ENVIRONMENTAL REGULATIONS: IMPACT ON THE UNITED STATES PETROLEUM EXPLORATION AND PRODUCTION INDUSTRY

by

JAMES LESLIE HARDIN, B.S.

THESIS

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

MASTER OF SCIENCE IN ENGINEERING

THE UNIVERSITY OF TEXAS AT AUSTIN

December 1993

ENVIRONMENTAL REGULATIONS: IMPACT ON THE

UNITED STATES PETROLEUM EXPLORATION

AND PRODUCTION INDUSTRY

APPROVED BY

SUPERVISORY COMMITTEE:

ACKNOWLEDGMENT

I would like to thank all those who had a part in a very rewarding experience in writing this thesis. My wife Cera Mae deserves most of the credit for its completion who spent many hours, some late at night, typing this thesis. I would also like to thank Dr. W.C.J. Van Rensburg for his knowledgeable guidance.

Most of all I thank my good Lord Jesus for all of the great things He has done for me.

15 November 1993

ABSTRACT

ENVIRONMENTAL REGULATIONS: IMPACT ON THE

U.S. PETROLEUM EXPLORATION

AND PRODUCTION INDUSTRY

by

JAMES LESLIE HARDIN, M.S.E.

The University of Texas at Austin, 1993

SUPERVISOR: DR. W.C.J. VAN RENSBURG

In the past 20 years environmental regulations have progressed from being nearly nonexistent to a main concern in an oil company's activities. This thesis reviews the more significant environmental regulations, focusing on how these regulations have impacted the U.S. oil and gas exploration and production industry. A brief history of each environmental Act is given. Then the current regulations, stemming from these Acts and their amendments, are reviewed. Also, a brief overview of the common wastes generated in the oil and gas exploration and production industry and the waste management practices used to deal with these wastes are discussed. Finally, the economic impacts of these regulations are reviewed.

Table of Contents

Table of Contents

Table of Contents

List of Tables

List of Figures

CHAPTER I

INTRODUCTION

Since the 1970's, many environmental laws have been written and passed. These laws came about initially due to concerns about well-known, highly-publicized hazardous waste dump sites such as "Valley of the Drums" in Brooks, Kentucky and "Love Canal" in New York.[1] These laws and regulations have had a significant impact on the petroleum exploration and production (E&P) industry.[1]

In 1976, one of the first laws to be passed as a result of this public concern was the Resource Conservation and Recovery Act (RCRA). Most of the regulations concerning the generation, transportation and treatment of hazardous waste are included in this Act.

Hazardous wastes are defined in four broad categories: corrosivity, flammability, reactivity, and toxicity. Any material that falls into these categories must be stored and disposed of according to the regulations contained in RCRA. One of the most significant parts of RCRA is the "Cradle to Grave" tracking system. This tracking system requires generators to track the hazardous waste from the point of generation to the point of disposal. These special requirements make disposal of hazardous waste extremely expensive.

In 1980, during the reauthorization of RCRA, Congress temporarily exempted waste generated from primary oil field operations, and required the EPA to conduct a

study to see if these wastes should be classified as hazardous wastes. In 1987, the EPA completed the study and recommended that these waste continue to be exempted. Congress agreed with these recommendations and the EPA later defined the wastes to be included in the exemption. Most analysts agree that if this exemption were ever lifted, the U.S. E&P industry would be devastated.

The Clean Water Act (CWA) was designed to control the discharge of pollutants from point sources into U.S. waters. This is carried out mainly through the National Pollutant Discharge Elimination system which requires permits for waste water discharges to U.S. waters. Another important aspect of the CWA is to prevent spills of hazardous substances or oil in to U.S. waters.

The Clean Air Act (CAA) was established to control hazardous air pollutants. Under the CAA the EPA established a national air permit system. In 1990, Congress approved the Clean Air Act Amendments (CAAA) which have and will drastically change the regulations concerning the management of air quality. The CAAA has four broad areas which include non-attainment provisions, air toxics, operating permits and outer continental shelf (OCS) provisions. Probably the most significant impact of these new regulations on the U.S. E&P industry will be on the OCS where production platforms will be required to meet very strict emission standards near non-attainment areas. The above regulations and others are discussed in the following chapters with

an emphasis on how the laws and regulations impact the U.S. E&P industry. The last two chapters estimate the economic impacts of these laws and regulations.

REFERENCE

1. Nathanson, Jerry A., P.E. Basic Environmental Technology: Water Supply, Waste Disposal, and Pollution Control., New York: John Wiley & Sons, Inc., 1986 (pp. 2324)

CHAPTER II

ENVIRONMENTAL REGULATIONS

The major federal laws and regulations affecting oil E&P include: Resource Conservation and Recovery Act (RCRA), Clean Water Act (CWA), Safe Drinking Water Act (SDWA), and Clean Air Act (CAA). These and others are discussed in detail below.

Resource Conservation and Recovery Act (RCRA)

Hazardous waste regulation began with the Resource Conservation and Recovery Act (RCRA) of 1976. The major objective of RCRA is to protect human health and the environment through EPA-developed standards.[1] Another important aspect of the RCRA is to encourage the recovery of valuable material and energy resources from these wastes instead of disposing of them as hazardous waste.[1] In the Code of Federal Regulations (CFR) Title 40, Parts 261 through 270, Subtitle C, the strict "Cradle-to-Grave" tracking of hazardous waste is outlined. Included are stringent requirements for generators of hazardous waste, transporters, and treatment, disposal and storage (TDS) facilities.

Wastes considered hazardous fall into four broad categories: corrosivity, ignitability (flammability), reactivity, toxicity.[2] If a generated waste falls into any one of the above categories, at or above the levels specified, it must be disposed of

according to regulations under the Subtitle C. Hazardous waste disposal costs can be ten (10) times greater than non-hazardous waste, depending on volume, type, and location of the generated waste.[2]

Hazardous waste with characteristics of ignitability include ignitable liquids with a flash point of less than 140°F, ignitable compressed gas, ignitable reactives and oxidizers.[2] Corrosive characteristics cover aqueous solutions with pH less than or equal to 2 or greater than 12.5[2]. Reactive hazardous wastes are any materials that react violently with water and explosives.[2] Toxicity is measured by the Toxicity Characteristic Leaching Procedure (TCLP).[2]

A generator is any entity whose act or process produces hazardous waste.[2] The EPA classifies generators into three categories: Large quantity, small quantity, and conditionally exempt small quantity generators, based upon the amount of hazardous waste generated.[2] The regulatory requirements significantly increase as the generator goes from small to large.

A generator is given a generator identification number for a particular hazardous waste generation site. The waste is tracked from "Cradle-to-Grave" by the hazardous waste manifesting system. With this system the EPA can trace back to the original waste generators and hold them liable for any future cleanup costs.[2]

In drilling for oil and gas, the operator generally holds the generator ID number although there are instances where the driller holds the generator ID number.[2]

There can be problems with both these scenarios. If the operator holds the ID number, then he is responsible for all activities related to the E&P process and therefore is responsible for the driller's actions.[2] If the driller holds the ID number, once the driller completes the well and moves off site, any future illegal practices of the operator could lead to the driller being held liable.[2]

If any hazardous waste stream is mixed with a non-hazardous waste stream, the entire waste stream becomes hazardous waste. This is known as the mixture rule. This rule was included in RCRA to prohibit generators from diluting hazardous wastes to get under a concentration threshold.

Non-hazardous wastes are regulated under RCRA Subtitle D. These regulations are less extensive than Subtitle C regulations described above. To date the EPA has established minimal criteria for Subtitle D wastes. The criteria are mainly based on making sure that non-hazardous waste management facilities operate as sanitary land fills rather than "open dumps". The states are required to submit Solid Waste Management Plans to the EPA for approval and funding.[3]

During the reauthorization of RCRA during 1980, Congress required the EPA to complete a study to determine whether or not E&P waste should be regulated under Subtitle C.[4] The study was completed in December 1987.[4] Congress temporarily exempted "drilling fluids, produced waters and other wastes associated with the exploration, development, or production of crude oil or natural gas."[4]

The term "other wastes associated" was meant as waste materials intrinsically derived from primary field operations associated with the exploration, development, or production of crude oil, and/or natural gas. It would cover such substances as: hydrocarbon-bearing soil in and around related facilities; drill cuttings; and materials (such as hydrocarbons, water, sand, and emulsion) produced from a well in conjunction with crude oil and/or natural gas and the accumulated material (such as hydrocarbons, water, sand and emulsion) from production separators, fluid treating vessels, storage vessels, and production impoundments.[4]

The phrase "intrinsically derived from the primary field operations" is intended to differentiate exploration, development, and production operations from transportation (from the point of custody transfer or of production separation and dehydration) and manufacturing operations.[4]

The major recommendations of the study completed in December 1987 were to: 1) Continue use of Subtitle D and existing state and federal regulations and to not include exempted wastes under Subtitle C regulations.[4] 2) Consider undertaking cooperative efforts with states to review and improve the design implementation and enforcement of existing state and federal programs to manage oil and gas wastes.[4] 3) Encourage the industry to explore waste minimization, recycling waste, treatment, innovative technology and substitution as long-term improvements.[4]

A test of whether or not a particular waste would qualify as an exempted waste was also provided in the December 87 report. A partial list of exempted and non-exempted waste is shown in Table 2.1.[4]

Congress agreed with these recommendations and the regulatory determination was released in July, 1988.[5]

As one part of the regulatory determination, the EPA funded $300,000 to the oil-producing states under the Interstate Oil Compact Commission (IOCC) to develop effective regulation guidelines, and/or standards for state level management of oil and gas E&P wastes.[6] The IOCC completed the report in December 1990.[6] This report gave specific recommendations for technical criteria related to pits, landspreading, burial and landfilling, road spreading, commercial and centralized disposal facilities.[6] This report was not a regulation but only a guideline for the states.

Safe Drinking Water Act (SDWA)

The SDWA was enacted in 1974 and was most recently amended in 1986. The SDWA is designed to protect human health by eliminating contaminants in harmful quantities in drinking water supplies. It authorizes national drinking water standards and a joint federal/state system for insuring compliance with these standards.[3]

Part C of Title XIV authorizes establishment of a permit program designed to prevent the contamination of underground sources of drinking water.[3]

Table 2.1

EXEMPT WASTE

- Drill cuttings
- Drill fluids
- Well completion, treatment, and stimulation fluids
- Packing fluids
- Sand, hydrocarbon solids, and other deposits removed from production wells
- Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment
- Hydrocarbon-bearing soil
- Pigging wastes from gathering lines
- Wastes from subsurface gas storage and retrieval
- Basic sediment and water and other tank bottoms from storage facilities and separators
- Produced water
- Constituents removed from produced water before it is injected or otherwise disposed of
- Accumulated materials (such as hydrocarbons, solids, sand, and emulsion) from production separators, fluid-treating vessels, and production impoundments that are not mixed with separation or treatment media
- Drilling muds from offshore operations
- Appropriate fluids injected downhole from secondary and tertiary recovery operations
- Liquid hydrocarbons removed from the production stream but not from oil refining
- Gases removed from the production stream, such as hydrogen sulfide, carbon dioxide, and volatilized hydrocarbons
- Materials ejected from a production well during well blowdown
- Waste crude oil from primary field operations
- Light organic volatized from recovered hydrocarbons or from solvents or other chemicals used for cleaning, fracturing, or well completion

Table 2.1 Con't.

NON-EXEMPT WASTES

Waste lubricants, hydraulic fluids, motor oil, and paint	Sanitary wastes, trash, and gray water	Waste iron sponge, gylcol, and other separation media
Waste solvents from cleanup operations	Gases, such as SOx, NOx, and particulates from gas turbines or other machinery	Filters
Off-specification and unused materials intended for disposal	Drums - (filled, partially filled, or cleaned) whose contents are not intended for use	Spent catalysts
Incinerator ash		Wastes from truck and drum cleaning operations
Pigging wastes from transportation pipelines		Waste solvents from equipment

Source: 4

The (SDWA) establishes a special class (Class II) of injection wells for the disposal of oil field fluids.[6] The minimum requirements for Class II wells are:

a. Only approved E&P wastes may be injected.[6]

b. No well may endanger an underground source of drinking water.[6]

c. Unless permitted by rule, all wells must be permitted before construction.[6]

d. All wells must demonstrate mechanical integrity at least once every five years.[6]

The 1986 amendments to the SDWA established a Well Head Protection program that the states use to protect water wells and springs used for drinking water. The EPA issued guidance on this issue in June 1987.[3]

Some of these regulations are administered through the states through primacy agreements which may be amended with approval from the EPA.[6] Any state or local government environmental regulations may be more stringent than federal regulation but not less so. Therefore, regulations may change not only from state to state, but also within different areas within any state.

In 1987, the EPA forwarded a report to Congress on management of oil and gas production wastes. In that report the EPA identified the continued use of minimal well construction practices in some states related to underground injection. In 1989

there was a mid course evaluation of the Class II program which identified the need to reevaluate construction requirements particularly relating to level of protection afforded to specific Under Ground Sources of Drinking Water (USDWs).[7]

The mid course evaluation also recommended that the EPA study the effects of injection wells on abandoned oil and gas wells within the area defined as "zone of endangering influence" or "area of review" to see if further control measures would be required.[7]

The EPA then formed a committee of concerned parties including, petroleum producing companies, public and environmental interest organizations, state UIC regulatory agencies and others to develop a consensus on new regulation concerning the Class II program. The current regulation outlined in 40 CFR 144.6(b) provides considerable latitude in the construction of a Class II injection well. About 60 percent of all Class II wells feature a conventional construction program where "conventional" indicates:[7]

- surface casing set and cemented to protect USDWs $\leq$ 3000 mg/l Total Dissolved Solids (TDS)
- long string casing that extends from the surface to or through the injection zone and is cemented for some specified vertical distance
- injection tubing set on a packer

The above three features of conventional construction are also known as "layers of protection". Unconventional well construction would lack at least one of the above features of construction. Approximately 40 percent or 66,500 Class II wells are of unconventional construction.[7]

The "area of review" (AOR) was included into the UIC regulations to insure that any improperly abandoned oil wells, or improperly completed producing wells are identified. Any offset wells that would provide a conduit for injected fluids to contaminate USDW must be properly plugged or repaired. Current regulation exempt injection wells existing prior to the implementation of the UIC program.[7]

The 40 CFR 146.6 requires that all operators submitting a permit application for a new Class II injection well review all publicly available completion and plugging records for all wells that penetrate the injection zone within a specified radius. The EPA exempted existing injection wells because they believe that all existing injection wells would be reviewed with time as new injection wells were brought on line. However, a study conducted in Texas showed that only about 25 percent of the existing injection wells were included in the "area of review" between 1982 and 1990. Therefore, the EPA believes that a change in the regulations is required.[7]

The advisory committee mentioned earlier recommended to the EPA the following changes to the Class II program on 23 March 1992.[7]

- All wells drilled or converted from a producing well, that were drilled after the effective date of the regulations will be required to have all three elements of conventional construction.
- All wells having only two construction elements will be required to undergo Mechanical Integrity Tests (MIT) every three years.
- All wells having one construction element will require an MIT annually.
- An area of review must be performed on all Class II injection wells including those previously exempted unless 1) the well is covered under a previously performed AOR 2) the well, project, or basin is subject to a variance.
- Variances may be granted in areas where risk of contamination of USDW is minimal. Variances would be issued by the Directors of each state's UIC program based on a predetermined understanding between the EPA and the UIC Directors.

Clean Water Act (CWA) of 1977

In 1972, Congress enacted the first significant act for the purpose of protecting water from pollution, named the Water Pollution Control Act. One of the requirements of this Act is the National Pollutant Discharge Elimination System (NPDES) discharge permits. This Act was modified significantly in 1977 to address toxic water pollutants, and was renamed the Clean Water Act (CWA). This Act has been amended several times. The most recent amendment is the Water Quality Act of 1987.

The CWA's main purpose is to control the discharge of pollutants from point sources into U.S. waters. This requirement is carried out through the following:

- A permit program (NPDES)
- Minimum national effluent standards for each industry
- Water quality standards
- Provisions for problems such as oil and toxic chemical spills
- Construction grant program for publicly-owned treatment works

All point source discharges of pollutants to surface waters of the United States must comply with the requirements of permits issued under the National Pollutant Discharge Elimination System (NPDES).[1] The CWA requires NPDES permits for

E&P waste discharges to surface waters.[5] Currently, discharges to surface waters is not allowed except:[5]

a. Discharges to coastal areas containing brackish waters not suitable for human use.[5]

b. Discharges of low salinity produced waters which are of beneficial use in arid regions west of the 98th meridian.[5] California and Wyoming are the main states where this occurs.[8]

c. Discharges from stripper oil wells.[5] This is only allowed in some Appalachian states.[8]

Section 311 of the Clean Water Act prohibits the discharge of oil or hazardous substances in "quantities as may be harmful" into U.S. Waters. This Section also requires immediate notification to the National Response Center (NRC) if a reportable quantity release has occurred. The definition of "quantities as may be harmful" is defined as a discharge that causes a sheen; sludge or emulsion in the receiving water or upon the adjacent shoreline.[3]

Hazardous substance spills are treated differently under the CWA. Approximately 300 hazardous substances are listed with their Reportable Quantities (RQ) in the 40 CFR, Section 116 and Section 117. This designation is different than the RCRA hazardous waste designation under 40 CFR Subtitle C. Again, any

discharge of more than the RQ requires notification to the NRC. The NPDES now includes storm water run-off that comes in contact with contaminated materials on items such as machinery and trucks.[3]

A statutory immunity from criminal prosecution is available for a person in charge who notifies the EPA as required by Section 311. However, there is no immunity from civil penalties that may be attached. Failure to notify is punishable by a fine of up to $10,000 and up to one year in prison. The civil penalty for "ordinary negligence is $5,000 and up to $250,000 for "willful negligence or willful misconduct."[3]

The 40 CFR 110 and 40 CFR 112 is regulation for the purpose of Oil Pollution Prevention and came about through Section 311 of the CWA. This regulation requires the development of a Spill Prevention Control and Counter measures (SPCC) Plan for all non-transportation-related facilities onshore and offshore which could discharge or have discharged oil into navigable waters of the U.S. or adjoining shoreline.[2] SPCC plans are required for those facilities which have storage capabilities greater than 600 gallons in a single tank or 1,320 collectively or 42,000 gallons underground.[3]

The accomplishment of the above objective is carried out through:

- Training of employees to reduce human error
- Inspection procedures
- Installing pollution prevention equipment

- Secondary containment if practicable[3]

Comprehensive Environmental Response Compensation & Liability Act CERCLA) of 1980

The purpose of the Comprehensive Environmental Response, Compensation & Liability Act (CERCLA) of 1980 is to assign liability and provide compensation for cleanup and emergency response for hazardous substances released into the environment.[1] The law provides for the creation of a fund (superfund) to provide the money needed to address cleanups at abandoned disposal sites and major spill sites.[1] Crude oil and fractions thereof are exempted from CERCLA.[1]

It allows the government to recover costs associated with cleanup and disposal of major spill sites by suing parties who have contributed to the creation of the contamination. The EPA can require one company to clean up a hazardous waste site even though others may have contributed to the waste. Also, a generator can be held liable for hazardous waste in a disposal facility if the facility goes bankrupt. Therefore, it is important to know who is transporting the waste and who is disposing of the waste to make sure it is completed properly.[3]

Under Section 102 and 103 there are reporting requirements for the release of hazardous substances into the environment unless it is authorized by a permit. The

reportable qualities listed in the 40 CFR 302.4 names 700 chemicals and their reportable quantities.

Clean Air Act (CAA)

The Clean Air Act of 1970 authorized the EPA to control hazardous pollutants, which were defined as those which may cause or contribute to an irreversible or incapacitating illness.[1] The EPA established a national air permit system for regulation of air emission sources.[1]

The Clean Air Act Amendments of 1990 (CAAA) will bring about significant changes in the way air quality is managed. There have been over 200 federal regulations created from the CAAA. These regulations can be broadly categorized as follows:[9]

- Non-attainment provisions - planning and controls will be required of those geographic areas which have not attained the air quality standards.
- Air toxics - major sources of air toxics will be required to install maximum achievable control technologies (MACT) for the new expanded list of 189 air toxics by 1997.

- Operating permits - large sources, starting in 1995, will be required to obtain detailed federal operating permits for toxic air pollutants.
- Outer Continental Shelf - jurisdiction over OCS air emissions has been transferred from the Minerals Management Service (MMS) to the EPA, except in the central and western Gulf of Mexico.

Each of the above types of regulations are discussed, relating their effects on E&P operations:

Non-Attainment Areas

In certain geographic areas of the country where current air quality standards are not being met, the states are required to adopt control requirement regulations and new source emission standards to attain the air quality standards.

Some of the pollutants listed in the current air quality standards include oxides of sulfur, nitrogen; CO, lead, particulates and ozone-depleting substances.

The CAAA established a new approach to obtain compliance in non-attainment areas. This new approach sets five new ozone classifications with deadlines for each. These regulations, probably will have the most significant effect on the E&P industry. Table 1.2 lists the ozone non-attainment classifications.[9]

Table 2.2

Ozone Classifications for Major Sources and their Attainment Deadline[9]

"Major" Source		
Classifications	Definition tpy	Attainment Deadline year
Extreme	10	2,010
Severe	25	2,007
Serious	50	1,999
Moderate	100	1,996
Marginal	100	1,993

Source: 9

The majority of E&P operations affected by these non-attainment regulations are in California. Even in California, impacts will be in a few areas because most E&P operations are outside heavily-populated areas.[9]

Air Toxics

The regulation of air toxics was dramatically changed by the CAAA. The previous regulations, called National Emissions Standards for Hazardous Air Pollutants (NESHAPS), were apparently too slow and cumbersome for Congress. Therefore, the current technology-based framework, which included requirements for 189 air toxics, was established. Table 2.3 lists some of these Air Toxics. The existing air quality does not affect the air toxic regulations, unlike the non-attainment

regulations. Major sources defined as 10 tons per year of any one air toxic or 25 tpy for any combination are required to install maximum achievable control technology (MACT). For new sources, MACT should be the best achieved in practice and the best 12 percent for existing sources retrofit.[9]

One provision of the CAAA which is significant to E&P operations is stated as follows: "... emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources ..." 42 U.S.C.7412(n)(4).[9]

The provision is obviously of benefit to the E&P industry because most well equipment and small production facilities would not meet the major source definition if evaluated separately.

Table 2.3

Partial List of Air Toxics (Hazardous Air Pollutants)

Acrolein	Asbestos	Benzene
Carbon disulfide	Chlorine	Cresols
Diethanolamine	Ethylbenzene	Ethylene glycol
Formaldehyde	Hexane	Hydrochloric acid
Methanol	Naphthalene	Toluene
Xylenes	Lead compounds	Mercury compounds
Polycyclic organic matter		Radionuclides

Source: 9

The EPA will define the MACT for each industry type over the next 10 years. It is expected that the E&P industry will have a defined MACT by 1977. From the time the MACT is defined, operators will have 30 months to comply.[9]

The types of E&P equipment which are expected to be affected by the Air Toxics regulations include large glycol dehydrators, gas plant units, and light oil stock tanks.

Operating Permits

The CAAA also dramatically changed the permitting process and increased federal involvement in this process. For the first time, E&P sources will have to obtain federally-enforceable operating permits for stationary sources, instead of just construction permits. The permit program will apply to major stationary sources as indicated in Figure 2.1.

Most E&P sources will have to apply for these permits, starting in 1995. Common elements of the permits include:[9]

- A compliance plan and certification requirement
- Monitoring inspection and reporting requirements
- Fixed term of the permit not to exceed five years
- A "reopener" provision if the regulations change

The most significant impact of the permitting process is expected to be in the process of obtaining one which will take up to 18 months, which would cause indirect costly delays or lost opportunity.

Major Stationary Sources

* 100 tpy of any regulated pollutant (using standard emission factors, a 250-hp compressor would emit 25+ tpy of NOx)
* 50, 25, or 10 tpy of VOCs in serious, severe, or extreme ozone non-attainment areas
* 50 tpy CO in serious CO non-attainment areas
* 70 tpy PM in serious PM non-attainment areas
* 10/25 tpy of any/all air toxics

Other sources requiring a permit: sources subject to New Source Performance Standards, NESHAPS, the acid-rain provisions of the CAA, or those the EPA designates by regulation.

Figure 2.1 Thresholds for Needing a Federal Operating Permit

Source: 9

Outer Continental Shelf

The jurisdiction of control of the OCS has been transferred from the MMS to the EPA, except for the central and western Gulf of Mexico. Activities in areas within 25 miles of shore will essentially be under the same regulations as onshore facilities. The MMS has until November 1993 to complete a study determining the effects of OCS emissions on onshore ozone and non-attainment areas to determine if any additional actions are required.

Naturally Occurring Radioactive Materials (NORM)

NORM are present in oil and gas operations in some areas. NORM are usually found in scale which forms on surface piping, production tubing, vessels, pumps, and other production or operating equipment. NORM are usually brought to the surface by produced water. As the produced water comes to the surface, the temperature drops causing precipitates to form. The scale and sludge which form from the precipitates can contain NORM. Figure 2.2 shows a survey on NORM conducted on production facilities in the U.S. This figure only indicates the probability of finding NORM in a certain areas. NORM may exist in higher or lower concentrations than shown.[10,11]

There are no specific federal regulations yet which address the potential problems NORM may cause, other than the regulations which apply generally to other radioactive material. Louisiana and Mississippi have created regulations for NORM. Other states are working on regulations expected to be released in the near future. However, OSHA regulations permit occupationally-exposed employees to receive a maximum radiation dose of 1250 millirem per quarter. Personnel are required to use personal dosimeters in areas where more than 312.5 millirem per quarter is expected. This equals 600 microrem/hr for a 40 hour work week. Typically, work area radiation levels are far below this exposure limit. However, for airborne NORM the limit is 5×10^{-11} microcuries per milliliter for insoluble radium and 2×10^{-10} microcuries per

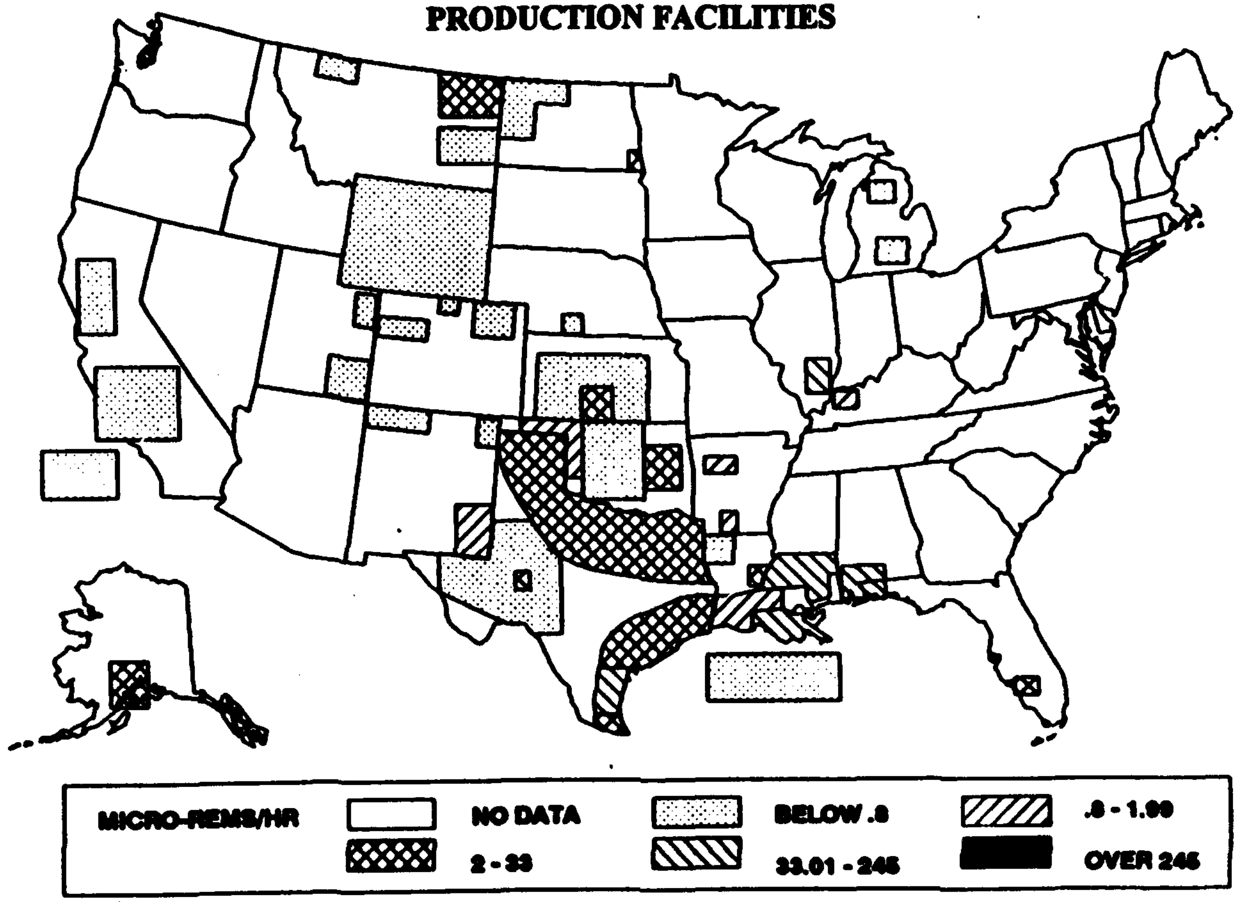


FIGURE 2.2
API NATIONAL SURVEY ON NORM -- 1989
PRODUCTION FACILITIES
(Values Shown are the Median of Readings Less Background)
Source: 11

milliliter for lead - 210 which are the two common occurrences of NORM in an oil field.[11]

Endangered Species Act (ESA) of 1973

The ESA establishes a national policy aimed at protecting threatened or endangered species and the ecosystem which they depend on for their survival. The "taking" of endangered species or harassing or forcing it away from its natural habits is prohibited under this Act. Willful violation is subject to criminal punishment.[3]

The listing of an endangered species may be initiated by petition of any person requesting review by the Secretary of the Interior of the status of a species of wildlife or plant.[3]

REFERENCES

1. Naval Energy and Environmental Support Activity. Hazardous Waste Facility Managers Course, Niagara Falls: Waste Resource Associates, Inc., 1986.

2. Rappold, Keith. "Drilling Wastes Require Extra Attention." Oil & Gas Journal December 16, 1991. (pp. 5657)

3. Brown, C.W. "It's Not Business as Usual Anymore." Environmental Considerations SPE Reprint Series, No 37, Richardson: SPE, 1992. (pp. 133-137)

4. SOLID WASTE: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy. Report to Congress, December 1987, EPA/530-SW-88-003, Washington: U.S. Environmental Protection Agency, 1987. (pp. 6, 7, 9, 48)

5. U.S. Environmental Protection Agency. Regulatory Determination for Oil & Gas & Geothermal Explorations Development and Production Wastes; Regulatory Determination; Federal Register. Vol. 53 No.129, July 6, 1988, Washington: U.S. Government Printing Office, 1988. (pg. 25446)

6. U.S. Interstate Oil Compact Commission. EPA/IOCC Project on State Regulation of Oil & Gas Exploration & Production Waste. December 1990, Oklahoma City: Interstate Oil Compact Commission, 1990, (pp. 1, 2, 46)

7. Smith, S.B. Browning, L.A. "Proposed Changes to EPA Class II Well Construction Standards and Area of Review Procedures." Presented at the SPE/EPA Exploration and Production Environmental Conference of the Society of Petroleum Engineers in San Antonio, Texas, 7-10 March 1993.

8. Mortis, Guntis. "Producers Modify Activities as Threat of New Rules Looms." Oil & Gas Journal December 16, 1991. (pg. 53)

9. Tulloh, Brian. "Uncle Sam's Plans for You." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Colorado, August 1992.

10. Gray, P.R. "NORM Contamination in the Petroleum Industry." Journal of Petroleum Technology, January 1993. (pp. 12-15)

11. Bulletin on Management of Naturally Occurring Radioactive Materials (NORM) in Oil & Gas Production. American Petroleum Institute. Washington D.C., April 1992. (pp. 10, 14, 15)

CHAPTER III

E&P ACTIVITIES THAT GENERATE WASTES

In Chapter II, a brief overview of the environmental regulations affecting the oil and gas exploration and production industry was given. In this Chapter, the common operations in the E&P industry which lead to generation of regulated wastes or regulated activities are discussed. The primary activities associated with E&P are gas plants, production facilities, drilling and workovers.[1]

Gas Plants

Natural gas plants provide centralized dehydration, compression, sweetening, and extraction of LPG such as ethane, propane and butane. The raw natural gas stream generally contains small amounts of LPG and may also contain other compounds, such as carbon dioxide, hydrogen sulfide, mercaptans, water, sand and other impurities. The natural gas stream, if treated to remove the impurities, then goes through extraction to remove the LPG and heavier hydrocarbons. There are five common extraction and treating processes used in gas plants which include:

Inlet Separation and Compression

Gas is gathered throughout the producing field and gathered at the inlet of the gas plant. At the inlet, a separator is used to separate produced water and liquids from the gas. Also, the gas may have to be compressed to bring the pressure to that

required for the plant. Wastes produced are production water, pigging material, filter materials, corrosion treatment fluids, engine cooling water, lubrication oils and filters for the compressor and NORM.[1]

Dehydration

All natural gas contains a certain amount of water vapor. The vapor content must be reduced to a certain level before the gas is allowed to enter a pipeline. This vapor limit is indicated in a sales contract.[1]

The typical method for dehydration is to contact the water vapor with liquid or solid desiccants. Some liquid desiccants include ethylene, diethelyne or triethylene glycol. These desiccants absorb the water vapor out of the natural gas. Then the desiccant is removed from the production stream and heated to boil off the water vapor. Since the boiling point of the desiccant is higher than water, the desiccant remains a liquid. Once the water vapor has been removed, the desiccant is recycled into the production stream to extract more water vapor. The solid desiccants generally are tower vessels filled with aluminum silica gel or silica alumina beads or a molecular sieve which absorbs the water vapor.[1]

Wastes generated are glycol-based fluids, glycol filters, condensed water and solid dessicants. These materials may contain trace amounts of hydrocarbons as well.

Sweetening/Sulfur Recovery

As indicated earlier, natural gas may contain certain impurities such as carbon dioxide, and hydrogen sulfide. These impurities and any others must be removed to meet the requirements of the sales contract. The process of lowering the concentration of carbon dioxide and hydrogen sulfide is call sweetening. Hydrogen sulfide is removed by contact with amine, sulfinol, iron sponge, caustic solutions and other sulfur converting chemicals. Heat is used to regenerate amine and sulfinol. However, iron sponge and caustic solutions are spent in the process. Almine treating is probably the most widely used process. Wastes generated are water vapor, regeneration gas, spent amine, used filters, acid gas, spent caustic solutions, spent iron sponge, and NORM.[1]

NGL Recovery

NGL recovery is the process of extracting hydrocarbons such as butane and propane. This process is carried out by compression and/or cooling, absorption, or cryogenic processes. These processes either absorb heavier molecular compounds with an absorption oil which is recycled or separate fractions of different boiling points through temperature and pressure variations.[1]

Wastes generated are lubrication oils and filters, spent absorption oils, waste water, cooling tower waters, boiler blow down waters, and NORM.

Production Facilities

Production facilities collect oil and gas from production wells and prepare them for sale. Purchasers have standards for the oil and gas that they will accept. Oil standards typically allow one percent basic sediment and water. Similiar limitations for gas include water, hydrogen sulfide, carbon dioxide and BTU content. Common wastes generated at production facilities are:[1]

- Production Wells - Paraffin, contaminated soil, used gear box oil.
- Flowlines - Scales, paraffin, NORM
- Separators - Produced water, bottom sludges and solids, NORM
- Heater Treaters - Produced water, bottom sludges and solids, absorption material
- Oil Stock Tanks - Produced water, bottom sludges and solids

Drilling Operations

Wastes generated during drilling operations include rig wash drilling muds, cuttings, cement returns, household rubbish, used hydraulic and lubricating oil, unused chemical products.

Completions and Workovers

Wastes generated during completions and workovers include hydraulic and lubricating oil, weighting agents, surfactants, produced water, acids, inhibitors, gels, and solvents.[1]

REFERENCES

1. API Environmental Guidance Document. American Petroleum Institute Production Department. Washington D.C., 1989. (pp. 20-33)

CHAPTER IV

MANAGEMENT PRACTICES FOR ENVIRONMENTAL CONCERNS

Chapter Three indicated the common E&P operations and the wastes they generate. In this chapter, some of the practices used to manage these wastes in accordance with current regulatory requirements are discussed. Also, other regulatory requirements related to the environment are reviewed, such as audits, and risk analysis in Purchase/Sale of Property.

Produced Water

Produced water originates from the producing formation or from supplemental water used in enhanced recovery operations, such as water flooding and steam flooding. The quality of this produced water is dependent upon the nature of the producing formation and the time the field has been producing.[1]

The primary issue in managing produced water is the potential for contamination of soil, vegetation and sources of usable water. The following practices are used to manage produced water, and the particular practice selected depends on the composition of the produced water, presence of usable ground or surface waters, geography, and regulations that apply to that specific area.[1]

Underground Injection

Underground Injection - As stated in chapter two, the regulations applying to this practice is covered under the Class II injection program of the UIC program as authorized by the SDWA.[1]

Discharge to Water - Discharge to surface waters is allowed under certain circumstances. The NPDES of the CWA or state programs set the criteria for this practice.[1]

Discharge to Land - Percolation or evaporation is allowed where fresh water is not present or in an area where contamination by produced waters cannot occur.[1]

Drilling Waste

Drilling Fluids - As indicated in Chapter II, federal regulation consider drilling fluids as exempt wastes. However, drilling fluids must still be managed in such a way as to prevent contamination of soil, usable ground and surface waters.[1]

In environmentally-sensitive areas such as wetlands, closed loop mud systems are required by some states. Whenever possible less toxic additives are used to decrease the toxicity of the drilling fluid. Table 4.1 indicates some additive substitutions which result in a less toxic mud system. Appendix A includes a list of additives approved by the California Dept. of Health Services.

Table 4.1

Additive Substitution Used for Reducing

the Toxicity of Drilling Fluids

Generic Additive	Toxicity	Use	Substitute
Chrome Lignosulfonate/Lignite	chromium	thinner	(a)
Sulfomethylated tannin/ dichromate	chromium	thinner	(a)
Sodium dichromate/ chromate	chromium	corrosion control	(b)
Zinc chromate	chromium	H_2S control	(c)
Pentachlorophenol	pentachioropehenol	biocide	(d)
Paraformaldehyde	formaldehyde	biocide	(d)
Arsenic	arsenic	biocide	(d)
Lead-base pipe dope	Lead	thread sealant/ Lubricator	(e)
Barite	cadmium/mercury	densifier	(f)

(a) use polyacrylate and/or polyacrylamide polymers

(b) use sulfites, phosphonates, and ames

(c) use non-chromium H_2S scavengers

(d) use isothiazoline, carbamates, and gluteraldehydes

(e) use non-Lead pipe dope for casing (teflon-base additives that meet API specifications), and use non-Lead base drill pipe when it becomes available

(f) choose barite from sources that are low in cadmium and mercury

Source: 1

Non-exempt and potentially hazardous drilling waste are not allowed to enter reserve pits, otherwise contamination of the fluids could result in loss of the exemption. Drilling personnel are being properly trained to recognize and manage these wastes in accordance with state and federal regulations.

As an example of what not to do, in the past, a common practice often occurring on a drill site after completion of the well would be to dispose of unused materials such as broken sacks of mud additives or solvents into a drill pit.[2] Another common practice was to place used motor oil into an oil-based mud.[2] All of these practices could lead to declaring the contents of the entire reserve pit as hazardous waste if, in fact, those materials that were placed in the pit were hazardous wastes.

Instead of having to properly dispose of a few hundred pounds of hazardous waste, possibly many barrels of hazardous waste have been generated. Also, the site could be declared a non-permitted hazardous waste disposal site. Most of these environmental regulations can carry criminal prosecution and stiff fines for every day the regulations are violated, in addition to the cost of having to clean up the site.

Even if the current federal and state regulations are being met, that still does not exempt the generator from CERCLA.[2] As an example, a drilling pit was properly closed after finishing a well under current environmental regulations. However, two years later the EPA received a complaint about the drinking water near the location of the closed pit. After an initial investigation, if the EPA has a reason to suspect that the contamination was coming from the pit, the EPA can require the generator of that pit to pay for an investigation and cleanup.[2]

Most companies now insist that service or contract companies be responsible for removing any remaining materials they bring to the site.[3] Some hydrocarbon liquids are mixed into the production stream for sale.[3]

Where practical, drilling pads are being designed to contain storm water and rig wash off. Storm water run off outside the pad is directed away from the pad. Catch areas are constructed so that lubricating and hydraulic oils do not enter the reserve pit. Reserve pits are lined if salt or oil-based muds are used. Recycling of oil -based or high-density brines is now becoming economical in lieu of disposal.[1]

Living quarters waste and sewage should be collected and treated in accordance with state and local effluent requirements. Solid wastes, such as garbage, paper, etc. should be disposed of in accordance with state solid waste regulations.

Empty drums are recycled when possible. Any acute toxic chemical drum requires triple rinsing under current federal regulations before disposal. Non-acute

chemical drums must be empty before disposal. Empty generally means no more than one inch of the chemical left in the bottom. However, state regulations should be reviewed before using this practice. Unused chemicals are used at the next location, returned to the vendor, or disposed of according to RCRA regulations if they are hazardous wastes when disposed.[1]

Workover and Completion Waste

Exempt workover wastes include well completion, treatment, and stimulation fluids; inert material from down-hole, such as produced formation sand, pipe scale, and cement cuttings. Drilling rig or work-over rig wastes such as used oils hydraulic fluids paint, etc. are not exempt.[1]

Workover fluids are primarily fresh water or produced water-based fluids with additives included for special purposes. Some additives include acids, biocides, surfactants, paraffin solvents and dispersants. As with drilling fluids, work-over fluids should be managed to protect soil, usable ground water and surface water.[1]

When possible, these fluids are returned to the production facilities for disposal or reprocessing or, if regulations allow, they may be collected in pits.

Tank Bottoms

Tank bottoms are basic sediment and water that contain heavy hydrocarbons, solids, sand and emulsion. EPA considers these wastes as exempt wastes. Heat is used to dissolve the heavy precipitated hydrocarbon into the crude stream. Dispersants are used to segregate water from crude. For those heavy hydrocarbons that do not dissolve into the production stream, the remaining options include disposal, land spreading and road spreading.[1]

Contaminated Soils

"Hydrocarbon-bearing" soils are also exempt wastes. Exempt contaminated soil that is to be reclaimed to allow revegetation generally responds well to biodegration of the hydrocarbons. This is a tried and proven method of remediation. Disking and mixture with other soils will usually provide the impetus for biodegration to occur. Note that contaminated soil, due to a spill of a commercial chemical product, may be subject to RCRA subtitle C and CERCLA reporting requirements.[1]

Used Oil and Solvents

Used oils and solvents are generated as described earlier from gas plants, drilling rigs and work-over rigs, etc. Although the EPA did not specifically address

the recycling issue, current EPA regulations allow recycled oil to be reintroduced into the crude stream if it is to be processed at a refinery.[1]

An exception would be oil contained in electrical components which may contain PCBs. PCBs are managed under the Toxic Substance Control Act (TSCA).[1]

NORM

Thorium -232 and Uranium -238 are found in the earth's crust almost everywhere. The concentrations vary widely. However, the solubility of these two radio nuclides is very low, even at elevated temperatures. However, once these undergo decay other products created may be quite soluble. Therefore, NORM seen at the surface are these decayed products of Uranium and Thorium. Figure 4.1 shows the decay of Uranium -238. The most common NORM found in oil and gas E&P operations is Radium -226, Radium 228, Radon -222 and Lead -210. As can be seen from its half life in Figure 4.1 Radium -226 represents the most significant health or environmental risk. NORM emits alpha, beta and gamma radiation. Alpha radiation is a particle type radiation, big and slow, not capable of penetrating clothing. Beta is also a particle radiation. However, it is much smaller and moves much faster and is capable of penetrating human tissue. Gamma radiation is of wave form with extremely high energies, capable of penetrating several inches of steel.[4]

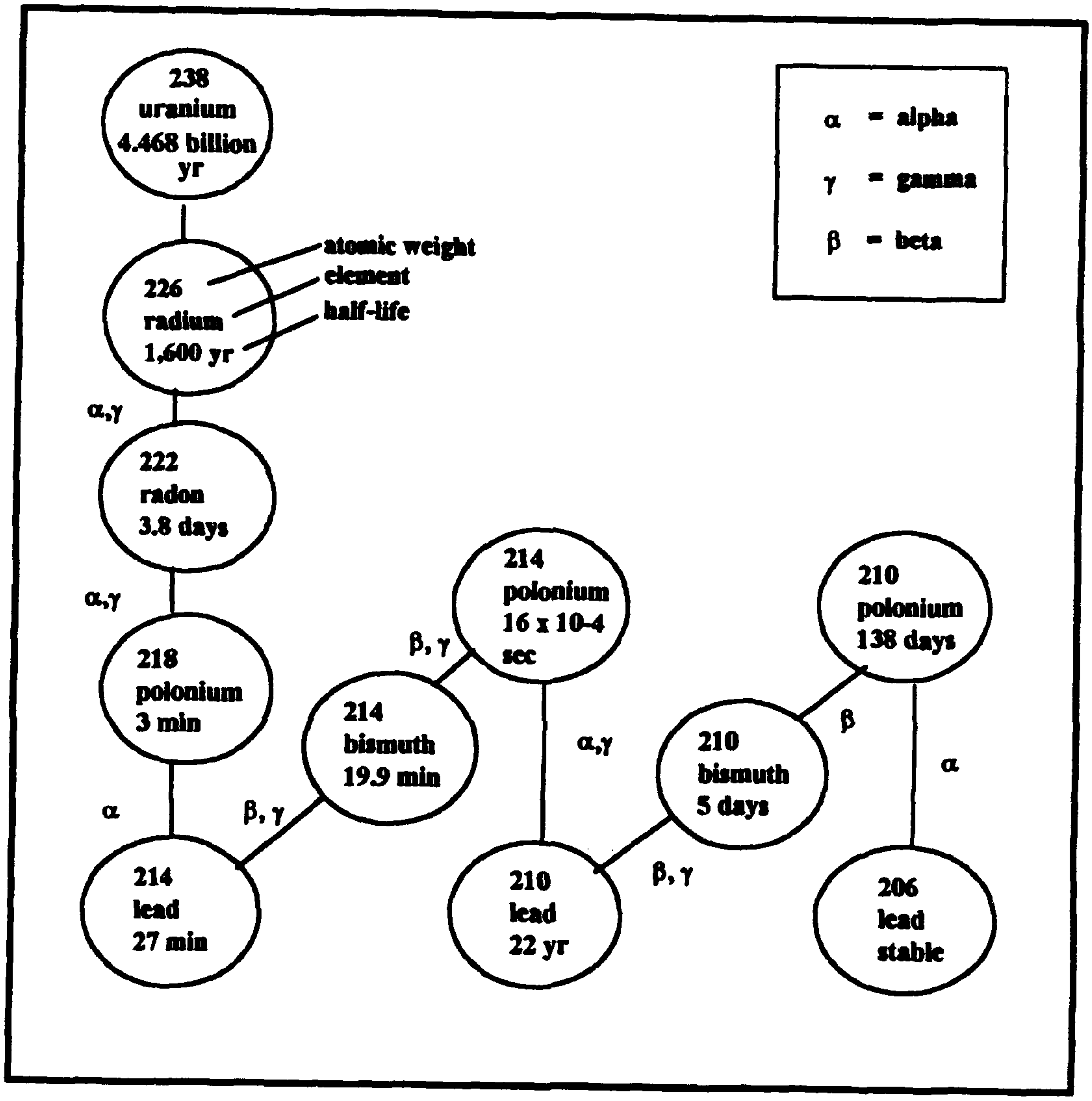


Figure 4.1 Radioactive decay of uranium - 238.
Source: 4

Radon has a boiling point that is in-between those of ethane and propane. Therefore, when Radon-contaminated produced gas is processed to extract the LPG, radon will accumulate in the LPGs. However, since the half life of Radon gas is 3.8 days, 99 percent of the radon will have decayed into lead -210 by the end of 30 days. Therefore, radon does not usually pose any significant health risks as long as it is contained in the vessels, equipment and piping.[4]

Once radon decays, as seen in Figure 4.1 lead -210 is formed. This lead continues to accumulate on the walls of vessels, piping, and other equipment during the life of the production facility. Personnel who inspect the insides of these equipment facilities should take particular care to prevent exposure. Safe work practices include purging of vessels, to remove gas and use of appropriate respiratory protection when working inside vessels, or in any way disturbing the inner walls of NORM-contaminated equipment.[4]

NORM Disposal

As was stated earlier, the regulations concerning NORM have only recently come into existence. The EPA is considering enacting NORM regulations at the federal level. States, such as Mississippi and Louisiana, have specific guidelines for the management of NORM wastes and NORM-contaminated materials. Louisiana has required a NORM survey of all oil and gas production facilities. In these states,

NORM is managed similar to RCRA hazardous wastes, with a continuous paper trail and specific training of personnel handling NORM is required.

Audits for Purchase/Sale of Property

Under CERCLA, anyone involved in activities related to a property that has been found to be contaminated can be held liable for the cleanup of that property, even if the contamination was caused by someone who had owned the property previously. In 1986, under the Superfund Amendments and Reauthorization Act (SARA), the "innocent land owner defense" was established, to protect innocent purchasers of property later found to be contaminated.[5]

To take advantage of the "innocent landowner defense" under CERCLA, the purchaser or potentially responsible party (PRP) must establish that it did not know or had no reason to know that the property was contaminated. To established that it did not know that the property was contaminated, it must have at the time of purchase or acquisition, performed an appropriating inquiry into the previous uses of the property, consistent with good commercial and customary practice. This appropriate inquiry depends on each particular case. However, no law nor its legislative history mandates that soil or ground water samples be taken. Generally, appropriate inquiry starts with a phased approach to due diligence.[5]

Although, there are no zero risk property transactions, risk can be significantly reduced by performing an appropriate environmental audit. Most audits are conducted in two phases. Phase I is to determine whether sufficient information is available to evaluate a property's environmental status and history. This is accomplished by an information audit which includes researching the documented history of the property and interviewing persons knowledgeable about the property's history. Phase I also includes a site inspection; established checklists or protocols are used to insure all appropriate issues are covered. If the Phase I audit indicates there is little risk to the company, the audit is usually considered complete. However, if there are obvious problems, or an indication that problems may exist, the company may discontinue or modify the transaction or initiate a Phase II audit.[5]

A Phase II audit is generally performed by a contracted expert. A Phase II audit is a detailed environmental review including, soil samples, ground water samples, building material samples, or any other analysis technique required for the determination of the full extent of contamination of any facility or other environmental problems.[5]

REFERENCES

1. API Environmental Guidance Document. American Petroleum Institute Production Department. Washington D.C., 1989. (pp. 34-42)

2. Candler, John. "Environmental Rules Make Scrutiny of Work Practices a Must." Oil & Gas Journal April 22, 1991. (pp. 83, 84)

3. Mortis, Guntis. "Producers Modify Activities as Threat of New Rules Looms." Oil & Gas Journal December 16, 1991. (pg. 53)

4. Steingraber, Buck. "New Challenge from Old Earth." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Colorado, October 1992.

5. Curtis, B.W. and Kirchof, C.E. "Purchase/Sale of Property: The Black Hole of Corporate Liability Ways to Minimize Risk." Presented at the SPE/EPA Exploration & Production Environmental Conference of the Society of Petroleum Engineers in San Antonio, Texas, 7-10 March 1993.

CHAPTER V

PENDING LEGISLATION AND ITS LIKELY ECONOMIC IMPACT

Some of the pending legislation in Congress has made nearly all major producers and large independents evaluate their E & P operations within the U.S.

Congress has approved Outer Continental Shelf (OCS) moratoria in Interior Department funding legislation for the last eleven years, increasing acreage under the moratoria almost every year. The moratoria for FY92 places most of the Atlantic and Pacific coasts off limits to leasing.[1]

U.S. offshore moratoria continue to inhibit exploration of many promising finds in the outer continental shelf (OCS).[1] There were four bills introduced into the 102nd Congress calling for marine sanctuary designations.[1] Sanctutorial designation has been sought through legislation, often including permanent denial to oil and gas resources.[1]

The 1990 amendments to the Clean Air Act include proposed changes in the OCS air emissions regulations. Under the proposed regulations, facilities within 25 miles of the shore would have to meet the same local, state and federal requirements as adjacent onshore facilities. Offshore facilities beyond 25 miles would only be subject to federal regulations.[1] The EPA estimates the cost of compliance to be $2.2 million per year.[2]

In 1986, EPA issued an audit policy which has an objective to encourage companies to implement audit programs.[1] While the EPA said it would not routinely request audit information, it reserved the right to use audit results on a case-by-case basis during criminal proceedings and enforcement.[1]

Reauthorization of the Clean Water Act has been the subject of a number of hearings in the 102nd Congress.[1] Legislation has been introduced that will tighten restrictions on discharges and strengthen the role of state water quality standards.[1]

Reauthorization of RCRA has been one of the top priorities of Congress. The primary focus of this reauthorization is reduction and recycling of both industrial and non-hazardous solid wastes.[1] E & P wastes continue to be an issue.[1]

In the 101st Congress, more than 50 bills were introduced to address the problem of wetland loss in the United States.[1] Permits to construct drilling and production locations have become a regulatory nightmare in wetlands.[3] Permitting can now take up to 12 months and do not allow for discharge of drill cuttings.[3]

The Oil Pollution Act (OPA) of 1990 requires operators of vessels and production platforms to establish evidence of financial responsibility to meet statutory defined liability limits.[1] The limit is $75 million plus unlimited removal costs for platforms.[1] The OPA did not exempt the state's rights, allowing individual states to maintain authority to impose unlimited liability on spillers.[1] The Act also allows direct legal action against the insurer.[1] It is believed that, because of this feature, insurance

will be hard if not impossible to find to cover the liability.[1] These coverages are eight times greater than was previously required.[4]

In December of 1990, a study was released by the Department of Energy (DOE) concerning the cumulative effects of legislative and regulatory initiatives being considered to protect the environment.[5] Production from four categories were evaluated: 1) Continued conventional operations in known onshore fields in the Lower 48 states; 2) Infill drilling and water flood projects in known onshore fields in the Lower 48 states; 3) Future EOR projects in known onshore Lower 48 fields; and 4) Onshore and offshore crude fields remaining to be discovered.[5,6]

The assessment involved a review of selected environmental initiatives under the authority of Resources Conservation and Recovery Act, Safe Drinking Water Act, Clean Water Act, and Clean Air Act.[5,6]

Impacts on current and future production were estimated by using the Tertiary Oil Recovery Information System and Replacement Costs of Crude Oil (REPCO) Supply Analysis System maintained by DOE's Office of Fossil Energy.[5,6] The assumptions for each scenario are listed in Tables 5.1 through 5.4.[5,6]

Figure 5.1 shows the impacts of the scenarios listed in Tables 5.1 through 5.4 at an average price of $20/Bbl, for nine states corresponding to 75 percent of the remaining oil in place in the Lower 48 states.[5,6]

TABLE 5.1

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Resource Conservation and Recovery Act

	Regulatory Initiative	Regulatory Scenario: Low	Regulatory Scenario: Medium	Regulatory Scenario: High
1.	Management and Disposal of Drilling Waste	Oil-based muds disposed into lined pits Salt water-based muds disposed into lined pits	Oil-based muds use closed systems Salt water-based muds disposed into lined pits	Oil-based muds use closed systems All water-based muds disposed into lined pits
2.	Disposal of Associated Wastes into Central Disposal Facilities	Liquid wastes into offsite disposal well; solid wastes into nonhazardous waste landfill	Liquid wastes into offsite disposal well; solid wastes into hazardous waste landfill	Liquid wastes into offsite disposal well; combustible solid wastes into incinerator; non-combustible solid wastes into hazardous waste landfill
3.	Upgrading Emergency Pits	All emergency pits must be lined.	Existing emergency pits must be lined; new pits must be replaced with tanks	Tanks must replace emergency pits for both new and existing pits
4.	Replace Workover Pits with Portable Rig Tanks	Required on all rigs	Required on all rigs	Required on all rigs
5.	Organic Toxicity Characteristic Test	Applied to all facilities and new wells	Applied to all facilities and new wells	Applied to all facilities and new wells
6.	Corrective Action (Soil Remediation Only)	Land treatment of hydrocarbon contamination at 50% of tank batteries and EOR projects*	Excavation of salt water contamination at 100% of SWD wells and 75% of EOR projects* and tank batteries Land treatment of hydrocarbon contamination at 50% of tank batteries and EOR projects*	Excavation of hydrocarbon and salt water contaminated sites at same frequency as Medium Scenario

* EOR projects refers to both secondary and tertiary recovery projects

SOURCE: 5

TABLE 5.2

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Safe Drinking Water Act

Regulatory Initiative	Regulatory Scenario: Low	Medium	High
1. Mechanical Integrity Testing*			
Part 1	No incremental requirements (5-year pressure test)	Pressure test frequency based on corrosive potential of basin	Continuous positive annular pressure monitoring and 5-year pressure test
Part 2	Radioactive tracer test every five years	Radioactive tracer test and noise or temperature log run to injection zone, frequency based on basin corrosivity	Radioactive tracer test, noise, and temperature log run to injection zone, frequency based on basin corrosivity
Non Injection-Related Fluid Movement	No incremental requirements	Oxygen activation log and noise or temperature log run to lowermost underground source of drinking water.	Oxygen activation, noise, and temperature log run to lowermost underground source of drinking water
2. Area of Review (on wells drilled prior to 1984)	No incremental requirements	1/4 mile area of review (AOR) under area permit	1/4 mile area of review (AOR) under individual injector permit
3. Corrective Action (on wells drilled prior to 1984)	No incremental requirements	5% of producing wells within AOR assumed to require remedial squeeze	15% of producing wells within AOR assumed to require remedial squeeze
		10% of abandoned wells within AOR assumed to require reentering and replugging	30% of abandoned wells within AOR assumed to require reentering and replugging
		1% of producing wells within AOR must be redrilled	3% of producing wells within AOR must be redrilled
4. Construction Requirements	No incremental requirements	10% of injectors require remedial squeeze	30% of injectors require remedial squeeze
		2% of injectors must be redrilled	6% of injectors must be redrilled

* MIT Part 1 addresses tubing, casing, and packer integrity. MIT Part 2 addresses fluid movement behind the casing.

SOURCE: 5

TABLE 5.3

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Clean Water Act

Regulatory Initiative	Regulatory Scenario: Low	Regulatory Scenario: Medium	Regulatory Scenario: High
1. NSPS for Offshore Discharge of Muds and Cuttings*	EPA Approach A (EPA's estimate of facilities affected and associated compliance costs)	API Partial Discharge Limitation Scenario (EPA Approach A with API estimates of compliance costs)	API Zero Discharge Limitation Scenario (API assumption that all facilities are affected, using API cost estimates)
2. NSPS for Offshore Discharge of Produced Water	Existing facilities: no change New facilities: treat to 59 mg/l	Existing facilities: treat to 59 mg/l New facilities: shallow water, no discharge; deep water, treat to 59 mg/l	Existing facilities: shallow water, no discharge; deep water, treat to 59 mg/l New facilities: no discharge all depths
3. NPDES Stormwater Permits	Required for 55% of facilities	Required for 55% of facilities	Required for 55% of facilities
4. Above Ground Storage Tanks	Only leak detection and financial responsibility for new tanks larger than 1,000 barrels	All aspects+ considered for new tanks larger than 500 barrels; financial responsibility for all tanks	All aspects+ considered for all new and existing tanks
5. Ban on Onshore Surface and Coastal Discharge of Produced Waters	No incremental requirements	Ban on discharges from new facilities	Ban on discharges from all facilities

* See EAI, 1988.

\+ Aspects of regulations include injection and integrity testing, overflow prevention equipment, leak detection equipment, additional corrosion protection, and financial responsibility requirements.

SOURCE: 5

TABLE 5.4

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

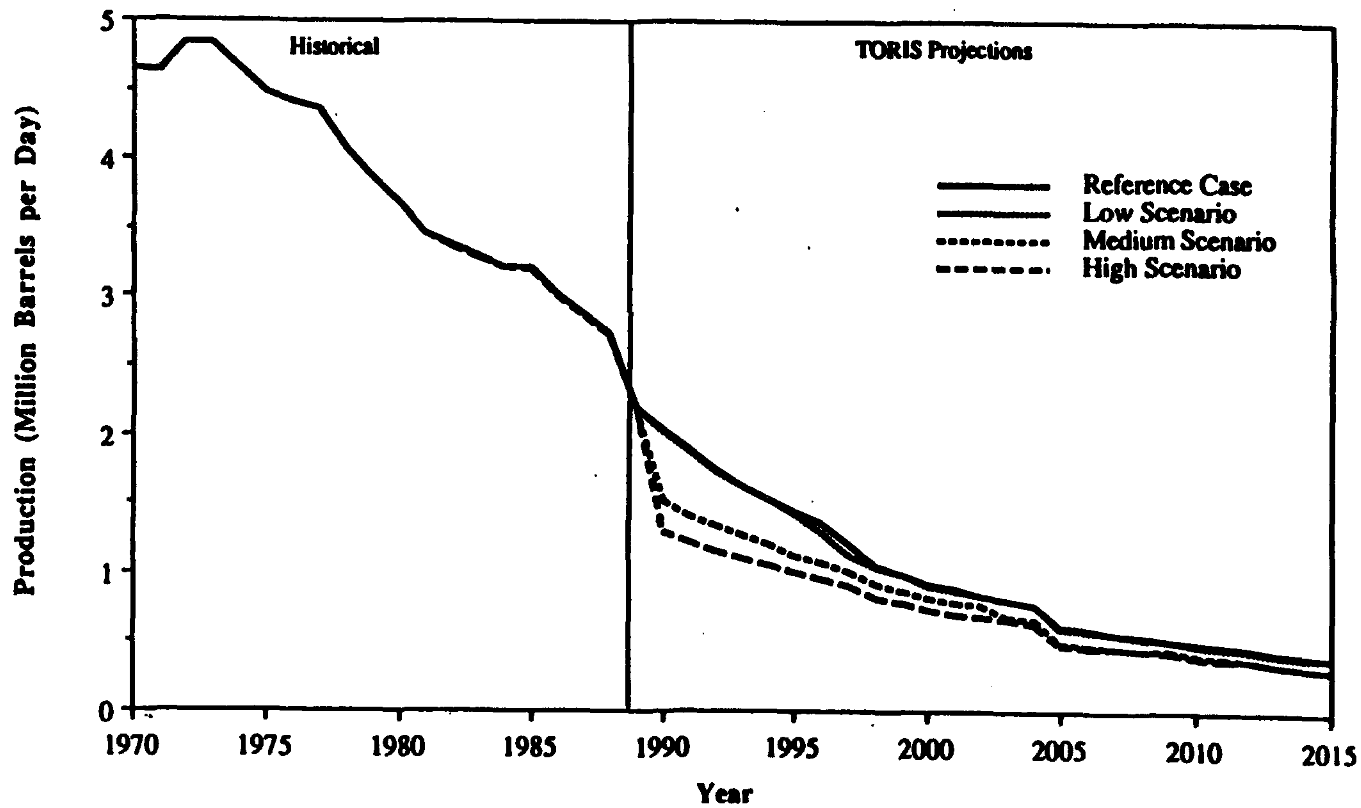
Clean Air Act

Regulatory Initiative	Regulatory Scenario		
	Low	Medium	High
1. Onshore Air Toxics Emissions Standards	API Case I scenario	API Case I Scenario	API Case II Scenario
2. Offshore Air Toxics Emissions Standards	California only; no mitigation costs considered	California only; mitigation costs considered	Entire OCS; mitigation costs fo. California only

SOURCE: 5

Figure 5.1

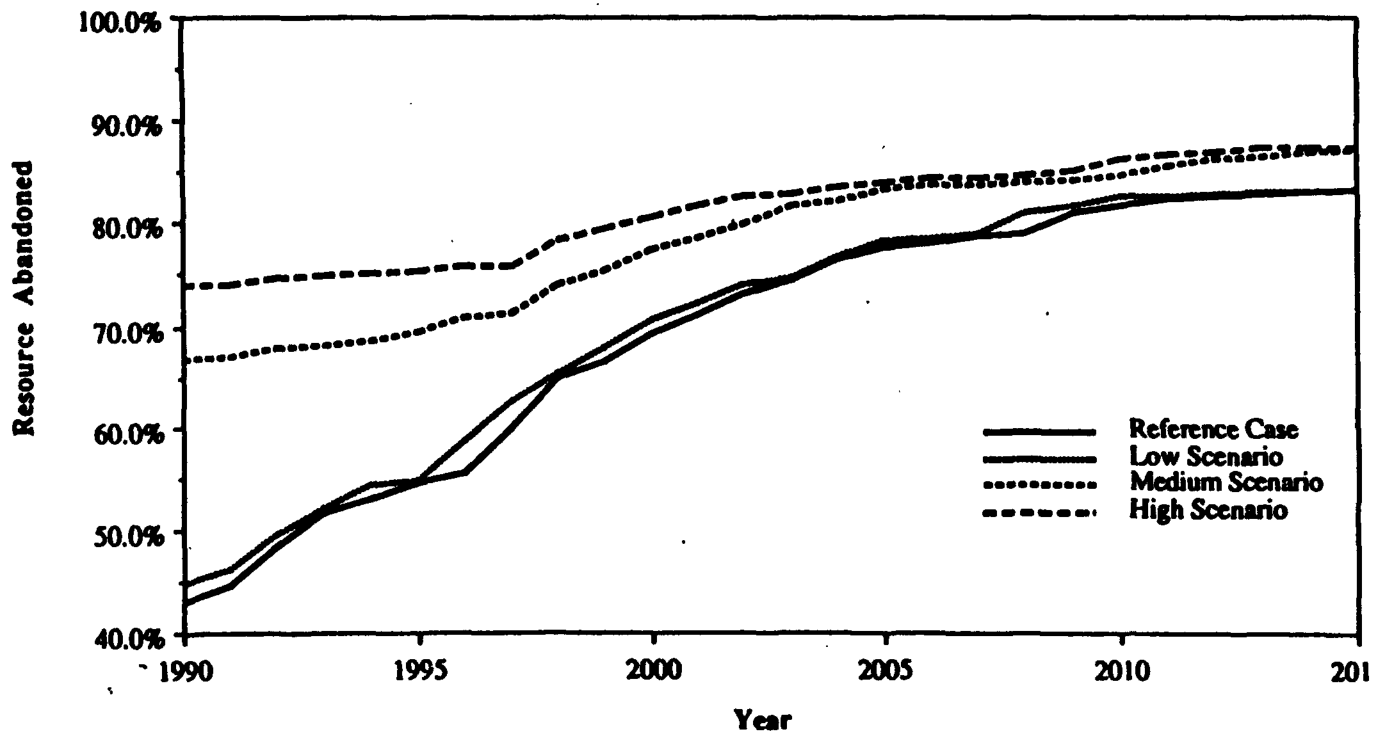
Impact of Environmental Regulations on Crude Oil Production in the Nine States Analyzed ($20/Bbl Oil Price)



Source: 5

Figure 5.2

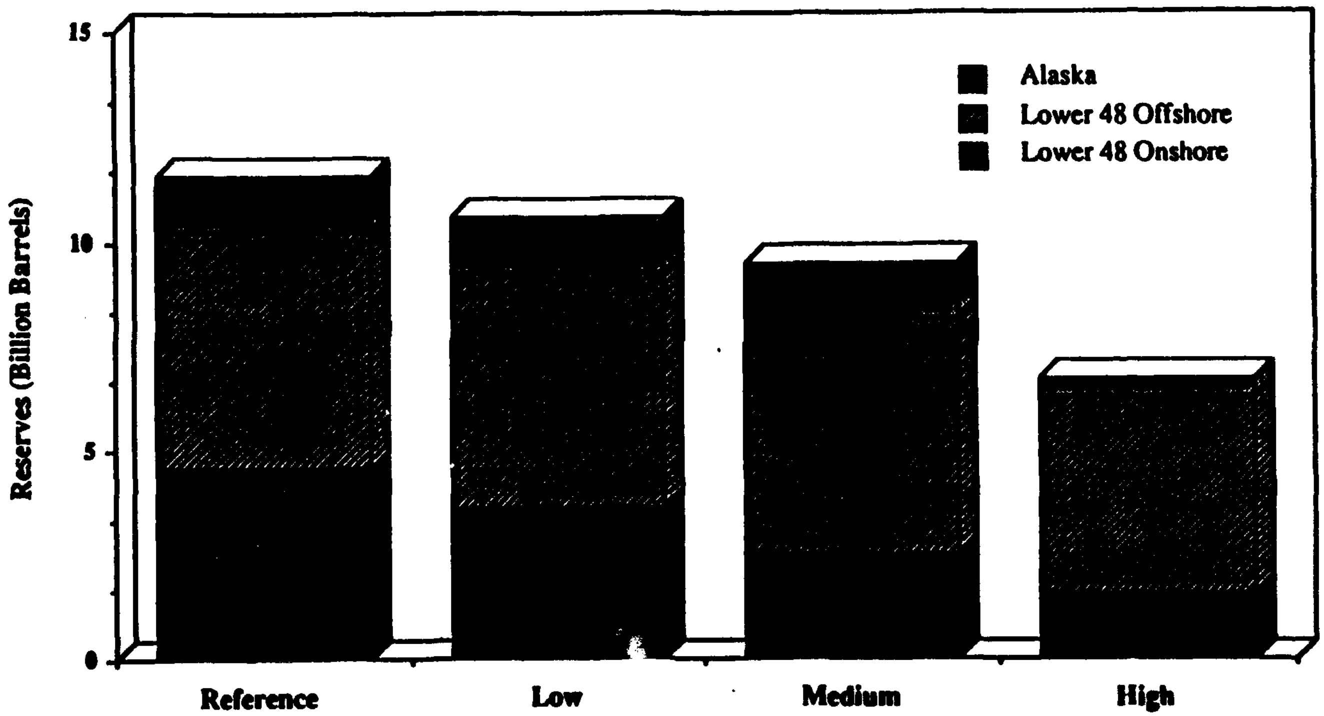
Impact of Environmental Regulations on Abandonment of the Crude Oil Resource in the Nine States Analyzed ($20/Bbl Oil Price)



Source: 5

Figure 5.3

Impact of Environmental Regulations on Undiscovered Crude Oil Reserves in the U.S. ($20/Bbl Oil Price)



Source: 5

Figure 5.2 shows abandonment rates assuming no future drilling or development of the producing reservoirs surveyed, for the mentioned scenarios.[5,6]

Figure 5.3 was based on all U.S. undiscovered reserves, including those areas under the present moratoria and the Arctic National Wildlife Refuge.[5,6]

The results of this analysis lead to the following conclusions:

1) New regulatory requirements when considered together could substantially decrease the future recovery of existing and future reserves.[5]

2) Abandonment of remaining resources in known producing oil reservoirs could be accelerated by approximately 10 years.[5]

The resulting losses in future U.S. crude oil supplies will have associated impacts in terms of reduced national energy security, decreased tax revenues, fewer oil field jobs, and increased levels of crude oil imports.[5,6] Moreover, the ability of the U.S. petroleum industry to compete in the world oil market could be significantly diminished.[5,6]

Another study estimates that 85 percent of the current oil wells and 75 percent of gas wells would be abandoned if exemption for E & P wastes was removed.[7] 40,000 jobs in the E & P sector would be lost and 148,000 jobs lost nationwide.[7]

One of the few areas of the E & P industry which has or will benefit from the environmental regulations is the natural gas industry. The non-attainment provisions may encourage fuel switching to natural gas. In the worst ozone non-attainment areas

"clean fuels" will be phased in for vehicle fleets as natural gas is considered a clean fuel.[8]

The acid rain provisions of the CAAA, which are aimed at reducing SOx emissions, will probably encourage several coal-burning plants to switch to natural gas rather than make costly retrofits.[8]

The utility companies are faced with the following regulatory requirements under the CAAA.[9]

- SO_x emissions for acid rain concerns, must be reduced by 10 million tons/year by the year 2000 from current levels of 25 tons per year, 80 percent of SO_x comes from coal utility plants.

- NO_x must be reduced by 2 million tons annually by 2000.

- For the units responsible for the most emissions, by 1995, these units must reduce SO_2 emissions to 2.5 lbs/MMBtu. This targets approximately 110 existing units.

- By 2000 all units must reduce emissions to 1.2 lbs/MMBtu of SO_2

- The allowance system creates one allowance per ton of emissions reductions below the required levels will allow the utility to sell this allowance or keep it for future growth. This is known as emissions trading.

There are several issues which may deter utilities from using natural gas, these include:[9]

- Utilities still remember the Fuel Use Act which came about under the Carter administration.

- The cost of gas could possibly increase to a point where gas plants would become uneconomical.

- Relatively small proven natural gas reserves lead to questions about supply.

- State prorating rules may restrict gas availablity to utilities.

- Are pipeline and storage capacities able to provide enough gas at peak demand levels.

Even with these questions the demand for gas for utilities is expected to increase.[9]

REFERENCES

1. "Status Report on Legislation, Regulation Impacting U.S. Offshore." Offshore May 1992. (pp. 99, 100, 102, 104, 105, 110)

2. "EPA Moves to Control Offshore Emissions." Oil & Gas Journal December 9, 1991. (pg. 32)

3. Navarro, Armado R. "Innovative Techniques Cut Costs in Wetlands Drilling." Oil & Gas Journal October 14, 1991. (pg. 88)

4. Wright, Thomas R. "Oil Spill Law Has Frightening Aspects." World Oil January 1992. (pg. 23)

5. U.S. Department of Energy. Potential Cumulative Impacts of Environmental Regulatory Initiatives on U.S. Crude Oil Exploration and Production. NTIS-PR-360, Springfield: National Technical Information Service, U.S. Department of Commerce, December 1990. (pp. 1, 3, 5-8, 10, 13-17, 24, 26)

6. Godec, Michael L. and Khosraw Biglarbigi. "Economic Effects of Environmental Regulations on Finding and Developing Crude Oil in the U.S." Journal of Petroleum Technology January 1991. (pp. 72-79)

7. Mortis, Guntis. "Producers Modify Activities as Threat of New Rules Looms." Oil & Gas Journal December 16, 1991. (pg. 53)

8. Tulloh, Brian. "Uncle Sam's Plans for You." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Colorado, August 1992.

9. Wilson, David W. "Yours - If You Act." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Colorado, March 1993.

CHAPTER VI

ACTUAL ECONOMIC IMPACTS

The actual impacts of existing and proposed environmental regulations and legislation is difficult to quantify. However, there is a clear indication that some effects have resulted due to environmental regulation alone, and some effects have resulted from environmental regulation in conjunction with other variables, such as oil and gas prices.

There have been no major blowouts over the last 20 years in offshore drilling; during that time 20,000 wells have been drilled on state and federal waters.[1] Yet, a survey found that seven times as many U.S. adults believe environmentalists' claims as believe oil industry claims.[1] The current moratorium on offshore drilling has actually increased the chance of oil spills.[1] There is a 10 times greater risk of a spill from tankers than from platforms.[1]

Senator Don Nickles, R-Okla., and eight cosponsors have introduced a bill to require analysis and estimates of the likely impact of federal legislation on the private sector. Senator Nickles noted that the total annual cost of federal regulations had grown to $562 billion, or $4,272 per household.[2]

In a survey, over half those responding said that, if a clean air law raised their taxes more than $100 per year, it was too much.[3] Frank Pitts, a Dallas oil man, in a speech to the National Association of Lease and Title Analysts explains, "Congress has

already tagged us with a $40 billion Clean Air Bill. We'll be lucky to get out with less than $1,500 for each family per year."[3]

Russ Luigs, Chairman and Chief Executive Officer of Global Marine Inc., had this to say about U.S. environmental regulations,

> Oil companies in the U.S. are exposed to unlimited pollution liability, oil executives are subject to criminal prosecution for accidents beyond their control, harmless drilling and production wastes have been declared toxic, drilling rigs are banned to protect the environment from fantasized risks, lawsuits prohibit drilling on drillable leases and production on producible leases -- the list goes on and on.[1]

The available U.S. drilling rigs now stands at 1996, down 11.3 percent from 1991, the lowest its been since 1974.[4] Utilization of the existing rigs has decreased to 60 percent in 1992 from 66 percent in 1991.[4] Since 1987, 40 percent of the drilling companies have left the industry.[4] Forty six rigs were moved out of the U.S. in 1992 and forty two moved out in 1991.[4]

1992 E & P spending outside the U.S. is up 9.1 percent from 1991.[5] In 1991, OGJ 300 companies net number of wells drilled in the U.S. fell 15.9 percent from 1990.[5] A cause cited was the new environmental regulations which have driven up the cost of operations and restricted access to potentially productive areas.[5]

Major oil companies have placed billions of dollars worth of U.S. oil and gas properties up for sale, cut 1992 capital budgets to the bare minimum and announced

early retirements affecting tens of thousands of domestic employees.[1,6] Much of the proceeds from these measures are not being shifted to promising upstream acquisitions. Instead, funds are being programmed for down-stream operations to pay for regulatory compliance.[6] Chevron alone faces a $2 billion environmental tab in the U.S. over the next several years. Its competitors are also facing the same situation.[6]

An estimated $10 to $12 billion worth of properties are up for sale in Alaska and the Lower 48 states.[6] The major oil companies account for approximately one third of this total.[6] U.S. upstream operations have long been a drain on oil companies' profits.[6] Surveyed companies netted returns of two to six percent for upstream operations, well below the cost of capital.[6] Chevron has put 300 "non-strategic" properties on the market.[6] Exxon is reportedly looking for buyers for 100 properties.[6] Mobil plans to defer some promising projects for at least a year.[6] Investment in the U.S. will largely be for non-discretionary downstream costs.[6] What little is left will probably go for the most promising foreign upstream plays.[1,6]

All of these actions have created a buyers' market for companies remaining in the U.S. Many of the U.S. properties that the majors and large dependents held are being sold to smaller independents.[5]

As was stated earlier in this chapter, the actual impacts of environmental regulations alone is very hard to quantify. In the past decade there have been several detrimental occurrences that have severely impacted the U.S. E & P industry. The

price collapse in December of 1985 was of course the single most crippling blow to the industry. Almost every economist was predicting $100/bbl for oil by the early 1990's. Before the collapse, many of the E & P projects were based on the price of oil continuing to rise. When the price dropped, these projects were no longer profitable. This led to many oil company bankruptcies and bank failures.

Other negative impacts include a change in the U.S. tax law that does not allow the deduction of all intangible drilling costs in the year they are expended. Also, the shear number of wells drilled in the lower 48 states significantly reduces the chance of finding any more large highly productive fields. However, in other countries there are relatively small areas that have been explored. These countries have offered many incentives for oil companies to come and explore for new oil production, and most have much less stringent environmental regulations.

Therefore, it can be seen that environmental regulations in the U.S. in and of itself has not caused the many negative changes to the U.S. E & P industry. Instead, a combination of these influences has led many of the major oil companies and large independents to seriously cut back on projects related to the U.S. E & P industry.

A report conducted in California by the California Department of Conservation, clearly indicates the negative impact the environmental regulations have had in that state. Since 1984, California's gas production has fallen 31 percent. Oil production has dropped 23 percent. The report also states "until either petroleum

prices increase or regulatory costs decrease, the California production industry will continue to decline faster than the national average, even though California's discovered reserves to production exceed the national average by 35 percent."[7]

Declining production in California caused "35 percent decrease in the number of jobs associated with the industry since 1984. There has been a decrease in wages of $160 million, and $130 million in taxes and royalty leases. According to the report, 34 federal, state and local agencies enforce dozens of regulatory requirements, many of which overlap or conflict with each other. Tax, fee and royalty payments to state and local governments totaled more than $600 million in 1990. The decline in production, prices and employment has decreased payments by $100 million since 1990.[7]

The DOE has commented that the OCS regulations could result in an additional cost of $9 to $26 million to the E & P industry.[8]

In 1989, the API conducted a study titled "An Analysis of Petroleum Industry Costs Associated with Air Toxics Amendments to the Clean Air Act". In this study, $8.5 billion industry wide was estimated to be the initial costs required to comply with these provisions. More recent estimates are about 25 percent of the original estimate. This decrease in the estimate is probably due to the non-aggregate provisions discussed earlier which did not exist during the original estimate. This translates to about $500 per year for every well in the lower 48 states. Without having an established MACT, this estimate is a good guess at best.[8]

In 1990, API conducted a study to determine the cost of environmental initiatives in the U.S. petroleum industry. The results were included in the Petroleum Industry Environmental Performance study of 1992. This study was the first API has conducted in seven years.[9]

According to the study the U.S. petroleum industry spent approximately $7.8 billion on the environment in 1990: $6.3 billion for ongoing activities, $175 million for corporate initiatives and $1.2 billion for cleanup and remediation of existing soil and ground water contamination. The refining sector spent $3.7 billion while exploration and production spent $1.5 billion. The remainder went to transportation and marketing.[9]

The study also concludes that the environmental expenditures for the petroleum industry have increased by over 30 percent between 1984 and 1990. The industry spent nearly as much on the environment as it did on drilling for oil and natural gas in 1990.[9]

REFERENCES

1. "Industry Decries Sharp Decline in U.S. Offshore Activity." Oil & Gas Journal May 11, 1992.

2. "Status Report on Legislation, Regulation Impacting U.S. Offshore." Offshore May 1992. (pg. 110)

3. Wright, Thomas R. "Fact Debunk Some Environmental Myths." World Oil March 1992. (pg. 25)

4. Price, Robin B. "U.S. Independent Operators Step Up The Pace on Non-U.S. Exploration, Development." Oil & Gas Journal April 27, 1992 (pp. 14, 15, 17, 18)

5. Beck, Robert J. and Valerie Sanders. "Financial, Operating Results Sag for OGJ 300 Companies." Oil & Gas Journal September 28, 1992. (pg. 49)

6. "Green Costs Force Fire Sale as Majors Cut U.S. E & P Assets." Petroleum Intelligence Weekly March 30, 1992.

7. Penn, Cyril. "Regulation, Output Prop Cost California Millions of Dollars." The Oil Daily Vol. 43, No. 65 Tuesday, April 6, 1993. (pp. 3, 5)

8. Tulloh, Brian. "Uncle Sam's Plans for You." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Colorado, August 1992.

9. Petroleum Industry Environmental Performance., American Petroleum Institute, Washington D.C., 1992 (pp. 5, 34, 36)

CHAPTER VII

CONCLUSION

Environmental regulations have become a major cost factor within the last few years for E & P operations. Recent environmental legislation and the threat of more to come has been a major factor leading to nearly all major oil companies and large independents drastically cutting budgets and personnel in the U.S. E & P industry. [1,2,3]

This decision does not come strictly due to environmental regulations alone. Other major factors leading to the mass exodus include; a) Low oil and gas prices; b) The possibility of large, highly productive plays in foreign countries; c) Because very few if any large fields remain in the U.S. due to the tremendous amount of drilling that has occurred in the past.[3,4,5]

Another subtle factor, but very significant, is the tremendous liability, and possible criminal prosecution for environmental regulation violations.[3,6,7]

Most of the properties being sold by the majors and large independents are going to small independent oil companies. Thus, existing oil and gas properties are not being abandoned at any alarming rate at the present time. Exploration, on the other hand, has seen a tremendous decrease in the U.S., especially in 1992.[8] If the present trend continues drilling activity will most likely be at an all time low in 1993.[8]

Although not directly related to E & P, downstream operations have been adversely affected by recently-passed environmental regulations. Since most major oil

companies have both downstream and upstream operations, E & P operations have suffered due to reallocation of funds to pay for downstream compliance upgrades.[3]

It is felt that the above can only lead to the following conclusions if present trends continue:

1) U.S. oil production will continue to decline at alarming rates, thereby increasing foreign dependency.[9]

2) U.S exploration will soon be at its lowest point in recent history.[8]

3) Well abandonment rates will significantly increase if additional stringent environmental regulations are imposed on the E & P industry; especially if the RCRA exemption is lifted.[9]

4) Many E & P jobs will be lost over the next few years in the U.S.[9]

5) E & P funds will continue shifting from the U.S. to foreign countries.[3,4,5,6,9]

6) The regulations of the 1990 CAAA will help the natural gas industry. How much and when will depend on the ability of the natural gas industry and other industries to work together to solve several problems and misconceptions. However, this is truly a ray of hope and opportunity for the natural gas industry.[10]

REFERENCES

1. "Status Report on Legislation, Regulation Impacting U.S. Offshore." Offshore May 1992. (pp. 99, 100, 102, 104, 105, 110)

2. "EPA Moves to Control Offshore Emissions." Oil & Gas Journal December 9, 1991. (pg. 32)

3. "Green Costs Force Fire Sale as Majors Cut U.S. E & P Assets." Petroleum Intelligence Weekly March 30, 1992.

4. Beck, Robert J. and Valerie Sanders. "Financial, Operating Results Sag for OGJ 300 Companies." Oil & Gas Journal September 28, 1992. (pg. 49)

5. "Industry Decries Sharp Decline in U.S. Offshore Activity." Oil & Gas Journal May 11, 1992. (pp. 17, 18)

6. Price, Robin B. "U.S. Independent Operators Step Up The Pace on Non-U.S. Exploration, Development." Oil & Gas Journal April 27, 1992. (pp. 14, 15, 17, 18)

7. Candler, John. "Environmental Rules Make Scrutiny of Rig Work Practices a Must." Oil & Gas Journal April 22, 1991. (pp. 83, 84)

8. Fitts, Robert and Tory Stokes. "40th Annual Reed Rig Census." World Oil October 1992. (pp. 55, 56, 59)

9. U.S. Department of Energy. Potential Cumulative Impacts of Environmental Regulatory Initiatives on U.S. Crude Oil Exploration and Production., NTIS-PR-360, Springfield: National Technical Information Service, U.S. Department of Commerce, December 1990. (pp. 1, 3, 5-8, 10, 13-17, 24, 26)

10. Wilson, David W. "Yours -- If You Act." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Co, March 1993.

APPENDIX A

The Non-Hazardous Drilling Mud Additives

The following information was included in a letter from the California Department of Health Services dated 9 July 1982.

STATE OF CALIFORNIA — HEALTH AND WELFARE AGENCY EDMUND G. BROWN JR., Governor

DEPARTMENT OF HEALTH SERVICES
714/744 P STREET
SACRAMENTO, CA 95814
(916) 324-1789

July 9, 1982

TO: Producers, Transporters, and Disposers of Waste Drilling Muds and Fluids

FROM: Hazardous Waste Management Branch
714 P Street, Room 523

SUBJECT: Identification of Nonhazardous Waste Drilling Muds and Fluids

Waste drilling muds and fluids are listed in state hazardous waste regulations (Section 66680, Chapter 30, Division 4, Title 22, California Administrative Code) as hazardous wastes if the muds or fluids contain hazardous materials. That listing does not take into account the likely dilution of hazardous additives during drilling operations.

Since the time of the listing, the Department has obtained from laboratory testing and from manufacturers more information about the nature of drilling fluid additives and their usage.

The information has made possible the development of the enclosed list of chemical and material drilling fluid additives which the Department has concluded do not render the waste muds and fluids hazardous wastes. Note that some chemicals on the enclosure are listed in the regulations as hazardous wastes (e.g., phosphoric acid and sodium hydroxide). If these, and other additives, are diluted and used as recommended by the manufacturers, however, they will not cause the waste muds and fluids to be considered hazardous wastes.

Accordingly, persons producing, transporting, and disposing of waste drilling muds and fluids containing only the listed additives may manage them as nonhazardous wastes, provided they do not contain substantial concentrations of toxic substances from other sources (e.g., toxic metal from geological deposits encountered during drilling operations). Drilling muds that contain additives which are not included on the list will continue to be considered hazardous waste. The Department will periodically revise the enclosed list as more information is obtained. If you wish to add a chemical or material to the list, please send to the Department supporting data such as Material Safety Data Sheets, chemical compositions, toxicities, and concentrations used (e.g., lbs/bbl).

Please note that all waste drilling muds and fluids, hazardous and nonhazardous, must be disposed at sites approved by the Regional Water Quality Control Boards.

If you have any questions on this matter please contact the Chemical Support Unit at (415) 540-2043.

Sincerely,

Peter A. Rogers, Acting Chief
Hazardous Waste Management Branch

Enclosure

CALIFORNIA DEPARTMENT OF HEALTH SERVICES

DRILLING MUD ADDITIVES
USED IN NONHAZARDOUS DRILLING MUDS AND FLUIDS*

May 1982

1. Aluminum stearate (Aluminum tristearate)
2. Attapulgite clay
3. Bagasse (dried sugar cane)
4. Barium sulfate
5. Bentonite
6. Calcium carbonate
7. Causticized lignite (Sodium lignite)
8. Cellophane
9. Chrome free lignosulfonate
10. Cottonseed pellets
11. Diamines and fatty acid amides
12. Detergents
13. Ethylene oxide adducts of phenol and nonylphenol
14. Guar gum
15. Hydroxyethyl cellulose
16. Lecithin
17. Lignite
18. Magnesium oxide
19. Methanol
20. Mica
21. Morpholine polyethoxyethanol

*These additives will not a render a waste drilling mud or fluid hazardous when used according to manufacturer's specifications and provided no other nonlisted hazardous constituents are used.

Drilling Mud Additives

22. Nut shells
23. Paraformaldehyde
24. Peptized bentonite
25. Phosphoric acid
26. Polyacrylamide resin
27. Polyanionic cellulosic polymer
28. Polysaccharides
29. Potassium chloride
30. Potassium hydroxide (Caustic potash)
31. Potassium sulfate
32. Pregelatinized corn starch
33. Quartz or cristobalite
34. Rice hulls
35. Sawdust
36. Shredded paper
37. Sodium acid pyrophosphate
38. Sodium bicarbonate (Bicarbonate of soda)
39. Sodium carbonate (Soda ash)
40. Sodium carboxymethylcellulose
41. Sodium chloride
42. Sodium hexametaphosphate
43. Sodium hydroxide (Caustic soda)
44. Sodium montmorillonite clay
45. Sodium polyacrylate
46. Sodium tetraphosphate

Drilling Mud Additives

47. Starch
48. Tetrasodium pyrophosphate
49. Tributyl phosphate
50. Vegetable and polymer fibers, flakes, and granules
51. Vinyl acetate/Maleic anhydrie copolymer
52. Xanthan gum (XC polymer)

BIBLIOGRAPHY

API Environmental Guidance Document. American Petroleum Institute Production Department. Washington D.C., 1989.

Beck, Robert J. and Valerie Sanders. "Financial, Operating Results Sag for OGJ 300 Companies." Oil & Gas Journal 28 September 1992.

Brown, C.W. "It's Not Business as Usual Anymore." Environmental Considerations SPE Reprint Series, No 37, Richardson: SPE, 1992.

Bulletin on Management of Naturally Occurring Radioactive Materials (NORM) in Oil & Gas Production. American Petroleum Institute. Washington D.C., April 1992. (pp. 10, 14, 15)

Candler, John. "Environmental Rules Make Scrutiny of Work Practices a Must." Oil & Gas Journal 22 April 1991.

Curtis, B.W. and Kirchof, C.E. "Purchase/Sale of Property: The Black Hole of Corporate Liability Ways to Minimize Risk." Presented at the SPE/EPA

Exploration & Production Environmental Conference of the Society of Petroleum Engineers in San Antonio, Texas, 7-10 March 1993.

"EPA Moves to Control Offshore Emissions." Oil & Gas Journal 9 December 1991.

Fitts, Robert and Tory Stokes. "40th Annual Reed Rig Census." World Oil October 1992.

Godec, Michael L. and Khosraw Biglarbigi. "Economic Effects of Environmental Regulations on Finding and Developing Crude Oil in the U.S." Journal of Petroleum Technology January 1991.

Gray, P.R. "Economic Contamination in the Petroleum Industry." Journal of Petroleum Technology January 1993.

"Green Costs Force Fire Sale as Majors Cut U.S. E & P Assets." Petroleum Intelligence Weekly 30 March 1992.

"Industry Decries Sharp Decline in U.S. Offshore Activity." Oil & Gas Journal 11 May 1992.

Mortis, Guntis. "Producers Modify Activities as Threat of New Rules Looms." Oil & Gas Journal 16 December 1991.

Nathanson, Jerry A., P.E. Basic Environmental Technology: Water Supply, Waste Disposal, and Pollution Control., New York: John Wiley & Sons, Inc., 1986.

Naval Energy and Environmental Support Activity. Hazardous Waste Facility Managers Course. Niagara Falls: Waste Resource Associates, Inc., 1986.

Navarro, Armado R. "Innovative Techniques Cut Costs in wetlands Drilling." Oil & Gas Journal 14 October 1991.

Penn, Cyril. "Regulation, Output Prop Cost "California Millions of Dollars." The Oil Daily Vol. 43, No. 65 Tuesday, 6 April 1993.

Petroleum Industry Environmental Performance. American Petroleum Institute, Washington D.C., 1992.

Price, Robin B. "U.S. Independent Operators Step Up The Pace on Non-U.S. Exploration, Development." Oil & Gas Journal 27 April 1992.

Rappold, Keith. "Drilling Wastes Require Extra Attention." Oil & Gas Journal 16 December 1991.

Smith, J.B. and Browning, L.A. "Proposed Changes to EPA Class II Well Construction Standards and Area of Review Procedures." Presented at the SPE/EPA Exploration and Production Environmental Conference of the Society of Petroleum Engineers in San Antonio, Texas, 7 - 10 March 1993.

SOLID WASTE: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy. Report to Congress, December 1987, EPA/530-SW-88-003, Washington: U.S. Environmental Protection Agency, 1987.

"Status Report on Legislation, Regulation Impacting U.S. Offshore." Offshore May 1992.

Steingraber, Buck. "New Challenge from Old Earth." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Colorado, October 1992.

Tulloh, Brian. "Uncle Sam's Plans for You." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Colorado, August 1992.

U.S. Department of Energy. Potential Cumulative Impacts of Environmental Regulatory Initiatives on U.S. Crude Oil Exploration and Production. NTIS-PR-360, Springfield: National Technical Information Service, U.S. Department of Commerce, December 1990.

U.S. Environmental Protection Agency. Regulatory Determination for Oil & Gas & Geothermal Explorations Development and Production Wastes; Regulatory Determination: Federal Register. Vol. 53, No. 129. July 6, 1988, Washington: U.S. Government Printing Office, 1988.

U.S. Interstate Oil Compact Commission. EPA/IOCC Project on State Regulation of Oil & Gas Exploration & Production Waste. December 1990, Oklahoma City: Interstate Oil Compact Commission, 1990.

Wilson, David W. "Yours - If You Act." Environmental Requirements: How To Survive, Special Report from Oil and Gas Investor, Hart Publications Inc., Denver, Colorado, March 1993.

Wright, Thomas R. "Oil Spill Law Has Frightening Aspects." World Oil January 1992.

Wright, Thomas R. "Fact Debunk Some Environmental Myths." World Oil March 1992.

VITA

James Leslie Hardin, was born in Oklahoma City, Oklahoma, on April 15, 1962, the son of Mary Hill Hardin and James L. Hardin, Sr. After completing his work at Caney Valley High School, Caney, Kansas, in 1980, he entered the University at Tulsa, Oklahoma. He received the degree of Bachelor of Science from the University at Tulsa in December, 1984. He was commissioned into the U.S. Navy on 26 September 1986, and is presently on active duty. In August, 1992, he entered the Graduate School at The University of Texas.

Permanent address: 408 Stonebridge Dr.
Round Rock, Texas 78681

This thesis was typed by Cera Mae I. Hardin