and on-site injection.[7] For Texas Alternative Baseline facilities with future produced water flow rates below 70.5 bpd, trucking costs were incurred in addition to commercial subsurface injection costs. Again, this cutoff figure was determined by cost parity with onsite injeciton.[7]

For Alternative Baseline facilities with future produced water flows above the cutoff flow rate, capital costs were estimated according to the appropriate regression in Table XI-8. Tables XI-20 and XI-21 present capital costs estimated for Alternative Baseline facilities. Table XI-22 presents total capital costs for Options 2 and 3, including Alternative Baseline facilities, Baseline facilities and Cook Inlet facilities.

5.4 GULF OF MEXICO ALTERNATIVE BASELINE OPTIONS 2 AND 3 O&M COSTS

Estimated design O&M costs for subsurface injection are presented in Tables XI-20, XI-21 and XI-22, alongside capital costs. Standard operating and maintenance costs were estimated to be ten percent of the total capital equipment cost.[8] In addition, labor costs were estimated based on one person-hour per day at a rate of $39.00 per hour (in 1995 dollars).[15] Typical operating and maintenance costs, other than increased labor, include: biocides, scale inhibitors, and replacement cartridge filters. Alternative Baseline O&M were calculated in the same way Baseline O&M costs were estimated, as presented in Section 3.2.3. O&M costs estimate first year expenditures, which may be expected to rise as produced water flow rates increase.

6.0 POLLUTANT REMOVALS

The pollutant removals for Options 1, 2, and 3 were calculated as the difference between the effluent levels associated with typical BPT treatment (gas flotation or gravity separation) and the levels after treatment by the BAT technology options (improved performance gas flotation and injection). Specifically, the pollutant removals were calculated by multiplying the annual average produced water flow rate by the difference in pollutant concentrations in BPT effluent relative to BAT technology effluent. Detailed calculations of the pollutant removals for produced water regulatory options for the Gulf of Mexico and Cook Inlet are presented in three supporting technical documents: 1) "Compliance Costs and Pollutant Removals for Coastal Gulf of Mexico Produced Water Assuming Compliance with Zero Discharge Under the EPA Region 6 General Permit,"[14] 2) "Compliance Costs and Pollutant Removals for Produced Water Generated at Oil and Gas Production Platforms Located in Cook Inlet, Alaska,"[48] and 3) a memorandum to the record regarding "Texas Dischargers Seeking Individual Permits and Louisiana 'Open Bays' Dischargers: Costs and Loadings."[63] Table XI-23 presents the baseline pollutant removals for the Gulf of Mexico and Cook Inlet, and Table XI-24 presents the alternative baseline pollutant removals. Note that the removals for Cook Inlet are identical in both tables, while those of the Gulf of Mexico differ between baselines.

7.0 BCT COST TEST

The three regulatory options developed in the produced water compliance cost analysis were also evaluated according to the BCT cost reasonableness tests. The BCT cost test methodology for produced water is the same as that described in Chapter X. The pollutant parameters used in this analysis are total suspended solids (TSS) and oil and grease. Table XI-23 lists incremental conventional pollutant removals for each regulatory option.

All of the produced water options considered for BCT regulation fail the BCT cost test. The ratio of cost of pollutant removal to pounds of pollutant removed (POTW Test) exceeds the POTW benchmark of $0.586 per pound (the 1986 benchmark of $0.46 per pound adjusted to 1992 dollars). Table XI-25 presents the BCT Cost Test analysis for conventional pollutants removed from produced water in both the Gulf of Mexico and Cook Inlet.

TABLE XI-23

ANNUAL BAT POLLUTANT REMOVALS FOR PRODUCED WATER IN THE GULF OF MEXICO AND COOK INLET

	Gulf of Mexico	Cook Inlet	Total
Option 1			
Conventionals	545,933	855,054	1,400,453
Priority Organics	37,240	70,367	107,607
Priority Metals	4,527	14,755	19,282
Non-Conventionals	193,419	560,011	753,430
Total	**781,119**	**1,500,186**	**2,281,305**
Option 2			
Conventionals	1,855,319	855,054	2,710,373
Priority Organics	108,018	70,367	178,385
Priority Metals	33,877	14,755	48,632
Non-Conventionals	1,490,602,961	560,011	1,491,162,972
Total	**1,492,600,175**	**1,500,186**	**1,494,100,361**
Option 3			
Conventionals	1,855,319	1,781,074	3,636,393
Priority Organics	108,018	120,587	228,605
Priority Metals	33,877	51,089	84,966
Non-Conventionals	1,490,602,961	1,054,589,456	2,545,192,417
Total	**1,492,600,175**	**1,056,542,206**	**2,549,142,381**

TABLE XI-24

ANNUAL BAT POLLUTANT REMOVALS FOR PRODUCED WATER IN THE GULF OF MEXICO AND COOK INLET (ALTERNATIVE BASELINE)

	Gulf of Mexico	Cook Inlet	Total
Option 1			
Conventionals	6,349,904	855,054	7,204,958
Priority Organics	433,145	70,367	503,512
Priority Metals	52,663	14,755	67,418
Non-Conventionals	2,249,709	560,011	2,809,720
Total	**9,085,421**	**1,500,186**	**10,585,607**
Option 2			
Conventionals	10,380,698	855,054	11,235,752
Priority Organics	651,027	70,367	721,394
Priority Metals	143,014	14,755	157,769
Non-Conventionals	4,590,303,908	560,011	4,590,863,919
Total	**4,601,478,647**	**1,500,186**	**4,602,978,833**
Option 3			
Conventionals	10,380,698	1,781,074	12,161,772
Priority Organics	651,027	120,587	771,614
Priority Metals	143,014	51,089	194,103
Non-Conventionals	4,590,303,908	1,054,589,456	5,644,893,364
Total	**4,601,478,647**	**1,056,542,206**	**5,658,020,853**

TABLE XI-25

PRODUCED WATER BCT COST TEST ANALYSIS

Options	Annualized BCT/BAT Costs[a] ($/yr)	Conventional Pollutants Removed (lbs)	POTW Cost Ratio ($/lb)	Pass POTW Test? (<$0.586/lb)
Option 1: Zero discharge except (a) major pass facilities and (b) Cook Inlet facilities = 29/42 mg/l oil and grease	3,028,508	1,400,987	2.162	N
Option 2: Zero discharge except Cook Inlet facilities = 29/42 mg/l oil and grease	15,118,423	2,710,373	5.578	N
Option 3: Zero discharge all facilities	47,400,434	3,636,393	13.035	N

[a] The total compliance costs presented in Table XI-1 were annualized at 7% over 10 years (i.e., (capital$ x 0.1424) + O&M$/yr).

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CHAPTER XII

COMPLIANCE COST AND POLLUTANT REMOVAL DETERMINATION- WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

1.0 INTRODUCTION

This chapter presents the compliance costs and pollutant removals for various regulatory options regarding effluent limitations guidelines and standards for well treatment, workover, and completion (TWC) fluids from coastal Gulf of Mexico oil and gas facilities.

Section 2.0 presents a detailed discussion of affected facilities. Compliance costs and pollutant removal developed for the final regulatory options are presented in Sections 4.0 and 5.0. The cost and pollutant removals analyses presented in these sections apply only to the Gulf of Mexico coastal area. For Cook Inlet, Alaska operations, waste TWC fluids are currently commingled with produced water prior to treatment and/or disposal,[1] and thus TWC costs to comply with Cook Inlet limitations are included in the costing of the produced water options presented in Chapter XI. California coastal oil and gas sources already meet zero discharge of TWC fluids, so there are no incremental costs or pollutant reductions associated with these effluent limitations.[2]

2.0 OPTIONS CONSIDERED AND SUMMARY COSTS

For the final rule, EPA considered for TWC fluid treatment and/or disposal the regulatory options identified for produced water:

Option 1: Option 1 prohibits all coastal oil and gas facilities from discharging TWC fluids except: Gulf of Mexico facilities discharging into major deltaic passes of the Mississippi River, and Cook Inlet, Alaska. Excluded facilities are required to comply with new BAT effluent limitations and NSPS for oil and grease at 29 mg/l monthly average, and 42 mg/l daily maximum based on improved performance gas flotation (IGF).

Option 2: Option 2 prohibits all coastal oil and gas facilities from discharging TWC fluids with the exception of coastal facilities in Cook Inlet, Alaska which are required to comply with new BAT effluent limitations and NSPS for oil and grease at 29 mg/l monthly average, and 42 mg/l daily maximum based on improved performance gas flotation.

Option 3: Option 3 prohibits discharges of TWC from all coastal oil and gas facilities. For coastal areas outside Cook Inlet, Option 3 is identical to Option 2.

Compliance cost estimates for coastal gulf states are based on the current practice of commingling TWC fluids with produced water for treatment and disposal.

Discharges of TWC fluids in the Gulf of Mexico are covered by the 1993 Region 6 General Permits for drilling activities and associated wastes [58 FR 49126 (September 21, 1993)]. The 1993 general permits prohibit discharges to freshwater and place limitations on discharges to brackish and saline waters.[3] EPA's analysis estimated the volume of TWC fluids being discharged in the Gulf of Mexico using data collected in the 1993 Coastal Oil and Gas Questionnaire.[4] EPA used the 1993 general permits and information collected in the Coastal Oil and Gas Questionnaire to establish the baseline profile of existing discharges, then calculated the incremental compliance costs incurred in meeting limitations based on either improved gas flotation or zero discharge.

Issuance of the 1995 Region 6 General Permits [60 FR 2387 (January 9, 1995)] placed zero discharge limitations on produced water and produced sand, except for major pass facilities.[5,a] As a result of the 1995 general permits, many coastal oil and gas facilities have now ceased discharges of produced water, or are expected to do so by January 1997. Since TWC fluids are typically commingled with produced water for treatment,[4] EPA believes that the zero discharge provision of the 1995 general permits has resulted in TWC fluids generated at many coastal gulf facilities to be now achieving zero discharge along with produced water, with the exception of major pass facilities.[5] Since EPA is unable to confirm the degree to which this may be taking place, EPA is continuing to use the data collected in the Coastal Oil and Gas Questionnaire to determine the volumes of TWC fluids incurring costs to meet zero discharge. It is worth noting, however, that using the same TWC volumes as in the proposal analysis likely overstates the true cost of compliance with the TWC limitations of the final effluent guidelines.

Major pass facilities not already discharging at effluent levels representative of IGF treatment incur compliance costs under Option 1. All major pass facilities incur costs under Options 2 and 3. Compliance cost estimates for major pass facilities are discussed in detail in Section 4.0, Compliance Cost Methodology.

[a] Major Pass Facilities are coastal oil and gas facilities discharging offshore subcategory produced water to the main deltaic passes of the Mississippi River or to the Atchafalaya River below Morgan City including Wax Lake Outlet (see discussion in Chapter IV).

Table XII-1 summarizes the BAT and NSPS compliance costs for the three regulatory options. Detailed spreadsheets containing the calculation of these estimates are included in Appendix XII-1.

TABLE XII-1

TOTAL ANNUAL COMPLIANCE COST ESTIMATES FOR TREATMENT, WORKOVER, AND COMPLETION FLUIDS (1995 $)[a]

Option	Fluid Type	Existing Sources	New Sources
Option 1: Zero discharge except Major Pass Facilities and Cook Inlet = 29/42 mg/l oil and grease based on IGF	Workover/Treatment	$492,713	$61,529
	Completion	$172,597	$24,380
	Total	**$665,310**	**$85,909**
Option 2: Zero discharge except Cook Inlet = 29/42 mg/l oil and grease based on IGF	Workover/Treatment	$496,354	$61,863
	Completion	$173,829	$24,500
	Total	**$670,183**	**$86,363**
Option 3: Zero discharge all	Workover/Treatment	$496,354	$61,863
	Completion	$173,829	$24,500
	Total	**$670,183**	**$86,363**

[a] This table includes TWC compliance costs for facilities in the states bordering the Gulf of Mexico. Alaska TWC compliance costs are included in Cook Inlet produced water cost estimates presented in Chapter XI.

3.0 BASIS FOR ANALYSIS

For Gulf of Mexico coastal facilities, the baseline requirements for TWC fluids were established in the 1993 Region 6 General Permits for drilling activities [58 FR 49126 (September 21, 1993)].[3] These permits allow TWC discharges into saline waters with prohibitions on the discharge of toxic pollutants and free oil, and a limited pH range of 6 to 9. Because TWC fluids would be commingled with produced water prior to treatment and discharge or injection, the proposal TWC compliance cost analysis included the same Gulf of Mexico population as the produced water cost analysis. Under the 1995 Region 6 General Permits,[5] much of the original coastal population is now prohibited from discharging produced water. Thus, the total TWC population has been subdivided into the following distinct facilities according to their produced water flow rates:

1) **Medium/Large Facilities:** Those facilities producing large enough amounts of produced water to make it cost effective to develop and operate on-site treatment technology. Because the 1995 Region 6 General Permits do not cover all of these facilities, EPA used separate baselines for facilities covered and facilities not covered by the 1995 General Permits:

    a) General Permit Facilities—Those medium/large facilities covered by the 1995 Region 6 General Permits requiring zero discharge of produced water.[5] TWC compliance costs for disposal at medium/large general permit facilities are based on incremental on-site subsurface injection costs for commingled TWC fluid volumes for all options.

    b) Major Pass Facilities—Those facilities which are not covered by the 1995 Region 6 General Permits because they treat and discharge offshore subcategory produced waters into major passes of the lower Mississippi or to the Atchafalaya River.[5,6] TWC compliance costs under Option 1 for treatment at major pass facilities are based on incremental costs for treatment and discharge of commingled TWC fluid volumes by improved operating performance of gas flotation produced water treatment systems. TWC compliance costs for Options 2 and 3 (zero discharge at major pass facilities) are based on incremental on-site subsurface injection costs for commingled TWC volumes.[6]

2) **Small Facilities:** Small facilities find it less expensive to meet zero discharge by using commercial treatment/disposal facilities than to inject on-site. All produced water small facilities are covered by the zero discharge provisions of the 1995 General Permits requiring zero discharge of produced water.[5] Thus, TWC compliance costs for small facilities are based on incremental commercial injection.

The distribution between medium/large facilities and small facilities was based on a detailed analysis of on-site treatment versus commercial disposal costs at various produced water discharge flow rates. The analysis is presented in a separate document entitled "Gulf of Mexico Coastal Oil and Gas: Produced Water Treatment Options Cost Estimates."[7]

TWC fluid compliance cost and pollutant removal analyses were based on the volume of treatment/workover and completion fluids generated at medium/large (i.e., major pass and general permit facilities) and small facilities for each regulatory option. The annual TWC fluid volume discharged was calculated from the annual number of wells having treatment/workovers or completions performed and the average volume of fluids generated per job. The Coastal Oil and Gas Questionnaire provided information described below and in Section 4.1.1 to derive the number of wells and the average volume per job of TWC fluids used in the cost and removals analyses.[4]

Annual Number of Existing Wells Discharging Workover/Treatment Fluids The number of wells at medium/large facilities and the number of wells at small facilities discharging workover/treatment fluids was derived from the responses to the 1993 Oil and Gas Questionnaire.[4] EPA determined that there were 350 wells in the coastal subcategory discharging workover/treatment fluids annually. Of these wells, 270 wells were located at medium/large facilities (inclusive of 58 coastal subcategory wells estimated for the major pass facilities), and 80 wells were at small facilities.[8] The number of wells discharging workover/ treatment fluids from major pass facilities was calculated by comparing the total number of wells at major pass facilities to the total number of coastal wells. The calculation based on this ratio resulted in an estimate of 58 major pass wells discharging workover/treatment fluids annually:

Refs: 6,8,9

$$\left[\frac{\textit{Total wells at all Major Pass Facilities} \times \textit{Total wells discharging workover/treatment fluids}}{\textit{Total Coastal wells discharging TWC fluids}} = \begin{array}{l}\textit{Major Pass wells with}\\ \textit{workover/treatment}\\ \textit{fluids}\end{array}\right]$$

$$\left[\frac{775 \times 350}{4675} = 58 \textit{ Major Pass wells with workover/treatment fluids}\right]$$

Because all major pass facilities are medium/large facilities,[6] all 58 major pass wells are included in the inventory of medium/large wells.

<u>Annual Number of Existing Wells Discharging Completion Fluids</u> The number of wells located at medium/large facilities and the number of wells located at small facilities were also derived from the responses to the Coastal Oil and Gas Questionnaire.[4] EPA determined that there were 334 wells discharging completion fluids annually. Of these 334 wells, 257 wells were located at medium/large facilities (inclusive of 55 coastal subcateogry wells discharging completion fluids estimated for major pass facilities), and 77 wells were located at small facilities.[8] The annual number of major pass wells discharging completion fluids was calculated from the ratio of:

Refs: 6,8,9

$$\left[\frac{\textit{Total wells at all Major Pass Facilities} \times \textit{Total wells discharging completion fluids}}{\textit{Total Coastal wells discharging TWC fluids}} = \begin{array}{r}\textit{Wells discharging}\\ \textit{completion fluids}\end{array}\right]$$

$$\left[\frac{775 \times 334}{4,675} = 55 \textit{ wells discharging completion fluids}\right]$$

Because all major pass facilities are medium/large facilities,[6] all 55 wells estimated to be discharging completion fluids at major pass facilities are included in the inventory of medium/large wells. Table XII-2 presents a summary of the annual TWC jobs at existing Gulf of Mexico sources.

The volumes of TWC fluids per job used in the cost and removals calculations are based on the statistical results of the Coastal Oil and Gas Questionnaire.[4] The questions in the questionnaire asked for the discharged volumes of workover/treatment fluids (Question a42a) and completion fluids (Question b32a) in units of barrels per well for the year 1992. For the purposes of cost and removals calculations, these units are used as barrels per job, assuming that the volumes reported in the survey represent single TWC job volumes. This assumption is based on the statistical responses to survey question a40 that indicate the frequency of workover/treatment jobs. The greater number of respondents (27) reported generating workover/treatment fluids approximately once every three years, while only five respondents reported a job frequency of about twice per year. Thus, it is assumed that the volumes reported for 1992 statistically represent single-job volumes rather than the totals from multiple jobs.

Annual Number of New Wells Discharging TWC Fluids The number of new wells discharging TWC fluids was derived from the Coastal Oil and Gas Questionnaire data. The Questionnaire results indicate that 187 new production wells were drilled in 1992.[4] EPA determined that due to the existing prohibition of TWC fluid discharges to fresh water areas imposed by the 1993 Region 6 General Permit for drilling activities and associated wastes [58 FR 49126], a proportion of the 187 new wells would not be affected by the proposed regulation. Data used to identify the population of coastal operators to be included in the Coastal Oil and Gas Questionnaire were used to determine the proportion of new wells that would be located in fresh versus saline water areas. Table XII-3 lists the data and results of this analysis, and shows that approximately 76% of the wells in the coastal Gulf of Mexico region that were completed since 1990 are located in fresh water areas and 24% are located in saline water areas. The calculation of the number of wells located in saline water areas, and hence subject to the proposed regulations, is as follows:

(187 *wells discharging TWC fluids in 1992*) x (24% *saline water areas*) = 45 *new source wells/year*

In the analysis, 45 new sources were included in each of the calculations for workover/treatment fluids and completion fluids. Table XII-4 presents a summary of annual TWC jobs at new Gulf of Mexico sources.

TABLE XII-2

SUMMARY OF ANNUAL TWC JOBS AT EXISTING GULF OF MEXICO SOURCES

Job Type	OPTION 1			OPTIONS 2 & 3		
	Medium/Large Facilities		Small Facilities	Medium/Large Facilities		Small Facilities
	Major Pass	General Permit		Major Pass	General Permit	
Workover/Treatment	25[a]	212	80	58	212	80
Completion	23[b]	202	77	55	202	77
Total	48	414	157	113	414	157

[a] Based on CBI data, it is estimated that 33 workover/treatment jobs are currently treated through IGF. [9] Thus, 33 jobs incur no cost and achieve no pollutant reduction incremental to IGF. These 33 jobs are excluded from the analysis as follows:
(58 total jobs at Major Pass Facilities) - (33 jobs achieving IGF) = 25 workover/treatment jobs incurring annual costs.

[b] Based on CBI data, it is estimated that 32 completion jobs are currently treated through IGF. [9] Thus, 32 jobs incur no costs and achieve no pollutant reduction incremental to IGF. These 32 jobs are excluded from the analysis, as follows:
(55 total jobs at Major Pass Facilities) - (32 jobs achieving Option 1) = 23 completion jobs incurring annual costs.

TABLE XII-3

NUMBER OF WELLS LOCATED IN FRESH VERSUS SALINE WATERS IN THE COASTAL GULF OF MEXICO REGION [4,a]

Size of Operator	Freshwater Areas	Saline Water Areas
Major	174	65
Small Independent	14	2
Other	287	80
Total	**475**	**147**

[a] The values in this table are the sum of the values in Tables 2, 6, and 7 in the source document, only for wells completed during or after 1990. [4]

4.0 COMPLIANCE COST METHODOLOGY

The following sections describe the bases, data and methodology used to develop the cost estimates in Table XII-1.

4.1 GENERAL ASSUMPTIONS AND INPUT DATA

The technology basis used for developing compliance cost estimates for TWC fluids is either commingling of TWC fluids with produced water for on-site treatment and/or disposal (major pass and general permit medium/large facilities) or commercial disposal (small facilities). Costs for on-site treatment and/or disposal of TWC fluids are based on operating and maintenance (O&M) costs developed for produced water at medium/large facilities as presented in Chapter XI and in Sections 4.1.1 and 4.1.2. Costs for small facilities are based on the transportation of TWC fluids for off-site commercial disposal. Disposal cost information was obtained directly from industry sources as listed below in Section 4.1.3. Because TWC fluids are commingled with produced water which is already required to meet zero discharge, no additional capital expenses are included for handling TWC fluids under all three options.

Since TWC operations are occasional occurrences rather than continuous, all necessary tankage and equipment would be brought on-site at the time of the job as a matter of standard operating procedure, and would be removed at the conclusion of the job. In some cases TWC fluids might be captured for reuse

TABLE XII-4

SUMMARY OF ANNUAL TWC JOBS AT NEW GULF OF MEXICO SOURCES

Job Type	OPTION 1			OPTIONS 2 & 3		
	Medium/Large Facilities		Small Facilities	Medium/Large Facilities		Small Facilities
	Major Pass	General Permit		Major Pass	General Permit	
Workover/Treatment	6	29	10	6	29	10
Completion	6	29	10	6	29	10
Total	12	58	20	12	58	20

or separate disposal after the job (e.g., oil-based fluids), TWC fluids can be left in the hole and brought up with the produced fluids when the well is brought back on-line, thus requiring no additional fluids management equipment to be purchased.[10] EPA compliance cost estimates do not include credit for TWC reuse and therefore tend to be conservatively high.

4.1.1 Assumptions and Input Data Derived from the Results of the 1993 Coastal Survey

- Annual Number of Existing Wells Discharging TWC Fluids: The numbers of existing wells currently discharging workover/treatment fluids and completion fluids were derived from the Coastal Oil and Gas Questionnaire results and state Discharging Monitoring Report (DMR) data. The survey results indicate that in 1992, 219 wells discharged workover/treatment fluids and 209 wells discharged completion fluids.[4] A comparison of the number of wells in the survey to the number of wells for which DMR data are available revealed that the survey count of wells must be increased by a factor of 1.6 for an accurate count of existing wells. Thus, the estimates of 219 wells discharging workover/treatment fluids and 209 wells discharging completion fluids were increased to 350 and 334, respectively. Calculation of the number of wells for each facility type is presented in Section 3.0.

- Annual Number of New Source Wells Discharging TWC Fluids: The number of new source wells discharging TWC fluids was also derived from the Coastal Oil and Gas Questionnaire data.[4] The survey results indicate that 187 new source production wells were drilled in 1992.[4] As presented in Section 3.0, EPA determined that 24 percent of the wells or 45 new source wells/year are located in saline water areas.[4]

- Percentage of Land- versus Water-Access Facilities: The 1995 Coastal Development Document lists responses to three 1993 Questionnaire questions that relate to facility location (i.e., over water or on land).[4,8] Using the response data, it was estimated that the percentage of water-access facilities is 65.6 percent and land-access facilities represent 34.4 percent. This assumption is used to distinguish which facilities will incur barge versus truck transportation costs for those facilities that must dispose of their TWC fluids at commercial off-site disposal facilities.

- Average Volume of TWC Fluids Discharged Per Well: The annual volumes of workover/treatment fluids and completion fluids discharged per well were reported in the statistical results of the Coastal Oil and Gas Questionnaire as 587 bbl and 209 bbl, respectively.[4]

4.1.2 Assumptions Adopted from the Produced Water Cost Estimate Methodology

- Percentage of Large versus Small Facilities: Two categories of facilities were developed based on produced water flow rate: 1) medium/large facilities that would employ on-site treatment technology,[b] and 2) small facilities that would utilize commercial disposal based on injection.[c]

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[b] On-site treatment technology for general permit facilities includes injection for all options, and IGF for major pass facilities in Option 1.

[c] All small facilities are encompassed in the zero discharge provisions of Options 1,2, and 3.

EPA calculated the distribution of facilities and determined that 23 percent were small facilities (which use commercial off-site disposal facilities) and 77 percent were medium/large facilities (which use on-site treatment/disposal technology).

- Costs to Inject TWC Fluids: These costs were calculated from the O&M costs (normalized to a per barrel basis) that were developed for injection of produced water at medium/large facilities. The normalized cost was multiplied by the TWC volume to obtain TWC incremental injection costs. Detailed design O&M costs for produced water (and therefore commingled TWC fluids) injection are presented in Chapter XI. The assumptions used to develop design O&M costs for injection are as follows:

  - **Labor:** Labor costs are based on an hourly rate of $39.00 per hour (1995 $).[11,12] Labor is estimated at 2 person-hours per day for the operation of single-well injection systems. Labor costs for multiple-well injection systems are based on 2.42 person-hours per day.

  - **Fuel:** Fuel cost was calculated based on the maximum pumping horsepower required above 25 hp, continuous operation (365 days per year), and a natural gas unit cost of $2.50 per 1,000 cubic feet (1995 $).[13]

  - **Maintenance Materials:** Maintenance materials represent 5 percent of the equipment purchase cost.[11]

  - **Cartridge Filter Replacement:** The cost to replace filters within the cartridge filtration system was is $0.005/bpd.[9,11] Cost of replacement was based on vendor quotes and industry comments on frequency of replacement as a function of produced water flow.[9,11]

  - **Chemicals:** Total chemical cost for treating produced water for injection is $24.64/yr (1995 $) multiplied by the daily flow rate in barrels.[9]

  - **Well Backwash:** The well backwash unit cost rate was based on the results of the statistical analysis of the Coastal Oil and Gas Questionnaire.[4] Well backwash cost is $11,135 (adjusted to 1995 $) per job and the backwash frequency is once per year.[11,14]

- Costs to Treat TWC Fluids with Improved Performance Gas Flotation (Option 1): The cost to treat TWC fluids using IGF at water-access sites were calculated from the O&M costs and volumes that were developed for IGF treatment of produced water at major pass facilities. As described in Section 3.0, under Option 1, only major pass facilities are considered for a discharge option based on IGF. All other medium/large facilities comply with the Region 6 general permit zero discharge requirement for produced water.

  Major Pass Facilities: Improved operation of gas flotation TWC treatment costs for medium/large facilities were based on the costs at a water-access site. The cost of $0.021/bbl was derived using produced water IGF operating and maintenance costs and average annual coastal Gulf of Mexico produced water flow rate.[11] For this option, the flow did not include the flow generated by Flores & Rucks because Flores & Rucks already uses IGF and thus would not incur incremental compliance costs. For one outfall at North Central, only O&M costs are incurred because that particular facility is expected to upgrade operation of an existing gas flotation system to IGF performance through operational improvements.[6]

General Permit Facilities (medium/large facilities excluding major pass facilities): Medium/large facilities typically commingle TWC fluids with produced water.[4] Since these facilities will be required to cease produced water discharges effective January 1997, capital investment for injection wells and ancillary equipment has already been made. As a result, only incremental O&M injection costs are incurred for disposal of TWC fluids (see Section 4.1.2 for details).

Small Facilities: Small facilities typically commingle TWC fluids with produced water.[4] Since these facilities will be required to cease produced water discharges effective January 1997, only incremental costs for commercial disposal of TWC fluids are incurred (see Section 4.1.3 for details).

4.1.3 Additional Assumptions and Data

- Barge Capacity and Cost: Water-access facilities that were determined to utilize commercial disposal rather than on-site treatment and/or disposal were assumed to require a portion of a small capacity (1,500 bbl) barge to transport the waste TWC fluids to a land-based commercial disposal facility. These barges are divided into four equivalent and separate sections. The cost for the use of a barge was derived by assuming that a portion of the barge would be dedicated to TWC fluids while other wastes would be transported in the remainder of the barge. Although it is recognized that TWC fluids would likely be mixed with other field wastes with comparable disposal costs, such as spent drilling fluid, this approach reflects the fraction of the barge cost attributable to the TWC volumes. Each 587-bbl volume of workover/treatment fluid would require one-half of a single barge's capacity (750 bbl). Each 209-bbl volume of completion fluid would require one-fourth of a barge (375 bbl). The transportation cost for a single barge and tug is $1,097.50 (1995 $). The costs for barge transportation are estimated to be $548.75 (1995 $) per job for workover/treatment fluids, and $274.38 (1995 $) per job for completion fluids.[14,15,16]

- Truck Capacity and Cost: Land-access facilities that were determined to utilize commercial disposal rather than on-site treatment and/or disposal were based on requiring 120-bbl capacity vacuum trucks to transport the waste TWC fluids to a land-based commercial disposal facility for injection.[7] The cost for a vacuum truck is $1.92/bbl and was scaled (using ENR Index numbers of 5471 to 4985)[14] to 1995 dollars from the 1992 dollar cost.
- Commercial Disposal Cost for TWC Fluids: The disposal cost for disposal for TWC fluids at a commercial disposal facility is $8.78/bbl (1995 $). The cost in 1992 dollars was scaled to 1995 dollars using ENR Index numbers of 4985 to 5471, respectively.[14] This cost was obtained from a commercial disposal company for completion fluids,[17] and is applied to all TWC fluids based on the fact that completion and workover fluids are similar types of fluids and typically weigh nine pounds per gallon or more.

4.2 COMPLIANCE COST METHODOLOGY

Tables A-1 through A-8 in Appendix XII-1 were developed to calculate the compliance cost estimates for existing and new sources of TWC fluids. For each option and for each source category (existing or new), two spreadsheets were created: one for workover/treatment fluids and one for completion fluids. The input data (described in Section 4.1) applicable to each scenario are listed in each spreadsheet. Within each spreadsheet, several different costs were calculated. Three costs were calculated for Option 1: treatment based on improved operation of gas flotation costs at major pass facilities, treatment based on injection for all other medium/large facilities, and commercial disposal costs at small facilities.

For Options 2 and 3 two costs were calculated. First, on-site incremental injection costs were calculated for all medium/large facilities (i.e., major pass facilities and general permit facilities). Second, costs for incremental commercial disposal at small facilities were calculated. The treatment costs, determined separately for water- and land-access facilities, consist of the following calculations:

- Number of workover/treatment or completion jobs per year
- Number of jobs injected or treated by IGF per year
- Total volume treated per year
- Treatment cost based on IGF or injection cost per year.

The commercial disposal costs, also determined for water- and land-access facilities, consist of the following calculations:

- Number of workover/treatment or completion jobs per year
- Number of jobs disposed commercially per year
- Total volume disposed commercially per year
- Transportation cost per year
- Commercial disposal cost per year
- Total transportation and disposal cost per year.

The total costs presented in Table XII-1 are the sum of the costs presented in Appendix XII-1.

5.0 POLLUTANT LOADINGS AND REMOVALS

The following sections describe the bases, data and methodology used to develop pollutant removals estimates for each regulatory option.

5.1 GENERAL ASSUMPTIONS AND INPUT DATA

Total TWC volumes are presented in Table XII-5. These volumes are based on the volume per job for well treatment/workover (587 bbl/job) and for well completions (209 bbl/job) as described in Section 4.1.1.[4] Development of the total number of jobs is detailed in Section 3.0, and summarized in Tables XII-2 and XII-4.

TABLE XII-5

TOTAL TWC VOLUMES

Job Type	From Existing Sources (bbl/yr)	From New Sources (bbl/yr)
OPTION 1[a]		
Treatment/Workover	186,079	26,415
Completion	63,118	9,405
Total	249,197	35,820
OPTIONS 2 & 3		
Treatment/Workover	205,450	26,415
Completion	69,806	9,405
Total	275,256	35,820

[a] Excludes volume already meeting IGF.

The concentration data for TWC fluids used to calculate pollutant removals from settling effluent were from an Office of Solid Waste sampling effort designed to characterize TWC fluids.[18,19,20] This information represents the best data currently available about the characteristics of TWC fluids. These data are presented and summarized in Chapter IX and are used in the cost effectiveness analysis as the best available representation of the characteristics of TWC fluids as they are currently discharged.[18,19,20] Furthermore, since TWC fluids can be commingled and treated without upsetting the treatment system, concentration data for effluent from IGF treatment is the basis for characterizing TWC fluids following commingling and treatment with produced water.[4]

5.2 METHODOLOGY

The tables presented in Appendix XII-2 were developed to calculate the pollutant removal estimates for existing and new sources of TWC fluids. For each option and for each source category (existing or new), two tables were created: one for workover/treatment fluids and one for completion fluids. The annual volumes discharged, injected, treated, or disposed in these tables are those calculated in the corresponding compliance cost tables in Appendix XII-1. A summary of the pollutant removal estimates is presented in Table XII-6.

TABLE XII-6

TOTAL ANNUAL POLLUTANT REMOVALS FOR TREATMENT, WORKOVER, AND COMPLETION FLUIDS (pounds/year)

Option	Pollutant Type	Existing Sources	New Sources
Option 1: Zero discharge except Major Pass Facilities and Cook Inlet = 29/42 mg/l oil and grease based on IGF	Conventionals	65,179	8,750
	Priority Pollutant Organics	363	51
	Priority Pollutant Metals	260	33
	Non-Conventionals	2,818,074	380,804
	Total	**2,883,876**	**389,638**
Option 2: Zero discharge except Cook Inlet = 29/42 mg/l oil and grease based on IGF	Conventionals	67,665	8,838
	Priority Pollutant Organics	407	53
	Priority Pollutant Metals	281	36
	Non-Conventionals	3,372,530	438,676
	Total	**3,440,883**	**447,603**
Option 3: Zero discharge all	Conventionals	67,665	8,838
	Priority Pollutant Organics	407	53
	Priority Pollutant Metals	281	36
	Non-Conventionals	3,372,530	438,676
	Total	**3,440,883**	**447,603**

6.0 BCT COST TEST

This section presents the results of the BCT cost test for the zero discharge and treatment followed by discharge options. The methodology for the BCT cost test is presented in Chapter X.

The compliance costs and pollutant reductions presented in Sections 4.0 and 5.0 are all considered to be incremental to BPT-level costs and reductions because they were based on costs and pollutant characteristics that are additional or supplemental to BPT-level treatment.

Table XII-7 presents the BCT cost test for the three regulatory options. All three options fail the POTW test.

TABLE XII-7

BCT COST TEST FOR TREATMENT, WORKOVER, AND COMPLETION FLUIDS

Option	Annualized BCT/BAT Costs ($/yr)	Conventional Pollutants Removed (lbs)	POTW Cost Ratio ($/lb)	Pass POTW Test? (<$0.586/lb)
Option 1: Zero discharge except Major Pass Facilities and Cook Inlet = 29/42 mg/l oil and grease based on IGF	$665,310	65,179	10.2	N
Option 2: Zero discharge except Cook Inlet = 29/42 mg/l oil and grease based on IGF	$670,183	67,665	9.9	N
Option 3: Zero discharge all	$670,183	67,665	9.9	N

7.0 REFERENCES

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17. McIntyre, J., SAIC, Communication with Kathy Cavalier, Campbell Wells, regarding waste disposal cost information, May 12, 1994.

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CHAPTER XIII

NON-WATER QUALITY ENVIRONMENTAL IMPACTS AND OTHER FACTORS

1.0 INTRODUCTION

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

Regulatory options were developed to analyze the costs and pollutant removals for drilling wastes, produced water and treatment, workover and completion fluids (see Chapters X, XI, and XII). The non-water quality environmental impacts (NWQI) were determined for the technologies considered to be the bases for each of the selected regulatory options. Therefore, the control options established for each wastestream are the same as those used in the cost and removals analyses. Table XIII-1 presents the non-water quality environmental impacts in terms of air emissions and energy requirements for each wastestream and option.

The produced water NWQI presented in Table XIII-1 are the sum of the impacts of treatment and/or disposal as they apply to Cook Inlet, Alaska and Gulf of Mexico operations. Gulf of Mexico operations include those facilities not included in the 1995 Region 6 General Permits governing discharges of Gulf Coastal production wastes (60 FR 2387, January 9, 1995) and are referred to in the cost, pollutant removal and NWQI analyses as the current requirements baseline (see Chapter XI).

TABLE XIII-1

ANNUAL ENERGY REQUIREMENTS AND AIR EMISSIONS FOR THE REGULATORY OPTIONS BY WASTESTREAM

Waste Stream Options		Fuel[a] (BOE/yr)	Air Emissions[b] (tons/yr)
Drilling Wastes			
Option 1:	Cook Inlet = no free oil, no diesel, and limits of 30,000 ppm SPP, 1 mg/l Hg and 3 mg/l Cd	0	0
Option 2:	Zero discharge via Scenario 1: Landfill Scenario 2: Injection	 5,183 7,024	 36.37 10.58
Produced Water (Current Requirements Baseline)			
Option 1: Zero discharge except: major pass dischargers and Cook Inlet, Alaska operators at 29/42 mg/l oil and grease limitations.[c]		3,428	28.03 (17.71)
Option 2: Zero discharge except: Cook Inlet, Alaska operators at 29/42 mg/l oil and grease limitations.[d]		92,252	1,098.11 (356.02)
Option 3: Zero discharge for all.[d]		187,269	1,241.19 (499.10)
Treatment, Workover, and Completion Fluids			
Option 1: Zero discharge except: major pass dischargers and Cook Inlet, Alaska operators at 29/42 mg/l oil and grease limitations.[c]		1,360	14.86
Option 2: Zero discharge except: Cook Inlet, Alaska operators at 29/42 mg/l oil and grease limitations.[d]		1,414	15.52
Option 3: Zero discharge for all.[d]		1,414	15.52

[a] BOE (barrels of oil equivalent) is the total diesel volume required converted to equivalent oil volume (by the factor 1 BOE = 42 gal diesel) and the volume of natural gas required converted to equivalent oil volume (by the factor 1,000 scf = 0.178 BOE).[1]

[b] Air emissions calculated using emission factors for uncontrolled sources. Values in parentheses are the sum of air emissions from Gulf of Mexico controlled sources and Cook Inlet uncontrolled sources (see Sections 3.1.2 and 3.2.2).

[c] Flores & Rucks, Inc. (FRI) and North Central permit #2184, outfall #003-1 are not included in Option 1 analyses due to existing gas flotation units at these facilities.

[d] Flores & Rucks, Inc. (FRI) NWQIs at Case 2 for Options 2 and 3. FRI air emissions and energy requirements may be considerably lower (see Section 3.1.1.2).

As discussed in Chapters IV and XI, EPA also assessed impacts of the Gulf of Mexico produced water regulatory options for a larger population of facilities. This "alternative baseline" includes Texas dischargers seeking individual permits (TDSIPs) and Louisiana open bay dischargers (LOBDs). Table XIII-2 presents the non-water quality environmental impacts calculated for the alternative baseline requirements. NWQIs for the current requirements baseline listed in Table XIII-1 were summed with the NWQIs for the TDSIPs and LOBDs to obtain the total NWQI for the alternative requirements baseline.

TABLE XIII-2

AIR EMISSIONS AND ENERGY REQUIREMENTS FOR PRODUCED WATER OPTIONS (ALTERNATIVE BASELINE)

Regulatory Options	Fuel[a] (BOE/yr)	Air Emissions[b] (tons/yr)
Option 1: Zero discharge except: major pass river dischargers and Cook Inlet, Alaska operators at 29/42 mg/l oil and grease limitations.[c]	32,771	393 (261)
Option 2: Zero discharge except: Cook Inlet, Alaska operators at 29/42 mg/l oil and grease limitations.[d]	322,496	3,870 (1,294)
Options 3: Zero discharge for all.[d]	417,513	4,013 (1,437)

[a] BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor 1 BOE = 42 gal diesel) and the volume of natural gas required converted to equivalent oil volume (by the factor 1,000 scf = 0.178 BOE).[1]

[b] Air emissions calculated using emission factors for uncontrolled sources. Values in parentheses are the sum of air emissions from Gulf of Mexico controlled sources and Cook Inlet uncontrolled sources (see Sections 3.1.2 and 3.2.2).

[c] Flores & Rucks, Inc. (FRI) and North Central permit #2184, outfall #003-1 are not included in Option 1 analyses due to existing gas flotation units at these facilities (see Section 3.1.1.1).

[d] Flores & Rucks, Inc. (FRI) NWQIs at Case 2 for Options 2 and 3. FRI air emissions and energy requirements may be considerably lower (see Section 3.1.1.2).

2.0 DRILLING WASTES - COOK INLET

This section presents the energy requirements and air emissions calculated for waste management control options for drilling wastes generated by oil and gas extraction operations in Cook Inlet, Alaska. In the final rule, and as detailed elsewhere in this document, EPA determined that zero discharge of drilling wastes was not technologically available in Cook Inlet. EPA has, nevertheless, calculated the non-water quality environmental impacts of both the selected option and of zero discharge, assuming it were available.

The NWQI analyses presented herein follow directly from the assumptions and data used in the cost and removals analyses presented in Chapter X.

Table XIII-1 lists two control options for management of drilling fluids and drill cuttings (drilling waste). Option 1 allows the discharge of drilling fluid and drill cuttings with limitations requiring toxicity of no less than 30,000 ppm (SPP), no discharge of free oil or diesel, and no more than 1 mg/kg mercury and 3 mg/kg cadmium in the stock barite. Because Option 1 reflects current practice in Cook Inlet, there are no incremental NWQIs associated with this option. Option 2 requires zero discharge of drilling wastes. The NWQIs were calculated in two scenarios for Option 2, as described below.

The two control technology bases for compliance with the zero discharge option considered for drilling wastes in Cook Inlet are:

Scenario 1: Waste minimization via closed-loop solids control followed by transportation of drilling wastes to shore for disposal.

Scenario 2: Grinding followed by subsurface injection at the platform.

Appendices XIII-1 and XIII-2 present the detailed energy requirements and air emissions calculated for each of these compliance scenarios, respectively. The calculations for Scenario 1 are based on the total estimated volume of drilling waste generated in the period of analysis (1996 through 2002), as calculated for a system featuring closed-loop solids control technology. This seven-year volume, 431,988 barrels (bbls) of waste drill cuttings and drilling fluid, was calculated as part of the compliance cost analysis presented in Chapter X. The seven-year waste volume basis for Scenario 2 is 689,370 bbls, also presented in Chapter X, reflecting current waste generation rates without closed-loop solids control technology. The total 689,370 bbl comprises 626,070 bbl of waste generated from new wells and recompletions plus 63,300 bbl generated by drilling disposal wells. Hence, all drilling waste NWQI calculations presented in the following sections represent totals for the same seven-year period on which the compliance cost calculations are based. The following sections discuss the bases and methods used in these calculations.

2.1 Energy Requirements

Energy requirements were calculated by identifying the energy-consuming activities involved in the two zero discharge scenarios described above and assessing the energy requirements for all fuel-driven equipment. Table XIII-3 lists the equipment, horsepower demands (where applicable), and associated fuel consumption calculated for each scenario, as detailed in the following discussions.

2.1.1 Closed-Loop Solids Control and Landfill

The assumptions developed for calculating fuel consumption for Scenario 1 (landfill disposal) were based on three general activities: 1) improving the efficiency of solids control systems with a decanting centrifuge; 2) transporting drilling wastes to landfills via boats, barges, cranes, and trucks; and 3) using earthmoving equipment at landfills. Zero discharge of drilling wastes by landfill disposal was found to be not technologically available in Cook Inlet (see Chapter XIV). Chapter X describes the use of boats, barges and trucks in terms of logistics, frequency, and transport capacity. The NWQIs for waste transportation activities are based on the data developed for the unit landfill cost analysis (see Appendix XIII-2). The energy-specific bases used to assess Scenario 1 are as follows:

Decanting Centrifuge: A 40 horsepower decanting centrifuge[2] was added to the existing solids control equipment to increase efficiency and reduce the waste volume by 69 percent (see Chapter X). A detailed description of decanting centrifuges and other solids control equipment is presented in Chapter VII.

Supply Boats: Regardless of the landfill location, drilling wastes must be transferred from the platform to the east side of Cook Inlet as the first leg of the trip. Four modes of supply-boat operation are considered in the accounting of fuel consumption:

- Transit Fuel Consumption: Supply boats consume 130 gallons of diesel per hour while in transit.[3] Average supply boat speed is 11.5 miles per hour.[4] Supply boat fuel use and speed data are from Gulf of Mexico sources; vessels serving Gulf of Mexico platforms are considered comparable to those serving Cook Inlet platforms. The average round-trip distance for the supply boats to go from platforms to the East Forelands dock on the east side of Cook Inlet is 50 miles.[5]

- Maneuvering Fuel Consumption: Supply boats maneuver at the platform for an average of one hour per visit. The maneuvering fuel use factor is 15 percent of full throttle fuel consumption, or 25.3 gallons of diesel per hour.[6]

- Loading Fuel Consumption: Due to ocean current and wave action, boats must maintain engines idling while at platforms unloading empty cuttings boxes and loading drilling fluids and boxes. The total average time idling on station at the drill site for loading is 4.15 hours per visit. This is based on the crane operating time of 3.15 hours to transfer empty cuttings boxes to the platform and loading the full cuttings boxes onto the supply boat (i.e., 2 x 1.575 hours. See discussion of cranes below). The average idling time includes an additional one hour to account for potential delays in the transfer process.

TABLE XIII-3

POWER AND FUEL REQUIREMENTS FOR DRILLING WASTE ZERO DISCHARGE OPTION SCENARIOS[a]

Equipment	Total hp-hrs[b]	Fuel Use	
		Natural Gas (10^3 scf)	Diesel (10^3 gal)
SCENARIO 1: LAND DISPOSAL			
Closed Loop Solids Control			
• Decanting Centrifuge	38,920	369.74	--
Transport to Landfill			
• Supply Boats	914,400	--	533.09
• Barges	--	--	31.56
• Supply Boat Cranes	544,068	--	33.32
• Barged Cranes	103,027	--	6.31
• Trucks to/from Temporary Storage	--	--	7.89
• Trucks to Oregon	--	--	886.65
Equipment at Landfill			
• Wheel Tractor	--	--	0.81
• Dozer/Loader	--	--	21.47
TOTAL FUEL	--	369.74	1,521.11
TOTAL FUEL (BOE)[c] = 36,283			
SCENARIO 2: GRINDING AND INJECTION			
Grinding and Processing/ Equipment	27,926,595	265,303	--
Injection Equipment	1,148,950	10,915	--
TOTAL FUEL	--	276,218	--
TOTAL FUEL (BOE)[c] = 49,167			

[a] All values shown are cumulative totals for the seven-year period following promulgation (1996 - 2002).

[b] Hp-hr requirements are only reported for equipment whose air emission factors are based on these data. Air emission factors for other equipment are based on rates of fuel consumption.

[c] BOE (barrels of oil equivalent) is the total diesel volume required converted to equivalent oil volume (by the factor 1 BOE = 42 gal diesel) and the volume of natural gas required converted to equivalent oil volume (by the factor 1,000 scf = 0.178 BOE).[1]

- Auxiliary Electrical Generator: An auxiliary generator is needed for electrical power only when propulsion engines are shut down. Since the supply boats remain at the drill site only for the length of time necessary to conduct loading/unloading evolutions and the propulsion plant remains idling at the drill site, the auxiliary generator is only used while in port.

  The average in-port time for unloading drilling wastes, tank cleanout, and demurrage is 24 hours per supply boat trip.[4] The boat engines are shut down during this period. It is assumed that while in port, the boat operator relies on the auxiliary generator for electrical power.

  Estimates of fuel requirements and air emissions are based on the auxiliary generator rating at 120 horsepower, operating at 50 percent load,[6] and consuming 6 gallons of diesel per hour.[4]

Barges: Barges consume fuel at a rate of 24 gallons of diesel per hour.[3] Average barge speed is 6 miles per hour.[7] Barge fuel use and speed data are from Gulf of Mexico sources; vessels serving Gulf of Mexico platforms are considered comparable to those serving Cook Inlet platforms. The average round-trip distance for barges to go from the east side of Cook Inlet to the west side is 50 miles.[8]

Cranes: Cranes used to load and unload cuttings boxes at the drill site and in port are diesel powered, require 170 horsepower operating at 80 percent load,[6] and consume 8.33 gallons of diesel per hour.[3] Cranes make 10 lifts per hour.[4] For supply boats, cranes will lift four boxes at a time (see Appendix XIII-1). Given that a supply boat will carry 12 boxes of cuttings plus 51 box-equivalents of waste drilling mud during each trip (see Appendix X-2), and that the cranes must load and unload empty boxes as well as full boxes within one round trip, each supply boat round trip requires 6.3 hours of crane time, calculated as follows:

Crane lifts per boat load = 63 box-equivalents per boat load / 4 boxes per lift = 15.75 lifts/boat load
Crane hours per boat load = 15.75 lifts per load / 10 lifts per hour = 1.575 hours/boat load
Crane hours per round trip = 1.575 hrs/boat load x 4 boat loads/per round trip = 6.3 hours per round trip

For barges, cranes will lift 10 boxes per lift because the boxes are loaded into shipping containers that hold 10-12 boxes.[8] Also, no empty boxes are loaded onto or unloaded from barges. Therefore, crane time for a single barge round trip is 4.8 hours, based on a barge capacity of 240 boxes.[8]

Operator "B" Trucks: In the drilling waste compliance cost analysis, Operator "B" uses trucks to transport wastes to and from the temporary storage area located on the east side of Cook Inlet and from the barges to the disposal facility located on the west side of Cook Inlet (see Chapter X). These trucks travel approximately four miles per gallon of diesel consumed[4] and hold 12 drilling waste boxes per trip. The round trip distance from the East Foreland dock to the temporary storage facility is four miles.[9] The round trip distance from the barge landing area to the disposal site is six miles.[9] Appendix XIII-1 shows energy consumption calculations for a 10-mile round trip, which represents the total distance for trucks used by Operator B.

Trucks to Oregon: In the drilling waste compliance cost analysis, Operators "A" and "C" use trucks to transport wastes to a commercial land disposal facility located in Arlington, Oregon (see Chapter X). These trucks travel approximately four miles per gallon of diesel consumed[4] and to hold 22 tons of waste per trip.[10] The one-way distance between the east-side docking facility and the land disposal facility is estimated to be 2,200 miles.

Land Disposal Equipment: The bases supporting estimates for the use of land disposal equipment have not changed since the proposal. These are as follows:

- Wheel Tractor: Wheel tractors are used at the facility for grading. One day (8 hours) of tractor operation is required to grade the drilling waste volume from one well. The estimated fuel consumption rate for a wheel tractor is 1.67 gallons of diesel per hour.[4]

- Track-Type Dozer/Loader: A track-type dozer is required at the facility for waste spreading. Two days (16 hours) of dozer operation are required to spread drilling wastes generated from one well. The estimated fuel consumption rate for a dozer is 22 gallons of diesel per hour.[4]

2.1.2 Grinding and Injection

Zero discharge of drilling wastes in Cook Inlet by grinding and injection was found to be not technologically available (see Chapter XIV). The results of the NWQI analysis are presented here, nevertheless, for informational purposes. The NWQI analysis for the second scenario of the zero discharge option consists of determining the power and fuel requirements of the grinding and injection (G&I) equipment. The volume of wastes injected include wastes generated from the drilling of injection wells as well as wastes generated from the drilling of new production wells and recompletions. The volume of waste generated from the drilling of an injection well, 5,275 barrels per well, was derived from industry data obtained in the 1993 Coastal Oil and Gas Questionnaire, as presented in Appendix X-1. The number of injection wells to be drilled in the seven-year period following promulgation (12) was derived from industry-supplied information as noted in Appendix X-1. The energy-specific basis for the Scenario 2 NWQI analysis is as follows:

Waste Processing Equipment: The waste processing equipment power and fuel requirements were estimated based on the following horsepower requirement information submitted by the industry:[11]

- Grinder (500 KVA Transformer):
  2 x 150 hp motors at 480V
  1 x 10 hp auger motor
  Additional lights/heating 100 KVA

- Cuttings Transfer Equipment:
  2 x 30 hp disk flow motors
  1 x 10 hp hydraulic pump
  Steam as required

- Dewatering Unit:
  2 x 5 hp shaker motors
  1 x 10 hp agitator
  1 x 45 hp dewatering centrifuge
  1 x 10 hp underflow pump
  2 x 30 hp disk flow pumps
  1 x 30 hp Galliger pump
  4 x 1/2 hp motors

For the purpose of calculating energy requirements, a total of 747 horsepower per well was used for the above equipment.

Injection Equipment: The power and fuel requirements for the injection equipment were calculated based on one 500 horsepower injection pump rated at 5 barrels per minute.[9]

Hours of Operation: The grinding and injection equipment usage (hours per well) was calculated based on the average time required to drill a new well (733 hrs), a recompleted well (240 hrs), or an injection well (211 hrs). These data are derived from information presented in Appendix X-1. For a 4,000-foot injection well, the following equation was used:

$$(11 \text{ days} \times 13 \text{ hrs/day})(2500 \text{ ft}/2533 \text{ ft}) + (25 \text{ days} \times 14 \text{ hrs/day})(1500 \text{ ft}/7348 \text{ ft}) = 211 \text{ hours}$$

The above equation is the sum of the hours required to drill a well in two intervals, the first being 2,500 feet deep and the second being 1,500 feet deep. The time data are relative to the first two intervals of the model production well presented in Chapter X, whose first two intervals are 2,533 feet and 7,348 feet deep, respectively.

Fuel Requirements: Fuel requirements were calculated for gas turbines using an average heating value of 1,050 Btu per standard cubic foot (scf) of natural gas and an average fuel consumption of 10,000 Btu per horsepower-hour (hp-hr), or 9.5 (10,000/1,050) scf/hp-hr.[12]

2.2 Air Emissions

The total air emissions for Scenarios 1 and 2 presented in Table XIII-1 were calculated using the total system energy utilization rate (horsepower-hours or miles traveled) and emission factors developed for different types of engines and fuels used. Emission factors were determined for uncontrolled sources. The term "uncontrolled" refers to the emissions resulting from a source which does not utilize add-on control technologies to reduce the emissions of specific pollutants. The use of "uncontrolled" emission factors provides conservatively higher estimates of total emissions resulting from disposal of drilling wastes in Cook Inlet. Table XIII-4 presents the uncontrolled emission factors for different types of diesel and natural gas driven engines used to calculate air emissions from activities related to onshore disposal and injection of drilling wastes. Note that the factors are not all based on the same units. Detailed calculations of the air emissions from each type of engine used are presented in Appendix XIII-1.

TABLE XIII-4

UNCONTROLLED EMISSION FACTORS FOR DRILLING WASTE MANAGEMENT ACTIVITIES

Equipment		Nitrogen Oxides (NO_x)	Total Hydrocarbons (THC)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Total Suspended Particulates (TSP)
Supply Boats[a] (lb/1,000 gal)	Idle	419.6	22.6	28.48[b]	59.8	33.0
	Transit	391.7	16.8	28.48[b]	78.3	33.0
Supply Boat Auxiliary Generator (g/bhp-hr)[c]		14.0	1.12	0.931	3.03	1.0
Barges (lb/1,000 gal)[a]		391.7	16.8	28.48[b]	78.3	33.0
Cranes (g/bhp-hr)[d]		14.0	1.12	0.931	3.03	1.0
Trucks (g/mile)[e]		11.23	2.49	NA	8.53	NA
Wheel Tractor (lb/hr)[f]		1.269	0.188	0.090	3.59	0.136
Track-type Dozer (lb/hr)[f]		0.827	0.098	0.076	0.201	0.058
Natural Gas Turbine Engine (g/hp-hr)[g]		1.3	0.18	0.002[h]	0.83	NA
Auxiliary Diesel Engines (lb/1,000 gal)[c]		469.0	37.5	31.2	102.0	33.5

[a] Source: Table II-3.3, AP-42 Volume II, September 1985.[13]
[b] Based on assumed 0.20 percent sulfur content of fuel and fuel density of 7.12 lbs/gal (AP-42 Vol. II, September 1985).[13]
[c] Source: Table 3.3-1, AP-42 Volume I, January 1975.[14] Note: bhp is brake horsepower.
[d] Source: Table 3.3-1, AP-42 Volume I, Supplement F, July 1993.[15] Note: bhp is brake horsepower.
[e] Source: Table 1.7.1, AP-42 Volume II, September 1985.[13]
[f] Source: Table II-7.1, AP-42 Volume II, September 1985.[13]
[g] Source: Table 3.2-1, AP-42 Volume I, Supplement F, July 1993.[15]
[h] This factor depends on the sulfur content of the fuel used. For natural gas fired turbines, AP-42, 1976 (Table 3.2-1) gives this emission factor based on assumed sulfur content of pipeline gas of 2,000 g/10^6 scf (AP-42 Vol. I, April 1976).[12]

NA = Not Applicable

Table XIII-5 summarizes the contribution of air pollutants from each type of activity associated with disposal of drilling wastes in Cook Inlet. For example, a seven-year total of 635 supply boat trips is needed to transport the volume of drilling wastes under the Scenario 1 (landfill) zero discharge option. For a boat in transit, a NO_x emission factor of 391.7 lbs/1,000 gallons of diesel was used. The seven-year total fuel requirement for supply boats in transit was calculated to be 358,913 gallons (see Appendix XIII-1).

TABLE XIII-5

AIR EMISSIONS ASSOCIATED WITH ZERO DISCHARGE SCENARIOS FOR EXISTING SOURCES OF DRILLING WASTES IN COOK INLET (Total Tons for 1996 - 2002)

Equipment	NO_x	THC	SO_2	CO	TSP	Total
Scenario 1: Closed-Loop Solids Control and Landfill						
Supply Boats[a]	101.75	5.07	7.23	19.57	8.30	141.92
Barges	6.18	0.27	0.45	1.24	0.52	8.66
Supply Boat Cranes	8.39	0.67	0.56	1.82	0.60	12.04
Barge Cranes	1.59	0.13	0.11	0.34	0.11	2.28
Trucks for Operator B	0.39	0.09	0.00	0.30	0.00	0.78
Trucks to Oregon	43.86	9.73	0.00	33.32	0.00	86.91
Wheel Tractor	0.31	0.05	0.02	0.88	0.03	1.29
Dozer/Loader	0.40	0.05	0.04	0.10	0.03	0.62
Decanting Centrifuge	0.06	0.01	0.00	0.04	0.00	0.11
Total	162.93	16.07	8.41	57.61	9.59	**254.61**
Scenario 2: Grinding and Injection						
Grinding/Processing Equipment	39.98	5.54	0.06	25.53	NA	71.11
Injection Equipment	1.64	0.23	0.00	1.05	NA	2.92
Total	41.62	5.77	0.06	26.58	NA	**74.03**

[a] The values given for supply boats are the sum of emissions from fuel used in transit, maneuvering, loading, and auxilliary generator use while in port. See Appendix XIII-1 for detailed calculations.

The total annual NO_x emissions resulting from this activity are:

(391.7 lb/1000 gal) x (358,913 gal) x (1 ton/2000 lbs/7 yrs) = 10 tons NO_x per year.

The operation of the grinding and injection equipment to dispose of the drilling wastes under the Scenario 2 zero discharge option requires a total of 29,075,545 hp-hr over seven years (see

Appendix XIII-2). For a natural gas driven turbine, an NO_x emission factor of 1.3 g/hp-hr was used. The total annual NO_x emissions resulting from this activity are:

$$(1.3 \text{ g/hp-hr}) \times (29{,}075{,}545 \text{ hp-hr/7 years}) \times (1 \text{ ton/908,000 g}) = 5.95 \text{ tons } NO_x \text{ per year.}$$

2.3 SOLID WASTE GENERATION AND MANAGEMENT

The limitations selected for drilling wastes in the final rule will not cause generation of additional solids. As discussed below, if zero discharge were available in Cook Inlet, spent drilling fluids and the associated cuttings would be disposed of at onshore disposal sites or injected underground.

There are currently no commercially operating disposal sites in Cook Inlet accepting coastal drilling wastes. The only land disposal facility accepting drilling wastes from Cook Inlet operations is privately owned and operated. The lack of commercial disposal sites would require operators that do not own a land disposal facility to either transport the drilling wastes to the nearest known commercial disposal facility located in Oregon or inject the drilling wastes into underground formations if available.

Capacity estimates for the disposal facility at Kustatan show that this landfill has enough storage capacity to accept the volume of drilling wastes (303,022 bbl/7 years) that would be generated under the no discharge limitation, from the platforms that it now serves. The solid waste disposal facility at Kustantan has 86 cells, each with a storage capacity of 2,000 yd^3 (9,620 bbl).[16,17] The total capacity is 827,320 bbl. Under a zero discharge requirement, the volume of drilling wastes generated by the operators that own/operate the Kustatan landfill represents about 37 percent of the excess available capacity at Kustatan.

Under the zero discharge limitations of Option 2, the volume of drilling wastes estimated in Scenario 1 as requiring land disposal is 431,988 bbl (see Appendix XIII-1). Of this total volume of drilling wastes, 128,966 bbl over the next seven years, or 18,424 bbl/yr (see Chapter X) were estimated for disposal to commercial facilities in the lower 48 states. The Arlington, Oregon landfill has an available capacity of about 4.8×10^8 bbl.[18] The Cook Inlet drilling waste that would be transported to Oregon represents about 0.03 percent of the available capcity at the Arlington, Oregon site.

2.4 CONSUMPTIVE WATER USE

Since little or no additional water is required above that of usual consumption, no consumptive water loss is expected as a result of the final rule.

2.5 OTHER FACTORS

2.5.1 Impact of Marine Traffic on Coastal Waterways in Cook Inlet

EPA does not expect any incremental increase in vessel traffic as a result of the drilling waste requirements in the coastal guidelines. EPA did evaluate the number of boat trips that would result from zero discharge limitations, if available, and estimated that 635 supply boat trips and 158 barge trips would occur for a total of 793 additional vessel trips over seven years (see Section 2.1.1). This is equivalent to approximately 113 trips per year as a result of compliance with a zero discharge requirement.

2.5.2 Safety

In 1992, EPA evaluated data associated with personnel casualties that occurred on mobile offshore drilling units (MODUs) and offshore supply vessels (OSV) for the years 1981 through 1990. The personnel casualty data was compiled from the U.S. Coast Guard's Personnel Casualty file (PCAS). The study focused on accidents related to the handling and transportation of material, since this would be most similar to the additional activities required should a zero discharge limitation be imposed in Cook Inlet.[19]

EPA reviewed the data to determine the number of accidents related to activities similar to those taht would occur during the handling of drill cuttings. The following types of accidents were selected from the database as indicators of injuries that may have resulted from the handling of drill cuttings:

- Struck by falling object
- Struck by flying object
- Stuck by moving object
- Struck by vessel
- Struck by object - Not Otherwise Classified
- Bumped fixed object
- Cargo handling - Not Otherwise Classified
- Line handling
- Caught in lines

- Pinched/crushed
- Unknown
- Not classified

The PCAS file is composed of U.S. Coast Guard 2692 forms and contains the following information: case number, last name, first name, date of birth, status, nature of the accident, nature of the injury, the body part injured, result, cause, office, location of the person at the time of accident, the activity of the person at the time of the accident, the body of water, the year the vessel was built, the date of the casualty, industry time, company time, name of the vessel, operating company, vehicle identification number, flag, service, use, design, length, gross tonnage, time on duty, and case year. Form 2692 is entitled, "Report of Marine Accident, Injury or Death." The 2692 form is included in the PCAS file based on the occurrence of the following:

- A death
- An injury to five or more persons in a single incident
- An injury causing any person to be incapacitated for more than 72 hours.

The actual injury report forms were not reviewed, therefore the specific number of casualties resulting from the handling of drilling waste is not known. The casualties evaluated in this report are the total number of casualties for general types of accidents and may include casualties resulting from other drilling activities as well as the handling of drilling waste.

In addition to the type accident, the survey identified the cause of the accidents. The cause of accidents was further classified into "safety related" and "not safety related" categories. Safety related causes were results of accidents that could be avoided through some form of increased safety awareness. Non-safety related causes were those accidents considered unavoidable. Table XIII-6 presents the primary causes and classification of accidents on MODUs and OSVs.

Evaluation of the database revealed that the majority of the accidents were caused by human factors related to safety practices and procedures. Accident reports from one oil and gas company "showed that more than 80 percent of all injury accidents were caused by human behavior or more specifically,

TABLE XIII-6

PRIMARY CAUSES AND CLASSIFICATION
OF ACCIDENTS ON MODUs AND OSVs

Primary Cause	Classification
Adverse Weather	unavoidable
Carelessness, Another or Self	avoidable
Chemical Reaction	unavoidable
Deck Cluttered or Slippery	avoidable
Equipment or Material Failure	unavoidable
Failure to use Safety Equipment	avoidable
Improper Loading/Storage	avoidable
Improper Maintenance or Supervision	avoidable
Improper Tools/Equipment	avoidable
Inadequate/Missing Guarding or Railing	avoidable
Inadequate Training	avoidable
Misuse of Tools/Equipment	avoidable
Mooring Line Surge	unavoidable
Physical Factors, Self	avoidable
Unsafe Movement, Another or Self	avoidable
Unsafe Practice, Another or Self	avoidable
Vessel Casualty	unavoidable
Unknown	unavoidable
Not Elsewhere Classified	unavoidable

by unsafe practices."[20] The evaluation of the personnel casualty data concluded the following:

- Greater than 75 percent of the accidents occurring on MODUs from 1981 through 1990 were caused by human error or unsafe practices or procedures.
- Greater than 60 percent of the accidents occurring on OSVs from 1981 through 1990 were caused by human error or unsafe practices or procedures.
- Over the last three years of the study (1988 to 1990), the number of casualties on MODUs decreased while the drilling activity remained fairly constant.
- From the data examined it is not possible to predict the effect of transportation of drilling waste to shore on the number of personnel casualties.
- The number of casualties occurring on supply vessels does not appear to be directly related to drilling activity.

- Since the number of increased crane handling events is very small in relation to the total number of handling operations occurrring at drilling and production sites, no discernable increase in casualties attributable to onshore disposal of drilling wastes is anticipated.

The technology basis for compliance with zero discharge limitations of drilling fluids and cuttings is to either bulk load the material onto barges or load individual containers onto offshore service vessels (OSV). Typically, OSVs in Cook Inlet are used to transport wastes from the platform to shore, then barges are used in summer to transport drilling wastes across the Inlet to the Kustatan landfill for disposal. Containers or boxes are used to hold the excess and/or used drilling fluids and cuttings and have approximate capacity of 8 barrels. Cranes load these containers onto and off of offshore service vessels. A zero discharge limitation for drilling wastes would be expected to increase crane-related and vessel transport activity because of the need to deliver drilling fluids and cuttings wastes to shore for disposal.

3.0 PRODUCED WATER

In assessing non-water quality environmental impacts for produced water, EPA projected energy requirements and air emissions associated with the regulatory options considered and evaluated the potential for degradation of underground sources of drinking water. The annual energy requirements and air emissions for the produced water control technologies considered by EPA for the Gulf of Mexico and Cook Inlet are presented in Table XIII-1 and Table XIII-2 for the current and alternative baselines, respectively. The following sections describe the bases and methodologies for the NWQI analyses performed for Gulf of Mexico and Cook Inlet regions and for both the current and alternative baselines.

3.1 GULF OF MEXICO BASELINE

Annual energy requirements and air emissions for the produced water control technologies considered by EPA for the Gulf of Mexico are presented in Table XIII-7. These estimates are incremental to current NPDES permit requirements and thus represent the expected increase above current emissions levels and energy consumption. Only the incremental NWQIs resulting from additional requirements for to current NPDES permit requirements and thus represent the expected increase above current emissions levels and energy consumption. Only the incremental NWQIs resulting from additional requirements for facilities discharging offshore produced water into major passes of the Mississippi River are presented in the following sections.

TABLE XIII-7

GULF OF MEXICO AIR EMISSIONS AND ENERGY REQUIREMENTS FOR PRODUCED WATER OPTIONS (CURRENT REQUIREMENTS BASELINE)

Regulatory Options		Fuel[a] (BOE/yr)	Air Emissions[b] (tons/yr)
Option 1:	Zero discharge except: major pass river dischargers at 29/42 mg/l oil and grease limitations.[c]	2,023	25.92 (15.6)
Options 2 and 3:	Zero discharge for all Gulf of Mexico facilities.[d]	90,847	1,095.6 (353.9)

[a] BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor 1 BOE = 42 gal diesel) and the volume of natural gas required converted to equivalent oil volume (by the factor 1,000 scf = 0.178 BOE).[1]

[b] Air emissions calculated using emission factors for uncontrolled sources. Values in parentheses represent air emissions from controlled sources (see Section 3.3.2).

[c] Flores & Rucks, Inc. (FRI) and North Central permit #2184, outfall #003-1 are not included in Option 1 analyses due to existing gas flotation units at these facilities.

[d] Flores & Rucks, Inc. (FRI) NWQIs at Case 2 for Options 2 and 3. FRI air emissions and energy requirements may be considerably lower (see Section 3.1.1.2).

As in the Gulf of Mexico produced water baseline compliance cost and pollutant removals analyses (see Chapter XI), separate NWQI analyses were performed for Flores & Rucks Inc., in which four produced water zero discharge cases were considered, as follows:

Case 1: All produced water is injected for disposal in dedicated disposal wells.

Case 2: Some produced water is injected for waterflood; the remainder is injected for disposal.

Case 3: Coastal Subcategory produced water is disposed by injection into dedicated disposal wells; Offshore-derived produced water is treated and discharged offshore.

Case 4: Coastal Subcategory produced water is disposed by waterflood injection; Offshore-derived produced water is treated and discharged offshore.

3.1.1 Energy Requirements

This section provides a detailed discussion on the analysis of energy requirements for improved gas flotation and produced water injection in the Gulf of Mexico region, based on equipment power requirements and the volume of produced water discharged from each facility. These requirements were calculated by identifying the specific activities that are necessary for the treatment and injection of produced water.

3.1.1.1 Improved Gas Flotation

Energy requirements for improved gas flotation represent the power required to operate an improved gas flotation system designed for compliance with oil and grease limitations in produced water discharged to surface waters. The following assumptions were made in calculating the energy requirements for improved gas flotation:

- Gas flotation equipment including the feed pumps will be run by electricity.[21]
- Electric power will be supplied by existing diesel-fueled power sources for systems requiring less than or equal to 25 horsepower.[21]
- Electric power will be supplied by natural gas-fueled generators for systems requiring power greater than 25 horsepower.[22]
- Fuel requirements and air emissions for improved gas flotation are based on either the additional electricity required above 25 horsepower or the additional incremental load on existing power sources less than or equal to 25 horsepower.

Energy requirements for commercially available IGF systems were obtained from equipment vendors for systems of four different sizes ranging in treatment capacity from 1,700 to 77,000 barrels per day (bpd).[23] Electricity requirements in kilowatts (kW) for each unit were calculated using 0.75 kW/hp as a conversion factor. Fuel requirements were calculated for natural gas turbines assuming a heating value of 1,050 Btu/scf of natural gas and an average fuel consumption of 10,000 Btu/hp-hr, or 9.5(10,000/1,050) standard cubic feet (scf) of natural gas per horsepower-hour (hp-hr).[12] The usage rate for these systems is assumed to be 365 days per year or 8,760 hours per year. An example calculation of the natural gas fuel requirement for a 1,700 bpd IGF unit is:

$$\text{Natural gas fuel (million standard cubic feet)} = 12.25 \text{ hp} \times 8{,}760 \text{ hrs/yr} \times 9.5 \text{ scf/hp-hr} = 1.02 \text{ MMscf}$$

Table XIII-8 presents energy and fuel requirements for the four IGF units evaluated.

TABLE XIII-8

FUEL REQUIREMENTS FOR GAS FLOTATION UNITS[24]

Feed Rate (bpd)	1,700	10,000	25,000	77,000
Power Required (hp)	12.25	20.5	40.5	100.5
Electricity Required (kW)	9.2	15.4	30.4	75.4
Fuel Required (scf/yr)	1.02×10^6	1.7×10^6	3.37×10^6	8.36×10^6

A linear mathematical model was developed via regression analysis using the above four feed rates versus horsepower. The resultant formula was of the form:

$$HP = 9.92 + 0.0012 \times (\text{flow, bpd})$$

The above equation was used to predict the gas flotation horsepower requirements for the nine produced water design flow rates listed in Table XIII-9.[21] For flows below 2,000 bpd, IGF equipment size is constant, so the calculated power requirement is constant at 11.9 hp.

Feed pump horsepower was calculated using the following mathematical relationship as provided by the equipment vendor:[25]

$$HP = \frac{\text{gpm} \times \text{psi}}{1475}$$

where: gpm = Produced water flow in barrels per day converted to gallons per minute
psi = Discharge pressure in pounds per square inch

Based on vendor information, pump efficiency was assumed to be 85 percent and discharge pressure was assumed to be 50 psi.[21] The feed pump horsepower for each of the nine design flows is listed in Table XIII-9. The total IGF system energy requirements for each of the design flows was the sum of the IGF and feed pump horsepowers.[21]

Diesel fuel requirements were calculated as follows:

$$\text{Diesel fuel (gal/yr)} = \text{hp} \times 8760 \text{ hr/yr} \times 0.066 \text{ gal/hp-hr}$$

TABLE XIII-9

IMPROVED GAS FLOTATION ENERGY REQUIREMENT CALCULATIONS

Design Flow	Improved Gas Flotation Calculated Horsepower	Feed Pump Calculated Horsepower	Totals			
			Diesel-Fueled Electric Power (hp)[a]	Natural Gas-Fueled Electric Power (hp)	Diesel Fuel (gal/yr)	Natural Gas Fuel (MMscf/yr)
200	11.9	0.3	12.2	--	7,054	--
1,000	11.9	1.5	13.4	--	7,747	--
2,000	12.3	3.0	15.3	--	8,846	--
5,000	15.8	7.0	22.8	--	13,182	--
10,000	21.7	14	--	35.7	--	2.97
15,000	27.6	21	--	48.6	--	4.04
25,000	39.4	35	--	74.4	--	6.19
40,000	57.1	57	--	114.1	--	9.49
80,000	104.2	113	--	217.2	--	18.06

[a] Electricity is based on supply by an existing diesel-powered source.

The diesel fuel usage factor of 0.066 gal/hp-hr is based on fuel consumption of diesel industrial engines listed in the EPA AP-42 document entitled "Compilation of Air Pollutant Emission Factors."[14]

In order to predict the energy requirements and fuel usage for treatment systems with other than the nine design flows listed in Table XIII-9, two linear mathematical models were developed via regression analysis, as follows:[26]

Diesel-Fueled Electric Power Model Equation: $HP = 11.30 + 0.0023 \times (\text{flow, bpd})$

Natural Gas-Fueled Electric Power Model Equation: $HP = 9.77 + 0.0026 \times (\text{flow, bpd})$

For each facility with a flow less than 5,000 bpd (or a power demand less than 25 hp), the diesel-fueled electric power model equation was used. For facilities with flows greater than 5,000 bpd, the natural gas model equation was used. Table XIII-10 lists the power, diesel and natural gas fuel requirements for the facilities in the Gulf of Mexico (current requirements baseline). Flores & Rucks, Inc.

TABLE XIII-10

POWER AND FUEL REQUIREMENTS FOR PRODUCED WATER GAS FLOTATION IN THE GULF OF MEXICO

Permit-Outfall Number	Operator	Current Avg. Vol[a] (bpd)	Diesel-Fueled Electric Power		Diesel Fuel Requirements (gal/yr)	Natural Gas-Fueled Electric Power		Natural Gas Fuel Requirements (MMscf/yr)
			(hp)	(hp-hr/yr)		(hp)	(hp-hr/yr)	
3229-001-3	Chevron Pipe Line Co.	18,920	--	--	--	58.87	515,685	4.90
2963-006	Warren Petroleum Co.	1,808	15.38	134,719	8,891	--	--	--
2071-004-1	Flores & Rucks, Inc. (b)	153,895	--	--	--	--	--	--
2400-001	Gulf South Operators	291	11.96	104,731	6,912	--	--	--
2184-002-2	North Central	1,910	15.61	136,735	9,025	--	--	--
2184-003-1	North Central (b)	7,606	--	--	--	--	--	--
2184-001	North Central	572	12.59	110,286	7,279	--	--	--
3407-001	Amoco	6,290	--	--	--	26.09	228,582	2.17
TOTAL		**191,292**		**486,471**	**32,107**		**744,267**	**7.07**

[a] See Chapter XI.

[b] These facilities have existing gas flotation systems and do not require additional power and fuel.

and North Central (permit #2184, outfall #003-1) do not incur any incremental energy requirements since they have existing gas flotation systems.

3.1.1.2 Subsurface Injection

Energy requirements for produced water injection systems were estimated based on produced water being pretreated by cartridge filtration and then injected into a well with a capacity of 5,000 bpd at an injection pressure of 1500 psig.[21] The following list summarizes the bases used in calculating the energy requirements for injection:

- Fuel Sources: For facilities with total energy requirements for their injection systems of less than 25 horsepower, existing diesel-fueled power is available.[21] For facilities with total injection system energy requirements of 25 horsepower or more, the first 24 horsepower of electrical energy requirements is supplied by existing natural gas-fueled power sources.[21] All injection equipment that exceeds the first 24 horsepower of energy requirements is powered by natural gas-fueled engines.[22]

- Feed Pumps: For feed pumps included in injection systems whose total power demand is less than 25 horsepower (up to the design produced water flow rate of 500 bpd), electricity will be supplied by existing diesel-fueled power sources.[21] Feed pumps that are included in systems whose total power demand is 25 horsepower or greater will be powered by electricity or natural gas-fueled engines, depending on the produced water flow rate. For design flow rates of 1,000 bpd to 18,000 bpd, all feed pumps are electric. For produced water flow rates of 30,000 and 42,000, both electric and natural gas engine feed pumps are used. The electric pumps used in these larger injection systems are included to take advantage of the existing source of electricity that supplies up to 24 horsepower.

- Injection Pumps: Injection pumps included in injection systems whose total power demand is less than 25 horsepower[21] will be powered by existing diesel-fueled power sources. For injection systems with total power demands of 25 horsepower or greater, the injection pumps will be powered by natural gas-fueled engines.[22] One natural gas driven injection pump (reciprocating internal combustion engine) is required per every 5,000 barrels of produced water per day.[25] According to one operator, reciprocating internal combustion engines are more prevalent in the Gulf of Mexico operations than gas turbine engines.[27]

To determine the produced water flow rate at which a power demand of 25 hp is reached, a regression analysis was performed using the data in Table XIII-11. Using data for the four design flows between 200 bpd and 5,000 bpd, the total horsepower resulted in the following equation:[26]

$$HP = 4.204 + 0.035 \times (\text{flow, bpd})$$

For 25 horsepower, the corresponding calculated produced water flow was 603 bpd. It was assumed that the existing electric power for facilities below 603 bpd was diesel generated for both the feed and injection pumps. For facilities with flows above 603 bpd, both the incremental electric load for the feed pumps and the engines for the injection pumps were assumed to be supplied by natural gas. This is based on the assumption that larger facilities use natural gas as their onsite power source.[22]

Because the filter feed and injection pumps were assumed to be driven by either diesel or natural gas fuel, mathematical models were generated for each fuel type to determine the distribution of the energy requirements corresponding to the range of design flow rates. Table XIII-11 lists the power requirements for produced water injection systems. Electric power supplies power to feed pumps, except for injection pumps at the 200 bpd and 500 bpd design flows. Natural gas-driven engines primarily power injection pumps, except for the 30,000 bpd and 42,000 bpd design flows where two 12-hp and five 12-hp natural gas driven feed pumps are included, respectively.

Three mathematical models were developed to determine the requirements for flows other than the design flows. The model equations used to determine energy requirements and fuel type distribution are listed in Table XIII-12.[26]

The equations in Table XIII-12 were used to determine the energy requirements for the facilities in the Gulf of Mexico to inject produced water. The results are listed in Table XIII-13. For the current requirements baseline, the total diesel fuel use (19,328 gal/yr) and the total natural gas fuel use (507.80 MMscf/yr) were converted to BOE per year and summed to determine the total fuel use for Options 2 and 3 (90,847 BOE/yr), as shown in Table XIII-7.

The zero discharge option NWQI data presented in Table XIII-13 include Flores & Rucks, Inc. (FRI) at Case 2. A discussion of the selection of Case 2 as a reasonable scenario is provided in Chapter XI. Energy requirements for FRI were calculated separately for all four cases and are also presented in Table XIII-13. As described in Section 3.1, all of the produced water is injected in dedicated injection wells in Case 1 or is injected into waterflood wells as well as some dedicated injection wells in Case 2. For Cases 3 and 4, coastally-derived produced water is injected and natural gas is used to supply all power requirements. Offshore-derived produced water is segregated and treated using improved gas flotation units installed on satellite platforms offshore. Natural gas power was calculated for the IGF unit and feed pumps using the regression formula presented in Section 3.1.1.1. Existing equipment and power

TABLE XIII-11

DESIGN POWER AND FUEL REQUIREMENTS FOR PRODUCED WATER INJECTION[a]

Design Flow (bpd)	Power Requirements															Total Horse-power
	Diesel-Fueled Electric Power (hp)						Natural Gas-Fueled Electric Power (hp)			Natural Gas-Driven Engines (hp)						
	Feed Pumps			Injection Pumps			Feed Pumps			Feed Pumps			Injection Pumps			
	No.	hp	Tot. hp	No.	hp	Tot. hp	No.	hp	Tot. hp	No.	hp	Tot. hp	No.	hp	Tot. hp	
200	1	1	1	1	8	8	--	--	--	--	--	--	--	--	--	9
500	1	1	1	1	18	18	--	--	--	--	--	--	--	--	--	19
1,000	--	--	--	--	--	--	1	2	2	--	--	--	1	42	42	44
5,000	--	--	--	--	--	--	1	6	6	--	--	--	1	170	170	176
10,000	--	--	--	--	--	--	2	6	12	--	--	--	2	170	340	352
18,000	--	--	--	--	--	--	4	6	24	--	--	--	4	170	680	704
30,000	--	--	--	--	--	--	4	6	24	2	12	24	6	170	1,020	1,068
42,000	--	--	--	--	--	--	4	6	24	5	12	60	9	170	1,530	1,614

[a] Source: Erickson, M., January 5, 1995.[21]

TABLE XIII-12

MATHEMATICAL MODELS FOR POWER REQUIREMENTS

Condition of Power Requirement	Mathematical Model
Diesel electric power for flows less than 603 bpd	HP = 2.33 + 0.033 x (flow, bpd)
Natural gas electric power for flows greater than 603 bpd	HP = 0.0013 x (flow, bpd) - 0.372
Natural gas power for flows greater than 603 bpd	HP = 0.037 x (flow, bpd) - 10.855

sources currently used for waterflooding are assumed to be available for produced water disposal in Cases 2 and 4. Therefore, incremental non-water quality environmental impacts are not incurred by waterflooding activities in these cases. Only dedicated injection wells and offshore improved gas flotation units incur incremental NWQIs.

3.1.1.3 New Sources

All North Slope coastal facilities and coastal facilities in California, Alabama, Mississippi, and Florida already inject all produced water for disposal or for use in waterflood operations (see Chapter IV). The EPA Region 6 general permits for coastal Louisiana and Texas prohibit the discharge of produced water (produced water derived from the offshore subcategory which is discharging to major deltaic passes of the Mississippi River are not covered by the general permit). New sources in these areas would be expected to comply with zero discharge limitations under applicable existing regulatory requirements. EPA projects no new sources of produced water "discharging [produced water from the Offshore Subcategory] into the main passes of the Mississippi River below Venice or into the Atchafalaya River below Morgan City including Wax Lake Outlet."[28,29] In the absence of NSPS, new sources in the coastal Gulf of Mexico region would be required to comply with the zero discharge requirement of the Region 6 General Permits. Thus, new sources in the Gulf of Mexico are expected to incur no incremental NWQIs due to promulgation of zero discharge limitations under NSPS.

3.1.2 Air Emissions

EPA estimated air emissions for each facility not covered by the Region 6 General Permits by calculating the product of specific emission factors, the usage in hours (i.e., hours per year), and the horsepower requirements. Air emissions for each treatment technology were calculated on the basis of

TABLE XIII-13
ENERGY AND FUEL REQUIREMENTS FOR PRODUCED WATER INJECTION IN GULF OF MEXICO FACILITIES

Permit-Outfall Number	Operator	Current Avg. Vol. (bpd) (a)	Electric Power From Diesel		Diesel Fuel Use (gal/yr)	Electric Power From Natural Gas		Natural Gas Power For Injection Pumps		Natural Gas Fuel Use (MMscf/yr)
			(hp)	(hp-hr/yr)		(hp)	(hp-hr/yr)	(hp)	(hp-hr/yr)	
3229-001-3	Chevron Pipe Line Co.	18,920	--	--	--	24.0	210,240	714.36	6,257,770	61.45
2963-006	Warren Petroleum Co.	1,808	--	--	--	2.77	24,248	78.08	684,000	6.73
2071-004-1	Flores & Rucks, Inc. (b)	153,895	--	--	--	24.0	210,240	4,616.23	40,438,153	386.16
2400-001	Gulf South Operators, Inc.	291	12.03	105,403	6,957	--	--	--	--	--
2184-002-2	North Central	1,910	--	--	--	2.90	25,432	81.87	717,223	7.06
2184-003-1	North Central	7,606	--	--	--	10.45	91,561	293.67	2,572,541	25.31
2184-001	North Central	572	21.40	187,447	12,371	--	--	--	--	--
3407-001	Amoco	6,290	--	--	--	8.71	76,283	244.74	2,143,890	21.09
TOTAL		191,292	--	292,850	19,328	--	638,004	--	52,813,577	507.80

(a) See Chapter XI. (b) FRI data presented is at Case 2. All four cases are detailed in the table below.

FLORES & RUCKS, INC ZERO DISCHARGE CASE ANALYSES

Cases	Current Avg. Vol. (bpd) (a)	Electric Power From Natural Gas		Natural Gas Power For Gas Flotation		Natural Gas Power For Injection Pumps		Natural Gas Fuel Use (MMscf/yr)
		(hp)	(hp-hr/yr)	(hp)	(hp-hr/yr)	(hp)	(hp-hr/yr)	
Case 1: PW to New Injection Wells	153,895	24	210,240	--	--	5,733	50,222,217	479.11
Case 2								
PW to Waterflooding Wells	30,038	--	--	--	--	--	--	--
PW to New Injection Wells	123,857	24	210,240	--	--	4,616	40,438,153	386.16
Case 3								
Coastal Portion (New Injection)	30,038	24	210,240	--	--	1,128	9,879,157	95.85
Offshore Portion (IGF)	123,857	--	--	331	2,901,090	--	--	27.56
Case 4								
Coastal Portion (Waterflooding)	30,038	--	--	--	--	--	--	--
Offshore Portion (IGF)	123,895	--	--	331	2,901,090	--	--	27.56

[a] See Chapter XI.

emission factors for diesel industrial engines and natural gas-fired reciprocating engines. According to industry sources, engines used at Gulf of Mexico tank batteries and compressor stations are reciprocating internal combustion engines.[27] Table XIII-14 presents the emission factors used in calculating air emissions for all treatment technologies considered. The natural gas emissions factors have been updated since proposal to incorporate current factors published by EPA in "Compilation of Air Pollutant Emission Factors."

EPA based air emissions calculations on the assumption that the fuel-burning equipment used for compliance with either the gas flotation or zero discharge options does not contain any emissions control technology. In fact, engines with some form of emissions control are readily available to the oil and gas industry.[30] EPA, therefore, estimated for comparative purposes the air emissions of natural gas engines with nitrogen oxides- (NO_X) reducing technology. Table XIII-14 also lists the controlled emission factors for natural gas-fired reciprocating engines.

Nitrogen oxides readily form in the high-temperature, pressure, and excess air environment found in natural gas-fired compressor engines. To lower NO_X emissions, reciprocating engines have been developed with both combustion controls and post-combustion catalytic reduction. Sulfur oxides (SO_X) emission are not affected by the control technology. This is because SO_X emissions are proportional to the sulfur content of the fuel and will usually be quite low for natural gas oxide due to its negligible sulfur content.[30]

Emission reduction technologies are also available for diesel fueled industrial engines. These technologies are categorized into fuel modifications, engine modifications, and exhaust treatments. However, current data are insufficient to quantify the resulting emissions due to the modifications and are not presented in the AP-42 publication.[30]

Tables XIII-15 and XIII-16 list the uncontrolled and controlled air emissions, respectively, calculated for each of the Gulf of Mexico facilities for improved gas flotation. Tables XIII-17 and XIII-18 list each facility's uncontrolled and controlled air emissions, respectively, for subsurface injection. An example calculation for uncontrolled natural gas carbon monoxide emissions is:

$$(515{,}685 \text{ hp-hr/yr}) \times (1.6 \text{ g CO/hp-hr}) \times (1 \text{ ton}/908{,}000 \text{ g}) = 0.91 \text{ tons CO/yr}$$

TABLE XIII-14

UNCONTROLLED AND CONTROLLED EMISSION FACTORS

Pollutant	Uncontrolled Natural Gas Factors For Reciprocating Engines[a] (g/hp-hr)	Controlled Natural Gas Factors For Reciprocating Engines (g/hp-hr)	Uncontrolled Diesel Fuel Factors For Industrial Engines[c] (g/hp-hr)
Carbon Monoxide (CO)	1.6	1.1	3.03
Nitrogen Oxides (NO_x)	12	2.2	14
Sulfur Dioxide (SO_2)	0.002[d]	--	0.931
Total Hydrocarbons (THC)	4.9	2.5	1.12
Total Suspended Particulates	--	--	1.0

[a] Source: Table 3.2-1, AP-42, July, 1993.[15]
[b] Source: Table 3.2-7, AP-42, January, 1995.[30]
[c] Source: Table 3.3-1, AP-42, January, 1975.[14]
[d] Based on 0.20 percent sulfur content fuel (Table II-3.1, AP-42, September, 1985).[13]

3.1.3 Landfill Capacity for Drilling Wastes from New Produced Water Injection Wells

EPA projects the need for drilling only five new produced water injection wells and recompleting only 46 idle production wells for the purpose of complying with the zero discharge requirement for produced water generated by major pass dischargers (see Chapter XI). Compared to the 187 new production wells estimated to be drilled in the Gulf coast region annually,[31] the five new injection wells projected for compliance purposes represent only 2.7 percent of the total wells to be drilled. Compared to the 240 recompletions estimated to be drilled in the Gulf coast region annually,[31] the 46 recompletions to be drilled for compliance represent 19 percent of the total to be drilled. New injection wells are estimated to be completed at approximately 3,000 feet of depth (see Chapter XI), which is 35 percent of the average 8,500-foot depth of Gulf coast production wells.[31] The volume of drilling waste from these injection wells is therefore expected to be significantly less than the volume annually generated from the drilling of production wells. Using model well data presented in Chapter X, approximately 121,200 barrels of drilling waste are estimated to be generated from the drilling of these new and recompleted injection wells. Compared with an estimated 2.5 million barrels of drilling waste generated from drilling new and recompleted production wells annually, the injection well-derived waste is approximately 4.6 percent of the total volume to be generated. It is important to note that the generation of waste from the drilling of injection wells is a one-time event to come into compliance with the coastal guidelines, and would not take place annually.

TABLE XIII-15
UNCONTROLLED AIR EMISSIONS FOR PRODUCED WATER IMPROVED GAS FLOTATION IN COASTAL GULF OF MEXICO
(Current Requirements Baseline)

Permit-Outfall Number	Operator	Diesel Power (hp-hr/yr)	Natural Gas Power (hp-hr/yr)	Emissions (tons/yr)					
				CO	NO_x	SO_2	THC	TSP	Total
3229-001-3	Chevron Pipe Line Co.	--	515,685	0.91	6.82	0	2.78	0	10.51
2963-006	Warren Petroleum Co.	134,719	--	0.45	2.08	0.14	0.17	0.15	2.98
2071-004-1	Flores & Rucks, Inc. (a)	--	--	--	--	--	--	--	--
2400-001	Gulf South Operators, Inc.	104,731	--	0.35	1.61	0.11	0.13	0.12	2.32
2184-002-2	North Central	136,735	--	0.46	2.11	0.14	0.17	0.15	3.02
2184-003-1	North Central (a)	--	--	--	--	--	--	--	--
2184-001	North Central	110,286	--	0.37	1.70	0.11	0.14	0.12	2.44
3407-001	Amoco	--	228,582	0.40	3.02	0	1.23	0	4.66
TOTAL		486,471	744,267	2.93	17.34	0.50	4.62	0.54	25.92

TABLE XIII-16
CONTROLLED AIR EMISSIONS FOR PRODUCED WATER IMPROVED GAS FLOTATION IN COASTAL GULF OF MEXICO
(Current Requirements Baseline)

Permit-Outfall Number	Operator	Diesel Power (hp-hr/yr)	Natural Gas Power (hp-hr/yr)	Emissions (tons/yr)					
				CO	NO_x	SO_2	THC	TSP	Total
3229-001-3	Chevron Pipe Line Co.	--	515,685	0.62	1.31	0	1.42	0	3.35
2963-006	Warren Petroleum Co.	134,719	--	0.45	2.08	0.14	0.17	0.15	2.98
2071-004-1	Flores & Rucks, Inc. (a)	--	--	--	--	--	--	--	--
2400-001	Gulf South Operators, Inc.	104,731	--	0.35	1.61	0.11	0.13	0.12	2.32
2184-002-2	North Central	136,735	--	0.46	2.11	0.14	0.17	0.15	3.02
2184-003-1	North Central (a)	--	--	--	--	--	--	--	--
2184-001	North Central	110,286	--	0.37	1.70	0.11	0.14	0.12	2.44
3407-001	Amoco	--	228,582	0.28	0.58	0	0.63	0	1.49
TOTAL		486,471	744,267	2.53	9.39	0.50	2.65	0.54	15.60

[a] These facilities have existing improved gas flotation systems and do not require additional power and fuel.

TABLE XIII-17
UNCONTROLLED AIR EMISSIONS FOR PRODUCED WATER INJECTION IN GULF OF MEXICO COASTAL FACILITIES

Permit-Outfall Number	Operator	Diesel Power (hp-hr/yr)	Total Natural Gas Power (hp-hr/yr)	Emissions (tons/yr)					
				CO	NO_x	SO_2	THC	TSP (c)	Total
3229-001-3	Chevron Pipe Line Co.	--	6,468,010	11.40	85.48	0.01	34.90	NA	131.80
2963-006	Warren Petroleum Co.	--	708,248	1.25	9.36	0 (b)	3.82	NA	14.43
2071-004-1	Flores & Rucks, Inc. (a)	--	40,648,415	71.63	537.20	0.09	219.36	NA	828.28
2400-001	Gulf South Operators, Inc.	105,403	--	0.35	1.63	0.11	0.13	0.12	2.33
2184-002-2	North Central	--	742,655	1.31	9.81	0 (b)	4.01	NA	15.13
2184-003-1	North Central	--	2,664,101	4.69	35.21	0.01	14.38	NA	54.29
2184-001	North Central	187,447	--	0.63	2.89	0.19	0.23	0.21	4.15
3407-001	Amoco	--	2,220,173	3.91	29.34	0 (b)	11.98	NA	45.24
TOTAL		**292,850**	**53,451,602**	**95.17**	**710.92**	**0.42**	**288.81**	**0.32**	**1,095.64**

(a) FRI is analyzed for Case 2. All four cases are analyzed separately below.
(b) These values are rounded to zero due to limitation of significant figures.
(c) Emission factors for total suspended particulates (TSP) are given only for diesel-fueled power sources.

FLORES & RUCKS, INC ZERO DISCHARGE UNCONTROLLED AIR EMISSIONS

Cases	Natural Gas Power For Gas Flotation (hp-hr/yr)	Natural Gas Power for Inj. Pumps and Electricity (hp-hr/yr)	Emissions (tons/yr)					
			CO	NO_x	SO_2	THC	TSP	Total
Case 1								
PW to New Injection Wells	--	50,432,457	88.87	666.51	0.11	272.16	NA	1,027.64
Case 2								
PW to Waterflood Wells	--	--	--	--	--	--	--	--
PW to New Injection Wells	--	40,648,415	71.63	537.20	0.09	219.36	NA	828.28
Case 3								
Coastal Portion (New Injection)	--	10,089,397	17.78	133.34	0.02	54.45	NA	205.59
Offshore Portion (IGF)	2,901,290	--	5.11	38.34	0.01	15.66	NA	59.11
Case 4								
Coastal Portion (Waterflooding)	--	--	--	--	--	--	--	--
Offshore Portion (IGF)	2,901,090	--	5.11	38.34	0.01	15.66	NA	59.11

TABLE XIII-18
CONTROLLED AIR EMISSIONS FOR PRODUCED WATER INJECTION IN GULF OF MEXICO COASTAL FACILITIES

Permit-Outfall Number	Operator	Diesel Power (hp-hr/yr)	Total Natural Gas Power (hp-hr/yr)	Emissions (tons/yr)					
				CO	NO_x	SO_2	THC	TSP (c)	Total
3229-001-3	Chevron Pipe Line Co.	--	6,468,010	7.84	16.38	0.01	17.81	NA	42.04
2963-006	Warren Petroleum Co.	--	708,248	0.86	1.79	0 (b)	1.95	NA	4.60
2071-004-1	Flores & Rucks, Inc. (a)	--	40,648,415	49.24	102.96	0.09	111.92	NA	264.21
2400-001	Gulf South Operators, Inc.	105,403	--	0.35	1.63	0.11	0.13	0.12	2.33
2184-002-2	North Central	--	742,655	0.09	1.88	0 (b)	2.04	NA	4.83
2184-003-1	North Central	--	2,664,101	3.23	6.75	0.01	7.34	NA	17.32
2184-001	North Central	187,447	--	0.63	2.89	0.19	0.23	0.21	4.15
3407-001	Amoco	--	2,220,173	2.69	5.62	0 (b)	6.11	NA	14.43
TOTAL		**292,850**	**53,451,602**	**65.73**	**139.91**	**0.42**	**147.53**	**0.32**	**353.91**

(a) FRI is analyzed for Case 2. All four cases are analyzed separately below.
(b) These values are rounded to zero due to limitation of significant figures.
(c) Emission factors for total suspended particulates (TSP) are given only for diesel-fueled power sources.

FLORES & RUCKS, INC ZERO DISCHARGE CONTROLLED AIR EMISSIONS

Cases	Natural Gas Power For Gas Flotation (hp-hr/yr)	Natural Gas Power for Inj. Pumps and Electricity (hp-hr/yr)	Emissions (tons/yr)					
			CO	NO_x	SO_2	THC	TSP	Total
Case 1 PW to New Injection Wells	--	50,432,457	61.10	127.75	0.11	138.86	NA	327.81
Case 2 PW to Waterflood Wells PW to New Injection Wells	-- --	-- 40,648,415	-- 49.24	-- 102.96	-- 0.09	-- 111.92	-- NA	-- 264.21
Case 3 Coastal Portion (New Injection) Offshore Portion (IGF)	-- 2,901,290	10,089,397 ---	12.22 3.51	25.56 7.35	0.02 0.01	27.78 7.99	NA NA	65.58 18.86
Case 4 Coastal Portion (Waterflooding) Offshore Portion (IGF)	-- 2,901,090	-- --	-- 3.51	-- 7.35	-- 0.01	-- 7.99	-- NA	-- 18.86

The subject of landfill capacity was discussed in detail in the 1993 Offshore Guidelines Development Document.[24] EPA determined that existing landfills in the areas accessible to the Gulf of Mexico offshore and coastal oil and gas subcategories have 5.5 million barrels annual capacity available for oil and gas wastes. Therefore, EPA believes that the incremental quantity of solid waste (121,200 bbls) generated by drilling injection wells for compliance with the zero discharge produced water option makes no significant impact on the available landfill capacity. Similarly, the air emissions associated with hauling the wastes generated by drilling injection wells will likewise be a small fraction (approximately 4.6 percent based on the waste volume ratio) of the annual total emissions generated by coastal drilling activities. The emissions from drilling injection wells would be a one-time occurrence as compared with the annual emissions from production well drilling activities.

3.2 COOK INLET

For the eight facilities currently discharging produced water in Cook Inlet, energy requirements and air emissions were estimated for equipment that would be added to existing equipment to meet the limitations of the regulatory options considered for control of produced water. The three options, as they apply to Cook Inlet operations, are as follows:

Options 1 and 2: Cook Inlet facilities must meet a monthly average oil and grease content of 29 mg/l and a daily maximum of 42 mg/l.

Option 3: Zero discharge.

The technology bases for these options are improved gas flotation for Options 1 and 2, and subsurface injection for Option 3. Detailed discussions of the additional equipment required to comply with these control options are included in Chapter XI. The following sections present the methodology used to calculate energy requirements and air emissions associated with the produced water control options for Cook Inlet.

3.2.1 Energy Requirements

The horsepower requirements and fuel consumption for the equipment needed to comply with the produced water control options are presented in Table XIII-19. The totals in Table XIII-19 are the sum of the energy and fuel requirements calculated for the eight discharging facilities in Cook Inlet. Appendices XIII-3 and XIII-4 present spreadsheets that detail these calculations for both improved gas

TABLE XIII-19

COOK INLET POWER AND FUEL REQUIREMENTS FOR PRODUCED WATER CONTROL OPTIONS

Equipment	Total hp-hrs	Natural Gas Consumption (10^3 scf/yr)
Options 1 and 2: Improved Gas Flotation		
Improved Gas Flotation Unit	831,062	7,895
TOTAL FUEL	--	7,895
TOTAL FUEL (BOE/yr[a]) = 1,405		
Option 3: Subsurface Injection		
Improved Gas Flotation Unit	831,062	7,895
Granular Filtration Unit	262,800	2,497
Filter Backwash Centrifuge	2,958	28
Injection Pumps	1,611,840	15,312
Booster and Shipping Pumps	54,312,000	515,964
TOTAL FUEL	57,020,660	541,696
TOTAL FUEL (BOE/yr) = 96,422		

[a] BOE (barrels of oil equivalent) is the total diesel volume required converted to equivalent oil volume (by the factor 1 BOE = 42 gal diesel) and the volume of natural gas required converted to equivalent oil volume (by the factor 1,000 scf = 0.178 BOE).[1]

flotation (Options 1 and 2), and subsurface injection (Option 3), respectively. Following is a list of energy-specific assumptions used in all analyses according to the specified equipment:

Improved Gas Flotation Systems: The horsepower requirements for improved gas flotation systems that were added to two facilities and four platforms that do not currently have one are based on those presented in the Offshore Development Document.[24] In the Cook Inlet produced water compliance cost and pollutant removal analyses, systems with capacities of 1,000, 5,000, and 10,000 bpd were added for both the improved gas flotation analysis (Options 1 and 2) and the zero discharge analysis (Option 3) (see Chapter XI). The corresponding horsepower demands are 12.25, 15.53, and 20.5 hp. The horsepower demands of the 1,000 and 5,000 bpd systems were calculated via linear interpolation. See Appendix XIII-3 for details.

Granular Filtration Systems: One facility and one platform required additional filtration equipment in the cost and removals analyses for Option 3. The horsepower demands for the 1,000 bpd and 5,000 bpd systems are 10 and 20 hp, respectively. These horsepower requirements are presented in the Offshore Development Document.[24]

Filtration Backwash Centrifuge: Centrifuges were added to reduce the volume of filtration backwash requiring disposal in Option 3 (see Chapter XI). The horsepower demand for filtration backwash centrifuges was calculated using a method developed for the Offshore rulemaking effort.[24] The required horsepower was calculated as being proportional to the 26-horsepower demand of a 2,000 bpd centrifuge quoted by a vendor. Thus, using the produced water discharge flow rate and the assumption that 0.5 percent of the produced water flow becomes filtration backwash,[24] the horsepower demand was calculated as in this example for Anna platform:

Centrifuge hp = (919 bbl PW/day x 0.005) / 2,000 bbl centrifuge input per day = 0.0023.

Injection Pumps: Injection pumps of 1,000 and 3,000 bpd capacities were added as needed in Option 3 (see Chapter XI). Their respective horsepower demands of 42 and 100 hp were calculated via linear interpolation from data presented in Chapter 18 of the 1993 Offshore Development Document.[24]

Booster and Shipping Pumps: In the Option 3 cost and removals analyses, booster and shipping pumps were added to two facilities for sending produced water back to specific platforms for injection (see Chapter XI). Trading Bay Production Facility required four shipping pumps, one for each of three pipelines plus a spare. East Foreland required only one shipping pump. One booster pump was added for each pipeline. The horsepower requirements, obtained from information submitted by Cook Inlet operators, are 1,000 hp for shipping pumps and 300 hp for booster pumps.[5]

Fuel Consumption: Based on information from Cook Inlet operators, fuel consumption was calculated based on all equipment being powered by electric motors and electricity being supplied by natural gas-driven generators.[5] Fuel requirements were calculated for natural gas turbines assuming a heating value of 1,050 Btu/scf of natural gas and an average fuel consumption of 10,000 Btu/hp-hr, or 9.5 (10,000/1,050) scf/hp-hr.[12] The usage rate for these systems is 365 days per year or 8,760 hours per year. These values are used in all three control options. The following is an example fuel consumption calculation for Anna platform under Options 1 and 2:

Natural gas consumed = 15.53 hp x 8,760 hrs/yr x 9.5 scf/hp-hr = 1,292,407 scf/yr

3.2.2 Air Emissions

Air emissions for the produced water control options were calculated using the uncontrolled air emission factors for natural gas-fired turbines listed in Table XIII-4. Table XIII-20 lists the air emissions for all three options, and Appendix XIII-4 presents detailed calculations of these emissions.

3.2.3 Landfill Capacity of Drilling Waste for Injection Wells

EPA projects that to comply with a zero discharge requirement for produced water in Cook Inlet, operators would need to drill two new produced water injection wells and recomplete two idle production

TABLE XIII-20

AIR EMISSIONS ASSOCIATED WITH CONTROL OPTIONS FOR EXISTING SOURCES OF PRODUCED WATER IN COOK INLET
(tons/year)

Option	NO_x	THC	SO_2	CO	Total
1 & 2: Improved Gas Flotation	1.919	0.165	0.000	0.758	2.114
3: Subsurface Injection	81.64	11.30	0.125	52.12	145.19

wells for use as disposal wells (see Chapter XI). The volume of drilling waste (drilling fluid and cuttings) estimated for the new wells is 10,550 barrels, and the recompletions are estimated to generate 4,344 barrels,for a total of 14,894 barrels. The drilling waste volumes are based on the data presented in Worksheets 1 and 2 in Appendix X-1.

In addition, EPA projected an estimated 33,712 barrels of dewatered sludge would be generated annually from the centrifuging of produced water filtration backwash as part of the zero discharge by subsurface injection option. This volume was calculated as 0.06 percent of the volume of fluid to be filtered, based on the waterflood demand and produced water volumes reported for Cook Inlet production operations (see Chapter XI).

Assuming a remaining life span of 15 years for the existing Cook Inlet production operations, the above solid waste volumes represent 0.1 percent of the available capacity at the Kustatan landfill and the commercial disposal site in Oregon (see Section 2.3). The incremental quantity of drilling waste generated by drilling injection wells for compliance with the zero discharge produced water option makes no significant impact on the available landfill capacity. As discussed in Chapter XIV, however, zero discharge of produced water in Cook Inlet was not found to be economically achievable.

3.3 GULF OF MEXICO ALTERNATIVE BASELINE

In addition to the major pass dischargers (current requirements baseline) non-water quality environmental impacts, the alternative baseline NWQI analysis assessed the incremental impacts for Texas dischargers seeking individual permits (TDSIPs) and Louisiana open bay dischargers (LOBDs), who are already subject to zero discharge (see Chapter IV). NWQIs for the current requirements baseline were summed with the NWQIs for the TDSIPs and LOBDs to obtain the total NWQI for the alternative requirements baseline. Table XIII-21 presents the NWQIs calculated for the current requirements baseline analysis as well as the alternative baseline analysis. The following sections describe the methodologies used to determine the energy requirements and air emissions for the total alternative baseline.

3.3.1 Energy Requirements

The methodologies used to calculate energy requirements are based on the produced water volume generated and the location of each facility. As part of the alternative baseline compliance cost analysis presented in Chapter XI, the volumes of produced water were used to categorize facilities as either medium to large (herein called "medium/large") or small. The volume that defines the cut-off between medium/large and small volumes was determined from the intersection of the annualized capital plus O&M cost curves calculated from design flow equations developed for medium/large volume facilities and for small volume facilities. Facility locations were defined as being either water-access or land-access sites. Information used by EPA in developing the proposed and final rules shows that it is reasonable to model all Louisiana facilities as water-access sites and all Texas facilities as land-access sites (see Chapters IV and XI).

The information below was used in estimating the energy requirements associated with the final rule for the alternative baseline:

- Small-volume land-access facilities transport their produced water by truck to a commercial disposal facility for subsurface injection. Small-volume water-access facilities transport their produced water by barge to a commercial disposal facility.
- The produced water flow above which it is more economical to treat on site for the treatment option based on improved gas flotation (Option 1) is 76.5 bpd for land-access and 70.5 bpd for water-access facilities.
- Medium/Large-volume facilities treat and/or dispose of their produced water on site.treatment option based on improved gas flotation (Option 1) is 76.5 bpd for land-access and 70.5 bpd for water-access facilities.
- The produced water flow above which it is more economical to treat and inject produced water for the zero discharge options (Options 2 and 3) is 70.5 bpd for land-access and 108.4 bpd for water-access facilities.

The above flow rates define the "cut-off" between medium/large facilities and small facilities, and thus define the method of disposal used. Because there are different cut-off flow rates for Option 1 (improved gas flotation) versus Options 2 and 3 (zero discharge), Table XIII-21 shows a greater number of small

TABLE XIII-21

SUMMARY POWER REQUIREMENTS AND AIR EMISSIONS FOR PRODUCED WATER CONTROL OPTIONS FOR GULF OF MEXICO FACILITIES

Facility Type	No. of Facilities	PW Flow (bpd)	Fuel Use [a] (BOE/yr)	Uncontrolled Air Emissions (tons/yr)	Controlled Air Emissions (tons/yr)
Option 1					
Current Requirements Baseline					
Major Pass Dischargers[b]	6	29,791	2,023	25.9	15.6
Cook Inlet	8	135,285	1,405	2.1	2.1
LA Open Bay Dischargers					
Medium/Large Facilities	30	329,678	16,891	210.2	99.0
Small Facilities[c]	7	136	1,334	15.4	15.4
TX Individual Permit Dischargers					
Medium/Large Facilities	48	67,117	9,681	133.7	123.2
Small Facilities	29	656	1,437	5.9	5.9
Total Alternative Baseline [d]	**120**	**427,378**	**31,366**	**393**	**261**
Option 2					
Current Requirements Baseline					
Major Pass Dischargers[b]	8	191,292	90,847	1,096	353.9
Cook Inlet	8	135,285	1,405	2.1	2.1
LA Open Bay Dischargers					
Medium/Large Facilities	30	329,678	191,016	2,302	738.6
Small Facilities[c]	7	136	1,334	15.4	15.4
TX Individual Permit Dischargers					
Medium/Large Facilities	49	67,192	36,621	448.8	178.8
Small Facilities	28	581	1,273	5.2	5.2
Total Alternative Baseline[d]	**122**	**588,879**	**321,091**	**3,870**	**1,294**
Option 3					
Current Requirements Baseline					
Major Pass Dischargers[b]	8	191,292	90,847	1,096	353.9
Cook Inlet	8	135,285	96,422	145.2	145.2
LA Open Bay Dischargers					
Medium/Large Facilities	30	329,678	191,016	2,302	738.6
Small Facilities	7	136	1,334	15.4	15.4
TX Individual Permit Dischargers					
Medium/Large Facilities	49	67,192	36,621	448.8	178.8
Small Facilities	28	581	1,273	5.2	5.2
Total Alternative Baseline[d]	**122**	**588,879**	**321,091**	**4,013**	**1,437**

[a] BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor 1 BOE=42 gal diesel) and the volume of natural gas required converted to equivalent oil volume (by the factor: 1,000 scf = 0.178 BOE oil).[1]

[b] Values for the major pass dischargers are presented here for comparison purposes only. The derivation of these values is detailed in Section 3.1.

[c] Values for Louisiana small facilities are the same under all options because small facilities utilize commercial transport and subsurface injection under all options.

[d] Total alternative baseline is the sum of the NWQIs for the current requirements baseline, the Texas Dischargers Seeking Individual Permits and the Louisiana Open Bay Dischargers. The total number of facilities under Option 1 differs from the total under Options 2/3 because two of the eight outfalls for major pass dischargers have existing gas flotation systems and are not included in the Option 1 analysis (see Chapter XI). In addition, Texas permit number 582, discharging 75 bpd, is a small facility under Option 1 and a medium/large facility under Options 2/3.

facilities in Texas under Option 1 than under Options 2 and 3. This is because two of the eight oufalls for major pass dischargers have existing gas flotation systems and are not included in the Option 1 analysis. In addition, Texas permit number 582, currently discharging 75 bpd, is below the Option 1 cut-off and above the Options 2 and 3 cut-off.

In addition to the above, the approach used to mathematically model the relationship of produced water flow versus horsepower demands for the major pass dischargers in the current requirements baseline analysis (see Section 3.1.1) was also used to model the flow versus horsepower demands for the Texas and Louisiana medium/large facilities for the alternative baseline analysis. This is true for both the improved gas flotation option (Option 1) and the zero discharge options (Options 2 and 3). The resulting energy requirements for medium/large volume facilities under each option are presented in Appendices XIII-5 and XIII-6.

For medium/large volume facilities, the technology basis for the zero discharge options (Options 2 and 3) differs slightly between land- and water-access sites. While both facility locations dispose of produced water via subsurface injection, only water-access sites include cartridge filtration prior to injection. This is because information in the record shows that for land-access facilities, cartridge filtration is less necessary and well workover costs are cheaper.[7] Thus, horsepower demands for filtration feed pumps are included for water-access sites but not for land-access sites.

For small-volume facilities, the technology basis for all control options is zero discharge via transporting the produced water to a commercial disposal facility for subsurface injection. NWQIs for water-access sites are based on weekly barge trips provided by a commercial service company. The bases and methodology for determining the frequency and duration of the barge trips are presented in Appendix XIII-7, along with the resulting energy requirements. Small-volume land-access sites use vacuum trucks to transport produced water off-site. Appendix XIII-8 presents the energy requirements calculated for small-volume land-access sites.

3.3.2 Air Emissions

Air emissions for all options were calculated by multiplying the estimated fuel use by the emission factor for the specific type of equipment. As in the current requirements baseline NWQI analysis, uncontrolled as well as controlled air emissions were calculated for Gulf of Mexico medium/large facilities for the gas flotation and subsurface injection options (see Section 3.1.2). The emission factors used for small Louisiana and Texas facilities were for barging and trucking activities, respectively, as presented in Table XIII-4. Controlled air emissions were not calculated for small facilities because installation of controlled emissions technology onto trucks or service vessels is the decision of the commercial disposal company, not that of the small produced water volume generating facility. The resulting air emissions for all alternative baseline facilities are summarized in Table XIII-21 and are presented in detail in Appendices XIII-5 and XIII-6.

3.4 OTHER FACTORS

3.4.1 Impact of Marine Traffic on Coastal Waterways

In evaluating the impact of the final rule on the potential for increased service vessel traffic, dredging, and the widening of navigation channels, EPA reviewed MMS data and EPA estimates regarding transport boat usage. The service vessel usage at coastal facilities may be as high as two supply boats per day and two crew boats per day during the exploration and development operations. In general, service vessels make three trips per week to exploration and development operations and one trip per week to production facilities. A boat may visit only one site or, if it is only going to production facilities, it may visit as many as five facilities in a single trip.[6]

The oil and gas industry in the Gulf of Mexico uses the extensive waterway system located within the Gulf Coastal States to provide access between onshore support operations and coastal production facilities and drilling rigs. Oil industry support vessels moving along coastal navigation channels include crew boats, supply boats, barge system, derrick vessels, geophysical-survey boats, and floating production platforms. Navigation channels serve as routes for service vessels traveling back and forth from service and supply bases.[24] Generally, oil and gas industry use accounts for approximately 12 percent of all commercial usage of the Gulf Coastal navigation channels according to MMS data.[32]

In terms of the Gulf of Mexico current requirements baseline, service vessels will only be necessary to support produced water injection well drilling. The volume of waste generated from drilling injection wells is only 1.7 percent of the annual offshore drilling waste volume (see Section 3.1.3).[33] The number of service vessels servicing drilling waste disposal from injection wells for the current requirements baseline is only 1.7 percent of the total offshore vessel traffic or 0.2 percent of all commercial traffic. It is important to note that the injection well drilling waste volume will occur only once and the vessel traffic will be effected temporarily.

MMS data show that for offshore operations alone, an average of 30,000 service vessel trips per year support oil and gas related activities in Federal waters of the Gulf of Mexico.[34] These data do not include vessel traffic destined for coastal or offshore activities in the State territorial seas and therefore under-count actual boat traffic. In estimating the vessel traffic resulting from this rule, EPA projected that transporting produced water from wells subject to zero discharge would require a total of 60 barge trips per year (see Section 3.3, alternative baseline). In comparison to the offshore MMS data alone, it is apparent that the differential increase in boat traffic due to this rule would be less than 0.2 percent of all service vessel traffic.[34]

Since service vessels must have unimpeded access to supply bases to continue servicing coastal activities, maintenance dredging of navigation channels would be required regardless of whether this rule was promulgated. Recalling that oil and gas related traffic accounts for approximately 12 percent of all commercial use of the navigation channels and that oil/gas related vessel traffic resulting from this rule will increase less than 0.2 percent, any increase in vessel traffic due to this rule is expected to be minimal. No significant increase in dredging activities is anticipated as a result of this rule.

3.5 UNDERGROUND INJECTION OF PRODUCED WATER

Produced water is required to be disposed of in Class II injection wells. The authority of the Underground Injection Control (UIC) program extends to all offshore injection wells located in state territorial waters, but does not apply to injection wells located in federal waters (40 CFR Parts 144, 145 and 146). EPA does not believe that zero discharge in properly constructed Class II injection wells will endanger underground sources of drinking water.

In the 1987 Report to Congress (EPA/530-SW-88-003), EPA analyzed the impact of the disposal of produced water in injection wells.[35] The study found that injection wells used for the disposal of produced water have the potential to degrade fresh groundwater in the vicinity if they are inadequately designed, constructed, or operated. Highly mobile chloride ions can migrate into freshwater aquifers through corrosion holes in injection tubing, casing and cement. To prevent groundwater contamination, the UIC program (administered by EPA and states pursuant to the Safe Drinking Water Act, sections 1421-1425) requires mechanical integrity testing of all Class II injection wells every 5 years. All states with permitted Class II injection wells meet this requirement, although some states have requirements for more frequent testing.

4.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

Treatment, workover, and completion (TWC) fluids are commingled with produced water for treatment in Cook Inlet, thus non-water quality enviromental impacts (NWQI) for TWC fluids in Cook Inlet are included in the NWQI analysis for produced water. Coastal facilities in Alaska's North Slope, Alabama, Mississippi, Florida, and California are already achieving zero discharge of TWC fluids. The population of facilities included in the NWQI analysis for TWC fluid discharges in Texas and Louisiana is the same as for the TWC compliance cost and pollutant removals analysis. As described in detail in Chapter XII, the total TWC population was subdivided into the following distinct facility types:

- Medium/Large Facilities: Those facilities generating large enough amounts of produced water to make it cost effective to develop and operate onsite treatment technology. Medium/Large facilities are subject to two different produced water discharge limitations:

  a) *General Permit Facilities*: Those Medium/Large facilities required to meet zero discharge limitations under the 1995 Region 6 General Permits.

  b) *Major Pass Dischargers*: Those Medium/Large Facilities not covered by the zero discharge requirements of the 1995 Region 6 General Permits because they discharge off-shore or stripper subcategory produced waters into major passes of the Mississippi River or to the Atchafalaya River below Morgan City including Wax Lake Outlet.

- Small Facilities: Those facilities which, due to their lower produced water flow rates, use commercial treatment/disposal facilities for pollution control. All of these facilities were covered by the 1995 Region 6 General Permits.

Since TWC fluids are, or can be, commingled with produced water for treatment and discharge or injection, the regulatory options for the TWC NWQI analysis are the same as those developed for produced water. Table XIII-22 presents the summary energy requirements and air emissions calculated for TWC fluids according to the regulatory options. Note that, as in the produced water NWQI analysis, Option 1 allows discharge (from major pass dischargers only) of TWC fluids meeting compliance with limitations based on improved performance of gas flotation (IGF), and Options 2 and 3 are both zero discharge for all facilities in the Gulf of Mexico based on onsite injection or commercial transport to offsite injection.

Although Option 1 is based on IGF, only those operators currently discharging produced water (i.e., major pass dischargers) are expected to utilize gas flotation to meet the Option 1 limitations, whereas those operators currently required to meet zero discharge of produced water (i.e., general permit facilities)

TABLE XIII-22

UNCONTROLLED AIR EMISSIONS AND ENERGY REQUIREMENTS FOR GULF OF MEXICO TWC FLUIDS BAT AND NSPS OPTIONS

Option	Facility Type	Fuel Requirements (BOE/year)[a]		Air Emissions (tons/year)	
		BAT	NSPS	BAT	NSPS
Option 1:[b]	• Medium/Large Facilities:				
	– Major Pass Dischargers	3.62	0.89	0.05	0.01
	– General Permit Facilities	216.85	30.04	2.62	0.36
Zero discharge except: major pass river dischargers at 29/42 mg/l oil and grease limitations.[c]	• Small Facilities:				
	– Water-access	1,006.21	136.76	11.65	1.58
	– Land-access	131.26	14.33	0.54	0.06
	Total	**1,359.94**	**182.02**	**14.86**	**2.01**
Options 2 & 3:[b]	• Medium/Large Facilities	276.10	36.25	3.33	0.44
	• Small Facilities:				
Zero discharge for all Gulf of Mexico facilities.[d]	– Water-access	1,006.21	136.76	11.65	1.58
	– Land-access	131.26	14.33	0.54	0.06
	Total	**1,413.57**	**187.34**	**15.52**	**2.08**

[a] BOE (barrels of oil equivalent) is the sum of the total diesel volume required and total natural gas volume converted to equivalent oil volume by the factors: 1 BOE = 42 gal diesel, and 1,000 scf = 0.178 BOE.[1]
[b] Cook Inlet produced water NWQIs are presented in a separate document.
[c] FRI is already at IGF and North Central outfall #003-1, permit #2184 is at gas flotation; therefore there are no incremental emissions for these two outfalls.
[d] FRI at Case 2.

are expected to utilize subsurface injection to meet the Option 1 limitations. Therefore, the NWQIs calculated for TWC fluids generated by major pass dischargers under Option 1 are based on the NWQIs calculated for produced water treated by improved gas flotation systems as presented in Section 3.1.1.1. The NWQIs for TWC fluids generated by general permit facilities under Option 1 are based on the NWQIs calculated for produced water disposed by injection as presented in Section 3.1.1.2. For TWC fluids generated by all medium/large facilities, including both major pass and general permit facilities, the NWQIs calculated under Options 2 and 3 are based on the NWQIs calculated for produced water disposed by injection as shown in Section 3.1.1.2.

Based on the practice of commingling, the quantity of NWQIs generated by treating or disposing of one barrel of TWC fluid is equal to the NWQIs generated by treating or disposing of one barrel of produced water. Hence, EPA estimated the total NWQIs for TWC fluids as being proportional to the total NWQIs calculated for produced water. To calculate TWC fluid NWQIs proportional to produced water

NWQIs, the total annual volume of combined TWC fluids generated per job per facility type was divided by the annual produced water volume generated by the major pass dischargers (see Section 3.1.1, Table XIII-10). The ratio was then multiplied by the total fuel consumption and power requirements that were originally calculated for the facilities in the produced water NWQI analysis presented in Section 3.0 of this document. A detailed description of these calculations is provided in the following sections.

EPA determined that incremental energy requirements and air emissions would occur from medium/large facilities and from small facilities. The following sections present the methodology used to estimate energy requirements and air emissions from onsite gas flotation, onsite injection, and transportation and handling activities associated with commercial disposal of TWC fluids.

4.1 ENERGY REQUIREMENTS

4.1.1 Medium/Large Facilities

The energy requirement calculations for medium/large facilities (comprised of major pass dischargers and general permit facilities) took into account the total number of treatment/workover jobs and completion jobs per year and the corresponding volumes of TWC fluids to be disposed of or discharged. The TWC fluid volumes and jobs per year are based on information presented in Chapter XII. Appendix XIII-9 presents two tables (for existing and new sources, respectively) that list the following data for each facility type (i.e., major pass dischargers and general permit facilities) and regulatory option:

- Number of workover/treatment jobs per year
- Workover/treatment fluid volume per job (in bbl per year)
- Total workover/treatment fluid volume per year (in bbl per year)
- Number of completion jobs per year
- Completion fluid volume per job (in bbl per year)
- Total completion fluid volume per year (in bbl per year)
- Total TWC fluid volume per year (in bbl per year).

After multiplying the number of jobs per year by the corresponding volume of fluid generated per job, the total volumes from the two types of jobs were summed, resulting in a weighted average volume of TWC fluids. To illustrate the derivation of the data presented in Appendix XIII-9, the following is an example using the data in the first row of Table A, namely, the calculation of the total TWC fluid volume generated per year by major pass dischargers under Option 1 (discharge based on IGF):

(25 W/T jobs/yr x 587 W/T bbl/job) + (23 Compl. jobs/yr x 209 Compl. bbl/job) = 19,482 bbl TWC fluids/yr

As discussed in the preceding section, EPA estimated the total NWQIs for TWC fluids as being proportional to the total NWQIs calculated for produced water. The proportional relationship was calculated as the ratio of the total annual volume of combined TWC fluids generated per job per facility type (as listed in Appendix XIII-9) relative to the annual produced water volume generated by the major pass dischargers (as listed in Table XIII-10). Three such ratios were calculated: one for major pass dischargers under Option 1, one for general permit facilities under Option 1, and one for all medium/large facilities under Options 2 and 3. Below are the three equations used to calculate these ratios:

Option 1 Equations:[a,b]

$$\frac{\textit{TWC Volume from Major Pass Dischargers (App. XIII}-9)}{\textit{PW Volume from Major Pass Dischargers Not Using Gas Flotation (Table XIII}-10)} =$$

$$\frac{19{,}482\ bbl/yr}{(29{,}791\ bpd \times 365\ days/yr)} = 0.00179 \qquad \text{Eqn. 1}$$

$$\frac{\textit{TWC Volume from General Permit Facilities (App. XIII}-9)}{\textit{PW Volume from All Major Pass Dischargers (Table XIII}-10)} =$$

$$\frac{166{,}662\ bbl/yr}{(191{,}292\ bpd \times 365\ days/yr)} = 0.00239 \qquad \text{Eqn. 2}$$

Option 2 Equation:

$$\frac{\textit{TWC Volume from All Medium/Large Facilities (App. XIII}-9)}{\textit{PW Volume from All Major Pass Dischargers (Table XIII}-10)} =$$

$$\frac{212{,}203\ bbl/yr}{(191{,}292\ bpd \times 365\ days/yr)} = 0.003 \qquad \text{Eqn. 3}$$

Note that the volume of produced water in the denominator of Equation 1 is less than the volume in the denominator of Equation 2. Although both volumes are derived from Table XIII-10 and both apply

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[a] Those major pass facilities already employing gas flotation to treat produced water (and commingled TWC fluids) incur no NWQIs under Option 1.

[b] Equation 1 uses the ratio of TWC fluids that would undergo gas flotation to the volume of produced water used in Section 2 to calculate NWQIs associated with gas flotation. Thus, the NWQIs resulting from gas flotation treatment of one barrel of TWC fluids is equal to the NWQIs resulting from gas flotation treatment of one barrel of produced water. The resulting value for Equation 1 is 0.00179, or 0.179%. Thus, IGF treatment of TWC fluids under Option 1 will require 0.179% of the total fuel consumption calculated for IGF treatment of produced water under Option 1. The same percentage holds true for air emissions estimates. Equations 2 and 3 perform similar calculations to estimate NWQIs for those TWC fluids that would be injected.

to Option 1, the volume in Equation 1 excludes those major pass dischargers that currently use gas flotation, and the volume in Equation 2 includes all major pass dischargers. As noted in the preceding section, only major pass dischargers are expected to utilize gas flotation to comply with Option 1 limitations, while general permit facilities are expected to utilize injection to meet the same limitations. Therefore, the proportion of NWQIs associated with TWC fluids treatment at major pass dischargers under Option 1 is relative only to the NWQIs resulting from adding IGF treatment for the incremental volume of produced water at those facilities. The proportion of NWQIs due to TWC fluids injection by general permit facilities under Option 1 is relative to the NWQIs resulting from injection of the total produced water volume by major pass facilities. For Option 2 in which all medium/large facilities utilize injection, the denominator is the total produced water volume for major pass facilities.

To determine TWC energy requirements, the TWC/PW volume ratios were then mulitplied by the corresponding produced water power requirements and fuel usage derived in Section 3.1.1. For example, the incremental amounts of diesel and natural gas fuels used to treat TWC fluids onsite via improved gas flotation for the major pass dischargers under Option 1 was calculated as follows:

From PW Analysis		TWC/PW Proportion		For TWC Analysis
32,107 gal/yr diesel	x	0.00179	=	57.53 gal/yr diesel
7.07 MMscf/yr natural gas	x	0.00179	=	0.0127 MMscf/yr natural gas

The produced water data and resulting TWC fuel use and power requirements for all options of the major pass discharge and general permit facilities are presented in Table XIII-23.

4.1.2 Small Facilities

The NWQI analysis for TWC fluids generated by small facilities was based on the assumption that all small facilities use commercial disposal services to transport and dispose via injection TWC fluids.[36] Water-accessed small facilities transport their waste by barge for commercial disposal. Land-accessed small facilities transport their waste by truck for commercial disposal.

The fuel usage due to the operation of barges and trucks to transport TWC fluids from either water- or land-accessed facilities to commercial facilities for disposal was calculated by estimating the fuel consumption required by trucks and barge tugs, the distance barges and trucks have to travel, fuel con-

TABLE XIII-23

TWC FLUID ENERGY REQUIREMENTS FOR MAJOR PASS DISCHARGERS AND GENERAL PERMIT FACILITIES (EXISTING SOURCES)

Facility Type	Fuel Type	PW Fuel Use (a)	PW Power Requirements (hp/hr/yr)	TWC/PW Volume Ratio	TWC Fuel Use	TWC Power Requirements (hp-hr/yr)
Option 1:						
• Major Pass Dischargers	Diesel	32,107 gal/yr	486,471	0.00179	57.53 gal/yr	871.59
	Natural Gas	7.07 MMscf/yr	744,267	0.00179	0.0127 MMscf/yr	1,333.47
• General Permit Facilities	Diesel	19,328 gal/yr	292,850	0.002387	46.14 gal/yr	699.02
	Natural Gas	507.79 MMscf/yr	53,451,602	0.002387	1.21 MMscf/yr	127,587.36
Option 2:						
• All Medium/Large Facilities	Diesel	19,328 gal/yr	292,850	0.003039	58.74 gal/yr	890.03
	Natural Gas	507.79 MMscf/yr	53,451,602	0.003039	1.54 MMscf/yr	162,451.07

[a] Values for Major Pass Dischargers under Option 1 are from Table XIII-10. Values for General Permit facilities under Option 1 and all Medium/Large Facilities under Option 2 are from Table XIII-13.

sumption by auxiliary generators when the barges are loaded and tugs are idling, and by vacuum pumps and compressors to unload the barges (see Appendix XIII-10). To simplify calculations, the treatment/workover and completion fluid volumes were combined. Table A in Appendix XIII-9 shows how these volumes were calculated. The total TWC volumes were used to determine NWQIs of either trucking or barging.

Table XIII-24 presents the fuel required to transport TWC fluids from existing small water- or land-accessed facilities to commercial facilities for disposal. Fuel requirement calculations for small facilities are presented in Appendix XIII-10.

TABLE XIII-24

EXISTING FACILITY TWC FLUIDS NON-WATER QUALITY IMPACTS FOR ALL REGULATORY OPTIONS

Facility Type	TWC Volume (bbl/yr)	Fuel Requirements (gal/yr)			
		Barge	Truck	Auxiliary Equipment	Total
Water-Access	41,183	41,200	0	1,061	42,261
Land-Access	21,870	0	5,513	0	5,513

4.1.3 New Sources

The basis for the number of new sources generating TWC fluids is described in detail in Chapter XII. Table B in Appendix XIII-9 lists the number of jobs and TWC volumes corresponding to each of the options. As in the existing source NWQI analysis, energy requirements for new source medium/large facilities were based on the ratio of TWC-to-major pass discharger produced water volumes. The TWC/PW volume ratios for each option and facility type are presented in the following equations:

Option 1 Equations:

$$\frac{\text{TWC Volume from "New" Major Pass Sources (App. XIII-9)}}{\text{PW Volume from Major Pass Dischargers Not Using Gas Flotation (Table XIII-10)}} =$$

$$\frac{4{,}776\ bbl/yr}{(29{,}791\ bpd \times 365\ days/yr)} = 0.00044 \qquad \text{Eqn. 4}$$

$$\frac{TWC\ Volume\ from\ \text{"New"}\ General\ Permit\ Sources\ (App.\ XIII-9)}{PW\ Volume\ from\ All\ Major\ Pass\ Dischargers\ (Table\ XIII-10)} =$$

$$\frac{23{,}084\ bbl/yr}{(191{,}292\ bpd \times 365\ days/yr)} = 0.00033 \qquad \text{Eqn. 5}$$

Option 2 Equation:

$$\frac{TWC\ Volume\ from\ \ All\ \text{"New"}\ Medium/Large\ Sources\ (App.\ XIII-9)}{PW\ Volume\ from\ All\ Major\ Pass\ Dischargers\ (Table\ XIII-10)} =$$

$$\frac{27{,}860\ bbl/yr}{(191{,}292\ bpd \times 365\ days/yr)} = 0.00040 \qquad \text{Eqn. 6}$$

Table XIII-25 presents the data and the TWC fuel usage and power requirements for medium/large facilities for all options.

For the NWQI analysis of new sources of TWC fluids generated at small facilities, the number of TWC jobs per year and volumes are the same as in Chapter XII and are presented in Table B in Appendix XIII-9. The methodology and estimates used for existing small facilities were also used to calculate the energy requirements for new source small facilities as presented in Table XIII-26.

4.2 AIR EMISSIONS

The air pollutants evaluated for the TWC fluids options are the same as those identified for the produced water treatment options: nitrogen oxides (NO_x), total hydrocarbons (THC), sulfur dioxide (SO_2), carbon monoxide (CO), and total suspended particulates (TSP). Air emissions were calculated for each facility type by multiplying the product of specific emission factors by the power requirements in hp-hr per year. The annual power requirements for each fuel type were calculated for all medium/large facilities generating TWC fluids by multiplying the TWC/PW volume ratios derived for each facility type and option (see Equations 1 through 6) by the corresponding produced water power requirements. Table XIII-14 presents the emission factors for diesel- and natural gas-powered reciprocating engines used in calculating the air emissions for medium/large facilities. Tables XIII-27 and XIII-28 present the summary air emissions for existing and new sources, respectively, for all facility types and regulatory options.

Table XIII-4 presents the emission factors for barges, trucks and auxiliary equipment used in calculating air emissions for TWC fluid disposal from small facilities. Tables XIII-27 and XIII-28

TABLE XIII-25

TWC FLUID ENERGY REQUIREMENTS FOR MAJOR PASS DISCHARGERS AND GENERAL PERMIT FACILITIES (NEW SOURCES)

Facility Type	Fuel Type	PW Fuel Use (a)	PW Power Requirements (hp/hr/yr)	TWC/PW Volume Proportion	TWC Fuel Use	TWC Power Requirements (hp-hr/yr)
Option 1:						
• Major Pass Dischargers	Diesel	32,107 gal/yr	486,471	0.000439	14.10 gal/yr	213.67
	Natural Gas	7.07 MMscf/yr	744,267	0.000439	0.0031 MMscf/yr	326.90
• General Permit Facilities	Diesel	19,328 gal/yr	292,850	0.000331	6.39 gal/yr	96.82
	Natural Gas	507.79 MMscf/yr	53,451,602	0.000331	0.168 MMscf/yr	17,671.85
Option 2:						
• All Medium/Large Facilities	Diesel	19,328 gal/yr	292,850	0.000399	7.71 gal/yr	116.85
	Natural Gas	507.79 MMscf/yr	53,451,602	0.000399	0.203 MMscf/yr	21,328.10

(a) Values for Major Pass Dischargers under Option 1 are from Table XIII-10. Values for General Permit Facilities under Option 1 and all Medium/Large Facilities under Option 2 are from Table XIII-13.

TABLE XIII-26

SMALL FACILITY ENERGY REQUIREMENTS FOR NEW SOURCES OF TWC FLUIDS

Facility Type	TWC Volume (bbl/yr)	Fuel Requirements (gal/yr)			
		Barge	Truck	Auxiliary Equipment	Total
Water-Access	4,109	5,600	0	144	5,744
Land-Access	2,348	0	602	0	602

summarize the air emissions resulting from the transportation of TWC fluids to commercial facilities for disposal for existing and new small sources, respectively.

TABLE XIII-27

FUEL CONSUMPTION AND UNCONTROLLED AIR EMISSIONS FOR EXISTING SOURCES

Industry Segment	Total Diesel Fuel Use (gal/yr)	Total Natural Gas Use (MMscf/yr)	NO_x Total (tons/yr)	THC Total (tons/yr)	SO_2 Total (tons/yr)	CO Total (tons/yr)	TSP Total (tons/yr)	Total Air Emissions (tons/yr)
Option 1								
Major Pass Dischargers[a]	57.53	0.0127	0.0031	0.0083	0.0009	0.0053	0.0010	0.0466
General Permit Faciliites	46.14	1.2121	1.6970	0.6894	0.0010	0.2272	0.0008	2.6154
Small Water-Access	42,261	0	8.3178	0.3660	0.6032	1.6671	0.6976	11.6517
Small Land-Access	5,513	0	0.2728	0.0605	--	0.2072	--	0.5405
Total	**47,878**	**1.2248**	**10.3187**	**1.1242**	**0.6051**	**2.1068**	**0.6994**	**14.854**
Options 2 & 3								
Medium/Large Facilities[b]	58.74	1.543	2.1607	0.8778	0.0013	0.2892	0.0010	3.330
Small Water-Access	42,261	0	8.3178	0.3660	0.6032	1.6671	0.6976	11.6517
Small Land-Access	5,513	0	0.2728	0.0605	--	0.2072	--	0.5404
Total	**47,833**	**1.543**	**10.7513**	**1.3043**	**0.6045**	**2.1635**	**0.6986**	**15.522**

[a] Due to existing gas flotation systems, FRI and North Central permit no. 2184-003-1 are not included in the Option 1 analysis.

[b] For Options 2 and 3, all major pass facilities are included in the analyses.

TABLE XIII-28

FUEL CONSUMPTION AND UNCONTROLLED AIR EMISSIONS FOR NEW SOURCES

Industry Segment	Total Diesel Fuel Use (gal/yr)	Total Natural Gas Use (MMscf/yr)	NO_x Total (tons/yr)	THC Total (tons/yr)	SO_2 Total (tons/yr)	CO Total (tons/yr)	TSP Total (tons/yr)	Total Air Emissions (tons/yr)
Option 1								
Major Pass Dischargers	14.10	0.0031	0.0076	0.0020	0.0002	0.0013	0.0002	0.0113
General Permit Facilities	6.39	0.1679	0.2350	0.0955	0.0001	0.0315	0.0001	0.3622
Small Water-Access	5,744	0	1.1305	0.0497	0.0820	0.2266	0.0948	1.5836
Small Land-Access	602	0	0.0298	0.0066	--	0.0226	--	0.0590
Total	**6,367**	**0.171**	**1.4029**	**0.1538**	**0.0823**	**0.282**	**0.0951**	**2.0161**
Options 2 & 3								
Medium/Large Facilities	7.71	0.2026	0.2837	0.1152	0.0002	0.0380	0.0001	0.4372
Small Water-Access	5,744	0	1.1305	0.0497	0.0820	0.2266	0.0948	1.5836
Small Land-Access	602	0	0.0298	0.0066	--	0.0226	--	0.0590
Total	**6,354**	**0.2026**	**1.444**	**0.1715**	**0.0822**	**0.2872**	**0.0949**	**2.0798**

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CHAPTER XIV

OPTIONS SELECTION: RATIONALE AND TOTAL COSTS

1.0 INTRODUCTION

This section presents the options EPA selected for control of the coastal oil and gas wastestreams and a discussion of EPA's rationale for selecting the options which were chosen.

2.0 SUMMARY OF OPTIONS SELECTED AND COSTS

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

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

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

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

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

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

While coastal areas other than Alaska, California and the Gulf of Mexico are not specifically addressed throught this chapter or other sections of the Development Document, the zero discharge requirements of the effluent limitations guidelines and standards in the final rule were found to be technologically available and economically achievable in all coastal areas of the United States, and would result in acceptable non-water quality environmental impacts. The limitations for all wastestreams are presented in Tables XIV-1 through XIV-5.

TABLE XIV-1

BPT EFFLUENT LIMITATIONS PROMULGATED BY THIS RULE[a]

Pollutant Parameter Waste Source	Limitation
Produced Sand	No discharge

[a] Existing BPT limitations for other wastestreams are not changed by this final rule (see 40 CFR Part 435.42).

TABLE XIV-2

BAT EFFLUENT LIMITATIONS

Wastestream	Pollutant Parameter	Limitations
Drilling Fluids, Drill Cuttings and Dewatering Effluent		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Free Oil(1)	No discharge
	Diesel Oil	No discharge
	Mercury	1 mg/kg dry weight maximum in the stock barite
	Cadmium	3 mg/kg dry weight maximum in the stock barite
	Toxicity	Minimum 96-hour LC50 of the SPP shall be 3 percent by volume(2) (maximum test result of 30,000 ppm)
Produced Water		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l
Well Treatment, Workover and Completion Fluids		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l
Produced Sand		No discharge
Deck Drainage	Free Oil(3)	No discharge
Domestic Waste	Foam	No discharge

(1) As determined by the static sheen test (see Appendix 1 to 40 CFR Subpart A).
(2) As determined by the toxicity test (see Appendix 2 of 40 CFR Subpart A).
(3) As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).

TABLE XIV-3

BCT EFFLUENT LIMITATIONS

Wastestream	Pollutant Parameter	Limitations
Drilling Fluids, Drill Cuttings and Dewatering Effluent		
A) All facilities except Cook Inlet		No discharge
B) Cook Inlet	Free Oil	No discharge(1)
Produced Water (all facilities)	Oil and Grease	The maximum for any one day shall not exceed 72 mg/l, and the 30-day average shall not exceed 48 mg/l
Well Treatment, Workover and Completion Fluids		
A) All facilities except fresh water locations in TX and LA	Free Oil	No discharge(1)
B) Fresh water locations in TX and LA		No discharge
Produced Sand		No discharge
Deck Drainage	Free Oil	No discharge(2)
Sanitary Waste		
Sanitary M10	Residual Chlorine	Minimum of 1 mg/l maintained as close to this concentration as possible
Sanitary M9IM	Floating Solids	No discharge
Domestic Waste	Floating Solids and Garbage	No discharge of floating solids or garbage(3)

(1) As determined by the static sheen test (see Appendix 1 to 40 CFR Subpart A).
(2) As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
(3) As defined in 40 CFR § 435.41.

TABLE XIV-4

NSPS EFFLUENT LIMITATIONS

Wastestream	Pollutant Parameter	NSPS Limitations
Drilling Fluids, Drill Cuttings and Dewatering Effluent		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Free Oil(1) Diesel Oil Mercury Cadmium Toxicity	No discharge No discharge 1 mg/kg dry weight maximum in the stock barite 3 mg/kg dry weight maximum in the stock barite Minimum 96-hour LC50 of the SPP shall be 3 percent by volume(2) (maximum test result of 30,000 ppm)
Produced Water		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l
Well Treatment, Workover and Completion Fluids		
A) All coastal areas except Cook Inlet		No discharge
B) Cook Inlet	Oil and Grease	The maximum for any one day shall not exceed 42 mg/l, and the 30-day average shall not exceed 29 mg/l
Produced Sand		No discharge
Deck Drainage	Free Oil(3)	No discharge
Sanitary Waste		
Sanitary M10	Residual Chlorine	Minimum of 1 mg/l and maintained as close to this concentration as possible.
Sanitary M9IM	Floating Solids	No discharge
Domestic Waste	Floating Solids, Garbage(4) and Foam	No discharge of floating solids or garbage or foam

(1) As determined by the static sheen test (see Appendix 1 to 40 CFR Subpart A).
(2) As determined by the toxicity test (see Appendix 2 of 40 CFR Subpart A).
(3) As determined by the presence of a film or sheen upon or a discoloration of the surface of the receiving water (visual sheen).
(4) As defined in 40 CFR § 435.41.

TABLE XIV-5

PSNS AND PSES EFFLUENT LIMITATIONS

Wastestream	PSNS and PSES Limitations
Drilling Fluids, Drill Cuttings and Dewatering Effluent	No discharge
Produced Water	No discharge
Well Treatment, Workover and Completion Fluids	No discharge
Produced Sand	No discharge
Deck Drainage	No discharge

3.0 OPTION SELECTION RATIONALE

3.1 DRILLING FLUIDS, DRILL CUTTINGS AND DEWATERING EFFLUENT

3.1.1 BAT and NSPS

EPA is establishing BAT and NSPS limitations that require zero discharge of drilling fluids, drill cuttings, and dewatering effluent (drilling wastes), except in Cook Inlet, Alaska. For BAT and NSPS in Cook Inlet, discharge limitations include no discharge of free oil, no discharge of diesel oil, 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation of 30,000 ppm in the suspended particulate phase (SPP). BAT and BCT limitations for dewatering effluent are applied prospectively. BAT and BCT limitations in this rule are not applicable to discharges of dewatering effluent from reserve pits which as of the effective date of the coastal guidelines no longer receive drilling fluids and drill cuttings. Limitations on such discharges shall be determined by the NPDES permit issuing authority. BAT and BCT limitations are applicable to dewatering effluent from reserve pits which receive drilling wastes after the effective date of the coastal guidelines.

In the 1995 proposal, EPA presented three options for both BAT and NSPS limitations. The three options were: (1) Zero discharge of drilling fluids, drill cuttings, and dewatering effluent except for Cook Inlet, where discharge limitations include no discharge of free oil, no discharge of diesel oil, 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation of 30,000 ppm; (2) Zero discharge of drilling fluids, drill cuttings, and dewatering effluent except for Cook Inlet, where discharge limitations include no discharge of free oil, no discharge of diesel oil, both 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation in range of 100,000 ppm to 1 million ppm; and (3) Zero discharge everywhere. The control option including the more stringent toxicity limitation was based, in part, on the volume of drilling wastes that could be injected or disposed of onshore without interfering with ongoing drilling operations. The more stringent toxicity limit would have been based on (1) the volume of drilling wastes that could be subjected to zero discharge without interfering with ongoing drilling operations and (2) a specified level of toxicity selected such that no more than this volume of waste, determined in the previous step, would exceed the specified level of toxicity. However, as pointed out in comments on the proposal and confirmed with further investigation, there are a number of problems with the database that would be used to establish a more stringent toxicity limitation. Many of the records in the database do not have either a waste volume identified or indicate whether the drilling fluids were discharged. Where waste volumes are reported, the methods used to determine these volumes are not consistent and they are not documented. It is also unclear whether the volumes and fluid systems reported for any given well represent a complete record of the drilling activity associated with the well. For these reasons, EPA rejected the option of developing a more stringent toxicity limitation for the final rule.

Following elimination of the more stringent toxicity limitation, EPA's analyses for the final rule considered two options for the BAT and NSPS level of control for drilling fluids, drill cuttings and dewatering effluent. (In the discussion of limitations for drilling wastes in this chapter and elsewhere in the Development Document, the limitations discussed for drilling fluids and drill cuttings also apply to dewatering effluent.)

Under Option 1 for the final rule, BAT and NSPS would require zero discharge of drilling fluids and drill cuttings for all coastal drilling operations except those located in Cook Inlet. Allowable discharge limitations for drilling fluids and cuttings in Cook Inlet would require compliance with a toxicity value of no less than 30,000 ppm; no discharge of free oil (as determined by the static sheen test); no discharge of diesel oil; and a maximum of 1 mg/kg of mercury and 3 mg/kg of cadmium in the stock barite. Limitations for Cook Inlet are identical to the limitations applicable to offshore discharges in Alaska. Option 1 was developed taking into consideration that Cook Inlet operations are unique to the industry due to a combination of geology available for grinding and injection, climate, transportation logistics, and structural and space limitations that interfere with drilling operations. Operators would not incur any incremental costs, nor are there any incremental pollutant reductions or non-water quality environmental impacts due to the coastal guidelines under Option 1 because the requirements reflect current practice.

Under Option 2 for the final rule, BAT and NSPS would prohibit the discharge of drilling fluids and drill cuttings from all coastal oil and gas drilling operations. In Cook Inlet, for reasons discussed below, this option uses onshore disposal as the basis for complying with zero discharge of drilling fluids and drill cuttings. Outside of Cook Inlet, this option uses a combination of grinding and injection and onshore disposal as a basis for complying with zero discharge of drilling fluids and drill cuttings. Costs to comply with Option 2 (zero discharge all) are attributed only to Cook Inlet operators. Costs to comply with BAT zero discharge limits are estimated to be approximately $8,200,000 annually for the Cook Inlet operators. The BAT limitations would remove approximately 24,089,000 pounds/year of conventional pollutants, 1,194,000 pounds/year of nonconventional pollutants, and 4,300 pounds/year of priority pollutants. Non-water quality environmental impacts due to zero discharge under BAT include 5,200 barrels of oil equivalent (BOE) of fuel being used annually, resulting in approximately 72,000 pounds/year of air emissions (see Chapter X for a discussion of pollutant reductions and costs associated with the control options; non-water quality environmental impacts are discussed in Chapter XIII).

EPA has identified no incremental costs, pollutant reductions, or non-water quality environmental impacts attributable to the zero discharge NSPS requirements under Option 2 of the coastal guidelines. In the absence of the NSPS being promulgated in the coastal guidelines, all new coastal facilities outside Cook Inlet would be expected to comply with existing NPDES or State zero discharge requirements. Based on information available in the record, EPA projects that no new sources will be developed in Cook Inlet and thus no costs would be attributable to NSPS requirements for drilling wastes. This is because all future development wells are expected to be drilled from existing platforms in Cook Inlet. According to the definition of new sources, these wells would be existing sources. Additionally, any drillings that may occur in the recently discovered Sunfish formation or other areas identified by industry in Cook Inlet are projected to be exploratory wells, which are also existing sources according to the new source definition. Thus, no costs are attributed to NSPS in Cook Inlet. (Nonetheless, EPA did conservatively assess the costs and economic impacts that would be attributed to NSPS should a new source be developed in Cook Inlet. EPA determined that the costs to meet zero discharge would not pose a barrier to entry for the drilling project; however, as described below there are technical problems associated with any individual new source meeting zero discharge. The analysis of NSPS costs for a model new source platform in Cook Inlet is discussed in the Economic Impact Analysis[1] and Chapter X of the Development Document.)

In the final rule, EPA is establishing BAT and NSPS limitations described above for Option 1, which requires zero discharge for drilling fluids, drill cuttings and dewatering effluent, except in Cook Inlet. In Cook Inlet, discharge limitations include no discharge of free oil, no discharge of diesel oil, both 1 mg/kg mercury and 3 mg/kg cadmium limitations on the stock barite, and a toxicity limitation of 30,000 ppm. With regard to coastal facilities outside of Cook Inlet, zero discharge is technically and economically achievable because it reflects current industry practices under existing permit requirements.

With regard to coastal facilities in Cook Inlet, EPA rejected zero discharge in large part because the technology of grinding and injection has not been demonstrated to be available throughout Cook Inlet, and because of operational interferences that would result if operators were required to haul all drilling wastes to shore for disposal.

Drilling fluids and drill cuttings can not be injected into producing formations, as is sometimes the case for produced water, because they would interfere with hydrocarbon recovery. The high solids content of these wastes would plug the formation and impede subsurface fluid flow. Thus, operators must have available different formation zones with appropriate characteristics (e.g., porosity and permeability) for injection of drilling fluids and drill cuttings (see Chapter VII for a discussion of geologic characteristics for the injection of these drilling wastes). Unlike the coastal region along the Gulf of Mexico or the North Slope of Alaska, where the subsurface geology is relatively porous and formations for injection are readily available, the geology in Cook Inlet is highly fragmented and information in the record indicates that formations amenable to injection may not be available throughout Cook Inlet.[2,3] EPA reviewed information where attempts to grind and inject drilling fluids and drill cuttings failed in the Cook Inlet area. For example, one operator attempted to operate a grinding and injection well in the Kenai gas field that failed due to downhole mechanical failure of the injection well (1992/1993).[2,3] There, the well experienced abnormal pressure on the well annulus, necessitating shutdown of the disposal operation. The operator also attempted annular pumping of drilling fluids and drill cuttings in two production wells in the Ivan River Field (onshore on the west side of Cook Inlet) where the annuli of both wells plugged during injection.[4] Another operator, attempting to pump drilling waste into the annuli of exploration wells, lost the integrity of the well.[3] In view of these difficulties encountered in injecting drilling wastes and the limited data available to date, EPA is unable to estimate the degree to which injection would be available in Cook Inlet and believes that the information in the record indicates that certain sites in Cook Inlet may not be able to inject sufficient volumes of drilling wastes to enable compliance with zero discharge.

Because not all of the drilling fluids and drill cuttings can be injected, much of the waste would have to be land disposed. The sole land disposal site for drilling wastes in Cook Inlet (referred herein as the Kustatan landfill) is a private facility owned by two of the operators. While no regulatory obstacles would prohibit disposing of the wastes from other operators at the Kustatan landfill, since it is a private facility its availability for use by third parties cannot be assured. As a result, EPA's analysis considers the Kustatan landfill to be available for use by only two of the operators in the region. Since no other land disposal facilities in Alaska are believed available to the remaining Cook Inlet operators, land disposal costs for these operators are based on transporting the drilling wastes to a disposal facility in Oregon. (EPA is unaware of any other land disposal facilities coming into existence in Cook Inlet, as Cook Inlet is a fairly mature field nearing the end of its useful life. All but one of the existing platforms were installed in the 1960s. The newest platform began production in 1987, but production from the facility has remained well below expectations.) Land disposal is a problem for Cook Inlet operators, analogous to those faced by offshore operators in Alaska, because the climate and safety conditions that exist during parts of the year in Cook Inlet make transportation of drilling fluids and drill cuttings particularly difficult and hazardous. The harsh climate, snow, ice, and poor visibility from fog and snow often restrict land and sea transportation. Also, the extensive tidal fluctuations (typically near, and frequently in excess of, 30 feet), strong currents affecting waste transfer operations between the platforms and boats (on the order of 6-9 knots in the vicinity of platforms), and ice formation during winter months in the Inlet impose severe logistical difficulties for storing and transporting the drilling wastes (see Chapters VII and X for a discussion of tides, currents and climatological factors affecting waste transfer operations and navigation in Cook Inlet).

Moreover, the limited storage space on platforms and transportation-related difficulties and delays associated with a zero discharge limitation for all drilling wastes would impose severe operational constraints on drilling activities. Under current NPDES permit requirements (which are the same as the requirements for Option 1), the volumes of drilling wastes which cannot be discharged are sufficiently small to allow operators flexibility to schedule removal of the wastes from the platform in a manner which minimizes operational impacts. That is, the waste volumes requiring transport to shore generally are small enough in comparison to the available storage space on the platform to allow operators to hold the drilling wastes long enough to schedule waste removal in a manner that minimizes drilling interruptions (e.g., can conduct waste transfer evolutions during periods of slack tide and avoid severe fog and other weather conditions). However, under a zero discharge scenario where all drilling wastes are taken to shore for disposal, the rate of waste generation is large enough (relative to the platform storage capacity of 12 cuttings boxes) that frequent boat trips are required at certain phases of the drilling operation. Over the first fifty days of drilling, wastes must be transferred to boats an average of every 1-2 days, and more often at certain stages when drill cuttings are generated at high rates.[5]

The required frequency of boat trips makes it difficult to avoid the effects of large tidal ranges, current action (especially during peak flood and ebb tides when the boats must remain on station next to fixed platforms while countering 6-9 knot currents and wave action), ice, fog and other climatological conditions such as snow and high winds. Currents in Cook Inlet narrows have average speeds of more than 8.5 knots and 6 knot currents at East Foreland are common. Currents are highest during peak ebb and flow tides, and the slack tide (the time in between ebb and flow tides, when the currents are relatively slow) is brief. High waves are common in this area and localized rip currents where the current is extremely fast are not unusual in Cook Inlet.[6]

Due to ocean currents and wave action, boats must maintain engines idling while at platforms unloading empty cuttings boxes and loading drilling fluids and boxes. The total average time idling on station at the drill site for loading is 4.15 hours per visit.[7] As a result, it is likely that a zero discharge requirement for all drilling wastes in Cook Inlet could interfere with operations to the extent that drilling would be periodically halted due to the inability to remove drilling wastes from the platform expeditiously. Thus, for purposes for BAT and NSPS, EPA does not believe that land disposal of all drilling wastes is generally available for Cook Inlet operators. These same operational constraints hindering land disposal of large drilling waste volumes would also apply in the case of operators being required to haul all drillings to shore locations where subsurface injection of drilling wastes may be available.

There are non-water quality environmental impacts associated with a zero discharge limitation for Cook Inlet, as discussed above. While EPA believes the non-water quality environmental impacts -- in and of themselves -- are not unacceptable, by comparison with the operational constraints discussed above and pollutants removed by zero discharge (4,300 pounds of toxic pollutants annually), these non-water quality environmental impacts weigh against requiring zero discharge in Cook Inlet.

The NSPS requirements selected for the final rule, both inside and outside of Cook Inlet, are technically and economically achievable because they reflect current practice. With regard to the potential for a barrier to entry, NSPS are equal to BAT limitations. BAT limitations have been demonstrated to be economically achievable for existing structures. Design and construction of pollution control equipment on new production facilities is generally less expensive than retrofitting existing facilities. Therefore, while the NSPS are equal to BAT limitations, it is less costly for new structures to meet these requirements and these costs would not inhibit development of new sources. Costs for new sources are generally less than BAT because process modifications can be incorporated into the drilling rig design prior to its installation rather than retrofitting an existing operation. Since EPA has determined that BAT is economically achievable, equivalent NSPS requirements would also be economically achievable, and cause no barrier to entry.

3.1.2 BCT

With the exception of Cook Inlet, BCT limitations require zero discharge of drilling fluids, drill cuttings, and dewatering effluent. In Cook Inlet, BCT limitations prohibit the discharge of free oil.

Because all operators throughout the coastal subcategory, except in Cook Inlet, are currently practicing zero discharge of drilling fluids and drill cuttings and dewatering effluent, zero discharge was the only option considered for coastal areas outside Cook Inlet. Since zero discharge reflects current practice, there are no incremental costs, pollutant reductions, or non-water quality environmental impacts associated with this limitation. Thus, EPA has determined that zero discharge passes the BCT cost tests and other statutory factors and is establishing the BCT limitation equal to zero discharge for all areas except Cook Inlet.

In Cook Inlet, EPA considered two options for BCT control: (1) setting BCT equal to the BPT limits prohibiting discharges of free oil; and (2) zero discharge. As discussed above for BAT, EPA determined that zero discharge of all drilling wastes in Cook Inlet is not technologically available. The costs, pollutant reductions, and the results of the BCT cost test calculations are presented in Chapter X for informational purposes. There are no incremental costs, pollutant reductions, or non-water quality environmental impacts associated with the BCT "no free oil" limitation for Cook Inlet because it is equal to current BPT requirements.

3.1.3 Pretreatment Standards for Drilling Wastes

EPA develops pretreatment standards for existing sources (PSES) under Section 307(b) of the Clean Water Act (CWA). Pretreatment standards are designed to prevent the discharge of the pollutants that pass through, interfere with, or are otherwise incompatible with the operation of publicly owned treatment works (POTWs). PSES are technology-based and analogous to the best available technology economically achievable (BAT) for direct dischargers. Section 307(c) of the CWA requires EPA to promulgate pretreatment standards for new sources (PSNS) at the same time that it promulgates new source performance standards (NSPS). PSNS are technology-based and analogous to the best demonstrated control technology (BADCT) for direct dischargers. New indirect discharging facilities, like new direct discharging facilities, have the opportunity to install the best available demonstrated technology, including process changes, in-plant controls, and end-of-pipe treatment technologies.

EPA determines whether or not to regulate a pollutant under pretreatment standards on the basis of whether or not the pollutant passes through, interferes with, or is incompatible with the operation of the POTW. EPA evaluates pollutant pass through by comparing the average percentage removed nationwide by well-operated POTWs (those meeting secondary treatment requirements) with the percentage removed by directly discharging facilities applying BAT for that pollutant. When the average percentage removed by well-operated POTWs is less than the percentage removed applying BAT, the pollutant is said to pass through and a pretreatment standard would be required. When the pollutant does not pass through (average percentage removed by well-operated POTWs is greater than the percentage removed by applying BAT) a pretreatment standard would not be required. To the extent that BAT and NSPS require zero discharge under the coastal guidelines, any pretreatment standard which allows discharge of the wastestream would be allowing toxic pollutants to pass through because biological treatment will not achieve complete pollutant removal.

The general pretreatment regulations, applicable to existing and new source indirect dischargers (PSES and PSNS) are codified at 40 CFR Part 403. These regulations describe the Agency's overall policy for establishing and enforcing pretreatment standards for new and existing users of a POTW as well as the prohibited discharges that apply.

Based on comments, the 1993 Coastal Oil and Gas Questionnaire, and other information reviewed as part of this rulemaking, EPA has not identified any existing coastal oil and gas facilities which discharge drilling fluids and drill cuttings to POTWs, nor are any new facilities projected to direct these wastes in such manner. However, due to the high solids content of drilling fluids and drill cuttings, EPA is establishing pretreatment standards for existing and new sources in all coastal areas equal to zero discharge because these wastes are incompatible and would interfere with POTW operations. Certain constituents present in drilling wastes can exhibit effluent toxicity and would be expected to further interfere with POTW operations. In addition, the high solids content of the wastes would likely cause obstruction to the flow in the POTW resulting in interference with POTW operations due to the high total suspended solids (TSS) content which could not only cause clogging in the piping leading into the POTW, but interfere with the biological treatment systems as well. And as stated in 40 CFR Part 403.5 "National Pretreatment Standards: Prohibited discharges": Solid or viscous pollutants in amounts which will cause obstruction to the flow in the POTW resulting in interference shall not be introduced into POTWs. This can occur with drilling fluids and drill cuttings due to the high solids content (pollutants found in drilling fluids and drill cuttings are listed in Chapter VII).

Further, where BAT and NSPS limitations require zero discharge, these limits result in complete removal of toxic pollutants. Any pretreatment standard allowing discharge after biological treatment at a POTW (which would not accomplish 100 percent removal of toxic pollutants) would effectively allow pass through of toxic pollutants to surface waters. For PSNS, zero discharge would not cause a barrier to entry.[1]

3.2 PRODUCED WATER AND TREATMENT, WORKOVER AND COMPLETION FLUIDS

3.2.1 Summary of Produced Water and TWC Requirements

EPA is establishing BAT and NSPS limitations prohibiting discharges of produced water and treatment, workover and completion (TWC) fluids from all coastal facilities, except for those facilities located in Cook Inlet. Coastal facilities in Cook Inlet are required to comply with oil and grease limitations (29 mg/l monthly average; 42 mg/l daily maximum) based on improved operating performance of gas flotation. EPA has determined the limitations are economically achievable and technologically available, and they reflect the BAT and BADCT (NSPS) levels of control.

EPA has reviewed the extensive information compiled during the coastal and offshore guidelines rulemaking efforts regarding treatment practices for TWC fluids. Based on industry responses to the 1993 Coastal Oil and Gas Questionnaire and other information in the record, including site visit reports and other industry contacts, EPA has determined that, in the coastal subcategory, TWC fluids are generally commingled with produced water, especially where the proportion of produced water to TWC fluids is high enough to overcome any interference the TWC fluids may have on the produced water treatment system. The rulemaking record also demonstrates that where TWC fluids are not currently commingled, they can be effectively commingled with produced water and be discharged in compliance with the NSPS and BAT limits of the coastal guidelines if the treatment equipment is operated properly and TWC fluids introduced to the system in a prudent manner. In view of this information, EPA is establishing limitations for TWC fluids equivalent to produced water limitations.

3.2.2 Options Considered

Three options were considered in the final rule for BAT and NSPS control of produced water and TWC fluids. The costs, pollutant reductions, and non-water quality environmental impacts associated with these options are presented in Chapters XI, XII, and XIII.

Option 1 - (Zero Discharge; Except Major Deltaic Pass and Cook Inlet Based On Improved Gas Flotation): With the exception of facilities in Cook Inlet and facilities discharging offshore produced water into the coastal subcategory waters of a major deltaic pass of the Mississippi River or the Atchafalaya River below Morgan City, all coastal oil and gas facilities and all facilities discharging offshore produced water into coastal locations would be prohibited from discharging produced water and treatment, workover, and completion fluids. Coastal facilities in Cook Inlet and facilities discharging offshore produced water into a major deltaic pass would be required to comply with oil and grease limitations of 29 mg/l monthly average and 42 mg/l daily maximum based on improved performance of gas flotation.

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

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

3.2.3 Rationale for Selection of BAT for Produced Water and TWC Fluids

3.2.3.1 BAT Rationale for Coastal Subcategory (Except Cook Inlet)

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

Zero discharge of produced water and TWC fluids is technically available. Zero discharge of produced water has been required of onshore facilities since EPA promulgated BPT regulations for the onshore subcategory of the oil and gas industry in 1979. 40 CFR Part 435 Subpart C (44 FR 22069; April 13, 1979). With the exception of Cook Inlet, injection of produced water is widely practiced by facilities in the coastal subcategory. Independent of this rule, all coastal facilities in Alabama, California, Mississippi, Florida, and the North Slope of Alaska are currently practicing zero discharge. EPA estimates that at least 80% to 99.9% of all coastal facilities in Louisiana and Texas will be practicing zero discharge by January 1, 1997. The 80% estimate is based on subtracting the sum of the six facilities discharging into a major deltaic pass of the Mississippi, the 37 facilities (82 outfalls) discharging to Louisiana open bays, and the 82 facilities associated with individual permit applications in Texas from the 853 total coastal facilities in Louisiana and Texas. The 99.9% estimate is based on subtracting the number of facilities discharging into a major deltaic pass of the Mississippi from the total number coastal facilities along Louisiana and Texas. Additionally, using data from the Coastal Oil and Gas Questionnaire and other information regarding facilities known to be discharging in 1992, EPA estimated that 62% of coastal facilities along the Gulf of Mexico were practicing zero discharge in 1992. For the onshore subcategory, injection is the predominant technology used to comply with the zero discharge BPT limitation promulgated in 1979.

Some coastal operators have voluntarily upgraded to zero discharge technologies while other coastal operators have been subject to consent decrees requiring zero discharge in citizen suits filed by environmental groups. In the western Gulf of Mexico, coastal dischargers are covered by the current general permits which require zero discharge, but these facilities also have an administrative order allowing until January 1997 to come into compliance with zero discharge. Formations appropriate for injection of produced water have been demonstrated to be available for coastal facilities in the Gulf of Mexico.

In response to comments that operators discharging offshore produced water into a major deltaic pass of the Mississippi should not be subject to zero discharge, EPA closely examined these facilities.

However, EPA has identified no basis for providing these facilities with limitations other than those established for the coastal subcategory outside of Cook Inlet. Injection has been widely demonstrated in practice as available to coastal facilities in states along the Gulf Coast, including facilities discharging coastal-derived produced water that are near these facilities discharging offshore-derived produced water.

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

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

For individual permit applicants in Texas and Louisiana open bay dischargers, a total of up to 94 wells may be first year shut-ins under zero discharge. Individual permit applicants in Texas and Louisiana open bay dischargers are considered to have financial impacts only under the alternative baseline. These wells are approximately 2 percent of all Gulf of Mexico coastal wells. EPA estimates related production losses would be approximately 12.8 million BOE. This represents less than one percent of all Gulf coastal production, most of which is in compliance with zero discharge requirements. A maximum of 1 firm among the Louisiana open bay dischargers and 3 firms among the individual permit applicants from Texas could fail as a result of the proposed regulatory options. However, EPA's modeling tends to overestimate economic impacts and firm failures, since these models project that some currently operating firms have already failed. These potential failures represent less than one percent of all Gulf of Mexico coastal firms. EPA also did a facility-level analysis, conducted in response to facility-level information received from Texas very late in the rulemaking, that shows fewer wells are baseline failures and fewer wells fail due to the costs of this rule because wells combine efforts for treatment and production. EPA views the small percentage loss of BOE and profitability, coupled with the determination of a small number of firm closures, to meet the definition of economic achievability under the CWA.

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

3.2.3.2 BAT Rationale for Cook Inlet

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

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

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

EPA's economic analysis shows a disproportionate impact of zero discharge on Cook Inlet as compared with the rest of the coastal subcategory. EPA projects that zero discharge requirements for Cook Inlet would close 1 of the 13 existing production platforms and result in the loss of 108 jobs in the oil and gas industry in Cook Inlet. In addition, there are severe economic impacts on two additional platforms that were projected to fail at proposal. These disproportionate impacts are demonstrated by a loss in net present value in Cook Inlet of 18.5 percent as compared to only 1.4 percent in the Gulf coast under the current requirements baseline. In addition, there are disproportionate impacts in Cook Inlet with regard to employment, where Cook Inlet already suffers from unemployment higher than the national average and higher than the rest of the coastal subcategory. The most recently reported (1991) unemployment rate in Cook Inlet is 12.7 percent, as compared with the unemployment rate in the Gulf coast of 6.2 to 6.4 percent and the national unemployment rate of about 5.2 percent. The loss of 108 jobs that would occur in Cook Inlet from zero discharge would raise the unemployment level in Cook Inlet 0.5 percent, to 13.2 percent. Thus, zero discharge would worsen the serious unemployment situation that exists in Cook Inlet. Because Cook Inlet is economically and geographically isolated and the economic effects of zero discharge in Cook Inlet are significant and disproportionately worse than they are in the rest of the subcategory, EPA rejects zero discharge in Cook Inlet as not economically achievable.

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

The non-water quality environmental impacts of improved gas flotation, discussed in Chapter XIII, are acceptable.

3.2.4 NSPS Rationale for Produced Water and TWC Fluids

For NSPS control of produced water and treatment, workover, and completion fluid discharges from new sources, EPA is establishing the limitations associated with "Option 2 - Zero Discharge; Except Cook Inlet Based On Improved Gas Flotation." Zero discharge for Cook Inlet was rejected because of uncertainties regarding the availability of geologic formations suitable for receiving injected produced water. Information in the record indicates that a potential new source in Cook Inlet could be unable to inject adequate produced water volumes near the new source. (See the discussion in Chapter XI which notes that the geology below the Trading Bay Production Facility is inadequate for subsurface disposal of produced water. For existing sources in Cook Inlet, because of uncertainties related to Cook Inlet geology, EPA assumed that compliance with zero discharge would be met through injection into the highly depleted production formations that are currently being waterflooded with seawater.) As a result, the new source could be faced with the substantial expenses associated with piping the produced water to a location (the distance of which is unknown at this time) where suitable geology would be available.

Option 2 is economically achievable for the reasons discussed below and in the Economic Impact Analysis.[1] The selected option for NSPS is equal to the selected BAT option for produced water and TWC fluids. The BAT option has been demonstrated to be technologically available and economically achievable for existing structures. Design and construction of pollution control equipment on new production facilities is generally less expensive than retrofitting existing facilities. Therefore, while the NSPS requirements are equal to the BAT requirement, it is less costly for new structures to meet these requirements and these costs would not inhibit development of new sources. EPA has determined the non-water quality environmental impacts (presented in Chapter XIII) to be acceptable for the selected NSPS option for control of produced water and TWC fluids.

EPA has identified no new sources of produced water discharges incurring costs due to the NSPS requirements of the coastal guidelines. In the absence of NSPS promulgation under the coastal guidelines, due to currently existing state and NPDES permit requirements, all new facilities in coastal areas, except Cook Inlet, would be considered new dischargers subject to existing zero discharge requirements for produced water. No new sources discharging offshore subcategory produced water into the major passes of the Mississippi River or to the Atchafalaya River are projected. Based on information in the record, EPA also projects that no new sources will be developed in Cook Inlet. Accordingly, EPA has identified no costs attributable to the NSPS requirements for produced water in the coastal guidelines. (EPA did identify costs associated with new source discharges of TWC fluids. The costs and pollutant reductions for these discharges are presented in Chapter XII. Non-water quality environmental impacts are discussed in Chapter XIII. Economic impacts are presented in the "Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category."[1]) Nevertheless, EPA assessed the costs and economic impacts incurred by a model new source facility under the zero discharge scenario should conditions and future information lead to development of new sources in Cook Inlet. For the modeled scenario, EPA based costs on injecting produced water near the new source facility. However, because of the uncertainties regarding availability of formations suitable for injection, it is possible that a new source structure would incur some unknown cost for piping the produced water to a suitable injection location. Since the location and availability of formations for any new source in Cook Inlet are unknown, the maximum cost associated with piping produced water from the wellhead to the nearest injection well cannot be estimated.

3.2.5 BCT for Produced Water and TWC Fluids

All options considered failed the BCT cost tests (See discussion in Chapter XI.) Therefore, EPA is establishing BCT limitations for produced water equal to the existing BPT limitations for oil and grease (48 mg/l monthly average; 72 mg/l daily maximum). Limitations for treatment, workover, and completion fluids are established equal to existing BPT and NPDES permit limitations which require zero discharge of TWC fluids in fresh water in Texas and Louisiana, and no discharge of free oil in all other coastal locations. The BCT limitations reflects existing discharge practices current permit requirements. There are no incremental costs, pollutant reductions, or non-water quality environmental impacts associated the BCT limitations because they reflect current discharge practices.

3.2.6 Pretreatment Standards for Produced Water and TWC Fluids

EPA is establishing pretreatment standards for existing and new sources (PSES and PSNS, respectively) that prohibit the discharge of produced water and treatment, workover, and completion fluids. There are no incremental costs, pollutant reductions, or non-water quality environmental impacts associated with the PSES and PSNS requirements. Thus, EPA has determined that PSES and PSNS are economically achievable and technologically available.

Based on the 1993 Coastal Oil and Gas Questionnaire and other information reviewed as part of this rulemaking, EPA has not identified any existing coastal oil and gas facilities which discharge produced water or treatment, workover, and completion fluids to POTWs, nor are any new facilities projected to direct their discharges of produced water and TWC fluids in such manner. (It should also be noted that most coastal facilities are not in locations amenable to sewer hookup.) However, because EPA is establishing a limitation requiring zero discharge for existing facilities, there is the potential that some facilities may consider discharging to POTWs in order to circumvent the BAT and /or NSPS limitations. Pretreatment standards for produced water and treatment, workover, and completion fluids are appropriate because EPA has identified the presence of a number of toxic and nonconventional pollutants, many of which are incompatible with the biological removal processes at POTWs. Large concentrations of dissolved solids in the form of various salts in the produced water and TWC fluids discharge are generally incompatible with the biological treatment processes at POTWs because these "brines" (and certain constituents in these wastes) can be lethal to the unacclimated organisms present in the POTW biological treatment systems. (See Chapter VIII for detailed information on produced water characterization. See Chapter IX for characteristics of TWC fluids. Certain constituents present in these wastes can exhibit effluent toxicity and would be expected to further interfere with POTW operations.) While it is possible that an acclimated biological treatment system under relatively constant pollutant load and wastewater flow may be capable of treating produced water discharges containing relatively low concentrations of total dissolved solids, such a situation would not be typical of that generally faced at coastal production facilities. It is uncommon for this industry to discharge produced water effluent at the nearly constant concentrations and flow rate that would be necessary for a biological treatment system to work properly. Variations in flow and pollutant concentrations exist, and production processes may cease periodically for a short time to rework and maintain the well. Major interruptions could occur as a result, causing interferences with the operation of POTWs.

Although there are no coastal subcategory facilities discharging produced water to POTWs, EPA is aware of some onshore subcategory discharges of produced water to POTWs. In these instances, the produced water comprises a very small proportion of the total wastewater flow received by the POTW, on the order of less than 0.5 percent. This level of dilution minimizes the adverse impacts on the POTWs. Except for one POTW, the POTWs discharge into the ocean where effluent limits for the POTW are less stringent than in inland surface waters. The POTW discharging to inland receiving waters has experienced difficulties in the past (exceeding NPDES discharge limitations) due to the high total dissolved solids (TDS) level in the POTW effluent. The high TDS level in the POTW effluent was attributed to the produced water.[8]

Further, in those locations where BAT require zero discharge, the BAT limitation results in complete removal of toxic pollutants. Any pretreatment standard allowing discharge after biological treatment at a POTW (which would not accomplish 100 percent removal of toxic pollutants) would effectively allow pass through of toxic pollutants to surface waters. For PSNS, zero discharge would not cause a barrier to entry.[1] Design and construction of pollution control equipment on new production facilities is generally less expensive than retrofitting existing facilities. Therefore, while the PSNS requirements are equal to the PSES requirement, it is less costly for new structures to meet these requirements and these costs would not inhibit development of new sources.

3.3 DECK DRAINAGE

EPA is establishing BCT, BAT and NSPS limitations which prohibit discharges of free oil. Since free oil discharges are already prohibited under existing BPT requirements, there are no incremental compliance costs, pollutant removals, or non-water quality environmental impacts associated with the limitations promulgated in the final rule. Since there are no incremental compliance costs, the BCT limitation passes the BCT cost tests. Also, since the limitations prohibiting discharges of free oil are equal to existing BPT standards, it is technologically available and economically achievable. EPA has determined that these limitations and standards properly reflect BAT and NSPS levels of control. EPA did not identify any other available technology for this waste stream.

EPA is requiring zero discharge of deck drainage for the entire coastal subcategory under PSES and PSNS. EPA believes that zero discharge for PSES and PSNS is appropriate because influent slugs of deck drainage would be expected to interfere with biological treatment processes at POTWs. Deck drainage, by its very nature, is contaminated with other process wastewaters from oil and gas operations and has the potential for interference and pass through of toxic pollutants, as described in Sections 3.1.3 and 3.2.6 above in this chapter for drilling wastes, produced water, and TWC fluids. EPA has identified no existing coastal subcategory facilities discharging deck drainage to POTWs, nor are any new source coastal facilities projected to do so. Moreover, technical difficulties associated with capture of deck drainage that make it difficult to require limitations other than the BPT prohibition on the discharge of free oil, as well as the fact that coastal facilities generally are not located in areas amenable to sewer hookup, makes it unlikely that this wastestream would be sent to POTWs. Thus, there are no incremental costs associated with the PSES and PSNS limitations.

At proposal, EPA considered establishing limitations based on commingling and treating deck drainage with produced water or drilling fluids. In such cases, the deck drainage would have become subject to the limitations imposed on these wastestreams. EPA also considered requiring facilities to implement best management practices (BMPs) as part of the deck drainage limitations. For the final rule, both of these options considered at proposal have been rejected. The commingling of deck drainage with produced water or drilling fluids is not a demonstrated technology, as discussed below. Promulgating BMPs in this rule would be redundant to the requirements of the "Final National Pollutant Discharge Elimination System Storm Water Multi-Sector General Permit for Industrial Activities" (60 FR 50804, September 29, 1995).

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

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

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

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

A requirement to implement BMPs for deck drainage is not included in the coastal guidelines. EPA believes that current industry practices, in conjunction with the requirements included in the previously mentioned general permit for storm water, are sufficient to minimize the introduction of contaminants from this wastestream to the extent possible. These storm water requirements require an oil and gas operator to develop and implement a site-specific storm water pollution prevention plan consisting of a set of BMPs depending on specific sources of pollutants at each site.

3.4 PRODUCED SAND

EPA is establishing BPT, BCT, BAT and NSPS equal to zero discharge for produced sand. Zero discharge is established as BPT because it reflects the average of the best existing performance by facilities in the coastal subcategory. Since BCT is established as equal to BPT, there is no cost of BCT incremental to BPT. Therefore, this option passes the BCT cost reasonableness tests. EPA has determined that zero discharge reflects the BAT level of control because, as it is widely practiced throughout the industry, it is both economically achievable and technologically available.

Based on responses to the 1993 Coastal Oil and Gas Questionnaire and existing NPDES permit requirements, EPA has determined that there are no discharges of produced sand currently in the coastal subcategory. Data from the 1993 Coastal Oil and Gas Questionnaire indicate that the predominant disposal method for produced sand is landfarming, with underground injection, landfilling, and onsite storage also taking place to some degree. Because of the cost of sand cleaning, in conjunction with the difficulties associated with cleaning some sand sufficiently to meet existing permit discharge limitations, operators use onshore (onsite or offsite) or downhole disposal. In fact, only one operator was identified in the 1993 Coastal Oil and Gas Questionnaire as discharging produced sand in the Gulf of Mexico, but this operator also stated that it planned to cease its discharge in the near future. In addition, subsequent to this operator's response, EPA Region 6 issued general permits prohibiting discharges of produced sand in coastal waters of Louisiana and Texas (60 FR 2387; January 9, 1995). Cook Inlet operators submitted information stating that no produced sand discharges are occurring in this area (see Chapter IX). No comments on the proposed guidelines contained contrary information.

Because current practice for the coastal subcategory is zero discharge, allowing the discharge of produced sand would not represent BAT level control. As stated above, EPA's identified only one discharger of produced sand in the coastal subcategory and that discharger reported an intent to cease discharging. Because the industry practice of zero discharge is already so widespread and based on data from the 1993 Coastal Oil and Gas Questionnaire (showing that only one operator was discharging produced sand, and those discharges have since been prohibited by the Region 6 permits), EPA determined that the zero discharge limitation for produced sand will result in minimal, if any, increased cost to the industry because zero discharge generally represents current practice. Non-water quality environmental impacts from the zero discharge limitation, if any, will be negligible.

EPA is also establishing PSES and PSNS which require zero discharge of produced sand. EPA has determined that, similar to drilling wastes, the high solids content of produced sand would likely cause obstruction to the flow in the POTW resulting in interference with POTW operations. Because EPA is not aware of any coastal operators discharging produced sand to POTWs, this requirement is not expected to result in operators incurring costs. Zero discharge for PSNS would not cause a barrier to entry. There are no additional non-water quality environmental impacts associated with this requirement because it reflects current practice.

3.5 Domestic Wastes

The conventional pollutant of concern in domestic waste is floating solids. The existing BPT limitations for domestic wastes prohibit discharges of floating solids. To comply with this limit, operators grind the waste prior to discharge. As proposed, EPA is establishing BCT and NSPS limitations which prohibit the discharge of floating solids. BCT and NSPS also include discharge limitations for garbage as included in U.S. Coast Guard regulations at 33 CFR Part 151. These regulations implement Annex V of the Convention to Prevent Pollution from Ships (MARPOL) and the Act to Prevent Pollution from Ships, 33, U.S.C. 1901 et seq. (The definition of "garbage" is included in 33 CFR 151.05). In addition, EPA is establishing BAT and NSPS limitations which prohibit discharges of foam. Foam is a nonconventional pollutant and its limitation is intended to control discharges that include detergents.

The pollutant limitations described above for domestic wastes are all technologically available and economically achievable and reflect the BCT, BAT and NSPS levels of control. These limitations are technologically available. Existing BPT requirements already prohibit discharges of floating solids. Existing permit requirements for Cook Inlet facilities prohibit discharges of visible foam. In addition, the availability of controls to prevent discharges of foam are demonstrated by the existing BAT limitations (which prohibit the discharge of foam) for the offshore subcategory. Under regulations issued by the U.S. Coast Guard, discharges of garbage, including plastics, from vessels and fixed and floating platforms engaged in the exploration, exploitation and associated offshore processing of seabed mineral resources are prohibited with one exception. Victual waste (not including plastics) may be discharged from fixed or floating platforms located beyond 12 nautical miles from nearest land, if such waste is passed through a screen with openings no greater than 25 millimeters in diameter. Because vessels and fixed and floating platforms must comply with these limits, EPA believes that all coastal facilities are able to comply with this limit. While not all coastal facilities are located on platforms, compliance with a no garbage standard should be as achievable, if not more so, for shallow water or land based facilities that have access to garbage collection services. Further, the final drilling permits issued by Region 6 for coastal Texas and Louisiana incorporates these Coast Guard regulations (58 FR 49126; September 21, 1993).

Because they represent current practice, the BCT, BAT and NSPS limitations result in no incremental costs or non-water quality environmental impacts. There are no incremental costs associated with the BCT limitations; therefore, they pass the BCT cost reasonableness tests. Pretreatment standards are not being developed for domestic wastes because domestic wastes are compatible with POTWs. POTWs typically receive these types of wastes from industrial and domestic users.

3.6 SANITARY WASTES

EPA is establishing BCT and NSPS as equal to BPT limits for sanitary waste discharges. Sanitary waste effluents from facilities continuously manned by ten (10) or more persons must contain a minimum residual chlorine content of 1 mg/l, with the chlorine level maintained as close to this concentration as possible. Coastal facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons must comply with a prohibition on the discharge of floating solids. Since there are no increased control requirements beyond those already required by BPT effluent guidelines, there are no incremental compliance costs or non-water quality environmental impacts associated with BCT and NSPS limitations for sanitary wastes. Since there are no incremental costs associated with the BCT limit, it passes the BCT cost tests.

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

EPA is not establishing BAT effluent limitations for the sanitary waste stream because no toxic or nonconventional pollutants of concern have been identified in these wastes. Pretreatment standards are not being developed for sanitary wastes because they are compatible with POTWs. POTWs typically receive these types of wastes from industrial and domestic users.

4.0 REFERENCES

1. U.S. EPA, "Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category," October 31, 1996.

2. SAIC, "Oil and Gas Exploration Wastes Handling Methods in Coastal Alaska," January 6, 1995.

3. Alaska Oil and Gas Association, "Alaska Oil and Gas Association Comments on U.S. Environmental Protection Agency 40 CFR Part 435 Effluent Limitation Guidelines, Pretreatment Standards, and New Source Performance Standards: Oil and Gas Extraction Point Source Category, Coastal Subcategory; Proposed Rule," June 1995.

4. Unocal and Marathon Oil Co., "Drilling Waste Disposal Alternatives - A Cook Inlet Perspective," March 1994.

5. *Avanti*, "Compliance Costs and Pollutant Removals for Drilling Fluids and Drill Cuttings," September 16, 1996.

6. Mason, T., *Avanti*, Memorandum to Ron Jordan, U.S. EPA, regarding "Navigation and Weather Conditions in Cook Inlet," September 16, 1996.

7. *Avanti*, "Non-Water Quality Environmental Impacts for Drilling Wastes and Produced Water in Cook Inlet, Alaska," September 20, 1996.

8. Jordan, R. P., U.S. EPA, "Record of Telephone Conversation with County Sanitation Districts of Los Angeles," June 14, 1996.

CHAPTER XV

BEST MANAGEMENT PRACTICES

Section 304(e) of the Clean Water Act authorizes the Administrator to prescribe best management practices (BMPs) to control "plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage." Section 402(a)(1) and NPDES regulation (40 CFR 122) also provide for best management practices to control or abate the discharge of pollutants when numeric effluent limitations are infeasible.

The coastal guidelines do not establish "best management practices" (BMPs). EPA believes that current industry practices, in conjunction with the requirements included in the stormwater regulations (60 FR 50803, September 29, 1995), are sufficient to minimize the introduction of contaminants to this wastestream to the extent possible and that additional regulations would be duplicative and unnecessary. Although BMPs are not required by this rule, EPA identified several BMPs applicable to this industry.

Good operation and maintenance practices reduce waste flows and improve treatment efficiencies, as well as reduce the frequency and magnitude of system upsets. Some examples of good coastal facility operation are:

1. Separation of used motor oil from deck drainage collection systems.
2. Minimization of wastewater treatment system upsets by the controlled usage of deck washdown detergents.
3. Reduction of oil spillage through the use of good prevention techniques such as drip pans and other handling and collection methods.
4. Segregation of deck drainage from oil leaks from pump bearings and seals by directing the leakage to the crude oil processing system.
5. If oil is used as a spotting fluid, careful attention to the operation of the drilling fluid system could result in the segregation from the main drilling fluid system of the spotting fluid and contaminated drilling fluid. Once segregated, the contaminated drilling fluid can be disposed of in an environmentally acceptable manner.

6. Substitution of standard drill pipe threading compound (pipe dope) with "toxic metals free" pipe dope. Standard pipe dope can contribute high amounts of lead and other metals to discharged drilling fluids and cuttings.

7. Careful application of standard drill pipe dope to minimize contamination of receiving water and drilling fluids.

8. Substitution of diesel oil with less toxic mineral oil or synthetic-based material in drilling fluid applications.

9. Substitution of standard drilling fluid additives with less toxic additives.

10. Segregation of contaminated process area deck drainage and runoff from relatively uncontaminated runoff from areas such as parking areas, office space, walkways, and living quarters.

11. Segregated handling, storage and disposal of contaminated drilling waste from less contaminated waste.

12. Installation of roofs and sheds to divert uncontaminated rainfall from areas with a high potential for generating contaminated runoff.

13. Segregation of existing roof drains from contaminated deck drainage sources.

14. Careful handling of drilling fluid materials and treatment chemicals to prevent spills.

15. Use of local containment devices such as liners, dikes and drip pans where chemicals are being unpackaged and where wastes are being stored and transferred.

16. Install treatment devices for deck drainage to reduce or remove pollutants in the discharges (e.g., skim tanks, oil/water separators, sediment tanks/basins, or detention ponds).

Careful planning, good engineering, and a commitment on the part of the operating, maintenance, and management personnel are needed to ensure that the full benefits of all pollution reduction facilities are realized.

GLOSSARY AND ABBREVIATIONS

Acidizing/Fracturing Fluids: Fluids used to induce formation fracturing, which is a method of stimulating production by opening new flow channels in the rock surrounding a production well. Often called a frac job. Under extremely high hydraulic pressure, a fluid (such as distillate, diesel fuel, crude oil, dilute hydrochloric acid, water, or kerosene) is pumped downward through production tubing or drill pipe and forced out below a packer or between two packers. The pressure causes cracks to open in the formation, and the fluid penetrates the formation through the cracks. Sand grains, aluminum pellets, walnut shells, or similar materials (propping agents) are carried in suspension by the fluid into the cracks. When the pressure is released at the surface, the fracturing fluid returns to the well. The cracks partially close on the pellets, leaving channels for oil to flow around them to the well.

Act: The Clean Water Act.

ADEC: Alaska Department of Environmental Conservation.

Agency: The U.S. Environmental Protection Agency.

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

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

AOGA: Alaskan Oil and Gas Association.

API: American Petroleum Institute.

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

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

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

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

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

BOD: Biochemical oxygen demand.

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

bpd: Barrels per day.

BPJ: Best Professional Judgment.

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

bpy: Barrels per year.

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

BTU: British Thermal Unit.

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

CBI: Confidential Business Information.

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

cfd: cubic feet per day

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

CO: Carbon Monoxide.

Coastal Oil and Gas Questionnaire: U.S. EPA, "Coastal Oil and Gas Questionnaire," OMB No. 2040-0160, July 1993.

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

Completion Fluids: Low-solids fluids or drilling muds used when a well is being completed. They are selected not only for their ability to control formation pressure, but also for the properties that minimize formation damage. Salt solutions, weighted brines, polymers, and various additives are used to prevent damage to the well bore during operations which prepare the drilled well for production.

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

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

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

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

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

Dewatering Effluent: The wastewater derived from dewatering drill cuttings.

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

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

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

DMR: Discharge Monitoring Report.

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

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

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

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

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

ENR-CCI: Engineering News Record-Construction Indices.

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

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

Facility: See Produced Water Separation/Treatment Facility.

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

Filter Backwash: Wastewater generated when filters are cleaned and maintained.

Filter Sludge: Solids removed via filtration.

Filtration: The process of removing the solids from a fluid. Filtration can be used on both produced water or workover/completion fluids.

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

Flotation: Process by which water that is slightly oil contaminated is circulated to be cleaned before it is disposed. Since oil droplets cling to rapidly rising gas, a device such as a bubble tower is usually installed in the flotation cell to permit the introduction of gas into the water.

Fluid Injection: Injection of gases or liquids into a reservoir to force oil toward and into producing wells. (See also "Water Flooding" and "Pressure Maintenance.")

Footprint: The square footage covered by various production equipment.

Formation: Various subsurface geological strata.

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

Fracturing: A method of stimulating production by opening new flow channels in the rock surrounding a production well. Often called a frac job. See "Acidizing/Fracturing Fluids."

Free Water Knockout (FWKO): A vertical or horizontal vessel into which oil or emulsion is run to allow any water not emulsified with the oil (free water) to drop out.

Gas Lift: A means of stimulating flow by aerating a fluid column with compressed gas.

GOM: Gulf of Mexico.

gph: Gallons per hour.

gpm: Gallons per minute.

hp: Horsepower.

IGF: Improved operating performance of gas flotation.

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

kW: Kilowatt.

96-hr LC_{50}: The concentration of a test material that is lethal to 50% of the test organisms in a bioassay after 96 hours of constant exposure.

LDEQ: Louisiana Department of Environmental Quality.

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

m: Meters.

Major Pass Facilities: Those oil and gas facilities discharging offshore subcategory produced water into major deltaic passes of the Mississippi River below Venice or to the Atchafalaya River below Morgan City including Wax Lake Outlet.

mcf: Thousand cubic feet.

µg/l: Micrograms per liter.

mg/l: Milligrams per liter.

MMcfd: Million cubic feet per day.

MMscf: Million standard cubic feet.

Mscf: Thousand standard cubic feet.

Mud: Common term for drilling fluid.

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

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

Multiple Completion: A well completion which provides for simultaneous production from separate zones.

NO_x: Nitrogen Oxide.

NPDES: National Pollutant Discharge Elimination System.

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

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

NWQI: Non-water quality environmental impact.

O&M: Operating and maintenance.

Oil/Water Separation Facilities: See "Produced Water Separation/Treatment Facilities."

Oil-based Drilling Fluid: A drilling fluid in which oil is the continuous phase.

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

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

Onshore Subcategory: Those facilities as defined in 40 CFR 435.30.

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

POTW: Publicly Owned Treatment Works.

Pressure Maintenance: The injection of water or gas into an oil or gas producing formation to maintain the desired formation pressure.

Priority Pollutants: The toxic pollutants listed in 40 CFR Part 423, Appendix A.

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

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

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

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

psi: pounds per square inch.

psig: pounds per square inch gauge.

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

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

Reserve Pit: A waste pit, usually an excavated earthen-walled pit. It may be lined with plastic or other material to prevent soil contamination.

Reserve Pit Liquids: Liquids surfacing to the top of reserve pits after settling of solids; can also include rain water, rig wash water, etc.

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

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

RRC: Railroad Commission of Texas.

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

scf: standard cubic feet.

Secondary Recovery: The use of waterflooding or gas injection to maintain formation pressure during primary production and to reduce the rate of decline of the original reservoir drive.

Settling or Skim Pit or Tank: A pit or tank into which produced emulsion is piped and in which water in the emulsion is allowed to settle out of the oil. Oil can be skimmed off the top.

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

SO_2: Sulfur Dioxide.

Source Water: The term used for subsurface waters produced from non-hydrocarbon bearing formations for waterflooding purposes.

Tank Battery: A group of production tanks located in a field to store crude oil.

TBPF: Trading Bay Production Facility.

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

THC: Total hydrocarbons.

Treatment Fluids: Any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled. Well treatment fluids include substances such as acids, solvents, and propping agents. (See "Acidizing/ Fracturing Fluids.")

TSP: Total suspended particulates.

TSS: Total Suspended Solids.

TWC: Treatment, workover, and completion.

UIC: Underground Injection Control.

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

USCG: United States Coast Guard.

USDW: Underground Sources of Drinking Water.

USGS: United States Geological Survey.

Water-based Drilling Fluid: A drilling fluid in which the continuous phase is water. In water-based fluids, any additives are dispersed in the water.

Waterflooding: Water is injected under pressure into the formation via injection wells to maintain reservoir pressure and to displaced oil toward the producing wells.

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

Workover Fluid: Salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures. A workover fluid is compounded carefully so that it will not cause formation damage.

APPENDIX VII-1

DRILLING FLUID COMPONENTS AND APPLICATIONS

Drilling Fluid Components and Applications
(Chilingarian and Vorabutr, 1983)

Drilling Fluid Component	Description or Principal Component	Primary Application
Weighting Agents and Viscosifiers	Barite	For increasing mud weight up to 20 ppg.
	Calcium Carbonate	For increasing weight of oil muds up to 10.8 ppg.
	Bentonite	Viscosity and filtration control in water-base muds.
	Sub-Bentonite	For use when larger particle size is desired for viscosity and filtration control.
	Attapulgite	Viscosifier in saltwater muds.
	Beneficiated Bentonite	Quick viscosity in fresh-water, upperhole muds with minimum chemical treatment.
	Asbestos Fibers	Viscosifier for fresh-water or saltwater muds.
	Bacterially Produced Polymer	Viscosifier and fluid-loss control additive for low-solids muds.
	Sepiolite	Viscosifier in all water-based muds, especially high-temperature drilling fluids.
Dispersants	Sodium Tetraphosphate	Thinner for low pH fresh-water muds where temperatures do not exceed 180°.
	Sodium Acid Pyrophosphate	For treating cement contamination.
	Quebracho Compound	Thinner for fresh-water and lime muds.
	Modified Tannin	Thinner for fresh-water and saltwater muds alkalized for pH control.
	Processed Lignite	Dispersant, emulsifier and supplementary additive for fluid-loss control.
	Causticized Lignite	1-6 ratio caustic-lignite dispersant, emulsifier and supplementary fluid-loss additive.
	Modified Lignosulfonate	Dispersant and fluid-loss control additive for water-base muds.
	Blended Lignosulfonate Compound	Blended multi-purpose dispersant, fluid-loss agent and inhibitor for IMCO RD-111 mud systems.
	Chrome-Free Lignosulfonate	Dispersant and fluid-loss control additive for water base muds.
Fluid-Loss Reducers	Organic-Polymer	Controls fluid loss in water-base systems.
	Pregelatinized Starch	Controls fluid loss in saturate salt water, lime and SCR muds.
	Sodium Carboxymethyl Cellulose	For fluid-loss control and barite suspension in water-base muds.
	Sodium Carboxymethyl Cellulose	For fluid-loss control and viscosity building in low-solids muds.
	Polyanionic Cellulosic Polymer	Fluid-loss control additive and viscosifier in salt muds.
	Polyanionic Cellulosic Polymer	Primary fluid-loss additive, secondary viscosifier in water-base muds.
	Sodium Polyacrylate	Fluid-loss control in calcium-free low solids and nondispersed muds.

Drilling Fluid Components and Applications (cont.)

(Chilingarian and Vorabutr, 1983)

Drilling Fluid Component	Description or Principal Component	Primary Application
Lubricants, Detergents, Emulsifiers, Surfactants	Extreme Pressure Lubricant	Used in water-base muds to impart extreme pressure lubricity.
	Processed Hydrocarbons	Used in water-based muds to lower downhole fluid loss and minimize heaving shale.
	Water Dispersible Asphalts	Lubricant and fluid-loss reducer for water-base muds that contain no diesel or crude oil.
	Oil Dispersible Asphalts	Lubricant and fluid-loss reducer for water-base fluids that contain diesel or crude oil.
	Oil Soluble Surfactants	Nonweighted fluid for spotting to free differentially stuck pipe.
	Detergent	Used in water-base muds to aid in dropping sand. Emulsifies oil, reduces torque and minimizes bit-bailing.
	Blend of Anionic Surfactants	Emulsifier for saltwater and freshwater muds.
	An Organic Entity Neutralized with Amines	Supplies the lubricating properties of oils without environmental pollution.
	Blend of Fatty Acids, Sulfonates, and Asphaltic Materials	Invert emulsion that may be weighted to desired density for spotting to free differentially stuck pipe.
Defoamers, Flocculants, Bactericides	Aluminum Stearate	Defoamer for lignosulfonate muds.
	Liquid Surface-Active Agent	Defoamer for all water-base muds.
	Surface-Active Dispersible Liquid Defoamer	All-purpose defoamer.
	Flocculating Agent	Used to drop drilled solids where clear water is desirable for a drilling fluid.
	Blended Solutions	Bactericide used to prevent fermentation.
Lost Circulation Materials	Fibrous Material	Filler as well as matting material.
	Nut Shells: Fine	Most often used to prevent lost circulation.
	Nut Shells: Medium	Used in conjunction with fibers or flakes to regain lost circulation.
	Nut Shells: Coarse	Used where large crevices or fractures are encountered.
	Ground Mica: Fine	Used for prevention of lost circulation.
	Ground Mica: Coarse	Forms a good mat at face of wellbore.
	Cellophane	Used to regain lost circulation.
	Combination of granules, flakes, and fibrous materials of various sizes in one sack.	Used where large crevices or fractures are encountered.

Drilling Fluid Components and Applications (cont.)
(Chilingarian and Vorabutr, 1983)

Drilling Fluid Component	Description or Principal Component	Primary Application
Corrosion Inhibitors	Zinc Compound	For use as a hydrogen sulfide scavenger in water-base and oil-base muds.
	Liquid Corrosion Inhibitor	Prevent stress cracking of drill strings in an H_2S environment.
	A Catalyzed Ammonium Bisulfite	For use as an oxygen scavenger.
	Filming Amine	Corrosion inhibitor.
	Filming Amine	Corrosion inhibitor.
	Organic Polymer	Scale inhibitor.
Specialty Products	Bentonite Extender	Increases yield of bentonite to form very low-solids drilling fluid.
	Inhibiting Agent	Imparts high-temperature fluid-loss control, temperature stability and increased inhibition.
	Synergistic Polymer Blend	Rheological stabilization and filtration control.
	Biodegradable Surfactant	Foaming agent in air or mist drilling.
	High-Temperature Polymer	High-temperature fluid-loss control.
	Multipurpose Polymer	Polymer for fluid-loss control.
Commercial Chemicals	Sodium Chromate	Used in water-base muds to prevent high-temperature gelation.
	Sodium Hydroxide	For pH control in water-base muds.
	Sodium Carbonate	For treating out calcium sulfate in low pH muds.
	Sodium Bicarbonate	For treating out calcium sulfate or cement in high pH muds.
	Barium Carbonate	For treating out calcium sulfate (pH should be above 10 for best results).
	Calcium Sulfate	Source of calcium for formulating gyp muds.
	Calcium Hydroxide	Source of calcium for formulating lime muds.
	Sodium Chloride	For saturated salt muds and resistivity control.
	Chrome Alum (chromic chloride)	For use in cross-linking XC Polymer systems.
Oil-Mud Additives	Primary Emulsifier	Primary additives to form stable water-in-oil emulsion.
	Viscosifier and Gelling Agent	Provides viscosity, weight suspension, and filtration control.
	High-Temperature Stabilizer	Improves emulsion under high-temperature conditions.
	Stabilizes Borehole Conditions	Stabilizes running shale, improves emulsion, weight suspension, and fluid loss under high-temperature conditions.
	Dispersant	Dispersant for reducing rheological properties.
	Calcium Oxide	Calcium source for saponification.
	Fatty Acid Emulsifier	Primary emulsifier and stabilizer for oil-base drilling fluids.

Drilling Fluid Components and Applications (cont.)

(Chilingarian and Vorabutr, 1983)

Drilling Fluid Component	Description or Principal Component	Primary Application
Oil Mud Additives (cont.)	Emulsion Stabilizer	Imparts gels, contributes to viscosity for weight suspension, and provides filtration control.
	Specially Modified Saponified Fatty Acid Chemicals	Gelling agent for formulating high-gelation casing packs.
	Powdered Wetting Agent	Dispersing agent in KEN-X systems with a $CaCl_2$ water internal phase.

APPENDIX X-1

WORKSHEETS FOR COOK INLET MODEL WELL AND FOUR DRILLING WASTE MANAGEMENT SCENARIOS

Worksheet No. 1, April 30, 1996, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
Zero Discharge Compliance Cost Analysis for Operations in Cook Inlet, Alaska
Cost Estimation for Drilling an Average Injection Well

(1) Operator ID	(2) Well ID	(3) DFS-01 Depth feet	(4) DFS-02 Depth feet	(5) DFS-03 Depth feet	(6) Well Total Depth feet	(7) DFS-01 Drill Time days	(8) DFS-01 Workday hours	(9) DFS-02 Drill Time days	(10) DFS-02 Workday hours	(11) DFS-03 Drill Time days	(12) DFS-03 Workday hours	(13) DFS-01 M & C bbls	(14) DFS-02 M & C bbls	(15) DFS-03 M & C bbls	(16) Total M & C bbls	(17) Average Cuttings % of Total
A	1A	1,389	8,477	2,029	11,895	9	6	21	14	20	11	1,528	9,325	2,232	13,085	NA
A	2A	1,256	8,368	2,176	11,800	3	13	32	12	20	8	1,213	8,081	2,101	11,395	NA
A	3A	1,155	8,642	2,343	12,140	5	9	27	13	47	9	1,361	10,180	2,760	14,300	NA
B	1B	2,110	7,999	860	10,969	23	23	30	23	13	23	3,313	7,334	1,334	11,981	19
B	2B	4,120	5,962	1,478	11,560	NA	NA	30	12	12	12	NA	9,558	1,583	NA	NA
B	3B	4,017	5,745	2,068	11,830	12	12	17	12	12	12	6,065	7,606	2,326	15,997	NA
B	4B	3,823	6,240	2,100	12,163	15	12	20	12	17	12	7,504	8,838	3,024	19,366	NA
AVERAGE		2,553	7,348	1,865	11,765	11	13	25	14	20	12	3,497	8,703	2,194	14,354	19

Operator ID	Well ID	(18) DFS-01 Drill Time hours	(19) DFS-02 Drill Time hours	(20) DFS-03 Drill Time hours	(21) Well Total Drill Time hours	(22) Total Well Drill Cost ($1,000)	(23) Average Drill Rate $/hr	(24) DFS-01 Drill Cost $	(25) DFS-02 Drill Cost $	(26) DFS-03 Drill Cost $	(27) DFS-01 Unit Cost $/ft	(28) DFS-02 Unit Cost $/ft	(29) DFS-03 Unit Cost $/ft	(30) DFS-01 Unit M&C bbls/ft	(31) DFS-02 Unit M&C bbls/ft	(32) DFS-03 Unit M&C bbls/ft
A	1A	54	294	220	568	3,567	6,280	339,104	1,846,235	1,381,536	244	218	681	1.1	1.1	1.1
A	2A	39	384	160	583	3,457	5,930	231,266	2,277,077	948,782	184	272	436	1.0	1.0	1.0
A	3A	45	351	423	819	4,610	5,628	253,269	1,975,500	2,380,731	219	229	1,016	1.2	1.2	1.2
B	1B	529	690	299	1,518	4,078	2,687	1,421,229	1,853,777	803,303	674	232	934	1.6	0.9	1.6
B	2B	NA	360	144	NA	6,722	NA	NA	NA	NA	NA	NA	NA	NA	1.6	1.1
B	3B	144	204	144	492	5,120	10,406	1,498,489	2,122,859	1,498,489	373	370	725	1.5	1.3	1.1
B	4B	180	240	204	624	5,935	9,512	1,712,100	2,282,800	1,940,380	448	366	924	2.0	1.4	1.4
AVERAGE		165	360	228	767	4,784	6,740	909,243	2,059,708	1,492,204	357	281	786	1.4	1.2	1.2

Average Cost of Drilling a 4000 Foot Injection Well = **$1,313,897**
(Sum of the costs of drilling the first 2,500 feet using the average cost of first drilling fluid system, DFS-01,
and the cost of drilling the last 1,500 feet using the average cost of the second drilling fluid system, DFS-02,
(2,500 x Column 27) + (1,500 x Column 28))

Average Muds and Cuttings Generated from Drilling a 4000 Foot Injection Well (BBLS) = **5,275**
(Sum of the muds and cuttings (M&C) generated from drilling the first 2,500 feet of well, using the average unit volume M&C of DFS-01,
and M&C generated from drilling the last 1,500 feet of the well, using the average unit volume M&C of DFS-02,
(2,500 x Column 30) + (1,500 x Column 31))

Average Number of Days for Drilling an Average New Well = **57**
(Sum of the average number of days for each drilled interval)
(Column 7 +Column 9 +Column 11)

Average Number of Days for Recompleting a Well = **20**
(Set equal to the average number of days spent drilling the third drilled interval of new wells, Column 11)

Worksheet No. 1, April 30, 1996, page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
Zero Discharge Compliance Cost Analysis for Operations in Cook Inlet, Alaska
Cost Estimation for Drilling an Average Injection Well

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (McIntyre, 1996).

(2) Well IDs are confidential, and are therefore discussed in a confidential supporting document (McIntyre, 1996).

(3), (4), and (5) The depth of each drilling fluid system (DFS) was obtained from the 308 Questionnaire.

(6) The final depth to which the well was drilled is the sum of all drilled intervals, Column 3 + Column 4 + Column 5.

(7), (8), (9), (10), (11), and (12) Drilling time for each drilling interval was obtained from 308 Questionnaires.

(13), (14), and (15) Muds and Cuttings (M&C) Volumes are as specified in the 308 Questionnaires or calculated from the reported total volume by weighted average based on the depth of each interval.

(16) Total muds and cuttings generated from each well are as reported in the 308 Questionnaires or are the sum of muds and cuttings from all drilled intervals.

(17) Average percent of total volume of drilling waste as cuttings was calculated by averaging reported percentages for each drilled interval in the 308 Questionnaires. Only one facility reported cuttings fractions.

(18) Total hours of drilling the first interval is the product of total number of drilling days and average number of drilling hours in a day. Column 7 x Column 8.

(19) Total hours of drilling the second interval is the product of total number of drilling days and average number of drilling hours in a day. Column 9 x Column 10.

(20) Total hours of drilling the third interval is the product of total number of drilling days and average number of drilling hours in a day. Column 11 x Column 12.

(21) Total drilling hours is the sum of total drilling hours for each drilling interval. Column 18 + Column 19 + Column 20.

(22) Total drilling costs were obtained from the 308 Questionnaires.

(23) The average hourly drilling cost for each well is calculated by dividing the total cost of drilling by the number of hours spent to drill the well, Column 22/Column21.

(24) Cost of drilling the first interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the first interval, Column 23 x Column 18.

(25) Cost of drilling the second interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the second interval, Column 23 x Column 19.

(26) Cost of drilling the third interval is calculated by multiplying the average hourly drilling cost rate for the entire well by the total hours spent drilling the third interval, Column 23 x Column 20.

(27) The cost of drilling per unit depth of the first interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column24/Column 3.

(28) The cost of drilling per unit depth of the second interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column25/Column 4.

(29) The cost of drilling per unit depth of the third interval is calculated by dividing the total cost of drilling the interval by total depth of the interval, Column26/Column 5.

(30) The unit muds and cuttings generated per foot of the first drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 14/Column 3.

(31) The unit muds and cuttings generated per foot of the second drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 15/Column 4.

(32) The unit muds and cuttings generated per foot of the third drilled interval is calculated by dividing the total volume of muds and cuttings for the interval by the total depth of the interval, Column 16/Column 5.

NA Data not available or not applicable.

Note: A 4000–foot injection well is assumed based on information provided by Operator B (McIntyre, 1996).

Worksheet No. 2, May 17, 1996, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Landfill Disposal (Without Closed–Loop System)

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms With Planned Drilling Program	(4) Total # of New Wells Scheduled 1996–2002	(5) Total # of Recomplts Scheduled 1996–2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recomplt Wells BBLS	(8) Total Incremental Volume of Waste All Wells BBLS	(9) Unit Cost of Disposing Drilling Waste $/BBL	(10) Total Disposal Cost New Wells $	(11) Total Disposal Cost Recomplts Wells $	(12) Total Disposal Cost All Wells $
A	2	1	3	1	42,631	2,172	44,803	112	4,774,715	243,271	5,017,985
B	12	9	28	19	397,893	41,269	439,162	103	40,982,967	4,250,721	45,233,688
C	1	1	10	0	142,105	0	142,105	112	15,915,715	0	15,915,715
Total	15	11	41	20	582,629	43,441	626,070	NA	61,673,396	4,493,992	66,167,388

Total Disposal Cost of Drilling Wastes for All Operators =
(Sum of Disposal Costs for All Operators, Column 12)
$66,167,388

Total Disposal Cost Per Barrel of Drilling Waste =
(Total Disposal Cost/Total Volume of Drilling Wastes, Column 12/Column 8)
$106

Total Disposal Cost of Drilling Wastes Per Platform =
(Total Disposal Cost/Total Number of Platforms with Planned Drilling, Column 12/Column 3)
$6,015,217

Total Disposal Cost of Drilling Wastes Per Drilling Event =
((Total Disposal Cost)/(Total Number of New and Recompletion Wells), Column 12/(Column 4 + Column 5))
$1,084,711

Total Disposal Cost of Drilling Wastes Per New Development Well =
(Total Disposal Cost Per Barrel x Volume of Drilling Waste from an Average new Well, (Cost Per Barrel)x(Column 6)/(Column 4))
$1,501,859

Total Disposal Cost of Drilling Wastes Per Recompletion Well =
(Total Disposal Cost Per Barrel x Volume of Drilling Waste from an Average Recompletion, (Cost Per Barrel)x(Column 7)/(Column 5))
$229,558

Worksheet No. 2, May 17, 1996, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Landfill Disposal (Without Closed–Loop System)

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (McIntyre, 1996).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (McIntyre, 1996).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling and Percent of total (99%) drilling waste discharged under current practice. Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet and the total number of wells scheduled for recompletion in Cook Inlet and percent of total (99%) drilling waste discharged under current practice. Based on information provided in 1993 Coastal Oil & Gas Industry Survey Questionnaires. See Worksheet No. 1 for details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all incremental wastes that will be generated in Cook Inlet, Column 5 + Column 6.

(9) Unit disposal costs for landfill disposal of muds and cuttings generated in Cook Inlet. Data were estimated from information provided by Cook Inlet operators. Also see Appendix B.

(10) Total Disposal Cost for new drilling is the product of Unit Disposal Cost and Total Volume of Drilling Waste from drilling new wells, Column (9) x Column (6).

(11) Total Disposal Cost for recompletions is the product of Unit Disposal Cost and Total Volume of Drilling Waste from Recompleting existing wells, Column (9) x Column (7).

(12) Total Disposal Cost of drilling wastes from all wells or all drilling activities, Column (10) + Column (11).

NA Not applicable.

Worksheet No. 3, May 17, 1996, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Landfill Disposal (with Closed-Loop System)

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996-2002	(5) Total # of Recomplts Scheduled 1996-2002	(6) Total Incremental Volume of Waste New Wells bbls	(7) Total Incremental Volume of Waste Recomplts Wells bbls	(8) Total Incremental Volume of Waste All Wells bbls	(9) Total # of Days High Efficiency Solid Separation Equipment Needed	(10) Unit Cost of Solid Separation Equipment $/day/unit	(11) Total Cost of High Efficiency Solid Separation $
A	2	1	3	1	29,416	1,499	30,914	191	2,085	398,235
B	12	9	28	19	274,546	28,476	303,022	1,976	2,085	4,119,960
C	1	1	10	0	98,052	0	98,052	570	2,085	1,188,450
Total	15	11	41	20	402,014	29,974	431,988	2,737	NA	5,706,645

Operator ID	(12) Retrofit Cost of Equipment Per Platform $/platform	(13) Total Cost of Retrofitting Platforms $	(14) Unit Cost of Operating Equipment $/day	(15) Total Cost of Operating Equipment $	(16) Unit Cost of Landfilling Drilling Waste $	(17) Total Cost of Landfilling Drilling Waste $	(18) Total Disposal Cost of Drilling Waste $
A	270,000	270,000	1,098	209,718	112	3,462,410	4,340,363
B	270,000	2,430,000	1,098	2,169,648	103	31,211,245	39,930,853
C	270,000	270,000	1,098	625,860	112	10,981,843	13,066,153
Total	NA	2,970,000	NA	3,005,226	NA	45,655,498	57,337,369

Total Disposal Cost of Drilling Waste for All Operators = **$57,337,369**
(Sum of Disposal Costs for All Operators, Column 18)

Total Disposal Cost of Drilling Waste Per Barrel = **$133**
((Total Disposal Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Disposal Cost of Drilling Wastes Per Platform = **$5,212,488**
((Total Disposal Cost)/(Total Number of Platforms with Planned Drilling Program, Column 3))

Total Disposal Cost of Drilling Wastes Per Drilling Event = **$939,957**
((Total Disposal Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Disposal Cost of Drilling Wastes Per New Development Well = **$1,301,436**
(Total Disposal Cost Per Barrel x Volume of Drilling Waste per an average new well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Disposal Cost of Drilling Wastes Per Recompletion Well = **$198,924**
(Total Disposal Cost Per Barrel x Drilling Waste Volume per for an average recompletion well, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 3, May 17, 1996, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Landfill Disposal (with Closed–Loop System)

(1) Operator IDs are confidential, and are therefore discussed in a confidential supporting document (McIntyre, 1996).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (McIntyre, 1996).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, the percent of total (99%) waste discharged under the current practice, and percent reduction (69%) of drilling waste by Closed–Loop System (SAIC, Oct. 10, 1994). Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet and the Total Number of Wells scheduled for recompletion in Cook Inlet, the percent of total (99%) waste discharged under the current practice, and percent reduction (69%) of drilling waste by closed–loop system. Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 5 + Column 6.

(9) Total Number of Days the High Efficiency Solid Separation Equipment is Needed is assumed to be equal to the total number of days it will take to complete all drilling operations. [(Column 4 x Number of days to drill a well)+(Column 5 x Number of days to recomplete a well)]

(10) Unit Cost of High Efficiency Solid Separation Equipment was estimated based on information from drilling operations in Louisiana. Although these costs included labor, additional labor costs are included in this worksheet (Column 14) to serve as an inflation factor. See SAIC, May 3, 1994 for details.

(11) Total Cost of High Efficiency Solid Separation equipment is the product of total number of days the equipment will be needed and the cost of the equipment per day, Column 9 x Column 10.

(12) Retrofit Cost of solid separation equipment per platform is estimated based on the need of 450 square feet of deck space and the cost of $600 per square foot of deck space. See SAIC, May 3, 1994 for details.

(13) Total Cost of Retrofitting the platforms is the product of the unit retrofit cost and the total number of Platforms with a planned drilling program, Column 3 x Column 12.

(14) Unit Cost of Operating Solid Separation Equipment was assumed to be the same as unit cost of operating the injection equipment provided in correspondance with a 308 Survey Respondent. See confidential supporting document (McIntyre, 1996).

(15) Total Cost of Operating the Solid Separation Equipment is the product of the unit operating cost per day and the total number of days the equipment is needed, Column 14 x Column 9.

(16) Unit Cost of Landfilling Drilling Wastes was estimated based on information provided by the Cook Inlet operators. See Appendix B.

(17) Total Cost of Landfilling Drilling Waste is the product of the total volume of drilling waste and the unit cost of landfilling, Column 8 x Column 16.

(18) Total Disposal Cost of Drilling Wastes is equal to the sum of equipment, retrofit, operating, and landfilling costs, Column 11 + Column 13 + Column 15 + Column 17.

NA Not applicable.

Worksheet No. 4, May 17, 1996, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Dedicated Well Injection

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996-2002	(5) Total # of Recomplts Scheduled 1996-2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recomplts Wells BBLS	(8) Total Incremental Volume of Waste All Wells BBLS	(9) Total # of Injection Wells Needed	(10) Estimated Cost of Drilling an Injection Well $/well	(11) Total Cost of Injection Wells $	(12) Total # of Injection Systems Needed
A	2	1	3	1	42,631	2,172	44,803	1	1,313,897	1,313,897	1
B	12	9	28	19	397,893	41,269	439,162	8	1,313,897	10,511,176	4
C	1	1	10	0	142,105	0	142,105	3	1,313,897	3,941,691	1
Total	15	11	41	20	582,629	43,441	626,070	12	NA	15,766,764	6

Operator ID	(13) Unit Cost of Injection System/Buy $/unit	(14) Unit Cost of Injection System/Rent $/day	(15) Buying Cost of Injection System $	(16) Renting Cost of Injection System $	(17) Applied Cost of Injection System $	(18) Retrofit Cost of Injection System Per Platform $/platform	(19) Total Cost of Retrofitting Platforms $	(20) Unit Cost of Operating Injection $/day	(21) Total Cost of Operating Injection System $	(22) Total Injection Cost for all Drilling Waste $
A	1,097,500	1,537	1,097,500	293,567	293,567	750,000	750,000	2,500	477,500	2,834,964
B	1,097,500	1,537	4,390,000	3,596,580	3,596,580	750,000	6,750,000	2,500	4,940,000	25,797,756
C	1,097,500	1,537	1,097,500	876,090	876,090	750,000	750,000	2,500	1,425,000	6,992,781
Total	NA	NA	6,585,000	4,766,237	4,766,237	NA	8,250,000	NA	6,842,500	35,625,501

Total Injection Cost of Drilling Wastes for All Operators = **$35,625,501**
(Sum of the total costs of Injection wells, Injection systems, Platform Retrofits, and Operating Injection Systems)
(Column 11 +Column 17 +Column 19 +Column 21)

Total Injection Cost of Drilling Waste Per Barrel = **$57**
((Total Injection Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Injection Cost of Drilling Wastes Per Platform = **$3,238,682**
((Total Injection Cost)/(Total Number of Platforms with Planned Drilling Program, Column 3))

Total Injection Cost of Drilling Wastes Per Drilling Event = **$584,025**
((Total Injection Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Injection Cost of Drilling Wastes Per New Development Well = **$808,623**
(Total Injection Cost Per Barrel x Volume of Drilling Waste for an average new well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Injection Cost of Drilling Wastes Per Recompletion Well = **$123,598**
(Total Injection Cost Per Barrel x Volume of Drilling Waste for an average recompletion well, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 4, May 17, 1996, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Dedicated Well Injection

(1) Operator IDs are confidential and are therefore discussed in a confidential supporting document (McIntyre, 1996).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (McIntyre, 1996).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, and the percent of total (99%) waste discharged under the current practice. Based on data provided in 1993 Coastal Oil & Gas 308 Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for recompletion in Cook Inlet, and the percent of total (99%) generated waste discharged under the current practice. Based on information in 1993 Coastal Oil & Gas survey questionnaires. See Worksheet No. 1 for details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 6 + Column 7.

(9) Total Number of Injection Wells Needed is calculated based on information provided by the industry which specifies 1 dedicated well for every 4 new development wells (Schmidt, April 7, 1994). The number of dedicated wells needed for recompletions was assumed to be 1 for every 16 recompletions, (Column 4/4)+(Column 5/16).

(10) Estimated Cost of Drilling an Injection Well is calculated in Worksheet 1.

(11) Total Cost of Injection Wells is the product of the total number of injection wells needed and the estimated cost of drilling an injection well, Column 9 x Column 10.

(12) Total Number of Injection Systems was estimated based on the assumption that 1 injection system is needed for every platform with a planned drilling program. Operator B specified the need for 4 injection systems since no more than 4 platforms are planned for drilling at one time. See confidential supporting document (Safavi, Jan. 30, 1995).

(13) Unit Cost of Injection System is provided by Operator B. See confidential supporting document (Safavi, Jan. 30, 1995).

(14) Unit Rental Cost of Injection System is provided by Operator A. See confidential supporting document (Safavi, Jan. 30, 1995).

(15) Buying Cost of Injection System is the product of the Total Number of Systems needed and Unit Buying cost of injection systems. Column 12 x Column 13.

(16) Rental Cost of Injection System is the product of the total number of days needed to complete drilling and the unit operating cost per day, [(Column 4 x number of days to drill a well)+(Column 5 x number of days to recomplete a well)] x (Column 14). The average drill time for a new development well or a recompletion was determined in Worksheet No. 1 and was assumed for Operators A and C. The numbers used for Operator B are as specified in the questionnaires.

(17) Applied Cost of Injection System is either the buying or the renting cost of injection systems depending on which is economically most feasible.

(18) Retrofit Cost of Injection System was provided by Operator B. See confidential supporting document (Safavi, Jan. 30, 1995).

(19) Total Cost of Retrofitting Platforms is the product of the Total Number of Platforms with planned drilling programs and the Unit Cost of Retrofitting Platforms, Column 3 x Column 18. This cost is based on the assumption that each platform with a planned drilling program must be retrofitted for an injection system.

(20) Unit Cost of Operating Injection Systems is provided by operators. See confidential supporting document (McIntyre, 1996).

(21) Total Cost of Operating Injection System is the product of the total number of days needed to complete drilling and the unit operating cost per day, [(Column 4 x number of days to drill a well)+(Column 5 x number of days to recomplete a well)] x (Column 20). The average drill time for a new development well or a recompletion was determined in Worksheet No. 1 and was assumed for all operators.

(22) Total Injection Cost for all Drilling Waste is the sum of the total costs in columns 11, 17, 19, and 21.

NA Not applicable.

Worksheet No. 4A, May 17, 1996, Page 1 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Dedicated Well Injection (With Closed–Loop System)

(1) Operator ID	(2) Total # of Platforms	(3) Total # of Platforms with Planned Drilling Program	(4) Total # of New Wells Scheduled 1996–2002	(5) Total # of Recomplts Scheduled 1996–2002	(6) Total Incremental Volume of Waste New Wells BBLS	(7) Total Incremental Volume of Waste Recomplts Wells BBLS	(8) Total Incremental Volume of Waste All Wells BBLS	(9) Total # of Injection Wells Needed	(10) Estimated Cost of Drilling an Injection Well $/well	(11) Total Cost of Injection Wells $	(12) Total # of Injection Systems Needed
A	2	1	3	1	29,416	1,499	30,914	1	1,313,897	1,313,897	1
B	12	9	28	19	274,546	28,476	303,022	8	1,313,897	10,511,176	4
C	1	1	10	0	98,052	0	98,052	3	1,313,897	3,941,691	1
Total	15	11	41	20	402,014	29,974	431,988	12	NA	15,766,764	6

Operator ID	(13) Unit Cost of Injection System/Buy $/unit	(14) Unit Cost of Injection System/Rent $/day	(15) Buying Cost of Injection System $	(16) Renting Cost of Injection System $	(17) Applied Cost of Injection System $	(18) Retrofit Cost of Injection System Per Platform $/platform	(19) Total Cost of Retrofitting Platforms $	(20) Unit Cost of Operating Injection $/day	(21) Total Cost of Operating Injection System $	(22) Cost of High Efficiency Solids Control Equip. $	(23) Cost of Platform Retrofit for Solids Control $
A	1,097,500	1,537	1,097,500	293,567	293,567	750,000	750,000	2,500	477,500	398,235	270,000
B	1,097,500	1,537	4,390,000	3,596,580	3,596,580	750,000	6,750,000	2,500	4,940,000	4,119,960	2,430,000
C	1,097,500	1,537	1,097,500	876,090	876,090	750,000	750,000	2,500	1,425,000	1,188,450	270,000
Total	NA	NA	6,585,000	4,766,237	4,766,237	NA	8,250,000	NA	6,842,500	5,706,645	2,970,000

Operator ID	(24) Cost of Operating Solids Control Equipment $	(25) Total Solids Control Cost $	(26) Total Injection Cost for all Drilling Waste $
A	209,718	877,953	3,712,917
B	2,169,648	8,719,608	34,517,364
C	625,860	2,084,310	9,077,091
Total	3,005,226	11,681,871	47,307,372

Total Injection Cost of Drilling Wastes for All Operators = **$47,307,372**
(Sum of the total costs of injection wells, Injection systems, Platform Retrofits, and Operating Injection Systems)
(Column 11 +Column 17 +Column 19 +Column 21)

Total Injection Cost of Drilling Waste Per Barrel = **$110**
((Total Injection Cost)/(Total Volume of Drilling Wastes, Column 8))

Total Injection Cost of Drilling Wastes Per Platform = **$4,300,670**
((Total Injection Cost)/(Total Number of Platforms with Planned Drilling Program, Column 3))

Total Injection Cost of Drilling Wastes Per Drilling Event = **$775,531**
((Total Injection Cost)/(Total Number of Wells, Column 4 + Column 5))

Total Injection Cost of Drilling Wastes Per New Development Well = **$1,073,777**
(Total Injection Cost Per Barrel x Volume of Drilling Waste for an average new well, (Cost Per Barrel)x(Column 6)/(Column 4))

Total Injection Cost of Drilling Wastes Per Recompletion Well = **$164,126**
(Total Injection Cost Per Barrel x Volume of Drilling Waste for an average recompletion well, (Cost Per Barrel)x(Column 7)/(Column 5))

Worksheet No. 4A, May 17, 1996, Page 2 of 2
Coastal Alaska Oil and Gas Drilling Industry
BAT Compliance Cost Analysis for Operators in Cook Inlet, Alaska
Zero Discharge Option by Dedicated Well Injection (With Closed–Loop System)

(1) Operator IDs are confidential and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(2), (3), (4), and (5) Some of the data in these columns are confidential, and are therefore discussed in a confidential supporting document (Safavi, Jan. 30, 1995).

(6) Total Incremental Volume of Drilling Waste from new wells is the product of the Average Volume of drilling waste generated from wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for drilling, the percent of total (99%) waste discharged under the current practice, and percent reduction (69%) of drilling waste by closed–loop system (SAIC, October 10, 1994). Based on data provided in 1993 Coastal Oil and Gas Survey Questionnaires. See Worksheet No. 1 for details.

(7) Total Incremental Volume of Drilling Waste from recompleted wells is the Product of the Average Volume of drilling waste generated from the third drilled interval of wells recently drilled in Cook Inlet, the Total Number of Wells scheduled for recompletion in Cook Inlet, the percent of total (99%) generated waste discharged under the current practice, and percent reduction (69%) of drilling waste by closed–loop system (SAIC, October 10, 1994). Based on information in 1993 Coastal Oil & Gas survey questionnaires. See Worksheet No. 1 for details.

(8) Total Incremental Volume of Drilling Waste from all wells is the sum of all wastes that will be generated in Cook Inlet, Column 6 + Column 7.

(9) Total Number of Injection Wells Needed is calculated based on information provided by the industry which specifies 1 dedicated well for every 4 new development wells (Schmidt, April 7, 1994). The number of dedicated wells needed for recompletions was assumed to be 1 for every 16 recompletions, (Column 4/4)+(Column 5/16).

(10) Estimated Cost of Drilling an Injection Well is calculated in Worksheet 1 or provided by the operators. See confidential supporting document (Safavi, Jan. 30, 1995).

(11) Total Cost of Injection Wells is the product of the total number of injection wells needed and the estimated cost of drilling an injection well, Column 9 x Column 10.

(12) Total Number of Injection Systems was estimated based on the assumption that 1 injection system is needed for every platform with a planned drilling program. Operator B specified the need for 4 injection systems since no more than 4 platforms are planned for drilling at one time. See confidential supporting document (Safavi, Jan. 30, 1995).

(13) Unit Cost of Injection System is provided by Operator B. See confidential supporting document (Safavi, Jan. 30, 1995).

(14) Unit Rental Cost of Injection System is provided by Operator A. See confidential supporting document (Safavi, Jan. 30, 1995).

(15) Buying Cost of Injection System is the product of the Total Number of Systems needed and Unit Buying cost of injection systems. Column 12 x Column 13.

(16) Rental Cost of Injection System is the product of the total number of days needed to complete drilling and the unit operating cost per day,
[(Column 4 x number of days to drill a well)+(Column 5 x number of days to recomplete a well)] x (Column 14).
The average drill time for a new development well or a recompletion was determined in Worksheet No. 1 and was assumed for Operators A and C. The numbers used for Operator B are as specified in the questionnaires.

(17) Applied Cost of Injection System is either the buying or the renting cost of injection systems depending on which is economically most feasible.

(18) Retrofit Cost of Injection System was provided by Operator B. See confidential supporting document (Safavi, Jan. 30, 1995).

(19) Total Cost of Retrofitting Platforms is the product of the Total Number of Platforms with planned drilling programs and the Unit Cost of Retrofitting Platforms, Column 3 x Column 18. This cost is based on the assumption that each platform with a planned drilling program must be retrofitted for an injection system.

(20) Unit Cost of Operating Injection Systems is provided by operators. See confidential supporting document (McIntyre, 1996).

(21) Total Cost of Operating Injection System is the product of the total number of days needed to complete drilling and the unit operating cost per day,
[(Column 4 x number of days to drill a well)+(Column 5 x number of days to recomplete a well)] x (Column 20).
The average drill time for a new development well or a recompletion was determined in Worksheet No. 1 and was assumed for all operators.

(22) Total Cost of High Efficiency Solids Control Equipment is the product of the total number of days the equipment will be needed and the cost of the equipment per day (Column 11, Worksheet 3).

(23) Total Cost of Retrofitting the platforms is the product of the unit retrofit cost and the total number of Platforms with planned drilling programs (Column 13, Worksheet 3).

(24) Total Cost of Operating the Solid Separation Equipment is the product of the unit operating cost per day and the total number of days the equipment is needed (Column 15, Worksheet 3).

(25) Total Cost of Solids Control System is the sum of Columns 22, 23, and 24.

(26) Total Injection Cost for all Drilling Waste is the sum of all total costs in Columns 11, 17, 19, 21, and 25.

NA Not applicable.

APPENDIX X-2

CALCULATION OF UNIT LANDFILL COSTS

Worksheet for Landfill Costs for Operators A&C

Assumptions and Input Data		Notes:
Total waste volume (bbls):	186,908	Worksheet 2, sum of A+C vol.s
Total waste volume (box–equivalents):	23,364	Volume / 8 bbl per box
Total cuttings volume (bbls):	35,513	19% of 186,908
Total cuttings volume (boxes):	4,439	Volume / 8 bbl per box
Total Muds Volume (bbls):	151,395	81% of 186,908
Density of Muds+Cuttings (lbs/bbl):	526	(0.19 x 980) + (0.81 x 420)
Density of Cuttings (lbs/bbl):	980	EPA, February 1995
Density of Muds (lbs/bbl):	420	EPA, February 1995
Supply Boat Capacity: See "Worksheet for Cook Inlet Supply Boat Frequency"		
Supply Boat Cost ($/day):	5,000	McIntyre, 1996
Truck Capacity (tons):	22	McIntyre, May 23, 1995
Truck Capacity (boxes):	10	(22 x 2000)lbs/526 lbspbbl/8 bpbox
Cost per Tuckload:	1,800	McIntyre, May 23, 1995
Per Box Purchase Cost:	125	EPA, February 1995
Disposal Facility Cost ($/box):	500	McIntyre, May 9 1995
Disposal Facility Cost ($/gallon):	1.9	McIntyre, May 9 1995

Supply Boats:

[(15 x 13 new)+(1 x 1 recompl)] x 2 days per trip x $5000/day = $1,960,000

Trucks to Oregon (Based on total box–equivalents of waste, although wastes will be transported as cuttings in boxes and muds in bulk):

(23,364 box–equiv./10 boxes per load) x $1,800 per load = $4,205,520

Cost of Boxes (Includes only cuttings boxes, assuming muds will be transported in bulk):

4,439 boxes x $125/box = $554,875

Disposal Facility Cost:

(4,439 cuttings boxes x $500/box) + (6,358,590 gal muds x $1.9/gallon) $14,300,821

TOTAL COST: $21,021,216

Cost per bbl: $112

Worksheet for Landfill Costs for Operator B

Assumptions and Input Data		Notes:
Total waste volume (bbls):	422,780	Worksheet 2
Total waste volume (box–equivalents):	52,848	Volume / 8 bbl/box
Total cuttings volume (bbls):	80,328	19% of 422,780
Total cuttings volume (boxes):	10,041	Volume / 8 bbl/box
Density of Cuttings (lbs/bbl):	980	EPA, February 1995
Density of Muds (lbs/bbl):	420	EPA, February 1995
Per Box Purchase Cost ($/box):	125	EPA, February 1995
Temporary Storage Cost ($/sq–ft/mo):	0.1	EPA, February 1995
Supply Boat Capacity: See "Worksheet for Cook Inlet Supply Boat Frequency"		
Supply Boat Cost ($/day):	5,000	McIntyre, 1996
Truck Capacity (boxes):	12	EPA, February 1995
Trucking Cost ($/day):	300	EPA, February 1995
Barge Capacity (boxes):	240	McIntyre, 1996
Barge Cost ($/day):	6,000	EPA, February 1995
Platform Handling Cost ($/bbl):	6.9	McIntyre, 1996
Waste Stabilization Cost ($/bbl):	12.47	McIntyre, 1996
Landfill Usage Fee ($/bbl):	45.38	McIntyre, 1996
Fill Cell Cost ($/bbl):	8.28	McIntyre, 1996

Cost of Boxes (Includes only cuttings boxes, assuming muds will be transported in bulk):
10,041 boxes x $125/box = $1,255,125

Temporary Storage (No change from original approach– –assumes temp. storage for bulk muds will be comparable to that of boxed cuttings):
52,848 box–equivalents x 16 sq–ft x $0.10 x 6 months = $507,341

Supply Boats:
[(15 x 27 new)+(1 x 18 recompl)] x 2 days per trip x $5000/day = $4,230,000

Trucks to Temporary Storage (Based on total box–equivalents of waste, although wastes will be transported as cuttings in boxes and muds in bulk):
(52,848 box–equiv/12 boxes per load) x $300 x 3 days = $3,963,600

Barges (Based on total box–equivalents of waste, although wastes will be transported as cuttings in boxes and muds in bulk):
(52,848 box–equiv/240 boxes per load) x $6000 x 2 days = $2,642,400

Platform Handling Cost:
422,780 bbl x $6.9/bbl = $2,917,182

Waste Stabilization Cost:
422,780 bbl x $12.47/bbl = $5,272,067

Landfill Usage Fee:
422,780 bbl x $45.38/bbl = $19,185,756

Fill Cell:
422,780 bbl x $8.28/bbl = $3,500,618

TOTAL COST: $43,474,089

Cost per bbl: $103

WORKSHEET for Cook Inlet Supply Boat Frequency

Assumptions and Input Data

Assumptions and Input Data		Notes:
Supply Boat Cuttings Capacity (tons):	300	McIntyre, May 12, 1995
Supply Boat Cuttings Capacity (boxes):	77	(300 x 2000)lbs/980 lbspbbl/8 bblpbox
Supply Boat Muds Capacity (tons):	170	McIntyre, May 12, 1995
Supply Boat Muds Capacity (box–equivalents):	101	(170 x 2000)lbs/420 lbspbbl/8 bblpbox
Cuttings Density (lbs/bbl):	980	EPA, February 1995
Muds Density (lbs/bbl):	420	EPA, February 1995
Average Cuttings % of Total:	19	Worksheet 1
Platform Cuttings Storage Capacity (boxes):	12	McIntyre, 1996
Regularly scheduled boat trips (per week):	2	McIntyre, 1996

Well Depth and Waste Volume Analysis

Depth Interval (feet)	Ft. Per Interval	M&C Vol. per Interval (bbls)*	Cuttings Vol. (bbls)	No. Cutting Boxes	Muds Vol. (bbls)	Hrs per Interval	Days Per Interval**	No. 12–Box Loads	Frequency of 12–bx Loads (hrs)
0–2553	2,553	3,462	658	82	2,804	165	13	7	24
2553–4500***	1,947	2,283	434	54	1,849	95	7	5	21
4500–9901	5,401	6,333	1,203	150	5,130	265	20	13	21
9901–10,000	99	115	22	3	93	12	1	0	52
10,000–11,765	1,765	2,057	391	49	1,666	216	17	4	53
		14,250	**2,708**	**339**	**11,542**	**753**	**58**	**28**	**172**

* Volumes per interval are 99% of the volumes presented in Worksheet 1. The total per well volume used here is slightly greater than the total in Worksheet 1 due to rounding differences in Worksheet 1.

** @ 13 hours per workday (from Worksheet 1).

*** The cut point at 4500 ft is from the Offshore NWQI document (EPA, Jan. 13, 1993), Appendix A, that states that drilling significantly slows down after 4500 ft. The coastal data from Worksheet 1 indicate a significant slowing after 9900 ft.

Conclusion:

<u>For New Wells:</u>

To 9901 feet, a boat is required every other day, for a total of 25 trips. Subtracting regularly scheduled boat trips:

25 – (40 days/7 days per week * 2 trips per week) = 14 trips

After 9901 feet, one additional dedicated trip will occur at the end of the drilling operation, for a total of 15 boat trips per well.

<u>For recompletions (that generate only 2172 bbls of muds and cuttings, or 272 box–equivalents):</u>

One dedicated boat trip is included in the calculations. Other regularly scheduled boats will transport the remainder of the waste volume.

APPENDIX X-3

DETAILED POLLUTANT REMOVAL ANALYSIS

Worksheet No. 10, May 17, 1996, Page 1 of 3
Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
Zero Discharge Option

Total Volume of Drilling Waste Currently Discharged, barrels = (From Worksheet No. 2; Column 8)	626,070
Average Cuttings Percent of Total. % = (From Worksheet No. 1, Column 17)	19%
Total Volume of Wet Cuttings Currently Discharged, barrels = (Total Volume) x (%Cuttings)	118,953
Volume of Drilling Muds Adhering to Cuttings, barrels = (5% of Wet Cuttings Volume; EPA, 1995)	5,948
Volume of Dry Cuttings, barrels = (95% of Wet Cuttings Volume)	113,006
Average Density of Dry Cuttings, pounds per barrel = (From SAIC, September 7, 1994)	980
Total Weight of Dry Cuttings Currently Discharged, pounds = (Average Density of Cuttings x Volume of Dry Cuttings) This value is used as TSS associated with cuttings	110,745,522
Total Volume of Drilling Muds Currently Discharged, barrels = [(Total Drilling Waste Volume) x (81% Fluids)] + (Volume of Muds Adhering to Cuttings) This value is used as the volumetric amount of muds discharged	513,064
Average Percent Dry Solids in Drilling Muds by Volume, % = (See SAIC, June 6, 1994)	11%
Total Volume of Dry Solids in Drilling Muds, barrels = (Percent Dry Solids x Total volume of Mud)	56,437
Average Density of Dry Solids in Drilling Muds, pounds per barrel = (See SAIC, June 6, 1994)	1025
Total Dry Weight of Muds Currently Discharged, pounds = (Average Density of Mud Solids x Total Volume of Mud Solids) This value is used as the dry-basis amount of muds discharged and the TSS associated with muds	57,848,007

Note: All volumes and weights are cumulative over 7 years from 1996 through 2002

Worksheet No. 10, May 17, 1996, Page 2 of 3
Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
Zero Discharge Option

(1) Pollutant Name	(2) Average Concentrations of Pollutants in Drilling Waste	(3) Total Amount of Drilling Waste Currently Discharged	(4) Total Cumulative Pollutant Loadings Based On Current Practices	(5) Percent Passing Zero Discharge Limitation (percent discharging)	(6) Total Cumulative Loadings Based on Zero Discharge	(7) Total Cumulative Reduction in Loadings Based on Zero Discharge
Conventional Pollutants	**lbs/bbl of mud**	**Barrels**	**Pounds**	**% of total**	**Pounds**	**Pounds**
TSS (Associated with Muds)			57,848,007	0%	0.0	57,848,007
TSS (Associated with Cuttings)			110,745,522	0%	0.0	110,745,522
TSS (Total)			**168,593,529**	**0%**	**0.0**	**168,593,529**
Total Oil (In Muds+Cuttings)	0.0596	513,064	30,579	0%	0.0	30,579
Total Conventional			168,624,108	0%	0.0	168,624,108
Priority Pollutants Organics	**lbs/bbl of mud**	**Barrels**	**Pounds**	**% of total**	**Pounds**	**Pounds**
Naphthalene	0.0000035	513,064	1.8	0%	0.0	1.8
Fluorene	0.0000563	513,064	28.9	0%	0.0	28.9
Phenenthrene	0.0000084	513,064	4.3	0%	0.0	4.3
Total Priority Pollutants Organics	0.0000682	513064	35.0	0%	0.0	35.0
Priority Pollutants Metals	**lbs/lb dry mud**	**Pounds**	**Pounds**	**% of total**	**Pounds**	**Pounds**
Cadmium	0.0000011	57,848,007	63.6	0%	0.0	63.6
Mercury	0.0000001	57,848,007	5.8	0%	0.0	5.8
Antimony	0.0000057	57,848,007	329.7	0%	0.0	329.7
Arsenic	0.0000071	57,848,007	410.7	0%	0.0	410.7
Beryllium	0.0000007	57,848,007	40.5	0%	0.0	40.5
Chromium	0.0002400	57,848,007	13,883.5	0%	0.0	13,883.5
Copper	0.0000187	57,848,007	1,081.8	0%	0.0	1,081.8
Lead	0.0000351	57,848,007	2,030.5	0%	0.0	2,030.5
Nickel	0.0000135	57,848,007	780.9	0%	0.0	780.9
Selenium	0.0000011	57,848,007	63.6	0%	0.0	63.6
Silver	0.0000007	57,848,007	40.5	0%	0.0	40.5
Thallium	0.0000012	57,848,007	69.4	0%	0.0	69.4
Zinc	0.0002005	57,848,007	11,598.5	0%	0.0	11,598.5
Total Priority Pollutants Metals	0.0005255	57,848,007	30,399.1	0%	0.0	30,399.1
Non-Conventional Pollutants	**lbs/lb or bbl of mud**	**Pounds or Barrels**	**Pounds**	**% of total**	**Pounds**	**Pounds**
Aluminum	0.0090699	57,848,007	524,675.6	0%	0.0	524,675.6
Barium	0.1200000	57,848,007	6,941,760.9	0%	0.0	6,941,760.9
Iron	0.0153443	57,848,007	887,637.2	0%	0.0	887,637.2
Tin	0.0000146	57,848,007	844.6	0%	0.0	844.6
Titanium	0.0000875	57,848,007	5,061.7	0%	0.0	5,061.7
Alkylated benzenes (a)	0.0021017	513,064	1,078.3	0%	0.0	1,078.3
Alkylated naphthalenes (b)	0.0000344	513,064	17.6	0%	0.0	17.6
Alkylated fluorenes (b)	0.0001218	513,064	62.5	0%	0.0	62.5
Alkylated phenanthrenes (b)	0.0000143	513,064	7.3	0%	0.0	7.3
Total biphenyls (b)	0.0001360	513,064	69.8	0%	0.0	69.8
Total dibenzothiophenes	0.0000004	513,064	0.2	0%	0.0	0.2
Total Non-Conventional Pollutants			8,361,216	0%	0.0	8,361,216
Total Reductions			177,015,758	0%	0.0	177,015,758

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Coastal Alaska Oil and Gas Drilling Industry
BAT Pollutant Loadings Analysis for Operators in Cook Inlet, Alaska
Cumulative Reduction in Pollutant Loadings
Zero Discharge Option

(1) Pollutant names include 14 heavy metals, 9 organic constituents, TSS, and Total Oil.
The listed pollutants of concern are as specified in Table VII−6 in the1995 Coastal Development Document (EPA, 1995).

(2) Average concentration of the listed heavy metals were obtained from the Offshore DD (Table XI−6) except the value for Barium (EPA, 1993).
Concentration of Barium in the drilling mud was estimated based on the average mud weight (see SAIC, June 6, 1994).
Average concentrations of organic constituents were estimated based on the assumption that the primary source of these compounds in the mud is mineral oil.
Organic concentrations were estimated based on 0.02% mineral oil by volume (see SAIC, June 7, 1994, and Schmidt, July 11, 1994).
Average concentration of Total Oil was also estimated based on the use of 0.02% mineral oil (see SAIC, June 7, 1994).

(3) Amount of drilling waste currently discharged is given as total dry weight of muds (lbs) for metals and as total volume of drilling muds (barrels) for organics and oil.
These values are calculated on page 1 of this worksheet.

(4) Total cumulative pollutant loadings based on the current practice is the product of the average concentrations of pollutants in drilling muds (Column 2) and the total amount of muds generated (Column 3).
The calculations for the TSS pollutant loadings are shown on page 1.

(5) Percent passing zero discharge limitation is zero.

(6) Total cumulative loadings based on zero discharge is zero since no waste is discharged.

(7) Total cumulative reduction in loadings is equal to the loading under the current practices (Column 4) minus Zero Discharge loading (Column 6).

APPENDIX XI-1

CAPITAL COSTS FOR OPTIONS 1 AND 2
GAS FLOTATION

TABLE A

CAPITAL COSTS FOR OPTIONS 1 AND 2
TRADING BAY PRODUCTION FACILITY

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
(4) 40,000 BPD Gas Flotation Units	827,699	
Piping and Instrumentation (15%)	124,155	
Total M&E Cost with Area Multiplier	951,854	
Installation		
Installation equal to M&E Cost	951,854	
Subtotal		1,903,708
Engineering (10%)	190,371	190,371
Contingency (15%)	285,558	285,558
Insurance & Bonding (4%)	76,148	76,148
Total		**2,455,786**

TABLE B

CAPITAL COSTS FOR OPTIONS 1 AND 2
GRANITE POINT TREATMENT FACILITY

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
5,000 BPD Gas Flotation Unit	147,804	
Piping and Instrumentation (15%)	22,171	
Total M&E Cost with Area Multiplier	339,948	
Installation		
Installation equal to M&E Cost	339,948	
Main Equipment Building	325,532	
Subtotal		1,005,428
Engineering (10%)	100,543	100,543
Contingency (15%)	150,814	150,814
Insurance & Bonding (4%)	40,217	40,217
Total		**1,297,002**

TABLE C

CAPITAL COSTS FOR OPTIONS 1 AND 2
EAST FORELAND TREATMENT FACILITY

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
5,000 BPD Gas Flotation Unit	147,804	
Piping and Instrumentation (15%)	22,171	
Total M&E Cost with Area Multiplier	339,948	
Installation		
Installation equal to M&E Cost	339,948	
Main Equipment Building	325,532	
Subtotal		1,005,428
Engineering (10%)	100,543	100,543
Contingency (15%)	150,814	150,814
Insurance & Bonding (4%)	40,217	40,217
Total		**1,297,002**

TABLE D

CAPITAL COSTS FOR OPTIONS 1 AND 2
DILLON PLATFORM

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
10,000 BPD Gas Flotation Unit	162,585	
Piping and Instrumentation (15%)	24,388	
Total M&E Cost with Area Multiplier	373,945	
Installation		
Installation equal to 2.5 x M&E Cost	934,862	
Subtotal		1,308,807
Engineering (10%)	130,881	
Contingency (15%)	196,320	
Insurance & Bonding (4%)	52,352	
SubTotal		379,553
Platform Modifications		
Cantilever Deck 266 SF @ $658.5/SF	175,161	
Engineering (10%)	17,516	
Contingency (15%)	26,274	
Insurance & Bonding (4%)	7,006	
SubTotal		225,957
TOTAL		**1,914,317**

TABLE E

CAPITAL COSTS FOR OPTIONS 1 AND 2
BRUCE PLATFORM

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
1,000 BPD Gas Flotation Unit	115,796	
Piping and Instrumentation (15%)	17,369	
Total M&E Cost with Area Multiplier	266,331	
Installation		
Installation equal to 2.5 x M&E Cost	665,828	
Subtotal		932,159
Engineering (10%)	93,216	
Contingency (15%)	139,824	
Insurance & Bonding (4%)	37,286	
SubTotal		270,326
Platform Modifications		
Cantilever Deck 112 SF @ $658.5/SF	73,752	
Engineering (10%)	7,375	
Contingency (15%)	11,064	
Insurance & Bonding (4%)	2,950	
SubTotal		95,141
TOTAL		**1,297,626**

TABLE F

CAPITAL COSTS FOR OPTIONS 1 AND 2
ANNA PLATFORM

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
5,000 BPD Gas Flotation Unit	147,804	
Piping and Instrumentation (15%)	22,171	
Total M&E Cost with Area Multiplier	339,948	
Installation		
Installation equal to 2.5 x M&E Cost	849,871	
Subtotal		1,189,819
Engineering (10%)	118,982	
Contingency (15%)	178,473	
Insurance & Bonding (4%)	47,593	
SubTotal		345,048
Platform Modifications		
Cantilever Deck 210 SF @ $658.5/SF	138,285	
Engineering (10%)	13,829	
Contingency (15%)	20,744	
Insurance & Bonding (4%)	5,531	
SubTotal		178,389
TOTAL		**1,713,256**

TABLE G

CAPITAL COSTS FOR OPTIONS 1 AND 2
BAKER PLATFORM

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
5,000 BPD Gas Flotation Unit	147,804	
Piping and Instrumentation (15%)	22,171	
Total M&E Cost with Area Multiplier	339,948	
Installation		
Installation equal to 2.5 x M&E Cost	849,871	
Subtotal		1,189,819
Engineering (10%)	118,982	
Contingency (15%)	178,473	
Insurance & Bonding (4%)	47,593	
SubTotal		345,048
Platform Modifications		
Cantilever Deck 210 SF @ $658.5/SF	138,285	
Engineering (10%)	13,829	
Contingency (15%)	20,744	
Insurance & Bonding (4%)	5,531	
SubTotal		178,389
TOTAL		**1,713,256**

APPENDIX XI-2

CAPITAL COSTS FOR OPTION 3
ZERO DISCHARGE VIA INJECTION

TABLE A
CAPITAL COSTS FOR OPTION 3
TRADING BAY PRODUCTION FACILITY

Cost Category	Itemized Cost (1995$)	Total Cost (1995$)
Materials and Equipment		
(4) Shipping Pumps	630,062	
(3) Pig Launchers	33,393	
(2) 15,000 Barrels Storage Tanks	1,260,124	
(3) Booster Pumps	220,522	
Piping and Instrumentation (15%)	321,615	
Total M&E Cost with Area Multiplier	4,931,430	
Installation		
Installation equal to M&E Cost	4,931,430	
Main Equipment Building	325,532	
SubTotal		10,188,392
Engineering (10%)	1,018,839	1,018,839
Contingency (15%)	1,528,259	1,528,259
Insurance & Bonding (4%)	407,536	407,536
Pipeline Costs		33,143,901
Total		**46,286,927**

TABLE B
CAPITAL COSTS FOR OPTION 3
GRANITE POINT TREATMENT FACILITY

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
5,000 BPD Gas Flotation Unit	147,804	
5,000 BPD Granular Filtration Unit	239,218	
Centrifuge	46,430	
Piping and Instrumentation (15%)	65,018	
Total M&E Cost with Area Multiplier		996,938
Installation		
Installation equal to M&E Cost		996,938
Main Equipment Building	325,532	325,532
Engineering (10%)	231,941	231,941
Contingency (15%)	347,911	347,911
Insurance & Bonding (4%)	92,776	92,776
TOTAL		**2,992,036**

TABLE C

CAPITAL COSTS FOR OPTION 3
EAST FORELAND TREATMENT FACILITY

Cost Category	Itemized Cost (1995$)	Total Cost (1995$)
Materials and Equipment		
5,000 BPD Gas Flotation Unit	147,804	
(2) Shipping Pumps	315,031	
(1) Pig Launcher	11,131	
(1) 15,000 Barrels Storage Tank	630,062	
(1) Booster Pump	73,507	
Piping and Instrumentation (15%)	176,630	
Total M&E Cost with Area Multiplier	2,708,328	
Installation		
Installation equal to M&E Cost	2,708,328	
Main Equipment Building	325,532	
SubTotal		5,742,188
Engineering (10%)	574,219	574,219
Contingency (15%)	861,328	861,328
Insurance & Bonding (4%)	229,688	229,688
Pipeline Costs		15,297,055
Total		**22,704,478**

TABLE D

CAPITAL COSTS FOR OPTION 3
KING SALMON, GRAYLING, DOLLY VARDEN PLATFORMS

Cost Category	Itemized Cost (1995$)	Total Cost (1995$)
Company Labor and Expense		
Project Engineer	43,900	
Hazard Analysis	18,658	
Expense	6,585	
SubTotal		69,143
Contract Engineering		
Design Contract	72,435	72,435
Contract Labor		
Offshore Piping & Structural	340,225	
Electrical & Instrumentation	43,900	
SubTotal		384,125
Contract Services		
Piping/Supports Prefabrication	38,413	
Foam Penetrations	8,231	
Painting	10,975	
PSM Document Revisions	10,975	
SubTotal		68,594
Materials		
Pig Receiver	11,131	
Pipeline, Valves, and Fittings	137,564	
Structural Steel	2,101	
Construction Consumables	63,006	
SubTotal		213,802
Construction Supervision/Inspection		
Inspector	59,265	59,265
X-Ray/Non-Destructive Testing		
NDE Contract	13,170	13,170
Logistics		
Boats and Helicopters	32,925	
Offshore Catering	49,388	
SubTotal		82,313
Alaska Region Indirect Expense	10,975	10,975
SubTotal		973,821
Contingency		
Contingency (10%)	97,382	97,382
Additional Centrifuge	539,091	539,091
Per Platform Equipment Cost		1,610,294
TOTAL (for 3 platforms)		**4,830,881**

TABLE E

CAPITAL COSTS FOR OPTION 3
SPARK PLATFORM

Cost Category	Itemized Cost (1995$)	Total Cost (1995$)
Company Labor and Expense		
Project Engineer	43,900	
Hazard Analysis	18,658	
Expense	6,585	
SubTotal		69,143
Contract Engineering		
Design Contract	72,435	72,435
Contract Labor		
Offshore Piping & Structural	340,225	
Electrical & Instrumentation	43,900	
SubTotal		384,125
Contract Services		
Piping/Supports Prefabrication	38,413	
Foam Penetrations	8,231	
Painting	10,975	
PSM Document Revisions	10,975	
SubTotal		68,594
Materials		
Pipeline, Valves, and Fittings	137,564	
Structural Steel	2,101	
Construction Consumables	63,006	
(2) Injection Pumps	64,046	
SubTotal		202,671
Construction Supervision/Inspection		
Inspector	59,265	59,265
X-Ray/Non-Destructive Testing		
NDE Contract	13,170	13,170
Logistics		
Boats and Helicopters	32,925	
Offshore Catering	49,388	
SubTotal		82,313
Alaska Region Indirect Expense	10,975	10,975
SubTotal		962,690
Contingency		
Contingency (10%)	96,269	96,269
Subtotal Capital Costs		1,058,959
Injection Well Costs		
(2) Well Recompletions	1,481,625	1,481,625
TOTAL		**2,540,584**

TABLE F

CAPITAL COSTS FOR OPTION 3
SWEPI "C" PLATFORM

Cost Category	Itemized Cost (1995$)	Total Cost (1995$)
Company Labor and Expense		
Project Engineer	43,900	
Hazard Analysis	18,658	
Expense	6,585	
SubTotal		69,143
Contract Engineering		
Design Contract	72,435	72,435
Contract Labor		
Offshore Piping & Structural	340,225	
Electrical & Instrumentation	43,900	
SubTotal		384,125
Contract Services		
Piping/Supports Prefabrication	38,413	
Foam Penetrations	8,231	
Painting	10,975	
PSM Document Revisions	10,975	
SubTotal		68,594
Materials		
Pig Receiver	11,131	
Pipeline, Valves, and Fittings	137,564	
Structural Steel	2,101	
Construction Consumables	63,006	
SubTotal		213,802
Construction Supervision/Inspection		
Inspector	59,265	59,265
X-Ray/Non-Destructive Testing		
NDE Contract	13,170	13,170
Logistics		
Boats and Helicopters	32,925	
Offshore Catering	49,388	
SubTotal		82,313
Alaska Region Indirect Expense	10,975	10,975
SubTotal		973,821
Contingency		
Contingency (10%)	97,382	97,382
Subtotal Capital Costs		1,071,203
Additional Centrifuge	269,481	269,481
TOTAL		**1,340,684**

TABLE G

CAPITAL COSTS FOR OPTION 3
DILLON PLATFORM

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
10,000 BPD Gas Flotation Unit	162,585	
Centrifuge	46,430	
Piping and Instrumentation (15%)	31,352	
Total M&E Cost with Area Multiplier		480,734
Installation		
Installation equal to 2.5 x M&E Cost		1,201,835
Engineering (10%)	168,257	
Contingency (15%)	252,385	
Insurance & Bonding (4%)	67,303	
SubTotal		487,945
Platform Modifications		
Cantilever Deck 266 SF @ $600/SF	175,161	
Engineering (10%)	17,516	
Contingency (15%)	26,274	
Insurance & Bonding (4%)	7,006	
SubTotal		225,958
TOTAL		**2,396,471**

TABLE H

CAPITAL COSTS FOR OPTION 3
BRUCE PLATFORM

Cost Category		Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment			
1,000 BPD Gas Flotation Unit		115,796	
Centrifuge		46,430	
Piping and Instrumentation (15%)		24,334	
Total M&E Cost with Area Multiplier			373,120
Installation			
Installation equal to 2.5 x M&E Cost			932,800
Engineering (10%)		130,592	
Contingency (15%)		195,888	
Insurance & Bonding (4%)		52,237	
	SubTotal		378,717
Platform Modifications			
Cantilever Deck 112 SF @ $600/SF		73,752	
Engineering (10%)		7,375	
Contingency (15%)		11,063	
Insurance & Bonding (4%)		2,950	
	SubTotal		95,140
Injection Well Costs			
(2) Injection Pumps		29,200	
Piping and Instrumentation (15%)		4,380	
Costs x Geog. Multiplier (Equip. Csts x 2)		33,580	
Installation (2.5 x Equip. Costs)		83,950	
Engineering (10%)		11,753	
Contingency (15%)		17,630	
Insurance & Bonding (4%)		4,701	
	SubTotal		185,194
(2) Injection Wells		2,627,795	2,627,795
TOTAL			4,592,766

TABLE I

CAPITAL COSTS FOR OPTION 3
ANNA PLATFORM

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
5,000 BPD Gas Flotation Unit	147,804	
Centrifuge	46,430	
Piping and Instrumentation (15%)	29,135	
Total M&E Cost with Area Multiplier		446,737
Installation		
Installation equal to 2.5 x M&E Cost		1,116,843
Engineering (10%)	156,358	
Contingency (15%)	234,537	
Insurance & Bonding (4%)	62,543	
SubTotal		453,438
Platform Modifications		
Cantilever Deck 210 SF @ $600/SF	138,285	
Engineering (10%)	13,829	
Contingency (15%)	20,743	
Insurance & Bonding (4%)	5,531	
SubTotal		178,388
TOTAL		**2,195,407**

TABLE J

CAPITAL COSTS FOR OPTION 3
BAKER PLATFORM

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
5,000 BPD Gas Flotation Unit	147,804	
Centrifuge	46,430	
Piping and Instrumentation (15%)	29,135	
Total M&E Cost with Area Multiplier		446,737
Installation		
Installation equal to 2.5 x M&E Cost		1,116,843
Engineering (10%)	156,358	
Contingency (15%)	234,537	
Insurance & Bonding (4%)	62,543	
SubTotal		453,438
Platform Modifications		
Cantilever Deck 210 SF @ $600/SF	138,285	
Engineering (10%)	13,829	
Contingency (15%)	20,743	
Insurance & Bonding (4%)	5,531	
SubTotal		178,388
TOTAL		**2,195,407**

TABLE K

CAPITAL COSTS FOR OPTION 3
TYONEK PLATFORM

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Materials and Equipment		
1,000 BPD Multi-Media Filtration System	113,154	
Centrifuge	46,430	
Piping and Instrumentation (15%)	23,938	
Total M&E Cost with Area Multiplier		367,043
Installation		
Installation equal to 2.5 x M&E Cost		917,608
Engineering (10%)	128,465	
Contingency (15%)	192,698	
Insurance & Bonding (4%)	51,386	
SubTotal		372,549
Platform Modifications		
Cantilever Deck 400 SF @ $600/SF	263,400	
Engineering (10%)	26,340	
Contingency (15%)	39,510	
Insurance & Bonding (4%)	10,536	
SubTotal		339,786
Injection Well Costs		
(2) Injection Pumps	29,200	
Piping and Instrumentation (15%)	4,380	
Costs x Geog. Multiplier (Equip. Csts x 2)	33,580	
Installation (2.5 x Equip. Costs)	83,950	
Engineering (10%)	11,753	
Contingency (15%)	17,630	
Insurance & Bonding (4%)	4,701	
SubTotal		185,194
(2) Injection Wells	2,627,795	2,627,795
TOTAL		**4,809,976**

APPENDIX XI-3

MODEL NEW SOURCE COOK INLET PLATFORM COMPLIANCE COST WORKSHEETS

TABLE A

MODEL NEW SOURCE COOK INLET PLATFORM PROFILE WORKSHEET: ESTIMATION OF PRODUCED WATER GENERATION RATE

Platform	Oil Prdn (bpd)	Oil Wells	Oil Prdn/Well (bpd)	Gas Prdn (MMcfd)	Gas Wells	Gas Prdn/Well (MMcfd)	Water Prdn (bpd)	bbl Water/bbl Oil	bbl Water/ MMcfd
K. Salmon	3,864	19	203				40,540	10.49	
Monopod	1,981	22	90				6,230	3.14	
Grayling	5,207	23	226				45,180	8.68	
G. Point	6,086	11	553				226	0.04	
Dillon	841	10	84				3,116	3.71	
Bruce	865	13	67				199	0.23	
Anna	3,117	23	136				919	0.29	
Baker	1,301	14	93				924	0.71	
D. Varden	4,983	24	208				31,510	6.32	
Steelhead	4,184	4	1,046	165	9	18	2,270	0.54	13.76
SWEPI A	3,200	17	188				300	0.09	
SWEPI C	1,800	17	106				1,400	0.78	
Tyonek				220	13	17	30		0.14
Average	**3,119**	--	**250**	**193**	--	--	**11,068**	**2.92**	(a)

PW Generation for Model New Source CI Platform:

(10 model oil wells x 250 bpd/well x 2.92 bbl PW/bbl oil) + (24 model gas wells x 17 MMcfd/well x 0.14 bbl PW/MMcfd) = **7,353 bpd**

(a) The value 13.76 bbl PW/MMcfd gas is not used to calculate an average produced water generation rate associated with gas production because the majority of the produced water from this platform is due to waterflooding for oil recovery.

TABLE B

MODEL NEW SOURCE COOK INLET PLATFORM CAPITAL AND O&M COSTS FOR PRODUCED WATER INJECTION (1995 $)

Model Produced Water Flow (BWPD) = 7,353

Cost Category	Itemized Cost (1995 $)	Total Cost (1995 $)
Capital Costs:		
Materials and Equipment		
10,000 BPD Granular Filtration Unit	127,381	
Centrifuge	46,430	
Piping and Instrumentation (15%)	26,072	
Total M&E Cost with Area Multiplier		**399,765**
Installation		
Installation equal to 2.5 x M&E Cost		**999,411**
Engineering (10%)	156,358	
Contingency (15%)	234,537	
Insurance and Bonding (4%)	62,543	
Subtotal		**453,438**
Injection Well Costs		
(2) 10,000 BWPD Injection Pumps (Installed)	437,454	
Piping and Instrumentation (15%)	65,618	
Total Injection Pump Cost w/ Area Multiplier		**1,006,143**
Engineering (10%)	50,307	
Contingency (15%)	75,461	
Insurance and Bonding (4%)	20,123	
Subtotal		**145,891**
(3) 6,000 BWPD Injection Wells	3,941,692	**3,941,692**
TOTAL CAPITAL COST		**$8,098,375**
O&M Costs:		
Standard O&M (10% Capital)	809,837	
Inj. Well Workovers	100,000	
Treatment Chemicals	245,100	
Sludge Disposal	162,641	
TOTAL O&M COST		**$1,517,578**

APPENDIX XII-1

TWC COMPLIANCE COST CALCULATIONS

EXISTING SOURCES/OPTION 1 FOR WORKOVER/TREATMENT FLUIDS

Input Data	
Total 1992 number of wells discharging W/T fluids (Sect. XII.4.1.1):	350
Average 1992 volume of W/T fluid discharged/well/yr (bbl/yr) (SAIC, Jan 31, 1995):	587
Percentage of Water-Access Facilities (Sect. XII.4.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.4.1.1):	0.344
Percentage of Medium/Large Facilities:	0.77
Percentage of Small Facilities:	0.23
Cost to treat W/T fluids with gas flotation at water-access sites ($/bbl)	0.021
Cost to treat W/T fluids with IGF at land-access sites ($/bbl)	0.10
Capacity of small-volume barge (bbls) (Sect. XII.4.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of one barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.4.1.3):	1097.5
Cost of 50% of barge transportation ($/job) (Sect. XII.4.1.3):	548.75
Cost of vacuum truck transportation ($/bbl) (Sect. XII.4.1.3):	1.92
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.4.1.3):	8.78

Gas Flotation Treatment Costs for Major Pass Facilities				
Facility Location	No. W/T Jobs/yr	No. Jobs/yr at IGF	Volume Treated per year (bbl)	IGF Treatm't Cost ($/yr)
Water-Access	58	25*	14,675	308
Land-Access	0	0	0	0
Total	58	25*	14,675	$308

*58 jobs less 33 jobs already going to IGF

Zero Discharge Costs for General Permit Facilities				
Facility Location	No. W/T Jobs/yr	Inj. Cost ($/bbl)	Volume Treated per year (bbl)	Injection Cost ($/yr)
Water-Access	119	$0.116	69,853	8,103
Land-Access	93	$0.218	54,591	11,901
Total	212		124,444	$20,004

Zero Discharge Costs for Small Facilities					
Facility Location	No. W/T Jobs/yr	Volume Disposed Commer'ly (bbl/yr)	Transportation Cost ($/yr)	Disposal Cost ($/yr)	Total Transport'n + Disposal Cost
Water-Access	52	30,524	28,535	268,001	$296,536
Land-Access	28	16,436	31,557	144,308	$175,865
Total	80	46,960	60,092	$412,309	$472,401

TOTAL TRANSPORTATION AND DISPOSAL COST FOR WORKOVER/TREATMENT FLUIDS ($/YR):	**$492,713**

EXISTING SOURCES/OPTION 1/COMPLETION FLUIDS

Input Data	
Total 1992 number of wells discharging completion fluids (Sect. XII-4.1.1):	334
Average 1992 volume of completion fluid discharged per well/yr (bbl/yr) (SAIC, Jan 31, 1995):	209
Percentage of Water-Access Facilities (Sect. XII.4.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.4.1.1):	0.344
Percentage of Medium/Large Facilities	0.77
Percentage of Small Facilities (dispose of completion fluids commercially):	0.23
Cost to treat completion fluids with gas flotation at water-access sites ($/bbl) (Sect. XII.4.1.2):	0.021
Cost to treat completion fluids with gas flotation at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.10
Capacity of small-volume barge (bbls) (Sect. XII.4.1.3):	1500
Assumed portion of barge used per job (i.e., 209 bbls per job require 1/4 of one barge):	0.25
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.4.1.3):	1097.5
Cost of 25% of barge transportation ($/job) (Sect. XII.4.1.3):	274.38
Cost of vacuum truck transportation ($/bbl) (Sect. XII.4.1.3):	1.92
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.4.1.3):	8.78

Gas Flotation Treatment Costs for Major Pass Facilities

Facility Location	No. Completion Jobs/yr	No. Jobs/yr at IGF	Volume Treated per year (bbl)	IGF Treatm't Cost ($/yr)
Water-Access	55	23*	4,807	101
Land-Access	0	0	0	0
Total	55	23*	4,807	$101

*55 jobs less 32 jobs already going to IGF

Zero Discharge Costs for General Permit Facilities

Facility Location	No. Comp. Jobs/yr	Inj. Cost ($/bbl)	Volume Treated per year (bbl)	Injection Cost ($/yr)
Water-Access	114	$0.116	23,826	2,764
Land-Access	88	$0.218	18,392	4,009
Total	202		42,218	$6,773

Zero Discharge Costs for Small Facilities

Facility Location	No. Comp. Jobs/yr	Volume Disposed Commer'ly (bbl/yr)	Transportation Cost ($/yr)	Disposal Cost ($/yr)	Total transport'n +Disposal Cost
Water-Access	51	10,659	13,993	93,586	$107,579
Land-Access	26	5,434	10,433	47,711	$58,144
Total	77	16,093	24,426	$141,297	$165,723

TOTAL TRANSPORTATION AND DISPOSAL COST FOR COMPLETION FLUIDS ($/YR):	**$172,597**

NEW SOURCES/OPTION 1 FOR WORKOVER/TREATMENT

Input Data	
Total number of wells discharging workover/treatment fluids (Sect. XII.4.1.1):	45
Average volume of workover/treatment fluid discharged per well/yr (bbl/yr) (SAIC, Jan 31, 1995):	587
Percentage of Water-Access Facilities:	0.656
Percentage of Land-Access Facilities:	0.344
Percentage of Medium/Large Facilities	0.77
Percentage of facilities that dispose of W/T fluids commercially:	0.23
Cost to treat W/T fluids with gas flotation at water-access sites ($/bbl):	0.021
Cost to treat W/T fluids with gas flotation at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.10
Cost to inject W/T fluids with produced water at water-access sites ($/bbl):	0.116
Cost to inject W/T fluids with produced water at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.218
Capacity of small-volume barge (bbls) (Sect. XII.4.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of one barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.4.1.3):	1097.5
Cost of 50% of barge transportation ($/job) (Sect. XII.4.1.3):	548.75
Cost of vacuum truck transportation ($/bbl) (Sect. XII.4.1.3):	1.92
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.4.1.3):	8.78

Gas Flotation Treatment Costs for Major Pass Facilities				
Facility Location	No. W/T Jobs/yr	No. Jobs/yr Treated	Vol. Treated (bbl/yr)	GF Treatm't Cost ($/yr)
Water-Access	6	6	3,522	74
Land-Access	0	0	0	0
Total	6	6	3,522	$74

Zero Discharge Costs for General Permit Facilities				
Facility Location	No. W/T Jobs/yr	No. Jobs Injected	Vol. Injected (bbl/yr)	Injection Cost ($/yr)
Water-Access	17	17	9,979	1,158
Land-Access	12	12	7,044	1,536
Total	29	29	17,023	$2,694

Zero Discharge Costs for Small Facilities						
Facility Location	No. W/T Jobs/yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly (bbl/yr)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	7	7	4,109	3,841	36,077	39,918
Land-Access	3	3	1,761	3,381	15,462	18,843
Total	10	10	5,870	$7,222	$51,539	$58,761

TOTAL OPTION 1 NSPS COST FOR WORKOVER/TREATMENT FLUIDS ($/YR):	**$61,529**

NEW SOURCES/OPTION 1 FOR COMPLETION FLUIDS

Input Data	
Total number of wells discharging workover/treatment fluids (Sect. XII.4.1.1):	45
Average volume of completion fluid discharged per well/yr (bbl/yr) (SAIC, Jan 31, 1995):	209
Percentage of Water-Access Facilities:	0.656
Percentage of Land-Access Facilities:	0.344
Percentage of Medium/Large Facilities	0.77
Percentage of facilities that dispose of W/T fluids commercially:	0.23
Cost to treat W/T fluids with gas flotation at water-access sites ($/bbl):	0.021
Cost to treat W/T fluids with gas flotation at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.10
Cost to treat W/T fluids with produced water at water-access sites ($/bbl):	0.116
Cost to treat W/T fluids with produced water at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.218
Capacity of small-volume barge (bbls) (Sect. XII.4.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of one barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.4.1.3):	1097.5
Cost of 50% of barge transportation ($/job) (Sect. XII.4.1.3):	548.75
Cost of vacuum truck transportation ($/bbl) (Sect. XII.4.1.3):	1.92
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.4.1.3):	8.78

Gas Flotation Treatment Costs for Major Pass Facilities				
Facility Location	No. W/T Jobs/yr	No. Jobs/yr Treated	Vol. Treated (bbl/yr)	GF Treatm't Cost ($/yr)
Water-Access	6	6	1,254	26
Land-Access	0	0	0	0
Total	6	6	1,254	$26

Zero Discharge Costs for General Permit Facilities				
Facility Location	No. W/T Jobs/yr	No. Jobs Injected	Vol. Injected (bbl/yr)	Injection Cost ($/yr)
Water-Access	17	17	3,553	412
Land-Access	12	12	2,508	547
Total	29	29	6,061	$959

Zero Discharge Costs for Small Facilities						
Facility Location	No. W/T Jobs/yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly (bbl/yr)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	7	7	1,463	3,841	12,845	16,686
Land-Access	3	3	627	1,204	5,505	6,709
Total	10	10	2,090	$5,045	$18,350	$23,395

TOTAL OPTION 1 NSPS COST FOR COMPLETION FLUIDS ($/YR):	$24,380

EXISTING SOURCES/OPTIONS 2 & 3 FOR WORKOVER/TREATMENT

Input Data	
Total 1992 number of wells discharging W/O,T fluids (Sect. XII.4.1.1):	350
Average 1992 volume of W/O,T fluid discharged per well/yr (bbl/yr) (SAIC, Jan 31, 1995):	587
Percentage of Water-Access Facilities (Sect. XII.4.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.4.1.1):	0.344
Percentage of Medium/Large Facilities (W/O,T fluids commingled with PW)	0.77
Percentage of Small Facilities that dispose of W/T fluids commercially (Sect. XII.4.1.2):	0.23
Cost to inject W/T fluids with produced water at water-access sites ($/bbl) (Sect. XII.4.1.2):	0.116
Cost to inject W/T fluids with produced water at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.218
Capacity of small-volume barge (bbls) (Sect. XII.4.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of one barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.4.1.3):	1097.5
Cost of 50% of barge transportation ($/job) (Sect. XII.4.1.3):	548.75
Cost of vacuum truck transportation ($/bbl) (Sect. XII.4.1.3):	1.92
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.4.1.3):	8.78

Zero Discharge Costs at Medium/Large-Volume Facilities				
Facility Location	No. W/O,C Jobs/yr	No. Jobs/yr Injected	Vol. Injected (bbl/yr)	Injection Cost ($/yr)
Water-Access	177	177	103,899	12,052
Land-Access	93	93	54,591	11,901
Total	270	270	158,490	$23,953

Zero Discharge Costs at Small-Volume Facilities						
Facility Location	No. W/T Jobs/yr	No. Jobs Dis-posed Commer'ly/yr	Volume Disp'd Comm'ly (bbl/yr)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	52	52	30,524	28,535	268,001	296,536
Land-Access	28	28	16,436	31,557	144,308	175,865
Total	80	80	46,960	$60,092	$412,309	$472,401

TOTAL ZERO DISCHARGE COST FOR WORKOVER/TREATMENT FLUIDS ($/YR):	**$496,354**

EXISTING SOURCES/OPTIONS 2 & 3 FOR COMPLETION FLUIDS

Input Data	
Total 1992 number of wells discharging completion fluids (Sect. XII.4.1.1):	334
Average 1992 volume of completion fluid discharged per well/yr (bbl/yr) (SAIC, Jan 31, 1995):	209
Percentage of Water-Access Facilities (Sect. XII.4.1.1):	0.656
Percentage of Land-Access Facilities (Sect. XII.4.1.1):	0.344
Percentage of Medium/Large Facilities	0.77
Percentage of Small Facilities (dispose of completion fluids commercially, Sect. XII.4.1.2):	0.23
Cost to inject completion fluids with produced water at water-access sites ($/bbl) (Sect. XII.4.1.2):	0.116
Cost to inject completion fluids with produced water at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.218
Capacity of small-volume barge (bbls) (Sect. XII.4.1.3):	1500
Assumed portion of barge used per job (i.e., 209 bbls per job require 1/4 of one barge):	0.25
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.4.1.3):	1097.5
Cost of 25% of barge transportation ($/job) (Sect. XII.4.1.3):	274.38
Cost of vacuum truck transportation ($/bbl) (Sect. XII.4.1.3):	1.92
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.4.1.3):	8.78

Injection Costs at Medium/Large-Volume Facilities				
Facility Location	# Comp. Jobs/yr	No. Jobs/yr Injected	Vol. Injected/yr (bbl)	Injection Cost ($/yr)
Water-Access	169	169	35,321	4,097
Land-Access	88	88	18,392	4,009
Total	257	257	53,713	$8,106

Disposal Costs at Small-Volume Facilities						
Facility Location	No. Comp. Jobs per yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly (bbl/yr)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	51	51	10,659	13,993	93,586	107,579
Land-Access	26	26	5,434	10,433	47,711	58,144
Total	77	77	16,093	$24,426	$141,297	$165,723

TOTAL INJECTION COST FOR COMPLETION FLUIDS ($/YR):	$173,829

NEW SOURCES/OPTIONS 2 & 3 FOR WORKOVER/TREATMENT FLUIDS

Input Data	
Total number of wells discharging workover/treatment fluids (Sect. XII.4.1.1):	45
Average volume of workover/treatment fluid discharged per well/yr (bbl/yr) (SAIC, Jan 31, 1995):	587
Percentage of Water-Access Facilities:	0.656
Percentage of Land-Access Facilities:	0.344
Percentage of Medium/Large Facilities	0.77
Percentage of facilities that dispose of W/T fluids commercially:	0.23
Cost to inject W/T fluids with produced water at water-access sites ($/bbl):	0.116
Cost to inject W/T fluids with produced water at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.218
Capacity of small-volume barge (bbls) (Sect. XII.4.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of one barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.4.1.3):	1097.5
Cost of 50% of barge transportation ($/job) (Sect. XII.4.1.3):	548.75
Cost of vacuum truck transportation ($/bbl) (Sect. XII.4.1.3):	1.92
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.4.1.3):	8.78

Zero Discharge Costs for Medium/Large Facilities				
Facility Location	No. W/T Jobs/yr	No. Jobs/yr Injected	Vol. Injected (bbl/yr)	Injection Cost ($/yr)
Water-Access	23	23	13,501	1,566
Land-Access	12	12	7,044	1,536
Total	35	35	20,545	$3,102

Zero Discharge Costs for Small Facilities						
Facility Location	No. W/T Jobs/yr	No. Jobs Disp'd Commer'ly/yr	Volume Disp'd Comm'ly (bbl/yr)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	7	7	4,109	3,841	36,077	39,918
Land-Access	3	3	1,761	3,381	15,462	16,666
Total	10	10	5,870	$7,222	$51,539	$58,761

TOTAL OPTION 2 & 3 NSPS COST FOR WORKOVER/TREATMENT FLUIDS ($/YR):	**$61,863**

NEW SOURCES/OPTIONS 2 & 3 FOR COMPLETION FLUIDS

Input Data	
Total number of wells discharging workover/treatment fluids (Sect. XII.4.1.1):	45
Average volume of completion fluid discharged per well/yr (bbl/yr) (SAIC, Jan 31, 1995):	209
Percentage of Water-Access Facilities:	0.656
Percentage of Land-Access Facilities:	0.344
Percentage of Medium/Large Facilities	0.77
Percentage of facilities that dispose of W/T fluids commercially:	0.23
Cost to inject W/T fluids with produced water at water-access sites ($/bbl):	0.116
Cost to inject W/T fluids with produced water at land-access sites ($/bbl) (Sect. XII.4.1.2):	0.218
Capacity of small-volume barge (bbls) (Sect. XII.4.1.3):	1500
Assumed portion of barge used per job (i.e., 587 bbls per job require 1/2 of one barge):	0.5
Cost of Barge + Tug Transportation ($/round trip) (Sect. XII.4.1.3):	1097.5
Cost of 50% of barge transportation ($/job) (Sect. XII.3.1.3):	548.75
Cost of vacuum truck transportation ($/bbl) (Sect. XII.4.1.3):	1.92
Commercial disposal cost for TWC fluids ($/bbl) (Sect. XII.4.1.3):	8.78

Zero Discharge Costs for Medium/Large Facilities				
Facility Location	No. W/T Jobs/yr	No. Jobs/yr Injected	Vol. Injected (bbl/yr)	Injection Cost ($/yr)
Water-Access	23	23	4,807	558
Land-Access	12	12	2,508	547
Total	35	35	7,315	$1,105

Zero Discharge Costs for Small Facilities						
Facility Location	No. W/T Jobs/yr	No. Jobs Disp.d Commercially/yr	Volume Disp'd Comm'ly (bbl/yr)	Transport'n Cost ($/yr)	Disposal Cost ($/yr)	Total Transp. + Disp. Cost
Water-Access	7	7	1,463	3,841	12,845	16,686
Land-Access	3	3	627	1,204	5,505	6,709
Total	10	10	2,090	$5,045	$18,350	$23,395

TOTAL OPTION 2 & 3 NSPS COST FOR COMPLETION FLUIDS ($/YR):	$24,500

APPENDIX XII-2

TWC POLLUTANT REMOVALS CALCULATIONS

ANNUAL POLLUTANT REMOVALS: OPTION 1 FOR EXISTING SOURCES OF WORKOVER/TREATMENT FLUIDS

Pollutant Parameter	Concentration (µg/l)			Vol. Currently Discharged (bbls)	Vol. Using IGF (bbls)	Vol. Using Zero Disch. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Zero Disch. Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Zero Disch. Effluent	Incremental
Conventionals										
Oil & Grease	231,688.00	23,500.00	0.00	186,079	14,675	171,404	15,078	121	0	14,957
Solids, Total Suspended	520,375.00	30,000.00	0.00	186,079	14,675	171,404	33,865	154	0	33,711
Total Conventionals							**48,943**	**275**	**0**	**48,668**
Priority Poll. Organics										
Benzene	1,341.00	1,225.91	0.00	186,079	14,675	171,404	87	6	0	81
Ethylbenzene	1,149.00	62.18	0.00	186,079	14,675	171,404	75	0	0	75
Methyl Chloride (Chloromethane)	29.00	29.00	0.00	186,079	14,675	171,404	2	0	0	2
Toluene	891.00	827.80	0.00	186,079	14,675	171,404	58	4	0	54
Fluorene	62.00	62.00	0.00	186,079	14,675	171,404	4	0	0	4
Naphthalene	525.00	92.02	0.00	186,079	14,675	171,404	34	0	0	34
Phenanthrene	64.00	64.00	0.00	186,079	14,675	171,404	4	0	0	4
Phenol	263.00	263.00	0.00	186,079	14,675	171,404	17	1	0	16
Total P.P. Organics							**281**	**11**	**0**	**270**
Priority Poll. Metals										
Antimony	29.60	29.60	0.00	186,079	14,675	171,404	2	0	0	2
Arsenic	166.00	73.08	0.00	186,079	14,675	171,404	11	0	0	11
Beryllium	8.64	8.64	0.00	186,079	14,675	171,404	1	0	0	1
Cadmium	26.08	14.47	0.00	186,079	14,675	171,404	2	0	0	2
Chromium	616.82	616.82	0.00	186,079	14,675	171,404	40	3	0	37
Copper	277.20	277.20	0.00	186,079	14,675	171,404	18	1	0	17
Lead	1,376.00	124.86	0.00	186,079	14,675	171,404	90	1	0	89
Nickel	115.52	115.52	0.00	186,079	14,675	171,404	8	1	0	7
Selenium	42.94	42.94	0.00	186,079	14,675	171,404	3	0	0	3
Silver	1.60	1.60	0.00	186,079	14,675	171,404	0	0	0	0
Thallium	13.46	13.46	0.00	186,079	14,675	171,404	1	0	0	1
Zinc	362.94	133.85	0.00	186,079	14,675	171,404	24	1	0	23
Total P.P. Metals							**200**	**7**	**0**	**193**

ANNUAL POLLUTANT REMOVALS: OPTION 1 FOR EXISTING SOURCES OF WORKOVER/TREATMENT FLUIDS

Pollutant Parameter	Concentration ($\mu g/l$)			Vol. Currently Discharged (bbls)	Vol. Using IGF (bbls)	Vol. Using Zero Disch. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Zero Disch. Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Zero Disch. Effluent	Incremental
Non-Conventionals										
Alumimum	6,468.40	49.93	0.00	186,079	14,675	171,404	421	0	0	421
Barium	498.10	498.10	0.00	186,079	14,675	171,404	32	3	0	29
Boron	15,042.00	15,042.00	0.00	186,079	14,675	171,404	979	77	0	902
Calcium	10,284,000.00	10,284,000.00	0.00	186,079	14,675	171,404	669,264	52,781	0	616,483
Cobalt	8.18	8.18	0.00	186,079	14,675	171,404	1	0	0	1
Cyanide, Total	52.00	52.00	0.00	186,079	14,675	171,404	3	0	0	3
Iron	384,412.00	3,146.15	0.00	186,079	14,675	171,404	25,017	16	0	25,001
Manganese	5,146.00	74.16	0.00	186,079	14,675	171,404	335	0	0	335
Magnesium	5,052,280.00	5,052,280.00	0.00	186,079	14,675	171,404	328,793	25,930	0	302,863
Molybdenum	63.00	63.00	0.00	186,079	14,675	171,404	4	0	0	4
Sodium	18,886,000.00	18,886,000.00	0.00	186,079	14,675	171,404	1,229,066	96,929	0	1,132,137
Strontium	142,720.00	142,720.00	0.00	186,079	14,675	171,404	9,288	732	0	8,556
Sulfur	245,300.00	245,300.00	0.00	186,079	14,675	171,404	15,964	1,259	0	14,705
Tin	27.00	27.00	0.00	186,079	14,675	171,404	2	0	0	2
Titanium	74.58	4.48	0.00	186,079	14,675	171,404	5	0	0	5
Vanadium	1,156.00	1,156.00	0.00	186,079	14,675	171,404	75	6	0	69
Yttrium	41.92	41.92	0.00	186,079	14,675	171,404	3	0	0	3
Acetone	7,205.00	7,205.00	0.00	186,079	14,675	171,404	469	37	0	432
Methyl Ethyl Ketone (2-Butanone)	58.00	58.00	0.00	186,079	14,675	171,404	4	0	0	4
Total Xylenes	2,675.00	378.01	0.00	186,079	14,675	171,404	174	2	0	172
4-Methyl-2-Pentanone	3,028.00	3,028.00	0.00	186,079	14,675	171,404	197	16	0	181
Dibenzofuran	137.00	137.00	0.00	186,079	14,675	171,404	9	1	0	8
Dibenzothiophene	111.00	111.00	0.00	186,079	14,675	171,404	7	1	0	6
N-Decane (N-C10)	275.00	275.00	0.00	186,079	14,675	171,404	18	1	0	17
N-Docosane (N-C22)	771.00	771.00	0.00	186,079	14,675	171,404	50	4	0	46
N-Dodecane (N-C12)	576.00	576.00	0.00	186,079	14,675	171,404	37	3	0	34
N-Eicosane (N-C20)	226.00	226.00	0.00	186,079	14,675	171,404	15	1	0	14
N-Hexacosane (N-C26)	481.00	481.00	0.00	186,079	14,675	171,404	31	2	0	29
N-Hexadecane (N-C16)	404.00	404.00	0.00	186,079	14,675	171,404	26	2	0	24
N-Octacosane (N-C28)	211.00	211.00	0.00	186,079	14,675	171,404	14	1	0	13
N-Octadecane (N-C18)	1,075.00	1,075.00	0.00	186,079	14,675	171,404	70	6	0	64
N-Tetracosane (N-C24)	801.00	801.00	0.00	186,079	14,675	171,404	52	4	0	48
N-Tetradecane (N-C14)	1,237.00	1,237.00	0.00	186,079	14,675	171,404	81	6	0	75
P-Cymene	72.00	72.00	0.00	186,079	14,675	171,404	5	0	0	5
Pentamethylbenzene	54.00	54.00	0.00	186,079	14,675	171,404	4	0	0	4
1-Methylfluorene	82.00	82.00	0.00	186,079	14,675	171,404	5	0	0	5
2-Methylnaphthalene	817.00	817.00	0.00	186,079	14,675	171,404	53	4	0	49
Tot. Non-Conventionals							**2,280,573**	**177,824**	**0**	**2,102,749**
Grand Total Pollutant Loadings/Removals							**2,329,997**	**178,117**	**0**	**2,151,880**

ANNUAL POLLUTANT REMOVALS: OPTION 1 FOR EXISTING SOURCES OF COMPLETION FLUIDS

Pollutant Parameter	Concentration ($\mu g/l$)			Vol. Currently Discharged (bbls)	Vol. Using IGF (bbls)	Vol. Using Zero Disch. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Zero Disch. Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Zero Disch. Effluent	Incremental
Conventionals										
Oil & Grease	231,688.00	23,500.00	0	63,118	4,807	58,311	5,114	40	0	5,074
Solids, Total Suspended	520,375.00	30,000.00	0	63,118	4,807	58,311	11,487	50	0	11,437
Total Conventionals							**16,601**	**90**	**0**	**16,511**
Priority Poll. Organics										
Benzene	1,341.00	1,225.91	0	63,118	4,807	58,311	30	2	0	28
Ethylbenzene	1,149.00	62.18	0	63,118	4,807	58,311	25	0	0	25
Methyl Chloride (Chloromethane)	29.00	29.00	0	63,118	4,807	58,311	1	0	0	1
Toluene	891.00	827.8	0	63,118	4,807	58,311	20	1	0	19
Fluorene	62.00	62.00	0	63,118	4,807	58,311	1	0	0	1
Naphthalene	525.00	92.02	0	63,118	4,807	58,311	12	0	0	12
Phenanthrene	64.00	64.00	0	63,118	4,807	58,311	1	0	0	1
Phenol	263.00	263.00	0	63,118	4,807	58,311	6	0	0	6
Total P.P. Organics							**96**	**3**	**0**	**93**
Priority Poll. Metals										
Antimony	29.60	29.60	0	63,118	4,807	58,311	1	0	0	1
Arsenic	166.00	73.08	0	63,118	4,807	58,311	4	0	0	4
Beryllium	8.64	8.64	0	63,118	4,807	58,311	0	0	0	0
Cadmium	26.08	14.47	0	63,118	4,807	58,311	1	0	0	1
Chromium	616.82	616.82	0	63,118	4,807	58,311	14	1	0	13
Copper	277.20	277.20	0	63,118	4,807	58,311	6	0	0	6
Lead	1,376.00	124.86	0	63,118	4,807	58,311	30	0	0	30
Nickel	115.52	115.52	0	63,118	4,807	58,311	3	0	0	3
Selenium	42.94	42.94	0	63,118	4,807	58,311	1	0	0	1
Silver	1.60	1.60	0	63,118	4,807	58,311	0	0	0	0
Thallium	13.46	13.46	0	63,118	4,807	58,311	0	0	0	0
Zinc	362.94	133.85	0	63,118	4,807	58,311	8	0	0	8
Total P.P. Metals							**68**	**1**	**0**	**67**

ANNUAL POLLUTANT REMOVALS: OPTION 1 FOR EXISTING SOURCES OF COMPLETION FLUIDS (Continued)

Pollutant Parameter	Concentration (µg/l)			Vol. Currently Discharged (bbls)	Vol. Using IGF (bbls)	Vol. Using Zero Disch. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Zero Disch. Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Zero Disch. Effluent	Incremental
Non-Conventionals										
Aluminum	6,468.40	49.93	0	63,118	4,807	58,311	143	0	0	143
Barium	498.10	498.10	0	63,118	4,807	58,311	11	1	0	10
Boron	15,042.00	15,042.00	0	63,118	4,807	58,311	332	25	0	307
Calcium	10,284,000.00	10,284,000.00	0	63,118	4,807	58,311	227,014	17,289	0	209,725
Cobalt	8.18	8.18	0	63,118	4,807	58,311	0	0	0	0
Cyanide, Total	52.00	52.00	0	63,118	4,807	58,311	1	0	0	1
Iron	384,412.00	3146.15	0	63,118	4,807	58,311	8,486	5	0	8,481
Manganese	5,146.00	74.16	0	63,118	4,807	58,311	114	0	0	114
Magnesium	5,052,280.00	5,052,280.00	0	63,118	4,807	58,311	111,527	8,494	0	103,033
Molybdenum	63.00	63.00	0	63,118	4,807	58,311	1	0	0	1
Sodium	18,886,000.00	18,886,000.00	0	63,118	4,807	58,311	416,899	31,751	0	385,148
Strontium	142,720.00	142,720.00	0	63,118	4,807	58,311	3,150	240	0	2,910
Sulfur	245,300.00	245,300.00	0	63,118	4,807	58,311	5,415	412	0	5,003
Tin	27.00	27.00	0	63,118	4,807	58,311	1	0	0	1
Titanium	74.58	4.48	0	63,118	4,807	58,311	2	0	0	2
Vanadium	1,156.00	1,156.00	0	63,118	4,807	58,311	26	2	0	24
Yttrium	41.92	41.92	0	63,118	4,807	58,311	1	0	0	1
Acetone	7,205.00	7,205.00	0	63,118	4,807	58,311	159	12	0	147
Methyl Ethyl Ketone (2-Butanone)	58.00	58.00	0	63,118	4,807	58,311	1	0	0	1
Total Xylenes	2675	378.01	0	63,118	4,807	58,311	59	1	0	58
4-Methyl-2-Pentanone	3,028.00	3,028.00	0	63,118	4,807	58,311	67	5	0	62
Dibenzofuran	137.00	137.00	0	63,118	4,807	58,311	3	0	0	3
Dibenzothiophene	111.00	111.00	0	63,118	4,807	58,311	2	0	0	2
N-Decane (N-C10)	275.00	275.00	0	63,118	4,807	58,311	6	0	0	6
N-Docosane (N-C22)	771.00	771.00	0	63,118	4,807	58,311	17	1	0	16
N-Dodecane (N-C12)	576.00	576.00	0	63,118	4,807	58,311	13	1	0	12
N-Eicosane (N-C20)	226.00	226.00	0	63,118	4,807	58,311	5	0	0	5
N-Hexacosane (N-C26)	481.00	481.00	0	63,118	4,807	58,311	11	1	0	10
N-Hexadecane (N-C16)	404.00	404.00	0	63,118	4,807	58,311	9	1	0	8
N-Octacosane (N-C28)	211.00	211.00	0	63,118	4,807	58,311	5	0	0	5
N-Octadecane (N-C18)	1,075.00	1,075.00	0	63,118	4,807	58,311	24	2	0	22
N-Tetracosane (N-C24)	801.00	801.00	0	63,118	4,807	58,311	18	1	0	17
N-Tetradecane (N-C14)	1,237.00	1,237.00	0	63,118	4,807	58,311	27	2	0	25
P-Cymene	72.00	72.00	0	63,118	4,807	58,311	2	0	0	2
Pentamethylbenzene	54.00	54.00	0	63,118	4,807	58,311	1	0	0	1
1-Methylfluorene	82.00	82.00	0	63,118	4,807	58,311	2	0	0	2
2-Methylnaphthalene	817.00	817.00	0	63,118	4,807	58,311	18	1	0	17
Tot. Non-Conventionals							**773,572**	**58,247**	**0**	**715,325**
Grand Total Pollutant Loadings/Removals							**790,337**	**58,341**	**0**	**731,996**

ANNUAL POLLUTANT REMOVALS: OPTION 1 FOR NEW SOURCES OF WORKOVER/TREATMENT FLUIDS

Pollutant Parameter	Concentration (µg/l)			Total Volume (bbls)	Vol. Using IGF (bbls)	Vol. Using Zero Disch. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Zero Disch. Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Zero Disch. Effluent	Incremental
Conventionals										
Oil & Grease	231,688.00	23,500.00	0	24,654	1,761	22,893	1,998	14	0	1,984
Solids, Total Suspended	520,375.00	30,000.00	0	24,654	1,761	22,893	4,487	18	0	4,469
Total Conventionals							**6,485**	**32**	**0**	**6,453**
Priority Poll. Organics										
Benzene	1,341.00	1,225.91	0	24,654	1,761	22,893	12	1	0	11
Ethylbenzene	1,149.00	62.18	0	24,654	1,761	22,893	10	0	0	10
Methyl Chloride (Chloromethane)	29.00	29.00	0	24,654	1,761	22,893	0	0	0	0
Toluene	891.00	827.8	0	24,654	1,761	22,893	8	1	0	7
Fluorene	62.00	62.00	0	24,654	1,761	22,893	1	0	0	1
Naphthalene	525.00	92.02	0	24,654	1,761	22,893	5	0	0	5
Phenanthrene	64.00	64.00	0	24,654	1,761	22,893	1	0	0	1
Phenol	263.00	263.00	0	24,654	1,761	22,893	2	0	0	2
Total P.P. Organics							**39**	**2**	**0**	**37**
Priority Poll. Metals										
Antimony	29.60	29.60	0	24,654	1,761	22,893	0	0	0	0
Arsenic	166.00	73.08	0	24,654	1,761	22,893	1	0	0	1
Beryllium	8.64	8.64	0	24,654	1,761	22,893	0	0	0	0
Cadmium	26.08	14.47	0	24,654	1,761	22,893	0	0	0	0
Chromium	616.82	616.82	0	24,654	1,761	22,893	5	0	0	5
Copper	277.20	277.20	0	24,654	1,761	22,893	2	0	0	2
Lead	1,376.00	124.86	0	24,654	1,761	22,893	12	0	0	12
Nickel	115.52	115.52	0	24,654	1,761	22,893	1	0	0	1
Selenium	42.94	42.94	0	24,654	1,761	22,893	0	0	0	0
Silver	1.60	1.60	0	24,654	1,761	22,893	0	0	0	0
Thallium	13.46	13.46	0	24,654	1,761	22,893	0	0	0	0
Zinc	362.94	133.85	0	24,654	1,761	22,893	3	0	0	3
Total P.P. Metals							**24**	**0**	**0**	**24**

ANNUAL POLLUTANT REMOVALS: OPTION 1 FOR NEW SOURCES OF WORKOVER/TREATMENT FLUIDS (Continued)

Pollutant Parameter	Concentration ($\mu g/l$)			Total Volume (bbls)	Vol. Using IGF (bbls)	Vol. Using Zero Disch. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Zero Disch. Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Zero Disch. Effluent	Incremental
Non-Conventionals										
Aluminum	6,468.40	49.93	0	24,654	1,761	22,893	56	0	0	56
Barium	498.10	498.10	0	24,654	1,761	22,893	4	0	0	4
Boron	15,042.00	15,042.00	0	24,654	1,761	22,893	130	9	0	121
Calcium	10,284,000.00	10,284,000.00	0	24,654	1,761	22,893	88,672	6,334	0	82,338
Cobalt	8.18	8.18	0	24,654	1,761	22,893	0	0	0	0
Cyanide, Total	52.00	52.00	0	24,654	1,761	22,893	0	0	0	0
Iron	384,412.00	3146.15	0	24,654	1,761	22,893	3,315	2	0	3,313
Manganese	5,146.00	74.16	0	24,654	1,761	22,893	44	0	0	44
Magnesium	5,052,280.00	5,052,280.00	0	24,654	1,761	22,893	43,562	3,112	0	40,450
Molybdenum	63.00	63.00	0	24,654	1,761	22,893	1	0	0	1
Sodium	18,886,000.00	18,886,000.00	0	24,654	1,761	22,893	162,842	11,632	0	151,210
Strontium	142,720.00	142,720.00	0	24,654	1,761	22,893	1,231	88	0	1,143
Sulfur	245,300.00	245,300.00	0	24,654	1,761	22,893	2,115	151	0	1,964
Tin	27.00	27.00	0	24,654	1,761	22,893	0	0	0	0
Titanium	74.58	4.48	0	24,654	1,761	22,893	1	0	0	1
Vanadium	1,156.00	1,156.00	0	24,654	1,761	22,893	10	1	0	9
Yttrium	41.92	41.92	0	24,654	1,761	22,893	0	0	0	0
Acetone	7,205.00	7,205.00	0	24,654	1,761	22,893	62	4	0	58
Methyl Ethyl Ketone (2-Butanone)	58.00	58.00	0	24,654	1,761	22,893	1	0	0	1
Total Xylenes	2675	378.01	0	24,654	1,761	22,893	23	0	0	23
4-Methyl-2-Pentanone	3,028.00	3,028.00	0	24,654	1,761	22,893	26	2	0	24
Dibenzofuran	137.00	137.00	0	24,654	1,761	22,893	1	0	0	1
Dibenzothiophene	111.00	111.00	0	24,654	1,761	22,893	1	0	0	1
N-Decane (N-C10)	275.00	275.00	0	24,654	1,761	22,893	2	0	0	2
N-Docosane (N-C22)	771.00	771.00	0	24,654	1,761	22,893	7	0	0	7
N-Dodecane (N-C12)	576.00	576.00	0	24,654	1,761	22,893	5	0	0	5
N-Eicosane (N-C20)	226.00	226.00	0	24,654	1,761	22,893	2	0	0	2
N-Hexacosane (N-C26)	481.00	481.00	0	24,654	1,761	22,893	4	0	0	4
N-Hexadecane (N-C16)	404.00	404.00	0	24,654	1,761	22,893	3	0	0	3
N-Octacosane (N-C28)	211.00	211.00	0	24,654	1,761	22,893	2	0	0	2
N-Octadecane (N-C18)	1,075.00	1,075.00	0	24,654	1,761	22,893	9	1	0	8
N-Tetracosane (N-C24)	801.00	801.00	0	24,654	1,761	22,893	7	0	0	7
N-Tetradecane (N-C14)	1,237.00	1,237.00	0	24,654	1,761	22,893	11	1	0	10
P-Cymene	72.00	72.00	0	24,654	1,761	22,893	1	0	0	1
Pentamethylbenzene	54.00	54.00	0	24,654	1,761	22,893	0	0	0	0
1-Methylfluorene	82.00	82.00	0	24,654	1,761	22,893	1	0	0	1
2-Methylnaphthalene	817.00	817.00	0	24,654	1,761	22,893	7	1	0	6
Tot. Non-Conventionals							**302,158**	**21,338**	**0**	**280,820**
Grand Total Pollutant Loadings/Removals							**308,706**	**21,372**	**0**	**287,334**

ANNUAL POLLUTANT REMOVALS: OPTION 1 FOR NEW SOURCES OF COMPLETION FLUIDS

Pollutant Parameter	Concentration (µg/l)			Total Volume (bbls)	Vol. Using IGF (bbls)	Vol. Using Zero Disch. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Zero Disch. Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Zero Disch. Effluent	Incremental
Conventionals										
Oil & Grease	231,688.00	23,500.00	0	8,778	627	8,151	711	5	0	706
Solids, Total Suspended	520,375.00	30,000.00	0	8,778	627	8,151	1,598	7	0	1,591
Total Conventionals							**2,309**	**12**	**0**	**2,297**
Priority Poll. Organics										
Benzene	1,341.00	1,225.91	0	8,778	627	8,151	4	0	0	4
Ethylbenzene	1,149.00	62.18	0	8,778	627	8,151	4	0	0	4
Methyl Chloride (Chloromethane)	29.00	29.00	0	8,778	627	8,151	0	0	0	0
Toluene	891.00	827.8	0	8,778	627	8,151	3	0	0	3
Fluorene	62.00	62.00	0	8,778	627	8,151	0	0	0	0
Naphthalene	525.00	92.02	0	8,778	627	8,151	2	0	0	2
Phenanthrene	64.00	64.00	0	8,778	627	8,151	0	0	0	0
Phenol	263.00	263.00	0	8,778	627	8,151	1	0	0	1
Total P.P. Organics							**14**	**0**	**0**	**14**
Priority Poll. Metals										
Antimony	29.60	29.60	0	8,778	627	8,151	0	0	0	0
Arsenic	166.00	73.08	0	8,778	627	8,151	1	0	0	1
Beryllium	8.64	8.64	0	8,778	627	8,151	0	0	0	0
Cadmium	26.08	14.47	0	8,778	627	8,151	0	0	0	0
Chromium	616.82	616.82	0	8,778	627	8,151	2	0	0	2
Copper	277.20	277.20	0	8,778	627	8,151	1	0	0	1
Lead	1,376.00	124.86	0	8,778	627	8,151	4	0	0	4
Nickel	115.52	115.52	0	8,778	627	8,151	0	0	0	0
Selenium	42.94	42.94	0	8,778	627	8,151	0	0	0	0
Silver	1.60	1.60	0	8,778	627	8,151	0	0	0	0
Thallium	13.46	13.46	0	8,778	627	8,151	0	0	0	0
Zinc	362.94	133.85	0	8,778	627	8,151	1	0	0	1
Total P.P. Metals							**9**	**0**	**0**	**9**

ANNUAL POLLUTANT REMOVALS: OPTION 1 FOR NEW SOURCES OF COMPLETION FLUIDS (Continued)

Pollutant Parameter	Concentration (µg/l)			Total Volume (bbls)	Vol. Using IGF (bbls)	Vol. Using Zero Disch. (bbls)	Loading (lbs)			Removals (lbs)
	Current-Level Effluent	Gas Flotation Effluent	Zero Disch. Effluent				Curr.-Level Effluent	Gas Flot'n Effluent	Zero Disch. Effluent	Incremental
Non-Conventionals										
Aluminum	6,468.40	49.93	0	8,778	627	8,151	20	0	0	20
Barium	498.10	498.10	0	8,778	627	8,151	2	0	0	2
Boron	15,042.00	15,042.00	0	8,778	627	8,151	46	3	0	43
Calcium	10,284,000.00	10,284,000.00	0	8,778	627	8,151	31,572	2,255	0	29,317
Cobalt	8.18	8.18	0	8,778	627	8,151	0	0	0	0
Cyanide, Total	52.00	52.00	0	8,778	627	8,151	0	0	0	0
Iron	384,412.00	3146.15	0	8,778	627	8,151	1,180	1	0	1,179
Manganese	5,146.00	74.16	0	8,778	627	8,151	16	0	0	16
Magnesium	5,052,280.00	5,052,280.00	0	8,778	627	8,151	15,510	1,108	0	14,402
Molybdenum	63.00	63.00	0	8,778	627	8,151	0	0	0	0
Sodium	18,886,000.00	18,886,000.00	0	8,778	627	8,151	57,979	4,141	0	53,838
Strontium	142,720.00	142,720.00	0	8,778	627	8,151	438	31	0	407
Sulfur	245,300.00	245,300.00	0	8,778	627	8,151	753	54	0	699
Tin	27.00	27.00	0	8,778	627	8,151	0	0	0	0
Titanium	74.58	4.48	0	8,778	627	8,151	0	0	0	0
Vanadium	1,156.00	1,156.00	0	8,778	627	8,151	4	0	0	4
Yttrium	41.92	41.92	0	8,778	627	8,151	0	0	0	0
Acetone	7,205.00	7,205.00	0	8,778	627	8,151	22	2	0	20
Methyl Ethyl Ketone (2-Butanone)	58.00	58.00	0	8,778	627	8,151	0	0	0	0
Total Xylenes	2675	378.01	0	8,778	627	8,151	8	0	0	8
4-Methyl-2-Pentanone	3,028.00	3,028.00	0	8,778	627	8,151	9	1	0	8
Dibenzofuran	137.00	137.00	0	8,778	627	8,151	0	0	0	0
Dibenzothiophene	111.00	111.00	0	8,778	627	8,151	0	0	0	0
N-Decane (N-C10)	275.00	275.00	0	8,778	627	8,151	1	0	0	1
N-Docosane (N-C22)	771.00	771.00	0	8,778	627	8,151	2	0	0	2
N-Dodecane (N-C12)	576.00	576.00	0	8,778	627	8,151	2	0	0	2
N-Eicosane (N-C20)	226.00	226.00	0	8,778	627	8,151	1	0	0	1
N-Hexacosane (N-C26)	481.00	481.00	0	8,778	627	8,151	1	0	0	1
N-Hexadecane (N-C16)	404.00	404.00	0	8,778	627	8,151	1	0	0	1
N-Octacosane (N-C28)	211.00	211.00	0	8,778	627	8,151	1	0	0	1
N-Octadecane (N-C18)	1,075.00	1,075.00	0	8,778	627	8,151	3	0	0	3
N-Tetracosane (N-C24)	801.00	801.00	0	8,778	627	8,151	2	0	0	2
N-Tetradecane (N-C14)	1,237.00	1,237.00	0	8,778	627	8,151	4	0	0	4
P-Cymene	72.00	72.00	0	8,778	627	8,151	0	0	0	0
Pentamethylbenzene	54.00	54.00	0	8,778	627	8,151	0	0	0	0
1-Methylfluorene	82.00	82.00	0	8,778	627	8,151	0	0	0	0
2-Methylnaphthalene	817.00	817.00	0	8,778	627	8,151	3	0	0	3
Tot. Non-Conventionals							**107,580**	**7,596**	**0**	**99,984**
Grand Total Pollutant Loadings/Removals							**109,912**	**7,608**	**0**	**102,304**

ANNUAL POLLUTANT REMOVALS: OPTIONS 2 AND 3 FOR EXISTING SOURCES OF WORKOVER/TREATMENT FLUIDS

Pollutant Parameter	Flores & Rucks (IGF to zero discharge)			All others (settling effluent to zero discharge)			Loadings (lbs)		Removals (lbs)
	Concentration (μg/l)		Volume Currently Discharged (bbls)	Concentration (μg/l)		Volume Currently Discharged (bbls)			
	Current-Level Effluent[a,b]	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent		Current-Lev el Effluent	Treat.-Level Effluent	Incremental
Conventionals									
Oil & Grease	23,500.00	0.00	19,371	231,688.00	0.00	186,079	15,237	0	15,237
Solids, Total Suspended	30,000.00	0.00	19,371	520,375.00	0.00	186,079	34,068	0	34,068
Total Conventionals							**49,305**	**0**	**49,305**
Priority Pollutant Organics									
Benzene	1,225.91	0.00	19,371	1,341.00	0.00	186,079	96	0	96
Ethylbenzene	62.18	0.00	19,371	1,149.00	0.00	186,079	75	0	75
Methyl Chloride (Chloromethane)	29.00	0.00	19,371	29.00	0.00	186,079	2	0	2
Toluene	827.80	0.00	19,371	891.00	0.00	186,079	64	0	64
Fluorene	62.00	0.00	19,371	62.00	0.00	186,079	4	0	4
Naphthalene	92.02	0.00	19,371	525.00	0.00	186,079	35	0	35
Phenanthrene	64.00	0.00	19,371	64.00	0.00	186,079	5	0	5
Phenol	263.00	0.00	19,371	263.00	0.00	186,079	19	0	19
Total P.P. Organics							**300**	**0**	**300**
Priority Pollutant Metals									
Antimony	29.60	0.00	19,371	29.60	0.00	186,079	2	0	2
Arsenic	73.08	0.00	19,371	166.00	0.00	186,079	11	0	11
Beryllium	8.64	0.00	19,371	8.64	0.00	186,079	1	0	1
Cadmium	14.47	0.00	19,371	26.08	0.00	186,079	2	0	2
Chromium	616.82	0.00	19,371	616.82	0.00	186,079	44	0	44
Copper	277.20	0.00	19,371	277.20	0.00	186,079	20	0	20
Lead	124.86	0.00	19,371	1,376.00	0.00	186,079	90	0	90
Nickel	115.52	0.00	19,371	115.52	0.00	186,079	8	0	8
Selenium	42.94	0.00	19,371	42.94	0.00	186,079	3	0	3
Silver	1.60	0.00	19,371	1.60	0.00	186,079	0	0	0
Thallium	13.46	0.00	19,371	13.46	0.00	186,079	1	0	1
Zinc	133.85	0.00	19,371	362.94	0.00	186,079	25	0	25
Total P.P. Metals							**207**	**0**	**207**

(a) Concentrations in this column are from the Offshore Development Document

(b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no data were available in the Offshore Development Document or because the Offshore Gas Flotations value was greater than the settling value.

ANNUAL POLLUTANT REMOVALS: OPTIONS 2 AND 3 FOR EXISTING SOURCES OF WORKOVER/TREATMENT FLUIDS (Continued)

Pollutant Parameter	Flores & Rucks (IGF to zero discharge)			All others (settling effluent to zero discharge)			Loadings (lbs)		Removals (lbs)
	Concentration ($\mu g/l$)		Volume Currently Discharged (bbls)	Concentration ($\mu g/l$)		Volume Currently Discharged (bbls)			
	Current-Level Effluent[a,b]	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent		Current-Level Effluent	Treat.-Level Effluent	Incremental
Non-conventionals									
Aluminum	49.93	0.00	19,371	6,468.40	0.00	186,079	421	0	421
Barium	498.10	0.00	19,371	498.10	0.00	186,079	36	0	36
Boron	15,042.00	0.00	19,371	15,042.00	0.00	186,079	1,081	0	1,081
Calcium	10,284,000.00	0.00	19,371	10,284,000.00	0.00	186,079	738,935	0	738,935
Cobalt	8.18	0.00	19,371	8.18	0.00	186,079	1	0	1
Cyanide, Total	52.00	0.00	19,371	52.00	0.00	186,079	4	0	4
Iron	3,146.15	0.00	19,371	384,412.00	0.00	186,079	25,038	0	25,038
Manganese	74.16	0.00	19,371	5,146.60	0.00	186,079	335	0	335
Magnesium	5,052,280.00	0.00	19,371	5,052,280.00	0.00	186,079	363,021	0	363,021
Molybdenum	63.00	0.00	19,371	63.00	0.00	186,079	5	0	5
Sodium	18,886,000.00	0.00	19,371	18,886,000.00	0.00	186,079	1,357,013	0	1,357,013
Strontium	142,720.00	0.00	19,371	142,720.00	0.00	186,079	10,255	0	10,255
Sulfur	245,300.00	0.00	19,371	245,300.00	0.00	186,079	17,626	0	17,626
Tin	27.00	0.00	19,371	27.00	0.00	186,079	2	0	2
Titanium	4.48	0.00	19,371	74.58	0.00	186,079	5	0	5
Vanadium	1,156.00	0.00	19,371	1,156.00	0.00	186,079	83	0	83
Yttrium	41.92	0.00	19,371	41.92	0.00	186,079	3	0	3
Acetone	7,205.00	0.00	19,371	7,205.00	0.00	186,079	518	0	518
Methyl Ethyl Ketone (2-Butanone)	58.00	0.00	19,371	58.00	0.00	186,079	4	0	4
Total Xylenes	378.01	0.00	19,371	2,675.00	0.00	186,079	177	0	177
4-Methyl-2-Pentanone	3,028.00	0.00	19,371	3,028.00	0.00	186,079	218	0	218
Dibenzofuran	137.00	0.00	19,371	137.00	0.00	186,079	10	0	10
Dibenzothiophene	111.00	0.00	19,371	111.00	0.00	186,079	8	0	8
N-Decane (N-C10)	275.00	0.00	19,371	275.00	0.00	186,079	20	0	20
N-Docosane (N-C22)	771.00	0.00	19,371	771.00	0.00	186,079	55	0	55
N-Dodecane (N-C12)	576.00	0.00	19,371	576.00	0.00	186,079	41	0	41
N-Eicosane (N-C20)	226.00	0.00	19,371	226.00	0.00	186,079	16	0	16
N-Hexacosane (N-C26)	481.00	0.00	19,371	481.00	0.00	186,079	35	0	35
N-Hexadecane (N-C16)	404.00	0.00	19,371	404.00	0.00	186,079	29	0	29
N-Octacosane (N-C28)	211.00	0.00	19,371	211.00	0.00	186,079	15	0	15
N-Octadecane (N-C18)	1,075.00	0.00	19,371	1,075.00	0.00	186,079	77	0	77
N-Tetracosane (N-C24)	801.00	0.00	19,371	801.00	0.00	186,079	58	0	58
N-Tetradecane (N-C14)	1,237.00	0.00	19,371	1,237.00	0.00	186,079	89	0	89
P-Cymene	72.00	0.00	19,371	72.00	0.00	186,079	5	0	5
Pentamethylbenzene	54.00	0.00	19,371	54.00	0.00	186,079	4	0	4
1-Methylfluorene	82.00	0.00	19,371	82.00	0.00	186,079	6	0	6
2-Methylnaphthalene	817.00	0.00	19,371	817.00	0.00	186,079	59	0	59
Total Non-Conventionals							**2,515,308**	**0**	**2,515,308**
Grand Total Pollutant Loadings\Removals							**2,565,120**	**0**	**2,565,120**

(a) Concentrations in this column are from the Offshore Development Document

(b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no data were available in the Offshore Development Document or because the Offshore Gas Flotation value was greater than the settling effluent value.

ANNUAL POLLUTANT REMOVALS: OPTIONS 2 AND 3 FOR EXISTING SOURCES OF COMPLETION FLUIDS

Pollutant Parameter	Flores & Rucks (IGF to zero discharge)			All others (settling effluent to zero discharge)			Loadings (lbs)		Removals (lbs)
	Concentration (µg/l)		Volume Currently Discharged (bbls)	Concentration (µg/l)		Volume Currently Discharged (bbls)			
	Current-Level Effluent[a,b]	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent		Current-Level Effluent	Treat.-Level Effluent	Incremental
Conventionals									
Oil & Grease	23500	0	6,688	231,688.00	0	63,118	5,169	0	5,169
Solids, Total Suspended	30000	0	6,688	520,375.00	0	63,118	11,557	0	11,557
Total Conventionals							18,360	0	18,360
Priority Pollutant Organics									
Benzene	1225.91	0	6,688	1,341.00	0	63,118	32	0	32
Ethylbenzene	62.18	0	6,688	1,149.00	0	63,118	26	0	26
Methyl Chloride (Chloromethane)	29	0	6,688	29.00	0	63,118	1	0	1
Toluene	827.80	0	6,688	891.00	0	63,118	22	0	22
Fluorene	62.00	0	6,688	62.00	0	63,118	2	0	2
Naphthalene	92.02	0	6,688	525.00	0	63,118	12	0	12
Phenanthrene	64.00	0	6,688	64.00	0	63,118	2	0	2
Phenol	263.00	0	6,688	263.00	0	63,118	6	0	6
Total P. P. Organics							107	0	107
Priority Pollutant Metals									
Antimony	29.60	0	6,688	29.60	0	63,118	1	0	1
Arsenic	73.08	0	6,688	166.00	0	63,118	4	0	4
Beryllium	8.64	0	6,688	8.64	0	63,118	0	0	0
Cadmium	14.47	0	6,688	26.08	0	63,118	1	0	1
Chromium	616.82	0	6,688	616.82	0	63,118	15	0	15
Copper	277.20	0	6,688	277.20	0	63,118	7	0	7
Lead	124.86	0	6,688	1,376.00	0	63,118	31	0	31
Nickel	115.52	0	6,688	115.52	0	63,118	3	0	3
Selenium	42.94	0	6,688	42.94	0	63,118	1	0	1
Silver	1.60	0	6,688	1.60	0	63,118	0	0	0
Thallium	13.46	0	6,688	13.46	0	63,118	0	0	0
Zinc	133.85	0	6,688	362.94	0	63,118	8	0	8
Total P.P. Metals							70	0	74

(a) Concentrations in this column are from the Offshore Development Document

(b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no other data were available in the Offshore Development Document or because the Offshore Gas Flotation value was greater than the settling effluent value.

ANNUAL POLLUTANT REMOVALS: OPTIONS 2 AND 3 FOR EXISTING SOURCES OF COMPLETION FLUIDS (Continued)

Pollutant Parameter	Flores & Rucks (IGF to zero discharge)			All others (settling effluent to zero discharge)			Loadings (lbs)		Removals (lbs)
	Concentration ($\mu g/l$)		Volume Currently Discharged (bbls)	Concentration ($\mu g/l$)		Volume Currently Discharged (bbls)			
	Current-Level Effluent[a,b]	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent		Current-Level Effluent	Treat.-Level Effluent	Incremental
Non-Conventionals									
Aluminum	49.93	0	6,688	6,468.40	0	63,118	143	0	143
Barium	498.10	0	6,688	498.10	0	63,118	12	0	12
Boron	15,042.00	0	6,688	15,042.00	0	63,118	367	0	367
Calcium	10,284,000.00	0	6,688	10,284,000.00	0	63,118	251,069	0	251,069
Cobalt	8.18	0	6,688	8.18	0	63,118	0	0	0
Cyanide, Total	52.00	0	6,688	52.00	0	63,118	1	0	1
Iron	3,146.15	0	6,688	384,412.00	0	63,118	8,493	0	8,493
Manganese	74.16	0	6,688	5,146.60	0	63,118	114	0	114
Magnesium	5,052,280.00	0	6,688	5,052,280.00	0	63,118	123,344	0	123,344
Molybdenum	63.00	0	6,688	63.00	0	63,118	2	0	2
Sodium	18,886,000.00	0	6,688	18,886,000.00	0	63,118	461,074	0	461,074
Strontium	142,720.00	0	6,688	142,720.00	0	63,118	3,484	0	3,484
Sulfur	245,300.00	0	6,688	245,300.00	0	63,118	5,989	0	5,989
Tin	27.00	0	6,688	27.00	0	63,118	1	0	1
Titanium	4.48	0	6,688	74.58	0	63,118	2	0	2
Vanadium	1,156.00	0	6,688	1,156.00	0	63,118	28	0	28
Yttrium	41.92	0	6,688	41.92	0	63,118	1	0	1
Acetone	7,205.00	0	6,688	7,205.00	0	63,118	176	0	176
Methyl Ethyl Ketone (2-Butanone)	58.00	0	6,688	58.00	0	63,118	1	0	1
Total Xylenes	378.01	0	6,688	2,675.00	0	63,118	60	0	60
4-Methyl-2-Pentanone	3,028.00	0	6,688	3,028.00	0	63,118	74	0	74
Dibenzofuran	137.00	0	6,688	137.00	0	63,118	3	0	3
Dibenzothiophene	111.00	0	6,688	111.00	0	63,118	3	0	3
N-Decane (N-C10)	275.00	0	6,688	275.00	0	63,118	7	0	7
N-Docosane (N-C22)	771.00	0	6,688	771.00	0	63,118	19	0	19
N-Dodecane (N-C12)	576.00	0	6,688	576.00	0	63,118	14	0	14
N-Eicosane (N-C20)	226.00	0	6,688	226.00	0	63,118	6	0	6
N-Hexacosane (N-C26)	481.00	0	6,688	481.00	0	63,118	12	0	12
N-Hexadecane (N-C16)	404.00	0	6,688	404.00	0	63,118	10	0	10
N-Octacosane (N-C28)	211.00	0	6,688	211.00	0	63,118	5	0	5
N-Octadecane (N-C18)	1,075.00	0	6,688	1,075.00	0	63,118	26	0	26
N-Tetracosane (N-C24)	801.00	0	6,688	801.00	0	63,118	20	0	20
N-Tetradecane (N-C14)	1,237.00	0	6,688	1,237.00	0	63,118	30	0	30
P-Cymene	72.00	0	6,688	72.00	0	63,118	2	0	2
Pentamethylbenzene	54.00	0	6,688	54.00	0	63,118	1	0	1
1-Methylfluorene	82.00	0	6,688	82.00	0	63,118	2	0	2
2-Methylnaphthalene	817.00	0	6,688	817.00	0	63,118	20	0	20
Total Non-Conventionals							**857,222**	**0**	**857,222**
Grand Total Pollutant Loadings\Removals							**875,759**	**0**	**875,763**

(a) Concentrations in this column are from the Offshore Development Document

(b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no data were available in the Offshore Development Document or because the Offshore Gas Flotation value was greater than the settling effluent value.

ANNUAL POLLUTANT REMOVALS: OPTIONS 2 AND 3 FOR NEW SOURCE OF WORKOVER/TREATMENT FLUIDS

Pollutant Parameter	Flores & Rucks (IGF to zero discharge)			All others (settling effluent to zero discharge)			Loadings (lbs)		Removals (lbs)
	Concentration (µg/l)		Volume Currently Discharged (bbls)	Concentration (µg/l)		Volume Currently Discharged (bbls)			
	Current-Level Effluent[a,b]	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent	Incremental
Conventionals									
Oil & Grease	23,500.00	0.00	1,761	231,688.00	0.00	24,654	2,012	0	2,012
Solids, Total Suspended	30,000.00	0.00	1,761	520,375.00	0.00	24,654	4,505	0	4,505
Total Conventionals							6,517	0	6,517
Priority Pollutant Organics									
Benzene	1,225.91	0.00	1,761	1,341.00	0.00	24,654	12	0	12
Ethylbenzene	62.18	0.00	1,761	1,149.00	0.00	24,654	10	0	10
Methyl Chloride (Chloromethane)	29.00	0.00	1,761	29.00	0.00	24,654	0	0	0
Toluene	827.80	0.00	1,761	891.00	0.00	24,654	8	0	8
Fluorene	62.00	0.00	1,761	62.00	0.00	24,654	1	0	1
Naphthalene	92.02	0.00	1,761	525.00	0.00	24,654	5	0	5
Phenanthrene	64.00	0.00	1,761	64.00	0.00	24,654	1	0	1
Phenol	263.00	0.00	1,761	263.00	0.00	24,654	2	0	2
Total P.P. Organics							39	0	39
Priority Pollutant Metals									
Antimony	29.60	0.00	1,761	29.60	0.00	24,654	0	0	0
Arsenic	73.08	0.00	1,761	166.00	0.00	24,654	1	0	1
Beryllium	8.64	0.00	1,761	8.64	0.00	24,654	0	0	0
Cadmium	14.47	0.00	1,761	26.08	0.00	24,654	0	0	0
Chromium	616.82	0.00	1,761	616.82	0.00	24,654	6	0	6
Copper	277.20	0.00	1,761	277.20	0.00	24,654	3	0	3
Lead	124.86	0.00	1,761	1,376.00	0.00	24,654	12	0	12
Nickel	115.52	0.00	1,761	115.52	0.00	24,654	1	0	1
Selenium	42.94	0.00	1,761	42.94	0.00	24,654	0	0	0
Silver	1.60	0.00	1,761	1.60	0.00	24,654	0	0	0
Thallium	13.46	0.00	1,761	13.46	0.00	24,654	0	0	0
Zinc	133.85	0.00	1,761	362.94	0.00	24,654	3	0	3
Total P.P. Metals							26	0	26

(a) Concentrations in this column are from the Offshore Development Document.
(b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no data were available in the Offshore Development Document or because the Offshore Gas

ANNUAL POLLUTANT REMOVALS: OPTIONS 2 AND 3 FOR NEW SOURCE OF WORKOVER/TREATMENT FLUIDS (Continued)

Pollutant Parameter	Flores & Rucks (IGF to zero discharge)			All others (settling effluent to zero discharge)			Loadings (lbs)		Removals (lbs)
	Concentration ($\mu g/l$)		Volume Currently Discharged (bbls)	Concentration ($\mu g/l$)		Volume Currently Discharged (bbls)			
	Current-Level Effluent[(a,b)]	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent	Incremental
Non-Conventionals									
Aluminum	49.93	0.00	1,761	6,468.40	0.00	24,654	56	0	56
Barium	498.10	0.00	1,761	498.10	0.00	24,654	5	0	5
Boron	15,042.00	0.00	1,761	15,042.00	0.00	24,654	139	0	139
Calcium	10,284,000.00	0.00	1,761	10,284,000.00	0.00	24,654	95,006	0	95,006
Cobalt	8.18	0.00	1,761	8.18	0.00	24,654	0	0	0
Cyanide, Total	52.00	0.00	1,761	52.00	0.00	24,654	0	0	0
Iron	3,146.15	0.00	1,761	384,412.00	0.00	24,654	3,316	0	3,316
Manganese	74.16	0.00	1,761	5,146.60	0.00	24,654	44	0	44
Magnesium	5,052,280.00	0.00	1,761	5,052,280.00	0.00	24,654	46,674	0	46,674
Molybdenum	63.00	0.00	1,761	63.00	0.00	24,654	1	0	1
Sodium	18,886,000.00	0.00	1,761	18,886,000.00	0.00	24,654	174,473	0	174,473
Strontium	142,720.00	0.00	1,761	142,720.00	0.00	24,654	1,318	0	1,318
Sulfur	245,300.00	0.00	1,761	245,300.00	0.00	24,654	2,266	0	2,266
Tin	27.00	0.00	1,761	27.00	0.00	24,654	0	0	0
Titanium	4.48	0.00	1,761	74.58	0.00	24,654	1	0	1
Vanadium	1,156.00	0.00	1,761	1,156.00	0.00	24,654	11	0	11
Yttrium	41.92	0.00	1,761	41.92	0.00	24,654	0	0	0
Acetone	7,025.00	0.00	1,761	7,205.00	0.00	24,654	67	0	67
Methyl Ethyl Ketone (2-Butanone)	58.00	0.00	1,761	58.00	0.00	24,654	1	0	1
Total Xylenes	378.01	0.00	1,761	2,675.00	0.00	24,654	23	0	23
4-Methyl-2-Pentanone	3,028.00	0.00	1,761	3,028.00	0.00	24,654	28	0	28
Dibenzofuran	137.00	0.00	1,761	137.00	0.00	24,654	1	0	1
Dibenzothiophene	111.00	0.00	1,761	111.00	0.00	24,654	1	0	1
N-Decane (N-C10)	275.00	0.00	1,761	275.00	0.00	24,654	3	0	3
N-Docosane (N-C22)	771.00	0.00	1,761	771.00	0.00	24,654	7	0	7
N-Dodecane (N-C12)	576.00	0.00	1,761	576.00	0.00	24,654	5	0	5
N-Eicosane (N-C20)	226.00	0.00	1,761	226.00	0.00	24,654	2	0	2
N-Hexacosane (N-C26)	481.00	0.00	1,761	481.00	0.00	24,654	4	0	4
N-Hexadecane (N-C16)	404.00	0.00	1,761	404.00	0.00	24,654	4	0	4
N-Octacosane (N-C28)	211.00	0.00	1,761	211.00	0.00	24,654	2	0	2
N-Octadecane (N-C18)	1,075.00	0.00	1,761	1,075.00	0.00	24,654	10	0	10
N-Tetracosane (N-C24)	801.00	0.00	1,761	801.00	0.00	24,654	7	0	7
N-Tetradecane (N-C14)	1,237.00	0.00	1,761	1,237.00	0.00	24,654	11	0	11
P-Cymene	72.00	0.00	1,761	72.00	0.00	24,654	1	0	1
Pentamethylbenzene	54.00	0.00	1,761	54.00	0.00	24,654	0	0	0
1-Methylfluorene	82.00	0.00	1,761	82.00	0.00	24,654	1	0	1
2-Methylnaphthalene	817.00	0.00	1,761	817.00	0.00	24,654	8	0	8
Total Non-Conventionals							**323,496**	**0**	**323,496**
Grand Total Pollutant Loadings/Removals							**330,078**	**0**	**330,078**

(a) Concentrations in this column are from the Offshore Development Document.
(b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no data were available in the Offshore Development Document or because the Offshore Gas Flotation value was greater than the settling effluent value.

ANNUAL POLLUTANT REMOVALS: OPTIONS 2 AND 3 FOR NEW SOURCES OF COMPLETION FLUIDS

Pollutant Parameter	Flores & Rucks (IGF to zero discharge)			All others (settling effluent to zero discharge)			Loadings (lbs)		Removals (lbs)
	Concentration (µg/l)		Volume Currently Discharged (bbls)	Concentration (µg/l)		Volume Currently Discharged (bbls)			
	Current-Level Effluent[a,b]	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent	Incremental
Conventionals									
Oil & Grease	23,500.00	0.00	627	231,688.00	0.00	8,778	716	0	716
Solids, Total Suspended	30,000.00	0.00	627	520,375.00	0.00	8,778	1,604	0	1,604
Total Conventionals							**2,321**	**0**	**2,321**
Priority Pollutant Organics									
Benzene	1,225.91	0.00	627	1,341.00	0.00	8,778	4	0	4
Ethylbenzene	62.18	0.00	627	1,149.00	0.00	8,778	4	0	4
Methyl Chloride (Chloromethane)	29.00	0.00	627	29.00	0.00	8,778	0	0	0
Toluene	827.80	0.00	627	891.00	0.00	8,778	3	0	3
Fluorene	62.00	0.00	627	62.00	0.00	8,778	0	0	0
Naphthalene	92.02	0.00	627	525.00	0.00	8,778	2	0	2
Phenanthrene	64.00	0.00	627	64.00	0.00	8,778	0	0	0
Phenol	263.00	0.00	627	263.00	0.00	8,778	1	0	1
Total P.P. Organics							**14**	**0**	**14**
Priority Pollutant Metals									
Antimony	29.60	0.00	627	29.60	0.00	8,778	0	0	0
Arsenic	73.08	0.00	627	166.00	0.00	8,778	1	0	1
Beryllium	8.64	0.00	627	8.64	0.00	8,778	0	0	0
Cadmium	14.47	0.00	627	26.08	0.00	8,778	0	0	0
Chromium	616.82	0.00	627	616.82	0.00	8,778	2	0	2
Copper	277.20	0.00	627	277.20	0.00	8,778	1	0	1
Lead	124.86	0.00	627	1,376.00	0.00	8,778	4	0	4
Nickel	115.52	0.00	627	115.52	0.00	8,778	0	0	0
Selenium	42.94	0.00	627	42.94	0.00	8,778	0	0	0
Silver	1.60	0.00	627	1.60	0.00	8,778	0	0	0
Thallium	13.46	0.00	627	13.46	0.00	8,778	0	0	0
Zinc	133.85	0.00	627	362.94	0.00	8,778	1	0	1
Total P.P. Metals							**10**	**0**	**10**

(a) Concentrations in this column are from the Offshore Development Document.
(b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no data were available in the Offshore Development Document or because the Offshore Gas Flotation value was greater than the settling effluent value.

ANNUAL POLLUTANT REMOVALS: OPTIONS 2 AND 3 FOR NEW SOURCES OF COMPLETION FLUIDS (Continued)

Pollutant Parameter	Flores & Rucks (IGF to zero discharge)			All others (settling effluent to zero discharge)			Loadings (lbs)		Removals (lbs)
	Concentration (μg/l)		Volume Currently Discharged (bbls)	Concentration (μg/l)		Volume Currently Discharged (bbls)			
	Current-Level Effluent[(a,b)]	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent		Current-Level Effluent	Treatment-Level Effluent	Incremental
Non-Conventionals									
Aluminum	49.93	0.00	627	6,468.40	0.00	8,778	20	0	20
Barium	498.10	0.00	627	498.10	0.00	8,778	2	0	2
Boron	15,042.00	0.00	627	15,042.00	0.00	8,778	49	0	49
Calcium	10,284,000.00	0.00	627	10,284,000.00	0.00	8,778	33,827	0	33,827
Cobalt	8.18	0.00	627	8.18	0.00	8,778	0	0	0
Cyanide, Total	52.00	0.00	627	52.00	0.00	8,778	0	0	0
Iron	3,146.15	0.00	627	384,412.00	0.00	8,778	1,181	0	1,181
Manganese	74.16	0.00	627	5,146.60	0.00	8,778	16	0	16
Magnesium	5,052,280.00	0.00	627	5,052,280.00	0.00	8,778	16,618	0	16,618
Molybdenum	63.00	0.00	627	63.00	0.00	8,778	0	0	0
Sodium	18,886,000.00	0.00	627	18,886,000.00	0.00	8,778	62,121	0	62,121
Strontium	142,720.00	0.00	627	142,720.00	0.00	8,778	469	0	469
Sulfur	245,300.00	0.00	627	245,300.00	0.00	8,778	807	0	807
Tin	27.00	0.00	627	27.00	0.00	8,778	0	0	0
Titanium	4.48	0.00	627	74.58	0.00	8,778	0	0	0
Vanadium	1,156.00	0.00	627	1,156.00	0.00	8,778	4	0	4
Yttrium	41.92	0.00	627	41.92	0.00	8,778	0	0	0
Acetone	7,025.00	0.00	627	7,205.00	0.00	8,778	24	0	24
Methyl Ethyl Ketone (2-Butanone)	58.00	0.00	627	58.00	0.00	8,778	0	0	0
Total Xylenes	378.01	0.00	627	2,675.00	0.00	8,778	8	0	8
4-Methyl-2-Pentanone	3,028.00	0.00	627	3,028.00	0.00	8,778	10	0	10
Dibenzofuran	137.00	0.00	627	137.00	0.00	8,778	0	0	0
Dibenzothiophene	111.00	0.00	627	111.00	0.00	8,778	0	0	0
N-Decane (N-C10)	275.00	0.00	627	275.00	0.00	8,778	1	0	1
N-Docosane (N-C22)	771.00	0.00	627	771.00	0.00	8,778	3	0	3
N-Dodecane (N-C12)	576.00	0.00	627	576.00	0.00	8,778	2	0	2
N-Eicosane (N-C20)	226.00	0.00	627	226.00	0.00	8,778	1	0	1
N-Hexacosane (N-C26)	481.00	0.00	627	481.00	0.00	8,778	2	0	2
N-Hexadecane (N-C16)	404.00	0.00	627	404.00	0.00	8,778	1	0	1
N-Octacosane (N-C28)	211.00	0.00	627	211.00	0.00	8,778	1	0	1
N-Octadecane (N-C18)	1,075.00	0.00	627	1,075.00	0.00	8,778	4	0	4
N-Tetracosane (N-C24)	801.00	0.00	627	801.00	0.00	8,778	3	0	3
N-Tetradecane (N-C14)	1,237.00	0.00	627	1,237.00	0.00	8,778	4	0	4
P-Cymene	72.00	0.00	627	72.00	0.00	8,778	0	0	0
Pentamethylbenzene	54.00	0.00	627	54.00	0.00	8,778	0	0	0
1-Methylfluorene	82.00	0.00	627	82.00	0.00	8,778	0	0	0
2-Methylnaphthalene	817.00	0.00	627	817.00	0.00	8,778	3	0	3
Total Non-Conventionals							**115,180**	**0**	**115,180**
Grand Total Pollutant Loadings/Removals							**117,524**	**0**	**117,524**

(a) Concentrations in this column are from the Offshore Development Document.
(b) For the purpose of regulatory analysis, these concentrations are substituted using the settling effluent concentrations either because no data were available in the Offshore Development Document or because the Offshore Gas Flotation value was greater than the settling effluent value.

APPENDIX XIII-1

ENERGY REQUIREMENTS AND AIR EMISSIONS DETAILED CALCULATIONS FOR COOK INLET DRILLING WASTE ZERO DISCHARGE SCENARIO 1:

CLOSED-LOOP SOLIDS CONTROL AND LANDFILL

DRILLING WASTE VOLUME

Drilling Operation	Total Volume Drilling Waste (bbls)	Muds & Cuttings Per Well (bbls)	Number of Wells	Number of Wells Using Barges to West Cook Inlet	Number of Wells Trucking to Oregon	Volume of Boxes (bbls)	Number of Boxes per Well
New Well	402,014 (a)	9,805	41 (a)	28 (a)	13 (a)	8	1,225.65
Recompletion	29,974 (a)	1,499	20 (a)	19 (a)	1 (a)	8	187.34
Total	431,988						

SUPPLY BOAT TRANSIT FUEL CONSUMPTION

Drilling Operation	No. Incremental Boat Trips per Well	Total Wells	Number of Boat Trips	Miles Per Boat Trip	Total Boat Miles	Average Boat Speed (mi/hr)	Diesel Usage Rate (gal/hr)	Total Diesel Usage (gal)
New Well	15 (a)	41	615	50 (b)	30,750	11.5 (c)	130 (d)	347,609
Recompletion	1 (a)	20	20	50 (b)	1,000	11.5 (c)	130 (d)	11,304
Total								358,913

BARGE TRANSIT FUEL CONSUMPTION

Drilling Operation	Number of Boxes per Barge	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes Per Barge	Total Wells	Number of Barge Trips	Miles Per Barge Trip	Total Barge Miles	Average Barge Speed (mi/hr)	Diesel Usage Rate (gal/hr)	Total Diesel Usage (gal)
New Well	240 (a)	0.000815892	0.1958	28	142.99	50 (e)	7,150	6 (f)	24 (g)	28,599
Recompletion	240 (a)	0.0053379596	1.2811	19	14.83	50 (e)	742	6 (f)	24 (g)	2,966
Total										31,565

SUPPLY BOAT MANEUVERING FUEL CONSUMPTION

Drilling Operation	Total Number of Boat Trips	Manuvering Time Per Trip (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	615	1 (h)	25.3 (h)	15,560
Recompletion	20	1 (h)	25.3 (h)	506
Total				16,066

SUPPLY BOAT LOADING FUEL CONSUMPTION (AT PLATFORM)

Drilling Operation	Total Number of Boat Trips	Loading Time Per Trip (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	615	4.15 (i)	25.3 (j)	64,572
Recompletion	20	4.15 (i)	25.3 (j)	2,100
Total				66,672

SUPPLY BOAT AUXILIARY ELECTRICAL GENERATOR (IN PORT)

Drilling Operation	Total Number of Boat Trips	Generator Hours Per Trip	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Generator Power Rating (hp)	Total Generator Horsepower-Hours
New Well	615	24 (k)	6 (k)	88,560	60 (h)	885,600
Recompletion	20	24 (k)	6 (k)	2,880	60 (h)	28,800
Total				91,440		914,400

SUPPLY BOAT CRANES

Drilling Operation	Number of Crane Lifts (drillsite)	Number of Crane Lifts (in port)	Total Crane Lifts Per Round Trip	Number of Crane lifts Per Hour	Crane lift Hours Per Round Trip	Total Number of Boat Trips	Total Crane Hours	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Crane Brake Horsepower (bhp)	Total Crane Brake Horsepower-Hours
New Well	31.5 (m)	31.5 (l)	63	10 (k)	6.3	615	3,875	8.33 (m)	32,275	136 (k)	526,932
Recompletion	31.5 (m)	31.5 (l)	63	10 (k)	6.3	20	126	8.33 (m)	1,050	136 (k)	17,136
Total									33,324		544,068

BARGE CRANES

Drilling Operation	Number of Crane Lifts (loading)	Number of Crane Lifts (unloading)	Total Crane Lifts Per Round Trip	Number of Crane lifts Per Hour	Crane lift Hours Per Round Trip	Total Number of Boat Trips	Total Crane Hours	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)	Crane Brake Horsepower (bhp)	Total Crane Brake Horsepower-Hours
New Well	24 (n)	24	48	10 (k)	4.8	142.99	686.4	8.33 (m)	5,717	136 (k)	93,346
Recompletion	24 (n)	24	48	10 (k)	4.8	14.83	71.2	8.33 (m)	593	136 (k)	9,682
Total									6,310		103,027

TRUCKS USED BY OPERATOR "B"

Drilling Operation	Boxes Per Truckload (bbls)	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes per Truck	Total Wells	Total Number of Truck Trips	Miles per Truck Trip	Total Truck Miles	Diesel Usage Rate (miles/gal)	Total Fuel Consumption (gal)
New Well	12 (o)	0.000815892	0.0097907	28	2,860	10 (p)	28,599	4 (k)	7,150
Recompletion	12 (o)	0.0053379596	0.06405551	19	297	10 (p)	2,966	4 (k)	742
Total					3,156		31,565		7,891

TRUCKS TO OREGON

Drilling Operation	Boxes Per Truckload (bbls)	Proportion of Well Waste Volume per Box	Number of Well Waste Volumes per Truck	Total Wells	Total Number of Truck Trips	Miles per Truck Trip	Total Truck Miles	Diesel Usage Rate (miles/gal)	Total Fuel Consumption (gal)
New Well	10 (q)	0.000815892	0.00815892	13	1,593	2200 (r)	3,505,366	4 (k)	876,341
Recompletion	10 (q)	0.0053379596	0.0533796	1	19	2200 (r)	41,214	4 (k)	10,304
Total					1,612		3,546,580		886,645

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COASTAL OIL AND GAS
DRILLING WASTE - COOK INLET ZERO DISCHARGE BASED ON LANDFILL + CLOSED-LOOP
FUEL USAGE, HORSEPOWER REQUIREMENTS, AND AIR EMISSIONS

WHEEL TRACTOR FOR GRADING AT LANDFILL

Drilling Operation	Total Wells	Tractor Time Per Well (hrs)	Total Tractor Time (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	41	8 (s)	328	1.67 (s)	548
Recompletion	20	8 (s)	160	1.67 (s)	267
Total			488		815

TRACK-TYPE DOZER/LOADER FOR SPREADING WASTE AT LANDFARM

Drilling Operation	Total Wells	Dozer Time Per Well (hrs)	Total Dozer Time (hrs)	Diesel Usage Rate (gal/hr)	Total Fuel Consumption (gal)
New Well	41	16 (s)	656	22 (s)	14,432
Recompletion	20	16 (s)	320	22 (s)	7,040
Total			976		21,472

DECANTING CENTRIFUGE FOR CLOSED-LOOP SOLIDS CONTROL

Drilling Operation	Total Wells	Centrifuge HP Requirement	Centr. Operating Hours Per Well	Centrif. Total HP-hrs	Centrif. Fuel Usage (scf nat'l gas)
New Well	41	40 (t)	733 (u)	29,320	278,540
Recompletion	20	40 (t)	240 (u)	9,600	91,200
Total				38,920	369,740

AIR EMISSION FACTORS

Category	Units	NOx	THC	SO2	CO	TSP
DIESEL						
Supply Boats						
Transit	(lb/1000 gal)	391.700	16.800	28.480	78.300	33.000
Maneuvering	(lb/1000 gal)	419.600	22.600	28.480	59.800	33.000
Idling	(lb/1000 gal)	419.600	22.600	28.480	59.800	33.000
Demurrage (aux gen)	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
Barge						
Transit	(lb/1000 gal)	391.700	16.800	28.480	78.300	33.000
Cranes						
Drill Site	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
In-Port	(g/bhp-hr)	14.000	1.120	0.931	3.030	1.000
Trucks	(g/mile)	11.230	2.490	NA	8.530	NA
Wheel Tractor	(lb/hr)	1.269	0.188	0.090	3.590	0.136
Dozer/Loader	(lb/hr)	0.827	0.098	0.076	0.201	0.058
NATURAL GAS						
Gas-fired Turbine	(g/hp-hr)	1.300	0.180	0.002	0.830	NA

COASTAL OIL AND GAS
DRILLING WASTE - COOK INLET ZERO DISCHARGE BASED ON LANDFILL + CLOSED-LOOP
FUEL USAGE, HORSEPOWER REQUIREMENTS, AND AIR EMISSIONS

TOTAL AIR EMISSIONS - ZERO DISCHARGE BASED ON TRANSPORT TO LANDFILL 15-Nov-96

Category	Total Diesel Fuel Usage (1000 gal)	Total Nat'l Gas Usage (1000 scf)	Power Requirements (hp-hr)	NOx Total (tons)	THC Total (tons)	SO2 Total (tons)	CO Total (tons)	TSP Total (tons)	TOTAL (tons)
DIESEL									
Supply Boats									
Transit	358.91		NA	70.29	3.01	5.11	14.05	5.92	
Maneuvering	16.07		NA	3.37	0.18	0.23	0.48	0.27	
Loading	66.67		NA	13.99	0.75	0.95	1.99	1.10	
Dumurrage (aux gen)	91.44		914,400	14.10	1.13	0.94	3.05	1.01	
Total	533.09			101.75	5.07	7.23	19.57	8.30	141.92
Barge									
Transit	31.56		NA	6.18	0.27	0.45	1.24	0.52	8.66
Supply Boat Cranes	33.32		544,068	8.39	0.67	0.56	1.82	0.60	12.04
Barge Cranes	6.31		103,027	1.59	0.13	0.11	0.34	0.11	2.28
Trucks Used by Operator "B"	7.89		NA	0.39	0.09	0.00	0.30	0.00	0.78
Trucks to Oregon	886.65		NA	43.86	9.73	0.00	33.32	0.00	86.91
Wheel Tractor	0.81		NA	0.31	0.05	0.02	0.88	0.03	1.29
Dozer/Loader	21.47		NA	0.40	0.05	0.04	0.10	0.03	0.62
Decanting Centrifuge		369.74	38,920	0.06	0.01	0.00	0.04	0.00	0.11
TOTAL FUEL USAGE	1,521.11	369.74							
TOTAL EMISSIONS - tons				162.93	16.07	8.41	57.61	9.59	254.61

Summary Data	Seven Years	Annual
Total Air Emissions (tons):	254.61	36.37
Total Fuel Usage (BOE):	36,283	5,183
Total Drilling Waste to Landfill (bbls):	431,988	61,713

Appendix XIII-1

Footnotes for Drilling Waste Zero Discharge Scenario 1
Closed-Loop Solids Control and Landfill

(a) Chapter X and Appendix X-1.

(b) Distance from platforms in Trading Bay Field and Granite Point Field is approximately 25 miles (50 miles round trip) to the East Foreland Facility. Supply boats unload at ports near the East Foreland Facility. From Marathon/Unocal, "Drilling Waste Disposal Alternatives - A Cook Inlet Perspective," March 1994.

(c) Average boat speed is 11.5 miles per hour. From Walk, Haydel & Associates, Inc., "Water-Based Drilling Fluids and Cuttings Disposal Study Update," January 1989.

(d) U.S. EPA, "Trip Report to Campbell Wells Landfarms and Transfer Stations in Louisiana," June 30, 1992. Note that the analysis for the Offshore Guidelines used 169 gallons per hour (gph) which is based on 100% utilization of supply boat engine maximum power output. Actual fuel consumption was rated at 110 gph. The 130 gph consumption rate is considered to be a conservative and realistic estimate. Vessels serving Gulf of Mexico platforms are considered comparable to those serving Cook Inlet platforms.

(e) Distance from east side of Cook Inlet to the west side near Trading Bay Field is approximately 25 miles (50 miles round trip).

(f) SAIC, "Produced Water Injection Cost Study for the Development of Coastal Oil and Gas Effluent Limitations Guidelines," March 8, 1993.

(g) U.S. EPA, "Trip Report to Campbell Wells Landfarms and Transfer Stations in Louisiana," June 30, 1992. Vessels serving Gulf of Mexico platforms are considered comparable to those serving Cook Inlet platforms.

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

(i) Loading time is equal to crane time plus one hour.

(j) Diesel usage rate for loading at platforms is equal to the usage rate for maneuvering because supply boats are not able to dock at drilling platforms in Cook Inlet due to strong currents.

(k) Walk, Haydel & Associates, Inc., "Water-Based Drilling Fluids and Cuttings Disposal Study Update," January 1989.

(l) Four boxes per lift at the drill site and at the port. The loading time of 6.3 hours (240 boxes/4 boxes per lift/ 10 lifts per hour) is consistent with the time of four to six hours cited in Wiedeman, A., U.S. EPA, "Trip Report to Alaska Cook Inlet and North Slope Oil and Gas Facilities, August 25-29, 1993," August 31, 1994.

Appendix XIII-1

Footnotes for Drilling Waste Zero Discharge Scenario 1
Closed-Loop Solids Control and Landfill
(continued)

(m) Crane fuel usage rate at Campbell Wells was 25 gallons for three hours or 8.33 gph. From Wiedeman, 1994.

(n) Assumes 10 boxes per lift at the port and at the beach since boxes are placed in shipping containers that hold 10-12 boxes each. Barge capacity is 240 boxes. From Marathon/Unocal. March 1994.

(o) U.S. EPA, Development Document for Proposed Effluent limitations Guidelines & Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category, January 31, 1995.

(p) Distance from barge landing to landfill at Kustatan is three miles (six miles round trip). Marathon/Unocal, March 1994. Distance from East Foreland port to the storage area is two miles (four miles round trip). Total trucking distance is 10 miles.

(q) Trucks to Oregon have a 22-ton capacity. From McIntyre, J., SAIC, Record of telephone call with Josh Stenson of Carlisle Trucking, regarding "Costs to Truck Wastes from Kenai, Alaska to Arlington, Oregon," May 23, 1995. This capacity converts to 10 boxes per load as calculated in Appendix X-2.

(r) One-way truck trip from Kenai, Alaska to Arlington, Oregon is approximately 2,200 miles.

(s) Time for a wheel tractor for grading wastes from one well is one day (8 hours). Time for a dozer/loader for spreading wastes from one well is two days (16 hours). From U.S. EPA, "Non-Water Quality Environmental Impacts Resulting from the Onshore Disposal of Drilling Fluids and Drill Cuttings from Offshore Oil and Gas Drilling Activities," January 13, 1993.

(t) Gauthier Brothers, Equipment and Services Catalog, 1993.

(u) Calculated from Worksheet 1 in Appendix X-1:

New Well: (11 days x 13 hours) + (25 days x 14 hours) = 733 hours
Recompletion: (20 days x 12 hours) = 240 hours

A decanting centrifuge is assumed to run continuously, although this is a conservatively high assumption.

APPENDIX XIII-2

ENERGY REQUIREMENTS AND AIR EMISSIONS DETAILED CALCULATIONS FOR COOK INLET DRILLING WASTE ZERO DISCHARGE SCENARIO 2:

GRINDING AND SUBSURFACE INJECTION

DRILLING WASTE VOLUME

Drilling Operation	Total Volume Drilling Waste (bbls)	Muds & Cuttings Per Well (bbls)	Number of Wells
New Well	582,629 (a)	14,210 (a)	41 (a)
Recompletion	43,441 (a)	2,172 (a)	20 (a)
Injection	63,300 (a)	5,275 (a)	12 (a)
Total	689,370		

CUTTINGS GRINDING AND MUDS/CUTTINGS INJECTION AT DRILLSITE

Drilling Operation	Total Well Equivilants	Grinding & Processing HP Requirements	Injection HP Requirements	Process Equip. Operation Hours Per Well	Process Equip. Total Hp-hrs	Process Equip. Fuel Usage (scf nat'l gas)	Injection Equip. Operation Hours Per Well	Injection Equip. Total Hp-hrs	Injection Equip. Fuel Usage (scf nat'l gas)	Total Hp-hrs
New Well	41	747 (b)	500 (c)	733 (d)	22,449,591	213,271,115	47.37 (e)	971,048	9,224,959	23,420,639
Recompletion	20	747 (b)	500 (c)	240 (d)	3,585,600	34,063,200	7.24 (e)	72,402	687,816	3,658,002
Injection	12	747 (b)	500 (c)	211 (d)	1,891,404	17,968,338	17.58 (e)	105,500	1,002,250	1,996,904
Total					27,926,595	265,302,653		1,148,950	10,915,025	29,075,545

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AIR EMISSION FACTORS

Category	Units	NOx	THC	SO2	CO
Gas-fired Turbine	(g/hp-hr)	1.300	0.180	0.002	0.830

TOTAL AIR EMISSIONS - ZERO DISCHARGE BASED ON GRINDING AND INJECTION

Category	Nat. Gas Fuel Usage (1000 scf)	Power Requirements (hp-hr)	NOx (tons)	THC (tons)	SO2 (tons)	CO (tons)	TOTAL (tons)
NATURAL GAS							
Grinding\Process Equipment	265,303	27,926,595	39.98	5.54	0.06	25.53	71.11
Injection Equipment	10,915	1,148,950	1.64	0.23	0.00	1.05	2.92
TOTAL	**276,218**		**41.62**	**5.77**	**0.06**	**26.58**	**74.03**

SUMMARY DATA	Seven Years	Annual
Total Air Emissions (tons):	**74.03**	**10.58**
Total Fuel Usage (BOE):	**49,167**	**7,024**
Total Drilling Waste Injected (bbls):	**689,370**	**98,481**

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Appendix XIII-2

Footnotes for Drilling Waste Zero Discharge Scenario 2
Grinding and Subsurface Injection

(a) Chapter X and Appendix X-1.

(b) Schmidt, R., Unocal, Correspondence with Manuela Erickson, SAIC, regarding Drill Cuttings and Fluid Discharge Economic Impacts, April 18, 1994.

(c) Marathon/Unocal, "Drilling Waste Disposal Alternatives - A Cook Inlet Perspective," March 1994.

(d) Calculated from Worksheet 1 in Appendix X-1.

New Well: (11 days x 13 hours) + (25 days x 14 hours) = 733 hours
Recompletion: (20 days x 12 hours) = 240 hours
Injection Well: (2500/2553)(11 days x 13 hours) + (1500/7348)(25 days x 14 hours) = 211 hrs

(e) Based on an injection rate of 5 barrels per minute and the total drilling waste volume per well. From Marathon/Unocal, March 1994.

APPENDIX XIII-3

ENERGY REQUIREMENTS AND AIR EMISSIONS DETAILED CALCULATIONS FOR COOK INLET PRODUCED WATER CONTROL OPTIONS 1 AND 2:

IMPROVED GAS FLOTATION

NON-WATER QUALITY ENVIRONMENTAL IMPACTS
FUEL REQUIREMENTS AND AIR EMISSIONS
COOK INLET PRODUCED WATER: DISCHARGE FOLLOWING IMPROVED GAS FLOTATION

Facility/ Platform	Prod. Water Flow (BPD)	New Gas Flotation System ?	Gas Flot.n Capacity (BPD)	Total HP Required	SCF NG per year	Total hp-hr Required	AIR EMISSIONS (tons/year)				
							CO	NOX	HC	SO2	Totals
Trading Bay	127,468	no	NA	0	0	0	0.000	0.000	0.000	0.000	0.000
Granite Point	929	yes	5,000	15.53	1,292,407	136,043	0.124	0.195	0.027	0.000	0.346
East Foreland	1,700	yes	5,000	15.53	1,292,407	136,043	0.124	0.195	0.027	0.000	0.346
Anna	919	yes	5,000	15.53	1,292,407	136,043	0.124	0.195	0.027	0.000	0.346
Baker	924	yes	5,000	15.53	1,292,407	136,043	0.124	0.195	0.027	0.000	0.346
Bruce	119	yes	1,000	12.25	1,019,445	107,310	0.098	0.154	0.021	0.000	0.273
Dillon	3,116	yes	10,000	20.5	1,706,010	179,580	0.164	0.257	0.036	0.000	0.457
Tyonek	30	yes	NA	0	0	0	0.000	0.000	0.000	0.000	0.000
TOTALS	135,205			94.87	7,895,083	831,062	0.758	1.191	0.165	0.000	2.114

SUMMARY DATA	
Total Air Emissions (tons/yr):	2.11
Total Fuel Usage (BOE/yr)	1,405.32

Air Emis'n Factors for Gas-Fired Turbines (converted to tons/hp-hr) Ref: Table 3			
CO	NOX	HC	SO2
9.1E-07	1.4E-06	2.0E-07	2.2E-09

APPENDIX XIII-4

ENERGY REQUIREMENTS AND AIR EMISSIONS DETAILED CALCULATIONS FOR COOK INLET PRODUCED WATER CONTROL OPTION 3:

SUBSURFACE INJECTION

NON-WATER QUALITY ENVIRONMENTAL IMPACTS
FUEL REQUIREMENTS AND AIR EMISSIONS
COOK INLET PRODUCED WATER: ZERO DISCHARGE VIA INJECTION

Facility/ Platform	Prod. Water Flow (BPD)	New Gas Flotation System?	Gas Flot.n Capacity (BPD)	Total HP Required	New Filtra.n System?	Filtra.n Capacity (BPD)	Total HP Required	New Centrifuge?	Total HP Required	New Injection System?	Inj. Pump Capacity (BPD)	Total HP Required	New Booster & Shipping Pumps?	Total HP Required
Trading Bay	127,468	no	NA	0	no	NA	NA	yes (a)	0.31867	no	NA	NA	yes	4900
Granite Point	929	yes	5,000	15.53	yes	5000	20	yes	0.00232	yes	3000	100	no	NA
East Foreland	1,700	yes	5,000	15.53	no	NA	NA	yes (b)	0.00425	no	NA	NA	yes	1300
Anna	919	yes	5,000	15.53	no	NA	NA	yes	0.0023	no	NA	NA	no	NA
Baker	924	yes	5,000	15.53	no	NA	NA	yes	0.00231	no	NA	NA	no	NA
Bruce	119	yes	1,000	12.25	no	NA	NA	no	NA	yes	1000	42	no	NA
Dillon	3,116	yes	10,000	20.5	no	NA	NA	yes	0.00779	no	NA	NA	no	NA
Tyonek	30	no	NA	0	yes	1000	10	no	NA	yes	1000	42	no	NA
TOTALS	135,205			94.87			30		0.33764			184		6200

HP For All Equipment	Total hp-hr Required	AIR EMISSIONS (tons/year)				
		CO	NOX	HC	SO2	Totals
4,900.32	42,926,803	39.239	61.459	8.510	0.095	109.303
135.53	1,187,243	1.085	1.700	0.235	0.003	3.023
1,315.53	11,524,043	10.534	16.499	2.285	0.025	29.343
15.53	136,043	0.124	0.195	0.027	0.000	0.346
15.53	136,043	0.124	0.195	0.027	0.000	0.346
54.25	475,230	0.434	0.680	0.094	0.001	1.209
20.51	179,668	0.164	0.257	0.036	0.000	0.457
52.00	455,520	0.416	0.652	0.090	0.001	1.159
6,509.20	**57,020,593**	**52.120**	**81.637**	**11.304**	**0.125**	**145.186**

SCF per yr: 541,695,634

(a) Two centrifuges were added to each of Dolly Varden, King Salmon, and Grayling platforms which receive treated produced water from Trading Bay Treatment Facility.
(b) One centrifuge was added to Platform "C" which receives treated produced water from East Foreland Treatment Facility.

SUMMARY DATA	
Total Air Emissions (tons/yr):	145.19
Total Fuel Usage (BOE/yr):	96,421.82

Air Emis'n Factors for Gas-Fired Turbines (converted to tons/hp-hr) Ref: Table 3			
CO	NOX	HC	SO2
9.1E-07	1.4E-06	2.0E-07	2.2E-09

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APPENDIX XIII-5

ENERGY REQUIREMENTS AND AIR EMISSIONS FOR LOUISIANA OPEN BAY DISCHARGERS AND TEXAS DISCHARGERS SEEKING INDIVIDUAL PERMITS

OPTION 1: IMPROVED GAS FLOTATION

LOUISIANA OPEN BAY PRODUCED WATER DISCHARGERS' NWQI ANALYSIS
OPTION 1
GAS FLOTATION FOR MEDIUM/LARGE-VOLUME FACILITIES

Permit-Outfall Number	Current Avg. Vol (bpd) (bpd)	Electric Power From Diesel (hp)	(hp-hr/yr)	Diesel Fuel Requmnt's (gal/yr)	Electric Power From Natural Gas (hp)	(hp-hr/yr)	Nat. Gas Fuel Requmnt's. (MMscf/yr)	Emissions (tons/yr) CO	NOx	SO2	THC	TSP	Total
2915	130	11.59	101,549	6,702.23	0.00	0.00	0.00	0.34	1.57	0.10	0.13	0.11	2.25
2952	223	11.80	103,387	6,823.54	0.00	0.00	0.00	0.35	1.59	0.11	0.13	0.11	2.29
2704	524	12.48	109,337	7,216.24	0.00	0.00	0.00	0.36	1.69	0.11	0.13	0.12	2.41
2901	1,076	13.73	120,249	7,936.43	0.00	0.00	0.00	0.40	1.85	0.12	0.15	0.13	2.65
3072	1,489	14.66	128,413	8,475.26	0.00	0.00	0.00	0.43	1.98	0.13	0.16	0.14	2.84
3002	2,017	15.85	138,851	9,164.17	0.00	0.00	0.00	0.46	2.14	0.14	0.17	0.15	3.06
2816	2,271	16.42	143,872	9,495.55	0.00	0.00	0.00	0.48	2.22	0.15	0.18	0.16	3.19
2825	2,910	17.87	156,503	10,329.20	0.00	0.00	0.00	0.52	2.41	0.16	0.19	0.17	3.45
2898	3,617	19.46	170,479	11,251.61	0.00	0.00	0.00	0.57	2.63	0.17	0.21	0.19	3.77
1866	4,621	21.73	190,326	12,561.52	0.00	0.00	0.00	0.64	2.93	0.20	0.23	0.21	4.21
2273	4,621	21.73	190,326	12,561.52	0.00	0.00	0.00	0.64	2.93	0.20	0.23	0.21	4.21
2995	4,621	21.73	190,326	12,561.52	0.00	0.00	0.00	0.64	2.93	0.20	0.23	0.21	4.21
3014	4,621	21.73	190,326	12,561.52	0.00	0.00	0.00	0.64	2.93	0.20	0.23	0.21	4.21
4206	4,621	21.73	190,326	12,561.52	0.00	0.00	0.00	0.64	2.93	0.20	0.23	0.21	4.21
2881	5,010	0.00	0.00	0.00	22.77	199,465	1.89	0.35	2.64	0.00	1.08	0.00	4.07
2523	5,364	0.00	0.00	0.00	23.69	207,524	1.97	0.37	2.74	0.00	1.12	0.00	4.23
2860	6,800	0.00	0.00	0.00	27.42	240,199	2.28	0.42	3.17	0.00	1.30	0.00	4.89
2672	8,366	0.00	0.00	0.00	31.48	275,765	2.62	0.49	3.64	0.00	1.49	0.00	5.62
2859	10,807	0.00	0.00	0.00	37.82	331,303	3.15	0.58	4.38	0.00	1.79	0.00	6.75
3063	11,500	0.00	0.00	0.00	39.61	346,984	3.30	0.61	4.59	0.00	1.87	0.00	7.07
2142	12,076	0.00	0.00	0.00	41.11	360,124	3.42	0.63	4.76	0.00	1.94	0.00	7.33
1856	15,000	0.00	0.00	0.00	48.70	426,612	4.05	0.75	5.64	0.00	2.30	0.00	8.69
1934	15,675	0.00	0.00	0.00	50.45	441,942	4.20	0.78	5.84	0.00	2.38	0.00	9.00
2084	16,743	0.00	0.00	0.00	53.22	466,207	4.43	0.82	6.16	0.00	2.52	0.00	9.50
2618	22,500	0.00	0.00	0.00	68.16	597,082	5.67	1.05	7.89	0.00	3.22	0.00	12.16
3320	22,579	0.00	0.00	0.00	68.36	598,834	5.69	1.06	7.91	0.00	3.23	0.00	12.20
2134	23,333	0.00	0.00	0.00	70.32	616,003	5.85	1.09	8.14	0.00	3.32	0.00	12.55
2504	37,113	0.00	0.00	0.00	106.08	929,261	8.83	1.64	12.28	0.00	5.01	0.00	18.93
2072	37,750	0.00	0.00	0.00	107.73	943,715	8.97	1.66	12.47	0.00	5.09	0.00	19.22
1901	41,700	0.00	0.00	0.00	117.98	1,033,505	9.82	1.82	13.66	0.00	5.58	0.00	21.06
TOTAL	329,678	--	2,124,270	140,202	--	8,014,525	76.14	21.22	138.65	2.18	45.85	2.33	210.23

Medium/Large LA Open Bay Produced Water Gas Flotation NWQI Summary Data	
Total Fuel Use	16,891.06 BOE/yr (a)
Total Air Emissions	210.23 tons/yr

(a) BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor: 1 BOE = 42 gal) and the volume of natural gas required converted to equivalent oil volume (by the factor: 1,000 scf = 0.178 BOE).

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LOUISIANA OPEN BAY DISCHARGERS
OPTION 1
SMALL VOLUME FACILITIES[a]
Commercial Disposal of Produced Water via Barge

Source	Diesel Usage (gal/yr)	BOE/yr	Air Emissions (tons/yr)					
			NO_x	THC	SO_2	CO	TSP	Total
Pump + Compressor	159.21	3.79	0.037	0.003	0.002	0.008	0.003	0.053
Tug	55,881.12	1,330.50	10.94	0.47	0.80	2.19	0.92	15.32
Total	**56,040.23**	**1,334.29**	**10.977**	**0.473**	**0.802**	**2.198**	**0.923**	**15.373**

[a] Detailed calculations of the above values are presented in Appendix XIII-7.

TEXAS INDIVIDUAL PERMIT APPLICANTS' NWQI ANALYSIS
OPTION 1
SMALL VOLUME FACILITIES
Commercial Produced Water Disposal via Truck

Permit No.	Location	Current Vol. (bpd)	No. of Truck Trips/yr	Miles Traveled/yr	Diesel Fuel Usage (gal/yr)	Emissions (tons/yr)					
						CO	NOx	SO2	THC	TSP	Total
*	Corpus Christi Bay	7	21.47	2,576.40	644.10	0.02	0.03	0.00	0.01	0.00	0.06
13	Kellers Bay	5	15.34	1,840.80	460.20	0.02	0.02	0.00	0.01	0.00	0.05
37	San Antonio Bay	15	46.01	5,521.20	1,380.30	0.05	0.07	0.00	0.02	0.00	0.14
41	Cox Bay	40	122.69	14,722.80	3,680.70	0.14	0.18	0.00	0.04	0.00	0.36
71	Tabbs Bay	3	9.20	1,104.00	276.00	0.01	0.01	0.00	0.00	0.00	0.03
104	Goose Creek	49	150.29	18,034.80	4,508.70	0.17	0.22	0.00	0.05	0.00	0.44
119	Goose Creek	2	6.13	735.60	183.90	0.01	0.01	0.00	0.00	0.00	0.02
199	Mustang Island	40	122.69	14,722.80	3,680.70	0.14	0.18	0.00	0.04	0.00	0.36
214	Corpus Christi Bay	16	49.08	5,889.60	1,472.40	0.06	0.07	0.00	0.02	0.00	0.14
233	Aransas Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
236	Mustang Island	44	134.96	16,195.20	4,048.80	0.15	0.20	0.00	0.04	0.00	0.40
282	Corpus Christi Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
284	Corpus Christi Bay	22	67.48	8,097.60	2,024.40	0.08	0.10	0.00	0.02	0.00	0.20
628	Copano Bay	24	73.61	8,833.20	2,208.30	0.08	0.11	0.00	0.02	0.00	0.22
663	Cedar Lake	10	30.67	3,680.40	920.10	0.03	0.05	0.00	0.01	0.00	0.09
690	Aransas Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
693	Aransas Bay	10	30.67	3,680.40	920.10	0.03	0.05	0.00	0.01	0.00	0.09
708		1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
723	Matagorda Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
732		6	18.40	2,208.00	552.00	0.02	0.03	0.00	0.01	0.00	0.05
733		2	6.13	735.60	183.90	0.01	0.01	0.00	0.00	0.00	0.02
752	Sabine River	29	88.95	10,674.00	2,668.50	0.10	0.13	0.00	0.03	0.00	0.26
919	Matagorda Bay	60	184.03	22,083.60	5,520.90	0.21	0.27	0.00	0.06	0.00	0.54
924	Matagorda Bay	31	95.08	11,409.60	2,852.40	0.11	0.14	0.00	0.03	0.00	0.28
925	Matagorda Bay	69	211.64	25,396.80	6,349.20	0.24	0.31	0.00	0.07	0.00	0.62
926	Matagorda Bay	48	147.23	17,667.60	4,416.90	0.17	0.22	0.00	0.05	0.00	0.43
939	Tabbs Bay	43	131.89	15,826.80	3,956.70	0.15	0.20	0.00	0.04	0.00	0.39
972	Aransas Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
582 (a)	Laguna Madre	75	230.04	27,604.80	6,901.20	0.26	0.34	0.00	0.08	0.00	0.68
TOTAL FOR GAS FLOTATION		**656**	**2,012.10**	**241,452.00**	**60,363.00**	**2.27**	**2.99**	**0.00**	**0.66**	**0.00**	**5.92**

* TRC permit pending

TX Produced Water Small Facilities Gas Flotation Option NWQI Summary Data	
Total Fuel Use	1,437.21 BOE/yr (b)
Total Air Emissions	5.92 tons/yr

(a) This outfall is classified as a small-volume discharger only for the gas flotation option.

(b) BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor: 1 BOE = 42 gal) and the volume of natural gas required converted to equivalent oil volume (by the factor: 1,000 scf = 0.178 BOE).

TXOBNWQI.WK3

TEXAS INDIVIDUAL PERMIT APPLICANTS' PRODUCED WATER NWQI ANALYSIS
OPTION 1
GAS FLOTATION FOR MEDIUM/LARGE–VOLUME FACILITIES

Permit–Outfall Number	Current Avg Vol (bpd) (bpd)	Electric Power From Diesel (hp)	(hp–hr/yr)	Diesel Fuel Reqmnt's (gal/yr)	Electric Power From Natural Gas (hp)	(hp–hr/yr)	Nat. Gas Fuel Reqmnt's (MMscf/yr)	Emissions (tons/yr) CO	NOx	SO2	THC	TSP	Total
905	86	11.49	100,652	6,643.06	0.00	0.00	0.00	0.34	1.55	0.10	0.12	0.11	2.23
675	92	11.51	100,828	6,654.62	0.00	0.00	0.00	0.34	1.55	0.10	0.12	0.11	2.23
*	93	11.51	100,828	6,654.62	0.00	0.00	0.00	0.34	1.55	0.10	0.12	0.11	2.23
927	95	11.51	100,828	6,654.62	0.00	0.00	0.00	0.34	1.55	0.10	0.12	0.11	2.23
242	104	11.53	101,003	6,666.18	0.00	0.00	0.00	0.34	1.56	0.10	0.12	0.11	2.23
264	114	11.56	101,266	6,683.53	0.00	0.00	0.00	0.34	1.56	0.10	0.12	0.11	2.24
*	115	11.56	101,266	6,683.53	0.00	0.00	0.00	0.34	1.56	0.10	0.12	0.11	2.24
552	140	11.61	101,704	6,712.44	0.00	0.00	0.00	0.34	1.57	0.10	0.13	0.11	2.25
922	143	11.62	101,791	6,718.22	0.00	0.00	0.00	0.34	1.57	0.10	0.13	0.11	2.25
605	150	11.64	101,966	6,729.78	0.00	0.00	0.00	0.34	1.57	0.10	0.13	0.11	2.26
202	153	11.64	101,966	6,729.78	0.00	0.00	0.00	0.34	1.57	0.10	0.13	0.11	2.26
684	165	11.67	102,229	6,747.13	0.00	0.00	0.00	0.34	1.58	0.10	0.13	0.11	2.26
694	185	11.72	102,667	6,776.04	0.00	0.00	0.00	0.34	1.58	0.11	0.13	0.11	2.27
637	200	11.75	102,930	6,793.38	0.00	0.00	0.00	0.34	1.59	0.11	0.13	0.11	2.28
822	200	11.75	102,930	6,793.38	0.00	0.00	0.00	0.34	1.59	0.11	0.13	0.11	2.28
970	250	11.86	103,894	6,856.98	0.00	0.00	0.00	0.35	1.60	0.11	0.13	0.11	2.30
710	358	12.11	106,084	7,001.52	0.00	0.00	0.00	0.35	1.64	0.11	0.13	0.12	2.35
174	384	12.17	106,609	7,036.21	0.00	0.00	0.00	0.36	1.64	0.11	0.13	0.12	2.36
967	397	12.19	106,784	7,047.77	0.00	0.00	0.00	0.36	1.65	0.11	0.13	0.12	2.36
921	410	12.22	107,047	7,065.12	0.00	0.00	0.00	0.36	1.65	0.11	0.13	0.12	2.37
679	454	12.32	107,923	7,122.93	0.00	0.00	0.00	0.36	1.66	0.11	0.13	0.12	2.39
124	455	12.33	108,011	7,128.71	0.00	0.00	0.00	0.36	1.67	0.11	0.13	0.12	2.39
238	515	12.46	109,150	7,203.87	0.00	0.00	0.00	0.36	1.68	0.11	0.13	0.12	2.41
619	536	12.51	109,588	7,232.78	0.00	0.00	0.00	0.37	1.69	0.11	0.14	0.12	2.42
968	540	12.52	109,675	7,238.56	0.00	0.00	0.00	0.37	1.69	0.11	0.14	0.12	2.43
666	628	12.72	111,427	7,354.20	0.00	0.00	0.00	0.37	1.72	0.11	0.14	0.12	2.46
105	650	12.77	111,865	7,383.10	0.00	0.00	0.00	0.37	1.72	0.11	0.14	0.12	2.47
937	659	12.79	112,040	7,394.67	0.00	0.00	0.00	0.37	1.73	0.11	0.14	0.12	2.48
60	685	12.84	112,478	7,423.57	0.00	0.00	0.00	0.38	1.73	0.12	0.14	0.12	2.49
167	690	12.86	112,654	7,435.14	0.00	0.00	0.00	0.38	1.74	0.12	0.14	0.12	2.49
166	1029	13.62	119,311	7,874.54	0.00	0.00	0.00	0.40	1.84	0.12	0.15	0.13	2.64
20	1151	13.90	121,764	8,036.42	0.00	0.00	0.00	0.41	1.88	0.12	0.15	0.13	2.69
904	1360	14.37	125,881	8,308.16	0.00	0.00	0.00	0.42	1.94	0.13	0.16	0.14	2.78
85	1379	14.41	126,232	8,331.29	0.00	0.00	0.00	0.42	1.95	0.13	0.16	0.14	2.79
45	1400	14.46	126,670	8,360.19	0.00	0.00	0.00	0.42	1.95	0.13	0.16	0.14	2.80
969	1480	14.64	128,246	8,464.26	0.00	0.00	0.00	0.43	1.98	0.13	0.16	0.14	2.84
80	1492	14.67	128,509	8,481.61	0.00	0.00	0.00	0.43	1.98	0.13	0.16	0.14	2.84
*	1500	14.68	128,597	8,487.39	0.00	0.00	0.00	0.43	1.98	0.13	0.16	0.14	2.84
90	1800	15.36	134,554	8,880.54	0.00	0.00	0.00	0.45	2.07	0.14	0.17	0.15	2.98
68	2185	16.23	142,175	9,383.54	0.00	0.00	0.00	0.47	2.19	0.15	0.18	0.16	3.14
81	3090	18.27	160,045	10,562.98	0.00	0.00	0.00	0.53	2.47	0.16	0.20	0.18	3.54
77	3552	19.31	169,156	11,164.27	0.00	0.00	0.00	0.56	2.61	0.17	0.21	0.19	3.74
164	4353	21.12	185,011	12,210.74	0.00	0.00	0.00	0.62	2.85	0.19	0.23	0.20	4.09
813	4893	22.34	195,698	12,916.09	0.00	0.00	0.00	0.65	3.02	0.20	0.24	0.22	4.33
952	4980	22.54	197,450	13,031.73	0.00	0.00	0.00	0.66	3.04	0.20	0.24	0.22	4.37
113	5127	0.00	0.00	0.00	23.08	202,181	1.92	0.36	2.67	0.00	1.09	0.00	4.12
954	7384	0.00	0.00	0.00	28.93	253,427	2.41	0.45	3.35	0.00	1.37	0.00	5.16
953	9316	0.00	0.00	0.00	33.95	297,402	2.83	0.52	3.93	0.00	1.60	0.00	6.06
TOTAL	67,117	--	5,349,382	353,059	--	753,010	7.16	19.18	92.43	5.49	10.66	5.89	133.65

* TRC permit pending

Medium/Large TX Ind. Permit Applicant Produced Water Gas Flotation NWQI Summary Data	
Total Fuel Use	9,680.65 BOE/yr (a)
Total Air Emissions	133.65 tons/yr

(a) BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor: 1 BOE = 42 gal) and the volume of natural gas required converted to equivalent oil volume (by the factor: 1,000 scf = 0.178 BOE).

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APPENDIX XIII-6

ENERGY REQUIREMENTS AND AIR EMISSIONS FOR LOUISIANA OPEN BAY DISCHARGERS AND TEXAS DISCHARGERS SEEKING INDIVIDUAL PERMITS

OPTIONS 2 AND 3: ZERO DISCHARGE VIA SUBSURFACE INJECTION

LA OPEN BAY PRODUCED WATER DISCHARGERS' NWQI ANALYSIS
OPTIONS 2 AND 3
INJECTION FOR MEDIUM/LARGE–VOLUME FACILITIES

Permit–Outfall	Current Avg. Volume	Electric Power From Diesel		Diesel Fuel Use	Electric Power From Natural Gas		Natural Gas Power For Inj. Pumps		Nat. Gas Fuel Use	Emissions (tons/yr)					
Number	(bpd)	(hp)	(hp–hr/yr)	(gal/yr)	(hp)	(hp–hr/yr)	(hp)	(hp–hr/yr)	(MMscf/yr)	CO	NOx	SO2	THC	TSP	Total
2915	130	6.67	58,429	3,856						0.19	0.90	0.06	0.00	0.00	1.16
2952	223	9.77	85,585	5,649						0.29	1.32	0.09	0.01	0.00	1.70
2704	524	19.80	173,448	11,448						0.58	2.67	0.18	0.01	0.00	3.44
2901	1,076				1.80	15,768	50.86	445,534	4.38	0.81	6.10	0.00	2.49	0.00	9.40
3072	1,489				2.35	20,586	66.22	580,087	5.71	1.06	7.94	0.00	3.24	0.00	12.24
3002	2,017				3.05	26,718	85.85	752,046	7.40	1.37	10.29	0.00	4.20	0.00	15.87
2816	2,271				3.38	29,609	95.30	834,828	8.21	1.52	11.42	0.00	4.66	0.00	17.61
2825	2,910				4.23	37,055	119.06	1,042,966	10.26	1.90	14.27	0.00	5.83	0.00	22.01
2898	3,617				5.17	45,289	145.35	1,273,266	12.53	2.32	17.43	0.00	7.12	0.00	26.87
1866	4,621				6.50	56,940	182.68	1,600,277	15.74	2.92	21.90	0.00	8.94	0.00	33.77
2273	4,621				6.50	56,940	182.68	1,600,277	15.74	2.92	21.90	0.00	8.94	0.00	33.77
2995	4,621				6.50	56,940	182.68	1,600,277	15.74	2.92	21.90	0.00	8.94	0.00	33.77
3014	4,621				6.50	56,940	182.68	1,600,277	15.74	2.92	21.90	0.00	8.94	0.00	33.77
4206	4,621				6.50	56,940	182.68	1,600,277	15.74	2.92	21.90	0.00	8.94	0.00	33.77
2881	5,010				7.01	61,408	197.14	1,726,946	16.99	3.15	23.63	0.00	9.65	0.00	36.44
2523	5,364				7.48	65,525	210.30	1,842,228	18.12	3.36	25.21	0.00	10.30	0.00	38.87
2860	6,800				9.38	82,169	263.70	2,310,012	22.73	4.22	31.61	0.01	12.91	0.00	48.74
2672	8,366				11.46	100,390	321.93	2,820,107	27.74	5.15	38.60	0.01	15.76	0.00	59.51
2859	10,807				14.69	128,684	412.69	3,615,164	35.57	6.60	49.48	0.01	20.20	0.00	76.29
3063	11,500				15.61	136,744	438.46	3,840,910	37.79	7.01	52.57	0.01	21.47	0.00	81.05
2142	12,076				16.38	143,489	459.88	4,028,549	39.63	7.35	55.14	0.01	22.51	0.00	85.01
1856	15,000				20.25	177,390	568.60	4,980,936	49.00	9.09	68.17	0.01	27.84	0.00	105.11
1934	15,675				21.15	185,274	593.70	5,200,812	51.17	9.49	71.18	0.01	29.07	0.00	109.75
2084	16,743				22.56	197,626	633.41	5,548,672	54.59	10.13	75.94	0.01	31.01	0.00	117.09
2618	22,500				24.00	210,240	847.47	7,423,837	72.52	13.45	100.89	0.02	41.20	0.00	155.56
3320	22,579				24.00	210,240	850.41	7,449,592	72.77	13.50	101.23	0.02	41.34	0.00	156.08
2134	23,333				24.00	210,240	878.45	7,695,222	75.10	13.93	104.48	0.02	42.66	0.00	161.09
2504	37,113				24.00	210,240	1,390.83	12,183,671	117.74	21.84	163.80	0.03	66.88	0.00	252.55
2072	37,750				24.00	210,240	1,414.51	12,391,108	119.71	22.21	166.54	0.03	68.00	0.00	256.77
1901	41,700				24.00	210,240	1,561.39	13,677,776	131.94	24.47	183.54	0.03	74.95	0.00	282.99
TOTAL	**329,678**	**--**	**317,462**	**20,953**	**--**	**2,999,862**	**--**	**109,665,652**	**1,070**	**199.59**	**1,493.87**	**0.57**	**608.02**	**0.00**	**2,302.05**

Medium/Large LA Open Bay Produced Water Zero Discharge NWQI Summary Data	
Total Fuel Use	191,016 BOE/yr (a)
Total Air Emissions	2,302 tons/yr

(a) BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor: 1 BOE = 42 gal) and the volume of natural gas required converted to equivalent oil volume (by the factor: 1,000 scf = 0.178 BOE).

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LOUISIANA OPEN BAY DISCHARGERS
OPTIONS 2 AND 3
SMALL VOLUME FACILITIES[a]
Commercial Disposal of Produced Water via Barge

Source	Diesel Usage (gal/yr)	BOE/yr	Air Emissions (tons/yr)					
			NO_x	THC	SO_2	CO	TSP	Total
Pump + Compressor	159.21	3.79	0.037	0.003	0.002	0.008	0.003	0.053
Tug	55,881.12	1,330.50	10.94	0.47	0.80	2.19	0.92	15.32
Total	**56,040.23**	**1,334.29**	**10.977**	**0.473**	**0.802**	**2.198**	**0.923**	**15.373**

[a] Detailed calculations of the above values are presented in Appendix XIII-7.

TEXAS INDIVIDUAL PERMIT APPLICANTS' PRODUCED WATER NWQI ANALYSIS
OPTIONS 2 AND 3
INJECTION FOR MEDIUM/LARGE-VOLUME FACILITIES

Permit-Outfall Number	Current Avg. Volume (bpd)	Electric Power From Diesel (hp)	(hp-hr/yr)	Diesel Fuel Use (gal/yr)	Natural Gas Power For Inj. Pumps (hp)	(hp-hr/yr)	Nat. Gas Fuel Use (MMscf/yr)	Emissions (tons/yr) CO	NOx	SO2	THC	TSP	Total
582	75	3.83	33,551	2,214				0.11	0.52	0.03	0.04	0.04	0.74
905	86	4.20	36,792	2,428				0.12	0.57	0.04	0.05	0.04	0.81
675	92	4.40	38,544	2,544				0.13	0.59	0.04	0.05	0.04	0.85
*	93	4.43	38,807	2,561				0.13	0.60	0.04	0.05	0.04	0.86
927	95	4.50	39,420	2,602				0.13	0.61	0.04	0.05	0.04	0.87
242	104	4.80	42,048	2,775				0.14	0.65	0.04	0.05	0.05	0.93
264	114	5.13	44,939	2,966				0.15	0.69	0.05	0.06	0.05	0.99
*	115	5.16	45,202	2,983				0.15	0.70	0.05	0.06	0.05	1.00
552	140	6.00	52,560	3,469				0.18	0.81	0.05	0.06	0.06	1.16
922	143	6.10	53,436	3,527				0.18	0.82	0.05	0.07	0.06	1.18
605	150	6.33	55,451	3,660				0.19	0.85	0.06	0.07	0.06	1.23
202	153	6.43	56,327	3,718				0.19	0.87	0.06	0.07	0.06	1.25
684	165	6.83	59,831	3,949				0.20	0.92	0.06	0.07	0.07	1.32
694	185	7.49	65,612	4,330				0.22	1.01	0.07	0.08	0.07	1.45
637	200	7.99	69,992	4,619				0.23	1.08	0.07	0.09	0.08	1.55
822	200	7.99	69,992	4,619				0.23	1.08	0.07	0.09	0.08	1.55
970	250	9.66	84,622	5,585				0.28	1.30	0.09	0.10	0.09	1.87
710	358	13.25	116,070	7,661				0.39	1.79	0.12	0.14	0.13	2.57
174	384	14.12	123,691	8,164				0.41	1.91	0.13	0.15	0.14	2.74
967	397	14.55	127,458	8,412				0.43	1.97	0.13	0.16	0.14	2.82
921	410	14.99	131,312	8,667				0.44	2.02	0.13	0.16	0.14	2.90
679	454	16.45	144,102	9,511				0.48	2.22	0.15	0.18	0.16	3.19
124	455	16.48	144,365	9,528				0.48	2.23	0.15	0.18	0.16	3.19
238	515	18.48	161,885	10,684				0.54	2.50	0.17	0.20	0.18	3.58
619	536	19.18	168,017	11,089				0.56	2.59	0.17	0.21	0.19	3.72
968	540	19.32	169,243	11,170				0.56	2.61	0.17	0.21	0.19	3.74
666	628	22.25	194,910	12,864				0.65	3.01	0.20	0.24	0.21	4.31
105	650				26.19	229,424	2.18	0.40	3.03	0.00	1.24	0.00	4.67
937	659				26.51	232,228	2.21	0.41	3.07	0.00	1.25	0.00	4.73
60	685				27.44	240,374	2.28	0.42	3.18	0.00	1.30	0.00	4.90
167	690				27.62	241,951	2.30	0.43	3.20	0.00	1.31	0.00	4.93
166	1,029				39.78	348,473	3.31	0.61	4.61	0.00	1.88	0.00	7.10
20	1,151				44.16	386,842	3.67	0.68	5.11	0.00	2.09	0.00	7.88
904	1,360				51.66	452,542	4.30	0.80	5.98	0.00	2.44	0.00	9.22
85	1,379				52.34	458,498	4.36	0.81	6.06	0.00	2.47	0.00	9.34
45	1,400				53.09	465,068	4.42	0.82	6.15	0.00	2.51	0.00	9.48
969	1,480				55.96	490,210	4.66	0.86	6.48	0.00	2.65	0.00	9.99
80	1,492				56.39	493,976	4.69	0.87	6.53	0.00	2.67	0.00	10.07
*	1,500				56.68	496,517	4.72	0.87	6.56	0.00	2.68	0.00	10.12
90	1,800				67.44	590,774	5.61	1.04	7.81	0.00	3.19	0.00	12.04
68	2,185				81.25	711,750	6.76	1.25	9.41	0.00	3.84	0.00	14.50
81	3,090				113.71	996,100	9.46	1.76	13.16	0.00	5.38	0.00	20.30
77	3,552				130.28	1,141,253	10.84	2.01	15.08	0.00	6.16	0.00	23.25
164	4,353				159.01	1,392,928	13.23	2.45	18.41	0.00	7.52	0.00	28.38
813	4,893				178.38	1,562,609	14.84	2.75	20.65	0.00	8.43	0.00	31.84
952	4,980				181.51	1,590,028	15.11	2.80	21.01	0.00	8.58	0.00	32.40
113	5,127				186.78	1,636,193	15.54	2.88	21.62	0.00	8.83	0.00	33.34
954	7,384				267.74	2,345,402	22.28	4.13	31.00	0.01	12.66	0.00	47.79
953	9,316				337.04	2,952,470	28.05	5.20	39.02	0.01	15.93	0.00	60.16
TOTAL	67,192	--	2,368,178	156,300	--	19,455,610	184.83	42.19	293.64	2.47	107.91	2.61	448.81

* TRC permit pending

Medium/Large TX Ind. Permit Applicant Produced Water Zero Discharge NWQI Summary Data	
Total Fuel Use	36,620.86 BOE/yr (a)
Total Air Emissions	448.81 tons/yr

(a) BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor: 1 BOE = 42 gal) and the volume of natural gas required converted to equivalent oil volume (by the factor: 1,000 scf = 0.178 BOE).

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TEXAS INDIVIDUAL PERMIT APPLICANTS' NWQI ANALYSIS
OPTIONS 2 AND 3
SMALL VOLUME FACILITIES
Commercial Produced Water Disposal via Truck

Permit No.	Location	Current Vol. (bpd)	No. of Tru Trips/yr	Miles Traveled/yr	Diesel Fuel Usage (gal/y	Emissions (tons/yr)					
						CO	NOx	SO2	THC	TSP	Total
*	Corpus Christi Bay	7	21.47	2,576.40	644.10	0.02	0.03	0.00	0.01	0.00	0.06
13	Kellers Bay	5	15.34	1,840.80	460.20	0.02	0.02	0.00	0.01	0.00	0.05
37	San Antonio Bay	15	46.01	5,521.20	1,380.30	0.05	0.07	0.00	0.02	0.00	0.14
41	Cox Bay	40	122.69	14,722.80	3,680.70	0.14	0.18	0.00	0.04	0.00	0.36
71	Tabbs Bay	3	9.20	1,104.00	276.00	0.01	0.01	0.00	0.00	0.00	0.03
104	Goose Creek	49	150.29	18,034.80	4,508.70	0.17	0.22	0.00	0.05	0.00	0.44
119	Goose Creek	2	6.13	735.60	183.90	0.01	0.01	0.00	0.00	0.00	0.02
199	Mustang Island	40	122.69	14,722.80	3,680.70	0.14	0.18	0.00	0.04	0.00	0.36
214	Corpus Christi Bay	16	49.08	5,889.60	1,472.40	0.06	0.07	0.00	0.02	0.00	0.14
233	Aransas Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
236	Mustang Island	44	134.96	16,195.20	4,048.80	0.15	0.20	0.00	0.04	0.00	0.40
282	Corpus Christi Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
284	Corpus Christi Bay	22	67.48	8,097.60	2,024.40	0.08	0.10	0.00	0.02	0.00	0.20
628	Copano Bay	24	73.61	8,833.20	2,208.30	0.08	0.11	0.00	0.02	0.00	0.22
663	Cedar Lake	10	30.67	3,680.40	920.10	0.03	0.05	0.00	0.01	0.00	0.09
690	Aransas Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
693	Aransas Bay	10	30.67	3,680.40	920.10	0.03	0.05	0.00	0.01	0.00	0.09
708		1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
723	Matagorda Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
732		6	18.40	2,208.00	552.00	0.02	0.03	0.00	0.01	0.00	0.05
733		2	6.13	735.60	183.90	0.01	0.01	0.00	0.00	0.00	0.02
752	Sabine River	29	88.95	10,674.00	2,668.50	0.10	0.13	0.00	0.03	0.00	0.26
919	Matagorda Bay	60	184.03	22,083.60	5,520.90	0.21	0.27	0.00	0.06	0.00	0.54
924	Matagorda Bay	31	95.08	11,409.60	2,852.40	0.11	0.14	0.00	0.03	0.00	0.28
925	Matagorda Bay	69	211.64	25,396.80	6,349.20	0.24	0.31	0.00	0.07	0.00	0.62
926	Matagorda Bay	48	147.23	17,667.60	4,416.90	0.17	0.22	0.00	0.05	0.00	0.43
939	Tabbs Bay	43	131.89	15,826.80	3,956.70	0.15	0.20	0.00	0.04	0.00	0.39
972	Aransas Bay	1	3.07	368.40	92.10	0.00	0.00	0.00	0.00	0.00	0.01
TOTAL		581	1,782.06	213,847.20	53,461.80	2.01	2.64	0.00	0.59	0.00	5.24

* TRC permit pending

TX Produced Water Small Facilities Zero Discharge Option NWQI Summary Data	
Total Fuel Use	1,272.90 BOE/yr (a)
Total Air Emissions	5.24 tons/yr

(a) BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume (by the factor: 1 BOE = 42 gal) and the volume of natural gas required converted to equivalent oil volume (by the factor: 1,000 scf = 0.178 BOE).

TXOBNWQI.WK3

APPENDIX XIII-7

CALCULATIONS FOR ENERGY REQUIREMENTS AND AIR EMISSIONS FOR LOUISIANA OPEN BAY SMALL VOLUME FACILITIES

LOUISIANA OPEN BAY DISCHARGERS
SMALL VOLUME FACILITIES
NWQI Calculations for All Options

Calculations are based on the methodology presented in Chapter XI of the 1995 Coastal Oil and Gas Development Document (EPA, 1995).

1. Each facility has one onsite storage tank sized to hold one week's produced water volume, as follows.

    - Facilities with flows less than or equal to 21 bpd will install one 150 bbl storage tank.
    - Facilities with flows greater than 21 bpd but less than or equal to 43 bpd will install one 300 bbl storage tank.
    - Facilities with flows greater than 43 bpd but less than or equal to 71 bpd will install one 500 bbl storage tank.

2. Barges are used to transport produced water from facilities. Barge capacity is 3,000 bbl. Each barge will service multiple facilities to full capacity or as close to full as possible, given each facility's onsite storage capacity.

3. Barge trip frequency and the order of pick up from each facility is dependent on the facility's produced water flow and onsite storage tank capacity.

4. The total annual diesel fuel consumption associated with the transportation of produced water was calculated based on yearly barge trip cycles.

5. Loading of produced water into the barge is accomplished by gravity.

6. Unloading of produced water from the barge is accomplished by vacuum pump.

Input Data (Appendices referenced below are in the 1995 Coastal Oil and Gas Development Document):

• Distance between facilities (Appendix XI-1, EPA, 1995)	10 miles
• Distance between port and facility (Appendix XI-1, EPA, 1995)	50 miles
• Distance to disposal facility (Appendix XI-1, EPA, 1995)	50 miles
• Tug fuel consumption (Appendix XVI-5, EPA, 1995)	24 gal diesel/hr
• Tug traveling speed (Appendix XI-1, EPA, 1995)	6 miles/hr
• Time to load/unload barge (Appendix XI-1, EPA, 1995)	8 hours
• Time to dock (Appendix XI-1, EPA, 1995)	1 hour
• Time to leave each facility (Chapter XVI, EPA, 1995)	15 minutes
• 4" vacuum pump rate (Appendix XVI-5, EPA, 1995)	60,000 gal/hr
• 4" vacuum pump fuel consumption (Appendix XVI-5, EPA, 1995)	0.60 gal diesel/hr
• Compressor fuel consumption (Appendix XVI-5, ref. 4)	3.5 gal diesel/hr

Louisiana Open Bay Small-Volume Discharger Facilities
(For Both Gas Flotation and Injection Options)

Operator and Permit Number	PW Volume (bpd)	Storage Tank Capacity (bbl)	Storage Tank Capacity (days)	Pick-up Order
1. 2827	1.0	150	150	7
2. 2856	3.0	150	5	6
3. 3023	3.4	150	44.1	5
4. 2479	10	150	15	4
5. 2857	20	150	7.5	1
6. 1870	49	500	10.2	3
7. 3032	50	500	10	2

CYCLE A WITH OPERATORS 4, 5, 6 AND 7

Day Number[a]	Time	Activity	Time Elapsed (hr)	Distance Travelled (mi)	Time Tug Operating (hr)	Fuel Consumed (gal)	PW Loaded (bbls)
1-6							
6.25	6:00 am	Barge leaves port	-	-	-	-	-
	2:20 pm	Barge arrives @ #5	8:20	50	8.33	199.92	
6.64	3:20 pm	Barge docks @ #5	1:00	0	1.00	24	132.8
	3:42 pm	PW loaded (132.8)	0:22	0	.37	8.88	
	3:57 pm	Barge leaves #5	0:15	0	.25	6	
	5:37 pm	Barge arrives @ #7	1:40	10	1.67	40.08	
6.78	6:37 pm	Barge docks @ #7	1:00	0	1.00	24	339
	7:32 pm	PW loaded (339)	0:55	0	0	0	
	7:47 pm	Barge leaves #7	0:15	0	0.25	6	
	9:27 pm	Barge arrives @ #6	1:40	10	1.67	40.08	
6.94	10:27 pm	Barge docks @ #6	1:00	0	1.00	24	340.06
	11:22 pm	PW loaded (340.06)	0:55	0	0	0	
	11:37 pm	Barge leaves #6	0:15	0	0.25	6	
	1:17 am	Barge arrives @ #4	1:40	10	1.67	40.08	
7.05	2:17 am	Barge docks @ #4	1:00	0	1.00	24	70.5
	2:27 am	PW loaded (70.5)	0:12	0	0.20	4.8	
	2:42 am	Barge leaves #4	0:15	0	0.25	6	
	11:02 am	Barge arrives @ Disp. Fac.	8:20	50	8.33	199.92	
	12:02 pm	Barge docks @ Disp. Fac.	1:00	0	1.00	24	
	2:24 pm	PW unloaded (882.36)	2:22	0	0	0	
	2:39 pm	Barge leaves Disp. Fac.	0:15	0	0.25	6	
	10:59 pm	Barge arrives @ port	8:20	50	8.33	199.92	
	11:59 pm	Barge docks @ port	1:00	0	1.00	24	
				Total	**37.82**	**907.68**	

[a] The day number multiplied by the facility's produced water flow equals the produced water volume loaded. See notes on produced water barge trip cycles following these tables.

CYCLE B WITH OPERATORS 2, 3, 4, 5, 6, AND 7

Day Number[a]	Time	Activity	Time Elapsed (hr)	Distance Travelled (mi)	Time Tug Operating (hr)	Fuel Consumed (gal)	PW Loaded (bbls)
1-6 (1-42)							
6.25 (42.25)	6:00 am	Barge leaves port	-	-	-	-	-
	2:20 pm	Barge arrives @ #5	8:20	50	8.33	199.92	
6.64 (42.64)	3:20 pm	Barge docks @ #5	1:00	0	1.00	24	132.8
	3:42 pm	PW loaded (132.8)	0:22	0	.37	8.88	
	3:57 pm	Barge leaves #5	0:15	0	.25	6	
	5:37 pm	Barge arrives @ #7	1:40	10	1.67	40.08	
6.78 (42.78)	6:37 pm	Barge docks @ #7	1:00	0	1.00	24	339
	7:32 pm	PW loaded (339)	0:55	0	0	0	
	7:47 pm	Barge leaves #7	0:15	0	0.25	6	
	9:27 pm	Barge arrives @ #6	1:40	10	1.67	40.08	
6.94 (42.94)	10:27 pm	Barge docks @ #6	1:00	0	1.00	24	340.06
	11:22 pm	PW loaded (340.06)	0:55	0	0	0	
	11:37 pm	Barge leaves #6	0:15	0	0.25	6	
	1:17 am	Barge arrives @ #4	1:40	10	1.67	40.08	
7.05 (43.05)	2:17 am	Barge docks @ #4	1:00	0	1.00	24	70.5
	2:27 am	PW loaded (70.5)	0:12	0	0.20	4.80	
	2:42 am	Barge leaves #4	0:15	0	0.25	6	
	4:22 am	Barge arrives @ #3	1:40	10	1.67	40.08	
7.22 (43.22)	5:22 am	Barge docks @ #3	1:00	0	1.00	24	146.95
	5:46 am	PW loaded (146.95)	0:24	0	0.39	9.36	
	6:01 am	Barge leaves #3	0:15	0	0.25	6	
	7:41 am	Barge arrives @ #2	1:40	10	1.67	40.08	
7.36 (43.36)	8:41 am	Barge docks @ #2	1:00	0	1.00	24	130.08
	9:02 am	PW loaded (130.08)	0:21	0	0.35	8.40	
	9:17 am	Barge leaves #2	0:15	0	0.25	6	
	5:37 pm	Barge arrives @ Disp. Fac.	8:20	50	8.33	199.92	
	6:37 pm	Barge docks @ Disp. Fac.	1:00	0	1.00	24	
	9:43 pm	PW unloaded (1159.39)	3:06	0	0	0	
	9:58 pm	Barge leaves Disp. Fac.	0:15	0	0.25	6	
	6:18 am	Barge arrives @ port	8:20	50	8.33	199.92	
8.30 (44.30)	7:18 am	Barge docks @ port	1:00	0	1.00	24	
				Total	**44.40**	**1,065.60**	

[a] The day number multiplied by the facility's produced water flow equals the produced water volume loaded. See notes on produced water barge trip cycles following these tables.

CYCLE C WITH ALL OPERATORS

Day Number[a]	Time	Activity	Time Elapsed (hr)	Distance Travelled (mi)	Time Tug Operating (hr)	Fuel Consumed (gal)	PW Loaded (bbls)
1-6 (1-126)							
6.25 (126.25)	6:00 am	Barge leaves port	-	-	-	-	-
	2:20 pm	Barge arrives @ #5	8:20	50	8.33	199.92	
6.64 (126.64)	3:20 pm	Barge docks @ #5	1:00	0	1.00	24	132.8
	3:42 pm	PW loaded (132.8)	0:22	0	.37	8.88	
	3:57 pm	Barge leaves #5	0:15	0	.25	6	
	5:37 pm	Barge arrives @ #7	1:40	10	1.67	40.08	
6.78 (126.78)	6:37 pm	Barge docks @ #7	1:00	0	1.00	24	339
	7:32 pm	PW loaded (339)	0:55	0	0	0	
	7:47 pm	Barge leaves #7	0:15	0	0.25	6	
	9:27 pm	Barge arrives @ #6	1:40	10	1.67	40.08	
6.94 (126.94)	10:27 pm	Barge docks @ #6	1:00	0	1.00	24	340.06
	11:22 pm	PW loaded (340.06)	0:55	0	0	0	
	11:37 pm	Barge leaves #6	0:15	0	0.25	6	
	1:17 am	Barge arrives @ #4	1:40	10	1.67	40.08	
7.05 (127.05)	2:17 am	Barge docks @ #4	1:00	0	1.00	24	70.5
	2:27 am	PW loaded (70.5)	0:12	0	0.20	4.8	
	2:42 am	Barge leaves #4	0:15	0	0.25	6	
	4:22 am	Barge arrives @ #3	1:40	10	1.67	40.08	
7.22 (127.22)	5:22 am	Barge docks @ #3	1:00	0	1.00	24	146.95
	5:46 am	PW loaded (146.95)	0:24	0	0.39	9.36	
	6:01 am	Barge leaves #3	0:15	0	0.25	6	
	7:41 am	Barge arrives @ #2	1:40	10	1.67	40.08	
7.36 (127.36)	8:41 am	Barge docks @ #2	1:00	0	1.00	24	130.08
	9:02 am	PW loaded (130.08)	0:21	0	0.35	8.4	
	9:17 am	Barge leaves #2	0:15	0	0.25	6	
	10:57 am	Barge arrives @ #1	1:40	10	1.67	40.08	
7.50 (127.50)	11:57 am	Barge docks @ #1	1:00	0	1.00	24	127.50
	12:18 pm	PW loaded (127.50)	0:21	0	0.35	8.4	
	12:33 pm	Barge leaves #1	0:15	0	0.25	6	
	8:53 pm	Barge arrives @ Disp. Fac.	8:20	50	8.33	199.92	
	9:53 pm	Barge docks @ Disp. Fac.	1:00	0	1.00	24	
	1:19 am	PW unloaded (1286.89)	3:26	0	0	0	
	1:34 am	Barge leaves Disp. Fac.	0:15	0	0.25	6	
	9:54 am	Barge arrives @ port	8:20	50	8.33	199.92	
8.45 (128.45)	10:54 am	Barge docks @ port	1:00	0	1.00	24	
				Total	**47.67**	**1,144.08**	

[a] The day number multiplied by the facility's produced water flow equals the produced water volume loaded. See notes on produced water barge trip cycles following these tables.

Notes on Produced Water Barge Trip Cycles for Small Volume Louisiana Facilities

- The first number of days represents the amount of time needed for the first operator to reach produced water storage capacity. This amount of time varies with the addition of operators to each cycle. That is, for operator 5, days 1 through 6 are needed to reach capacity. These days are included in the tables for all cycles because operator 5 is included in all cycles. For operator 3, days 1 through 42 are needed to reach capacity. These days are included in the tables for cycles B and C only. For operator 1, days 1 through 126 are needed to reach capacity. These days are included in cycle C only.

- The produced water volume accumulated is calculated as follows:

  Day number x flow (bpd) = Produced water volume accumulated (bbl)

- Cycle A occurs 52 times a year. Operators 4, 5, 6, and 7 must have their produced water picked up every six days. Operator 5 determines the cycle frequency since its storage capacity is limited to 7 days. The order of pick up by the barge is dependent on the number of days of produced water storage capacity of each facility.

- Cycle B occurs 6 times a year. In addition to the operators in cycle A (i.e. operators 4, 5, 6, and 7), cycle B also includes operators 2 and 3. For operators 4, 5, 6, and 7 the produced water pick up cycle begins on day 6. However, for operators 2 and 3, cycle B begins on day 42.

- Cycle C occurs 2 times a year and picks up produced water from all operators, including operator 1. For operator 1, cycle C begins on day 126.

- In each cycle, the day number corresponding to each facility's pick up schedule multiplied by the facility's produced water flow (in bpd) equals the volume of produced water loaded onto the barge.

Tug Boat Fuel Consumption Calculation:

= (cycle A iterations per year x 907.68 gal) + (cycle B iterations per year x 1,065.60 gal) + (cycle C iterations x 1,144.08 gal)
= (52 x 907.68 gal) + (6 x 1,065.60 gal) + (2 x 1,144.08 gal)
= (47,199.36 gal) + (6,393.60 gal) + (2,288.16 gal)
= 55,881.12 gal diesel/yr

Auxiliary Equipment Fuel Consumption Calculation:

Cycle A:

$$(882.36\ bbl\ PW)\ x\ (42\ gal/bbl) = \frac{37{,}059.12\ gal\ PW}{60{,}000\ gal/hr} = 0.618\ hr/cycle$$

Pump = 0.60 gal/hr x 0.618 hr/cycle = 0.37 gal/cycle
= 0.37 gal/cycle x 52 cycles/yr = 19.27 gal/yr

Compressor = 3.5 gal/hr x 0.618 hr/cycle x 52 cycles = 112.48 gal/yr

Cycle B:

$$\frac{(1{,}159.39\ bbl\ PW)\ x\ (42\ gal/bbl)}{60{,}000\ gal/hr} = 0.812\ hr$$

Pump = 0.60 gal/hr x 0.812 hr/cycle x 6 cycles/yr = 2.92 gal/yr
Compressor = 3.5 gal/hr x 0.812 hr/cycle x 6 = 17.052 gal/yr

Cycle C:

$$\frac{(1{,}286.89\ bbl\ PW)\ x\ (42\ gal/bbl)}{60{,}000\ gal/hr} = 0.901\ hr$$

Pump = 0.60 gal/hr x 0.901 hr/cycle x 2 cycles/yr = 1.08 gal/yr
Compressor = 3.5 gal/hr x 0.901 hr/cycle x 2 cycles/yr = 6.31 gal/yr

TOTAL DIESEL FUEL CONSUMPTION

Fuel Consumption (gal/yr)				BOE/yr[a]
Tug	Pump	Compressor	Total	
55,881.12	23.27	135.84	56,040.23	1,334.3

[a] BOE (barrels of oil equivalent) per year is the total diesel volume required converted to equivalent oil volume by the factor: 1 BOE = 42 gallons.

AIR EMISSIONS

Source	Diesel Usage (gal/yr)	Air Emissions (tons/yr)					
		NO_x	THC	SO_2	CO	TSP	Total
Pump + Compressor	159.21	0.037	0.003	0.002	0.008	0.003	0.053
Tug	55,881.12	10.94	0.47	0.80	2.19	0.92	15.32
Total							15.373

EMISSION FACTORS

Source	Emission Factors in lb/10^3 gal				
	NO_x	THC	SO_2	CO	TSP
Pump + Compressor[1]	469	37.5	31.2	102	33.5
Tug[2]	391.7	16.8	28.48	78.3	33.0

[1] Source: Table 3.3-1, AP-42, Jan., 1975.
[2] Source: Table II-3.3, AP-42, Sept., 1985.

Sample Emission Calculation:

$$\left(55{,}881.12\ \frac{gal\ diesel}{yr}\right) x \left(\frac{391.7\ lb\ NO_x}{1{,}000\ gal}\right) x \left(\frac{1\ ton}{2{,}000\ lb}\right) = 10.94\ tons\ NO_x/yr.$$

APPENDIX XIII-8

CALCULATIONS FOR ENERGY REQUIREMENTS AND AIR EMISSIONS FOR TEXAS SMALL VOLUME FACILITIES

TEXAS INDIVIDUAL PERMIT DISCHARGERS
SMALL FACILITIES
NWQI Calculations

Input Data:

All data is from Chapter XVI of the 1995 Development Document (EPA, 1995)

• Truck capacity	119 barrels
• Truck diesel fuel usage	4 mi/gal
• Round-trip distance between each facility and the commercial disposal facility	120 miles

Sample Calculation:
(For a facility generating 7 bpd produced water)

- Number of trucks per year:

  (2,555 bbl PW/yr)/(119 bbl/truck) = 21.47 trucks/yr

- Truck fuel consumption:

  (21.47 trucks/yr) x (1 gal/4 miles) x 120 miles/truck = 644.1 gal diesel/yr

APPENDIX XIII-9

GULF OF MEXICO TREATMENT, WORKOVER AND COMPLETION FLUID VOLUME CALCULATIONS FOR EXISTING AND NEW SOURCES

TABLE A
TWC FLUID VOLUME CALCULATIONS FOR EXISTING SOURCES

Facility Type	Number of W/T Jobs/yr[a]	W/T Vol./Job[b] (bbl/yr)	Total W/T Vol. (bbl/yr)	Number of Completion Jobs/yr[a]	Completion Vol./Job[b] (bbl/yr)	Total Completion Vol. (bbl/yr)	Total TWC Volume (bbl/yr)
OPTION 1							
Medium/Large Facilities:							
Major Pass Dischargers	25	587	14,675	23	209	4,807 [c]	19,482
General Permit Facilities	212	587	124,444	202	209	42,218	166,662
Small Facilities:							
Water-Access	52	587	30,524	51	209	10,659	41,183
Land-Access	28	587	16,436	26	209	5,434	21,870
OPTIONS 2 AND 3							
Medium/Large Facilities[d]	270	587	158,490	257	209	53,713	212,203
Small Facilities:							
Water-Access	52	587	30,524	51	209	10,659	41,183
Land-Access	28	587	16,436	26	209	5,434	21,870

[a] Source: *Avanti* Corp., "Compliance Costs and Pollutant Removals for Coastal Gulf of Mexico Oil and Gas Well Treatment, Workover, and Completion Fluids," September 16, 1996.

[b] Source: SAIC, "Statistical Analysis of the Coastal Oil and Gas Questionnaire," January 31, 1995.

[c] The number of major pass discharger W/T and completion jobs per year for Option 1 excludes the number of jobs at facilities with existing IGF or gas flotation treatment systems (i.e., 33 W/T jobs/yr and 32 completion jobs/yr have been excluded).

[d] Includes all major pass dischargers and general permit facilities (see also definitions in Section 4.0).

TABLE B
TWC FLUID VOLUME CALCULATIONS FOR NEW SOURCES

Facility Type	Number of W/T Jobs/yr[a]	W/T Vol./Job[b] (bbl/yr)	Total W/T Vol. (bbl/yr)	Number of Completion Jobs/yr[a]	Completion Vol./Job[b] (bbl/yr)	Total Completion Vol. (bbl/yr)	Total TWC Volume (bbl/yr)
OPTION 1							
Medium/Large Facilities:							
Major Pass Dischargers	6	587	3,522	6	209	1,254	4,776
General Permit Facilities	29	587	17,023	29	209	6,061	23,084
Small Facilities:							
Water-Access	7	587	4,109	7	209	1,463	5,572
Land-Access	3	587	1,761	3	209	627	2,388
OPTIONS 2 AND 3							
Medium/Large Facilities	35	587	20,545	35	209	7,315	27,860
Small Facilities:							
Water-Access	7	587	4,109	7	209	1,463	5,572
Land-Access	3	587	1,761	3	209	627	2,388

[a] Source: *Avanti* Corp., "Compliance Costs and Pollutant Removals for Coastal Gulf of Mexico Oil and Gas Well Treatment, Workover, and Completion Fluids," September 16, 1996.

[b] Source: SAIC, "Statistical Analysis of the Coastal Oil and Gas Questionnaire," January 31, 1995.

APPENDIX XIII-10

SUMMARY FUEL CONSUMPTION CALCULATIONS FOR SMALL FACILITIES

SUMMARY FUEL CONSUMPTION CALCULATIONS FOR SMALL FACILITIES[a]

Existing Facilities:

Land-Access Facilities:

- Number of truck trips per year:

  (21,870 bbl/yr)/(119 bbl/truck) = 183.8 trucks/yr

- Truck fuel consumption:

  (183.8 trucks/yr) x (1 gal/4 miles) x (120 miles/truck) = 5,513 gal/yr

Water-Access Facilities:

- Tug and barge transit fuel consumption:

  (103 trips/yr) x (100 miles/trip) x (24 gal/hr) x (1 hr/6 miles) = 41,200 gal/yr

- Auxiliary equipment fuel consumption:

  [(1 hr/trip) x (103 trips/yr) x (6 gal/hr)] + [(4.1 gal/hr) x (1.05 hr/trip) x (103 trips/yr)] = 1,061 gal/yr

New Facilities:

Land-Access Facilities:

- Number of truck trips per year:

  (2,388 bbl/yr)/(119 bbl/truck) = 20.1 trucks/yr

- Truck fuel consumption:

  (20.1 trucks/yr) x (1 gal/4 miles) x (120 miles/truck) = 602 gal/yr

Water-Access Facilities:

- Tug and barge transit fuel consumption:

  (14 trips/yr) x (100 miles/trip) x (24 gal/hr) x (1 hr/6 miles) = 5,600 gal/yr

- Auxiliary equipment fuel consumption:

  [(1 hr/trip) x (14 trips/yr) x (6 gal/hr)] + [(4.1 gal/hr) x (1.05 hr/trip) x (14 trips/yr)] = 144 gal/yr

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[a] All data presented here are from: EPA, "Development Document For Effluent Limitations Guidelines and Standards for the Coastal Subcategory of the Oil and Gas Extraction Point Source Category," February, 1995.