Chapter 4

Oil and Gas Wastes

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INTRODUCTION

In 1985, approximately 842,000 oil and gas wells in the United States produced 8.4 million barrels of oil, 1.6 million barrels of natural gas liquids, and 44 billion cubic feet of natural gas daily (117). Along with this high commodity production inevitably comes the generation of waste, most of which is disposed of through underground injection.

In searching for oil and gas, exploratory drilling usually results in "dry" wells that are plugged and abandoned. When an oil or gas reservoir is discovered, development wells are then drilled to extract the oil or gas. More than 70,000 exploration and development wells were drilled annually in the mid-1980s, although drilling activity decreased sharply in 1986 and has remained depressed (99, 117). These exploration and production (E&P) activities generate three types of "solid" wastes: produced waters, drilling fluids, and other "associated' wastes. Figure 4-1 illustrates the manner in which oil, gas, and water are separated in a typical production operation and the basic wastes that are generated. The U.S. Environmental Protection Agency (EPA) estimates that 3.7 billion tons of E&P waste was generated in 1985, whereas the American Petroleum Institute (API) estimates that about 2.9 billion tons was generated that year. The two estimates differ primarily in the amount of produced water generated, as well as in how much of the produced water is subject to jurisdiction under the Resource Conservation and Recovery Act (RCRA) (see "Waste Generation" below).

Produced waters are mixtures of the naturally occurring (and typically saline[1]) water in the geologic formation being drilled, naturally derived constituents such as benzene and radionuclides, and chemicals added for treatment (e.g., corrosion inhibitors). The produced waters must be separated from the oil and gas products before their entry into crude or natural gas pipelines. Produced waters account for 96 to 98 percent of all oil and gas wastes.

Drilling fluids include drill cuttings (i.e., rock removed during drilling) and drilling muds (water- or oil-based fluids with additives, pumped down the drilling pipe to offset formation pressure, provide lubrication, seal off the well bore to avoid contamination of various geologic layers, and remove cuttings) (117).[2] Drilling fluids account for about 2 to 4 percent of oil and gas wastes.

Much smaller quantities of associated wastes are produced. These include well completion, treatment, and stimulation fluids; sediment, water, and other tank bottoms; oily debris; contaminated soils; and produced sands.[3] They amount to about 0.1 percent of oil and gas wastes. In addition, naturally occurring radioactive material (NORM) such as radium may also be brought to the surface with crude oil (see box 4-A on page 77).

The exploration, development, and production of oil and gas reserves vary markedly from region to region. For example, wells range in depth from 30 feet in some areas to more than 30,000 feet in others, with an average depth of about 5,000 feet (7, 117). Production can range from fewer than 10 barrels per day for thousands of small 'stripper" wells to about 11,500 barrels per day for wells on the Alaskan North Slope. Only 14 percent of total U.S. production comes from stripper wells, yet they account for about 70 percent of all U.S. oil wells (117); because of their large numbers and potential environmental impacts, these wells pose significant regulatory challenges (e.g., concerns about enforcement and economic impacts).

The 1980 Bentsen amendments to RCRA exempted drilling fluids, produced waters, and associated wastes from hazardous waste regulation pending further study and regulatory determinations by EPA. The amendments also directed EPA to distinguish between large-volume wastes (i.e., produced

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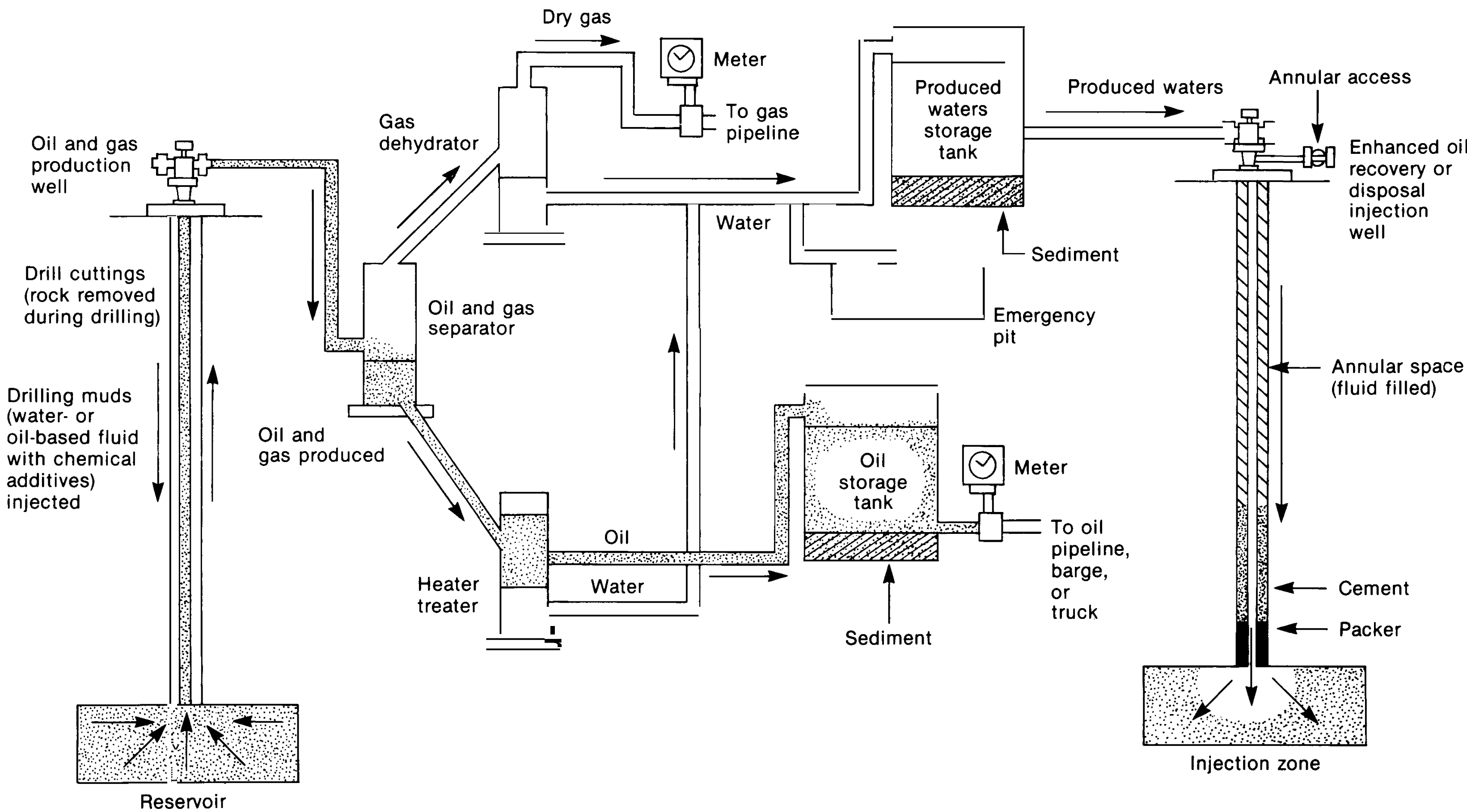
[1]The concentration of chlorides in produced waters can range from 5,000 to 180,000 parts per million. In contrast, seawater is 35,000 parts total dissolved solids; a portion of the total dissolved solids are chlorides, typically about 19,000 parts per million (117).

[2]Chemicals added to drilling muds include acids and bases, salts, corrosion inhibitors, flocculants, surfactants, viscosifiers, dispersants, fluid loss reducers, lubricants, and biocides (117).

[3]53 *Federal* Register 25453, July 6, 1988; also see ref. 25.

Figure 4-1—Typical Oil and Gas Production Operation



NOTE Se w was de ed se ra generally occurs at the well site or an adjacent tank battery. Produced waters are not ec ed nd ca ed

SO R E OTA based E ec ncy Of ce Solid Waste and Emergency Response, *Report to Congress: Management of Wa From Exploration Developmen and Production of Crude Oil, Natural Gas, and Geothermal Energy,* EPA/530-SW-88-003 Wa gt DC Decembe 7)

Photo credit: ARCO Alaska, Inc.

A 5-foot-thick gravel pad in the Prudhoe Bay field on the North Slope of Alaska supports drilling and production equipment and contains above-grade reserve pits.

waters and drilling fluids, including fluids from offshore operations that are disposed of onshore) and associated **wastes. In** 1988, EPA determined that Subtitle C regulation of these exempted wastes is not warranted (see "Current RCRA Status of Oil and Gas Wastes" below).[4] This means that the wastes are subject to existing State and Federal Subtitle D regulatory programs. Oil and gas wastes that are **not** exempt from Subtitle C regulation include refinery wastes, waste solvents from equipment maintenance, and spills from pipelines or other transport methods (117).

WASTE GENERATION

Oil and gas waste generation depends on the level of industry activity, which in turn varies with petroleum prices. Thus, oil and gas waste generation can vary considerably from year to year; it also varies geographically. Table 4-1 (based on data from API, cited in ref. 117) shows how the number of wells and the generation of drilling fluids and produced waters varied among States in 1985.

Based on data in its 1987 Report, EPA estimated that 3.7 billion tons of produced water was generated in 1985 (17). However, produced waters reinfected

Table 4-l—Estimated Volumes of Produced Water and Drilling Wastes, 1985[a]

State	Number of wells drilled	Produced water (thousand barrels)	Drilling wastes (thousand barrels)[b]
Alabama	367	87,619	5,994
Alaska	242	97,740	1,816
Arizona	3	149	23
Arkansas	1,034	184,536	8,470
California	3,208	2,846,978	4,529
Colorado	1,578	388,661	8,226
Florida	21	64,738	1,068
Georgia	1	—	2
Idaho	3	—	94
Illinois	2,291	1,282,933	2,690
Indiana	961	—	1,105
Iowa	1	—	1
Kansas	5,560	999,143	17,425
Kentucky	2,482	90,754	4,874
Louisiana	4,908	1,346,675	46,726
Maryland	91	—	201
Michigan	870	76,440	3,866
Mississippi	594	318,666	14,653
Missouri	23	—	18
Montana	623	223,558	4,569
Nebraska	282	164,688	761
Nevada	36	—	335
New Mexico	1,780	445,265	13,908
New York	436	—	1,277
North Dakota	514	59,503	4,804
Ohio	3,818	—	8,139
Oklahoma	7,690	3,103,433	42,547
Oregon	5	—	5
Pennsylvania	2,836	—	8,130
South Dakota	49	5,155	289
Tennessee	228	—	795
Texas	23,915	7,838,783	133,014
Utah	364	260,661	4,412
Virginia	91	—	201
Washington	4	—	15
West Virginia	1,419	2,844	3,097
Wyoming	1,497	985,221'	13,528
TOTAL	69,734	20,873,24@	361.406

[a]Based on American Petroleum Institute survey reported in EPA (December 1987). EPA and API estimates for drilling waste and produced waters differed significantly in some cases (see text).
[b]Based on total volume of drilling muds, drill cuttings, completion fluids, circulated cement, formation testing fluids, and other water and solids.
[c]Wyoming estimated that 1.72 billion barrels of produced water were generated in the State in 1985.
[d]Includes only those States surveyed.

SOURCE: U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response, *Report to Congress: Management of Wastes From the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy,* EPN530-SW-88-003 (Washington, DC: December 1987).

underground for enhanced oil recovery (EOR) operations are not subject to RCRA jurisdiction because this practice-at least from the point of the wellhead down-is regulated under the Safe Drinking Water

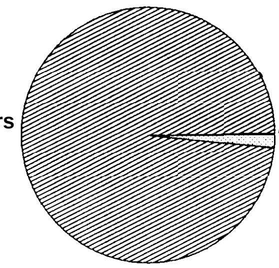
[4]Unlike the other ''special'' wastes, Congress in a seine reserved the ultimate regulatory decisions about oil and gas wastes to itself because EPA is prohibited from regulating these wastes as hazardous without approval by an act of Congress.

Act.[5] Since about 62 percent of produced waters are reinfected for EOR (6), this would leave about 1.4 billion tons to be managed as RCRA wastes. The API disagrees with these figures; based on data from its 1985 survey (6), industry analysts estimate that about 2.8 billion tons of produced water was generated in 1985, of which 2.5 billion tons was used for EOR operations.[6] In any event, produced waters clearly make up the largest portion of oil and gas E&P wastes (figure 4-2).

EPA and API estimates of the amount of drilling fluids generated in 1985 also differ by almost an order of magnitude (table 4-l). However, EPA concluded that API's method of predicting volumes was more reliable[7] and therefore used the API estimate of 361 million barrels (117).[8] EPA later used this volumetric estimate to calculate that the amount of drilling fluids generated in 1985 was 63 million tons, based on the assumption that the density of each waste type is equal to that of water (17).[9] About 65 percent of drilling mud is fresh water, 21 percent is salt water, 3 percent is oil, 2 percent is polymer, and the remainder is other materials (25); the specific type used in drilling depends on factors such as well depth and reservoir characteristics.

Associated wastes represent an estimated 0.1 percent (1 1.8 million barrels, or 2.0 million tons) of all oil and gas wastes.[10] The EPA/API estimate is based on the assumption that their densities are the same as the average density of water, which may result in underestimating the actual tonnage (17). However, it may be a reasonable estimate because much of the waste is oil-based and hence lighter than water. About half of the associated wastes are aqueous, and the remainder range from slurries to sludges and solids.

Figure 4-2-Relative Amounts,of Oil and Gas Exploration and Production Wastes, 1985



SOURCE: 53 *Federal Register 25448* (July 6, 1988).

CURRENT MANAGEMENT PRACTICES

Oil and gas exploration and production wastes can be stored in surface impoundments to recover the oil, injected underground, treated and applied to the land, or discharged into waterways. In some cases, percolation pits are used to allow wastes to seep into the soil, although this is not standard practice in most areas. Some recycling and source reduction options are also possible. API (7) estimated that in 1985 about 92 percent of oil and gas wastes was injected underground, 4 percent was discharged into waterways, and 2 percent was managed in surface impoundments.

Technical criteria and guidance documents on oil and gas waste management have been issued by API and the Interstate Oil and Gas Compact Commission (IOGCC) to supplement efforts by State and Federal agencies to improve such management (8, 44).[11] Both guidance documents recognize the applicability of a hierarchy for managing oil and gas wastes, similar to that often cited for managing other solid and hazardous wastes: 1) source reduction; 2)

[5] 53 *Federal Register* 25446, July 6, 1988. Reinfection of produced waters into the formation helps to maintain fluid pressure and to enhance oil and gas recovery.

[6] N. Thurber, Amoco, personal communication, Sept. 26, 1991.

[7] For example, EPA used estimates of reserve pit size as the basis for its calculation whereas API relied principally on survey data that it collected.

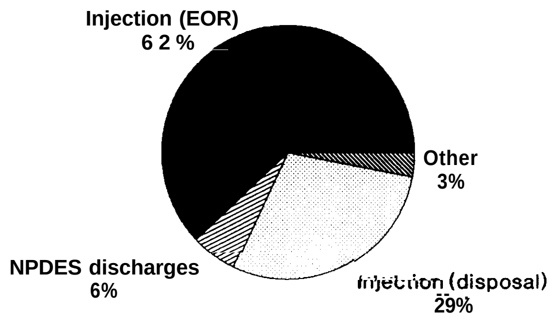
[8] Also see 53 *Federal Register 25448,* July 6, 1988.

[9] EPA considered it likely thatthis estimate is low (17). Similarly,industry analysts suggest that the amount might be in the range of 70 to 80 million tons (N. Thurber, Amoco, personal communication, Sept. 26, 1991).

[10] Based on ERT (25) and API (7) &@ about 48 percent are workover and completion fluids, including fluids used to stimulate the formation to produce additional oil; 32 percent are produced sand, tank bottoms, oily debris, and other production solid wastes; 15 percent are untreatable emulsions, used solvents and degreasers, cooling water, used oils, spent iron sponge, and other production liquid wastes; and 5 percent are dehydration and sweetening unit wastes used to remove sulfides from the oil or gas.

[11] The IOGCC, formed in 1935 (and formerly known as the Interstate Oil Compact Commission or IOCC), is an organization of Governors of 29 States that produce oil and gas. More than 99 percent of the oil and gas produced in the United States comes from member States.

Figure 4-3-Management Methods for Produced Waters



NOTE: Injection refers to underground injection; EOR refers to enhanced oil recovery.

SOURCES: Based on American Petroleum Institute, *API 7985 Production Waste Survey, Statistical Analysis and Survey Results, Final Report* (Washington, DC: October 1987); D. Derkics, "Revised Oil & Gas Statistics," memorandum, U.S. Environmental Protection Agency, Washington, DC, Jan. 28, 1991.

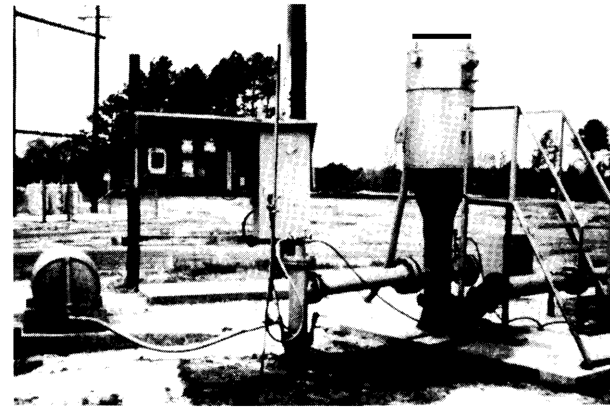


Photo credit: U.S. Environmental Protection Agency

This Class II injection well is equipped with corrosion inhibitors, constant pressure monitoring, automatic shut-off, and leak detection.

recycling and reuse; 3) treatment to reduce the volume or toxicity of waste; and 4) disposal of remaining wastes in ways that minimize adverse impacts to the environment and human health.

This section describes how each of the three basic waste types (drilling fluids, produced waters, and associated wastes) are managed. Because some management methods are used for more than one waste type, the section discusses each major method as well: surface impoundment; land application and landfilling; underground injection; discharge to surface waters; and source reduction and recycling. The management of naturally occurring radioactive material in oil and gas wastes is discussed below in box 4-A.

In general, most non-hazardous E&P wastes are managed and disposed of on-site, mainly through underground injection in Class II wells.[12] EPA concluded that many impacts can be minimized by improving housekeeping practices and using existing technologies to address design, operational, mixing (e.g., of associated wastes and produced waters), closure, and remediation problems (34). Many States restrict the types of wastes that can be stored in pits at Class II well sites, and require lining of these facilities (with either synthetic or clay liners, depending on site-specific conditions) and, where groundwater is present, groundwater monitoring systems (44). In addition, pumps can be built with features (e.g., their own containment sumps, alarm systems, automatic shutoff valves, and continuous pressure monitoring) that minimize releases, and tanks can be used as an alternative to liners. These practices generally afford more protection than systems that allow disposal of tank bottoms, produced waters, and other wastes in unlined pits or on the ground (34).

Management of Basic Waste Types

Produced Waters

Produced waters can be managed, with or without treatment, via injection in underground wells, evaporation and percolation from surface impoundments, application on roads, or discharges to surface water. Injection can take place on-site, off-site, or in centralized facilities. Most produced waters (about 90 percent) are reinfected underground, either in disposal wells (29 percent) or as part of EOR operations (62 percent) (figure 4-3).[13] Reinfection wells are regulated as part of the Underground Injection Control program (see "Other EPA Statutory Authority" below). The remainder are dis-

[12] Class II refers to three types of wells which inject fluids: 1) for enhanced recovery of oil or natural gas; 2) for storage of hydrocarbons which are liquid at standard temperature and pressure; and 3) for storage of liquids which are brought to the surface in connection with natural gas storage operations or conventional oil or natural gas production, and which may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waste waters are classified as a hazardous waste at the time of injection (40 CFR 144.6(b)).

[13] As noted above (see "Waste Generation"), however, produced waters used in EOR systems are not considered solid wastes.

charged to surface waters (6 percent), under conditions specified in National Pollutant Discharge Elimination System (NPDES) permits, or are disposed of by other means such as evaporation and percolation (3 percent). Discharges to surface waters depend on the composition of the fluid and NPDES permit conditions.

Drilling Fluids

Drilling fluids can be disposed of on-site (either directly or after treatment) in reserve pits (which are essentially surface impoundments), in the annular space of injection wells, on land, or into surface waters (117). The choice of on-site methods depends on factors such as geologic formation, costs and regulatory conditions, composition of the drilling fluids, and type of well and surrounding conditions. The onshore discharge of untreated drilling fluids into surface waters is prohibited by effluent guidelines promulgated under the Clean Water Act. However, fluids may be discharged into the Gulf of Mexico if they pass specified bioassay tests (1 17).

Off-site management methods include disposal in centralized pits, land application at commercial landfarms (for adsorption or degradation by soil and organisms), and treatment and disposal in centralized treatment facilities (117). EPA does not have information on how frequently these off-site management methods are used.

API (6) reported that in 1985, 29 percent of drilling fluid was evaporated, 28 percent was sent off-site for some type of management, 13 percent was injected underground, 12 percent was buried on-site, 10 percent was discharged into surface waters, 7 percent was landspread, and less than 1 percent was solidified. Drilling muds, which constituted about two-thirds of drilling fluids in 1985, were typically disposed of by evaporation, followed by discharge into surface water and injection in the annular space of drilled wells (25).

Associated Wastes

Associated wastes may be stored, treated, landfarmed, landfilled, discharged under a NPDES permit, injected into a Class II well, or recycled. In 1985, about 48 percent of associated waste was reportedly transported off-site for centralized treatment or disposal at commercial waste management sites; 27 percent was disposed of on-site either in pits, by burial, or by roadspreading and landspreading; 4 percent was recycled; 1 percent was injected underground; and 19 percent was managed by other, unspecified methods (6).

Management Technologies and Practices

Surface Impoundments

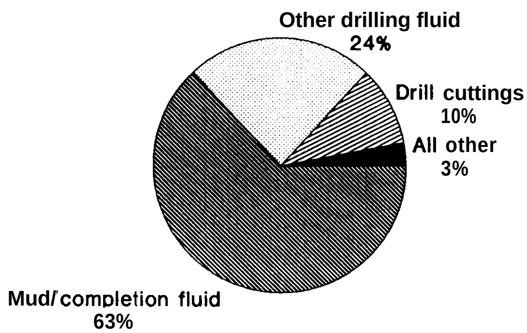
According to EPA (114), more than 125,000 oil and gas surface impoundments existed in 1984. Based on EPA data from themid-1980s(119), only 2.4 percent of the surface impoundments used for oil and gas wastes had synthetic liners, whereas another 27 percent had a natural liner of unknown composition quality. Furthermore, groundwater was monitored at only 0.1 percent, and surface water at 16 percent, of these impoundments. However, the data do not necessarily represent current practices in many States; moreover, not all impoundments are located near groundwater.

Reserve pits, a type of impoundment, are used to temporarily store drilling fluids for use in drilling operations or to dispose of wastes. Of all materials discharged to reserve pits, an estimated 90 percent are drilling fluids (mostly in the form of drilling muds and completion fluids) and cuttings (figure 4-4).

Some pits also are used for settling/skimmm g of solids and separation of residual oil; storage of produced waters prior to injection or off-site transport; percolation of liquids via drainage or seepage into surrounding soil; and evaporation (in lined pits) of produced waters into the atmosphere (44, 117). Other "special" pits are used for such purposes as flaring natural gas; collecting wastes from the emptying or depressurization of wells (or vessels); and, in emergencies, temporarily storing liquids resulting from process upsets (44, 117). These pits, however, may be in continuous use for many years before being closed or may at least be present on-site for use in emergencies. Many States now have-and IOGCC guidelines suggest—both reporting requirements and time limits for using such "temporary" pits, and long-term use can be a violation in those States.

Reserve pit size is largely a function of well depth (25); the average pit volume at depths less than 3,750 feet is about 3,600 barrels, whereas the average volume at depths greater than 15,000 feet is more than 65,000 barrels. Only 20 percent of reserve pits have a capacity greater than 15,000 barrels, whereas

Figure 4-4-Types of Drilling Fluids Discharged to Reserve Pits



SOURCES: ERT Co., *Oil and Gas Industry Exploration and Production Wastes,* prepared for American Petroleum Institute, No. 471-01-09 (Washington, DC: July 1987); U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response, *Report to Congress: Management of Wastes From the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy,* EPA/530-SW-88-003 (Washington, DC: December 1987).

44 percent have a capacity of 5,000 barrels or less (25).

Reserve pits are usually closed after drilling activity has been completed. After a reserve pit is closed, solids in the pit can be spread on land or buried on-site; liquids can be evaporated, discharged to land or surface waters, or reinfected in underground wells.[14] Although most States have established regulations for siting, operation, and closure of pits[15], the proper closure of reserve pits and the disposition of their contents are still matters of concern in environmentally sensitive areas such as wetlands (25).

One potential alternative is solidification of pit contents—adding solidifiers (e.g., commercial cement, fly ash, or lime kiln dust) to help immobilize pollutants and minimize leaching of toxic constituents. The Pennsylvania Department of Environmental Resources, among others, has conducted some demonstration solidification projects (32). One problem, however, is that after removal of the free liquid fraction of pit wastes, the remaining pit contents still contain about 30 percent water. In addition, the use of cement kiln dust, and possibly other solidifiers, increases the volume of solid waste to be managed (117). Other areas of concern include finding a better mixing method, identifying and minimizing groundwater and leachate impacts, and ensuring the use of the method in winter (32). EPA was unaware of data indicating whether the use of kiln dust adds harmful constituents to the reserve pit wastes (117).

Landfilling and Land Application

Landfilling basically consists of placing wastes in the ground and covering them with a layer of soil. Currently, most landfills used for oil and gas wastes are unlined. However, the IOGCC recommends that a protective bottom liner or a solidification, fixation, or encapsulation method be required when the salt or hydrocarbon content in the wastes exceeds applicable standards, unless the site has no underlying groundwater or is naturally protected from the risk of contamination (44). The IOGCC considers landfilling appropriate for drilling muds and cuttings, spent iron sponge, pipe scale with low levels of naturally occurring radioactive material (see below), gas plant catalysts, and molecular sieve materials.

The IOGCC also believes that roadspreading—using tank bottom sediments, emulsions, or heavy hydrocarbon and crude oil-contaminated soils as part of road oil, road mix, or asphalt-is acceptable if the waste materials are not ignitable and have a density and metal content consistent with approved road oils or mixes (44, 117). However, the Hazardous and Solid Waste Amendments of 1984 (RCRA Sec. 3004(1)) prohibited the use of material that is contaminated or mixed with a hazardous waste (other than a waste identified solely on the basis of ignitability) for dust suppression or road treatment.

Land application, known in the industry as landspreading or landfarming, consists of spreading or mixing wastes into soils to promote the natural biodegradation of organic constituents and the dilution and attenuation of metals. Nitrogen and other nutrients can be added to the soil to enhance biodegradation (44). The IOGCC recommends that the waste-soil mixture not contain more than 1 percent by weight of oil and grease; any free oil can be removed by skimming or filtration before landspreading. Liquid wastes may also have to be

[14] In 1985 the oil and gas industry reportedly spent more than $118 million on construction of reserve pits (35 percent of which had artificial liners, at a cost of $99 million), more than $187 million to close pits on-site, and $480 million to dispose of pit wastes off-site (25).

[15] J. Simmons, IOGCC, personal communication, July 9, 1991.

neutralized and should be applied so as to avoid pooling or runoff of the wastes.

Land application of drilling muds and cuttings has been used for years. Some studies conclude that it is a relatively low-cost method (which accounts for its increasing popularity) that does not adversely affect receiving soils (e.g., 75, 143). One of these studies concluded that landfarming could benefit certain sandy soils in Oklahoma by increasing their water-holding capacity and reducing fertilizer losses (75). These studies also suggest that the technique can be used in conjunction with cleanup and remedial processes for saltwater or hydrocarbon spills and pipeline breaks (75, 143).

Whether land application is appropriate for all mud is not clear. Some muds contain substantial quantities of oil and various additives, raising questions about the potential adverse effects on parts of the food chain or in areas with high water tables. EPA (117) suggested that land application might work best for treating organic chemicals that are susceptible to biodegradation, if the appropriate microorganisms are present in the soil. However, the ability of most soils to accept chlorides and other salts, which generally are highly soluble in water, and maintain beneficial use is limited (117). Whether heavy metals are attenuated by soil particles or taken up by plants depends on many factors, including the clay content and cation-exchange capacity. In addition, volatile organic compounds (VOCS) may evaporate from sites (117, 143).

Underground Injection Wells

About 90 percent of produced waters from on-shore oil and gas operations are disposed of in more than 166,000 underground injection wells, for either EOR or final disposal purposes (117, 121). When used for disposal, produced waters are injected (via gravity flow or pumps) into saltwater formations, the original formation, or older (depleted) formations. Figure 4-1 shows a typical injection well for produced waters. Steps generally taken before wastes are reinfected into wells include: 1) separation of free oil and grease from produced waters; 2) storage of wastes in tanks or reserve pits; 3) filtration; and 4) chemical treatment (e.g., coagulation, flocculation, and possibly pH adjustment) (117).

Again, one concern regarding this method is its potential for contaminating groundwater (117). For example, injection wells used for disposal are often older wells that require more maintenance (EPA regulations require periodic testing of the mechanical integrity of injection wells; see "Other EPA Statutory Authority" below). Well failure also can occur because of design and construction problems, the corrosivity of the injected fluid, and excess injection pressure. Concerns over the adequacy of injection well regulations are discussed below (see "Other EPA Statutory Authority").

Discharges to Surface Waters

Discharges to surface waters are permitted under the NPDES program: 1) into coastal or tidally influenced waters; 2) for agricultural and wildlife beneficial use; and 3) for produced waters from stripper oil wells to surface streams. Treatment to control pH and to minimize oil and grease, total dissolved solids, sulfates, and other pollutants often occurs before discharge. The presence of radiation and benzene or other organic chemicals, however, is typically not addressed in discharge regulations.

Pollution Prevention/Waste Reduction

Pollution prevention (i.e., reducing the volume and toxicity of wastes) and recycling are possible for all three types of oil and gas wastes. As the prospects for Superfund liability from past disposal practices become apparent (see "Other EPA Statutory Authority" below), the incentives for reducing and recycling oil and gas wastes increase (79, 117). As with other source reduction and recycling efforts, success depends on support from top management, a complete inventory and characterization of the wastestreams and chemical additives used in an operation, and the flexibility to address site-specific variations in formations and production activities (44, 79). EPA discourages some types of "recycling," specifically those involving the mixing of hazardous wastes with non-hazardous or exempt oil and gas wastes (117).

The greatest opportunities may involve drilling fluids. According to an analysis by Amoco Corp., basic waste minimization methods can potentially reduce the volume of drilling fluids, including cuttings, by more than 60 percent (79). EPA estimated that "closed-loop systems" can reduce the volume of drilling fluids by as much as 90 percent.[16] The high cost of formulating drilling mud has led to more reuse and reconditioning of spent muds (117).17 Closed-loop systems use mechanical solids control equipment (e.g., screen shakers, hydroclones, centrifuges) and collection equipment (e.g., vacuum trucks, shale barges) to minimize drilling waste muds and cuttings that require disposal and to maximize the volume of drilling fluid returned to the drilling mud system. These systems are increasingly being used (e.g., in California), because of the reduction in overall drilling costs and in the volume of waste needing disposal (79, 117, 141).[18] Without proper wastewater management, however, the volume reduction gains from using closed-loop systems can be negated (79). In addition to these methods, drilling wastes maybe used in the well-plugging process, depending on site location and conditions (117).

Reducing the toxicity of drilling fluids is also possible.[19] EPA and API survey data indicate that fluids in some reserve pits contain chromium, lead, and pentachlorophenol at hazardous levels, and oil-based fluids may contain benzene. These components, however, can potentially be reduced or eliminated by product substitution (79). In addition, the hydrocarbon content of drill cuttings might be reduced by using thermal and solvent extraction processes; these appear promising but have not yet been used extensively or evaluated (69).

For produced waters, volume reduction efforts are driven more by the direct costs of waste management than by regulatory incentives or liability. Horizontal drilling (an exploration technology designed to increase the exposure of fractured or productive zones to the borehole) can reduce the generation of produced waters, but this may be related more to the character of the producing formation than to the technology itself.[20] Reducing the toxicity of produced waters also may be possible by using less toxic or hazardous additives during drilling and completion or during stimulation of the well bore (79). In some cases, wastewaters can be physically or chemically treated and then reused in other parts of oil and gas production processes; solid residues can be separated during treatment and used in cement block or asphalt manufacturing (71).

Associated wastes may contain constituents similar to those in produced waters and other wastes, but often at higher concentrations. The toxicity of cooling tower blowdown, for example, can be reduced by replacing chromate corrosion inhibitors and pentachlorophenol biocides with less hazardous or toxic products (e.g., organic phosphonates or bisulfites; and isothiazolin, carbamates, amines, and glutaraldehydes, respectively) (79).[21] Oil recovery can also lead to reductions in tank and vessel sludges, emulsions, and other wastes (79).

RISKS FROM OIL AND GAS WASTES

In its 1987 Report to Congress and subsequent 1988 regulatory determination (see "Current RCRA Status of Oil and Gas Wastes" below), EPA concluded that oil and gas exploration and production wastes should remain exempt from regulation under Subtitle C. The oil and gas industry, as represented by the IOGCC, agrees with this and contends that the regulatory framework needed to prevent adverse impacts from the management of E&P wastes already exists in State programs (44).

Some of the general public, though, is still concerned about the environmental impacts and, in certain areas, the possible human health impacts of some oil and gas waste sites (e.g., 45, 63, 72). In addition, EPA also concluded that adverse impacts have resulted from mismanagement of oil and gas wastes and that some improvements in waste management are necessary (34, 117).

[16] 55 Federal Register 23355, June 7, 1991.

[17] EPA also suggested that greater potential for increased recycling appears possible through more efficient management of mud handling systems (117).

[18] J. Murphy, Amoco Oil Co., personal communication, Jan. 14>19910

[19] EPA concluded that drilling fluids are usually not characteristic hazardous wastes. However, the Extraction Procedure (EP) orToxicity Characteristic (TC) tests are not considered appropriate for oily wastes, and the TC is not legally applicable to exempt oil and gas wastes *(55 Federal Register 11835, Mar. 29, 1990; also see* ch. 5).

[20] D. Nielson, Utah Department of Natural Resources, review comments, Aug. 2, 1991.

[21] N. Thurber, Amoco, personal communication, Sept. 16, 1991.

Hazardous Characteristics and Health Risk Assessments

Both EPA and API analyzed samples of E&P wastes from drilling and production sites, waste treatment facilities, and commercial waste storage and disposal facilities. In summarizing these data, EPA (117) concluded that chemicals such as benzene, phenanthrene, lead, and barium were present in some samples at "levels of primary concern" (i.e., in amounts greater than EPA health-based limits multiplied by 1,000). EPA also noted that chemicals such as arsenic, fluoride, and antimony were found in some samples at "levels of secondary concern" (i.e., in amounts greater than health-based limits multiplied by 100).

In its 1988 rulemaking,[22] EPA estimated that from 10 to 70 percent of large-volume oil and gas wastes (i.e., drilling fluids and produced waters) and 40 to 60 percent of associated wastes (as defined in ''Introduction' above) could potentially exhibit RCRA hazardous waste characteristics.[23]

EPA conducted some risk assessments for oil and gas wastes, based on a relatively small sample data set on waste constituent concentrations (117). In general, it found that only negligible risks would be expected to occur for most of the model scenarios evaluated. However, EPA also noted that:

- It did not analyze all release modes, including releases from unlined pits;
- There were realistic combinations of measured chemical concentrations and release scenarios that could be of substantial concern;
- A few of the hundreds of chemical constituents detected in reserve pits and produced waters appeared to be of 'primary concern relative to health or environmental damage" (e.g., benzene, chlorides); and
- Wide variation (five or more orders of magnitude) existed in estimated health risks across the model scenarios, reflecting the great variation in the nature, location, and management of oil and gas sites.

Another potential exposure pathway involves consumption of contaminated seafood. Two studies in Louisiana suggested that potential human health risks exist from the bioaccumulation of radionuclides, metals, and hydrocarbons in benthic invertebrates, including edible species such as oysters (66, 78). In laboratory studies, oysters released accumulated hydrocarbons after being exposed to contaminant-free water; this may be particularly important because oysters are usually eaten directly after harvest and are not depurated (78). EPA (117) also concluded that potential endangerment of human health was associated with consumption of contaminated fish and shellfish.

Risks associated with naturally occurring radioactive materials are discussed in box 4-A.

Environmental Damages

EPA documented 62 actual or potential damage cases resulting from the management of E&P wastes, many of which were in violation of existing State and Federal requirements (117). These cases included: 1) damage to agricultural land, crops, streams, aquatic life, and other resources from produced water and drilling fluids (including potential contamination of aquatic and bird life in marine ecosystems by metals and polycyclic aromatic hydrocarbons from discharges of these wastes); 2) degradation of soil and groundwater from runoff and leachate from treatment and disposal facilities, reserve pits, and unlined disposal pits; 3) salt damage to groundwater, agricultural land, and domestic and irrigation water caused by seepage of native brines from improperly plugged or unplugged abandoned wells; 4) groundwater degradation from improper functioning of injection wells; and 5) damage to vegetation (including potential damage to tundra on the Alaska North Slope) from roadspreading of high-chloride drilling muds and seepage or discharges from reserve pits.

For example, activities such as drilling, EOR operations, and underground injection of produced waters have been associated with migration to nearby wells of various liquids and chemicals (e.g., brine, fracturing fluid, produced waters, hydrocarbons from oil or gas; ref. 117). According to the U.S. General Accounting Office (82), EPA data indicate 23 cases of drinking water contamination associated with Class II wells; EPA, however, noted that these incidents occurred prior to implementation of EPA's

[22] 53 *Federal Register 25455*, July 6, 1988.

[23] This estimate was made before the new TC test was promulgated. However, the TC *test* does not apply to exempt wastes *(55 Federal Register* 11835, Mar. 29, 1990).

Box 4-A—Risks and Management of Naturally Occurring Radioactive Materials

Naturally occurring radioactive material (NORM) is present in many industrial process residues, including produced waters and equipment from oil and gas production, sludges from drinking water treatment, fly ash from electricity generation, phosphogypsum from phosphate production (see ch. 2), and tailings from rare-earth and uranium mill processing.[1] The oil and gas industry has known about NORM since the 1930s (65), but concerns increased in the mid-1980s as the extent of NORM-enhanced pipi scale, sludges, and sediments became known (68).

For the oil and gas industry, the principal constituents of concern in NORM are radium-226 (a decay product of uranium-238), radium-228 (a decay product of thorium-232) and its daughter products radon-222 and lead-210.[2] The volume and concentration of these constituents in the material brought to the surface at a production site depend on the concentrations of the original uranium and thorium in the formations encountered during exploration and production, the temperatures and pressures at the production reservoir depth, the amount of water and natural gas produced, the duration of production, and the water chemistry.

Most radium remains in the produced waters, which typically are injected in Class II underground wells back into the original formation from which the waters were derived or into other saline formations below underground sources of drinking water. However, some radium precipitates on the inside of oil and gas production equipment in the form of barium/radium sulfate scales, which are difficult to remove because they are highly insoluble.[3] In addition, lead-210 also tends to precipitate on the inside of gas production equipment, primarily as a film in propane and ethane pumps (65). Because older production fields handle more produced water than newer fields, equipment at older fields is exposed to more water and thus tends to have higher concentrations of NORM.

The radiation exposure pathway of most concern in oil and gas operations is ingestion and inhalation by workers during cleaning of NORM-contaminated equipment. Internal exposure to radium and radon can cause bone and lung cancer, respectively, whereas lead-210 can attach to respirable particles and cause necrologic abnormalities and other problems. As a result, the industry has developed procedures for cleaning equipment containing NORM to prevent inhalation or ingestion by workers (7, 68); these include minimizing exposure by purging vessels (e.g., tanks) prior to entry, using respirators and other breathing gear while inside vessels, using masks while performing grinding and chipping operations, and other industrial hygiene practices.

An API-sponsored survey of major petroleum companies operating in 20 States and 2 offshore areas (Gulf of Mexico, California) obtained more than 36,000 measurements of NORM activity (i.e., gamma radiation) at background levels and on contact with equipment (65).[4] About 20 percent of the sites had readings above background levels, with the highest reported measurement being 4.49 Millirems/hour. Even so, more than 95 percent of all measurements, whether background or of equipment, were less than 0.11 millirem per hour.[5] However, these readings suggest that relatively insensitive measuring instruments were used, since normal background readings in uncontaminated areas should be 5 to 15 microroentgens per hour. Another, preliminary field study by the Michigan Departments of Natural Resources and Public Health found maximum readings of 3.2 microroentgens per hour, with the highest concentrations of NORM being found in sediment from the bottom of tanks (56).

Furthermore, since the principal source of any adverse health impacts due to exposure to NORM would be due to inhalation or ingestion of alpha radiation, not gamma dose, the relevance of the measurements in these studies is limited. Determination of the alpha radiation dose expected from contamination of NORM would require laboratory analyses of the types and amounts of specific radionuclides present in samples, in addition to estimates of the internal dose received by persons handling the contaminated equipment and at risk for ingesting or inhaling the materials. The Occupational Safety and Health Administration general industry standard for worker exposure

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1For further information on the management of commercial low-level radioactive waste, see ref. 96.

2Radium-226 and radium-228 have half-lives of more than 1,600 and 5,7 years, respectivelyRadon-222@ a half-life of o@'3.8 days, whereas lead-210, one of its decay products, has a half-life of 22 years.

3The industry is trying t. develop scale inhibitors to keep radium in the produced waters and inhibit its precipitation into scale. Although some short-term inhibitors do exist, effective longer-term inhibitors have yet to be developed.

4The decay products of uranium and thorium emit alpha, beta, and gamma radiations; alpha and beta radiations normally do not penetrate through vessel or pipe walls, but gamma radiation can do so and thus can be measured outside a vessel or pipe.

5The survey did not obtain measurements of NORM concentrations in tank sediments, soil, or groundwater—parameters that could be necessary if regulations are developed on design requirements for management and disposal operations. The API, the Department of Energy, and the Gas Research Institute are currently studying oilfield NORM concentrations (B. Steingraber, Mobil Exploration& Producing U.S., personal communication, Aug. 21, 1991).

Continued on next page

Box 4-A—Risks and Management of Naturally Occurring Radioactive Materials-Continued

is for the total of external (i.e., gamma) and internal (i.e., principally alpha) radiation-a maximum permissible dose for total body exposure of 5 reins per year (29 CFR 1910.96).[6]

Another health-related issue is the extent to which old equipment sent off-site for reuse or disposal results in the exposure of nonindustry workers to NORM. Although NORM-enhanced scale can be cleaned out of pipes and other equipment mechanically, the industry has usually found it cheaper to buy new equipment and send the old equipment off-site for smelting, cleaning, use in other ways (e.g., fencing or cattle guards), or disposal via land burial.[7] Most equipment with relatively low levels of radioactivity is sent to scrap yards and smelted. Past practices also included landspreading, landfilling, disposal along with scrap tanks, and on-site shallow burial (e.g., 56), although major petroleum companies no longer use these methods. Louisiana is the only State that presently regulates this material (cited in ref. 56).

How to handle equipment that exhibits higher levels of NORM is more problematic. Currently, equipment containing NORM with estimated exposure levels higher than 50 microrems per hour is stored, at least by major petroleum companies, until disposal alternatives are approved.[8] EPA, the Nuclear Regulatory Commission, and the States (except for Louisiana) have not issued regulations on land-based disposal and management of NORM. However, the industry is developing guidelines for disposal of NORM (7, 68).

Rogers and Associates (68) calculated radiation exposures via seven environmental pathways[9] for 12 different disposal methods and compared them with existing exposure limits developed for other, related radiation sources. They concluded that many methods could be used to manage NORM without exceeding the exposure limits, including some forms of landspreading, injection into inactive wells, burial at various sites (e.g., commercial oilfield waste sites, licensed NORM disposal sites, low-level radioactive waste disposal sites, surface mines, salt domes), and use of wells destined to be plugged and abandoned. Another study (57) also suggested that injecting NORM into wells is acceptable because it would allow for disposal at levels below groundwater standards[10] and because it is one of the least costly alternatives. However, improperly plugged wells and correctly plugged wells that later leak under some conditions are still of concern (see "Underground Injection Wells" in this chapter, and ref. 117). Methods such as shallow burial in humid environments or landspreading would also require consideration of the potential for groundwater contamination and human access.

In general, the industry feels that the relatively small volumes of NORM, especially compared with those from mill tailings, fly ash, phosphate fertilizer tailings, and other sources, can be adequately and carefully handled under State regulation. With the exception of Louisiana, however, no State has thus far adopted NORM regulations. However, at least a dozen other States are considering adopting such regulations in the next few years.[11] Abandoned NORM sites (e.g., old pipe cleaning operations or defunct wrap operations that handled pipe) are just beginning to be assessed in terms of potential exposures and risks and potential corrective actions.

6 The International Commission on Radiation Protection recently lowered its guidelines to a total of 2 rems per year (T. O'Toole, O'IA, personal communication, Nov. 8, 1991).

7 The Petroleum Environmental Research Forum is currently studying the fate of NORM during smelting operations to analyze potential exposures (B. Steingraber, personal communication, Aug. 21, 1991).

8 B. Steingraber, personal communication, Aug. 21, 1991.

9 The pathways were radon inhalation, external gamma exposure, groundwater ingestion, surface water ingestion, dust inhalation, food ingestion, and skin beta exposure.

10 Based on models using a criterion of 100-millirem total dose from all routes, including radon, to ensure safety.

11 B. Steingraber, review comments, Oct. 9, 1991.

Class II well regulations (see "Other EPA Statutory Authority" below).[24] All Class 11 wells are subject to these regulations. Although many injection wells now used for disposing produced waters were in existence prior to implementation of the regulations and did not need to be repermitted, they must still comply with construction, operating, testing, monitoring, and plugging requirements. EPA has formed a Class II Advisory Committee to consider potential improvements to the program, through guidance or regulation.

About 4 percent of drilling muds and produced waters are discharged to surface waters. Although

24 F. Brasier, U.S. EPA, review comments, Sept. 26, 1991.

these discharges may meet State and Federal permit standards, large volumes of discharges containing low levels of certain pollutants may cause damage to aquatic communities (117). Discharges into Gulf Coast bays and estuaries have resulted in the bioaccumulation of metals, hydrocarbons, and radionuclides in shellfish and other organisms. For example, the Louisiana Department of Environmental Quality (78) found that benthic invertebrates (including edible species such as oysters) growing near discharges of produced waters may accumulate radionuclides and organic chemicals (e.g., hydrocarbons) whose potential risks to humans are discussed above. Preliminary findings from another study in Louisiana, funded by the Louisiana Division of the Mid-Continent Oil and Gas Association, appear to corroborate the main findings, namely, that organic compounds and metals in produced waters can contaminate benthic communities, depending in part on the volume of discharges and on the hydrologic and sedimentary features of the sites (66).

In general, most cases of environmental impacts result from violations of existing State standards, but some do not. In Ohio and New Mexico, for example, oil and gas operators are allowed to dispose of produced waters in unlined surface impoundments in areas where there is no groundwater. Chronic, low-level discharges of produced waters into streams are often allowed legally under NPDES permit conditions.

Another problem may be surface water contamination from abandoned pits. As of August 1991, for example, Louisiana had identified 71 abandoned pits (31 with inactive operators, 28 with no operator of record, and 12 for which closure was in noncompliance) and 180 unclosed pits requiring remediation or closure.[25] However, Louisiana also considers groundwater contamination from numerous plugged and abandoned wells to be of more importance.

The Superfund National Priorities List (NPL) contains four sites that received oil and gas E&P wastes. Three are in Louisiana: two received oil drilling muds, salt water, and other drilling fluids; the third received sludges from oil field production. The fourth site is a landfill located in New Mexico, on Federal land managed by the U.S. Bureau of Land Management; this site received produced water, waste oil, spent acids, chlorinated organic solvents, and sewage. However, these sites were not necessarily listed on the NPL because of E&P wastes. In addition, some Potentially Responsible Parties (PRPs) at the Louisiana sites have contested their designation as PRPs because of perceived statutory exclusions in CERCLA, although as of November 1991, EPA is proceeding with initial site investigations.[26]

Two other issues of concern involve wetland losses and wildlife mortality.

Wetland Losses

Degradation or loss of some wetland areas has been linked with the physical nature of oil and gas exploration and production activities. For example, one study (80) estimated that canals accounted for 6 percent of total net wetland loss from 1955 to 1978. The Louisiana Mid-Continent Oil and Gas Association (cited in ref. 36) estimated that less than 10 percent of the land lost in coastal Louisiana since 1900 can be attributed to dredging of navigational channels and oil and gas access canals.

Wetland losses have also been associated with discharges of E&P wastes. One review of Louisiana's coastal wetlands concluded that a correlation exists between large numbers of brine discharge points and adjacent areas with rapidly deteriorating marsh (135). At one oil field, these investigators estimated that more than 13 million barrels of brine had been discharged into surface waters annually, and that roughly 30 percent of the wetlands within a 6-mile radius of the field had disappeared between 1956 and 1978. They concluded that the salinity associated with brine discharges can accelerate natural marsh loss rates and initiate vegetation loss in more stable, healthy marshes. In March 1991, the Louisiana Department of Environmental Quality issued new water quality regulations on discharges associated with oil and gas exploration and production activities (see "State Oil and Gas Programs" below).

Wildlife Mortality

Another problem concerns birds and other wildlife that are killed after landing at oily waste pits, whose reflection is apparently viewed as a sign of flesh water. The U.S. Fish and Wildlife Service (F&WS) surveyed New Mexico, Texas, and Okla-

[25] S. McCarty, Louisiana Office of conservation personal communication, Aug. 29, 1991.

[26] J. Vanbuskirk, U.S. EPA, personal communication, Nov. 14, 1991.

homa in 1987 and estimated that about 225,000 migratory birds had been killed in eastern New Mexico alone (109). This problem is not limited to the Southwest. During 1990 and 1991, for example, another study (26) found more than 600 dead animals at 88 pits in Wyoming; two-thirds were birds and one-third were mammals.

Several methods can be used to prevent animals from getting into pits, including plastic flagging, metal reflectors, strobes, complete covering with hardware cloth, and fencing; many States require fencing and other methods (26). The most effective measure is probably a cover of screening or netting, which can cost from a hundred to several thousand dollars. Many major oil companies have invested in such measures.

New Mexico's Oil Conservation Division enacted regulations in September 1989 that require screening or netting of all open pits; other States have been slower to adopt such requirements. Under the Migratory Bird Treaty Act, the F&WS can impose a $10,OOO fine for operations that result in the death of a migratory bird. In the fall of 1988, the F&WS suspended enforcement of this provision until October 1989, to provide industry with time to voluntarily clean up the problem (109). Although many industries responded, particularly in New Mexico, the F&WS felt that the situation might still be severe in areas such as Texas. As a warning to oil pit operators, the F&WS investigated mortality at oil pits operated by Union Pacific Railroad, which pleaded guilty in March 1990 to killing migratory birds. In addition, the Texas Railroad Commission revised its rules, effective November 1, 1991, to require that open-top tanks that are 8 feet or more in diameter be netted or screened.

CURRENT REGULATORY PROGRAMS

As with other solid wastes, the management of exploration and production wastes illustrates the multimedia dimension inherent in waste management decisionmaking. For example, when E&P wastes are stored in surface impoundments, some organic chemicals may volatilize into the air and other chemicals may seep into groundwater if the impoundment is improperly sited and managed. In addition, other air emissions are associated with exploration and production activities (117).[27] Similarly, some E&P wastes are discharged into surface waters, whereas others reach groundwater via leaks from underground injection wells.

Currently, oil and gas E&P wastes are regulated primarily at the State level. EPA has not developed a regulatory program under Subtitle D for these wastes. However, the Agency does regulate underground injection of produced waters under the Safe Drinking Water Act (SDWA), surface discharges of oil and gas wastes under the Clean Water Act (CWA), and air emissions under the Clean Air Act (CAA).[28] In all of these statutes, States generally have primacy in actually implementing the Federal regulations. The U.S. Bureau of Land Management (BLM) also has authority over the management of E&P wastes on Federal lands (but not over the State primacy programs under the Clean Air Act, Clean Water Act, or Safe Drinking Water Act).

Enforcement issues ace of great concern to Federal and State authorities, because there are large numbers,of oil and gas wells and sites, and relatively few government inspectors (see table 4-2). However, a U.S. District Court recently returned the frost-ever indictment under the Safe Drinking Water Act, against a Kentucky oil and gas company and its president for injecting fluids into an underground drinking water source without a permit.[29] EPA hopes the case will set an example for other small operators. Whether such targeted enforcement efforts will have a comprehensive effect remains to be seen.

[27] These include particulate matter and sulfur and nitrogen oxides from diesel engines that run drilling processes; sulfur dioxide released when hydrogen sulfide is removed from natural gas; and volatile organic compounds released from leaks in production equipment. In addition, hydrogen sulfide produced at thewellhead in gaseous form poses occupational risks from leaks or blowouts, although it poses no danger when dissolved in crude oil.

[28] Section 112(n)(5) of the Clean Air Act Amendments of 1990 requires EPA to assess the hazards to public health and the environment resulting from emissions of hydrogen sulfide that are associated with the extraction of oil and natural gas resources and to submit a report to Congress containing findings and recommendations within 24 months. The section also authorizes EPA to develop and implement a control strategy under this section and Section 111 for such emissions, based on the findings of the study.

[29] *United States* v. *Glen Weatherbee*, CR 90-00019-01BG(M), U.S. District Court, Western District of Kentucky, filed Nov. 5, 1990.

Table 4-2-Oil and Gas Wells, Injection Wells, Regulatory Agencies, and Enforcement Personnel, by State

State	Gas wells	Oil wells	Injection wells[a]	New wells completed in 1985	Agency	Number of Enforcement Positions[b]
Alaska	104	1,191	472 Class II 425 EOR 47 disposal	100 new onshore wells	Oil and Gas Conservation Commission; Department of Environmental Conservation	[illegible] each
Arkansas	2,492	9,490	1,211 Class II 239 EOR 972 disposal	1,055 new wells	Arkansas Oil and Gas Commission; Department of Polliution Control and Ecology	7 and 2, respectively
California	1,566	55,079	11,066 Class II 10,047 EOR 1,019 disposal	3,413 new wells	Department of Conservation; Department of Fish and Game	31
Kansas	12,680	57,633	14,902 Class II 9,366 EOR 5,536 disposal	6,025 new wells	Kansas Corporation Commission	30
Louisiana	14,436	25,823	4,436 Class II 1,283 EOR 3,153 disposal	5,447 new onshore wells	Department of Environmental Quality; Office of Conservation	32 and 36, respectively
New Mexico	18,308	21,986	3,871 Class II 3,508 EOR 363 disposal	1,747 new wells	Energy and Minerals Department	10
Ohio	31,343	29,210	3,956 Class II 127 EOR 3,829 disposal	6,297 new wells	Department of Natural Resources	66
Oklahoma	23,647	99,030	22,803 Class II 14,901 EOR 7,902 disposal	9,176 new wells	OklahomaCorporation Commission	52
Pennsylvania	24,050	20,739	6,183 Class II 4,315 EOR 1,868 disposal	4,627 new wells	Department of Environmental Resources	34
Texas	68,811	210,000	53,141 Class II 45,223 EOR 7,918 disposal	25,721 new wells	Texas Railroad Commission	120
West Virginia	32,500	15,895	761 Class ii 687 EOR 74 disposal	1,839 new wells	Department of Energy	15
Wyoming	2,220	12,218	5,880 Class II 5,257 EOR 623 disposal	1,735 new wells	Oil and Gas Conservation Commission; Department of Environmental Quality	7 and 4.5, respectively

[a]Class II = underground injection well; EOR = enhanced oil recovery wells.
[b]Only field staff are included in total enforcement positions.

SOURCE: U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response *Report to Congress: Management of Wastes From the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy, EPA/530-SW-88-003* (Washington, DC: December 1987).

State Oil and Gas Programs

State regulation of oil and gas E&P wastes may vary, depending on differences in climate, hydrology, geology, and economics (44, 117). Additional differences are attributable, in some locations, to the complexity of exploration and production processes and to the variety of waste management options. For example, the number of wells and the volume and types of waste generated vary dramatically from one State to another (see table 4-l). Regulations often differ for wastes managed on-site and those managed off-site at commercial or centralized facilities.

Most produced waters are injected in underground wells, which are regulated under the Underground Injection Control (UIC) program. Landspreading, evaporation, and storage in pits may also be regulated by States. Since the mid-1980s, for example, several States have enacted regulations for land application of oil and gas wastes (75).[30] Similar options, except for underground injection, exist for drilling fluids and low-volume associated wastes. Most States regulate pits and, thereby, at least indirectly regulate drilling fluids and associated wastes; however, few States single out associated wastes for special regulatory attention.

Discharges to surface waters generally are regulated by the States under the Clean Water Act. Given the concern about wetland losses in Louisiana (see "Environmental Damages" above), it is noteworthy that the Louisiana Department of Environmental Quality issued new water quality regulations in March 1991, on discharges and stormwater runoff associated with oil and gas exploration and production activities (Louisiana Title 33, Part IX, ch. 7, Sec. 708). The regulations set forth general guidelines requiring permits and spill prevention and control plans for all discharges. They prohibit discharges of produced waters to water bodies located in intermediate, brackish, or saline marsh areas after January 1, 1995, unless the discharge is authorized in an approved schedule for elimination or for effluent limitation compliance.[31]

All oil and gas producing States permit and therefore identify drilling sites (44). The permits may or may not cover waste management (whether on- or off-site) associated with drilling, but they usually require some financial assurance to cover closure or remediation of a well or disposal facility; the amounts required vary tremendously. A State's overall regulations, however, generally include requirements for using certain management methods, with varying levels of detail and site-specific flexibility.[32] All States have some enforcement program, but actual enforcement mechanisms and resources differ. As with regulatory programs for mining wastes (see ch. 2), often two or more State agencies are involved in regulating oil and gas wastes.

The IOGCC has issued administrative and technical criteria that it recommends States include in their oil and gas regulatory programs.[33] The criteria emphasize that States should retain control over implementation of the recommendations (because of their knowledge of local management practices, waste characteristics, climate, and hydrogeology) and suggest that States establish and implement site-specific performance standards and design specifications (44). The criteria cover the following:

- **Permitting:** States should have a recordkeeping mechanism (e.g., individual permits, permits by rule, registration of facilities, or notification of certain activities) to track waste management facilities.
- Compliance evaluation: States should be capable of evaluating compliance by facilities managing wastes. Capabilities should include a requirement for periodic reporting by facilities and evaluation of these reports by regulatory agencies; inspection and surveillance procedures independent of the self-reporting requirement; procedures to process complaints reported by the public; authority to enter any regulated site; and guidelines for investigations in support of enforcement proceedings.
- Enforcement: States should have the authority to take enforcement actions such as giving notice of violation and establishing a compliance schedule; restraining continued activity by an operator; identifying emergency conditions that warrant corrective action by a State agency; bringing suit in court for continuing violation; issuing administrative orders or bringing suit to correct past harm to public health and the environment; and revoking, modifying, or suspending a permit.

[30] Oklahoma and Kansas, for example, prohibit the use of reserve pit wastes for commercial landfarming (117).

[31] The regulations also prohibit discharges of produced waters to: 1) freshwater lakes, rivers, streams, bayous, and canals; and 2) freshwater swamps or marshes unless these are authorized in accordance with an approved termination schedule or under a permit allowing discharge to portions of the Mississippi River or the Atchafalaya River. Numerical effluent limitations are set for benzene, ethylbenzene, toluene, oil and gas, total organic carbon, pH, temperature, total suspended solids, chlorides, dissolved oxygen, acute and chronic toxicity, soluble radium, and visible sheen.

[32] For example, the State of Pennsylvania adopted regulations in 1989 that require oil and gas pits (and tanks) to be constructed according to standards to protect groundwater, with additional standards applicable if pits are also to be used for disposal (25 *Pennsylvania Code, Sections 78.51-78.63).* Alternative practices to the use of pits, such as solidification, can be approved by the Pennsylvania Department of Environmental Resources.

[33] The criteria do not address discharges to surface waters or injection in underground wells because these are regulated by EPA or the States under the authority of the CWA or SDWA, respectively.

- **Additional program requirements:** States should include provisions for public participation; contingency planning by operators in the event of a waste release; financial assurance (e.g., for closure and postclosure); waste hauler certification; waste tracking mechanisms; the ability to identify the location of closed disposal sites; and effective data management.

The criteria also included general recommendations for managing wastes in pits, land application units, and centralized and commercial facilities (44). In most cases these criteria are presented as goals that States should attempt to meet in establishing their own technical standards.[34]

API also issued guidelines for managing solid waste from oil and gas operations, to support EPA's activities and provide guidance to industry and State regulatory agencies (8).[35] API recently initiated a training program geared to small oil and gas operators to teach them how to implement the guidance.

No systematic, comparative information exists, however, on the overall quality of State oil and gas regulations and programs. Given the great variety in State regulations and in the level of State implementation and enforcement, the quality of the programs is difficult to assess without an extensive field survey, which is beyond the scope of this background paper. In its 1987 Report to Congress (117), EPA recommended that it work with State regulatory agencies to improve oil and gas programs where necessary. The IOGCC, under a grant from EPA and the U.S. Department of Energy, is in the process of evaluating individual State regulatory programs, and comparing them with IOGCC's criteria.[36] This peer review process includes environmental, industry, and State representatives; the first review-of Wyoming's program-was completed in June 1991.

However, some data are available to indicate the general problems and challenges facing State regulatory programs. A major constraint is that State programs often do not have adequate resources to address, for example, an estimated 1.2 million abandoned wells; Texas and Oklahoma have many more wells to plug than they have money to pay for the plugging.[37] EPA's 1987 Report to congress (117) included information on the number of active production and injection wells and field inspectors in 1985 (table 4-2). The number of field enforcement positions varied from 16 personnel for approximately 1,300 oil and gas wells in Alaska to 120 personnel for almost 300,000 wells in Texas. These data could argue that many States need more inspectors, although the exact number would still vary greatly with factors such as age of wells (older wells generate more produced water and require more maintenance) and compliance history of the companies involved. GAO (82) reviewed the underground injection programs of several States and concluded that program safeguards were far from complete or adequate. For example, the files for 41 percent of the wells with permits contained no evidence that pressure tests had ever been performed.

Current RCRA Status of Oil and Gas Wastes

Except for the general Subtitle D criteria (ch. 1), RCRA does not explicitly authorize EPA to control Subtitle D oil and gas wastes. The 1980 Bentsen amendments to RCRA exempted certain wastes unique to the exploration and production of oil and gas from regulation as hazardous wastes under Subtitle C (see table 4-3), pending further study and a determination by EPA of the appropriate level of regulatory action (and a subsequent act of Congress should EPA determine that Subtitle C regulation was warranted).

[34] For example, the technical criteria for construction of pits recommended t&t "talcs or liners should be required in certain instances based on type of fluid and site-specific characteristics. . . . Liners can be natural or constructed of natural or synthetic materials, provided they are installed according to accepted engineering practices and are compatible with expected pit contents" (44).

[35] The API plans to up&k this Environmental Guidance Document in 1991 to address in more detail issues such as waste minimization, guidelines for field sampling and analysis of oil field wastes, NORM guidelines, and land disposal criteria for metals; it also plans to review the consistency of its guidelines with the IOGCC criteria for exploration and production wastemanagement programs (142).

[36] J. Simmons, IOGCC, personal communication% March 1991.

[37] GAO (82) expected the number of such wells t. increase, because the economic downturn of the oil industry in the late 1980s might have led to more improperly plugged wells.

Table 4-3-Examples of RCRA Exempt and Nonexempt Oil and Gas Wastes

Exempt wastes	Nonexempt wastes
Produced waters	Unused fracturing fluids/acids
Drilling fluids	Painting wastes
Drill cuttings	Service company wastes
Rigwash	Refinery wastes
Well completion fluids	Used equipment lubrication oil
Workover wastes	Used hydraulic oil
Gas plant dehydration wastes	Waste solvents
Gas plant sweetening wastes	Waste compressor oil
Spent filters and backwash	Sanitary wastes
Packing fluids	Boiler cleaning wastes
Produced sand	Incinerator ash
Production tank bottoms	Laboratory wastes
Gathering line pigging wastes	Transportation pipeline wastes
Hydrocarbon-bearing soil	Pesticide wastes
Waste crude oil from primary field sites	Drums, insulation, and miscellaneous solids

SOURCE: M. Fitzpatrick, "Common Misconceptions About the RCRA subtitle C Exemption for Wastes From Crude Oil and Natural Gas Exploration, Development and Production," in *Proceedings of the First International Symposium on Oil and Gas Exploration and Production Waste Management Practices (New* Orleans, LA: U.S. Environmental Protection Agency, Sept. 1-13, 1990).

On the basis of its Report to Congress (117), EPA published its regulatory determination in July 1988.[38] EPA determined that Subtitle C regulation for oil and gas E&P wastes is not warranted and that the Agency instead would develop a Subtitle D program tailored to these wastes.[39] EPA reasoned that operators would be freed from prescriptive Subtitle C requirements, but that the combination of future Subtitle D requirements, other Federal and State regulatory requirements, and potential Superfund liability (from mismanagement of oil and gas wastes) would be sufficient incentives for prudent management and would encourage waste minimization and recycling; at the same time, although EPA hopes to promote greater national consistency in managing these wastes, it also stated a desire to maximize State authority. The Agency indicated that development of a Subtitle D program would consider requirements such as engineering and operating practices to manage releases to surface water and groundwater; procedures for closure; monitoring that accommodates site-specific variability; and cleanup provisions.

EPA further stated that it planed to develop "a three-pronged approach toward filling the gaps in existing State and Federal regulatory programs." This approach would aim to:

1. improve existing Federal programs in Subtitle D of RCRA, the Clean Water Act, and the Safe Drinking Water Act;
2. work with States to encourage improvement and changes in their regulation and enforcement of oil and gas wastes; and
3. work with Congress to determine any additional statutory authority that might be necessary.

To date, however, EPA has made little direct progress toward the goal of establishing a Subtitle D oil and gas program. Not surprisingly, environmental groups and the industry disagree about the need for such a program. Environmental groups contend that a Subtitle D program, along with possible Subtitle C regulation for some wastes, is necessary. The oil and gas industry believes that most wastes can be managed adequately with existing State and Federal programs (e.g., the UIC program under the Safe Drinking Water Act, the NPDES program under the Clean Water Act), provided the programs are adequately financed and enforced.

Other EPA Statutory Authority

EPA has additional statutory authority, other than RCRA, to issue regulations regarding oil and gas waste management. The most important areas are under the Clean Water Act, the Safe Drinking Water Act, and Superfund. In addition, the Clean Air Act regulates air emissions associated with oil and gas activities.

Clean Water Act

The Clean Water Act established a permitting program for wastewater discharges-the National Pollutant Discharge Elimination System. EPA grants primacy to most States to administer State NPDES programs that are equivalent to or more stringent than Federal requirements. NPDES per-

[38] 53 *Federal Register 25446,* July 6, 1988.

[39] EPA determined that Subtitle C regulation was not warranted because: 1) Subtitle C is extremely costly and unnecessary for safe management of these wastes; 2) Congress indicated that such regulations are unwarranted where existing programs can be used to address problems; 3) Subtitle C permit processing times are typically lengthy, which would cause disruptive delays for oil and gas operations; 4) inclusion of these wastes in Subtitle C would severely strain existing hazardous wastemanagement capacity; 5) such regulation would disrupt and duplicate State authorities; and 6) implementation would be impractical and inefficient.

mits are required for discharges to surface waters and to public sewer systems that lead to publicly owned treatment works.

To date, however, most States have not issued NPDES permits for discharges of produced waters to coastal areas and wetlands or for discharges from stripper wells to surface waters in general.[40] As of 1990, for example, EPA's Office of Inspector General noted that no general permits had been issued for discharges into coastal wetlands in Louisiana (125). One reason for the lack of such permits is that in the initial phases of implementing the Clean Water Act, EPA's Region VI concentrated on establishing control over single major dischargers.[41] As the NPDES program matured, emphasis shifted to controlling aggregate impacts from multiple minor dischargers, including coastal oil and gas exploration and development facilities. On February 25, 1991, Region VI issued a final NPDES general permit for "onshore" oil and gas production facilities, which allows for zero discharge of drilling fluids and produced water. The Region's final NPDES general permit for "coastal" oil and gas drilling activities, which also will establish a zero discharge limitation for drilling muds and cuttings, was expected to be published in late 1991.

EPA, GAO, and others have noted the need for national guidelines to underlie such permitting efforts (82, 125). Part of the problem is that EPA has not yet promulgated effluent limitation guidelines for discharges from the "offshore" crude oil and natural gas industry, nor has it revised guidelines for the "coastal" oil and gas subcategory so that they are based on best available technology economically achievable (BAT).[42] EPA is developing guidelines for the offshore subcategory, due to be finalized in 1992, and for the coastal subcategory, due to be finalized in 1995. EPA also has not decided whether or how to include stripper oil wells and marginal gas wells in these regulations, although it is considering this issue.[43] A related issue that may also warrant more attention concerns the impacts of nontoxic pollutants, such as chlorides, in effluents discharged from oil and gas operations.

Safe Drinking Water Act

The Safe Drinking Water Act established the Underground Injection Control program to regulate injection wells. The statute established a special class (Class II in EPA terminology) of injection wells in the UIC program for oilfield-related fluids, and stipulated that regulation of Class II wells should not impede oil and gas production unless necessary to prevent endangerment of underground sources of drinking water.

The UIC program regulates only the injection of fluids related to oil and gas production and hydrocarbon storage. These include produced waters and other fluids used for enhanced recovery, as well as disposal of brines.[44] UIC regulations require that injection of such fluids into Class II wells (for disposal or for enhanced oil recovery) must take place below all formations containing underground sources of drinking water (117, 121). They also require that periodic tests (at least every 5 years) be conducted of the mechanical integrity of the wells and that a one-quarter-mile radius around a well be reviewed (i.e., the area of review) for potential migration of injected fluids or brines from the site. EPA has noted, however, that produced waters stored in surface impoundments prior to injection may be subject to RCRA Subtitle D regulations[45]; whether this would extend to management in storage tanks prior to injection is unclear.

The UIC program is largely administered by the States, with EPA approval and oversight. EPA has granted primacy for administering the program to 25 of the 32 oil and gas producing States. EPA is responsible for management on tribal lands.

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[40] Exceptions to this general statement exist. For stripper wells, for example, Pennsylvania issued a general permit that was scheduled to finalized in October 1991, and Louisiana and Texas issue individual State water discharge permits without distinguishing between stripper and onshore wells. For coastal areas and wetlands, Louisiana issues individual State permits for discharges to State waters; these are not the same as NPDES permits because Louisiana is not a "delegated" State, but they do require monitoring and include discharge limitations and some best management practices.

[41] U.S. EPA, Office of Water, review comments, Oct. 3, 1991.

[42] EPA promulgated effluent limitations guidelines in 1979 for discharges in the coastal subcategory (44 *Federal Register* 22069, Apr. 13, 1979); these were based on best practicable control technology currently available (BPT), which provides a less stringent level of control than BAT.

[43] 54 Federal *Register 46919, Nov. 8,* 1989.

[44] Produced water injected for enhanced oil recovery is considered t. be beneficially recycled as an integral part of some crude oil and natural gas production processes and, as such, is not a waste for purposes of regulation under RCRA (53 *Federal Register 25454,* July 6, 1988).

[45] 53 *Federal Register* 25454, July 6, 1988.

Several concerns have been raised about the effectiveness of injection well regulations, and EPA continues to evaluate the UIC program (82, 121, 122). EPA's most recent evaluation of the Class II UIC program (122) indicated a need for: 1) further study of risks associated with abandoned oil and gas wells; 2) additional evaluation of State area of review programs for existing wells, which vary widely among States; and 3) possible changes in Class II well construction requirements. According to EPA (117), economic incentives for operators to comply with requirements may be lower for disposal wells than for EOR wells.[46]

CERCLA/Superfund

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), passed in 1980 and commonly known as Superfund, excludes petroleum (including crude oil) from its liability provisions. However, oil and gas operators are not exempt from CERCLA liability, for several reasons.[47] First, other nonpetroleum "special wastes" (see "Introduction" and table 4-3) from oil and gas exploration and production activities may still result in CERCLA liability if the waste constituents are hazardous substances as otherwise defined by CERCLA. Second, the petroleum exclusion does not apply to any constituents of oil and gas wastes that are hazardous substances added to the oil (and not normally found in petroleum at the levels added). Third, codisposal of exempt and nonexempt wastes can result in liability under the "mixture' rule of RCRA (see ch. 5). As noted above, oil field waste disposal sites have been designated as Super-fund sites because oil and gas wastes that are exempt from Subtitle C, along with other wastes at some sites, were not managed so as to avoid the release of hazardous substances (27).

Other Federal Agency and General Statutory Authority

Other Federal agencies also regulate certain aspects of oil and gas waste management, and several general Federal statutes contain provisions that affect oil and gas operations.

The National Environmental Policy Act (NEPA) requires Federal agencies to assess the potential environmental impacts of "major federal actions" undertaken or permitted by Federal agencies. If the assessment indicates that the environment will be significantly affected, then a more detailed Environmental Impact Statement must be prepared. In addition, the Endangered Species Act requires Federal agencies to ensure that their actions do not jeopardize endangered or threatened species or destroy critical habitats of endangered species.

The Federal Land Policy Management Act of 1976 (FLPMA) requires the U.S. Department of the Interior to develop land use plans for resources on Federal lands. With respect to regulating oil and gas E&P wastes, the Department generally favors continuing the existing approach of working relationships among the Federal Government, States, and industry. Within the Department, the U.S. Bureau of Land Management (BLM) is responsible for oil and gas production and waste management on many Federal lands, although not for the primacy programs of the Clean Water Act, Clean Air Act, or Safe Drinking Water Act. BLM manages public lands under its jurisdiction according to the comprehensive land use guidelines established by FLPMA and other acts. For example, BLM has issued orders that instruct onshore operators about how to conduct their operations in an environmentally safe manner.[48]

The U.S. Forest Service, within the Department of Agriculture, is responsible for administering oil and gas activities in the National Forests. It develops land use plans under the guidelines of the National Forest Management Act of 1976 and the Forest and Rangeland Renewable Resources Planning Act of 1974.

GAO (84) evaluated land use plans and related environmental impact statements in four resource areas administered by BLM and four national forests administered by the Forest Service, on the basis of five elements that it considered essential for assessing environmental impacts of oil and gas leasing and development decisions.[49] It concluded that most

46 For EOR wells, oil recovery depends on maintaining the pressure within the producing zone and avoiding communication between that zone and the reservoir where wastes are injected.

47 The precedent for Superfund liability by oil and gas companies was set by *Eagle-Picher Industries, Inc. v. US. Environmental Protection Agency, 83-2259,* U.S. Court of Appeals for District of Columbia, 822 F.2d 132, June 30, 1987.

48 BLM, review comments, Aug. 9, 1991.

49 The elements were oil and gas potential, reasonably foreseeable development scenarios, indirect impacts, cumulative impacts, and lease stipulations.

plans and impact statements for lands with high oil and gas potential did not contain adequate information on one or more of the five elements. GAO also found that leases and permits had been approved without including appropriate mitigation measures. In written comments to GAO, BLM and the Forest Service essentially agreed with its two major recommendations regarding the establishment of management controls to ensure that NEPA requirements are adequately addressed and that appropriate stipulations and conditions of approval are attached to leases and permits.

FLPMA also requires BLM and the Secretary of the Interior to review all public land roadless areas of 5,000 or more acres with wilderness characteristics to determine their suitability for wilderness designation by October 21, 1991. This is significant because it could potentially protector open up large areas of public lands (e.g., on the North Slope of Alaska) to potential oil and gas exploration and production (as well as other uses). If more oil and gas development occurs on Federal lands, the relationships among BLM, EPA, and the States will be even more important.

The Federal Oil and Gas Royalty Management Act of 1982, which is administered by the Department of the Interior (specifically by BLM and the Minerals Management Service) requires oil and gas operators on Federal lands to construct and operate wells in such a manner as to protect the environment and conserve Federal resources.[50] It also requires the Department to establish a comprehensive system, including inspections, for accurately determining oil and gas royalties.

The U.S. Department of Energy (DOE) charter is to ensure the Nation's energy security and, as such, includes research on waste management. DOE's concerns about oil and gas operations focus on production aspects (e.g., economic impacts of regulatory changes on the industry and on domestic production), in line with concerns of the oil and gas industry, rather than on environmental concerns, which are generally of secondary importance (100).

ISSUES AND QUESTIONS

Concerns over future liability may be encouraging oil and gas operators to improve waste management methods, but efforts on the parts of Federal and State agencies may still be needed in some areas. At the same time, the sheer number of oil and gas operators and sites and the variation in site-specific conditions pose many challenges for any waste management regulatory program, whether at the Federal or the State level. Some issues and questions related to oil and gas waste management that Congress might address include, but are not necessarily limited to, the following:

- **Relationships Among Federal Agencies and Programs-Is an** adequate mechanism available to ensure that EPA and Department of Interior regulations are consistent with each other and nonduplicative? How do Department of Interior regulations for managing oil and gas wastes on Federal lands compare with those of EPA's RCRA, UIC, and NPDES programs, which usually are implemented by the States? Does EPA need to better coordinate its own programs, which are authorized by multiple statutes (e.g., RCRA, SDWA, CWA)? Should EPA develop a multimedia approach within a RCRA Subtitle D oil and gas program? Are existing CVLA regulations on discharges of oil and gas waste to surface waters adequate, particularly for coastal discharges of produced waters and for discharges from stripper wells?
- Relationships Among Federal and State Agencies-should the Federal government specify requirements to be adopted by State programs? If so, does EPA need additional oversight, monitoring, and enforcement authority under RCRA to support an effective State-implemented Subtitle D program for oil and gas waste, or are existing State and Federal regulatory programs adequate? Should existing relationships among the Federal Government (including the Department of the Interior), States, and industry be maintained and strengthened? Can consistent environmental protection and flexibility to address variable conditions at oil and gas operations both be incorporated into a Federal waste management program?
- Scope of a Federal Regulatory Program—Should EPA or another agency develop a Federal regulatory program for the disposal of

[50] In addition, some oil and gas lease agreements may impose obligations on operators for waste management tbat are different from or more stringent than State or Federal requirements.

naturally occurring radioactive material, particularly off-site? Should a Federal regulatory program be developed for abandoned oil and gas wells? What components should such programs include? Should EPA regulate produced water in storage pits or tanks prior to injection into Class II wells, whether or not the water is used for enhanced oil recovery? Should stripper wells be included in any Federal regulatory program for E&P wastes (i.e., is the current distinction for small quantity generators warranted)? Are standards needed for land treatment and land application?

- **Resources for Administration and Enforcement of Programs-Are existing** resources sufficient to administer and enforce Federal and State oil and gas waste regulatory programs? If not, what mechanisms are available to provide such resources? What emphasis should be given to enforcement of such programs relative to other Subtitle D programs and, in turn, relative to other environmental protection programs? Should independent audits be conducted to assess how effectively various Federal and State regulations are being enforced?
- Pollution Prevention/Waste Reduction—How can pollution prevention and waste reduction efforts be encouraged, especially for drilling fluids?
- Adequacy of Existing Toxicity Tests-Do existing toxicity tests such as the Extraction Procedure and the Toxicity Characteristic adequately determine the potential for long-term leaching and migration of contaminants from oil and gas wastes (i.e., is a testing scenario based on mismanagement of wastes in municipal landfills appropriate for oil and gas wastes)? Should any oil and gas exploration and production wastes be regulated as hazardous?