I. INTRODUCTION TO THE SECTOR NOTEBOOK PROJECT

I.A. Summary of the Sector Notebook Project

Environmental policies based upon comprehensive analysis of air, water and land pollution (such as economic sector, and community-based approaches) are becoming an important supplement to traditional single-media approaches to environmental protection. Environmental regulatory agencies are beginning to embrace comprehensive, multi-statute solutions to facility permitting, compliance assurance, education/outreach, research, and regulatory development issues. The central concepts driving the new policy direction are that pollutant releases to each environmental medium (air, water and land) affect each other, and that environmental strategies must actively identify and address these interrelationships by designing policies for the "whole" facility. One way to achieve a whole facility focus is to design environmental policies for similar industrial facilities. By doing so, environmental concerns that are common to the manufacturing of similar products can be addressed in a comprehensive manner. Recognition of the need to develop the industrial ?sector-based" approach within the EPA Office of Compliance led to the creation of this document.

The Sector Notebook Project was initiated by the Office of Compliance within the Office of Enforcement and Compliance Assurance (OECA) to provide its staff and managers with summary information for eighteen specific industrial sectors. As other EPA offices, states, the regulated community, environmental groups, and the public became interested in this project, the scope of the original project was expanded. The ability to design comprehensive, common sense environmental protection measures for specific industries is dependent on knowledge of several interrelated topics. For the purposes of this project, the key elements chosen for inclusion are: general industry information (economic and geographic); a description of industrial processes; pollution outputs; pollution prevention opportunities; federal statutory and regulatory framework; compliance history; and a description of partnerships that have been formed between regulatory agencies, the regulated community and the public.

For any given industry, each topic listed above could alone be the subject of a lengthy volume. However, in order to produce a manageable document, this project focuses on providing summary information for each topic. This format provides the reader with a synopsis of each issue, and references where more in-depth information is available. Text within each profile was researched from a variety of sources, and was usually condensed from more detailed sources pertaining to specific topics. This approach allows for a wide coverage of activities that can be further explored based upon the references listed at the end of this profile. As a check on the information included, each notebook went through an external document review process. The Office of Compliance appreciates the efforts of all those that participated in this process and enabled us to develop more complete, accurate and up-to-date summaries. Many of those who reviewed this notebook are listed as contacts in Section IX and may be sources of additional information. The individuals and groups on this list do not necessarily concur with all statements within this notebook.

I.B. Additional Information

Providing Comments

OECA's Office of Compliance plans to periodically review and update the notebooks and will make these updates available both in hard copy and electronically. If you have any comments on the existing notebook, or if you would like to provide additional information, please send a hard copy and computer disk to the EPA Office of Compliance, Sector Notebook Project (2223-A), 401 M St., SW, Washington, DC 20460. Comments can also be sent via the web page.

Adapting Notebooks to Particular Needs

The scope of the industry sector described in this notebook approximates the national occurrence of facility types within the sector. In many instances, industries within specific geographic regions or states may have unique characteristics that are not fully captured in these profiles. The Office of Compliance encourages state and local environmental agencies and other groups to supplement or re-package the information included in this notebook to include more specific industrial and regulatory information that may be available. Additionally, interested states may want to supplement the "Summary of Applicable Federal Statutes and Regulations" section with state and local requirements. Compliance or technical assistance providers may also want to develop the "Pollution Prevention" section in more detail. Please contact the appropriate specialist listed on the opening page of this notebook if your office is interested in assisting us in the further development of the information or policies addressed within this volume. If you are interested in assisting in the development of new notebooks, please contact the Office of Compliance at (202) 564-2310.

II. INTRODUCTION TO THE OIL AND GAS EXTRACTION INDUSTRY

This section provides background information on the size, geographic distribution, employment, production, sales, and economic condition of the oil and gas extraction industry. Facilities described within the document are described in terms of their Standard Industrial Classification (SIC) codes.

II.A. Introduction, Background, and Scope of the Notebook

This industry sector profile provides an overview of the oil and gas industry as listed under SIC code 13. The SIC code 13 encompasses the oil and gas extraction process from the exploration for petroleum deposits up until the transportation of the product from the production site. There are five major groups within SIC code 13:

SIC 1311*. *Crude petroleum and natural gas. Establishments in this industry are primarily involved in the operation of oil and gas field properties. Establishments under this category might also perform exploration for crude oil and natural gas, drill and complete wells, and separate the crude oil and natural gas components from the natural gas liquids and produced fluids.

SIC 1321. Natural gas liquids. This industry is comprised of establishments that separate natural gas liquids from crude oil and natural gas at the site of production. Examples of these gases are propane and butane. Natural gas liquids producers that remove additional material at petroleum refineries are classified under SIC code 29, and establishments that recover other salable contaminants such as helium are classified under SIC code 28.

SIC 1381. Drilling oil and gas wells. This industry is made up of establishments that drill wells on a contract or fee basis.

SIC 1382. Oil and gas field exploration services. Establishments in this industry perform geological, geophysical and other exploration services for oil and gas on a contract or fee basis.

SIC 1389. Oil and gas field services, not elsewhere classified (NEC). Establishments in this industry perform services on a contract or fee basis that are not elsewhere classified. These include the preparation of drilling sites by building foundations and excavating pits, the completion of wells and preparation for production, and the performing of maintenance.

While this notebook covers all of the SIC codes listed above, the diverse nature of the industries will not allow a detailed description of each. Since the service industries (SIC codes 1381, 1382, and 1389) and natural gas liquids industry (SIC code 1321) are tied to the economic, geographic, and production trends of SIC code 1311, most attention is focused on the crude petroleum and natural gas industry. Although certain products under these SIC codes may not be specifically mentioned, the sector-wide economic, pollutant output, and enforcement and compliance data in this notebook covers all establishments involved with oil and gas extraction.

SIC codes were established by the Office of Management and Budget (OMB) to track the flow of goods and services within the economy. OMB is in the process of changing the SIC code system to a system based on similar production processes called the North American Industrial Classification System (NAICS). In the NAICS, the SIC codes for the oil and gas extraction industry correspond to the following NAICS codes:

1987 SIC	U.S. SIC Description	1997 NAICS	NAICS Description
1311	Crude Petroleum and Natural Gas	211111	Crude Petroleum and Natural Gas Extraction
1321	Natural Gas Liquids	211112	Natural Gas Liquid Extraction
1381	Drilling Oil and Gas Wells	213111	Drilling Oil and Gas Wells
1382	Oil and Gas Field Exploration Services	54136	Geophysical Surveying and Mapping Services
		213112	Support Activities for Oil and Gas Operations
1389	Oil and Gas Field Services, NEC	213112	Support Activities for Oil and Gas Operations

II.B. Characterization of the Oil and Gas Extraction Industry

II.B.1. Product Characterization

The primary products of the industry are crude oil, natural gas liquids, and natural gas. Crude oil is a mixture of many different hydrocarbon compounds that must be processed to produce a wide range of products. U.S. refinery processing of crude oil yields, on average, motor gasoline (approximately 40 percent), diesel fuel and home heating oil (20 percent), jet fuels (10 percent), waxes, asphalts and other nonfuel products (5 percent), feedstocks for the petrochemical industry (3 percent), and other lesser components [U.S.

Department of Energy, Energy Information Administration (EIA), 1999]. Volumes of oil and refined products typically are reported in barrels (bbl), which are equal to 42 gallons.

When crude oil is first brought to the surface, it may contain a mixture of natural gas and produced fluids such as salt water and both dissolved and suspended solids. On land (and at many offshore operations) Natural gas is separated at the well site and is processed for sale if natural gas pipelines (or other transportation vehicles) are nearby, or is flared as a waste (at onshore operations only). Water (which can be more than 90 percent of the fluid extracted in older wells) is separated out, as are solids. Only about one-third of the production platforms offshore in the Gulf of Mexico separate water. The other offshore Gulf platforms transport full well stream, sometimes great distances, to central processing facilities. The crude oil is at least 98 percent free of solids after it passes through this onsite treatment and is prepared for shipment to storage facilities and ultimately refineries (Sittig, 1978).

Natural gas can be produced from oil wells (called *associated gas*), or wells can be drilled with natural gas as the primary objective (called *non-associated gas*). Methane is the predominant component of natural gas (approximately 85 percent), but ethane (10 percent), propane, and butane are also significant components. The heavier components, including propane and butane, exist as liquids when cooled and compressed; these are often separated and processed as natural gas liquids.

Less frequently, oil and gas can be produced by other methods. Oil can be found in tar sands, which are porous rock (sandstone) structures on the surface to 100 meters deep. The material is fairly viscous and also is fairly high in sulfur and metals. Although the Athabasca region in Canada is the primary area of significant tar sand mining, there are some deposits in the western United States.

Oil may also be extracted from oil shale. These deposits may be 10 to 800 feet below the surface and can be removed by surface mining or subsurface excavation. The oil, in a highly viscous form called *kerogen*, is usually heated to allow it to flow. Because only approximately 30 gallons (less than a barrel) are produced per ton of shale, the process is costly, and the oil shale mining industry is currently only a minor contribution to the domestic oil supply.

A small but increasingly significant source of natural gas is coalbed methane. In all coal deposits, methane is found as a byproduct of the coalification process and is loosely bound to coal surface areas. This methane historically was considered a safety hazard in the coal mining process and was vented, but recently it has been recovered in conjunction with mining or produced independently via wells in deposits that are too deep for mining. Generally, coalbed methane is collected by drilling a well similar to those used for conventional oil and gas deposits, but with some adaptations to accommodate mining operations and different rock characteristics (EPA, 1992). In 1997, coalbed methane production accounted for six percent of the total U.S. natural gas production (EIA, 1998).

Methane hydrates are another form of natural gas, for which economically viable recovery methods are still in development. Methane hydrates are structures in which methane molecules are trapped within a lattice of ice. They are found principally in cold and/or pressurized conditions: on land in permafrost regions, or beneath the ocean at depths greater than 1,500 feet below the water surface. These eventually could be an immense resource; estimated amounts of methane in these structures in the United States is 200,000 trillion cubic feet, compared to an estimated 1,400 trillion cubic feet in conventional natural gas deposits. A goal of the U.S. Department of Energy methane hydrates research program is to develop a commercial production system by the year 2015 (U.S. DOE, 1998).

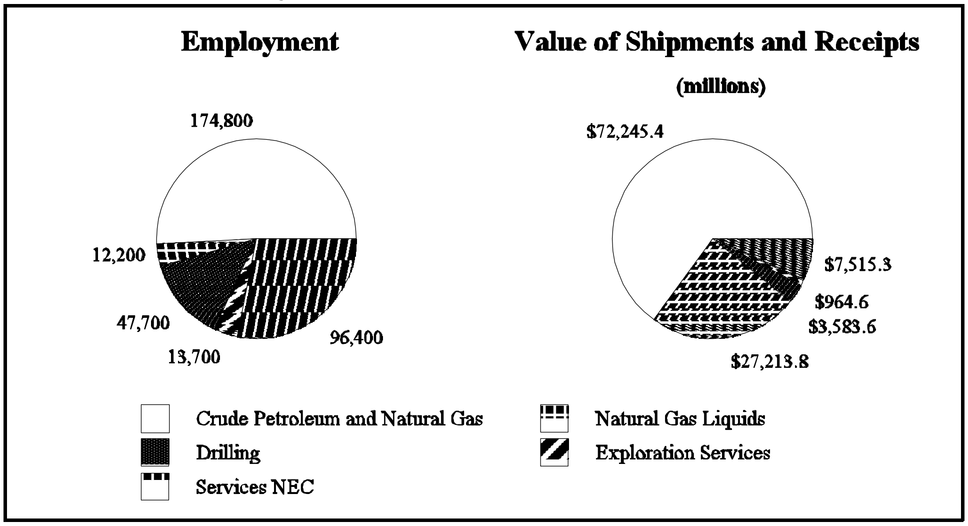
II.B.2. Industry Size and Distribution

The oil and gas extraction industry is an important link in the energy supply of the United States. Petroleum and natural gas supply 65 percent of the energy consumed in the United States, and domestic producers supply approximately 40 percent of the petroleum and 90 percent of the natural gas [EIA and Independent Petroleum Association of America (IPAA), 1999]. According to the 1992 Census of Mining Industries, the industry employed 345,000 people and had yearly revenues of $112 billion.

Several factors influence the size of the industry, including technology development and crude oil prices (which are set in world markets) (EIA, 1999). Employment in the industry is also affected by the recent trend in mergers and consolidation among companies in the industry.

Within the overall oil and gas extraction industry group (SIC code 13), SIC 1311 (crude petroleum and natural gas) is the largest. As shown in Figure 1, this industry employs half of the total workers in this SIC group, and accounts for about 60 percent of the sales. SIC code 1389 (services not elsewhere classified) is the next largest employer, but SIC code 1321 (natural gas liquids) is more significant with respect to sales.

Figure 1: Employment and Value of Shipments and Receipts in the Oil and Gas Industry



Source: *1992 Census of Mineral Industries*, U.S. Department of Commerce, 1995.

The major oil and gas producing areas in the United States are in the Gulf of Mexico region (onshore and offshore), California, and Alaska (see Figure 2). The Gulf of Mexico and surrounding land in particular is the most concentrated area of production; in 1998, Texas (onshore and offshore) produced 23 percent of the nation's crude oil, Louisiana produced 5 percent, and the Federal offshore region produced 14 percent.[1]

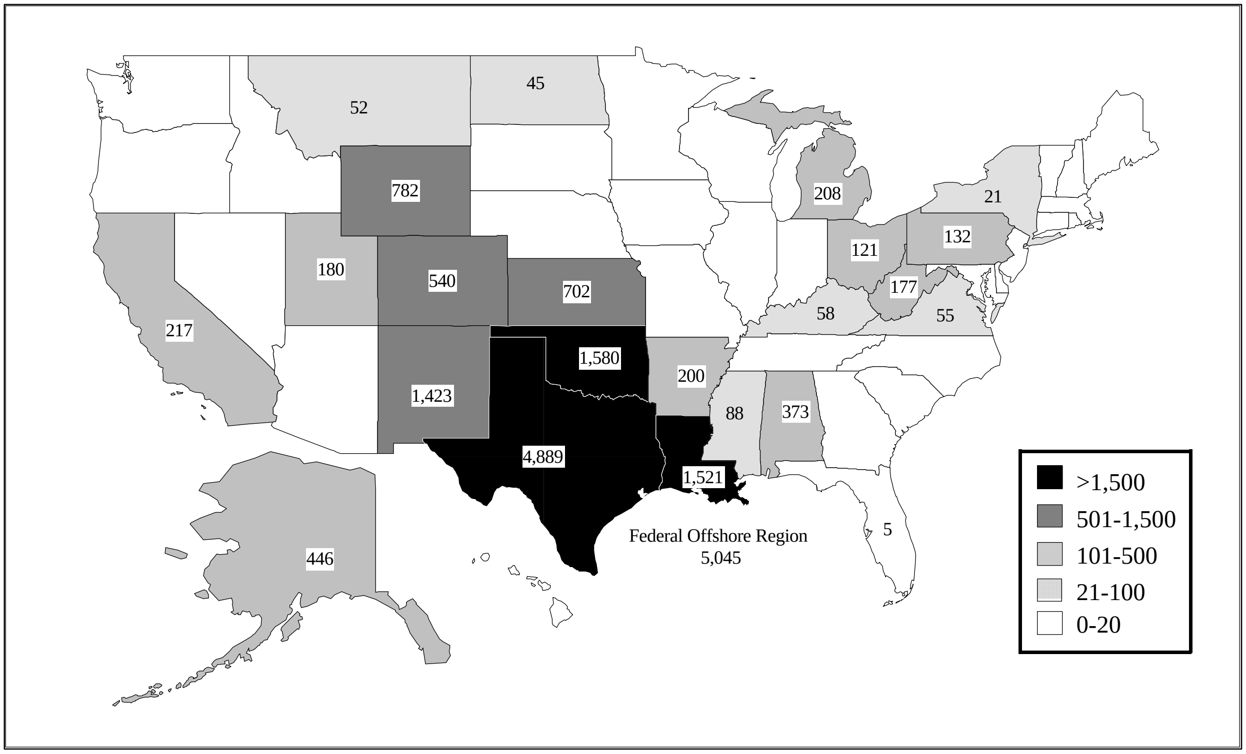
The geographic distribution is similar for natural gas; Texas, Louisiana, and the Gulf of Mexico are the major producing locations (Figure 3). New Mexico, Oklahoma, Wyoming, and Kansas are also important gas-producing states, while California and Alaska are less important with respect to natural gas production than they are for crude oil.

[1] The Federal Offshore Region, or Outer Continental Shelf (OCS), is seaward of State jurisdiction (3 nautical miles, or approximately 3.3 statute miles, from an established baseline except for Texas and the Gulf coast of Florida, for which the boundary is 3 marine leagues, or approximately 10 statute miles), and landward of a line defined by international law at a minimum of 200 nautical miles (MMS, 1997) (See p101 for more details).

Figure 2: 1996 U.S. Crude Oil Production (Million Barrels per Year)

Note: Small quantities are also produced in Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996 Annual Report*, EIA, 1997.

Figure 3: 1996 U.S. Natural Gas Production (Billion Cubic Feet per Year)



Note: Small quantities are also produced in Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996 Annual Report*, EIA, 1997.

The oil and gas industry has a unique standing for census purposes because of the sheer number of wells in the country. For the purposes of simplifying reporting procedures under SIC code 1311, the census defines an establishment as all activities of an operating company in an entire state. Therefore, these data give no information on the number of individual wells. Data collected by the Independent Petroleum Association of America, however, indicated that in 1997 there were 573,504 active wells extracting primarily crude oil, and 303,724 wells producing primarily natural gas in the United States (IPAA, 1999).

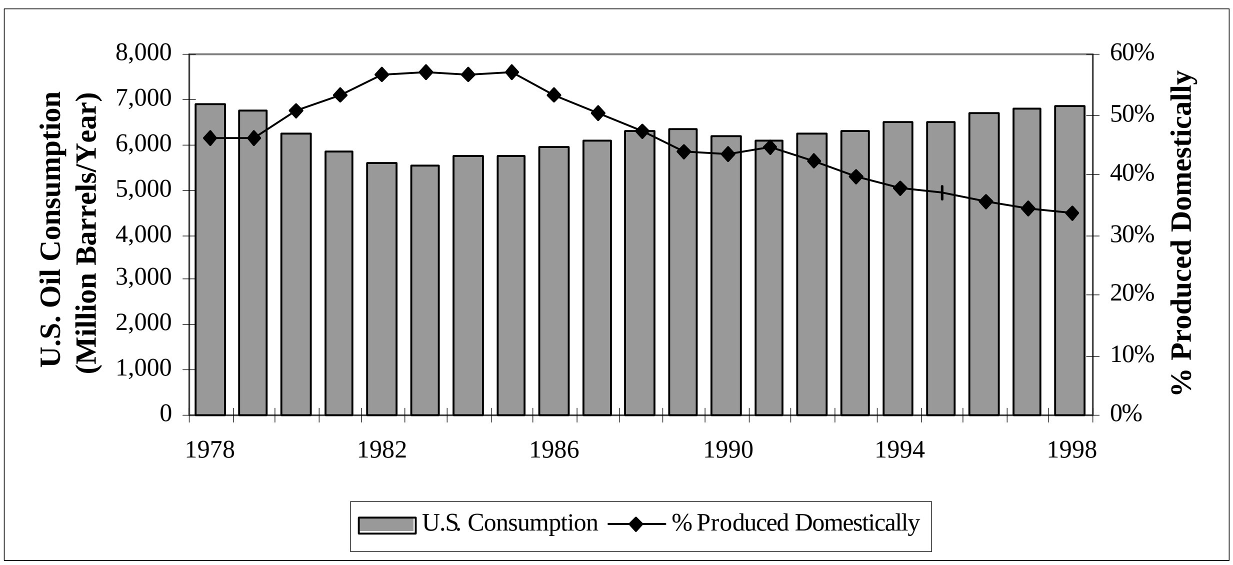
Another unique aspect of the industry is the marginal nature of many operations. Oil and gas wells can have very long lives (20 years or more); some wells drilled in the early years of this century are still producing, but only in small volumes. Wells typically have higher production in the early years, then decline and can level off at a low level of production that can be sustained for a long period (API, 1999). Wells that produce less than 10 barrels of oil per day are called “stripper wells.” As of 1997, there were 436,000 active stripper wells (76 percent of all active domestic wells) producing an average of 2.2 barrels each daily. Together stripper wells account for about 15 percent of domestic production (IPAA, 1999).

II.B.3. Economic Trends

Domestic Consumption

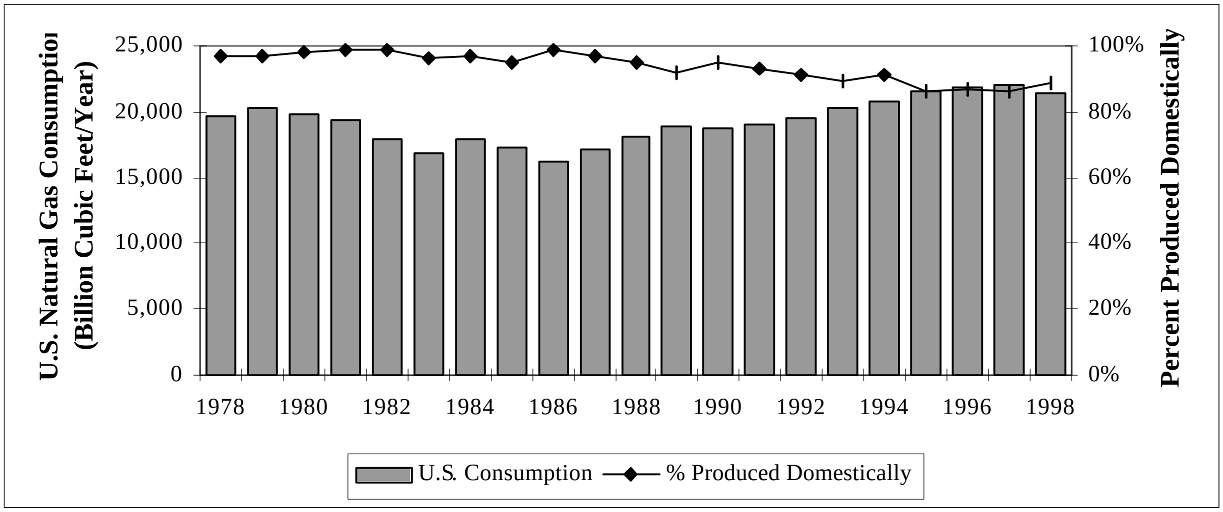
The consumption of oil and gas in the United States is closely linked to the overall economy of the country. Between 1990 and 1998, crude oil consumption increased approximately 1.4 percent each year, and natural gas consumption increased at a rate of 2.0 percent per year. The rate of natural gas consumption is expected to continue growing, mostly at the expense of coal. Natural gas is expected to become an important source of energy in the future and will be accelerated by government policies and the development of the natural gas transportation infrastructure. In the past several years, however, the percent of the domestic consumption of both oil and gas met by domestic producers generally has decreased (Figures 4 and 5).

Figure 4: U.S. Oil Consumption and Percent Produced Domestically



Source: EIA and IPAA, 1999.

Figure 5: U.S. Natural Gas Consumption and Percent Produced Domestically

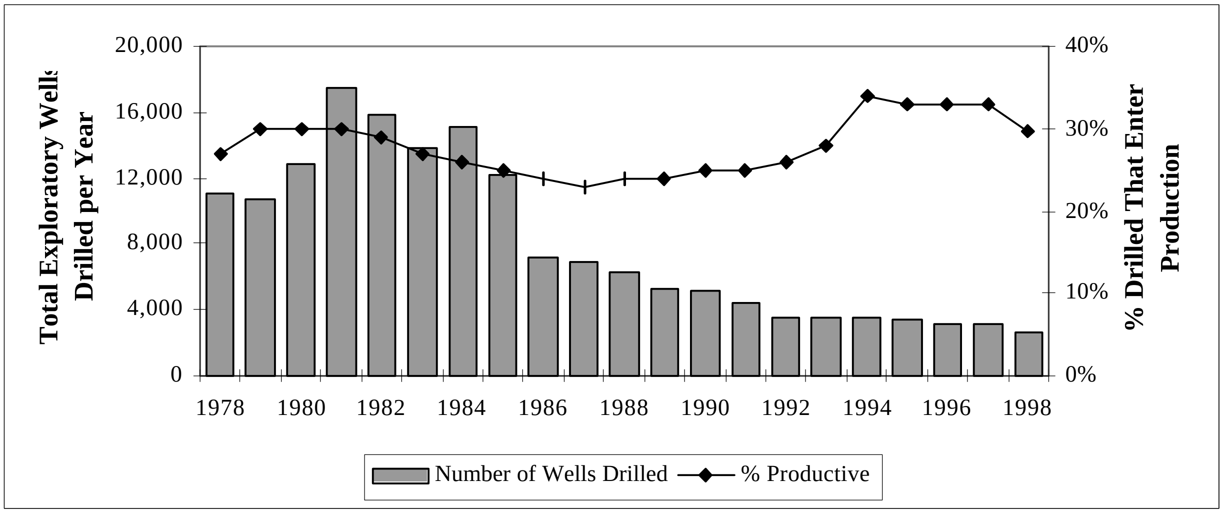


Source: EIA and IPAA, 1999.

Exploration and Reserves

The industry is exhibiting a general trend in exploration from domestic to foreign locations. In 1986, U.S. petroleum companies spent $17 billion on exploration and development within the United States and $7.5 billion abroad. In 1995, these firms spent $12.4 billion in the United States and $13.2 billion abroad (U.S. Department of Commerce (U.S. DOC), 1998). This shift in funds has placed an emphasis on drilling exploratory wells only at the most promising sites in the U.S. The results can be seen in Figure 6; many fewer exploratory wells are being drilled, but the success rate is higher.

Figure 6: Number of Exploratory Wells Drilled and Percent That Enter Production



Note: Includes both oil and natural gas wells.
Source: American Petroleum Institute, 1999.

The most active areas of exploration are the Gulf of Mexico and Alaska. In the Gulf of Mexico, the development of technology that facilitates drilling in deeper water (including floating structures, drillships and subsea completions) has made it more feasible to explore deep water sites. Another new source for potential reserves[2] is in Alaska, where roughly 87 percent of the Northeast National Petroleum Reserve was opened in 1998 for exploration and leasing (DOI, 1998). Developments such as these temporarily have boosted hydrocarbon reserves above production levels. In 1997, for the first time in a decade, crude oil reserves were added at a level greater than the amount depleted through production. However, it is expected that in the future reserves will again decline relative to production (EIA, 1998).

Natural gas exploration efforts in the United States have been more successful than crude oil exploration at keeping pace with production. Between 1994 and 1997, the industry added more reserves than it extracted in production. In 1997, about 64 percent of the new reserves of natural gas were found in the Gulf of Mexico Federal Offshore region and Texas (EIA, 1998).

Domestic Production and Prices

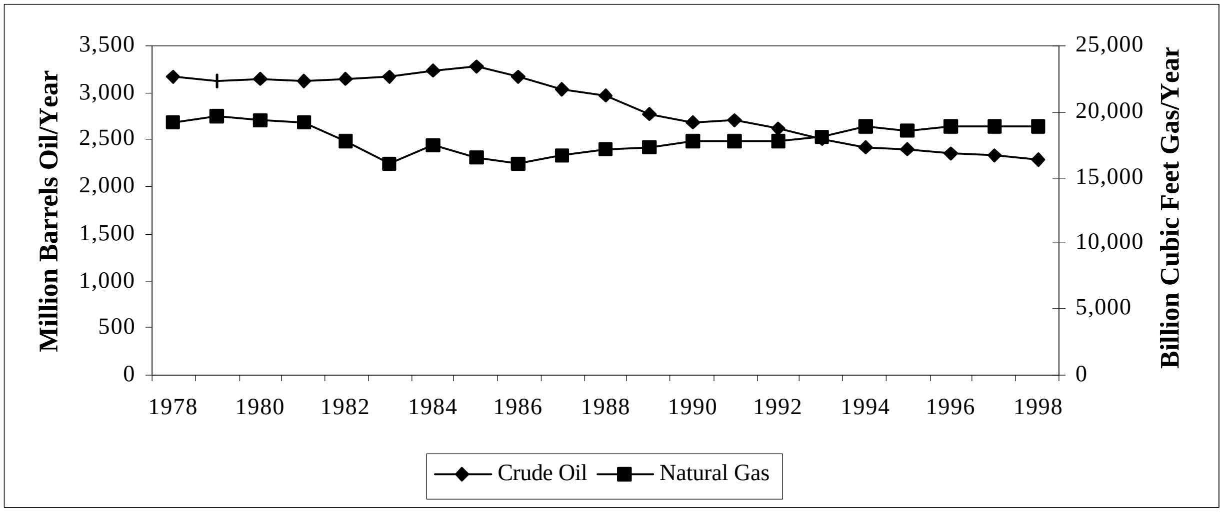
Production of crude oil is showing a decreasing trend, and natural gas production is showing an increasing trend. As shown in Figure 7, crude oil

[2] The Energy Information Administration of the U.S. Department of Energy defines proved reserves as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (EIA, 1998).

production is decreasing at an approximate rate of 1.5 percent per year. Leading the decline is Alaska, where production has declined approximately three percent per year in the past decade and six percent in 1997.

The production of natural gas, however, has been increasing steadily. Historically, growth has been about 1 percent per year, and is expected to grow at a rate of 1.6 percent per year through 2002 (U.S. DOC, 1998).

Figure 7: Domestic Crude Oil and Natural Gas Production

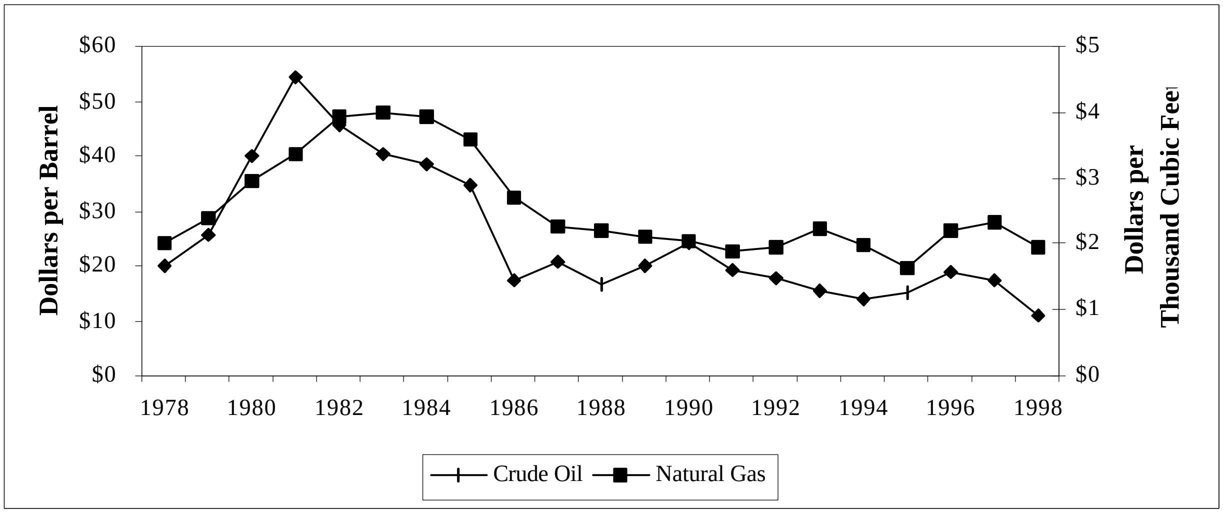


Source: EIA and IPAA, 1999.

As shown in Figure 8, the prices of both oil and gas have been quite volatile during the period between 1978 and 1997. In constant 1998 dollars, the wellhead price of crude oil has ranged between $10 and $54 per barrel. In 1998 and early 1999, prices were near $10 per barrel, but by August 1999 the price rebounded to over $20 per barrel (EIA, 1999).

Natural gas prices also have fluctuated. Wellhead prices reached a low point of $1.62 per thousand cubic feet in 1995, but increased in the subsequent two years. Prices of natural gas are expected to increase faster than those of oil through 2002, but still less than the rate of inflation (U.S. DOC, 1998).

Figure 8: Wellhead Crude Oil and Natural Gas Prices, Fixed 1998 Dollars



Source: EIA and IPAA, 1999.

III. INDUSTRIAL PROCESS DESCRIPTION

This section describes the major industrial processes within the oil and gas extraction industry, including the materials and equipment used and the processes employed. Specifically, this section contains a description of commonly used drilling and production processes, associated raw materials, the byproducts produced or discharges released, and the materials either recycled or transferred off-site. This discussion also provides a concise description of both the production and the potential fate of wastes produced in each process.

The section is designed for those interested in gaining a general understanding of the industry, and for those interested in the inter-relationship between the industrial process and the topics described in subsequent sections concerning waste outputs, pollution prevention opportunities, and federal regulations. This section does not attempt to replicate published engineering information that is available for this industry. Refer to Section IX for a list of reference documents that are available to supplement this document.

III.A. Industrial Processes in the Oil and Gas Extraction Industry

The oil and gas extraction industry can be classified into four major processes: (1) exploration, (2) well development, (3) production, and (4) site abandonment. Exploration involves the search for rock formations associated with oil or natural gas deposits, and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field, and involves the construction of one or more wells from the beginning (called *spudding*) to either abandonment if no hydrocarbons are found, or to well completion if hydrocarbons are found in sufficient quantities.

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. Production sites often handle crude oil from more than one well. Oil is nearly always processed at a refinery; natural gas may be processed to remove impurities either in the field or at a natural gas processing plant.

Finally, site abandonment involves plugging the well(s) and restoring the site when a recently-drilled well lacks the potential to produce economic quantities of oil or gas, or when a production well is no longer economically viable.

Two ancillary processes are also discussed in this section because they have significant economic and environmental implications. Maintenance of the well and reservoir is important in sustaining the safety and productivity of the operation and in ensuring protection of the environment. Spill mitigation is important in the oil and gas production industry because spills and other types of accidents can have serious implications for worker safety and the environment.

III.A.1. Exploration

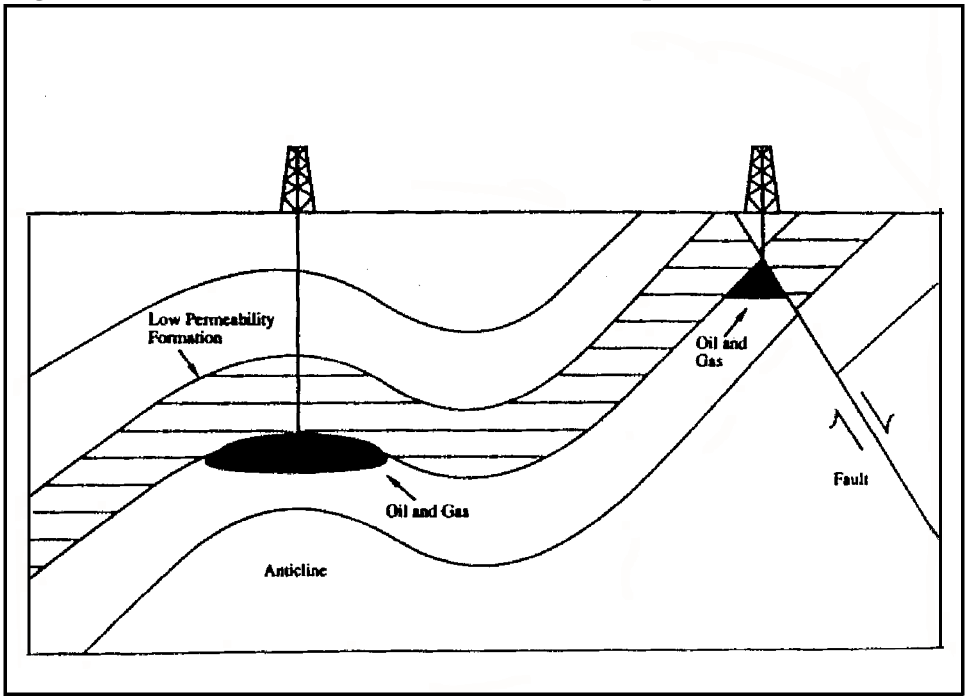
Oil and natural gas deposits are located almost exclusively in sedimentary rock and are often associated with certain geological structures. Geophysical exploration is the process of locating these structures in the subsurface via methods that fall under the category of remote sensing. In particular, common hydrocarbon-containing structures are those where a relatively porous rock has an overlying low-permeability rock that would trap the hydrocarbons (Berger and Anderson, 1992). Two common structural traps are found in Figure 9: anticlines are upward folds in the rock layers, while faults are fractures in the Earth's surface where layers are shifted.

Geophysicists search for these structures by taking advantage of the fact that seismic waves will travel through, bend, absorb, and reflect differently off of various layers of rock (Berger and Anderson, 1992). Geophysicists generate these seismic waves at the earth's surface, and measure the reflected seismic waves with a series of sensors known as geophones. Seismic waves can be generated by a variety of sources ranging from explosives that are detonated in holes drilled below the surface, to land vibroseis and marine airguns. Land vibroseis is typically used near populated areas and near sensitive environmental areas where detonations are not desirable. In the vibroseis process, trucks are used to drop a heavy weight on hard surfaces such as paved roads in order to create seismic waves.

In marine locations, explosives are less effective and have deleterious environmental impacts. In addition, vibroseis is impractical in water that is hundreds of feet deep. Seismic energy is therefore created by an airgun, a large device that can be emptied of air and water to create a vacuum. Seismic waves are created when water is allowed into the device at a very fast rate. It should be stressed that geophysical remote sensing cannot identify oil or gas accumulations directly; it can only indicate the potential for reserves via the presence or absence of certain rock characteristics that may be worthy of exploration.

After a site has been judged to have a reasonable chance of discovering a sufficient amount of hydrocarbons an exploratory well is drilled. It should be noted that although seismic exploration technology is constantly improving, it is not perfect. The only true way to discover the presence and quantity of petroleum is by drilling a well into the formation or structure suspected of containing hydrocarbons.

Figure 9: Common Oil and Gas Structural Traps



Source: EPA, 1992.

III.A.2. Well Development

Drilling

During the drilling process, wellsite geologists will augment the remote geophysical data with wireline logs, which are taken by means of devices lowered into the wellbore with wires. Wireline logs include several types of measurements that help to characterize the depths and thickness of subsurface formations and the type of fluids that they may contain. As an example, one type of log analyzes the resistance of the formation to electrical current, which helps to indicate the type of fluid and the porosity of the formation. For exploratory wells, mud logs may also be developed, which document the drill rate, types of rocks encountered, and any hydrocarbons encountered. The range of depths of well holes, or *wellbores,* is anywhere between 1,000 and 30,000 feet, with an average depth of all U.S. wells drilled in 1997 of 5,601 feet (API, 1998a).

For both onshore and offshore sites, the subterranean aspects of the drilling procedure are very similar. The drill bit is the component in direct contact with the rock at the bottom of the hole, and increases the depth of the hole by chipping off pieces of rock. The bit may be anywhere from three and three-fourths inches to two feet in diameter, and is usually studded with hardened steel or diamond. The selection of the drill bit can vary, depending on the type of rock and desired drilling speed. For example, a large-toothed steel bit may be used if the formation is soft and speed is important, while a diamond-studded bit may be used for hard formations or when a long drill life is desired (Kennedy, 1983). The drill bit is connected to the surface by several segments of hollow pipe, which together are called the *drill string*. The drill string is usually about 4 inches in diameter; drilling fluid is pumped down through its center and returns to the surface through the space, called the *annulus*, between the drill string and the rock formations or casing.

Drilling Fluids

Drilling fluid is an important component in the drilling process. A fluid is required in the wellbore to: (1) to cool and lubricate the drill bit; (2) remove the rock fragments, or *drill cuttings,* from the drilling area and transport them to the surface; (3) counterbalance formation pressure to prevent formation fluids (i.e. oil, gas, and water) from entering the well prematurely, and (4) prevent the open (uncased) wellbore from caving in (Berger and Anderson, 1992; Souders, 1998). Different properties may be required of the drilling fluid, depending upon the drilling conditions. For example, a higher-density fluid may be needed in high-pressure zones, and a more temperature-resistant fluid may be desired in high-temperature conditions. While drilling fluid may be a gas or foam, liquid-based fluids (called *drilling muds*) are used for approximately 93 percent of wells (API, 1997). In addition to liquid, drilling muds usually contain bentonite clay that increases the viscosity and alters the density of the fluid. Drilling mud may also contain additional additives that alter the properties of the fluid. The most significant additives are described later in this section. The American Petroleum Institute (API) environmental guidance document "Waste Management in Exploration and Production Operations," (API E5) considers the three general categories of drilling fluid (muds) to be water-based, oil-based, and synthetic-based. Synthetic-based muds are used as substitutes for oil-based muds, but also may be an advantageous replacement for water-based muds in some situations.

Water-based muds are used most frequently. The base may be either fresh or salt water, for onshore and offshore wells, respectively. The primary benefit of water-based muds is cost; they are the least expensive of the major types of drilling fluids, and in general they are less expensive to use since the resultant drilling waste can be discharged onsite provided these wastes pass regulatory requirements (EPA, 1999). The significant drawback with water-based muds is their limited lubricity and reactivity with some shales. In deep holes or high-angle directional drilling, water-based muds are not able to supply sufficient lubricity to avoid sticking of the drill pipe. Reactivity with clay shale can cause the destabilization of the wellbore. In these cases, oil-based and synthetic muds are needed.

In 1993 EPA estimated that about 15 percent of wells drilled deeper than 10,000 feet used some oil-based muds (USEPA, 1993b). Oil-based muds are composed primarily of diesel oil or mineral oil and are therefore more expensive than water-based muds. This higher cost, which includes the added burden of removing the oil from drill cuttings, and the required disposal options make oil-based muds a less frequently used option. Oil-based muds are well suited for the high temperature conditions found in deep wells because oil components have a higher boiling point than water, and oil-based muds can avoid the pore-clogging that may occur with water-based muds. Also oil-based muds are used when drilling through reactive (or high pressure) shales, high-angle directional drilling, and drilling in deep water. These situations encountered while drilling can slow down the drilling rate, increase drilling costs or even be impossible if water-based muds are used. In cases when oil-based muds are necessary, the upper section of a well generally is drilled with water-based muds and the conversion is made to oil-based mud when the situation requires it. It is predicted that since the industry trend is toward deeper wells, oil-based muds may become more prominent. However, because oil-based muds and their cuttings can not be discharged this may not be the case.

Since about 1990, the oil and gas extraction industry has developed many new oleaginous (oil-like) base materials from which to formulate high performance drilling fluids. A general class of these fluids are called synthetic materials, such as the vegetable esters, poly alpha olefins, internal olefins, linear alpha olefins, synthetic paraffins, ethers, linear alkylbenzenes, and others. Other oleaginous materials have also been developed for this purpose, such as enhanced mineral oils and non-synthetic paraffins. Industry developed synthetic-based fluids with these synthetic and non-synthetic oleaginous materials as the base fluid to provide the drilling performance characteristics of traditional oil-based fluids based on diesel and mineral oil, but with the potential for lower environmental impact and greater worker safety through lower toxicity, elimination of Polyaromatic hydrocarbons (PAH), faster biodegradability, lower bioaccumulation potential and in some drilling situations decreased drilling waste volume (FR 66086, December 16, 1996).

On land, air and foam fluids may be used in drilling wells. These fluids are less viscous than drilling muds and can enter smaller pores more easily. They are used when a higher rate of penetration into the formation is desired. Because air is less dense than a liquid, however, these fluids cannot exert the same pressure in the hole as liquid, and their viscosity can be altered if drilling encounters liquid in the formation. For this reason, air and foam fluids are used only in relatively low-pressure and water-free drilling locations, but are preferred in these situations because these fluids are much less expensive than other fluids (Kennedy, 1983; Souders, 1998). Air and foam fluids currently are used in the drilling of about seven percent of the wells in the United States (API, 1997).

Drilling muds typically have several additives. (Air and foam fluids typically do not contain many additives because the additives are either liquid or solid, and will not mix with air and foam drilling fluids.) The following is a list of the more significant additives:

- Weighting materials, primarily barite (barium sulfate), may be used to increase the density of the mud in order to equilibrate the pressure between the wellbore and formation when drilling through particularly pressurized zones. Hematite (Fe_2O_3) sometimes is used as a weighting agent in oil-based muds (Souders, 1998).

- Corrosion inhibitors such as iron oxide, aluminum bisulfate, zinc carbonate, and zinc chromate protect pipes and other metallic components from acidic compounds encountered in the formation.

- Dispersants, including iron lignosulfonates, break up solid clusters into small particles so they can be carried by the fluid.

- Flocculants, primarily acrylic polymers, cause suspended particles to group together so they can be removed from the fluid at the surface.

- Surfactants, like fatty acids and soaps, defoam and emulsify the mud.

- Biocides, typically organic amines, chlorophenols, or formaldehydes, kill bacteria that may produce toxic hydrogen sulfide gas.

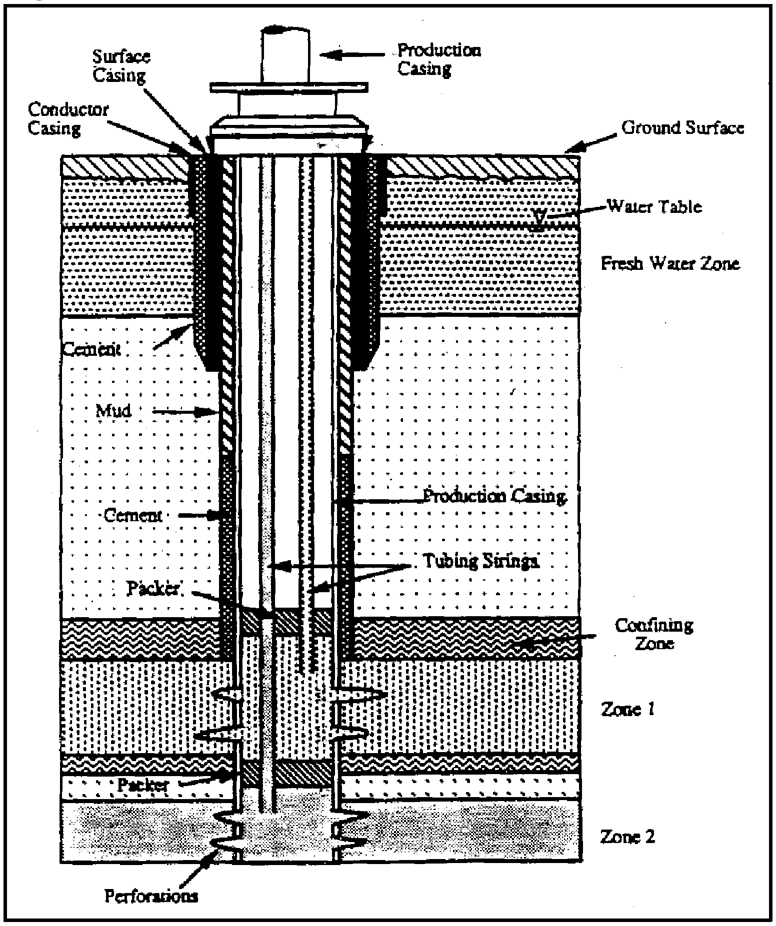
- Fluid loss reducers include starch and organic polymers and limit the loss of drilling mud to under-pressurized or high-permeability formations (EPA, Office of Solid Waste, 1987).

Casing

As the hole is drilled, casing is placed in the well to stabilize the hole and prevent caving. The casing also isolates water bearing and hydrocarbon bearing zones. As shown in Figure 10, three or four separate casing “strings” (lengths of tubing of a given diameter) may be used in intermediate-depth wells. In locations where surface soils may cave in during drilling, a "conductor" casing may be placed at the surface, extending only twenty to one hundred feet from the surface. This string is often placed prior to the commencement of drilling with a pile driver (Berger and Anderson, 1992). The next string, or "surface" casing, begins at the surface and may penetrate two thousand to three thousand feet. Its primary purpose is to protect the surrounding fresh-water aquifer(s) from the incursion of oil or brine from greater depths. The "intermediate" string begins at the surface and ends within a couple thousand feet of the bottom of the wellbore. This section prevents the hole from caving in and facilitates the movement of equipment used in the hole, e.g., drill strings and logging tools. The final "production" string extends the full length of the wellbore and encases the downhole production equipment. Shallow wells may have only two casing strings, and deeper wells may have multiple intermediate casings. After each casing string has been installed, cement is forced out through the bottom of the casing up the annulus to hold it in place and surface casing is cemented to the surface. Casing is cemented to prevent migration of fluids behind the casing and to prevent communication of higher pressure productive formations with lower pressure non-productive formations. Additional features and equipment shown in Figure 10 will be installed during the completion process for production: perforations will allow reservoir fluid to enter the wellbore; tubing strings will carry the fluid to the surface; and packers (removable plugs) may be installed to isolate producing zones.

Casing is important for both the drilling and production phases of operation, and must therefore be designed properly. It prevents natural gas, oil, and associated brine from leaking out into the surrounding fresh-water aquifer(s), limits sediment from entering the wellbore, and facilitates the movement of equipment up and down the hole. Several considerations are involved in planning the casing. First, the bottom of the wellbore must be large enough to accommodate any pumping equipment that will be needed either upon commencement of pumping, or in the later years of production. Also, unusually pressurized zones will require thicker casing in that immediate area. Any casing strings that must fit within this string must then be smaller, but must still accommodate the downhole equipment. Finally, the driller is encouraged to keep the hole size to a minimum; as size increases, so does cost and waste.

Figure 10: Cross Section of a Cased Well



Source: EPA, 1992.

Drilling Infrastructure

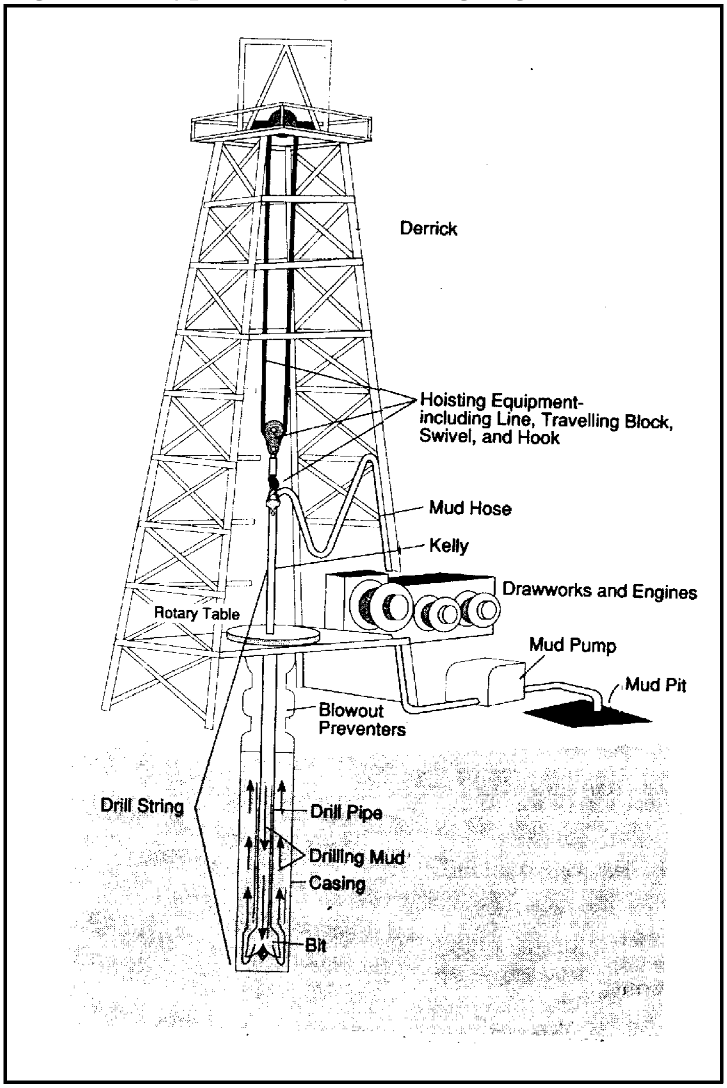
In addition to the well and its accouterments, infrastructure including construction and equipment is necessary at the surface. Roads and a pad are built at onshore sites; a ship, floating structure, or a fixed platform is needed for offshore operations. In addition, devices are needed to lift and lower the drilling equipment, filter rock cuttings from the drilling fluid, and store excess fluid and waste. The following sections describe the equipment required for onshore and offshore sites, respectively.

<u>Onshore Drilling</u>
Because the majority of onshore drilling sites are accessed by road, the equipment is geared toward mobility. First, an access road is built. In many locations the building of an access road is not difficult, but some areas present complications. On the North Slope of Alaska, for example, building a road that does not melt the permafrost can be both challenging and expensive. Board roads are used in some locations where soil conditions are not stable. Next, a footing for the equipment, usually gravel, is created in areas where the

ground may be either unstable or subject to freeze/thaw cycles. Finally, the drilling rig is brought in. For shallow wells, the drill rig may be self-contained on a single truck; for deeper wells, the rig may be brought to the site in several pieces and assembled at the site.

A basic arrangement of the actual drilling equipment, or *rig,* is shown in Figure 11. The derrick (sometimes referred to as the mast) is the centerpiece of the operation, and is the frame from which the drill string is lifted, lowered, and turned. The hoisting equipment, kelly, and drill pipe connect the bit to the derrick. The drawworks and engines next to the derrick lift and drive the drill string, by turning the rotary table. The drilling mud is circulated through the wellbore via the mud hose (also called a gooseneck), down through the rotary hose (not shown), kelly, and drillpipe, out nozzles in the drill bit, and back up to the surface between the drill string and the wellbore. The mud is pumped by the mud pump, and is stored in the mud (or reserve) pit or in mud tanks. Finally, blowout preventers, which are described later in this section, are installed as a safety measure to prevent the drill pipe and subsurface fluids from being blown out of the hole if a high-pressure formation is encountered during drilling. Rigs will often have much more equipment, including a shale shaker which separates rock cuttings, a desander and desilter, which remove smaller particles, and a vacuum degasser, which removes entrained gas (Berger and Anderson, 1992).

Figure 11: Typical Rotary Drilling Rig



Source: Energy Information Administration, Department of Energy, 1991.

<u>Offshore Drilling</u>

For offshore sites, selecting the type of drilling rig needed is very important. Two primary considerations in rig selection are: (1) the size of the rig needed for the depth drilled, and (2) the depth of the water. Exploratory wells (called wildcat wells) may be located far from established oil and natural gas fields, and the rig must be transported over a significant distance. Mobility is therefore a primary concern in these situations. The depth of water at the drilling site is also important. If the water is fairly shallow, a ground-supported rig may be used. If the water is deep (typically over 400 feet), a floating rig may be necessary. The following is a description of the significant offshore rig types:

Drillships are a popular choice for drilling in deep water, because they are the most mobile of the rig types and have a large capacity for drill strings, casing, and similar supplies. A drillship has a standard ship hull, with the derrick extending from its center. The ship is kept in place by anchors or by dynamic positioning, a system in which propellers on each side of the ship are coordinated to keep the ship in the same location despite wind, currents, and the torsion caused by drill activities.

Semi-submersible drilling rigs are another option at deep water sites. The rig is usually a rectangular structure that holds the drilling equipment, with ballast containers underneath. These containers can be filled with air to float the rig when moving it. The rig is held in place by anchors or dynamic positioning. The semi-submersible rig is more stable than a drillship, but it is also more cumbersome to move from site to site.

Jack-up rigs float and are very mobile, but rest on the sea floor when drilling. For this reason, they are used in relatively shallow water (i.e., under 400 feet). The rig is towed into place floating, and legs, previously raised for transportation, are lowered to the ocean bottom so that the rig is raised above the water and supported on the ocean floor. The legs may be raised and lowered independently to compensate for an uneven sea floor. In an alternative footing method, mat support, the legs are attached to a mat on the sea floor; this mat distributes the weight over a larger area and minimizes the risk of the rig sinking into the soft ocean floor.

Fixed structures are commonly used after exploratory or developmental drilling prove a site has economically recoverable hydrocarbons. In these cases, offshore drilling rigs are mounted onto the production platform, which are securely pinned to the sea floor by concrete, steel, or tension legs. Tension legs are hollow steel tendons that allow no vertical movement, but some horizontal movement. They are the largest and most complex offshore structures and can be used in water in depths of over 500 feet (usually less than 1,000 feet). Platforms are very stable and can withstand waves greater than 60 feet high, and winds in excess of 90 knots. Assembling a fixed platform is a sizeable investment; some platforms have been reported to cost over $1 billion (Berger and Anderson, 1992). For this reason, multiple wells are usually drilled at outward angles from a single platform. The centralizing of pumps and separation equipment also make this a convenient arrangement for production (Kennedy, 1983).

Lake and Wetland Drilling

Inland regions of water often require additional engineering techniques and special adaptations other than the onshore and offshore practices mentioned above. In places of deeper and more open water, barge rigs may be used for drilling. In shallow areas or wetlands, stationary rigs can be constructed or the area can be backfilled and drilled with a land-based rig. Canals may also be dredged to bring in floating or submergible drilling rigs. It is common while drilling in wetlands to use the directional drilling technique in order to disrupt as little of the wetland as possible while developing a field. Often supplies and equipment must be transported by helicopter, or dredging is required for access by barge rigs. Regardless of the approach used, these areas often pose challenges for erecting the rig and transporting materials and personnel to and from the site, and involves compliance with Clean Water Act wetlands regulations (See Section VI.B for additional information) (Kennedy, 1983, and EPA, 1995).

Well Completion

When drilling has been completed, several steps may be needed before production begins. First, testing is performed to verify whether the hydrocarbon-bearing formations are capable of producing enough hydrocarbons to warrant well completion and production. As many as three types of tests may be performed before the final (production) string of casing is installed. These tests are coring, wireline logging, and drill stem testing.

Coring is typically performed only in exploratory wells, and not in fields where several wells have already been drilled. A special drill removes an intact sample, or *core*, of rock at the depth where oil or gas is most likely to be. The core can be as short as 15 feet or as long as 90 feet. Special side-wall coring techniques may be employed in some wells. Unlike the more indirect testing methods described below, a core allows a geologist to observe the rock type directly, and measure its *porosity*, or the volume of fluid-occupying space relative to the volume of rock, and *permeability*, the ease with which fluids can flow through a porous rock.

Wireline logging refers to the recording of acoustical, electrical resistivity, and other geophysical measurements within a wellbore. These measurements provide detailed information on the geologic formations encountered by the well, and augment the seismic data recorded prior to the well drilling and the mud log for that well. These data often help to determine more precisely the depth at which oil and gas could be produced. A logging of electrical resistivity takes advantage of the fact that some compounds are better insulators of electrical charge than others. For example, oil, gas, and consolidated rock resist electrical current better than water and unconsolidated rock. Additional tests may be used; radioactivity logs can differentiate between types of rock, and neutron logs can measure the amount of liquid in the formation (but not differentiate between oil and water). Logging is performed on nearly all wells, and multiple forms of logging may be used in conjunction with each other to attain a more complete analysis. For example, a neutron log will indicate the amount of liquid in a formation, and a resistivity log may help to determine what percentage of that liquid is oil. Certain types of logs may be conducted during drilling with a special tool located on the drillstring above the bit.

Drill stem testing may be the most important and definitive test. Equipment attached to the bottom of a drill string traps a sample of formation fluid. Measuring the pressure at which the fluid enters the chamber and the pressure required to expel that fluid back into the formation yields an estimate of the flow rate of formation fluid to be expected during production. If the flow rate is expected to be too low, procedures such as stimulation (see below) may be required to increase the flow before production equipment is installed.

<u>Perforation</u>
When the production casing is cemented in the wellbore, the casing is sealed between the casing and the walls of the well. For formation fluid (oil, gas, and water) to enter the well, the casing must be perforated. The depth of the producing zone is determined by analyzing the logging data; small, directed explosive charges are detonated at this depth, thereby perforating the casing, cement, and formation. The result is that formation fluid enters the well, yet the rest of the well's casing remains intact.

<u>Stimulation</u>
Some formations may have a large amount of oil as indicated by coring and logging, but may have a poor flow rate. This may be because the production zone is not have sufficient permeability, or because the formation was damaged or clogged during drilling operations. In these cases, pores are opened in the formation to allow fluid to flow more easily into the well. The hydraulic fracturing method involves introducing liquid at high pressure into the formation, thereby causing the formation to crack. Sand or a similar porous substance is then emplaced into the cracks to prop the fractures open. Another method, acidizing, involves pumping acid, most frequently hydrochloric acid, to the formation, which dissolves soluble material so that pores open and fluid flows more quickly into the well. Both fracturing and acidizing may be performed simultaneously if desired, in an acid fracture treatment. Stimulation may be performed during well completion, or later during maintenance, or *workover*, operations, if the oil-carrying channels become clogged with time (EPA, 1992).

<u>Production equipment installation</u>
When drilling, casing, and testing operations are completed, the drilling rig is removed and the production rig is installed. In most cases, tubing is installed in the well which carries the liquids and gas to the surface. At the surface, a series of valves, collectively called the Christmas tree because of its appearance, is installed to control the flow of fluid from the well. Pumps are

added if the formation pressure is not sufficient to force the formation fluid to the surface. Different types of pumps are available; the most common is the rod pump. The rod pump is suspended on a string of rods from a pumping unit, and the prime mover for pumping units can be an electric motor, or a gas engine. Equipment is usually installed onsite to separate natural gas and liquid phases of the production and remove impurities. Finally, a pipeline connection or storage container (tank) is connected to the well to facilitate transport or store the product. In the case of natural gas, which cannot be stored easily, a pipeline connection is necessary before the well can be placed on production.

Although the practice is becoming less common, one or more pits may be constructed for onshore facilities. These may include a skimming pit, which reclaims residual oil removed with water that has been removed from the product stream; a sediment pit, which stores solids that have settled out in storage tanks; or an evaporation or percolation pit, which disposes of produced water (EPA, 1992).

III.A.3. Petroleum Production

The major activities of petroleum production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities. Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as well as the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Although the following discussion is geared toward wells producing both oil and gas, the majority of the discussion also applies to wells producing exclusively one or the other.

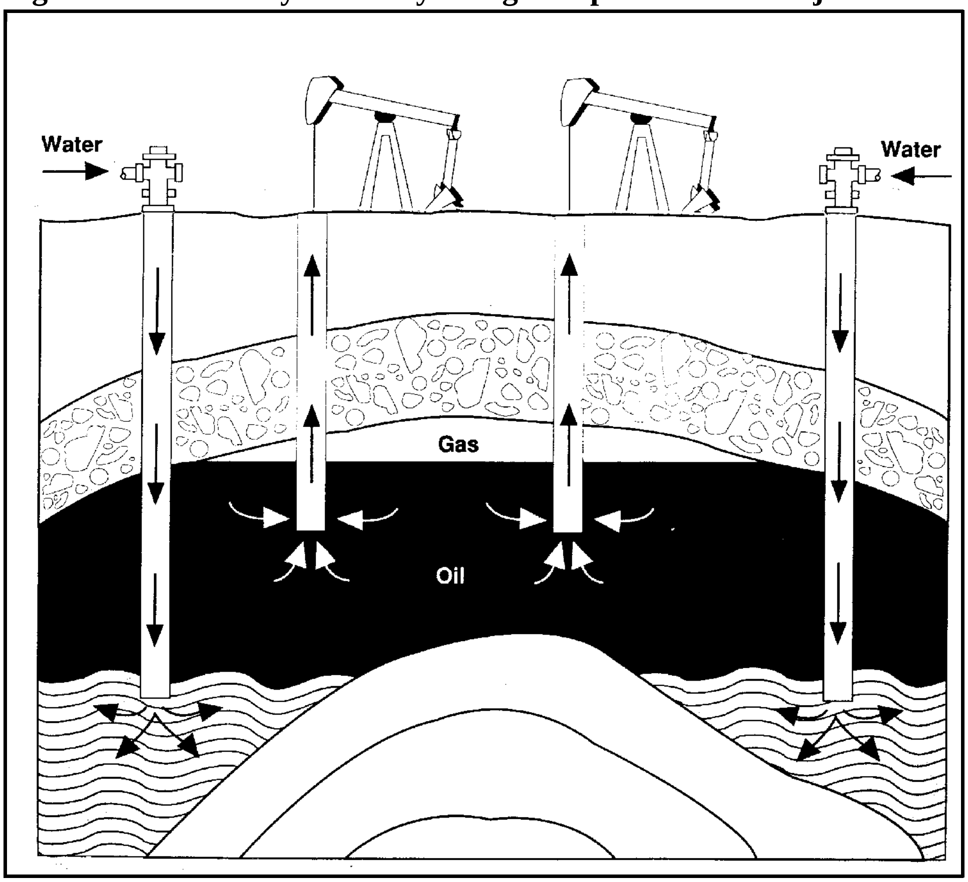
Primary Production

Primary recovery is the first stage of hydrocarbon production, and natural reservoir pressure is often used to recover oil. When natural pressure is not sufficiently capable of forcing oil to the surface, artificial lift equipment is then employed. This includes various types of pumps, gas lift valves, and may occasionally include oil stimulation. When pumping is employed, motors may be used at the surface or inside the wellbore to assist in lifting the fluid to the surface. Primary production accounts for less than 25 percent of the original oil in place.

Secondary Recovery

Secondary recovery enhances the recovery of liquid hydrocarbons by repressurizing the reservoir and reestablishing or supporting the natural water drive. Usually water which is produced with the oil is reinjected, but other sources of water may also be used. This type of secondary recovery is generally called a "waterflood" (See Figure 12). Produced water injection for enhanced recovery of crude oil and natural gas is recognized as a form of recycling of this waste. Furthermore, produced water is more commonly injected for the purpose of secondary recovery than in an injection well that is only used for disposal (in Texas, approximately 61 percent of injected produced water is for enhanced recovery) (Texas Railroad Commission, 1999). This procedure is described further in Section III.C., Management of Wastestreams. Gas is injected to enhance gas cap drive in some reservoirs.

Figure 12: Secondary Recovery Using Pumps and Water Injection



Source: Energy Information Administration, Department of Energy, 1991.

Tertiary Recovery

A final method for removing the last extractable oil and gas is tertiary recovery. In contrast to primary and secondary recovery techniques, tertiary recovery involves the addition of materials not normally found in the reservoir (Lake, 1989). These methods are often expensive and energy-intensive (Sittig, 1978). In most cases, a substance is injected into the reservoir, mobilizes the oil or gas, and is removed with the product. Examples include:

- Thermal recovery, in which the reservoir fluid is heated either with the injection of steam or by controlled burning in the reservoir, which makes the fluid less viscous and more conducive to flow;
- Miscible injection, in which an oil-miscible fluid, such as carbon dioxide or an alcohol, is injected to reduce the oil density and cause it to rise to the surface more easily;
- Surfactants, which essentially wash the oil from the reservoir; and
- Microbial enhanced recovery, in which special organic-digesting microbes are injected along with oxygen into the formation to digest heavy oil and asphalt, thereby allowing lighter oil to flow (Lake, 1989; EPA, 1992)

Crude Oil Separation

When the formation fluid is brought to the surface, it may contain a spectrum of substances including natural gas, water, sand, silt, and any additives used to enhance extraction. The general order of separation with respect to oil is the following: the separation of gaseous components, the removal of solids and water, and the breaking up of oil-water emulsions. (The conditioning of the natural gas that is removed in the first step will be discussed in the next subsection.)

The removal of gaseous components primarily is intended to remove natural gas from the liquid; however, gaseous contaminants such as hydrogen sulfide (H_2S) also may be produced in some fields during this process. The gases are removed by passing the pressurized fluid through one or two decreasing pressure chambers; less and less gas will remain dissolved in the solution as the pressure is lowered.

The liquids and solids that remain are usually a complex mix of water, oil, and sand. Water and oil are generally immiscible; however, the extraction process is usually very turbulent and may cause the water and oil to form an emulsion, in which the oil forms tiny droplets in the water (or vice versa). Fluid separation often produces a layer of sand, a layer of relatively oil-free water, a layer of emulsion, and a (small) layer of relatively pure oil. The free water and sand, or basic sediment and water (BS&W) are generally removed by a process called free water knockout, in which the BS&W are removed primarily by gravity. Finally, emulsions are broken by heating the fluid in a heater-treater to a temperature of 100-160 degrees fahrenheit, or by treating it with emulsion-breaking chemicals (Arnold and Stewart, 1998). Following the emulsion breaking, the oil is about 98 percent pure, which is sufficient for storage or transportation to the refinery (Sittig, 1978).

Natural Gas Conditioning

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of high enough quality to pass through transportation systems. It should be noted that conditioning is not always required; natural gas from some formations emerges from the well sufficiently pure that it can pass directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or problems. The most significant is hydrogen sulfide (H_2S), which may or may not be contained in natural gas. Hydrogen sulfide is toxic (and potentially fatal at certain concentrations) to humans and corrosive for pipes; it is therefore desirable to remove it as soon as possible in the conditioning process. Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas (methane) in the subsurface. These other gases must be separated from the methane prior to sale. At cold temperatures the water can freeze, also clogging pipes, valves, and gauges. High vapor pressure hydrocarbons that are found to be liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately. Two significant natural gas conditioning processes are dehydration and sweetening.

Dehydration is performed to remove water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration, and the glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing occurs in the field (at or near the well). At natural gas plants, solid desiccants are most commonly used (Smith, 1999).

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product. Another method of sweetening involves the use of iron sponge, which reacts with H_2S to form iron sulfide and later is oxidized, then buried or incinerated (EPA, 1992).

III.A.4. Maintenance

Production wells periodically require significant maintenance sessions, called *workovers*. During a workover, several tasks may be undertaken: repairing leaks in the casing or tubing, replacing motors or other downhole equipment, stimulating the well, perforating a different section of casing to produce from a different formation in the well, and painting and cleaning the equipment. The procedure often requires bringing in a rig for the downhole work. This rig can be smaller than those used for initially drilling a well.

Two procedures performed to improve the flow of fluid during workovers are removing accumulated salts (called *scale*) and paraffin, and treating production tubing, gathering lines, and valves for corrosion with corrosion-prevention compounds. As fluids are withdrawn from the formation, the salts that are dissolved in the produced water precipitate out of solution as the solution approaches the surface and cools. The resulting scale buildup can significantly reduce the flow of fluid through the tubing, gathering lines, and valves. Examples of scale removal chemicals are hydrochloric and hydrofluoric acids, organic acids, and phosphates (EPA, 1994). These solvents are added to the bottom of the wellbore and pumped through the tubing through which extracted fluid passes. In a similar fashion, corrosion inhibitors may be passed through the system to mitigate and prevent the effects of acidic components of the formation fluid, such as H_2S and CO_2. These corrosion inhibitors, such as ammonium bisulfite or several forms of zinc, may serve to neutralize acid or form a corrosion-resistant coating along the production tubing and gathering lines. Corrosion control activities can be continuous, not just at workover.

III.A.5. Well Shut-in/Well Abandonment

Production may be stopped for several reasons. If it is a temporary stoppage, the well is shut-in. If the closure is to be permanent, the well is either converted to a UIC Class II injection well, or it is plugged and abandoned.

A temporary shut-in is an option when the conditions causing the interruption in production are anticipated to be short-term. Examples include situations when the well may be awaiting a workover crew or a connection to a pipeline, or there may be a (temporary) lack of a market (Williams and Meyers, 1997). A well is shut in by closing the valves on the Christmas tree. Depending on the duration, the stoppage may be called a temporary abandonment, and regulatory approval and testing, including a mechanical integrity test (MIT), may be required in order to be idle (IOGCC, 1996). It is much more desirable to shut-in a well rather than plug it if production is still viable, because once the well is permanently plugged and abandoned, it is highly impractical to re-access the remaining oil in the reservoir.

If the well is part of a production field with many nearby wells still in production, the well may be converted to a UIC Class II injection well, which is regulated under the Safe Drinking Water Act (see Section VI.B, Sector-Specific Requirements for more information). Such a well can be used either for disposal of the produced water from these other wells, or may be part of a coordinated Enhanced Oil Recovery (EOR) effort in the field.

The final option is to plug and abandon the well. The goal of this procedure is to prevent fluid migration within the wellbore, which could contaminate aquifers or surface water. Oil and gas producing states all have specific regulations governing the plugging and abandonment of wells (see Section VI.B.4., State Regulations). When a well is plugged, the downhole equipment is removed and the perforated parts of the wellbore are cleaned of fill, scale and other debris. A minimum of three cement plugs are then placed, each of which are 100 to 200 feet long. The first is pumped into the perforated (production) zone of the well, in order to prevent the inflow of fluid. A second is placed in the middle of the wellbore. A third plug is placed within a couple hundred feet of the surface. Additional plugs may be placed anywhere within the wellbore when necessary. Fluid with an appropriate density is placed between the cement plugs in order to maintain adequate pressure. During this process, the plugs are tested to verify plug placement and integrity (Fields and Martin, 1998). Finally, the casing is cut off below the surface, capped with a steel plate welded to the casing, and at onshore sites, surface reclamation is undertaken to restore natural soil consistency and plant cover (EPA, 1992).

Problems are sometimes encountered with wells that have stopped production, yet neither have government approval nor have been plugged. These are generally called idle wells, or when the owners are not known or are insolvent, are called orphan wells. Please see Section III.B for the possible environmental impacts of such wells.

<u>Offshore Platform Decommissioning</u>
For offshore, the structure itself must be decommissioned in addition to plugging the well. Several options exist:

- Complete removal of the structure and disposing of the structure onshore
- Removing the structure and placing it in an approved location in the ocean
- Reuse of the structure elsewhere (National Research Council, 1996).

The method used will vary with the type of structure and water depth, but the most common approach is the complete removal of the structure, with removal at a minimum of 15 feet below the mudline (seafloor). Other approaches are less expensive and less intrusive to the existing environment, but can be more dangerous for commercial ships, military submarines, fishing trawlers, and recreational boaters. In Texas and Louisiana, however, it may be possible to participate in the states' "rigs-to-reefs" programs, which under the National Fishing Enhancement Act of 1984 seek to convert offshore structures to permanent artificial reefs (MMS, 1999).

When removing the structure, the most common approach is to sever the leg piles with explosives. Explosives must be placed at least five feet below the mud line (sea floor). Explosives are less expensive and are less risky to divers than alternatives such as manual or mechanical cutting, but concern has been raised about the use of explosives and their effect on marine life (National Research Council, 1996).

III.A.6. Spill and Blowout Mitigation

Accidental releases at oil and gas production facilities may come in two forms: spills or blowouts. Oil spills (usually consisting of crude oil or condensate) may come from several sources at production sites (and in some cases at drilling sites): leaking tanks, during transfers, or from leaking flowlines, valves, joints, or gauges. Other spills of oil have occurred such as diesel from drilling operations, oily drilling muds while being offloaded, and production chemicals (MMS, 1998). Spills are the most common type of accident and are often small in quantity.

Well blowouts are rare, but can be quite serious. They are most likely to occur during drilling and workovers, but can occur during any phase of well development including production operations. When the drill encounters an unusually pressurized zone or when equipment is being removed from the hole, the pressure exerted by the formation may become considerably higher than that exerted by the drilling or workover fluid. When this happens, the formation fluid and drilling or workover fluid may rise uncontrollably through the well to the surface. Downhole equipment may also be thrust to the surface. Especially if there is a significant quantity of associated natural gas, the fluid may ignite from an engine spark or other source of flame. Blowouts have been known to completely destroy rigs and kill nearby workers. Some blowouts can be controlled in a matter of days, but some -- particularly offshore -- may take months to cap and control (Kennedy, 1983).

Drilled wells and many workover wells are equipped with a blowout preventer. These blowout preventers (BOPs) are hydraulically operated, and serve to close off the drill pipe. BOPs can be operated manually, or can be automatically triggered. Most rigs have regular blowout drills and training sessions so that workers can operate the BOPs and escape as safely as possible.

Should a spill occur despite precautions, established responses should be undertaken. If the facility is subject to Spill Prevention Control and Countermeasure (SPCC) regulation (see Section VI.B for additional information), the facility will be equipped with secondary containment and diversionary structures to prevent the spill from reaching drains, ditches, rivers, and navigable waters. These structures may be berms, retention ponds, absorbent material, weirs, booms, or other barriers or equivalent preventive systems. Should these secondary containment devices not be adequate, the response will be different for onshore and offshore spills (EPA, 1999). In both cases, the goals are to stop the flow of oil, recover as much as possible of the material as a salable product, then minimize the impact on navigable waterways or groundwater.

<u>Onshore Spills</u>

For onshore spills, concern is for both surface runoff to streams, and for seepage into groundwater. The first considerations are to stop the source of the leakage and to contain the spill. Containment may either be achieved with pre-existing structures, or by using bulldozers at the time of response (Blaikley, 1979). Pooled oil would then be collected, pumped out, and whenever possible, processed for sale. When treating the contaminated soil, the remediation approach taken may vary considerably depending on the porosity of the soil and composition of the spilled fluid. If the spill has permeated less than about 6-10 inches of soil, bioremediation may be the most appropriate approach. With bioremediation, hydrocarbon-digesting microbes found naturally in soil are enhanced with fertilizers and moisture to degrade the material. The site would be tilled periodically and watered to maintain proper amounts of air and moisture. Should the temperature at the site be too cold or should the spill be too deep for bioremediation to be fully effective, approaches such as composting, or soil excavation with landspreading or landfilling, may be used either exclusively or in combination (Deuel and Holliday, 1997). Another option in remote locations or in situations when other options have not been successful is in-situ burning. In these situations, primarily when there is little surrounding vegetation, calm winds, and difficulty in transporting the equipment required for other methods, the oil is concentrated as much as possible and ignited by any of a variety of methods (Zengel, et al., 1998; Fingas, 1998). Application of in situ burning is still being refined.

<u>Offshore Spills</u>
The conditions for an offshore spill cleanup can vary substantially; from deep-water to coastal, from calm water to very choppy seas. As with onshore spills, initial priorities are to contain spilled oil and prevent further leakage. The oil is usually contained by booms, or floating devices that block the movement of surface oil. The booms may then be moved to concentrate the oil, at which point skimmers collect the oil. Booms may also be placed along a shoreline to minimize the amount of oil that reaches shore. For the oil that cannot be collected in this fashion, other approaches are used to minimize environmental impact, including sorbents, dispersants, or oil-digesting bacteria (EPA, 1993). In-situ burning also may be an option for offshore spills. This option may be best suited to arctic conditions, where cold temperatures keep the oil relatively concentrated and where ice may hinder the use of other methods. Depending on the thickness of the oil, the calmness of the seas, and other factors, the destruction rate can be over 90 percent (Fingas, 1998; Buist, 1998). This technique has not been widely used and is still considered experimental.

III.B. Raw Material Inputs and Pollution Outputs

This section describes the impacts that individual steps in the extraction process may have on adding contaminants to the environment. Relevant inputs and significant output wastes are presented, with outputs summarized in Table 2. The management techniques used to handle the wastes are discussed in Section III.C, and more information on the magnitude and qualities of the releases are found in Section IV.

Oil and gas extraction generates a substantial volume of byproducts and wastes that must be managed. Relatively small volumes of chemicals may be used as additives to facilitate drilling and alter the characteristics of the hydrocarbon flow. For example, acids may be used to increase rock permeability, or biocides may be added to wells to prevent the growth of harmful bacteria. The industry also contends with many naturally occurring chemical substances. Byproducts and wastes result from the separation of impurities found in the extracted hydrocarbons or from accidents when oil is spilled. In addition, most processes involving machinery will produce relatively small quantities of waste lubricating oils and emissions from fossil fuel combustion, and inhabited facilities will produce sanitary wastes. Finally, formation oil contamination may be present in the spent drilling fluids and cuttings.

Drilling

There are a number of possible environmental impacts from the wastes generated during the well drilling and completion/stimulation processes. In the drilling process, rock fragments (cuttings) are brought to the surface in the drilling fluid. These cuttings pose a problem both in the large volume produced and the muds that coat the cuttings as they are extracted. Oil-based fluids have the added stigma of having oil frequently coating the cuttings. The volume of rock cuttings produced from drilling is primarily a function of the depth of the well and the diameter of the wellbore. It has been estimated that between 0.2 barrels and 2.0 barrels (8.4 and 84.0 gallons) of total drilling waste are produced for each vertical foot drilled (EPA, 1987).

Drilling mud disposal generally becomes an issue at the end of the drilling process. However, sometimes drilling mud is disposed of during the drilling process when the mud viscosity or density needs to be changed to meet the demands of formation pressures. This can create special concerns for offshore operations where the disposal of a large volume of mud over a short period can create a mud blanket on the seafloor that can have an impact on benthic organisms. Industry is limited to using barite stock for the making of drilling mud, which passes 40 CFR 435 requirements (less than or equal to 1 ug/kg dry weight maximum mercury and 3 mg/kg dry weight maximum cadmium).

The muds are combined, however, with dissolved and suspended contaminants including mercury, cadmium, arsenic and hydrocarbons (typically found in trace amounts). The additives listed in Section III.A may be found in waste mud, and components from the formation, such as hydrogen sulfide and natural gas, may also be dissolved in the mud. Rock cuttings from the formations overlying the target formation may contribute contaminants to the drilling mud such as arsenic or metals. Also rock cuttings create a large volume of waste and for water-based fluids the rock cuttings may be discharged to surface waters offshore. Oil-based mud will also contain diesel oil that must be disposed of properly, or more typically, conditioned for reuse. Oil-based muds and cuttings cannot be discharged to surface waters. Both oil-based and synthetic-based fluid are conditioned and reused, which reduces waste volume from drilling operations.

Drilling operations also produce air emissions, such as exhaust from diesel engines and turbines that power the drilling equipment. The air pollutants from these devices will be those traditionally associated with combustion sources, including nitrogen oxides, particulates, ozone, and carbon monoxide. Additionally, hydrogen sulfide may be released during the drilling process (EPA, 1992).

Some steps in the well completion process may produce waste. The most prominent is stimulation. Unused hydrochloric acid must be neutralized if acid stimulation is being used, and paraffins and any other dissolved materials brought to the surface from the formation must be disposed of as well. In addition, solid wastes such as waste cement and metal casing may remain from the casing process.

Production

The primary byproduct from the production process (and the dominant one on a volume basis in the industry) is produced water. Other wastes that may be generated during production include the residual wastes that remain after separation of the oil and natural gas.

<u>Produced Water</u>
The largest volume byproduct by far in the extraction process is water extracted with oil. In wells nearing the end of their productive lives, water can comprise 98 percent of the material brought to the surface (Wiedeman, 1996). The American Petroleum Institute estimates that over 15 billion barrels of water are produced annually. This is nearly eight barrels of water for every barrel of oil produced. Natural gas wells typically produce much lower volumes of water than oil wells, with the exception of certain types of gas resources such as coalbed methane or Devonian/Antrim shales (API, 1997).

Although many petroleum components are separated from the water easily, some components and impurities are water-soluble and difficult to remove. Some substances may be found in high concentrations, including chloride, sodium, calcium, magnesium and potassium. Others found are:

- Organic compounds: benzene, naphthalene, toluene, phenanthrene, bromodichloromethane, and pentachlorophenol;
- Inorganics: lead, arsenic, barium, antimony, sulfur, and zinc;
- Radionuclides: uranium, radon, and radium (EPA, 1992).

It should be noted that concentrations of these pollutants will vary considerably depending on the location of the well and the extent of treatment of the water. Geography can be a key factor in whether a substance may exist in produced water. For example, radionuclides are found only in some areas of the country.

The risks of water pollution due to produced water management differ for onshore and offshore operations, and are discussed separately.

Onshore operations, and coastal and shallow offshore areas, may pose a risk to the environment if produced water with high saline concentrations is not properly managed. The saline concentration of produced water varies widely. In some locations, the produced water can have salt concentrations of 200,000 mg/L (Stephenson, 1992). However, in some areas west of the 98th Meridian, produced water may contain low enough levels of salt that it may be used (upon meeting regulatory limits for oil and grease) for beneficial use for irrigation or livestock watering (EPA, 1992; Railroad Commission of Texas, 1999).

The discharge of produced water inappropriately onto soil can result in salinity levels too high to sustain plant growth. If introduced to a water supply, the water can be unusable for human consumption. The introduction of metals and organic compounds from produced water are also a concern. (See Section IV for more details on contaminants in produced water.) However, over 90 percent of onshore produced water is injected for enhanced recovery or disposal (Smith, 1999). This injection involves a closed system from the producing wellbore to the injection wellbore, so the potential for release to the soil is minimized.

Offshore operations may impact the area immediately surrounding the platform if produced water effluents are not properly treated and discharged. The concentration of metals, radionuclides, residual oily materials and high BOD in the produced water may be higher than the surrounding water. However, the impact is reduced significantly at greater distances from the well; research in the Gulf of Mexico has indicated that produced water can be diluted 100-fold within 100 meters of the discharge (Neff and Sauer, 1996).

Natural Gas Processing

Wastes are generated when natural gas undergoes dehydration and sweetening. For dehydration, triethylene glycol is the most common desiccant. Although glycol is reused, it becomes less effective over time and must be replaced periodically. Glycols are volatile and can be hazardous if inhaled as a vapor. At larger natural gas processing plants, the solid molecular sieves that are used also require periodic replacement.

The wastes from gas sweetening will vary depending on the method used. Possible wastes include spent amine solution, iron sponge, and elemental sulfur. When there is a market for sulfur, it is sold.

Air Emissions

There are several sources of air emissions in the production process. Leaking tubing, valves, tanks, or open pits will release volatile organic compounds (VOCs). When natural gas produced from the well is not sold or used on-site, it is usually flared, thereby releasing carbon monoxide, nitrogen oxides, and possible sulfur dioxide if the gas is sour (see Section III.C. for more information on flaring). Finally, production involves the use of machinery including pumps, heater-treaters, and motors which require fuel combustion. Emissions from these include nitrogen oxides, sulfur oxides, ozone, carbon monoxide, and particulates (EPA, 1992). Where electricity is available, electric-powered equipment may be used. Emissions from natural gas processing plants (SIC 1321) are larger than field production operations due to the greater scale and concentration of equipment. Even at gas plants most engines are powered by natural gas or electricity.

Other Wastes

The sand that is separated from produced water must be disposed of properly. Similar to the sand removed during the drilling process, this sand is often contaminated with oil and trace amounts of metals or other naturally occurring constituents.

Most oil and gas operations include tanks for the temporary storage of oil, natural gas liquids, and/or produced water. While stored, small solid particles that were entrained in the liquids can settle out, forming a sludge on the bottom of the tank. These “tank bottoms,” or “basic sediment and water” (BS&W) wastes, may be periodically removed from the tank and disposed of. Some tanks may require cleaning a few times per year; others may require cleaning once every 10 years. The need for tank cleaning, and therefore the generation of these wastes, is dependent upon the characteristics of the fluids being handled and the operation. Because they are removed from hydrocarbon storage tanks, tank bottoms are likely to contain oil and smaller amounts of other constituents (see Section IV for an example of concentrations of contaminants in these sediments.)

Maintenance

The workover process requires many of the same inputs and produces similar outputs as the drilling process. In particular, workover fluid, which is similar to drilling fluid, is required to control downhole pressure. Also, emissions will result from the combustion of fuels to power the rig.

Workovers also use additional inputs and produce other pollutants, some of which are toxic. The compounds usually appear in the produced water when production resumes, or in the case of cleaning fluids, may be spilled from equipment at the surface.

Scale removal requires strong acids, such as hydrochloric or hydrofluoric acids. When carried to the surface in produced water, any acids not neutralized during use must be neutralized before being disposed, usually in a Class II injection well. Scale is primarily comprised of sodium, calcium, chloride and carbonate; however, trace contaminants such as barium, strontium, and radium may be present.

Also, corrosion inhibitors and stimulation compounds are flushed through the well. Corrosion-resistant compounds of concern include zinc carbonate and aluminum bisulfate. Stimulation may require acidic fluids.

In addition, painting- and cleaning-related wastes may be generated during workovers. Paint fumes and cleaning solvent vapor may produce gaseous emissions, paint and cleaning solvents with suspended oil and grease must be disposed of properly, and paint containers will require disposal as a solid.

Collectively, wastes produced by the industry other than drilling wastes and produced water are called associated wastes. The volume is usually small, about one barrel per well per year (DOE, 1993). Because associated wastes are those associated with chemical treatment or wells or produced fluids, post-treatment materials, and residual waste streams, they are more likely to have higher hydrocarbon or chemical constituent content than produced water or waste drilling fluids.

In 1985, API estimated that approximately 12 billion barrels of associated wastes were generated annually (Wakim, 1987). API estimates that in 1995, the annual volume of associated wastes is 22 millions barrels (API, 1997). The higher volume is attributed primarily to a difference in definitions between the two studies (i.e., the 1995 study includes wastes form gas plants that were not included in 1985). On a comparable basis, there has been only a slight increase in associated waste volumes over the past decade. This increase can be attributed primarily to aging wells requiring more stimulation or workover treatments to remain on production. Table 1 summarizes the types of associated wastes and their relative volume based on a 1985 API industry survey.

Table 1: Types of Associated Waste

Material	Process	Percent of Total Associated Waste Volume
Workover wastes (mud and other completion fluids, oil, chemicals, acid water, cement, sand)	Maintenance	34%
Produced sand, separator sludges	Production	21%
Other production fluid waste	Production	14%
Oily debris, filters, contaminated soils	All	12%
Cooling water, engine and other waste water	All	8%
Dehydration and sweetening unit wastes	Production	4%
Untreatable emulsions	Production	2%
Used solvents and cleaners	Maintenance	2%
Other production solid waste	Production	1%
Used lubricating or hydraulic oils	All	1%

Source: U.S. Department of Energy, 1993. (Based on a 1985 API survey)

Idle/Orphan Wells

Idle wells are wells that have ceased production (either temporarily or permanently) but have not been plugged. Generally the state regulatory agency knows the operator who is responsible for these wells, and in most states, wells require regulatory approval to be idle. However, a small percentage of these are orphan wells, for which no responsible party exists. This may be because the operator is unknown (in the case of wells drilled in the early part of the century) or because the operator has gone bankrupt and has no assets available.

Wells that have stopped production yet neither have state government approval nor have been plugged are uncommon. Approximately 134,000 of the nearly 2.7 million total wells drilled by 1995 in the United States are in this category (IOGCC, 1996). These wells may pose problems with respect to migrating reservoir fluid. With these wells, the mechanical integrity of the casing is not known, and therefore it may be possible for reservoir fluid to migrate to fresh water aquifers. In such cases, the primary contaminant would be saline formation water that could pollute fresh water aquifers and possibly surface waters.

It should be noted that not all of these wells will necessarily cause pollution; rather, the concern is that the risk posed by these wells is variable. Currently, most oil- and gas-producing states are handling the issue by prioritizing among these wells, and have established programs to plug dangerous orphan wells and clean up any contamination that may have already occurred. One way in which this prioritization is achieved is through area of review (AOR) studies that are required for the approval of new UIC wells. Under this requirement, the operator of the new well must study all active, idle and abandoned wells within an area (often a 1/4 mile radius) to determine whether they pose a risk of contamination (IOGCC, 1996).

Spills and Blowouts

Based on data from the U.S. Coast Guard and other sources, the American Petroleum Institute reported that in 1996, 1,276 onshore facilities reported spills of crude oil for a total of 131,000 gallons. This total would include spills from field operations, but also would include spills of crude oil at refineries, terminals, and other types of facilities. Spill volumes specifically for crude oil are not available. According to the Coast Guard, 78 percent of spills in 1996 were less than 10 gallons (API, 1998b).

Production facilities often have systems in place for handling larger accidents such as blowouts, and many onshore oil and gas operations must have a Spill Prevention Control and Countermeasures (SPCC) Plan in place for addressing spills. Under the CWA only spills above a certain threshold must be reported (see Section IV for more details on SPCC and CWA regulations). However, smaller spills appear to account for most reported crude oil releases. These are most likely to occur due to poor connections in filling or removing materials from tanks (Smith, 1999).

Offshore, the Marine Minerals Service collects data on oil spills. According to MMS, in 1995 there were 34 spills from production operations in the Gulf of Mexico, totaling 773 barrels. There was also one spill of one barrel of oil on the Pacific Coast (MMS, 1995).

In addition to oil spills, well blowouts can result in accidental releases of material. In a blowout, the pollutant can be produced water and oil, or drilling fluids and workover fluids, such that possible components of concern are salt, heavy metals, and oil. The produced water and oil mixture can be spread in a wide area around the rig possibly leaching through the soil to a fresh water aquifer or running off into nearby surface waters. Onshore, statistics on the number of blowouts annually are not available. Offshore, according to data from MMS, there was only one blowout in 1995, and 15 blowouts between 1991 and 1995. The total amount of oil spilled as a result of those blowouts was 100 barrels, all in 1992. It is assumed from the historical distribution that 14 percent of all blowouts could result in the spillage of crude oil or condensate, with 4 percent of the blowouts resulting in spills greater than 50 barrels. Since 1992, all blowouts have been controlled without any spills (MMS, 1995).

Accidental releases can also include air emissions. Crude oil contains organic compounds that may volatilize and be emitted before the spill can be cleaned up. In-situ burning of crude oil is one approach for cleaning up spills. Use of burning can result in emissions from the combustion, including particulates and carbon monoxide. Blowouts can result in the emission of methane (natural gas). If the well ignites, combustion outputs would be expected. In rare cases, process upsets at facilities that process sour natural gas could result in the release of hydrogen sulfide.

Table 2: Potential Material Outputs from Selected Oil and Gas Extraction Processes

Process	Air Emissions	Process Waste Water	Residual Wastes Generated
Well Development	fugitive natural gas, other volatile organic compounds (VOCs), Polyaromatic hydrocarbons (PAHs), carbon dioxide, carbon monoxide, hydrogen sulfide	drilling muds, organic acids, alkalis, diesel oil, crankcase oils, acidic stimulation fluids (hydrochloric and hydrofluoric acids)	drill cuttings (some oil-coated), drilling mud solids, weighting agents, dispersants, corrosion inhibitors, surfactants, flocculating agents, concrete, casing, paraffins
Production	fugitive natural gas, other VOCs, PAHs, carbon dioxide, carbon monoxide, hydrogen sulfide, fugitive BTEX (benzene, toluene, ethylbenzene, and xylene) from natural gas conditioning	produced water possibly containing heavy metals, radionuclides, dissolved solids, oxygen-demanding organic compounds, and high levels of salts. also may contain additives including biocides, lubricants, corrosion inhibitors. wastewater containing glycol, amines, salts, and untreatable emulsions	produced sand, elemental sulfur, spent catalysts, separator sludge, tank bottoms, used filters, sanitary wastes
Maintenance	volatile cleaning agents, paints, other VOCs, hydrochloric acid gas	completion fluid, wastewater containing well-cleaning solvents (detergents and degreasers), paint, stimulation agents	pipe scale, waste paints, paraffins, cement, sand
Abandoned Wells, Spills and Blowouts	fugitive natural gas and other VOCs, PAHs, particulate matter, sulfur compounds, carbon dioxide, carbon monoxide	escaping oil and brine	contaminated soils, sorbents

Sources: Sittig, 1978, EPA Office of Solid Waste, 1987.

III.C. Management of Wastestreams

The primary wastestreams are those associated with drilling wastes and produced water. As a result, most disposal options are oriented toward these two waste categories. The management of associated wastes and of gases is also briefly described.

Liquids

Underground Injection

Underground injection is the most common disposal method of produced water; over 90 percent of onshore produced water is disposed of through injection wells (API, 1997), but it is rare at offshore facilities. For disposal of produced water by underground injection, two options are available: to inject the water as a waste disposal method, or to use the produced water as part of a waterflooding effort for enhanced recovery. Water being disposed of typically is injected into known formations, such as a former producing formation. In a few Appalachian states, annular injection of produced water may be used, in which case the fluid is pumped into the space between tubing and casing (or uncased formation) within the well (EPA, 1992).

The second option, implemented especially in locations where formation pressure may be relatively low, is reinjecting produced water into the oil- and gas-producing formation. (See Figure 12 on page 29 for an illustration.) The volume of produced water used for enhanced recovery is approximately 57 percent of total produced water volumes (API, 1997). This method increases pressure in the formation to force oil toward the well and contributes to secondary recovery efforts. It requires that water be more thoroughly treated before injection; the water should be free of solids, bacteria, and oxygen, all of which could potentially contaminate the oil reservoir and, in the case of sulfur-reducing bacteria, could lead to increased hydrogen sulfide concentrations in the extracted oil. Please see Section VI.B, Sector-Specific Requirements for UIC regulations that apply to produced water underground injection.

Liquid wastes bought onshore may include produced water that fails NPDES toxicity requirements; water extracted from sludge; or treatment, workover, and completion fluids. At commercial waste treatment facilities liquid wastes are usually injected into disposal wells. As of February 1997, there are 94 disposal wells located in the Texas coastal zone and 17 in the Louisiana coastal zone. These wells could be used for disposal of OCS-generated liquid wastes (MMS, 1998).

Roadspreading

If the fluid has the characteristics of materials used for dust suppressants, road oils, deicing materials, or road compaction, the fluid may be used for roadspreading. In this procedure, water is applied to roads at approved rates, in order to prevent pooling or runoff and to minimize the risk of surface water or groundwater contamination. This practice may be subject to testing to ensure that the fluid is similar to the conventional road materials mentioned above, and also to ensure that the level of radioactive material is not above regulatory action levels (IOGCC, 1994). Roadspreading is declining as a disposal option, and accounts for less than 1 percent of produced water volumes (API, 1997).

Use of Produced Water for Irrigation

In areas west of the 98th meridian, produced water from onshore wells that are in the Agricultural and Wildlife Beneficial Use Subcategory may be used as a beneficial use with agriculture. In these cases, treated water that meets water quality standards may be released directly to agricultural canals for use in irrigation or livestock watering (EPA, 1992; Texas Railroad Commission, 1999). Beneficial use of produced water currently accounts for around 4 percent of onshore produced water volumes in the United States (API, 1997).

Evaporation or Percolation Pits

In this approach, produced water is placed in the pit and allowed to either evaporate to the air or percolate into the surrounding soil. These pits can only be used when the fluid will not adversely impact groundwater or surface water, and restrictions may be imposed on water salinity, hydrocarbon content, pH, and radionuclide content. This approach is declining because of potential environmental contamination of groundwater and the potential hazard posed to birds and waterfowl by residual oil in these open pits (IOGCC, 1994; Buckner, 1998). About 2 percent of produced water is currently disposed of using evaporation or percolation pits (API, 1997). Most of this volume is disposed of in percolation pits in arid portions of California.

Treat and Discharge

For this disposal method the water must meet standards for oil and grease content and pass a toxicity test prior to discharge. In 1997, 1 percent of onshore produced water was disposed of in this manner (API, 1997). Until recently, this method was also used at coastal facilities, but has been largely phased out since 1995. The only coastal area where discharge of produced water is currently allowed is Cook Inlet, Alaska.

Treatment and discharge is the primary method for disposing of produced water at offshore operations. Produced water discharges are not expected to take place at every platform or well. The trend in the Gulf of Mexico is for water treatment and separation of the well stream to occur only at designated locations. An industry survey of 1992 discharge monitoring reports submitted annually to USEPA (Shell Oil Company, 1994) found that only 29 percent of existing platforms contain water treatment systems and discharge their produced waters. As industry uses more sophisticated methods of developing shallow oil and gas fields and is required to conduct more complex treatment protocols, it is likely that operators will increasingly use central processing facilities (MMS, 1998).

Industry's projections (Deepstar, 1994) for deepwater are that the oil and gas produced in deepwater will most likely be piped from subsea completions through mixed line pipelines to large processing facilities primarily operating at the shelf break. These processing facilities will separate and process the production streams into oil, gas and water, and then discharge the treated water. The exception to this process would be whenever a floating production, storage and offloading system (FPSO) is chosen as the surface facility receiving oil and gas from subsea completions. An FPSO is a converted tanker used for a production and storage base, usually at a deepwater (greater than 400 meters) production site. These FPSO's, able to operate at any depth, would process the well stream prior to the transport of the products to shallower locations (MMS, 1998).

Table 3: Summary of 1995 Disposal Practices for Onshore Produced Water

Method	Percent of Onshore Produced Water
Injected for Enhanced Recovery	57%
Injection for Disposal	36%
Beneficial Use	4%
Evaporation and Percolation Ponds	2%
Treat and Discharge	1%
Roadspreading	<1%

Source: API, 1997.

Solids

The primary solid waste-generating process is drilling, and therefore the solid waste disposal processes are geared toward drilling waste. However, solid waste is also generated during production and maintenance. Production and maintenance wastes are usually transported offsite. Offshore, solids are often treated and discharged in accordance with Clean Water Act regulations.

In the Gulf of Mexico, offshore oil field wastes that are not discharged or disposed of onsite are brought onshore for disposal and taken to specifically designated commercial oil field waste disposal facilities. In Texas there are ten existing commercial oil field waste disposal facilities that receive all of the types of wastes that would come from the OCS operations (4 stationary treatment, 5 landfarms, and 1 commercial pit); in Louisiana there are seven facilities (5 land treatment, 1 incinerator, and 1 chemical stabilization facility); and in Alabama there are two landfarm/landtreatment facilities. Included in these numbers are one site in Texas and two sites in Louisiana that process naturally occurring radioactive material (NORM)-contaminated oil field wastes (MMS, 1998).

Reserve Pit

During drilling on land, a pit is usually constructed onsite to hold drill cuttings and extra drilling fluid. Depending on geology and hydrogeology, states might require reserve pits to be lined with geosynthetic or synthetic liners. Often the pit is intended only as a temporary holding vessel for drilling waste before being moved offsite for treatment and disposal; however, at some sites the reserve pit is used as the final disposal site. When used as a disposal method after drilling is completed, the liquid is removed (by suction or by evaporation if in a dry climate) and the solid remnants covered over with dirt. The liquids account for 62 percent of drilling waste by volume. Over two-thirds of the remaining drilling waste solids are disposed of by burying them onsite in the reserve pit (API, 1997).

Solidification

This is a modification of the reserve pit disposal method. When drilling is completed, a mixture of cement, flyash (from coal-fired utility boilers), and/or lime or cement kiln dust is added to the contents of the pit. The liquid in the pit does not necessarily need to be removed. The contents of the pit solidify into a concrete-like block, which immobilizes the heavy metal components. The process adds significantly to the bulk of the waste, but it prevents the mobilization of potential pollutants. In API's 1995 survey, less than 1 percent of drilling waste volumes were disposed of in this manner (API, 1997).

Landfarming or Landspreading

In this procedure, solids from the reserve pit (and potentially other solids from production) are broken up and thinly applied to soil, and tilled to mix the waste and soil. In theory, Volatile components evaporate off, metal ions bind to the clay, and heavy organic components are broken down by biological activity. State agencies do not use consistent terminology in referring to this process: some call it landfarming, others landspreading, and others use different terms. The disposal of solid wastes by spreading them on the land surface can occur either as a one-time application or in multiple applications. One-time application is most likely to be near the well site, and would most likely involve application of material from the reserve pit. Multiple applications of waste are often approved for centralized or commercial operations. In these cases, monitoring of soil constituents (e.g., pH, chlorides, and total hydrocarbons) is required by state agencies and once certain levels are reached, no more wastes may be applied on that site. In either one-time or multiple application operations, fertilizer may be added to enhance biodegradation of hydrocarbons. Land farming operations must be controlled to ensure that the hydrocarbons, salts and metals do not present a threat to groundwater or surface water, and that the hydrocarbon concentration does not inhibit biological activity. Approximately 10 percent of drilling waste solids are disposed of in landfarming operations (API, 1997; Smith, 1999).

Commercial Disposal

Offsite disposal of drilling wastes by commercial enterprises accounts for around 15 percent of drilling waste solids (API, 1997). This commercial disposal takes two formats. In major oil and gas producing areas of the country, dedicated facilities for managing exploration and production wastes exist. These facilities manage drilling waste and some associated waste streams using a range of processes from landfarming to slurry injection of solids to disposal in salt caverns. Drilling wastes from offshore that cannot be discharged (e.g., from oil-based muds) typically are barged to shore and disposed of in these commercial facilities. In areas of the country with less oil and gas activity, municipal or commercial landfills may accept drilling waste and certain other waste streams.

Reuse/Recycling

A growing share of drilling wastes are reused or recycled. It is currently estimated that around 10 percent of total drilling waste volume (solids and liquids) are reused or recycled. The liquids (mud) are reconditioned, with solids and other impurities removed, then used in the drilling of other wells. Because of the high cost of the base material, reuse of oil-based and synthetic-based muds is more common. Drilling waste is also used as landfill cover, roadbed construction, dike stabilization, and plugging and abandonment of other wells.

Associated Waste Disposal

Because associated wastes encompass such a diverse set of waste streams, generalizing about disposal options is difficult. What is appropriate for one stream may not be appropriate for another. Associated waste may be disposed of onsite or offsite. Some waste streams (e.g., waste solvents, unused acids, and painting wastes) are not unique to oil and gas exploration and production. These waste streams must be segregated from other wastes and managed the same as they would be at other industrial facilities. If these wastes exhibit hazardous characteristics they must be disposed of as RCRA hazardous wastes. (See Section VI.B. for more information on whether specific waste streams are exempt or non-exempt from RCRA hazardous waste requirements). Table 4 summarizes the general management of associated wastes across all waste streams.

Table 4: Management of Associated Wastes in 1995	
Management Technique	**Percent**
Underground Injection	58%
Commercial Facility	9%
Evaporation	8%
Recycling/Beneficial Use	8%
Municipal or Commercial Facility	4%
Landspreading	4%
Roadspreading	3%
Crude Oil Reclaimer	2%
Incineration	2%
Other (including hazardous waste disposal)	3%

Source: API, 1997. Data are based on a survey that may not fully represent a few lower producing areas of the country.

Gases

Flaring

Although most gas emissions are minimized through prevention, flaring can be used to reduce the impact of gaseous releases that are unavoidable or are too small to warrant the cost of capture. Nearly all drilling rigs and production wells are equipped with a vent and flare to release unusual pressure, and some wells that produce only a small amount of natural gas will flare it when there is no on-site use for the gas (e.g., to power engines) and no pipeline nearby to transport the gas to market. Since natural gas has economic value, flaring it is usually a last resort. Approval of state regulatory agencies is required prior to flaring.

When a gas is flared, it passes through the vent away from the well, and is burned in the presence of a pilot light. Although it is preferable to prevent the emission in the first place, flaring has benefits over simple venting of unburned material. First, by burning the gas, the health and safety risks in the vicinity of the well posed by combustible and poisonous gases like methane and hydrogen sulfide are reduced. Second, flaring reduces the potential contribution to climate change; methane is a much more potent greenhouse gas than carbon dioxide, the primary product of the combustion.