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Coastal Marine Institute

OCS-Related Infrastructure Fact Book

Volume I: Post-Hurricane Impact Assessment

U.S. Department of the Interior
Bureau of Ocean Energy Management
Gulf of Mexico OCS Region

Cooperative Agreement
Coastal Marine Institute
Louisiana State University

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Volume I: Post-Hurricane Impact Assessment

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ABSTRACT

This report examines a wide range of energy infrastructure assets along the Gulf of Mexico (GOM) that supports, or is supported by, offshore oil and gas production. The report does not explore any testable hypotheses or other complex research questions, but is merely a fact book that describes, examines, and outlines the nature of a variety of different, yet important, energy infrastructure assets in the region. The fact book examines these infrastructure assets' future development trends, and outlook given ongoing and expected offshore oil and natural gas exploration and production (E&P) activities.

This report examines 13 major energy infrastructure categories that are located along the GOM in significant numbers and capacity including: platform fabrication yards; shipyards and shipbuilding yards; port facilities; support and transport facilities; waste management facilities; pipelines; pipe coating yards; liquefied natural gas (LNG) facilities; natural gas processing facilities; natural gas storage facilities; refineries; petrochemical plants; and electric power infrastructure.

This report is an important update to earlier work (2004) sponsored by the Bureau of Ocean Energy Management's (BOEM) predecessor agency, the Minerals Management Service. The most important aspect of this update is the analysis of the various impacts that the tropical season of 2005 had on energy infrastructure in the GOM region. One of the most important conclusions drawn from the 2005 tropical season is that the area's critical energy infrastructure, including all forms of energy production, processing/refining, transportation, and distribution/sales is highly interrelated, perhaps to a degree not recognized during any other storm that has landed along the GOM. Outages in one energy sector had cascading impacts on other areas that may not have suffered significant physical damage from any of the storms.

The conclusion of the report is that the region's energy infrastructure is an important component of the overall value chain of North American energy production, refining, transportation, and distribution. A disruption in the region's infrastructure can have dramatic implications for not only domestic but also world-wide energy markets.

Also included as Volume II to this report is a study conducted by Eastern Resource Group (ERG) that takes infrastructure information and data compiled in this fact book analysis to develop a post-hurricane OCS infrastructure community impact analysis. The primary purpose of the ERG analysis has been to assess the post-hurricane impacts to communities with high concentrations of OCS-related infrastructure. The ERG study develops an empirical framework and methodology for measuring post-hurricane infrastructure/community relationships, and also includes six high infrastructure-concentrated community profiles and their hurricane recovery activities.

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EXECUTIVE SUMMARY

The purpose of this research has been to examine the wide range of energy infrastructure assets along the Gulf of Mexico (GOM) that supports, or is supported by, offshore oil and gas production. The sectors and infrastructure examined include: platform fabrication yards; shipyards and shipbuilding yards; port facilities; support and transport facilities; waste management facilities; pipelines; pipe coating yards; liquefied natural gas (LNG) facilities; natural gas processing facilities; natural gas storage facilities; refineries; petrochemical plants; and electric power infrastructure.

A number of issues and topics have been examined for each of these sectors including a basic description of the industry and the types of services provided; an overview of each sector's industry characteristics including an examination of the typical types of facilities, the geographical distribution of the firms and their location along the Gulf of Mexico; identification of typical or leading firms in each infrastructure sector; and the regulation and/or regulatory guidelines governing each industry sector.

Each chapter (or sector analysis) also includes an examination of the recent industry trends and forward-looking outlook for each infrastructure type. Each chapter also includes a section examining the impact that hurricane activity of 2005 had on each of the various infrastructure sectors and the ongoing, long-run implications of this tropical activity on continued infrastructure maintenance and development.

Fabrication Yards

Platform fabrication yards are defined as facilities where oil and gas drilling and production platforms are either manufactured, assembled, and/or prepared for deployment to offshore locations. Production operations at fabrication yards include cutting and welding of steel components, construction of living quarters and other structures, as well as assembling platform components.

Traditionally, platform fabrication yards are located onshore near inter-coastal waterways. However, there is a growing tendency to locate certain assembly operations directly offshore in order to minimize costs and maximize assembly flexibility. Onshore platform fabrication yards usually specialize in the production of a particular type of platform or component, such as living quarters, decks, or modules. This creates interdependence among different yards to complete an entire platform.

Platform fabrication yards saw minimal longer-term impacts from the 2005 hurricanes. Most of these facilities saw dramatically increased workloads resulting from the significant repair and recovery activities associated with the 2005 tropical season. The one challenge many of these facilities faced in the aftermath of the hurricane was securing a stable and reliable set of skilled laborers. This labor short fall was the result of both ongoing trends in the energy industry (i.e., greying of the labor force) and the fact that Hurricanes Katrina and Rita forced many workers away from their homes due to tremendous hurricane-created residential home damage.

Ongoing increases in annual capital budgets for GOM activities, created primarily from increased oil and gas prices in the post-2005 time period, create a positive outlook for future platform fabrication facilities activities. The companies that are capable of producing platforms for deepwater will most likely have a competitive advantage.

Shipyards and Shipbuilding

The shipbuilding and repair industry constructs, maintains, and repairs ships, barges and other large vessels, whether self-propelled or towed by other craft (i.e., barges). Most shipyards develop offshore watercraft on competitive bidding basis for an individual project or set of individual projects. Each year, only a small number of valuable orders are received by these various different shipbuilding yards that often take years to fill. Shipbuilding is a high-stakes industry represented by a high degree of competition between various shipbuilders. It is not common for several yards to be engaged in various specialized aspects of very large projects.

GOM rigs and platforms that were damaged during the 2005 tropical seasons created additional and new work for many in the shipbuilding and ship repair industries. Many of these facilities saw moderate to considerable damaged during the 2005 tropical season. For instance, some yards, such as Austal USA in Mobile, Alabama; and Conrad Industries in Morgan City, Louisiana sustained only minor damage. Other yards, such as Northrop Grumman in Pascagoula, Mississippi and New Orleans, Louisiana, and Bollinger Shipyards in Lockport, Louisiana, reported significant damage.

Shipyards also suffered considerable labor shortages as a result of the 2005 GOM tropical activity. Like other infrastructure categories, a large number of the shipyards' skilled labor force lived in the areas impacted by Hurricanes Katrina and Rita. Even two months after the storm, a number of companies remained shuttered for the sole reason that their employees did not have housing.

Some of the growth in the GOM shipbuilding market can be attributed to the development of offshore supply vessels (OSVs). The OSV market is of particular importance to the GOM shipbuilding and repair industry. As offshore exploration and production moves to deeper waters, newer boats with different operational capabilities (e.g., faster, more fuel efficient, larger) will be needed. The new generation of boats being developed along the GOM is technologically and physically more advanced relative to older boats. New OSVs and other service vessels are bigger and more robust. They have stronger winching power, more horsepower, higher speeds, and GPS-controlled dynamic thrusters, allowing for greater structure-side control and maneuverability.

Port Facilities

Ports play a vital role in the support of the offshore E&P sector, as well as the maritime industry, as a whole. Ports are the bases where the vehicles that support offshore platforms (notably ships, barges, and helicopters) are based and maintained. Ports are also the delivery, transfer, and launching points for the necessary structures, equipment, supplies, crew and other important products to offshore installations. Offshore exploration and production operations depend heavily upon a readily-available supply of these goods and services, making ports an invaluable centralized location for serving offshore E&P logistical needs.

Many ports along the GOM specialize in a particular set of activities while others handle more traditional transfers of goods associated with offshore activities. While GOM ports vary considerably by size, specialty, and defining characteristics, they can be categorized into two major types including 1) deep-draft seaports, and 2) inland river and intra-coastal waterways port facilities.

The 2005 tropical season highlighted the importance of both major shipping and supply ports. Several important deepwater ports suffered limited damage that curtailed operations for various periods of time. Further, many ports were impacted by the damage to the "upstream" forms of transportation including –roads and highway systems, rail transportation interruptions, and other inland waterway transportation disruptions created by debris blockage and silting in various different waterways and canals. The ports of New Orleans, St. Bernard, Plaquemines, Port Fourchon, South Louisiana, Venice, and Lake Charles experienced significant impacts during the 2005 tropical season. Other ports not directly affected by the storm experienced indirect impacts since water traffic had to be rerouted along a limited number of operational waterways, and to a limited number of operational ports. These impacts, for the most part, have been transitory, lasting for a few weeks, to no more than a few months. No ports were permanently shut down or shuttered as a result of the 2005 tropical season.

Support and Transport Facilities

Offshore oil and gas activities are supported by a considerable onshore supply and support logistics train. Support activities range from products and services such as engine and turbine construction and repair, electric generators, chains, gears, tools, pumps, compressors, and a variety of other tools and equipment. Additionally, drilling muds, chemicals, lubricants, and other fluids are produced and transported from onshore support facilities. Many types of transportation vessels and helicopters are used to transport workers, equipment, and materials to and from offshore platforms. Typical facilities for this sector include general support facilities, repair and maintenance yards, supply bases, heliports and offshore service vessels.

Offshore support and transportation facilities are highly dependent upon drilling and production activities, which are highly dependent upon oil and gas commodity prices. The cyclical nature of the oil and gas industry places competitive pressure on support and transportation facilities to be efficient, cost effective, flexible, responsive to tenant needs, and to diversify wherever possible. Often, the supply and transport segments of the offshore industry are the first sectors to feel the sting of oil and gas industry downturns. During periods of contraction, discretionary supply, repair, storage, and maintenance activities are the first to be cut to reduce E&P companies' costs.

Many transportation service companies were impacted by the 2005 hurricanes. One company, Bristow Group, suffered a total loss of one of its shore-based facilities due to Hurricane Katrina. Shortly thereafter, Hurricane Rita severely damaged two other of the Bristow Group locations. However, most of the offshore supply industry saw increased sales and activities as a result of the repair and restoration activities following the 2005 tropical season.

Support and transport facilities are crucial to the oil and gas industry. This sector relies upon a variety of management, personnel, construction, and design innovations in order to survive. Increased energy prices have created increased offshore oil and gas activity and in turn, a greater level of demand for offshore logistical support.

Waste Management Facilities

A variety of wastes are generated through offshore oil and gas E&P activities. Some wastes are common to most commercial-scale operations (e.g., disposal of garbage, sanitary waste (toilets), and domestic waste (sinks, showers)). Other wastes are unique to the oil and gas exploration and production industry (e.g., disposal of different types of drilling fluids, cuttings, and produced water). Some wastes can be discharged onsite, but many others must be transported to shore-based facilities for reclamation, storage and disposal, or transfer to longer-term storage sites. The most common methods of disposal of oil and gas E&P waste includes sea discharge, subsurface injection (salt cavern or other subsurface reservoir), and landfill disposal.

Factors that drive the demand for E&P-related disposal services include energy prices which drive overall E&P activities; a trend toward deeper, larger, and otherwise more complex drilling activities that increase drilling fluid consumption and technical requirements; and the continued trend of E&P development into more environmentally-sensitive and/or remote areas.

The 2005 tropical season appears to have imposed little negative direct impact on offshore disposal facilities. There were no reports from the industry overall or from individual operators along the GOM that there were any difficulties handling increased volumes or unique types of wastes created by the hurricanes. Further, there have been no recent reports by the industry or any individual waste industry operators along the GOM that identified any impending capacity-related constraints created by the hurricanes or recent industry growth. Research from this project indicated that current facilities appear to be well-situated to handle ongoing, even increased, oil and gas E&P-created wastes.

Pipelines

The movement of crude oil and natural gas from producing regions to consumption regions requires an extensive and elaborate transportation system. In many instances, crude oil and natural gas produced from a particular well must travel long distances to reach its point of processing and/or use. The transportation system for both crude and natural gas consists of a complex network of pipelines and supporting equipment designed to move these commodities quickly and efficiently from points of production to points of further processing (i.e., refineries, gas processing, fractionation), storage, or consumption.

Over 300,000 miles of steel pipe, ranging in diameter from 20 to 42 inches, serve as the "interstate highway" system for natural gas transportation. The offshore natural gas transportation system is comprised of some 33,000 miles of pipeline, linking approximately 4,000 operating platforms to onshore gas processing stations, underground storage facilities, and/or other transfer points. The natural gas pipeline system is composed of surface-level piping, valves, metering points, compressors, and dehydration and separation facilities, as well as sub-sea piping and valves. Secondary lines (typically less than 20 inches) feed the larger diameter primary lines (20 to 36 inches in diameter) that transport the natural gas directly to points onshore (USDOE, OFE, 2006).

Hurricane-created pipeline damage and outages were the result of a number of different factors. First, some pipelines were not physically damaged, but were forced out of service because of supply interruptions at the wells connected to, or upstream of the facility. As long as production was shut-in, many pipelines were under- or un-utilized. Second, physical damage to facilities was varied and could include displacement, partial or complete severing, or punctures/breaches. Offshore, this damage could result from a variety of impacts including riser damage and separation, movement stress, collision with other operating equipment in the Gulf (such as drilling rigs dragging mooring anchors), mudslides, and sea floor movement.

Since 2003, U.S. natural gas prices have remained sufficiently strong to keep large natural gas pipeline infrastructure projects moving forward. The need for these projects is coupled with current expectations regarding natural gas demand growth. Until recently, an increasing share of natural gas demand growth was expected to be met by imports of LNG. As net imports of LNG increase, it will have to be brought to the end-user via pipelines along the GOM. A number of developing and proposed natural gas pipeline projects are associated with new LNG import facilities along the Gulf Coast. The majority of these LNG import facilities are designed to regasify volumes at a high daily rate, 1 Bcf per day to 2.5 Bcf per day or greater. Strategic expansions in various places along the GOM pipeline grid will be needed to support the existing natural gas infrastructure.

Pipe Coating Yards

Pipelines that transport oil and natural gas have exterior coatings to protect against corrosion and other types of physical damage. Pipes may also be treated with interior coatings to protect against corrosion from the fluids moving within the pipe or to improve flow rates. In addition to corrosion protection, offshore oil and natural gas pipes are often coated with a layer of concrete to increase line weight to ensure it will stay on the seabed.

Threats to offshore pipeline integrity include third-party damage, geological activity, and corrosion. The most common threat, external corrosion, is recognized as the main deterioration mechanism that can reduce the structural integrity of all buried pipelines including those offshore. In fact, corrosion ranks second only to human error as the leading cause of pipeline failure.

The pipe coating business is highly dependent on the cyclical nature of oil and natural gas markets. During the early 1980s, the coatings business experienced significant growth. The mid to later 1990s saw companies researching new products to support deepwater GOM development. Over the years, pipe coatings have evolved from simple coal-tar applications to more sophisticated fusion-bonded epoxies and polypropylene coatings. Coating companies continue to test and develop new methods and new materials in the battle against corrosion and extreme environmental effects (i.e., temperature, pressure). Examples of new coating application methods include using multiple types or layers of protection. Examples of innovation in materials can include the use of new polymers and epoxies.

Activity for the pipe coating industry is expected to grow with expanded offshore oil and gas activities, particularly those attempting to develop newer and deepwater areas. Some companies are expanding their facilities to keep up with anticipated demand not only from production-induced growth, but also demand-driven growth that has been motivated, in large part, by increased concerns about emissions and the use of solid fuels (like coal) as an energy resource. Natural gas is increasingly becoming the fuel of choice in a new carbon constrained world.

LNG Facilities

Liquefied Natural Gas (LNG) is natural gas converted to liquid form by cooling it to a temperature of -256°F. This simple process, developed as early as the 19th century, allows natural gas to be transported from an area of abundance to one where it is in high demand. Once the LNG arrives at its destination, it is either stored as a liquid, or converted back to natural gas and delivered to end-users.

Large marine-based onshore LNG terminals that have been proposed across different areas of the coastal U.S. have received increased media and public attention in recent years. Currently, there are five LNG import facilities located in the Atlantic and Gulf Coast regions. Four of these facilities are original "legacy" assets developed during the energy crisis of the 1970s and early 1980s. These four facilities are all onshore facilities that have been expanded in recent years and each has a peak sendout of one Bcf per day or more. The newest terminal, Gulf Gateway Energy Bridge, began commercial operation in 2005 and operates offshore in the Gulf of Mexico, 116 miles off the south coast of Louisiana in 298 feet of water. This facility was the world's first deepwater LNG port. It delivers about 3 Bcf of regasified LNG into the natural gas pipeline grid at a rate of about 500 MMcf per day.

There have been a number of announcements and applications for new regasification facilities in various parts of the coastal U.S. More than 62 percent of capacity of proposed U.S. facilities (not including those in Bahamas, Canada or Mexico), comprising 33.9 Bcf per day, are located along the Gulf Coast. This is the highest concentration of proposed capacity anywhere in the U.S.

Excelerate Energy's Gulf Gateway Energy Bridge, located 116 miles off the Louisiana coast, narrowly avoided a direct hit by Hurricane Rita on September 23, 2005. Rita's eye passed just 25 nautical miles north of the Excelerate facility. Gulf Gateway suffered no major damage (the facility was designed using 100-year Gulf of Mexico storm conditions) despite wind driven seas near the eye of the storm reaching an estimated 70 feet in height. No damage was suffered at the facility, though pipelines serving the facility were affected and were not fully operational until mid-November.

Natural Gas Processing Facilities

Natural gas, as it is produced from reservoir rock, is typically a mixture of light hydrocarbon gases, impurities, and heavier liquid hydrocarbons. Natural gas processing removes the impurities and separates the hydrocarbon mixture into its useful components with methane being delivered into the natural gas pipeline system, and the heavier hydrocarbons separated for other uses. All natural gas is processed in some manner to remove unwanted water vapor, solids, and/or other contaminants that would interfere with pipeline transportation or marketing of the gas. Typical contaminants include hydrogen sulfide, carbon dioxide, nitrogen, and helium. Centrally located to serve different fields, natural gas processing plants have two main purposes: (1) to remove impurities from the natural gas stream; and (2) separate the gas into its various different useful components for eventual distribution to consumers.

The total number of gas processing plants operating in the U.S. has been declining over the past several years as companies merge, exchange assets, and close older, less efficient plants. Processing volumes in the GOM have recently declined given higher natural gas prices. These trends could reverse in the near future given BP and BHP's recent announcement commissioning the GOM Atlantis project, which is estimated to produce as much as 180 million cubic feet per day of natural gas and as much as 200 million barrels per day of crude oil.

Although the processing/treatment segment of the natural gas industry generally receives little public attention, its overall importance to the natural gas industry became readily apparent in the aftermath of Hurricanes Katrina and Rita in August and September 2005. Damage caused by the hurricanes resulted in a number of gas processing plant shut-ins. Causes of gas processing shut-ins were varied and can be categorized as either internally- or externally-created. Internally-created shut-ins arose from damage directly inflicted on the gas processing plants due to flooding, debris, and/or damage/destruction of plant equipment. Externally-created shut-ins were typically the result of events and factors beyond the direct control of the gas processing facilities themselves, such as lack of electricity, inaccessibility of the plant site because of road damage or other problems, lack of upstream supplies to the processing plant caused by production shut-ins or pipeline problems, and downstream problems related to the disposal of natural gas liquids or Y-grade liquids.

Natural Gas Storage Facilities

Gas storage serves three central roles: to meet seasonal demands for gas (base-load storage), to meet short-term peaks in demand (peaking storage), and to take advantage of changes in volatile natural gas prices between peak and non-peak usage periods (hedging and price arbitrage). The ability to store natural gas is essential to efficient natural gas market operation. Withdrawals from storage provide additional gas supply during seasonal and short-term gas demand peaks, help keep pipelines and distribution systems in physical balance, and play an important role in commodity trading and management. Generally, underground natural gas storage is filled during low utilization (off-peak) periods (April-October) and withdrawn during high utilization (peak) periods (winter). This results in a cyclical up and down pattern of gas storage volumes across any given year.

The number and total capacity of natural gas storage facilities continues to grow along the GOM. Many of these new facility announcements and expansions of existing facilities are being driven by the perceived need resulting from recently announced development of LNG regasification facilities and the significant increase in natural gas-fired power generation facilities that can cycle operations up and down upon momentary notice. Like pipelines, these storage investments represent additional dollars in local communities, and additions to supporting infrastructure.

There were no reports of significant damage by the 2005 hurricanes to any underground storage facilities. However, natural gas storage was impacted by the shut-in production throughout the Gulf region.

Refineries

A refinery is an organized arrangement of manufacturing units designed to produce physical and chemical changes that turn crude oil into final petroleum products. Refineries remove most of the non-hydrocarbon substances from crude oil and break down the remaining hydrocarbons into various components that are ultimately blended into useful refined products. Refineries vary in size, sophistication, and cost depending on their location, crude input types, and products manufactured. Crude oil is not a homogeneous raw material. It varies considerably by color, viscosity, sulfur content, and mineral content. Many of these qualitative variations are a function of the different fields or geographic areas from which crude is produced, leading to significant differences in both input values and refining profitability.

The Gulf Coast is the nation's leading supplier of refined products to the East Coast and the Midwest. Gulf Coast refineries supply the East Coast with more than half of its light refined product needs such as gasoline, heating oil, diesel, and jet fuel. Over 20 percent of the Midwest's light product consumption comes from the Gulf Coast.

The U.S. refining industry's ability to meet short-term increases in demand can also be measured by the rate at which operable capacity is utilized. Utilization rates are defined as a measure of gross inputs to operable capacity and are typically expressed as a percentage: higher percentages represent higher levels of utilization, and vice versa. Utilization rates can fluctuate as refinery operations adjust to changes in market demand and operating requirements (i.e., outages for planned and unplanned maintenance). Prior to Katrina, the refining sector was under tremendous pressure to keep up with growing domestic and global refined product demand. Strong global demand, driven by record levels of economic growth in China and India, has put pressure on the price and availability of all types of refined products. Tight refined product markets created two unique situations prior to the advent of Hurricane Katrina along the GOM. First, refineries in the Gulf region, as well as throughout the country, were running at record capacity factors and had little to no excess capacities to accommodate unanticipated outages. Second, high capacity utilizations, coupled with record refined product demand, resulted in record refined product prices in the summer of 2005 prior to Hurricane Katrina. The economic impact that Hurricane Katrina had on refined product markets was widely-reported. This has led, in some part, to a number of refineries announcing significant expansions and upgrades.

Petrochemical Plants

The chemical industry converts raw materials (oil, natural gas, air, water, metals, and minerals) into more than 70,000 different products (USDOE, EIA, 2000b). Final and intermediate chemical products that are formed from processed natural gas and refined are commonly referred to as petrochemicals. Sites for chemical manufacturing facilities are typically chosen for their (1) access to raw materials (inputs), (2) access to transportation routes (for outputs), and (3) access to other types of chemical manufacturing facilities since the chemical industry can be one of its own best customers by swapping and trading a variety of primary and intermediate chemical products.

Laid out like industrial parks, most petrochemical complexes include various component plants that manufacture various combinations of primary, intermediate, and end-use products. Changes in market conditions and technologies are reflected over time in the changing product slates of petrochemical complexes. In general, petrochemical plants are designed to attain the cheapest manufacturing costs and thus are highly synergistic. Product slates and system designs are carefully coordinated to optimize the use of chemical by-products and to use heat and power efficiently.

In the Gulf Coast area, the petrochemical industry is heavily concentrated in coastal Texas, South Louisiana, and various counties along the Alabama, Mississippi, and Florida coast. The Houston area is one of the world's largest manufacturing centers for petrochemicals, and six of the top 10 largest ethylene production complexes in the world are found on the Gulf Coast.

When Hurricanes Katrina and Rita hit the Gulf Coast in 2005, they had a considerable impact on U.S. petrochemical production. Hurricane Rita severely affected petrochemical production in Lake Charles, Louisiana, and eastern parts of Texas, but spared most major petrochemical plants elsewhere. Rita's size and the uncertainty of its landfall closed plants all along the Texas Gulf Coast and into Louisiana. The storm missed the Houston Ship Channel but still landed in an area supporting important chemical and refining operations between Port Arthur, Texas, and Lake Charles, Louisiana. Most chemical plants had returned to service by mid-October and a few plants in the Port Arthur-Lake Charles area were making final repairs or in the process of restarting. Like gas processing facilities, petrochemical plants had both direct and indirect impacts resulting in outages. Direct impacts were created by storm damage, while indirect impacts were the result of natural gas input shortages, pipeline supply interruptions, employee dislocations, and transportation (water, rail, and road) disruptions.

The health of the petrochemical industry is reliant upon oil and gas industry production as the primary feedstock source. The chemical industry represents only about 7.5 percent of the world's energy consumption. However, to prepare for the future, chemical companies increasingly need to use alternative technologies and feedstocks to remain competitive. This is particularly true for petrochemical facilities located in mature producing basins and mature (lower growth) chemical markets like the GOM region.

Electric Power Infrastructure

Electricity is an integral part of economic life in the United States and is used for a variety of lighting, appliance, and electronic uses as well as heating and cooling. Electricity is also indispensable to factories, commercial establishments, and most recreational facilities. The more than 3,170 traditional electric utilities in the U.S. are responsible for delivering an adequate and reliable source of electricity to all consumers within their respective service territories at a reasonable cost.

Electric power systems are based upon a collection of generation, transmission, distribution, and communication facilities that are physically connected and operated as a single unit under one control. Power plants (generation) can be grouped into the types of fuel or energy source they use to produce electricity. These include fossil fuels (coal, natural gas, or a refined oil product), nuclear energy, and renewable energy sources such as water (hydroelectric power), biomass, waste-to-energy, geothermal, wind, and solar energy, as well as other emerging alternative fuels. Power generation along the GOM is heavily dependent upon natural gas as a fuel source. Thus, the price and availability of natural gas can have important implications for power generation supply and price.

The electric power system in the Southeast was significantly impacted by Hurricanes Katrina and Rita. Generation facilities and a large number of transmission and distribution substations were flooded. High winds ripped out miles of transmission and distribution lines, poles, and towers. This damage left millions of customers without power for an extended period of time. Many power generation facilities along the GOM were impacted by natural gas availability challenges in the aftermath of the hurricanes. All utilities in the region saw immediate and significant increases in fuel costs for running power generation facilities. In Florida, several emergency warnings of potential outages were reported to regulators and the general public during and immediately after the hurricanes due to a combination of summer time peak demands and fuel shortages on certain pipeline systems originating in the GOM that supply fuel to the Florida generators.

According to the EIA, total electricity sales are projected to increase significantly over the next 25 years including sales in the southeastern U.S. and GOM region. The largest increase will be seen in the commercial sector. Service industries will continue to drive growth, particularly in the GOM region. For the residential sector, electricity demand is also projected to grow as population growth, and disposable income is expected to lead to increased demand for products, services, and floor space, with a corresponding increase in demand for electricity for space heating and cooling and to power the appliances and equipment used by buildings and businesses. Continued growth in all major sectors of the power industry will increase pressure for the new development of natural gas-fired generation, which in turn, will increase pressure to develop new sources of natural gas production, including those in the GOM.

1. INTRODUCTION

1.1. Overview

Onshore oil and natural gas activity began in the early 20th century with the development of the Spindletop field in East Texas and the Jennings field in Louisiana. From that point, an extensive amount of development began to spread throughout the region into more remote and geographically difficult areas. In South Louisiana, this expanded exploratory effort included the development of wells located in lake beds, river bottoms, bayous, and other areas considered "wet" by most measures. Tools like marsh buggies, drilling barges, semisubmersibles, and jackup platforms were all developed in the swampy and challenging environment of the region. These innovations, along with the extensive amount of surplus marine watercraft and manufacturing capabilities in the region after World War II, served as the launching point for the offshore industry. The experience gained during these early efforts set the foundations for today's offshore oil and natural gas industry (Austin et al., 2004).

The birth of offshore activity is commonly dated as 1947 when Kerr McGee, an Oklahoma independent oil and gas company, drilled the first well out of the sight of land along the GOM. Subsequent activity increased dramatically, particularly in what was considered state waters[1] as an increasing number of oil and gas operators attempted to develop what appeared to be large, profitable hydrocarbon reserves. Since that time, the offshore GOM has been a vibrant area of oil and gas exploration, development, and production with an ever increasing share of this activity being devoted to exploring the new frontier areas in the deepwater depths of the region.[2]

It was challenging to reach these remote offshore areas with labor, equipment, and supplies and to move hydrocarbon production to shore to be processed and delivered to end-users. The past five decades have seen the development of a massive and complicated network of support facilities, ports, roads, pipelines, and processing stations dedicated to supporting offshore drilling and production.

The GOM region is an inseparable part of the North American energy value chain and the supporting infrastructure in the region is an invaluable link connecting these important energy resources with North American markets. Even a moderate disruption of any link can have far-reaching impacts and can weaken other operations along the entire chain. Critical energy infrastructure in the GOM region accounts for:

- Over 20 percent of total U.S. natural gas production.
- Close to 30 percent of all U.S. crude oil production.
- Over 60 percent of all U.S. crude oil imports.
- Over 46 percent of total U.S. petroleum refining capacity.
- The single largest and most concentrated natural gas pipeline network in North America.

[1] The Submerged Land Act of 1953, recognized state ownership of the seabed within three miles of the shore.
[2] A "deepwater" lease is defined as having a minimum water depth of 200 meters, or 656 feet.

- Home of the U.S. Strategic Petroleum Reserve (SPR). The SPR is stored at four sites on the GOM, each located near a major center of refining and processing.
- Home to over 90 percent of total U.S. petrochemical production as measured by both value added and value of shipments.
- The two largest energy producing states in the U.S. Louisiana, including its offshore area, ranks first in crude oil production and second in natural gas production. Texas and its offshore regions, on the other hand, ranks second in crude oil production and first in natural gas production.
- A major set of product pipelines bringing millions of gallons of refined fuel products (i.e., gasoline, diesel, fuel oil) to eastern states as well as a major pipeline that transports crude oil from the GOM to refineries in the Midwest.

Various small and large businesses along the GOM provide important support services to offshore activities that include drilling support, general service companies, geophysical and geological services, equipment sales and maintenance, insurance, permitting, legal services, demurrage and storage, environmental services, waste disposal services, water supplies, mud and drilling fluids, and air and water transportation. The assets supporting the provision of these services (i.e., ports, terminals, buildings, warehouses, storage yards, etc.) can be thought of as an important part of the GOM oil and natural gas infrastructure.

Other important types of physical infrastructure have developed over the last five decades and have grown with the increase in offshore oil and gas E&P activities. Two important types of infrastructure, using regionally-produced (and imported) hydrocarbons as a feedstock, process these fossil fuels and their by-products into intermediate and final goods. This infrastructure includes modern petroleum refining and diverse chemical plants commonly referred to as the "petrochemical industry" along the GOM.

Petroleum refineries followed developing regional crude oil production into the GOM region at the turn of the century. Producers at that time had strong incentives to develop, or utilize, refineries that were located close to production sources. At the turn of the century, the refinery operations were typically based upon processes that boiled or distilled regionally produced crude oil into various different hydrocarbon cuts that focused almost exclusively on the valuable resource of the time: kerosene. Later, the development of an increasingly sophisticated set of distillation processes and catalysts allowed a greater variety of refined fuels such as gasoline, lubricants, and other hydrocarbon products to be "cracked" from crude oil as the demand created by internal combustion engines for transportation arose, and the U.S. and global economy moved to one almost exclusively driven by liquid fuels.

Modern petrochemicals are another important category of energy infrastructure in the region that arose during World War II to create products that supported the war effort (like fuel additives, plastics, carbon black, and artificial rubber products) and were later important to the post-WWII economic boom. These petrochemical industries took what was at the time low refinery by-products, as well as low-cost natural gas and its by-product liquids, and used these inputs as a feedstock to create a variety of products that has become the backbone of the modern chemical industry.

Historic trends in oil and gas production in the GOM are provided in Figure 1. Since natural gas is typically measured in volume (cubic feet) or heat content (British Thermal Units or Btus), production trends have been standardized to barrels of oil equivalent (BOE).[3] The economic prosperity of the GOM region typically grew in reaction to the success in offshore activities. As seen in the figure, production trends in the federal GOM OCS were positive throughout the 1960s and into the 1970s.

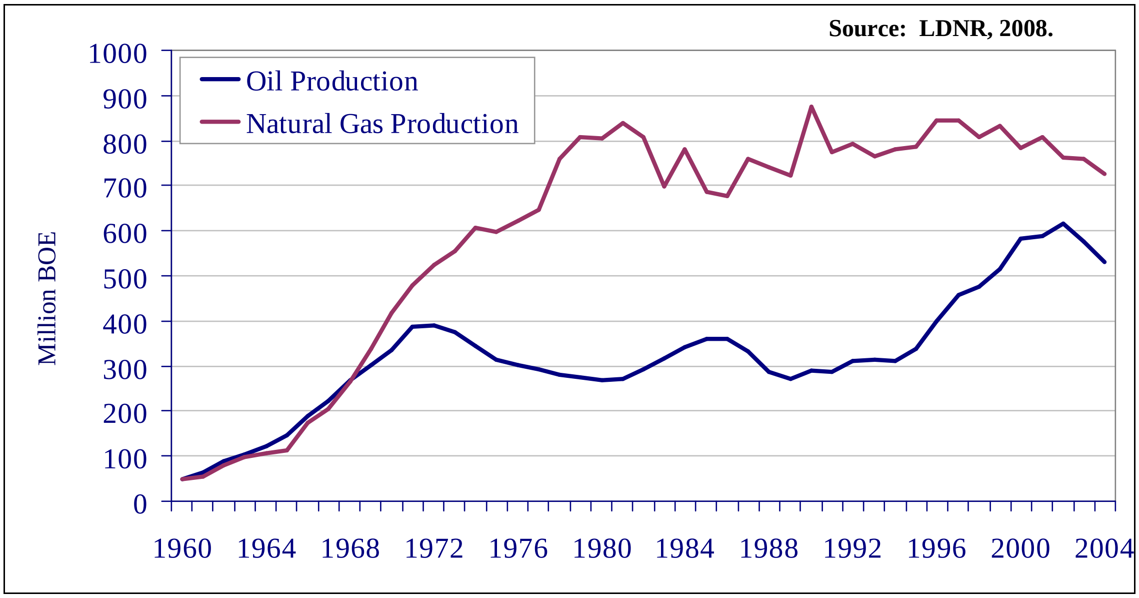


Figure 1. Historic oil and gas production in the Gulf of Mexico.

GOM crude oil production saw its initial production peak in 1971. Production activity revived in the mid-1990s with the passage of Congressional incentive legislation promoting new deepwater oil and natural gas drilling activity. Natural gas production along the GOM saw an initial production peak in the early 1980s and has continued to see rather steady production gains since that time.

One of the more dramatic historic events for the GOM was the crash in energy prices occurring in the mid-1980s. During this period, crude oil prices fell 60 percent, from $37 per barrel in 1981 to $15 per barrel in 1986. Natural gas prices fell a couple years later, from $2.66 per thousand cubic feet (Mcf) to $1.64/Mcf, or by some 40 percent. The 1986 price decrease resulted in a massive reorganization of most aspects of the oil and gas industry from major oil producers to the industries supporting offshore (and onshore) E&P activities. Many of the coastal economies along the GOM suffered from the drilling and production decline. Figure 2 shows overall gross state product for Louisiana and Texas and the contraction resulting from reduced oil and gas activities.

[3] One cubic foot of natural gas is equivalent to 0.0001767 barrels of oil.

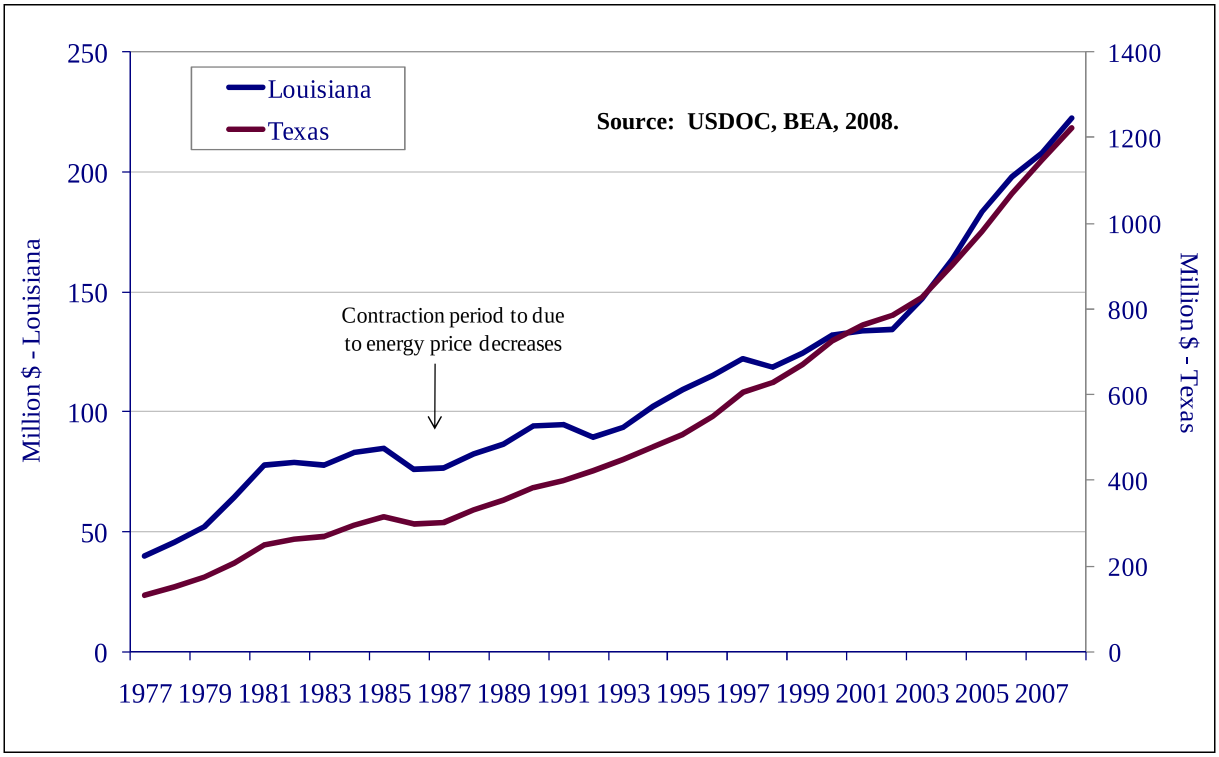


Figure 2. Louisiana and Texas gross state product.

Decreased oil and gas activities and concerns about future oil and gas production in the U.S. stimulated Congress to pass the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 (DWRRA). The purpose of the DWRRA was to create incentives for oil and gas producers to make the considerable capital and technological commitments to develop natural gas and crude oil resources in deepwater areas of the GOM. The Act implemented a royalty relief program to relieve eligible leases from paying royalties on certain amounts of deepwater production.

A simple review of production and drilling statistics since the mid-1990s indicates the success of DWRRA in stimulating interest in deepwater development. As seen in Figure 3, more than 900 exploration wells have been drilled in the deepwater GOM since 1995 and at least 115 deepwater discoveries have been announced since the passage of the DWRRA. Drilling of deepwater wells has increased over 80 percent since 1995, and 380 percent since 1992.

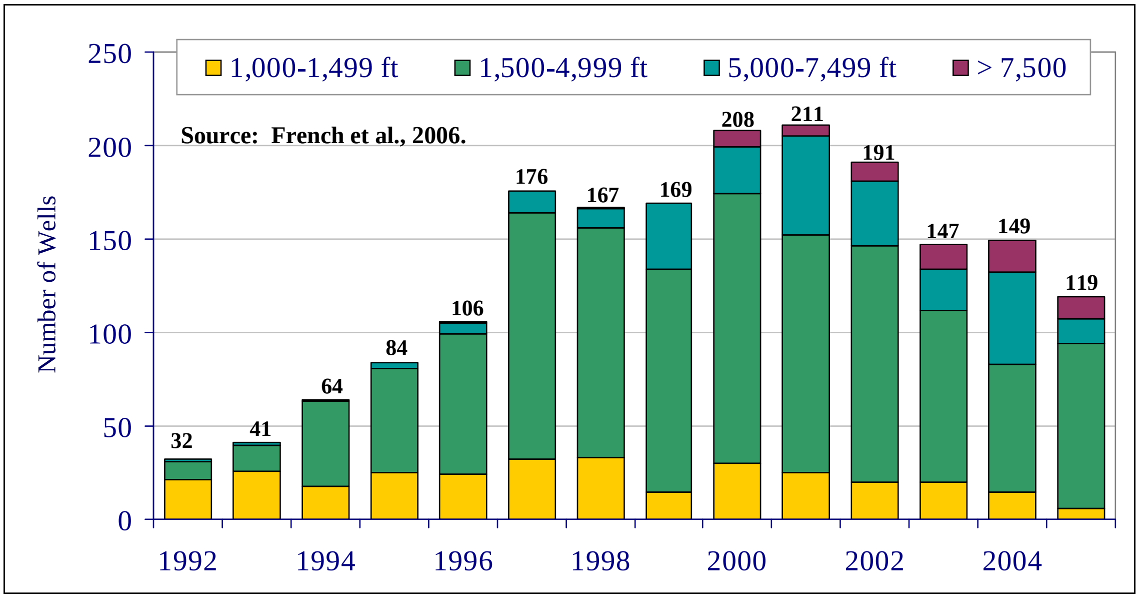


Figure 3. All deepwater wells drilled in the GOM, by water depth.

In terms of production, in 1994 deepwater leases produced 115 thousand barrels of oil per day (MBbls/d) and 0.4 billion cubic feet of natural gas per day (Bcf/d or 71 thousand BOE or MBOE). By 2004, production had increased to 922 MBbls/d and 3.9 Bcf/d (689 MBOE).

Average deepwater oil wells produce 20 times the rate of average shallow oil wells (French et al., 2006). The average deepwater gas well currently produces at 8 times the rate of an average shallow water gas well (French et al., 2006). Table 1 shows that the most prolific blocks are currently located in deepwater.

One of the considerable differences between shallow and deepwater production is the type of structures utilized for drilling and production operations. Figure 4, for instance, shows the different types of production facilities used in the GOM. Shallow waters tend to use fixed platforms and some semisubmersibles much as they have for close to five decades in one form or another. Deepwater structures, however, are typically floating structures that include various forms of semisubmersibles and SPARs.

Table 2 shows a number of the more recent deepwater discoveries, their associated platform structures, and their on-stream dates. Subsea systems have seen increasing use over the past decade primarily in the deepwater areas of the GOM. Most of these subsea systems are not entirely independent but "tie-back" to other types of deepwater platforms, primarily TLPs and Spars.

Table 1

Top 20 Producing Blocks in the Gulf of Mexico

Block	Project Name	Owner	Water Depth (ft)	Production (BOE)
MC 807	Mars	Shell	2,933	93,697,105
MC 809	Ursa	Shell	3,800	55,745,876
MC 127	Horn Mountain	BP	5,909	41,587,128
MC 763	Mars	Shell	3,261	34,808,598
GB 215	Conger	Amerada Hess	1,500	32,908,596
VK 786	Petronius	ChevronTexaco	1,753	28,140,012
MC 765	Princess	Shell	3,600	26,557,440
EB 602	Nansen	Kerr-McGee	3,675	25,711,854
MC 686	Mensa	Shell	5,364	24,876,468
EB 643	Boomvang	Kerr-McGee	3,650	24,650,727
MC 305	Aconcagua	Total	7,100	22,071,492
GC 202	Brutus	Shell	3,327	21,938,285
EB 945	Diana	ExxonMobil	4,500	21,857,743
MC 85	King	BP	5,689	18,400,654
MC 899	Crosby	Shell	4,259	18,135,470
GC 243	Aspen	Nexen	3,065	18,111,481
VK 915	Marlin	BP	3,236	17,746,359
VK 912	Ram Powell	Shell	3,216	17,278,987
ST 37	Unnamed	ChevronTexaco	59	15,834,599
MP 61	Unnamed	POGO	151	15,201,087

Source: French et al., 2006.

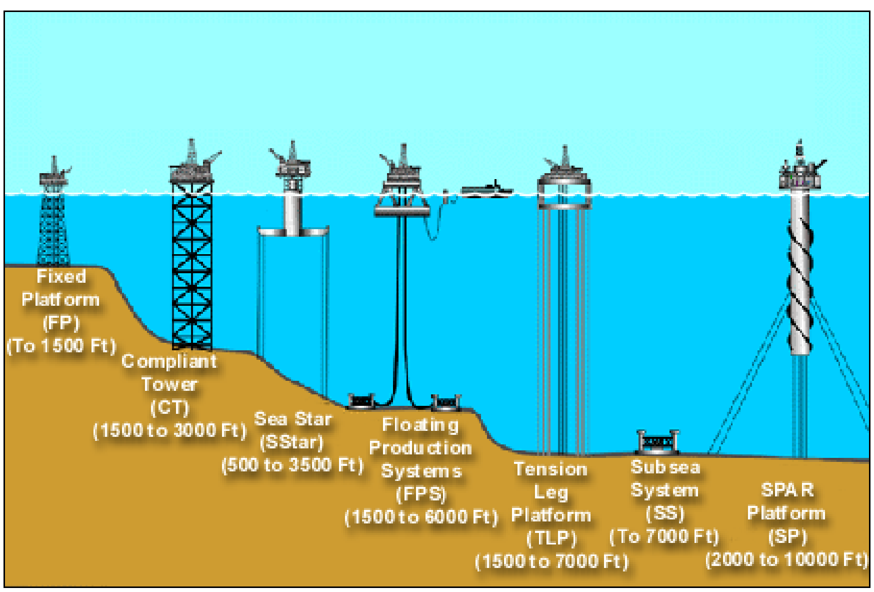


Figure 4. Offshore drilling platforms.

Table 2

Deepwater Discoveries and Production Dates

Field Name	Location	Year of Discovery	Water Depth (ft)	Onstream	Production Type
Ewing Bank 878	Ewing Bank 878	2000	1,523	2001	Subsea
Front Runner	Green Canyon 338	2000	3,500	2004	Spar
Gunnison	Garden Banks 668	2000	3,131	2003	Spar
Marco Polo	Green Canyon 608	2000	4,300	2004	TLP
Princess	Mississippi Canyon 765	2000	3,650	2002	Subsea
Aspen	Green Canyon 243	2001	3,063	2002	Subsea
Boris	Green Canyon 282	2001	2,393	2003	Subsea
Durango	Garden Banks 667	2001	3,150	2004	Subsea
Falcon	East Breaks 579	2001	3,400	2003	Subsea
Lost Ark	East Breaks 421	2001	2,740	2002	Subsea
Navajo	East Breaks 690	2001	4,114	2002	Subsea
Pardner	Mississippi Canyon 400	2001	1,200	2002	Subsea
Red Hawk	Garden Banks 877	2001	5,300	2004	Spar
Swordfish	Viosca Knoll 961	2001	4,677	2005	Subsea
Tulane	Garden Banks 158	2001	1,100	2001	Subsea
Yosemite	Green Canyon 516	2001	4,452	2002	Subsea
Brutus Ru	Green Canyon 202	2002	3,160	2003	Subsea
King West	Mississippi Canyon 84	2002	5,430	2003	Subsea
Northwest Navajo	East Breaks 646	2002	3,937	2003	Subsea
Ochre	Mississippi Canyon 66	2002	1,144	2003	Subsea
Triton	Mississippi Canyon 772	2002	5,610	2005	Subsea
West Navajo	East Breaks 689	2002	3,905	2003	Subsea
Ewing Bank 1006	Ewing Bank 1006	2003	1,854	2005	Subsea
Raptor	East Breaks 713	2003	3,600	2004	Subsea
Tomahawk	East Breaks 623	2003	3,514	2004	Subsea
Goldfinger	Mississippi Canyon 771	2004	5,423	2005	Subsea

Source: Offshore, 2006.

1.2. Energy Markets Prior to the 2005 Tropical Season

An important pre-Katrina trend impacting GOM energy production was the combined changes associated with relatively rapid increases in the global demand for energy commodities, tight to very limited excess capacity in oil and gas production, crude oil refining, and energy processing capabilities. These constraints resulted in high and volatile energy prices prior to 2005. Crude oil markets are global in nature, while natural gas markets have tended to be restricted to North America prior to 2005.[4] Commodity prices set in both markets impact the degree and speed of development activities along the GOM. More importantly, conditions in these markets can also impact the speed of recovery and restoration (R&R) activities in a storm's aftermath, as was seen after the 2005 tropical season.

[4]Today, natural gas prices are becoming increasingly more influenced by imports of LNG from foreign production sources. However, prior to the 2005 tropical season, only one new LNG regasification facility had come online.

Figure 5 shows the changes in crude oil and natural gas prices prior to the 2005 tropical season. The tight crude oil market leading to these price increases was the result of strong demand in the U.S. and rapid increases in demand in developing countries, particularly China and India. Figure 6 shows the increases in demand from these countries.

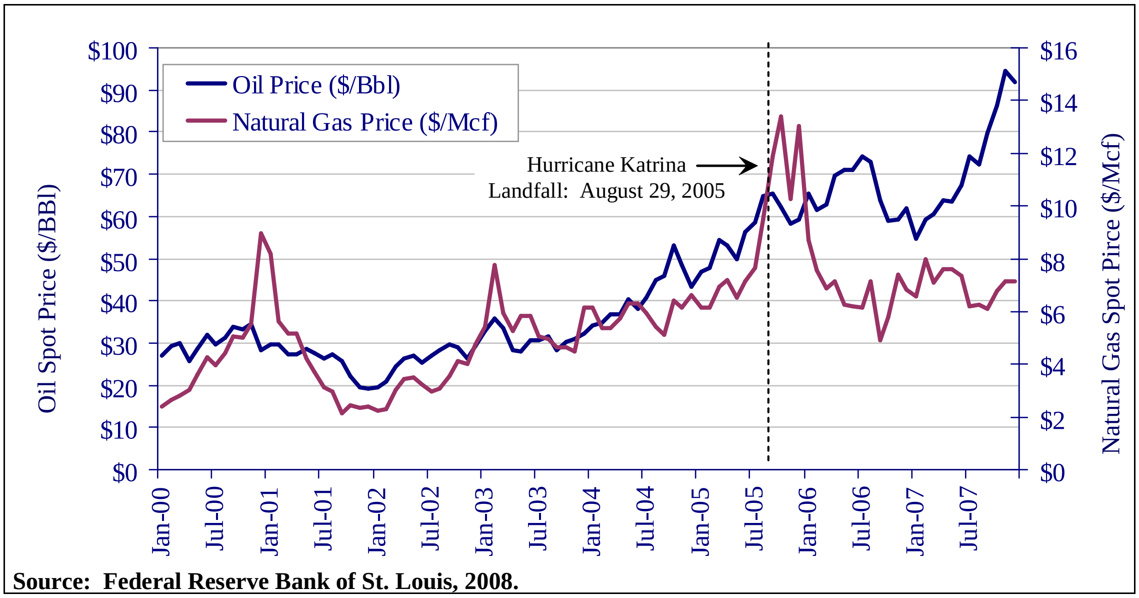


Figure 5. Crude oil and natural gas spot prices.

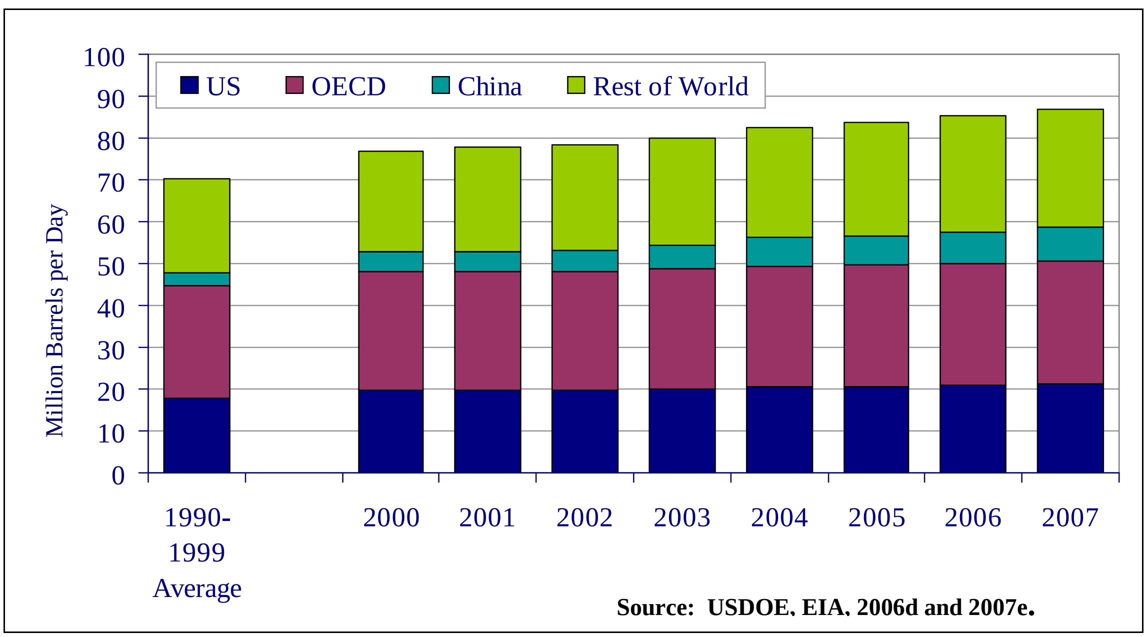


Figure 6. World oil demand.

Changes in global demand have driven spare production capacities down to record lows. Figure 7 shows the changes in global excess crude oil production capabilities. The rapid decrease in excess production capabilities and the perceived challenges of major producing areas like Saudi Arabia and other parts of the Persian Gulf to meet these new requirements inflamed market fears that the world was running short on fossil fuels in the period leading up to, and immediately following, the 2005 tropical season.

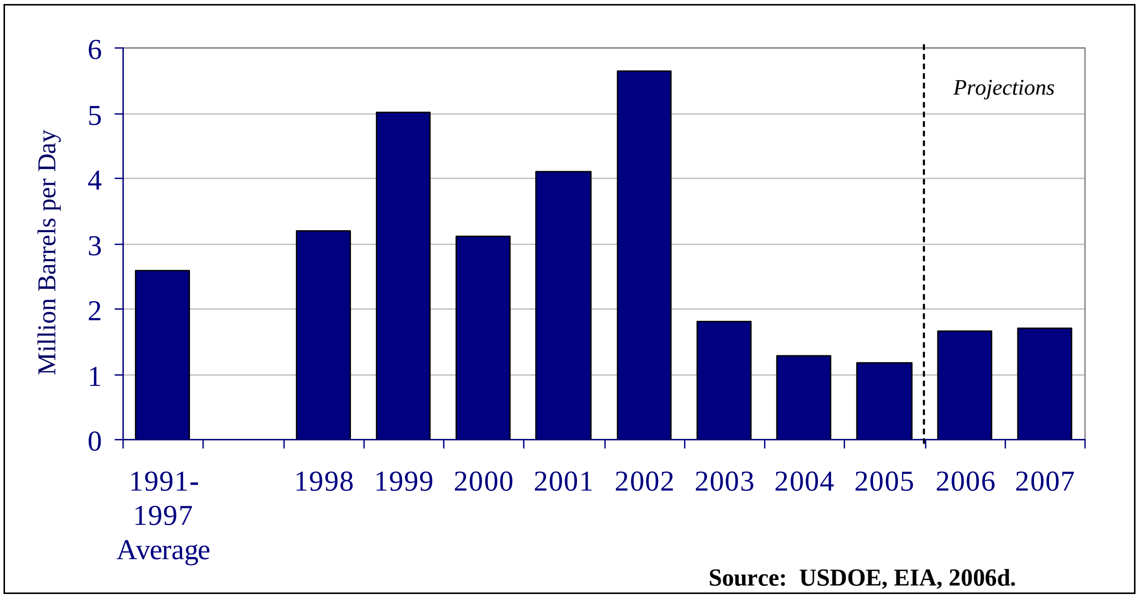


Figure 7. World oil spare production capacity (2005).

North American natural gas markets were following trends similar to those occurring in crude oil markets prior to the advent of Hurricanes Katrina and Rita. For instance, natural gas prices increased rapidly beginning in the winter of 2000-2001. Some dampening of prices occurred in the early part of 2004 when markets anticipated slowing natural gas demand, and increased supply opportunities from the considerable number of LNG projects being announced around the U.S. However, Hurricane Ivan, which took an easterly path in 2004, managed to "graze" a number of offshore production facilities in the central GOM, creating enough energy supply disruptions to increase price, and serve as a harbinger of how production interruptions could impact markets.

For instance, some 150 days after Ivan's landfall, 7.4 percent of total GOM crude oil production and 1.2 percent of GOM natural gas production was still shut-in. Figure 8 shows the production shut-in trends for crude oil and natural gas production in percentage terms in the aftermath of Ivan's landfall. The long shut-in plateau would prove to be a trend not unique to Ivan and would have similar, but much greater impacts in the aftermath of Katrina, and later, Rita.

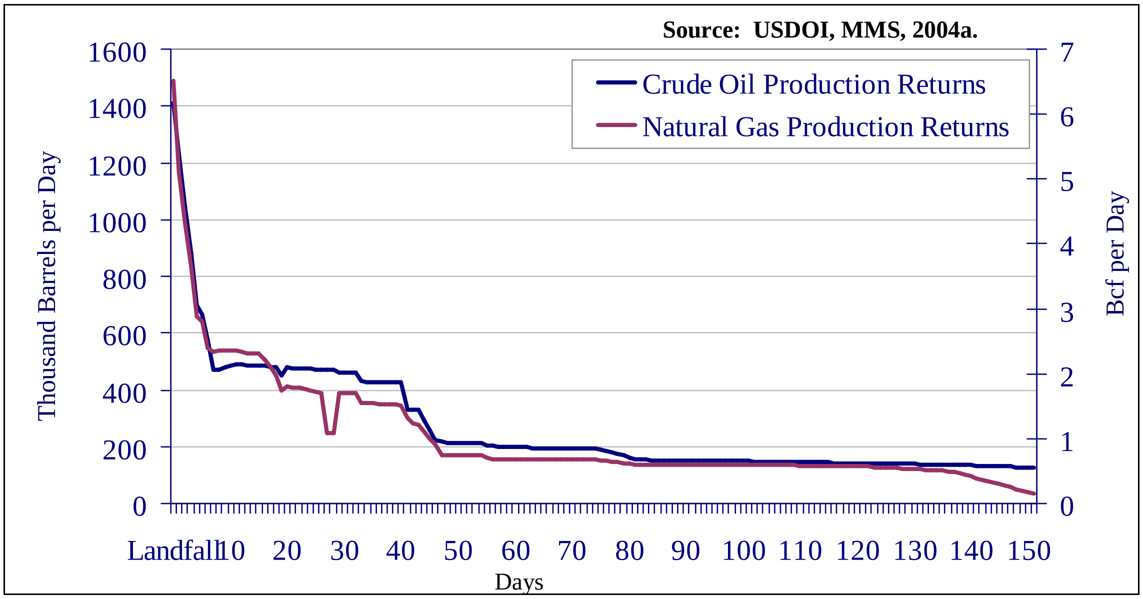


Figure 8. Production returns after Hurricane Ivan.

One of the more important conclusions drawn from the 2005 tropical season is that the GOM's critical energy infrastructure, including all forms of energy production, processing/refining, transportation, and distribution/sales is highly interrelated, perhaps to a degree not recognized by any other storm that has landed along the GOM. Outages in one energy sector had cascading affects on others, even those assets that may not have suffered any significant physical storm damage. Consider the following examples related to Hurricane Katrina:

- Power outages in the Clovelly, Houma, and St. James terminals prevented crude oil from being pumped to the area's refineries including the massive ExxonMobil refinery in Baton Rouge, and other refineries such as Motiva, Marathon, and Equilon.

- Gas processing facilities prevented some crude oil and natural gas production from coming online because the onshore facilities were not ready to take the raw natural gas. This halted deliveries on natural gas pipelines, reduced petrochemical plants' ability to create product (like blood bags and milk jugs that ran in short supply after Katrina), and prevented power generation facilities from running.

- Power crews had difficulty restoring power due to gasoline shortages from area refineries and refined product pipeline shut-ins.

- Power outages prevented refined product pipelines from delivering gasoline to eastern markets where prices skyrocketed to historic highs. The city of Atlanta shut down school to conserve gasoline costs for school busses.

The tight energy markets in the summer months of 2005, prior to Katrina and Rita, enhanced the urgency of restoration and recovery. As noted earlier, tight energy markets and high energy demand placed a high level of importance on GOM energy infrastructure restoration and recovery. The combination of tight markets and storm damaged infrastructure created or contributed to some of the following post-storm challenges.

- U.S. retail gasoline prices were at record high levels, exceeding $3.00 per gallon in most areas, and in some areas reaching levels exceeding $5.00 per gallon.

- Emergency gasoline rationing occurred in many areas along the Gulf Coast. Areas were more dependent than normal on refining production. There was no slack in the system to cover gasoline production shortfalls.

- The summer months are the "injection period" for natural gas. During this period, natural gas is injected into underground caverns for use in the winter. There was a serious concern post-Katrina that storage levels would not reach needed levels for the upcoming winter.

- Temperature trends leading up to, and following Katrina, were above average. New record electricity peaks were being set around the Eastern U.S. Most of the new power generation built in the last five years is natural-gas fired. Shortages of gas put some areas under electricity alerts. The state of Florida issued a Stage 1 alert indicating that power interruptions were probable due to lack of natural gas to run generating units.

- Refinery outages placed distillate production, which includes home heating oil, at risk. There was a post-Katrina concern that if refineries were not brought back quickly, there would be a short-fall of heating oil stocks for the winter.

- The U.S. was forced to loosen environmental fuel standards, allowing less environmentally friendly fuels from European refineries to be imported to cover domestic refining shortfalls.

Ironically, local restoration activities proved to be equally dependent upon critical energy infrastructure in order to sustain restoration and recovery activities. Consider the following:

- Gasoline shortages created significant challenges for first responders throughout the region. The availability of fuel during this period was the result of significant actions of the area's energy companies and state agencies including the Louisiana Department of Agriculture, the agency with primary regulatory authority over gasoline pumps and metering calibration. Gasoline was in short supply because of refinery outages as well as refined product pipeline outages.

- Diesel shortages were considerable. Diesel fuel was needed for large military vehicles for evacuation, for restoration trucks for power service and debris clearing, and for the numerous back-up generators that were being used at many critical relief facilities and hospitals. Diesel was in short supply because of refinery and refined product pipeline outages.

- Electricity outages affected shelters and emergency hospitals being set up around the states. These facilities were in jeopardy without power given the high heat and humidity post-Katrina.

- There was widespread shortage of back-up and emergency generators given the high demand resulting from significant power system damage and prolonged outages. Quick restoration was needed to take pressure off the demand for this vital generation equipment.

- Aviation fuel shortages hampered search and rescue activities. Energy infrastructure needed to be restored to facilitate these activities. Aviation fuel was eventually transported in by military and other sources.

- Floodwater pumping stations in New Orleans are run on natural gas while others run on diesel back-ups. Both natural gas and diesel fuel supplies were in short supply after the storm and dewatering was dependent on getting energy infrastructure up to provide these fuels.

The short-term catastrophe experienced in the impacted area was felt by the nation and the world as energy prices soared to record high levels in fear that restoration and recovery efforts would not be fast or successful enough to replace the important lost energy production needed by an energy hungry nation.

Restoration and recovery problems for critical energy infrastructure in the impacted area included the following:

- The nature of the storm, the degree of damage, and the nature of the destruction had no precedent. The storm set a new standard in the “worst case scenario” for which no restoration crew was prepared.

- The 2005 season can be described as an “episodic” catastrophe that ran from one failure to the next, starting with the advent of the hurricane and evacuation process, to the approach and passage of the storm, to the storm aftermath, to the levee breaches, to the complete abandonment of New Orleans, to the preparation for a second category 5 hurricane (Rita) and the additional associated destruction and chaos and an entirely new set of restoration and recovery challenges. This created a “dodge-ball” like effect for restoration activities of all types.

- Massive communication failures stalled critical energy infrastructure restoration activities. Restoration crews for all types of critical energy infrastructure (production, refining, processing, transportation, power) were operating in the dark without input from anyone not within speaking distance.

- Difficulty in finding housing for displaced workers and a perception in the industry that cumbersome and bureaucratic restrictions on housing eligibility limited restoration activities. There was (and is) a perception in industry that federal emergency management did not have a "can-do" or "get-the-job-done" philosophy in facilitating access and restoration and alleviating logistical challenges.

- A perception that federal emergency management teams were "cornering the market" on vital equipment needs and limited resources. There have been repeated (but few documented) reports of federal emergency management and military confiscation of equipment needed by industry restoration crews.

- Cascading failures across the entire energy infrastructure system that was exceptionally aggravated by power outages and fuel shortages.

- Lack of complete independent start-up or "black-start" capabilities. Many energy infrastructure components were dependent upon one another for restart.

1.3. Recommendations and Lessons Learned

On January 19-20, 2006, the U.S. Department of Energy held an Energy Leadership Forum in Tunica, Mississippi. The forum was sponsored by the Office of Electricity Delivery and Energy Reliability (OE). The OE was a point division within DOE evaluating R&R activities in the aftermath of both Katrina and Rita. In addition to DOE, a number of other agencies and associations collaborated in the event including: the National Association of Utility Regulatory Commissioners, National Conference of State Legislators, the National Association of State Energy Officials, the National Governors Association, Center for Best Practices, and the Public Technology Institute.

The goal of the forum was to bring together a range of stakeholders including industry, state government agencies, federal government agencies, emergency management officials, trade associations, and academia. Over 170 key players attended the event including 12 federal agencies, 23 state and local government agencies, and 40 private organizations throughout the Gulf South, including the impacted Greater New Orleans (GNO) area.

In February 2006, the DOE issued the findings, recommendations, and lessons learned from the event. To date, there is no other more comprehensive listing of the "lessons learned" associated with the recent hurricane activity on critical energy infrastructure. These lessons learned can be summarized as follows:[5]

- Consider worst-case scenarios created by multiple hurricanes that cause widespread regional damage to critical energy infrastructure.

- Create effective mutual aid agreements within the energy sector.

[5]The list provided is summarized from: Office of Electricity Delivery and Energy Reliability. *After Action Report: Energy Leadership Forum* (USDOE, OE, 2006b).

- Create an overall awareness of the critical specific interdependencies between and within the various energy sectors.

- Coordinate regional contingency plan for the distribution of limited fuel supplies to critical response organizations.

- Understand the responsibilities of state, local, and tribal governments, public agencies, organizations, and private industry.

- Improve understanding of critical supply chains and infrastructure by the general public, government entities, and within sub-sectors of the energy industry.

- Improve communications systems across all governmental, private, and public entities.

- Coordinate among government agencies and energy industry companies before communicating with the public.

- Improve response and recovery data quality.

- Integrate additional training programs across all levels of government and the energy industry.

- Understand the interdependencies amongst various entities in the energy industry in emergency management.

- Conduct more exercises to improve plans and procedures in all levels of government sectors.

- Educate the public in energy industry operations relative to the supply of reliable energy.

- Revise resource management plans and train personnel to accommodate multi-regional catastrophic disasters.

- Provide adequate materials and equipment for response and recovery to avoid competition for resources.

- Enhance critical infrastructure to provide virtually uninterruptible energy.

- Improve current hurricane consequence analysis to provide more effective risk management planning and preparedness.

1.4. Project Scope

This fact book was developed to assist the BOEM in conducting its regulatory responsibilities particularly in the analysis of (1) understanding the role of energy infrastructure support on continued offshore oil and gas leasing activities and (2) understanding the economic impacts of the 2005 tropical season and its impact on infrastructure and continued offshore drilling and production activities.

Because of its statutory responsibilities, the BOEM has an ongoing need to understand the role that this infrastructure plays on local communities. Specifically, BOEM must

1. Produce lease-sale Environmental Impact Statements (EISs) that depict existing, OCS-related infrastructure and its future growth and trends;

2. Make a large number of permitting decisions that consider existing, future, and past infrastructure;

3. Annually update maps that depict infrastructure supporting offshore activities; and,

4. Guide and monitor long-range planning and development of OCS activities.

BOEM sponsored an earlier version of this project in 2000 to address each of the above-listed issues.[6] This fact book updates that original work. There are, however, three critical differences between the original fact book and the current effort. First, and most importantly, this updated fact book includes an extensive discussion of how each infrastructure sector/area was impacted by the 2005 tropical season. The status of the industry prior to the tropical season is discussed, the impacts that the hurricanes had on each sector is described, critical activities that comprised the R&R process are explained, and post-hurricane status is discussed and examined.

Second, examination of the impact of the hurricanes on various infrastructure sectors lead to an important realization. The first fact book effort inadvertently omitted an important energy infrastructure asset along the Gulf Coast that supports virtually all other areas of operations: electric power. As a result, this current fact book includes a new chapter not found in the earlier version discussing the region's electric power infrastructure and how it is related to other important energy sectors.

Third, ongoing trends, outlooks, and issues for each of the infrastructure categories and sectors have been examined. The post-hurricane period and the period leading up to the release of this report has been one reflected by considerable fossil fuel price volatility and concerns about energy security and availability. Issues addressing major expansions in many of these sectors, like petroleum refineries, have been discussed. Likewise, a new chapter on LNG has been added to this fact book that was not included in the prior effort. LNG is a new, emerging, and important form of energy infrastructure in the region.

[6] The Louis Berger Group, Inc., 2004. OCS-related infrastructure in the Gulf of Mexico: Fact book. U.S. Dept. of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, OCS Study MMS 2004-027.

The 13 major infrastructure categories identified for this study include:

Platform Fabrication Yards: Facilities in which platforms are constructed and assembled for transportation to offshore areas. Facilities can also be used for maintenance and storage.

Shipyards and Shipbuilding Yards: Facilities in which ships, drilling platforms, and crew boats are constructed and maintained.

Port Facilities: Major maritime staging areas for movement between onshore industries and infrastructure classifications and offshore leases.

Support and Transport Facilities: Facilities and services that support the offshore activities. This includes repair and maintenance yards, supply bases, crew services, and heliports.

Waste Management Facilities: Sites that process drilling and production wastes associated with offshore oil and gas activities.

Pipelines: Infrastructure that is used to transport oil and gas from offshore facilities to onshore processing sites, and ultimately to end users.

Pipe Coating Yards: Sites that condition and coat pipelines used to transport oil and gas from offshore production locations.

Liquefied Natural Gas: Facilities which take super-cooled natural gas produced in other regions of the world and raise the temperature through various vaporization processes to inject into regional natural gas storage and/or transportation assets. These assets can also be thought of as special natural gas import facilities.

Natural Gas Processing Facilities: Sites which process natural gas and separate its component parts for the market.

Natural Gas Storage Facilities: Sites that store processed natural gas for use during peak periods.

Refineries: Industrial facilities that process crude oil into numerous end-use and intermediate-use products.

Petrochemical Plants: Industrial facilities that intensively use oil and natural gas, and their associated by-products, for fuel and feedstock purposes.

Electric Power: A collection of infrastructure assets that include those that produce electricity (generation) and transmit and distribute the electricity to households and industry along the Gulf.

The following chapters of this fact book discuss each of these critical infrastructure areas and their relationship with offshore oil and gas activities. Each chapter outlines:

Description of Industry and Services Provided: This section examines the infrastructure in question, and provides a description of its unique features.

Industry Characteristics: This section discusses the industry characteristics associated with the infrastructure under examination. Typical facilities or common characteristics, geographic distribution, and typical firms are also discussed.

Regulations: This section discusses the salient regulations associated with the infrastructure.

Industry Trends and Outlook: This section examines the current trends and future outlook of infrastructure development in the Gulf. Also included in this section is a discussion of the impacts the recent hurricanes have had on the specific infrastructure.

1.5. Data, Sources, and Methods Used to Evaluate Supporting Infrastructure

A variety of different data sources have been used to examine energy infrastructure in the GOM region. A full list of these sources has been included in the references section. In general, the following sources have been consulted:

- Data series regularly collected by the DOE, particularly the Energy Information Administration (EIA), that include power generation and facility capacities, utility sales and customers, refinery locations and capacities, oil and gas production, natural gas storage facilities, LNG regasification facilities, and gas processing capabilities.

- Reports and press releases published by BOEM that include offshore production, facility locations, and other descriptive statistics. Statistics compiled by BOEM during and immediately after the hurricanes of 2004 and 2005 were also consulted.

- Oil and gas production statistics collected and published by state utility and natural resource regulators like the Louisiana Department of Natural Resources (LDNR) and the Public Utilities Commission of Texas (PUCT).

- Commercial databases including Pennwell MapSearch and IHS Energy's Major Industrial Plant Database (MIPD) that includes descriptive and locational information about transportation pipelines and industrial facilities.

- News reports, trade press articles and research, independent research reports, individual company press releases, and government press releases discussing or examining the current status of critical energy infrastructure and their trends.

2. PLATFORM FABRICATION YARDS

2.1. Description of Industry and Services Provided

Immediately following the turn of the century, the GOM region's early wildcatters attempted different techniques in their efforts to extract oil from Louisiana's swampy terrain. By 1930 a variety of successful solutions were developed, most of which facilitated the use of some type of floating vessels or barge containing drilling equipment and other materials to sustain activities over open water or swampy marshes. These technologies were crude, and somewhat limited, thereby restricting the range of drilling operations over water and in marshes. Operations tended to be limited to times or locations where the water body was calm or shallow and without current, waves, significant tide movements, and protected from wind exposure. While the early "offshore" activities were limited, progress in these environments ultimately led to one of the most important developments in offshore drilling—the mobile drilling rig.

In 1933 a prototype called the "Giliasso" was built as the world's first submersible oil platform (USDOI, MMS, 2005). This design was based on a concept envisioned by G.E. McBride, a former Texas Company employee (formerly Texaco, now part of Chevron) (USDOI, MMS, 2005). The design used barges to carry a platform for equipment and a rig or derrick. The vessel was towed to a location, sunk, and then acted as a fixed foundation for the platform which remained above the water (USDOI, MMS, 2005).

The Giliasso spurred a number of new techniques and ideas about how floating structures could be modified to support over-water (but near-shore) E&P activities. The Giliasso was a technological breakthrough, but logistic support proved difficult. Drilling crews were living in piling-support camps suspended over the marsh muck. In addition, drilling mud had to be hauled 35 miles to the drilling site, and once these drilling fluids arrived, there were a number of difficulties securing an aboveground storage site (Davis, 2002). Operators working for the Texas Company again showed the ingenuity that would form the backbone of offshore exploration by using three grounded, obsolete oil tankers connected to an old steel schooner as a storage facility and loading dock for the site's drilling fluids (Davis, 2002). Oil produced from the lease was then lightered to vessels offshore. It was not until the 1950s that oil began to be piped out of this facility with the completion of a 135-mile pipeline (Davis, 2002).

Since the 1950's, more than 5,500 platforms have been installed in the GOM (Hunt and Gary, 2000). Today there are more than 3,900 fixed structures at depths of up to 1,700 feet and floating structures have reached almost 10,000 ft water depths (USDOI, MMS, 2007a). Throughout the years, the Gulf Coast platform fabrication industry has been a principal contributor to offshore oil and gas industry advances. The platform fabrication industry has expanded considerably from its early days in the marshy areas of Louisiana. Today it is a regional and in part international industry, spanning the GOM from Texas to Alabama. Various "yards" along the GOM design, develop, and construct a variety of offshore structures and components necessary for E&P operations (Hunt and Gary, 2000).

Of the approximately 8,220 active leases in the Gulf of Mexico OCS, 54 percent are in deepwater, which is defined as operations occurring in over 1,000 feet of water depth (French et al., 2006). Deeper water activities have forced the platform fabrication industry to change and advance. One the most obvious changes has been in the size of these fabrication yards and facilities. Deeper water structures are much larger than their shallow water counterparts. Bigger structures require larger fabrication yards, docks, and other assembly facilities. Each yard located along the GOM usually specializes in the production of a particular type of platform or component, such as living quarters, decks, or modules. Many will "team" on large projects in order to develop various components in a modular fashion. This modular-based approach creates interdependence among different yards to complete an entire platform (USDOI, MMS, 2005).

2.2. Industry Characteristics

2.2.1. Typical Facilities

Early offshore drilling was typically based upon a process that fitted a derrick to a barge and towed it to a drilling site. Modifications of this basic approach still exist today, but on a slightly more sophisticated basis. The four offshore rig types used to drill wildcat or exploration wells (AIP, 2007) include:

Rigzone.com, 2008a

Submersibles are one of the earliest forms of offshore drilling rigs particularly in shallow coastal zones or inland waters. These submersibles are generally towed to shallow water locations then ballasted (flooded with water) to sit on the seabed. True submersibles, like those that were used in the coastal marshes at the turn of the century, are rarely used given concerns about their operational stability, particularly in deeper water. Deeper water applications also require more space between the platform deck and the barge, something not found on typical true submersibles. The picture to the left is the *Noble Joe Alford*, a submersible rig that is rated for operations up to 70 feet of water and drilling depths up to 25,000 feet (Rigzone.com, 2008a).

Rigzone.com, 2008a

Jackups are very common types of offshore drilling structures that are used along the GOM and throughout the world. Once on station, a jackup drops its long characteristic legs to the seabed while the hull is "jacked-up" above the water's surface. Jackups are typically used in water depths up to approximately 160 meters (or 525 feet). The jackup presented in the figure is the ENSCO 75, and is rated for operating in 390 feet of water and drilling depths up to 30,000 feet (Rigzone.com, 2008a).


Rigzone.com, 2008a

Drill ships are more modern, advanced drilling structures that are floating marine craft (ships) with a derrick on top and a moon pool in the center of the hull for drilling operations. Drill ships are anchored and/or positioned with computers and GPS systems that continually correct the ship's drift. Drill ships are often used to drill wildcat wells in deep waters. The pictured drillship, named the *Deepwater Millennium*, has a water depth rating of up to 10,000 feet and a drilling depth rating of up to 30,000 feet (Rigzone.com, 2008a).


Rigzone.com, 2008a

Semisubmersibles have become an increasingly more important and highly utilized offshore drilling, as well as production structure. "Semi-subs" are supported by columns sitting on hulls or pontoons, which are ballasted (with water) below the water surface to provide stability in rough, deep waters. The semisubmersible to the left, the *Deepwater Nautilus*, has a water depth rating of up to 8,000 feet and a drilling depth of up to 30,000 feet (Rigzone.com, 2008a.).

Once oil or gas is found, an exploratory drilling rig is replaced with or converted to, a production platform assembled at the site using a barge equipped with heavy lift cranes. In many instances in GOM deepwater areas, drilling and production occur on the same structure, particularly semi-subs. Platforms vary in size, shape, and type depending on the size of the field, the water depth, and the distance from shore.

Today, platforms play an important role in the development of offshore oil and gas resources. Production platforms house mechanical, electrical and telecommunications equipment, other types of supplies (fuels, drilling fluids, etc.), and living quarters for personnel (for manned platforms). As shown in Figure 9, several types of production systems are used in offshore oil and gas development.[7]

A production structure, or platform, consists of two major components: an underwater part (jacket or tower) and an above water part (deck). Larger and more sophisticated production structures have been developed over the past two decades to support the increasing activity in deepwater areas of the Gulf. Figure 9 provides a schematic of the general types of production structures utilized in the GOM while the following discussion generally describes each type of structure in the figure.

[7] Although some recently developed production systems, such as the floating production system, are not platforms in the strict sense, platform-type structures continue to be the staple of the offshore oil and gas operations.

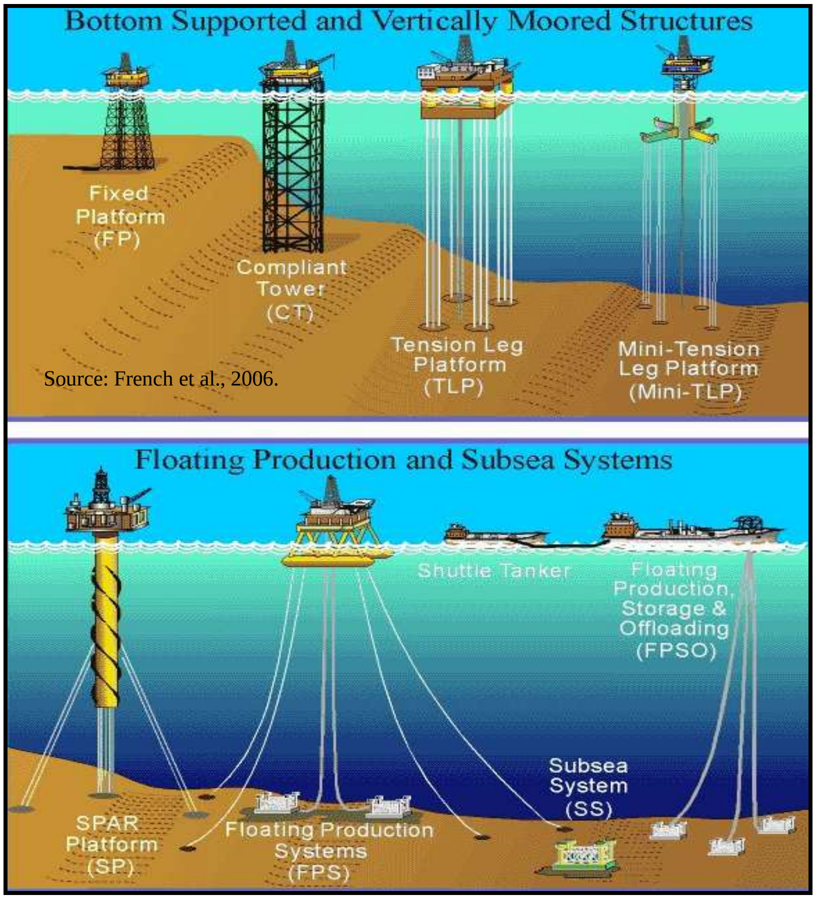


Figure 9. Permanent production systems on the GOM OCS.

- Fixed Platform – This is the most common type of production system in the GOM, particularly in shallow waters. A fixed platform has a large skeletal-type structure extending from the bottom of the ocean to above the water level. It consists of a metal jacket, which is attached to the ocean bottom with piles, and a topside deck (above water), that accommodates drilling, production, and support equipment and living quarters. Fixed platforms are typically installed in water depths of up to 2,000 feet (French et al., 2006).
- Compliant Tower – This is similar to a fixed platform, but the underwater section is not a jacket. It is a narrow, flexible tower that can move (or is compliant) around in the horizontal position allowing for a limited range of motion created by winds and wave action. Compliant towers are typically installed in water depths from 1,000 up to 2,000 feet (French et al., 2006).
- Tension and Mini-Tension Leg Platforms (TLP) – These structures are based upon the semi-sub technology discussed earlier and are floating structures that do not originate on the seafloor and rise to the surface. A TLP is a ship-based type of structure that is towed to its location and anchored to the seabed with vertical, taut steel cables or solid pipes. Wellheads can be placed on the TLP's deck, unlike the free-floating platforms (like ships and "normal"

semisubmersibles). The deepest TLP in the world was installed by ConocoPhillips at Magnolia in December 2004 in 4,674 feet of water (French et al., 2006).

- SPAR Platform – SPARs are more recent developments in offshore production structures, designed to facilitate deepwater production in potentially up to 10,000 feet in water depth. SPARs consist of a large vertical hull, moored to the ocean floor with up to twenty lines. Production equipment and living quarters are located on the top of the hull. In 2009, Shell completed installation of the deepest SPAR production facility 200 miles offshore to a depth of 8,000 feet (Parker, 2009).
- Floating Production System – This application is a variation of a semi-sub and is kept stationary either by anchoring with wire ropes and chains or by the use of rotating thrusters, which self propel the semisubmersible unit. Floating production systems are suited for deepwater production in depths up to 7,500 feet. In the GOM, BP's Thunder Horse began production in March 2009 and produces over 300,000 barrels per day of crude oil (Rigzone.com, 2007a).
- Subsea System –Consists of a single subsea well or several producing wells connected (tied back) to either a nearby platform or a distant production facility (like a TLP or SPAR) through a pipeline, umbilical, and manifold system. Currently, subsea systems are used in water depths exceeding 5,000 feet (French et al., 2006).
- Floating Production, Storage, and Offloading (FPSO) System – Originally developed for North Sea applications, an FPSO consists of a large vessel housing production equipment to collect and store oil produced from several subsea wells. Ultimately, this oil is offloaded to a shuttle tanker for transportation to markets for refining and distribution. FPSO systems are particularly useful in development of remote (or frontier) oil fields where pipeline infrastructure is not available. Recent developments (i.e., Excelerate facility off Louisiana) project announcements for offshore LNG regasification facilities are based on variations of FPSO technology/application. In January 2002, the BOEM announced its decision to accept applications for FPSOs after a rigorous environmental and safety review (USDOI, MMS, 2002a). To date, there are two pending projects which have been approved by the BOEM for FPSOs in the GOM (Fletcher, 2007).

Most production platforms are fabricated onshore and then towed to an offshore location for installation and sea-fastening. Facilities where the platforms are fabricated are called platform fabrication yards (Figures 10 and 11). Production operations at fabrication yards include cutting and welding of steel components, construction of living quarters and other structures, as well as assembling platform components. Fixed platform fabrication can be subdivided into two major tasks: (1) jacket fabrication and (2) deck fabrication.

Figure 10. Independence Hub's topsides under construction at fabrication yard near Corpus Christi, Texas.

1. Deck Assembly Buildings
2. Pipe Fabrication Shop
3. Erection Area (29 crawler cranes)
4. Rotoblast Facilities
5. Leg Fabrication Area
6. Structural Fabrication Facility
7. K-Mills
8. Brace Cutting Facility
9. Deck Leg Fabrication Shop
10. Pile Fabrication
11. Pipe Mill

Source: J. Ray McDermott, 2008.

Figure 11. J. Ray McDermott's Morgan City facility.

- Jacket Fabrication – The jacket is constructed by welding together steel plates and tubes to form a tower-like skeletal structure. Jackets are typically constructed and assembled horizontally on skid runners since the height of the structure, once vertical, can span a height of several hundred feet. Once the jacket is completed, a crane lifts the structure onto a barge (typically remaining in a horizontal position) and then transports that structure to an offshore location where the jacket is lowered into the water and fastened into place. Additional supporting fabrication and installation activities also occur during the jacket construction process that include the development of smaller ancillary structures including pile guides, boat landings, walkways, buoyancy tanks, handrails, etc. These structures are attached to the jacket while it is in the vertical position.

- Deck Fabrication – Deck components are typically fabricated and assembled separately from the jacket. A typical deck is a flat platform supported by several vertical columns (deck legs). The deck provides the necessary surface to place production equipment, living quarters, and various storage facilities. Once the deck fabrication is completed, it is loaded onto a barge and transported to the site of the platform where it is lifted by derrick barges and attached to the already installed jacket.

Fabrication yards typically span several hundred acres. The site will need to facilitate large construction projects and maintain an inventory of construction components such as metal pipes and beams as well as a sizable amount of heavy construction equipment such as cranes and welding equipment. Other equipment often housed on-site includes various types of lifts, rolling mills, and sandblasting machinery. Most fabrication yards have large open spaces for jacket assembly as well as a number of covered warehouses and shops for storing materials and to support operations in inclement weather.

New drilling and production structures usually require unique drilling and production structures given the increased movement into unique deepwater areas. Since no two structures are usually the same, an assembly-line approach to fabrication typically does not occur. Instead, fabrication yards tend to work on only one or two projects at a time. Once a platform is completed, it is towed to its offshore location, and work on the new platform commences.

The unique nature of modern platform fabrication has led to a great degree of specialization in the industry. No two fabrication yards are the same and most specialize in the fabrication of a particular type of platform or platform component. For instance, some yards may specialize in the construction of living quarters, others on the provision of hook-up services, and still others may focus exclusively on the fabrication of jackets and decks. The Baldpate platform (Figure 12), the world's first free-standing offshore compliant tower, is an example of a relatively recent development that was assembled from a variety of specialized components from different fabrication yards and facilities along the GOM. The structure was engineered and designed by McDermott Engineering in Houston, Texas. The jacket-base section was constructed by J Ray McDermott in Morgan City, Louisiana. The jacket-tower section and topsides were fabricated at Aker Gulf Marine in Corpus Christi, Texas, and its pipe was provided by Sumitomo (Offshore-Technology.com, 2007a; Moritis, 1998).

Figure 12. Baldpate platform.

A 2000 survey of 51 fabrication yards conducted by Mustang Engineering, estimates that there were 23 yards that fabricate jackets, 15 fabricate decks, 29 fabricate modules, 22 fabricate living quarters, and 20 fabricate control buildings (Gary and Nutter, 2000). Despite the specialization of these yards, most platform fabrication facilities include:

- steel stockyards and cutting shops which supply and shape steel;
- assembly shops which put together a variety of components such as deck sections, modules, and tanks;
- paint and sandblasting shops;
- drydocks, which work on small vessels;
- piers which work on transportation equipment and the platform components that are mobile and can be transported onto barges; and
- pipe and welding shops.

The principal materials and supplies used in the fabrication business are standard steel shapes, steel plate, welding gases, fuel oil, gasoline, coatings, and paints. Like other industrial construction-oriented industries, the platform fabrication industry has also been exposed to recent primary commodity price increases with increases in both steel delivery times and price per ton (SEC, 2006a).

The number of employees at fabrication yards may vary from less than a hundred to several thousand, and due to the project-oriented nature of work, temporary and contract workers account for a significant portion of the fabrication yard workforce. Industry employment trends can be seasonal as well as cyclical and can be very dependent upon large orders. The typical platform fabrication workforce can vary during the year with increases and decreases in contract labor depending upon the jobs in progress and backlog.

In order for a fabrication yard to remain productive and profitable, it must be able to attract and retain skilled construction workers, primarily welders, fitters, and equipment operators (SEC, 2006a). Like other industrial construction activities, the supply of these workers can be limited, particularly in periods of high activity. Because most construction work takes place outdoors, the number of direct labor hours generally declines during the winter months, although some work continues year-round in covered areas of a given yard. In order to keep their labor force, Gulf Island Fabrication tries not to lay off their employees during these months, but rather reduces the number of hours worked per day to coincide with the reduction in daylight hours during that period. Gulf Island reports that none of their employees belong to a union (SEC, 2006a) and for the most part, fabrication yard labor along the GOM is not unionized.

2.2.2. Geographic Distribution

The location of platform fabrication yards is tied to the availability of a navigable channel sufficiently large to allow towing of bulky and long structures, such as offshore drilling and production platforms. Thus, platform fabrication yards are located either directly along the GOM coast or inland, along large navigable channels, such as the Intracoastal Waterway. These waterways, which facilitate or limit movement into and out of the yard, can impact the size and scope of various projects that can be developed at a given location. For example, Gulf Island Fabricators has noted that the dimensions of the Houma Navigation Canal prevent it from being able to transport jackets designed for water depths exceeding 800 feet. However, their newly acquired yards from Gulf Marine, located near the Gulf Intercoastal Highway, allow unrestricted access to the Gulf, and therefore unlimited fabrication or assembly of any size structure (SEC, 2006a).

Despite a large number of platform fabrication yards along the Gulf, only a few facilities can handle large-scale fabrication. According to the Mustang Engineering survey, nine yards have single piece fabrication capacity over 100,000 tons and twelve have capacity to fabricate structures for water depths over 1,000 feet (Gary and Nutter, 2000).

The Atlantic Communications 2006 Gulf Coast Oil Directory includes the platform fabrication industry in its ‘Ship, Boat & Offshore Rig Builders’ section. According to the directory and as seen in Figure 13, most of the 87 companies listed have locations in Louisiana and Texas, with the other companies evenly distributed between Mississippi and Alabama (Atlantic Communications, 2006).[8]

[8] Three locations in Florida are not shown on this map.

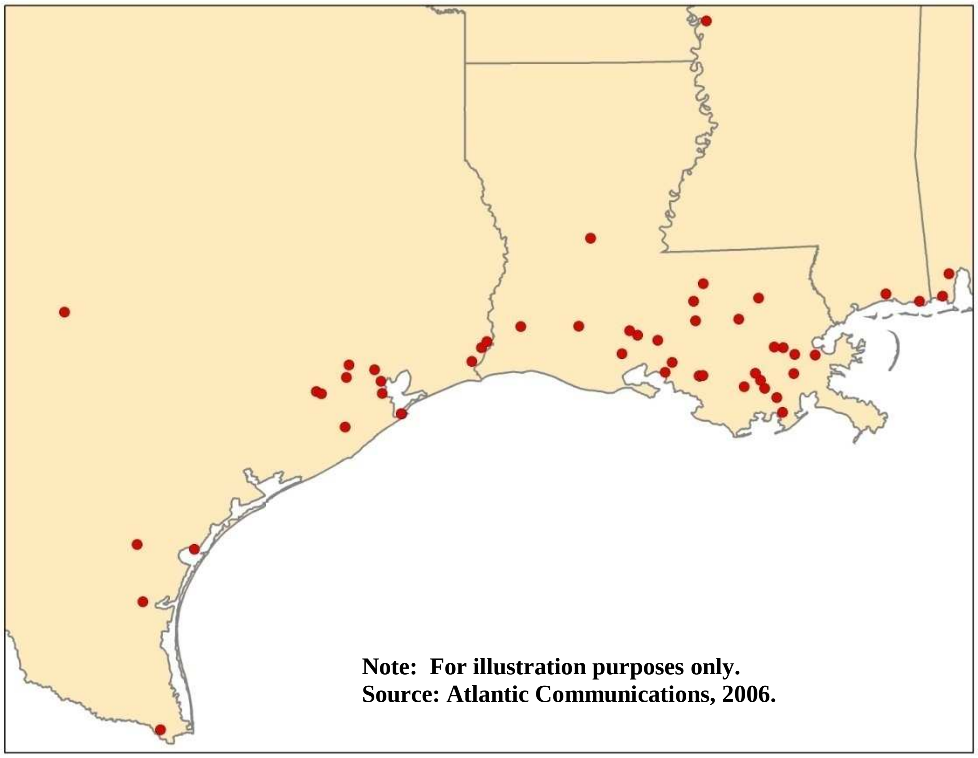


Figure 13. Locations of ship, boat, and offshore rig builders.

2.2.3. Typical Firms

The platform fabrication industry is represented by a high degree of interdependency and cooperation among the fabrication yards. Because offshore platforms, particularly those destined for the deepwater, are complex engineering projects, most fabrication facilities do not have technical capabilities to complete entire projects “in-house” without subcontractors and specialized yards. Some of the larger companies have proprietary designs that they can offer as solutions to new construction. Although competition for customers can be substantial, companies often find that they must also work together on rather large projects. High capital costs restrict many companies from becoming full service offshore construction companies, so many simply specialize on certain types of activities (SEC, 2006b). Therefore, these smaller, more specialized fabrication yards work almost exclusively as subcontractors for competitors on larger jobs (SEC, 2006a).

One of the industry’s largest marine fabrication companies, J. Ray McDermott, S.A., is owned by McDermott International and has principle fabrication facilities near Morgan City, Louisiana, as well as Indonesia, and in Dubai. McDermott’s fourth and newest facility is located on the east coast of Mexico in Altamari, and the yard’s first contract was awarded on December 14, 2007 (SmartBrief.com, 2007). J. Ray McDermott fabricates structures from compliant towers to FPSO technology, making it one of the few companies to offer a full range of offshore structures (SEC, 2006b).

Signal International is a relatively new industry player, yet one that has a sizeable presence along the GOM. Signal was established in February of 2003 with the acquisition of six different yards: four of which are in Texas, with the other two located in Mississippi. The company's activities are very diverse, from module fabrication to rig refurbishments. In fact, the CEO of Signal touts diversification as one of the major keys to the company's longevity (Paganie, 2006b).

Gulf Island Fabrication began operations in southern Louisiana, approximately 30 miles from the coast. The facilities are located on 630 acres, of which 283 are currently developed for fabrication and 347 acres are available for future expansion. On January 31, 2006, they acquired Gulf Marine Fabricators (372 acres, all developed for fabrication), which is located in San Patricio County, Texas. The acquisition has given Gulf Island Fabrication the largest fabrication footprint along the GOM with both the largest individual facility on the GOM and the greatest number of facilities allowing the company to fabricate and assemble all components of deepwater construction projects. The acquisition has also allowed Gulf Island to increase its skilled labor pool and add the ability to construct 1,300 foot conventional jackets (SEC, 2006a).

Many companies who offer platform construction split their operations between shipbuilding, conversions, engineering, and repair. One such company is Keppel FELS, an international company based in Singapore with 17 construction yards around the world. One of their construction yards is located in the GOM area, offering rig construction, repair, and conversion. The company also has an administrative office in Houston (Keppel FELS, 2007a).

Heerema is another regional GOM fabrication company with three construction yards around the world and administrative offices in New Orleans and Houston. Heerema's U.S. locations provide engineering support for the international fabrication yards (Heerema Fabrication Group, 2007).

Technip is also a GOM competitor that operates both regionally and internationally in the construction of offshore drilling vessels, as well as plant and manufacturing yards. (Technip, 2007b). Technip also has a unique cooperation agreement with Gulf Island Fabrication to utilize the services of Gulf Island's yard, giving them greater GOM access (Technip, 2007a).

In addition to just physical location and ability to construct and assemble large structures, most of the larger fabrication yards along the GOM are able to offer proprietary designs to their customers, giving them a competitive edge. For example, Keppel Offshore and Marine, a subsidiary of Keppel FELS, owns proprietary designs such as a suite of semisubmersible designs. Keppel is the world's leading designer and builder of jackups as well as FPSO conversions (Keppel FELS, 2007b). Technip is another example, with designs offering technological solutions for Spar and floating Extendable Draft Platforms and self-installing fixed platforms (TPG 500) (SEC, 2006b).

Fabrication industry customers are generally major and independent oil and gas exploration and production companies and contracts are usually awarded based on the price and ability to meet a customer's delivery schedule. Contracts vary depending upon the size and scope of the project and are usually awarded through a competitive bidding process (SEC, 2006b). Both JRM and Gulf Coast Fabricators price their services on a fixed price basis, although JRM has utilized day-rate and cost-plus pricing methods (SEC, 2006a and b). Most customers schedule their projects to be completed during the summer months, since seasonality and the outdoor nature of the process play an important role in determining construction activities. Some yards are adding covered fabrication areas to avoid this limitation (SEC, 2006a).

2.2.4. Regulation

Numerous aspects of the offshore exploration industries are affected by federal, state, and local regulations as well the guidelines established by many professional engineering associations and organizations. Environmental laws and regulations have become increasingly stringent over recent years, including those governing discharges into the ocean and air, disposal of solid and hazardous wastes, and the health and safety of employees. In addition, the construction of platforms is strictly regulated according to a variety of engineering and construction regulations (SEC, 2006a).

Given their proximity to ports and other navigable waterways, the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, and the Safe Drinking Water Act are laws that heavily influence construction and operation activities in the platform fabrication industry. Fabrication yards and their operators are subject to a variety of potential civil penalties under each of these laws should significant environmental and/or safety-related incidents occur. Offshore platforms are primarily regulated by the BOEM. All platforms destined for eventual location in the OCS must be designed, fabricated, installed, used, inspected, and maintained to assure their structural integrity for the safe conduct of operations at specific locations. Applications for platform approval are filed in accordance with Federal Regulations number 30 CFR 250.900 (unless otherwise noted, information in this section is from 30 CFR §250, 2008).

Applications for all new platforms or major modifications must be submitted in triplicate and contain the following information:

- General platform information including the platform designation, lease number, area name, and block number; Longitude and latitude coordinates, Universal Transverse Mercator grid-system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection system, and a plat drawn to a scale of 1 inch = 2,000 feet showing surface location of the platform and distance from the nearest block lines;

- Drawings, plats, front and side elevations of the entire platform, and plan views that clearly illustrate essential parts, i.e., number and location of well slots, design loadings of each deck, water depth, nominal size and thickness of all primary load-bearing jacket and deck structural members, and nominal size, makeup, thickness, and design penetration of piling;

- Corrosion protection or durability details which consist of the corrosion-protection method; expected life; and durability criteria for the submerged, splash, and atmospheric zones;

- A summary of environmental data, which has a bearing on the platform's design, installation, and operation, e.g., wave heights and periods, current, vertical distribution of wind and gust velocities, water depth, storm and astronomical tide data, marine growth, snow and ice effects, and air and sea temperatures;

- Foundation information including a geotechnical investigation report; and,

- Structural information including the design life of the platform and the basis for such determination.

The platform lessee must evaluate a variety of environmental factors in developing an offshore structure such as waves, wind, currents, tides, temperature, and the potential for marine growth.

In July of 2005, BOEM published a final rule, 70 FR 41556, titled "Fixed and Floating Platforms and Structures and Documents Incorporated by Reference" in the Federal Register. The rule expanded BOEM regulations to include coverage of floating oil and gas production platforms in regards to the design, construction, and operation of OCS facilities, as well as a number of industry-developed standards pertaining to floating platforms. Prior to this rulemaking, BOEM regulations did not specifically address these facilities and permits were approved on a case-by-case basis. This rule was added to streamline the permitting process and enable the BOEM to more efficiently examine plans and issue permits for these floating offshore platforms (USEPA, 2005).

The BOEM regulations define the terms and conditions under which structures are reviewed and also utilize technical input in the verification process from independent third-parties through the use of what is referred to as a "Certified Verification Agent" (CVA). These CVAs inspect platforms during the construction process to ensure that new structures meet standard engineering practices and BOEM guidelines and are not subject to design or construction deficiencies that could lead to structural failures. The CVAs are also responsible for conducting a documented hazard analysis of new facilities (USEPA, 2005).

Construction inspections are conducted to verify that the platform is consistent with its approved construction plan. Any unusual or innovative application of materials or construction methods not included in the originally-approved construction plan must receive special attention and review to ensure platform integrity.

In 2006, BOEM proposed to amend some of its regulations under 30 CFR 250, including various sections of Subpart A – General, Subpart I – Platforms and Structures, and Subpart J – Pipelines and Pipelines Rights-of-Way. These amendments included new requirements to lease operators, lessees, and pipeline right-of-way (ROW) holders to submit an annual assessment on the structural integrity of their OCS platforms each year, and to submit an inspection program on an annual basis. These new requirements are meant to help ensure that lessees, lease operators, and pipeline ROW holders are appropriately assessing their OCS structures to ascertain their fitness for continued use. This change also allows BOEM to better regulate the safety of oil and gas infrastructure and to promptly assess hurricane damage (USEPA, 2006a).

2.3. Industry Trends and Outlook

2.3.1. Trends

Platform fabrication is highly dependent upon the structural nature of the oil and gas industry. When oil prices are high, business is generally good: when oil prices are low, business opportunities tend to deteriorate and yards have to diversify their operations into other marine-related activities, or scale back on the scope of overall operations. To shield themselves from the volatility inherent in the oil and gas industry, platform fabrication yards along the GOM have implemented a variety of diversification strategies. These diversification strategies, coupled with the new challenges brought about by the deepwater oil and gas E&P, are significantly changing the industry.

In order to utilize existing equipment and to keep the highly-skilled workforce during periods with limited to no new orders, many fabrication yards will tend to expand their operations into areas such as maintenance and renovations of drilling rigs, fabrication of barges and other marine vessels, dry-docking, and survey of equipment. These projects, although much smaller in scale and scope than platform fabrication, allow the yards to survive economic downturns.

Deepwater activities have also changed the nature of construction activities at fabrication yards along the GOM. Since the mid-1990s there has been an increasing emphasis in the development of larger, more complicated floating structures, with less emphasis being placed on fixed structures. Fabrication yards are also moving away from the development of single-purpose structures (i.e., those focused exclusively on drilling or production) to platforms that can accommodate both drilling and production operations. These combination platforms (typically floating structures) are larger and more costly since they have to accommodate a broader and potentially more expensive set of equipment. E&P developers are pushing for these types of combined structures since having a single structure that can perform two activities is more cost-effective than utilizing two separate structures that focus on one task or another (SEC, 2006a).

New records are being set in terms of depth and size of platforms. A new TLP design, dubbed the "FourStar" is soon to be implemented by SBM Atlantia Inc. (Williams et al., 2007). Like traditional TLPs, the FourStar has four columns set atop a rectangular ring pontoon. The design diverges from traditional TLPs in the angle of its columns. While traditional TLPs have vertical columns, the four columns of the FourStar are angled toward the center of the platform (Williams et al., 2007) which adds considerable stability and facilitates structure towing to the desired installation site. Figure 14 is a picture of this new design, showing both above and below water structures (Williams et al., 2007).

Source: Williams et al., 2007.

Figure 14. The FourStar, showing both above water and underwater structures.

The Independence Hub[9] (Figure 15), a semisubmersible production facility, is one of the more recent offshore structures and is responsible for breaking a number of critical installation and operation records. These include the world's deepest: platform (located in 8,000 feet of water); subsea completion; steel catenary riser (SCR) installation; and export pipeline. The Independence Hub is one of the largest, in terms of geographic area covering 142 blocks or 1,800 sq mi in the GOM. The semisubmersible is anchored by a 12-line taut polyester/chain mooring system connected to 12 suction piles in Mississippi Canyon block 921 in 8,000 ft of water (Paganie, 2007a).

While the hub's hull was fabricated in Singapore, Atlantia Offshore of Houston was responsible for the hull and mooring systems design, construction, and transportation to the staging site in Ingleside, Texas (Paganie, 2007c; Tubb, 2005). Heerema Marine Contractors was responsible for hull and mooring systems transport from the Jurong Shipyard and final installation (Tubb, 2005). Alliance Engineering of Houston, Texas, designed the topsides and Kiewit Offshore Services of Ingelside, Texas, fabricated and installed the topsides (Kammerzell. 2005). Allseas USA, also of Houston, Texas, was awarded the pipeline installation contract (Tubb, 2005).

The Independence Hub processes production from 10 fields, all of which are developed with subsea infrastructure and connected to the central processing facility using 1,100 miles of umbilical and 210 mi of flow lines. Touch-sensitive data screens installed on the deck and in the control room of the central processing platform control the valves in the subsea infrastructure (Paganie, 2007a).

[9] The Independence Hub is the result of six companies coming together to facilitate the development of multiple ultra-deepwater natural gas and condensate discoveries in the Eastern GOM. It is an affiliate of Enterprise and the Atwater Valley Producers Group, which includes Anadarko, Dominion, Kerr-McGee, Spinnaker and Devon Energy (Offshore-Technology.com, 2009a).

Gas flows from the subsea fields to Independence Hub, which has capacity to process 1 Bcf per day of gas, 5,000 barrels per day of condensate, and 3,000 barrels per day of water.[10] The product then moves to West Delta Block 68 through 134 miles of 24-inch pipe called Independence Trail. From West Delta Block 68, the gas flows to shore (Paganie, 2007a). It has been reported that "once the project reaches full processing capacity, it will represent 10 percent of all natural gas production in the Gulf of Mexico and comprise 1.5 percent of overall U.S. gas supply (Paganie, 2007a)."


Source: Rigzone.com, 2007b.

Figure 15. Independence Hub.

New and increasingly efficient and flexible platform technologies are critical in facilitating the development of deepwater areas. These technologies are not limited to typical civil and marine architecture developments but can include a host of improved systems and software improvements and innovations. One new development is the move to remote power systems which allow platforms to be unmanned. MT-Power™, which is supplied by Northern Power System's Inc. (Vermont), is a power system architecture that uses a fully-integrated fossil fuel-based micro turbine in a continuous-run mode as its primary source of power generation. These power systems are being used by COMMSA (on behalf of Pemex) for three platforms in the Gulf of Mexico (PR Newswire, 2005).

New software products also facilitate accurate and safe platform construction such as the product recently released by the Canadian company Strucsoft Solutions, Inc. called "JACKET Pro." This software uses 3D technology to design, construct, and fabricate offshore structures such as jackets and barges (World Oil, 2007). Another product is called Online Monitoring (OLM), which was developed by Furgo (the Netherlands) to be a cost-effective method to monitor the

[10] Independence Hub began flow of natural gas in July 2007 at an initial flow rate of 72 MMcf per day. By December 2007, the final production well was connected and the flow rate averaged 891 MMcf per day (FERC, 2008a).

safety of many of the geometries of jacket structures. The software detects member severance quickly and accurately in addition to giving guidance on the location of the problem (Offshore-Technology.com, 2007b).

The platform fabrication industry faces considerable competition both domestically and internationally. Most facilities along the GOM find themselves competing with yards located in places as far away as South Korea, Italy, and several countries in the North Sea. Many are seeking assistance from state and local government in order to make facility improvements that will enhance their regional competitiveness. For instance, Gulf Island Fabrication, Inc, located in Houma, Louisiana, announced in the fall of 2008 that it would be receiving $2.3 million in state assistance to aide in its $29.3 million expansion plans that include the development of a new operating division dedicated to building barges and other marine vessels on the Houma Navigational Channel in Terrebonne Parish. According to press releases, this expansion promises to bring 200 new jobs to Houma within the next two years as well as securing a commitment for Gulf Island to keep its headquarters in Louisiana (Perilloux, 2008).

Deepwater development, in addition to global competition, creates another set of challenges for the GOM fabrication industry given the greater technical sophistication and increased project complexity of the deepwater structures. Deepwater activities impact the regional platform fabrication industry in two important ways. First, larger, more sophisticated and more costly projects may bring some degree of industry consolidation. For instance, in 2006 Gulf Island Fabrication acquired the facilities, machinery, and equipment of Gulf Marine Fabricators in San Patricio County, Texas (SEC, 2006a). Gulf Island Fabrication stated that the acquisition would enable the company to perform dockside integration, increase rolled goods capabilities, afford 45 feet of water depth access, and provide the ability to construct 1,300 foot conventional jackets and tendons for floating production platforms. Perhaps most importantly, the acquisition of Gulf Marine enables Gulf Island to fabricate and assemble all components of deepwater construction projects, which it was previously limited from doing by the physical constraints of its Houma yards. In addition, the acquisition would give Gulf Island greater lifting capacity dockside (4,000 tons) which makes available an additional labor pool (SEC, 2006a).

Second, companies may find themselves operating in closer integration, through alliances, special project relationships, and joint ventures. With its acquisition of Gulf Marine, Gulf Island and Technip-Coflexip USA Holdings, Inc., (which was the former indirect parent of Gulf Marine) entered into a cooperation agreement to work together on "mutually agreed upon engineer, procure, and construct (EPC) projects and engineer, procure, install, and commission (EPIC) projects requiring fabrication work in the Gulf Coast region." Under this agreement, Gulf Island has the right of first refusal on the fabrication work in connection with certain bids that Technip may submit.

Shipbuilders and platform fabricators have also expanded operations into supply and support activities, not only for the oil and gas industry, but for other industries as well. A number of general attributes associated with these facilities have led to their successful diversification. These characteristics include general large geographic areas for work and storage, varied sources of unskilled and skilled labor (i.e., electricians, pipefitters, welders), and access to supporting infrastructure (i.e., roads, waterways, ports, communications). The shipbuilders and platform fabricators are now conducting activities like dry-docking, inspections, maintenance, and surveys of stacked rigs and equipment. Another area of operation includes work on production systems. While this is relatively low-dollar-per-task work, it is more stable than traditional fabrication work and can help keep important yards economically viable during downturns.

2.3.2. Hurricane Impacts

The platform fabrication industry felt two general effects from the 2005 tropical season. One impact was the increased repair and restoration work that occurred in the aftermath of Hurricanes Katrina and Rita. It is estimated that 3,050 of the GOM's 4,000 platforms (or 76 percent of platforms) were in the direct path of either Hurricane Katrina or Hurricane Rita. Hurricane Katrina destroyed 46 platforms and damaged 20 others. Hurricane Rita destroyed 69 platforms and damaged 32 others (USDOI, MMS, 2006a). In comparison, in 2004 Hurricane Ivan, a Category 4 storm, destroyed seven platforms and damaged 24 others. Table 3 and Table 4 are a highlight of rig damage from Hurricanes Katrina and Rita (Rach, 2006).

Table 3

GOM Rig Damage, Hurricane Katrina

GULF OF MEXICO RIG DAMAGE, HURRICANE KATRINA
Major damage, total loss
- Diamond Offshore Drilling Inc.'s Ocean Warwick, jack up, drifted 66 miles northeast from Main Pass Block 299; beached on Dauphin Island, Ala.
- ENSCO 29, platform rig, severely damaged, future status unclear.
- H&P 201, platform rig, on Mars TLP in Mississippi Canyon Block 807, smashed.
- Hercules 25, jack up, derrick broke, crushed crew quarters.
- Nabors Offshore Corp.'s Super Sundowner XII, platform rig, platform collapsed, rig lost.
- Pride 210, platform rig in West Delta Block 73, mast damage, may be scrapped.
- Rowan New Orleans, jack up, presumed capsized in Main Pass Block 185.
Damaged
- Diamond's Ocean Quest, semisubmersible, minor damage.
- Diamond's Ocean Voyager, semisubmersible, drifted 9 miles north from MS Canyon Block 711.
- ENSCO 7500, semisub, tow line parted while under tow, listing.
- GSF Arctic I, semisub, drifted, grounded near mouth of Mississippi River.
- GSF Celtic Sea, semisub, listing.
- GSF Development Driller I, semisub, found listing slightly, with water damage to thruster control.
- GSF Development Driller II, semisub, anchor damage.
- Nabors' Dolphin 110, jack up, broken windows, water damage.
- Noble Jim Thompson, semisub, drifted 17 miles NNE from MS Canyon Block 935; mooring line damage.
- Transocean Inc.'s Deepwater Nautilus, moored semisub, drifted 80 miles; damage to mooring system and thrusters, lost about 3,200 ft of marine riser and part of subsesa well control system.

Source: Rach, 2006.

Table 4

GOM Rig Damage, Hurricane Rita

GULF OF MEXICO RIG DAMAGE, HURRICANE RITA
Major damage; total loss
- GSF Adriatic VII, jack up, drifted 80 miles from Eugene Island Block 338; ran aground off LA.
- GSF High Island III, jack up, ran aground off Louisiana.
- Noble Joe Alford, submersible, drifted 8 miles from Vermillion Blcok 52; support members below the hull are bent or broken.
- Noble Max Smith, semisubmersible, drifted 123 miles, hole in starboard outboard column and decks damaged; sustained heaviest damage among Noble's rigs.
- Rowan-Fort Worth, jack up, drifted from South Marsh Island Block 146; found beached in W. Cameron
- Rowan-Halifax, jack up, drifted from East Cameron Block 346; found beached.
- Rowan Louisiana, jack up, hull detached in Vermilion Block 338; ran aground near Cameron, LA
- Rowan-Odessa, jack up on Ship Shoal Block 250; missing.
Damaged
- Diamond Offshore Drilling Inc.'s Ocean Saratoga, semisubmersible, drifted 100 miles NW, ran aground in Vermilion Block 111.
- Diamond's Ocean Star, semisubmersible, drifted 100 miles northwest, ran aground in Eugene Island.
- ENSCO 68, jack up, drill floor shifted.
- ENSCO 69, jack up, drilling skid shifted.
- ENSCO 90, jack up, listing in South Marsh Block 130
- ESV 7500, semisubmersible, moorings broke.
- Hercules 21, jack up, listing in Main Pass Block 21.
- Nabors Offshore Corp.'s Dolphin 111, jack up, Sabine Pass, windows blown out, water damage to control systems and quarters.
- Nabors's Pool 54, jack up, mast blown over.
- Nabors's Rig 300, deep drilling barge, submerged east of Cameron, LA; electric and pump systems damaged
- Noble Lorris Bouzigard, semisubmersible, broke mooring lines, drifted.
- Rowan-Louisiana, jack up, legs severed, grounded near Cameron, La.
- Transocean Marianas, moored semisub, grounded in shallow water at Eugene Island Block 133; damage to mooring system, thrusters, and hull; one column partially flooded.

Source: Rach, 2006.

The second impact of the 2005 tropical season was the direct wind and water damage, as well as the significant business interruptions, imposed upon the fabrication facilities and yards by the storms. Gulf Island Fabricators, for instance, reported that its Houma facilities were shut down for a total of approximately 3 weeks (SEC, 2005a). Worker displacement, and ultimately worker availability, was another significant challenge for many of the fabrication yards along the GOM. The general economic trend of a lack of skilled laborers in the region was exacerbated by Hurricane Katrina as many local employees were forced from their homes, many of which were significantly, if not permanently damaged. At least one company (Gulf Island Fabrication) estimated that close to 100 employees were "lost" or made unavailable for fabrication yard repair activities due to either the personal losses of property (i.e., homes) or through competition with FEMA contractors that were paying higher wages than local companies (SEC, 2005a).

Many navigation canals, which are significant to the platform fabrication industry, required substantial maintenance after the 2005 hurricanes. For example, Hurricane Rita caused major silting problems in the Houma Navigation Canal, resulting in restrictions on vessel size. The U.S. Army Corps of Engineers had to use emergency funding to dredge the canal back to its design depth (SEC, 2006a).

Rebuilding and repair activities were subjected to very high commodity and component costs in the aftermath of the 2005 storms. During this period (2005-2008), global commodity prices were at record levels given increased worldwide demand particularly in developing countries such as China and India. Steel prices in the U.S. increased about 50 percent during this period. Similarly, concrete in the U.S. increased 20 percent. Critical components and equipment from wallboard to copper were seeing record increases. The hurricanes placed great cost pressure on restoration activities given the high demand in the aftermath of the 2005 hurricanes. Gulf Island, for instance, noted that capital and resources directed to the rebuilding of New Orleans created scarcity in both products and labor (Gulf Island Fabrication, 2006).

Many fabricators found that the 2005 hurricanes would have lasting implications for the way in which they constructed new platforms and the structure of existing platforms and other oil and gas vessels such as barges and jackups. For instance, increasing design deck elevation is one area being considered by industry as a means of circumventing, or at least minimizing, potential future hurricane damage. According to Frank Puscar, President of Energo Engineering Inc. located in Houston, Texas, 60 percent of the 120 platforms destroyed in Hurricanes Rita and Katrina had waves on the deck. The 2004 and 2005 hurricanes prompted the American Petroleum Institute (API) to revise their recommended practices in regards to expected wind and wave data during hurricanes in the Gulf. Their documents included a number of recommended changes in the construction and operation of both mobile offshore drilling units and fixed and floating production platforms (Fletcher, 2007).

One interesting innovation arising from the 2005 tropical activity was the development of a new type of "hurricane resistant" vessel, called a "Satellite Services Platform" (SSP) vessel designed to withstand extreme conditions. OPE, Inc., headquartered in Houston, designed this vessel to have various uses, including as an FPSO or early production platform. The SSP, which became operational in 2007, rides waves vertically with slow acceleration in order to maintain a high degree of stability in extreme environmental conditions. The patented spherical hull differentiates this vessel from others. It is this spherical design with a round platform shape "that presents a constant 'face' to winds and seas from any direction (Maksoud, 2007)."

2.3.3. Outlook

The offshore drilling industry has come a long way since it installed the first subsea wellhead in 1961. The oil and gas industry is expected to increase its annual capital spending to more than $275 billion by 2011 from $219 billion in 2006. The GOM is one of three regions, including the North Sea and the South China Sea, that together attract more than half these capital expenditures (Fletcher, 2007). The GOM continues to represent an expanding frontier with growth opportunities, especially deepwater. For instance, the following deepwater achievements were made in just 2006 alone, and highlight the frontier nature of the GOM:

- Chevron Corp set a drilling depth record for the U.S. Gulf at 34,189 feet.

- Oil and gas operators announced 12 deepwater discoveries in 2006, with the deepest being in 7,600 ft of water.

- More than half of the active oil and gas leases in the Gulf are in more than 1,000 feet of water, which are classified as deepwater by the BOEM. (Fletcher, 2007).

The continued business opportunities in the deepwater GOM strongly motivate platform fabricator decisions. Gulf Island, for instance, noted in their 2006 SEC Form 10-K that one reason they acquired Gulf Marine was to utilize its yards for deeper water construction (SEC, 2006a). Technip also cited growth in deeper offshore fields as a reason for focusing on specific regions of development (SEC, 2006c).

The challenges faced by the platform fabrication industry are similar to those being faced by other sectors supporting offshore activities. There will be continued pressures arising from new and expanded environmental regulations, new engineering and economic challenges created by deploying new technologies, continued infrastructure cost pressures, and a shortage of skilled labor created in large part by the considerable demographic changes impacting all energy sectors across the country (Keppel FELS, 2006). According to Douglas-Westwood analysts, experienced personnel and assets will command mounting premiums over the next five years (Fletcher, 2007).

2.4. Chapter Resources

Atlantic Communication's Gulf Coast Oil Directory
Includes a wide range of data from company name, address, web and email addresses to contact names with titles, direct phone numbers, and email addresses all organized alphabetically by industry categories. Also included is "Company Detail" information such as company size, revenue, areas operated in last 12 months, operations onshore or offshore, and stock information for publicly traded companies.
http://www.oilonline.com/Directory/DirectoriesDatabases.aspx

Rigzone.com
Hundreds of photos of rigs can be found at Rigzone.com. Rigzone.com also has rig utilization reports, and day rate reports. The site also provides the following Rig Reports:

- Offshore Rig Fleet by Manager: Provides a listing of the active rig managers in the world with overall utilization statistics for each manager's rig fleet and links to view rig details and photos for each manager's rigs.

- Offshore Rig Fleet by Region: Presents a list of the offshore drilling areas of the world with the utilization statistics for each region and links to view rig details and photos of the rigs in each area.

- Offshore Rig Fleet by Rig Type: Presents a listing of the offshore rig types tracked by Rigzone with the worldwide utilization statistics for each rig type and links to view rig details and photos for all the rigs of each type.
- Offshore Rig Fleet by Operator: Provides a listing of the active operators in the world with the number of rigs each operator currently has under contract and links to view rig details and photos for each operator's rigs.

http://rigzone.com/data/

U.S. Securities and Exchange Commission
Quarterly and annual reports of operations for publicly traded companies are filed with the Securities and Exchange Commission.
http://www.sec.gov/edgar/searchedgar/companysearch.html

3. SHIPYARDS / SHIPBUILDING

3.1. Description of Industry and Services Provided

The shipbuilding and repair industry can be used as a general term defining the sector responsible for building ships, barges and other large vessels, whether self-propelled or towed by other craft. These marine vessels are perhaps the most important means of transporting equipment and personnel from onshore bases and ports to offshore drilling and production structures. However, facilities dedicated to constructing and repairing these various types of marine vessels are not limited to the oil and gas industry. Orders for marine vessels and ship repairs come from a wide range of industries that can include: commercial shipping companies; passenger and cruise companies; ferry companies; petrochemical companies; commercial fishing companies; and towing and tugboat companies.

One of the largest customers of the shipbuilding and repair industry is the federal government. There is a wide range of naval and marine craft utilized by the federal government which can range from large military-related construction (i.e., aircraft carriers, guided missile cruisers, destroyers, frigates, etc.) to small experimental craft used for ocean and marine life observation. Most shipbuilding yards along the GOM have a heavy, if not principle, interest in serving the federal government market: oil- and gas-related vessels, while a very important target market segment, are of secondary interest. The principal federal government agencies placing shipbuilding and repair orders include the Naval Sea Systems Command, the Military Sealift Command, the Army Corps of Engineers, the U.S. Coast Guard, the National Oceanic and Atmospheric Administration, the National Science Foundation, and the Maritime Administration (USEPA, 1997).

The development of the U.S. shipbuilding industry was primarily driven by military needs in the beginning of the century. In 1932, there was little shipbuilding in the U.S. outside of naval military construction. In the early 1930s there were only nine commercial shipyards with about 19,000 employees, eight of which were on the East Coast. In comparison, there were eight navy yards employing 25,000 dedicated to the development of military craft (GlobalSecurity.org, 2008a).

Through the Merchant Marine Act of 1936, Congress created the U.S. Maritime Commission (currently known as the Maritime Administration). The Maritime Commission facilitated an expanded ship construction program in the late 1930s and significantly increased its efforts as the U.S. moved close to engagement in the Second World War. By the end of the war, the federal government owned and operated nine different shipyards and operated, controlled, or contracted with approximately 132 privately-owned shipyards (GlobalSecurity.org, 2008a).

The end of WWII, and its corresponding decrease in the demand for naval craft to support military operations around the world, raised a number of policy concerns regarding the continued economic viability of private shipyards. This economic concern was coupled with the national security interests of maintaining a diverse set of strategically-located shipyards with the advent of the Cold War. As a result, the federal government began a process immediately after WWII of redirecting its construction and maintenance activities away from government-owned facilities and toward private yards. By 1961, over 60 percent of total funding for naval construction was directed toward private yards. The Navy's own yards were designated for maintenance and repair (GlobalSecurity.org, 2008a).

Since the 1960s the shipbuilding industry has seen significant change with small and mid-sized shipyards continuing to build a variety of vessels for use on inland and coastal waterways, as well as for foreign markets. The large increase in offshore E&P activity has also helped expand the markets that these shipbuilding yards can serve. The primary vessels these shipbuilding yards provide to the oil and gas industry are known as "offshore service vessels" (OSVs). These vessels transport a wide range of personnel and equipment ranging from pipes to wrenches to computers, fuel, and drinking water (OMSA, 2008).

3.2. Industry Characteristics

3.2.1. Typical Facilities

Shipyards are often categorized into a few basic subdivisions characterizing either the type of operation (shipbuilding or ship repairing), the type of ship (commercial or military), or the shipbuilding or repairing capacity of the vessels being constructed or repaired (first-tier or second-tier). Ships themselves are often classified by their basic dimensions, weight (displacement), load-carrying capacity (deadweight), or their intended service. Shipbuilding activities in the U.S., and particularly along the GOM, can vary considerably depending upon the primary markets these shipyards serve (i.e., commercial or military) (USEPA, 1997).

Commercial Ships

Commercial ships can be subdivided into a number of classes based on their intended use including: dry cargo ships; tankers; bulk carriers; passenger ships; fishing vessels; industrial vessels; and others. Dry cargo ships include break bulk, container, and roll-on/roll-off types.

Unlike the military market, the commercial ship markets face intense international competition. Developing cost-competitive commercial ships has a significant impact on the manner in which commercial ships are built and repaired. This competition has also had a negative impact on the number of shipyards constructing commercial ships. Since 1981, U.S. shipyards have received less than one percent of all commercial orders for large ocean going vessels in the world, and no commercial orders for large ocean going cruise ships (USEPA, 1997).

Military Ships

Military ship orders have been the mainstay of the industry for many years. The military ship market differs from the commercial market since it is driven in large part by military budgets and government appropriations supporting marine craft development. The military ship market can be divided into combatant ships and ships that are ordered by the government, but are built and maintained to commercial rather than military standards. Combatant ships are primarily ordered by the U.S. Navy and include surface combatants, submarines, aircraft carriers, and auxiliaries. Government-owned noncombatant ships are mainly purchased by the Maritime Administration's National Defense Reserve Fleet and the Navy's Military Sealift Command. Other government agencies that purchase non-combatant ships are the Army Corps of Engineers (USACE), National Oceanic and Atmospheric Administration (NOAA), and the National Science Foundation (NSF). These non-combatant ships often include cargo ships, transport ships, roll on/roll off ships, crane ships, tankers, patrol ships, and ice breakers (USEPA, 1997).

U.S. shipyards are classified by the Maritime Administration (MARAD) by the size of the establishment. MARAD has two major categories, the first being the major U.S. private shipbuilders and the second the small and medium-sized shipyards.

A major shipbuilding and repair facility is defined by MARAD and the Department of Transportation in *Report on Survey of U.S. Shipbuilding and Repair Facilities, 2006*, as one that is open and has the capability to construct, drydock, and/or topside repair vessels with a minimum length overall of 122 meters, provided that water depth in the channel to the facility is at least 3.7 meters. Facilities are further classified as follows (USDOT, MARAD, 2006a):

- ***Active Shipbuilding Yards:*** are defined as those privately-owned U.S. shipyards/facilities, that are open, with at least one building position capable of accommodating a vessel 122 meters (400 feet) in length and over, and are currently engaged in the construction of naval ships and/or major oceangoing merchant vessels 122 meters (400 feet) in length and over.

- ***Other Shipyards with Build Positions:*** are defined as privately-owned shipyards/facilities that are open, with at least one build position capable of accommodating a vessel 122 meters in length and over, and that have not constructed a naval ship or major oceangoing merchant vessel in the past two years.

- ***Repair Yards with Drydock Facilities:*** are defined as those facilities having at least one drydocking facility that can accommodate vessels 122 meters in length and over. These facilities may also be capable of constructing a vessel less than 122 meters in length overall.

- ***Topside Repair Facilities:*** are defined as those shipyards that have sufficient berth/pier space, including dolphin piers, to accommodate a naval ship or major oceangoing merchant vessel of 122 meters in length or over. These facilities may also have drydocks and/or construction facilities.

The second classification, small and medium-size shipyards, construct and repair smaller vessels (under 122 meters) that can include, but are not limited to: military and non-military patrol boats; fire and rescue vessels; casino boats; water taxis; tug and towboats; offshore crew and supply boats; ferries, fishing boats; and shallow draft barges. A number of second-tier shipyards are also able to make topside repairs to ships over 122 meters in length. These facilities are further categorized as follows (USDOT, MARAD, 2003):

- ***Boatbuilding and Repair Companies:*** privately-owned shipyards capable of building and/or repairing commercial and military vessels less than 122 meters (400 feet) in length.

- ***Vessel Repair Companies:*** facilities that only provide repair services, either repair with drydocking or topside repair, to vessels less than 122 meters (400 feet). These companies must have their own waterfront facilities.

- ***Fabricators/Manufacturers of Maritime Vessels:*** companies that build small commercial crafts less than 76 meters (250 feet).

In 2006, there were 23 active shipbuilding yards and other shipyards with building positions (USDOT, MARAD, 2006a). These yards accounted for about 68 percent of the total U.S. shipbuilding and repair industry's total workforce. There were approximately 78 total private shipyards, 28 of which were in the Gulf Coast region, employing 19,000 production workers. As shown in Figure 16, the largest number of production workers are employed by some of the smallest types of shipyards (USDOT, MARAD, 2006a).

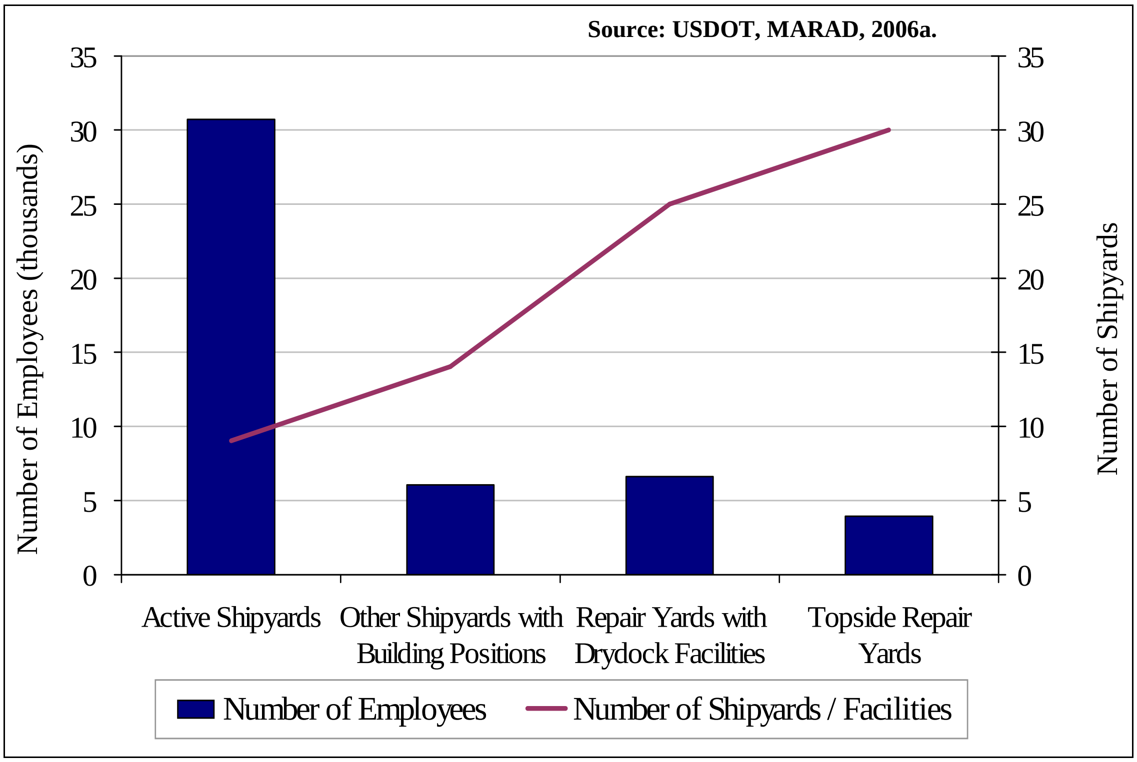


Figure 16. Number of production workers by shipyard type.

Like platform fabrication, almost all shipyard facilities do not have the capability to construct or repair vessels under cover, most of the shipbuilding and repair work is done outdoors and near some major body of water such as a river or deep channel.

For the most part, shipyards are designed to facilitate flow of materials and assemblies. Like platform fabrication yards, growth and expansion of the facility is piecemeal and depending on technology and the availability of land and waterfront property, no typical shipyard exists. Most facilities however, do include the following physical characteristics:

- dry-docks;
- shipbuilding positions;
- piers and berthing positions;
- workshops for electrical, pipe cutting and machining, assembly, paint and sanding operations;
- areas for carpenter, sheet metal and construction work;
- steel storage;
- warehouses;
- service/fueling stations; and
- offices.

According to the *2002 Census of Manufacturers* data, there were 642 shipbuilding and repairing yards under NAICS Code 336611 (Shipbuilding and Repairing).[11] Like many construction oriented sectors, shipbuilding yards are very labor intensive, with 2002 payroll totaling $3.6 billion for a workforce of 87,000 employees, and value of shipments totaling $12.8 billion. The average salary for these employees is $36,800. Value of shipments per employee is often used as a measure of labor intensity where smaller numbers mean greater labor intensity and larger number mean less labor intensity. The shipbuilding and repair industry has a value of shipments per employee of $147,000; half the level of steel manufacturing ($286,000 per employee) and only about five percent of the petroleum refining industry ($3 million per employee). It is the relatively few (but large) shipyards, however, that account for the majority of the industry's employment and sales (USDOC, Census, 2002a).

Offshore Supply Vessels

OSVs are those boats that work solely to provide services to the offshore oil and gas industry. OSVs primarily serve exploratory and developmental drilling rigs and production facilities, and support offshore and subsea maintenance activities. Besides transporting deck cargo, OSVs also transport liquid mud, potable and drilling water, diesel fuel, dry bulk cement, and personnel between shore bases and offshore rigs and facilities (SEC, 2006d).

There are six primary types of OSVs that include: tugs; marine platform supply vessels (PSV); anchor handling, towing and supply vessels (AHTS); mini-supply vessels (MSV); fast support vessels (FSV); and liftboats. A seventh category, Floating, Production, Storage and Offloading (FPSO) vessels, has just been conceptually approved for use in the GOM by the Bureau of Ocean Energy Management (BOEM) office in late 2006 (Petroleum Economist, 2007).

[11] NAICS 336611 (Ship Building and Repairing) is defined as the industry of establishments primarily engaged in operating a shipyard. Shipyards are fixed facilities with drydocks and fabrication equipment capable of building a ship, defined as watercraft typically suitable or intended for other than personal or recreational use. Activities of shipyards include the construction of ships, their repair, conversion and alteration, the production of prefabricated ship and barge sections, and specialized services, such as ship scaling.

Each category of OSV has specific uses and is designed and constructed for that type of activity. Design, length, horsepower and cargo capabilities are some of the means by which these OSVs are differentiated. For example, PSVs are involved in providing offshore drilling and production facilities with various supplies including equipment, pipes, lubricants, chemicals and drilling mud. They can also perform fire fighting as well as oil recovery operations in case of an oil spill at an offshore platform. AHTS vessels include highly-specialized vessels that are a combined supply and anchor-handling ship. Anchor-handling means that the vessel moves anchors and tows drilling vessels and other similar vessels (GlobalSecurity.org, 2008b).

The main trade association for the OSV industry is the Offshore Marine Service Association (OMSA), representing more than 250 member companies, including about 100 firms that own and operate marine service vessels. The OMSA reports that there are some 1,200 OSVs operating in the GOM (OMSA, 2008). Not all of the 1,200 vessels are in operation since many of the older boats are taken out of commission or "cold-stacked." Most of the cold-stacked vessels may never function again and are being reserved for either salvage or used for spare parts. OMSA estimates that of the total vessels in the GOM, only about 200 to 350 (16 to 29 percent) are in active operation. Other industry sources, however, estimate the U.S.-flagged OSV fleet at 335 vessels (SEC, 2006d).

3.2.2. Geographic Distribution

Table 5 provides the geographic distribution of the shipbuilding industry by major coastal area. Over one-third (28 facilities) of the major shipbuilding yards are located on the GOM, with most of these being topside repair yards. Another one-third is found on the East Coast with 26 facilities, and the West Coast has 14 (again, mostly for repair).

Table 5

Number of Shipyards by Type and Region

	Active Shipbuilders	Other Shipyards with Build Positions	Repair with Drydocking	Topside Repair
East Coast	4	1	11	10
Gulf Coast	**4**	**7**	**5**	**12**
West Coast	1	1	6	6
Great Lakes	0	5	0	2
Non-Continuous	0	0	3	0
Total	**9**	**14**	**25**	**30**

Source: USDOT, MARAD, 2006a.

While the Gulf Coast shipbuilding region covers an area between south Texas and the tip of Florida, most shipbuilding facilities are concentrated in a 200-mile area between New Orleans and Mobile. This 200-mile region has four of the nation's nine active major yards (Mississippi

Gulf Coast Alliance for Economic Development, 2007). These companies actually benefit from such close proximity, known as "clusters," in order to optimize construction and repair synergies.

Atlantic Communication's *2006 Gulf Coast Oil Directory* includes the shipbuilding and repair industry in its "Ship, Boat & Offshore Rig Builders" section. According to the directory, most of the 87 companies listed have locations in Louisiana and Texas, with the remainder being evenly distributed between Mississippi, Alabama, and Florida (Atlantic Communications, 2006).

3.2.3. Typical Firms

There are currently nine active major shipyards in the U.S. The six largest companies have been dubbed the "Big Six," accounting for two-thirds of the industry's revenues (Mississippi Gulf Coast Alliance for Economic Development, 2007).

The American Shipbuilding Association (ASA) is the professional trade organization for companies capable of constructing "mega-vessels" in excess of 400 ft in length and weight in excess of 20,000 DWT. The ASA represents the designers and producers of the safest and most technologically-advanced ships in the world, as well as employing 90 percent of all the workers involved in ship construction. Two of the six members of the ASA have a presence along the GOM (ASA, 2008). Both Avondale Shipyard of New Orleans, LA and Ingalls of Pascagoula, MS have enormous capabilities and expertise in the design, construction, and repair of marine vessels. Their highly-developed level of expertise makes both ideal contractors for the nation's defense efforts. Therefore, most of the work that has been accomplished in these two yards has been for the U.S. Military. The following are brief descriptions of some of the major shipyards along the GOM:

<u>Bollinger Shipyards</u>

Started in 1946, Bollinger specializes in the repair, conversion, and construction of a wide variety of small to medium-sized offshore and inland vessels (Figure 17). It primarily serves the energy, commercial, and government marine markets along the GOM (Bollinger Shipyards, Inc., 2008).

Bollinger currently operates 13 shipyards located throughout South Louisiana and Texas with direct access to the central GOM. Bollinger operates a wide variety of dry-docks and service facilities ranging in capacity from 100 tons to 22,000 tons, for both shallow and deepwater vessels and rigs (Bollinger Shipyards, Inc., 2008).

Bollinger offers a wide range of standard vessel designs and has the capability of developing new designs and/or existing design modification to meet specific customer requirements. Bollinger's design classifications include patrol craft, OSVs, liftboats, barges, specialties craft, and tugs (Bollinger Shipyards, Inc., 2008).

Figure 17. Bollinger's Algiers shipyard in New Orleans, Louisiana.

Harrison Brothers Dry Dock & Repair Yard, Inc.

Harrison Brothers, which has been in operation for over 100 years, is a well-established shipyard along the GOM engaged in the repair of tugboats, barges, supply boats, small ships, and other commercial vessels. Their facilities are located in Mobile, Alabama, with full service operations expanding over two yards and two drydocks. Their drydocks can handle vessels between 700 tons and 2,000 tons. Harrison markets its workforce experience as a main advantage since the majority of its workforce has been with them for over 10 years (Harrison Brothers Dry Dock and Repair Yard, Inc., 2007).

Edison Chouest Offshore

Louisiana Edison Chouest Offshore (ECO) was founded in 1960 and has doubled in size since 1993. Design and construction capabilities have made ECO prominent in the offshore boat service industry. Chouest's business model differs from most of its competitors because it designs, builds, owns, and operates each of its vessels. These vessels, in turn, are leased and not sold to clients. Today, ECO has under charter the largest number of privately-owned and operated special-purpose vessels to the U.S. Government. ECO also owns and operates the largest independently-owned fleet of seismic and research vessels in the world, a growing fleet of new generation offshore deepwater service vessels, and a variety of high-tech, high-capacity offshore vessels that range from 87 feet to 320 feet in length (ECO, 2007a).

North American Shipbuilding (NAS) is another significant shipyard along the GOM that specializes in a variety of offshore vessels. The Company was founded in 1974 and is located in Larose, Louisiana. NAS is wholly owned by ECO and designs and constructs vessels exclusively for ECO and its affiliated companies. NAS has built many ground-breaking ships including the first U.S. Antarctic icebreaking research vessel, the largest and most powerful anchor handling vessel in the U.S. fleet, the first dynamically positioned vessel in the U.S. fleet, the world's first floating production system installation vessel, and the largest water throw capacity vessel in the

U.S. fleet. It has a formal welding training program and on the job apprenticeship training for all other trades (ECO, 2007b).

North American Fabricators (NAF), located in Houma, Louisiana, is another ECO affiliate. Since its founding in 1996, NAF has developed into a state-of-the-art, world-class shipbuilding facility. NAF's 500 shipyard workers build modern, highly specialized offshore supply vessels from lengths of 190 feet and larger. NAF's first delivered vessel was the "C-Commander," the largest OSV in the U.S. fleet at that time (1997), at 240 ft. long and 56 ft. wide. NAF's new construction projects will be designed to work in deepwater production and global research expeditions (ECO, 2007c).

Northrop Grumman Corporation

Northrop Grumman Corporation has two shipbuilding sectors: Northrop Grumman Ship Systems (NGSS) and Newport News. NGSS is headquartered in Pascagoula, Mississippi, and has primary operations in New Orleans, Louisiana (formerly Avondale Shipyards), and shipyards in Pascagoula and Gulfport, Mississippi (formerly Ingalls Shipyards) and Tallulah, Louisiana. Newport News is located in Newport News, Virginia. In January 2008, Northrop Grumman Corp. announced the merger of these two entities into a new entity named "Northrop Grumman Shipbuilding." New headquarters for the merged sectors has yet to be determined. Both sectors are involved in commercial, as well as naval services (The Daily Advertiser, 2008).

NGSS is a large company that can provide full life-cycle services for major surface vessels including design, engineering, and construction. NGSS employs over 18,000 professionals (NGSS, 2008). In 2000, NGSS acquired Litton Industries, including their two shipyards, Avondale (Louisiana) and Ingalls (Mississippi).

Avondale's main shipyard is located on the Mississippi River twelve miles upriver from the Port of New Orleans and has been in continuous operation since 1938. Avondale is Louisiana's largest manufacturing employer with more than 6,000 employees. The facility includes two separate construction areas, a fully-equipped machine shop, semi-automated pipe shop, electrical shop, and sheet-metal shop. Avondale is the prime contractor for the Navy/Marine Corps Team's SAN ANTONIO (LPD17) Class of amphibious assault ships. The company is currently building three double-hull oil tankers (the first to be built in the U.S.), for ARCO Marine. These giant ships are designed to be the world's most environmentally safe crude oil and product tankers (NGSS, 2008).

In 1982, Avondale began the use of modular construction techniques for ship construction. This modular technology was acquired from a leading Japanese shipbuilder and has been mastered by Avondale's work force. Modular construction consists of constructing 150 to 200 separate units (or modules) and completely outfitting them with pipe, ventilation systems, etc. The modules are then joined just prior to launching (NGSS, 2008).

NGSS Ingalls Operations is headquartered in Pascagoula, Mississippi, and has been in continuous operation since 1938. Like Avondale in Louisiana, Ingalls is Mississippi's largest private employer, with over 10,000 employees and is one of the nation's leading full service systems companies for the design, engineering, construction, and life cycle support of major surface ships for the U.S. Navy, U.S. Coast Guard and international navies, and for commercial vessels of all types. NGSS Ingalls holds contracts in a far-ranging modernization of the United States Coast Guard's deepwater assets, in a joint venture with Lockheed Martin known as Integrated Coast Guard Systems (ICGS) (NGSS, 2008).

Newport News is the nation's sole designer, builder and re-fueler of nuclear-powered aircraft carriers. Their facilities are located on more than 550 acres and they are Virginia's largest industrial employer with more than 21,000 personnel. Many of their workers are third and fourth generation shipbuilders (Northrop Grumman Corp., 2008). At the current time, this facility is primarily dedicated to the construction of military craft, and does not construct any types of craft or structures for offshore oil and gas activities.

Bender Shipbuilding and Repair

Bender has been in business for about 80 years and is located on the Mobile River in Mobile, Alabama, covering over a mile long stretch of land and employing about 850 personnel, as of mid-2006 (USDOT, MARAD, 2006a). Bender's facilities boast 7,000 feet of deep water frontage and dry docks with lifting capabilities of more than 24,000 tons. Bender's around-the-clock workforce has built over 800 vessels of many different types, including OSV, tug boats, factory trawlers, etc. (USDOT, MARAD, 2006a).

Bender has been modernizing their facilities in the past few years in order to meet the challenges of global competition. This modernization effort includes the development of a state-of-the-art steel processing facility, and enhanced main assembly shed and crane capabilities. The production processes are managed and controlled with contemporary software tools that control a fully integrated fiber and wireless communications and data network that runs throughout the yard (USDOT, MARAD, 2006a).

In recent years, Bender's customers have included the foreign-flagged commercial ship operators, as well as the Maritime Administration, Army Corps of Engineers, U.S. Navy, and the Military Sealift Command. Many of these contracts were for repair and conversion rather than for new ship construction.

3.2.4. Regulation[12]

The shipbuilding and repair industry faces two significant sets of regulations. Environmental regulations have important industry impacts since most shipbuilding and repair takes place outdoors, over, in and around water. Shipbuilding activities can expose marine waters to potential pollutants. Also, since many facilities have various docks, slips, and canals, in addition to very large open working spaces (yards), they have the ability to contain significant volumes of water potentially exposing surrounding areas to a large amount of storm water run-off and

[12]This section discusses the federal regulations that apply to this sector. The purpose of this section is to highlight and briefly describe the applicable regulations. The descriptions below are general information. Depending upon the nature and scope of the activities at a particular facility, these summaries may or may not necessarily describe all applicable regulatory requirements.

discharge. Storm water runoff frequently carries sediments, chemicals and debris from the ground, as it enters the marine or river waters.

The industry is also subject to a wide range of other regulations governing the flagging and movement of ships and other types of surface vessels traveling navigable waterways. Many of these regulations are designed to provide various forms of economic protection to domestic water transportation-based industries. They are also designed to protect national security concerns regarding facilities that construct some of the most important armaments protecting U.S. interests domestically and abroad.

Merchant Marine Act of 1920

More commonly known as the "Jones Act," the Merchant Marine Act requires all domestic water-based commerce between different locations within the U.S. (i.e., U.S. port to U.S. port) be conducted in vessels that are American-owned and built, and crewed by U.S. mariners. The Jones Act also restricts foreign cruise ships from transporting passengers between U.S. ports. The purpose of the Jones Act is to maintain a shipbuilding and ship repair industrial base, a trained merchant mariner manning pool, and marine assets to respond in times of national security emergencies. The U.S. Customs Service has direct responsibility for enforcing the provisions of the Jones Act.

The Jones Act is known for its economic, as well as national security benefits. The Jones Act is responsible for creating jobs in almost every state in the U.S., either directly or indirectly. This policy is not unique, and is similar to the policies and laws of almost 50 foreign nations that also reserve their coastwise shipping and passenger trades for their domestic fleets. The Jones Act keeps shipping and shipbuilding assets under U.S. control, subject to all U.S. laws and standards, and provides essential services in U.S. coastal states and waters and to the economies of Alaska, Hawaii, and Puerto Rico. Nationwide, there are more than 39,000 vessels in the Jones Act fleet generating nearly 125,000 jobs, 80,000 of which are shipboard (Maritime Cabotage Task Force, 2005). The Jones Act fleet represents a $26 billion private sector investment in vessels and infrastructure and routinely moves more than 1 billion tons of cargo and 100 million passengers each year (Maritime Cabotage Task Force, 2005).

Resource Conservation and Recovery Act (RCRA)

Solid waste materials that meet certain pre-defined characteristics are typically classified as a hazardous waste under the RCRA. A material defined as a hazardous waste may then be subject to provisions outlined in Subtitle C of the legislation that governs the generation, transportation, treatment, storage and disposal of these wastes from a wide range of sources, including ports and coastal areas. The shipbuilding and repair industry must address a wide range of provisions included in the RCRA given its use of a variety of hazardous materials (USEPA, 1997).

Some of these hazardous wastes include:

- Machining and Other Metalworking
    - Metalworking fluids contaminated with oils, phenols, creosol, alkalies, phosphorus compounds, and chlorine

- Cleaning and Degreasing
  - Solvents
  - Alkaline and Acid Cleaning Solutions
  - Cleaning filter sludges with toxic metal concentrations

- Metal Plating and Surface Finishing and Preparation
  - Wastewater treatment sludges from electroplating operations
  - Spent cyanide plating bath solutions
  - Plating bath residues from the bottom of cyanide plating baths
  - Spent stripping and cleaning bath solutions from cyanide plating operations

- Surface Preparation, Painting and Coating
  - Paint and paint containers containing paint sludges with solvents or toxic metals concentrations
  - Solvents
  - Paint chips with toxic metal concentrations
  - Blasting media contaminated with paint chips

- Vessel Cleaning
  - Vessel sludges
  - Vessel cleaning wastewater
  - Vessel cleaning wastewater sludges

- Fiberglass Reinforced Construction
  - Solvents
  - Chemical additives and catalysts (USEPA, 1997).

Shipbuilding and repair facilities may also generate used lubricating oils which are regulated under RCRA but may or may not be considered a hazardous waste.

United States Code, Title 10, Section 7311

Title 10, Section 7311 of the U.S. Code applies specifically to the handling of hazardous waste (as defined by RCRA) during the repair and maintenance of U.S. naval vessels. These regulations require the Navy to identify the types and amounts of hazardous wastes that will be generated or removed by a contractor working on a naval vessel. This includes identifying all aspects of the contractor's work including hazardous waste removal, handling, storage, transportation, and disposal. The regulations also require a number of generator identification requirements for the handling of Navy waste. For instance, waste generated solely by the Navy and handled by the contractor, bears a generator identification number issued to the Navy; waste generated and handled solely by the contractor, bears a generator identification number issued to the contractor; and waste generated by both the Navy and the contractor, and handled by the contractor bears a generator identification number issued to the contractor and a generator identification number issued to the Navy.

Clean Air Act

Under Title III of the 1990 Clean Air Act Amendments (CAAA), the U.S. Environmental Protection Agency (EPA) is required to develop national emission standards for 189 hazardous air pollutants (NESHAP). EPA is developing maximum achievable control technology (MACT) standards for all new and existing sources. The National Emission Standards for Shipbuilding and Repair Operations (surface coating) were finalized in 1995 and apply to major source shipbuilding and ship repairing facilities that carry out surface coating operations. Shipyards that emit ten or more tons of any one hazardous air pollutant, or 25 or more tons of two or more hazardous air pollutants combined, are subject to the MACT requirements. The MACT requirements set volatile organic compound (VOC) limits for different types of marine coatings and performance standards to reduce spills, leaks, and fugitive emissions. EPA estimates that there are approximately 35 major source shipyards affected by this regulation. Shipbuilding and repair facilities may also be subject to National Emissions Standards for Asbestos. The NESHAP were revised and clarified in 2006 to define eligible ships in a much more inclusive manner in order to eliminate what was perceived as a significant loophole. The final rule was effective on February 27, 2007 (USEPA, 2006b).

Both NESHAPs require emission limits, work practice standards, record keeping, and reporting. Under Title V of the CAAA 1990, all of the applicable requirements are integrated into one federal renewable operating permit. Facilities defined as "major sources" under the Act must apply for permits within one year of state permit approval by EPA. Since most state programs were not approved until after November 1994, Title V permit applications, for the most part, began to be due in late 1995. Due dates for filing complete applications vary significantly from state to state, based on the status of review and approval of the state's Title V program by EPA.

The definition of a "major source" under Title V includes facilities that release a certain amount of any one of the CAAA-regulated pollutants (SOx, NOx, CO, VOC, PM10, hazardous air pollutants, extremely hazardous substances, ozone depleting substances, and pollutants covered by NSPSs) depending on the region's air quality category. Title V permits may set limits on the amounts of pollutant emissions, require emissions monitoring, and record keeping and reporting. Facilities are required to pay an annual fee based on emission levels.

Clean Water Act

Shipbuilding and repair facility wastewater released to surface waters is regulated under the CWA. National Pollutant Discharge Elimination System (NPDES) permits must be obtained to discharge wastewater into navigable waters (USEPA, 2008d). Facilities that discharge to a publically owned treatment works (POTW) may be required to meet National Pretreatment Standards (NPS) for some contaminants (USEPA, 1997). General pretreatment standards applying to most industries discharging to a POTW are described in 40 CFR Part 403. In addition, effluent limitation guidelines, new source performance standards, pretreatment standards for new sources, and pretreatment standards for existing sources may apply to some shipbuilding and repair facilities that carry out electroplating or metal finishing operations (USEPA, 1997).

Storm water rules require certain facilities with storm water discharge from any one of 11 categories of industrial activity defined in 40 CFR 122.26 be subject to the storm water permit application requirements. Many shipbuilding and repair facilities fall within these categories. Required treatment of storm water flows are expected to remove a large fraction of both conventional pollutants, such as suspended solids and biochemical oxygen demand, as well as toxic pollutants, such as certain metals and organic compounds.

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and the Superfund Amendments and Reauthorization Act of 1986 (SARA) provide the basic legal framework for the federal "Superfund" program to clean up abandoned hazardous waste sites. Metals and metal compounds often found in shipyards' air emissions, water discharges, or waste shipments for off-site disposal include chromium, manganese, aluminum, nickel, copper, zinc, and lead. Metals are frequently found at CERCLA's problem sites (USEPA, 1997). When Congress ordered EPA and the Public Health Service's Agency for Toxic Substances and Disease Registry to list the hazardous substances most commonly found at problem sites and that pose the greatest threat to human health, lead, nickel, and aluminum all made the list (USEPA, 1997).

3.3. Industry Trends and Outlook

3.3.1. Trends

The 1980s were dismal times for the U.S. shipbuilding industry. A combination of factors including the perception that maritime policies were not being comprehensively enforced, failure to continually fund subsidies established by the Merchant Marine Act of 1936, and the collapse of the U.S. offshore oil industry after 1986, not only hurt the shipbuilding industry, but all supporting industries such as small shipyards, repair yards, and local crafts and trades professions that worked at these facilities on a contract basis.

By the mid-1970s, the shipbuilding industry controlled a significant portion of the international commercial market while maintaining its ability to supply all military orders. A decade later, new ship construction, the number of shipbuilding and repair yards, and overall industry employment decreased sharply. The decline was particularly severe in the construction of commercial vessels at first tier shipyards. New construction was reduced from a level of about 77 ships (1,000 gross tons or more) per year in the mid-1970s, to approximately eight ships total through the late 1980s and early 1990s. In the 1980s, the industry's loss of the commercial market share was somewhat offset by a substantial increase in military ship orders. A decade later, the combination of the end of the Cold War, and a contraction in commercial construction activity found the industry with a much smaller military market share and a negligible share of the commercial shipbuilding market. The second tier shipyards and the ship repairing segment of the industry have also suffered in recent decades; however, the decline has not been as drastic as it has been for the major shipbuilders (USEPA, 1997).

The U.S. shipbuilding and repairing industry's loss of the commercial shipbuilding market has been attributed to a number of factors. First, a world-wide shipbuilding boom in the 1970s created a large quantity of surplus tonnage that ultimately created a capacity bubble that had to be worked off over several subsequent years. Further, the industry's ability to compete internationally was hampered by the growing level of subsidies offered by foreign nations to their own domestic shipbuilding and repair industries. These subsidies created significant competitive advantages for foreign shipyards resulting in U.S. commercial shipbuilding work going overseas. Compounding this problem was a significant policy shift in 1980 that reduced what was referred to as "Construction Differential Subsidies" (CDS) to U.S. shipbuilding companies. These CDS were allowances offered to ship builders compensating them for the difference between foreign and domestic shipbuilding costs. Over 40 percent of the shipbuilding industry was eligible for these subsidies until its cancellation in 1981 (USEPA, 1997).

The U.S. government and the shipbuilding industry have made great strides in their efforts towards industry revitalization and market transformation. In 1994, the Maritime Administration established the National Maritime Resource and Education Center to assist in increasing U.S. shipbuilding competitiveness (USDOT, MARAD, 2008). Although there are large investments in an effort to increase the competitiveness of American shipbuilders, one constant problem is the loss of many thousands of workers within the industry. For example, in 1996 there were about 98,000 workers in private shipyards (USDOT, MARAD, 1996). Whereas, as of October 2006, the number fell to 47,000, which is a 49 percent decrease in 10 years (USDOT, MARAD, 2006a).

Figure 18 shows the general historic trends in new ship orders from the mid-1970s to 2004. The rapid deterioration in domestic shipbuilding activity is readily recognizable from this chart. While recent activity has increased somewhat, new shipbuilding activity today is a very small fraction of the level of effort observed in the late 1970s. One major stimulus for the recent increase in shipbuilding activity has been associated with deepwater oil and gas activity (USDOT, MARAD, 1999). Figure 18 also shows that the recent increase in shipbuilding activity corresponds very closely with the recent increase in deepwater activity following the passage of the Deepwater Royalty Relief Act of 1995.

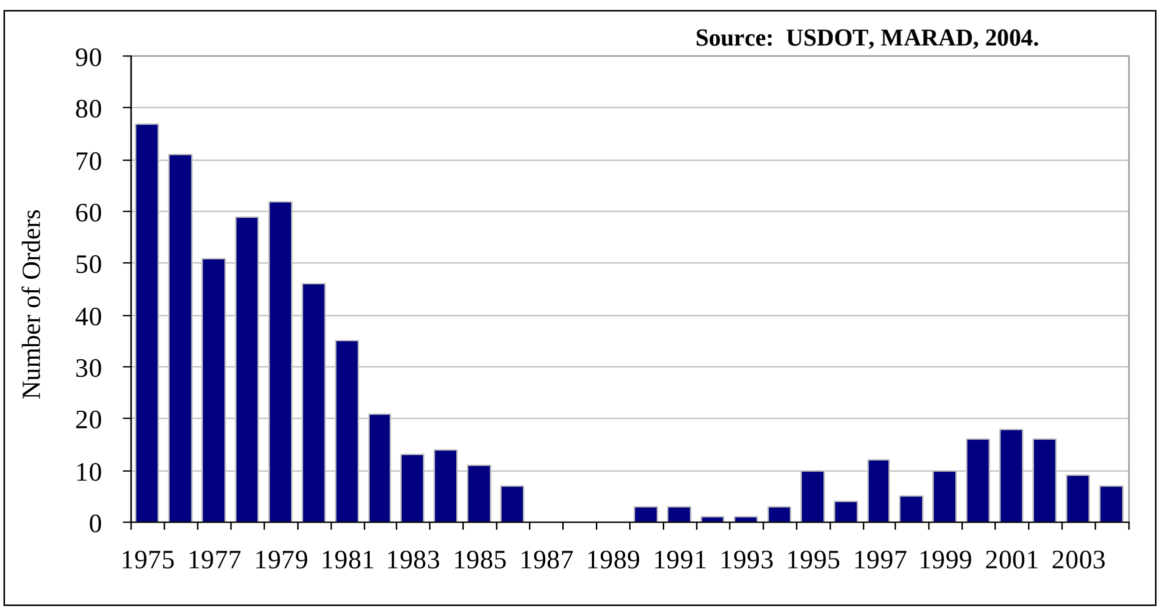


Figure 18. Commercial shipbuilding order book history.

The deterioration of commercial shipbuilding activity throughout the 1980s had significant implications for the industry's ability to attract skilled labor. A 2001 survey by the Bureau of Industry and Security addressed a host of operating and labor conditions at U.S. shipyards. The survey indicated that skilled labor shortages have contributed to reduced shipyard profits, negatively altered project construction costs, and resulted in significant schedule delays for projects at most shipyards.

Historically, turnover rates at shipyards have been high relative to other industries. Production work in the shipyard industry tends to be difficult, working conditions are outside and workers are therefore exposed to uncomfortable environmental conditions that usually arise in coastal zones (i.e., high heat, humidity). These negative work environment conditions continue to exist and, coupled with a low skilled worker pool, have resulted in continued high turnover rates for the industry. To combat the lack of skilled labor, many shipyards have subcontracted work normally done within their own yards (USDOC, BIS, 2001).

Technological innovation, through active research and development (R&D) activities, can be an important substitute for shortages of skilled resources, particularly labor. R&D can also assist in enhancing domestic shipyards competitiveness. However, a 2001 Bureau of Industry and Security survey reported that U.S. shipyard R&D expenditures averaged about 1.23 percent of total revenues from 1996 to 2000, with the "Big Six" accounting for 80 percent of the effort. Less than one percent of industry employees are engaged in these efforts at least part-time. The U.S. military has been a major driver of this R&D activity, funding 42 percent of recent shipyard efforts. The survey concluded that extensive modernization would be needed to improve productivity and thus lower the cost of American-made ships (USDOC, BIS, 2001).

During fiscal year 2004, the U.S. ship construction and ship repair industry invested more than $401 million in the upgrade and expansion of facilities (Figure 19). A significant portion of this investment was to improve efficiency and competitiveness in commercial shipbuilding. Improvements are continually being made to update and convert shipyard facilities to be more commercially viable and competitive. Typical improvements include investments on new pipe and fabrication shops, drydock extensions, military work enhancement programs, automated steel process buildings and expanded design programs. Many of these improvements have been necessary due to the increased utilization of U.S. shipyards, particularly those along the Gulf Coast. According to data received by MARAD, the industry planned to spend about $364 million in the upgrade and expansion of facilities in 2005. In total, the industry's cumulative capital investments since 1970 are approximately $9.3 billion. Actual expenditures between 1985 and 2004, with the exception of 1990 and 2001, have consistently exceeded those planned (USDOT, MARAD, 2004).

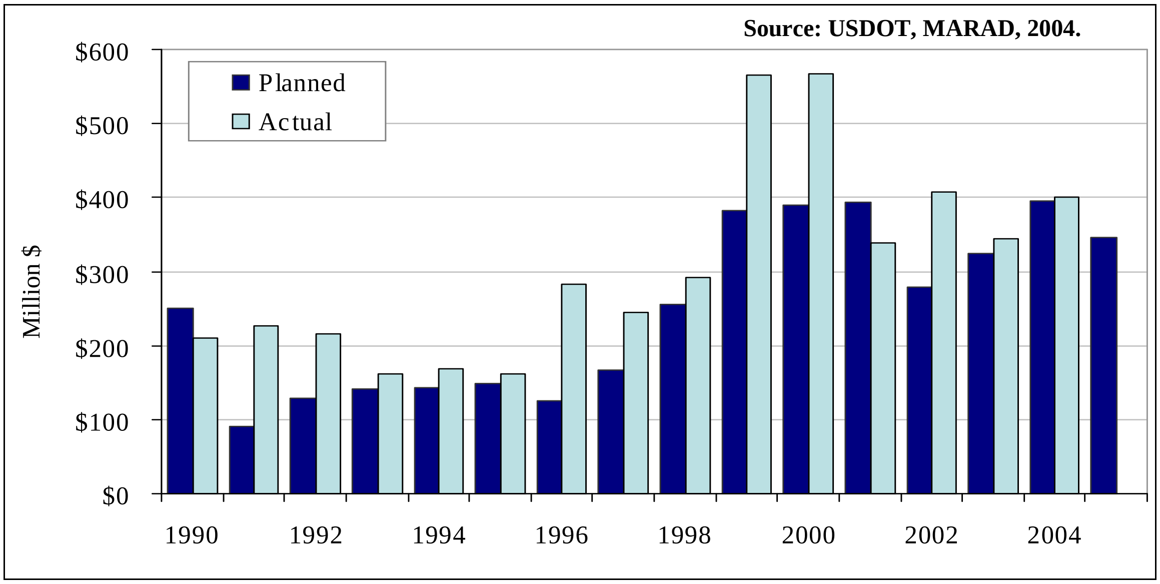


Figure 19. U.S. shipbuilding and repair industry capital investments.

Safety at the yards has become an important issue, and the industry's commitment to operational safety is recognized by the Shipbuilders Council of America (SCA) annual SCA Excellence in Safety award. This award is given to shipyards having some of the lowest total recordable incidence rates for injuries and fatalities. Bollinger Shipyards and Signal Shipyards, both of which have operations along the GOM, were two of the winners in 2006 (SCA, 2007).

Although the shipbuilding industry has been shrinking, the Gulf Coast has managed to increase its overall market share relative to other coastal regions in the U.S. Figure 20 shows that the GOM has grown, as a share of total number of shipyards, faster than any other region in the U.S.

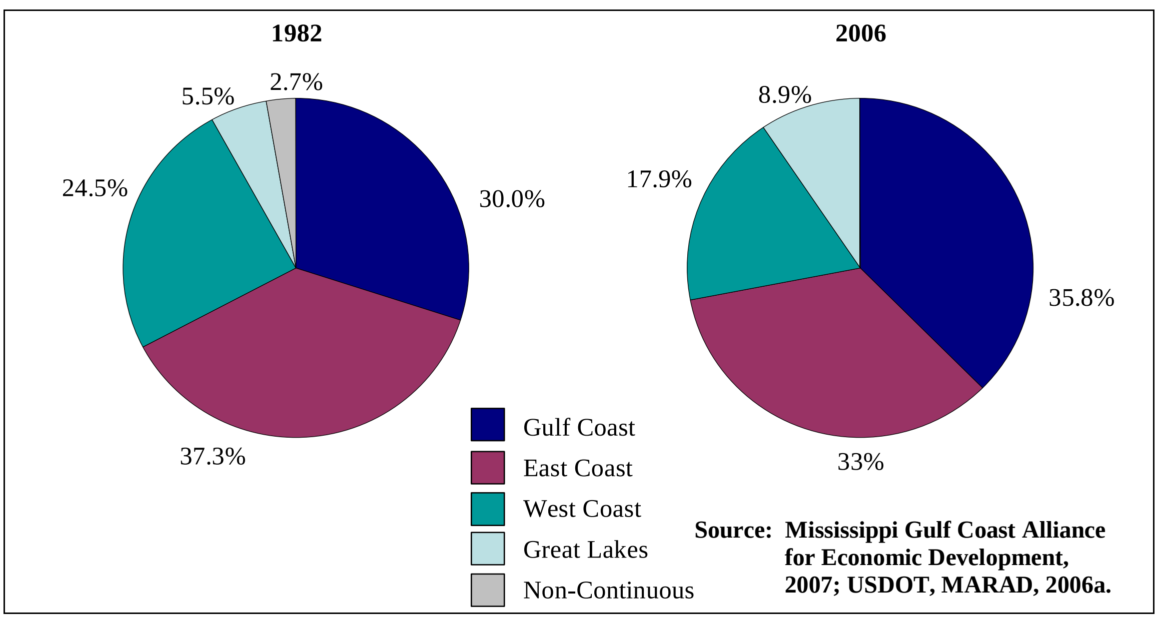


Figure 20. Comparing major shipbuilders/repairers between 1982 and 2006.

A good share of the GOM shipbuilding market can be attributed to OSV construction. As noted earlier, the OSV market is of particular importance to the GOM shipbuilding and repair industry. Increased deepwater activity will require newer, larger, and more sophisticated boats. These next-generation OSVs will be technologically and physically more robust since most will include stronger winching power, more horsepower, higher speed capabilities, and will be equipped with GPS-controlled dynamic thrusters that allow greater structure-side control.

However, the primary advantage of the next generation OSVs will be their capabilities for bulk transport. Newer OSVs will likely have the capability to transport the equivalent of two loads of an older "legacy" boat, which saves time and expensive fuel. The size disparities are noticeably larger. Whereas legacy crew boats are 110 to 150 feet, new generation OSVs will be in the 145 to 190 foot range. Legacy AHTS boats are typically in the 190 to 235 foot range while new generation AHTS boats are anticipated to be sized between 220 and 295 feet (Barrett, 2005).

Other major changes within the OSV industry include greater international market sales from some of the largest OSV companies in the GOM. For example, about 10 years ago, less than half of Tidewater's revenue came from international operations. Today, that percentage has jumped to 85 and 91 percent. Tidewater is also investing heavily in fleet updating from its current status as the second oldest among the U.S. companies in the industry (Barrett, 2005). About 75 percent of Tidewater's fleet has an average age of 25 years. Recently the company accepted 16 new vessels and plans to receive another 50 by 2011 (MarineLink, 2007).

Trico Marine is another example of a major company pursuing greater international market opportunities. In 2007, Trico announced it would be moving four Gulf-class vessels to international markets. This move is in keeping with implementing their global strategy to move more vessels to higher growth markets. The shift decreases Trico's GOM fleet to 20 ships (Trico, 2007).

3.3.2. Hurricane Impacts

The 2005 hurricanes had significant impacts on the GOM shipbuilding industry. Both major hurricanes (Katrina, Rita) caused considerable damage and displaced numerous workers. Hurricane Katrina toppled cranes, ripped the tops off construction sheds and threw workboats into nearby woods (DuPont et al., 2005). Some shipyards fared better than others. Edison Chouest's two shipyards in Larouse and Houma, Louisiana escaped with little damage. However ECO's C-Port 2 facility in Port Fourchon, Louisiana, sustained substantial damage (DuPont et al., 2005). The damage to this facility was not inconsequential since it is an important, if not one of the more important facilities serving deepwater structures in the GOM.

Further east, the Bender Shipbuilding & Repair in Mobile, Alabama, suffered light damage and was running at full capacity by September 7 (DuPont et al., 2005), some eight days after Katrina passed. Austal, USA (also in Mobile, Alabama), and Conrad Industries with shipyards in Morgan City, Louisiana, and Orange, Texas, sustained only minor damage (Marine Log, 2005). The Conrad President and CEO stated, "Hurricane Katrina did not have a direct impact on any of our four shipyards. Unfortunately, Hurricane Rita did not spare our Orange employees from loss and damage…. Power has been restored to our Orange yard, and we are gradually returning to normal operations as employees are able to return to the area after three weeks of limited activity (Marine Log, 2005)."

The storm surge up Bayou Cassotte near Pascagoula, Mississippi, submerged the VT Halter Marine and Signal International shipyards (Surratt, 2005). In addition VT Halter suffered both water and wind damage at all three of its Mississippi yards – Pascagoula, Halter Moss Point and Moss Point Marine (DuPont et al., 2005).

Of Bollinger's 12 Louisiana yards, seven – Lockport Repair and New Construction, Calcasieu, Larose, Fourchon, Amelia Repair, Marine Fabricators, and Morgan City – were fully operational shortly after Katrina passed (DuPont et al., 2005). Bollinger's four New Orleans-area yards, however, did not fare as well. As late as September 16, communications including all telephones, cell phones and emails, continued to be one of the shipyard's biggest problems (DuPont et al., 2005). Of Bollinger's 40 drydocks, 33 were in service by mid-September. However, one from the Algiers yard broke free during the storm, with a vessel aboard, and was pushed up the Mississippi River before grounding on a levee in Gretna (DuPont et al., 2005).

In late 2007, Bollinger Shipyards announced it would close its yard on the Industrial Canal in New Orleans by the end of 2008. Bollinger reported to the media at the time that "the company plans to shift its ship repair and conversion yard to Bollinger locations in Morgan City and Sulphur (DeGregorio, 2007)." The Army Corps of Engineers recommended that the MR-GO be shut due to its role in the flooding of St. Bernard during Hurricane Katrina. The Port of New Orleans did not have space on the Mississippi River to accommodate Bollinger, so the company decided to integrate its Industrial Canal operations with its other yards. Bollinger had four dry docks on the Industrial Canal, but two were destroyed in Hurricane Katrina (DeGregorio, 2007).

Hurricane damage to Northrop Grumman's Mississippi and Louisiana shipyards was reported to have exceeded $1 billion (MSNBC.com, 2005). The Pascagoula shipyard was inundated with at least 8 to 12 feet of water, and buildings, electrical grids, construction equipment and infrastructure were damaged or destroyed (MSNBC.com, 2005). However, damages to the Louisiana facilities were minimal in comparison. Four yards had a total of $1 billion in damages from Hurricane Katrina alone. Some of the companies, such as Gulf Ship, moved operations within the Gulf region to a safer distance to prevent future damage (Mississippi Gulf Coast Alliance for Economic Development, 2007).

In addition to the physical damage, severe labor shortages caused even more problems for GOM area shipyards in the immediate aftermath of the 2005 hurricane season. A large number of the shipyards' skilled labor force was displaced by Hurricane Katrina. In November 2005, Bollinger Shipyards was forced to back out of a $700 million contract it had worked for years to win due to concerns about performance abilities in the aftermath of the 2005 hurricanes. Bollinger also passed on another project valued at approximately $150 million because high wages and a lack of employees threatened the company's ability to make a profit (White, 2006). In addition to the shortage of workers, there was a shortage of housing due to the widespread destruction of residential structures in the greater New Orleans area from the hurricanes. The lack of adequate housing served as a major short-run impediment to restoration activities, particularly for workers from outside the area who didn't have FEMA identification numbers (White, 2006). One company reported using its employees' FEMA ID numbers in order to secure trailers for employees (White, 2006).

Even two months after the storm, a number of companies remained closed simply because their employees did not have housing (Carr, 2005). In late 2005, Northrop was still hiring at all of its facilities along the Gulf Coast. The Company did not expect 1,500 to 2,000 of its employees to return (Inside the Navy, 2005). The labor shortage also forced the Navy to make an adjustment to its contract with Northrop Grumman and to defer an order for an amphibious assault ship scheduled to be built at Northrop's Avondale yard from fiscal year 2007 to fiscal year 2008 (White, 2006).

In addition to the yards themselves, Hurricanes Katrina and Rita dealt a heavy blow to the GOM rig fleet, sending more than 20 rigs to shipyards for repairs, not to mention the rigs that were completely lost and would have to be replaced. There was an average of 10 rigs located at GOM shipyards between August 2000 and August 2005. That number more than doubled between August and September when rig counts in yards moved from 15 rigs to 38. Rig counts moved even higher in October to 43 GOM rigs, more than 27 percent of the GOM fleet, in the shipyard that month. From September 2005 to July 2006, the percentage of the GOM fleet in the shipyard stayed near or above 20 percent. In August 2006 it finally fell to 17 percent – which is still exceptionally high for a region that has averaged about 5 percent of the fleet undergoing maintenance during any given month over the previous 5 years (Rigzone.com, 2006a).

Supply vessels working repairs were also kept very busy in the immediate aftermath of the 2005 hurricanes. In fact, some operators say that the post 2005 demand for OSVs has been primarily for repair and construction needs. Most vessel operators believe it will take until 2008 to completely repair all the damage from the 2005 hurricanes alone (Greenberg, 2007).

Day rates for offshore vessels and drilling rigs proved to be good indicators of the tightness of the vessel and drill ship market. Trico Marine reported that their day rates increased considerably. In addition, the fourth quarter of 2005 saw the highest average day service vessel rates ever in the GOM and near-full capacity utilization levels for active vessels. None of their vessels or operating bases sustained any significant damages (SEC, 2005b).

Due to the close ties with the Navy, many shipyards received aid from the Naval Sea Systems Command military and civilian personnel. Northrop Grumman, which suffered extensive damage to their facilities, accepted the Navy's help. A temporary operations center was established to further the assistance program (GlobalSecurity.org, 2005).

3.3.3. Outlook

The current outlook for the shipbuilding and ship repair industry is neutral. The sector still faces many economic challenges and is highly dependent on military contracts. The industry's international competitiveness challenges still exist and appear to not be going away any time in the near future. It is likely that continued investment in worker training, efficiency efforts, and R&D are needed to make the industry more competitive and increase overall projects and revenues. These trends are not isolated to commercial vessels and include the competition for

OSVs and other surface vessels and drillships needed to support deepwater activities along the GOM.

The lack of international competitiveness was raised in a May 2001 U.S. Commerce Department assessment conducted by the Bureau of Industry and Security and the Bureau of Export Administration. The Report noted that without a strong industry, the necessary future military needs as well as commercial needs are in danger of not being fulfilled (USDOC, BIS, 2001). In 2007, China's government declared that they would like to be the number one shipbuilding power in a decade and began a process of vigorously building new yards to grow their market share (The Standard, 2005). Today, Chinese shipbuilding facilities are able to provide about 10 percent lower prices than other major shipbuilders, partly due to their lower labor costs as well as the significant subsidies and support provided by the Chinese government (The Standard, 2005). Foreign government subsidization of shipbuilding activities continues to be a sore-spot for U.S. trade policy since domestically, the government has completely eliminated direct subsidization of the shipbuilding industry (USDOC, BIS, 2001). Like other heavy construction and manufacturing sectors, the shipbuilding industry is very concerned about workforce development issues. According to Douglas-Westwood analysts, most sectors of the global offshore industry will continue to be labor constrained up to 2011 a trend that should continue to place increased pressure on sector wages at least through that period if not longer (Fletcher, 2007).

The 2001 U.S. Commerce Department report also cited workforce development as an important issue for the shipbuilding industry. The issue has become so important domestically that some yards are finding themselves aggressively competing for workers (USDOC, BIS, 2001). Without enough skilled labor, U.S. companies were finding it difficult to conduct quick, quality, and profitable work. The companies are facing financial pressures such as lower profits, impacted construction costs and delayed project completion. To compensate for the shortages, a few yards had begun using contract labor and others were subcontracting their work that was normally done at the yard. Among the most notable declining skilled laborers are welders, pipe fitters and ship fitters, machinists, electricians, and marine engineers (Fletcher, 2007).

Availability of capital has been an additional concern for the shipbuilding industry, both nationally and along the GOM. In order to address these challenges, Title XI of the Merchant Marine Act (enacted in 1936 and later amended in 1993) started a "National Shipbuilding Initiative" program to provide financial support, primarily through capital support and debt-underwriting. Under this program, the federal government guarantees full payment to the lender of the unpaid principal and interest in the event of default by the vessel owners or general shipyard facility. As of September 2006, the Title XI had nine pending applications totaling over $600 million in loan guarantees. A small amount, $7.35 million, is still available for new guarantee commitments. The program consisted of $2.94 billion in loan guarantees outstanding, and all commitments had been funded. Title XI has funded 77 projects, which have included passenger vessels, supply vessels, tugs and shipyard modernization projects (USDOT, MARAD, 2006b). In 2007, testimony was received on the program. The president of the American Shipbuilding Association testified on the significance of continuing to fund and improve the program. She stated that Title XI helps American shipyards to retain their skilled employees, to expand the fleet of U.S. built commercial ships available to the Department of Defense in time of war and to provide the highest construction standards in the world (MarineLink.com, 2007).

Another resource that has been lacking in recent years in the shipbuilding industry has been the availability of R&D funding. Between 1996 and 2000 approximately 0.64 percent of total shipbuilding company revenues were invested in R&D compared to the overall U.S. manufacturing sector average of 3 percent of total manufacturing revenues. This anemic level of R&D funding from the shipbuilding industry was equally low when compared to international companies, many of whom receive direct financial support from their home governments. Total and relatively low R&D investment has clear implications for international competitiveness and in response, the Navy and 11 major shipbuilders created a new program referred to as "the National Shipbuilding Research Project Advanced Shipbuilding Enterprise (NSRPASE)." Partners in this project jointly fund R&D on projects that directly address improving commercial shipbuilding competitiveness (Mississippi Gulf Coast Alliance for Economic Development, 2007).

These industry teaming approaches to solving problems, such as R&D, are not limited to large federal projects alone. The shipbuilding industry along the GOM has recently combined to form a marine composite consortium with local colleges and universities. This consortium will focus on problems with the use of composites in the shipbuilding industry, as well as work to generate future skilled laborers for the industry (Mississippi Gulf Coast Alliance for Economic Development, 2007).

Market Opportunities

The U.S. shipbuilding industry will continue to compete in several domestic and international markets. These markets include:

Offshore Market

The offshore market is undergoing a rapid expansion since the marked decline of the 1980s. Advancements in deepwater drilling have encouraged exploration, leading to greater production and activity in the coastal areas. The need for supply and other types of industry support vessels has increased. With changing technology has come the need for more sophisticated and higher capacity vessels.

Barges, Towboats, and OSV Market

The bulk of the nation's barges and towboats operate in the Mississippi River and the Gulf Intracoastal Waterway. As a greater amount of goods and commodities are transported through this network, Louisiana shipyards are in a good position to offer services to that industry.

Opportunities for expanding shipbuilding and OSV markets are directly related to offshore oil and gas activities. Industry reports watch offshore developments closely including recent expectations that oil production will increase over the next few years as exploration activities move into deeper waters of the GOM (Fletcher, 2007). The GOM is one of three regions, including the North Sea and South China Sea, that together are expected to account for half of total offshore investment spending through 2011 (Fletcher, 2007).

The move toward deepwater should create significant opportunities for larger and more sophisticated OSV construction and development. There has been continuous development of technology that enables tasks to be performed by OSVs more cost effectively than typical rig-based operations. New OSVs are larger, have longer range, and are being developed explicitly to handle these new deepwater activities. A recent study released by the Offshore Marine Service Association (OMSA) found that the U.S. flag offshore service vessel operators plan to build more than 150 new vessels in the next five years, with an average price tag of $10 to $20 million per vessel and that the total value of these orders may reach $3 billion (Blenkey, 2007).

Shipyards in New Orleans are currently experiencing strong demand. Many recently executed contracts are commercial, while some are for the Department of Defense. Ben Bordelon, executive vice-president at Bollinger Shipyards, stated that every market (in shipbuilding) is strong right now. Bollinger currently has 30 ships under construction and has recently added three new construction yards to handle the increase in demand. Recent tropical activity, including continued activity following the 2005 hurricane season, facilitates strong repair service demand (Guillet, 2007a).

C&G Boat Works, a shipyard on Mobile's Blakeley Island, recently announced in 2008 that it plans to add as many as 150 new jobs in the next three years. C&G is one of a series of fast growing Mobile-area shipyards. Today, C&G is building 11 aluminum-hulled boats, three tugboats and three boats for the U.S. Navy. The company also has a contract to build seven boats for Marathon Oil and is negotiating to build seven more tugboats (Amy, 2008). In addition, Austal USA, located to the south of C&G, is planning a $254 million expansion that could almost double its current 1,100 employee count.

Edison Chouest announced in March 2008 that it would add up to 1,000 employees at its Port of Terrebonne facilities in order to expand shipyard operations supporting deepwater oil and gas exploration in the GOM (The Advocate, 2008). A $14 million state investment will support infrastructure improvements at the port to allow Edison Chouest's LaShip subsidiary to expand into a new market to build vessels with hulls greater than 350 feet (The Advocate, 2008).

3.4. Chapter Resources

Atlantic Communication's Gulf Coast Oil Directory
Includes a wide range of data from company name, address, web and email addresses to contact names with titles, direct phone numbers, and email addresses all organized alphabetically by industry categories. Also included is "Company Detail" information such as company size, revenue, areas operated in last 12 months, operations onshore or offshore, and stock information for publicly traded companies.
http://www.oilonline.com/Directory/DirectoriesDatabases.aspx

U.S. Census Bureau – Economic Census, Manufacturing
The Economic Census provides a detailed account of the U.S. economy once every five years, from the national to the local level.
http://www.census.gov/econ/census02/data/us/US000_31.HTM

U.S. Department of Transportation, Maritime Administration

Annual report documenting fiscal year activities in support of the U.S. Department of Transportation's goals of Reduced Congestion; Security; Preparedness and Response; Global Connectivity; and Environmental Stewardship.

http://www.marad.dot.gov/library_landing_page/maritime_publications/Library_Publications.htm

Annual survey of the U.S. shipbuilding and repair facilities.

http://www.marad.dot.gov/ships_shipping_landing_page/nmrec_home/nmrec_shipyard_reports/Shipyard_Reports.htm

U.S. Securities and Exchange Commission

Quarterly and annual reports of operations for publicly traded companies are filed with the Securities and Exchange Commission.

http://www.sec.gov/edgar/searchedgar/companysearch.html

Workboat.com

Provides daily news reports and a weekly newsletter for the commercial marine industry. It also provides historic industry statistics on day rates and fleet utilization.

http://www.workboat.com/

4. PORT FACILITIES

4.1. Description of Industry and Services Provided

Ports play a vital role in the support of the offshore oil and gas E&P sector as well as the maritime industry as a whole. Ports are the bases from which the vehicles that support offshore platforms (notably ships and helicopters) are based and maintained. Ports are also the delivery, transfer, and launching points for the necessary structures, equipment, supplies, crew and other important products to offshore installations. Offshore E&P operations depend heavily upon these goods and services, and thus ports are critical to the entire industry.

There are generally two types of ports along the GOM that support offshore activities. The first includes a large number of small facilities that are specifically, or primarily, developed to support offshore activities, many of which are privately-owned. The second includes a smaller number of much larger facilities that support a wide range of maritime activities including offshore oil and gas E&P. Within the spectrum of these types of ports are also those that specialize in a range of distinct goods and services required by the GOM offshore E&P, including shipbuilding, repair, structure fabrication, and general support and supply services, amongst other principal specializations.

The offshore support industry is a large, multi-billion dollar industry with thousands of rigs and platforms in the GOM, each with a need for supporting goods and services. Hundreds of ocean-going vessels and helicopters dedicated to these offshore activities are in operation in the GOM. Ports that focus exclusively on the offshore E&P support sector are directly responsible for the oil and gas production that is ongoing in the GOM, making these ports critical energy infrastructure sites.

Large traditional ports, while supporting various degrees of offshore activity, do not focus exclusively on offshore oil and gas E&P along the GOM (for example, the Port of Houston and Port of New Orleans). These traditional ports focus most of their attention on supporting large-scale conventional port "bulk" operations that include handling a variety of cargo, including: bulk or loose cargo; break bulk cargo in packages such as bundles, crates, barrels and pallets; liquid bulk cargo like petroleum, dry bulk such as grain; and general cargo in steel boxes called containers.

Leading commodities shipped for domestic and foreign trade through U.S. ports in 2007 include (AAPA, 2008b and c):

- Crude petroleum and petroleum products (such as gasoline, aviation fuel, natural gas).
- Chemicals and related products, including inorganic fertilizers.
- Coal.
- Food and farm products - wheat and wheat flour, corn, soybeans, rice, cotton, coffee.
- Forest products - lumber, wood chips.

- Iron and steel.
- Soil, sand, gravel, rock, stone.

Other products include:

- Automobiles, automobile parts and machinery.
- Clothing, shoes, electronics, toys.

Figure 21 provides a comparison of the principal commodity groups transported on U.S. waters versus the Gulf Intracoastal Waterway for 2005. About 44 percent of total U.S. waterborne commerce (both foreign and domestic) is attributed to petroleum and petroleum products (USACE, IWR, 2005). For the GOM Intracoastal Waterway, this figure is even higher, at a little more than half of total commodity short tons.

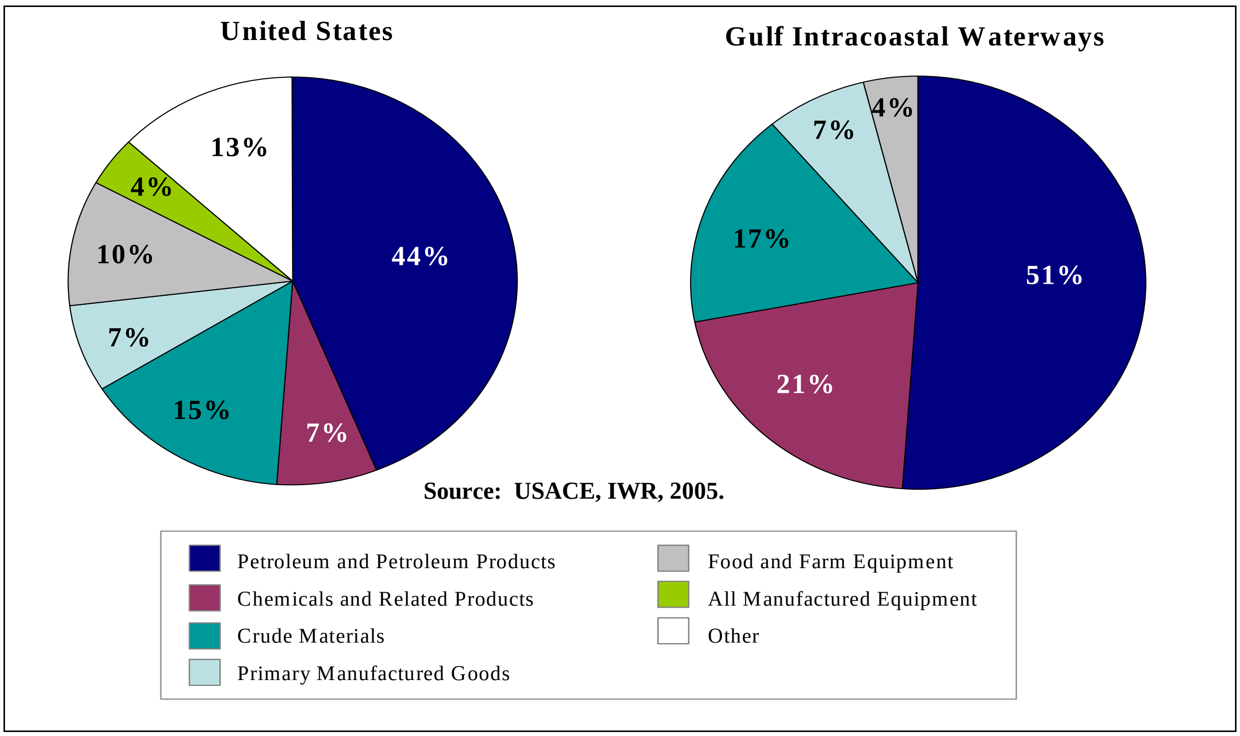


Figure 21. Principle commodity groups carried by water, 2005 (percentage of short tons).

In the GOM, transport of produced oil and gas from offshore installations to onshore facilities occurs almost entirely by pipeline. Nevertheless, secondary transportation of these commodities, as well as the refined and processed goods that are derived from petroleum products occurs by traditional shipping methods. The petrochemical industry in particular relies on conventional port services, especially barge transportation, to transport their goods. Thus, there is considerable overlap and shared linkages between conventional and OCS offshore support port operations, services, and commodities.

4.2. Industry Characteristics

4.2.1. Typical Facilities

GOM ports vary considerably by size, specialty, and defining characteristics. In general, however, there are two major types of port facilities: 1) deep-draft seaports; and 2) inland river and intra-coastal waterways port facilities. Deep-draft seaports are ports that mostly accommodate ocean going vessels and are most likely to serve and supply offshore drilling platforms. Deep-draft seaports are also more likely to be publicly owned and operated.

Inland ports, however, are located on rivers or intra-coastal waterways, and are mostly privately owned – 87 percent of inland facilities are privately owned. More than 1,800 river terminals are located in 21 states within the U.S. These shallow water ports of less than 14 feet are less concentrated geographically than deepwater facilities and provide almost limitless access points to the waterways (USDOT, MARAD, 1999). Generally, there are a larger number of inland as opposed to traditional port facilities and most are less constrained providing greater water access flexibility (USDOT, MARAD, 1999). These inland terminals are abundant along the GOM, particularly in South Louisiana and Southeastern Texas, and have become increasingly important to the offshore oil and gas industry.

Despite their differences, all ports typically have similar logistical systems (major shipping ports included) that can be divided into three principal components (Jayawardana and Hochstein, 2004). Figure 22 shows a schematic diagram of a typical OCS port's logistic systems.

1. The inland transport component: almost all ports must transport supplies, equipment and personnel from land-based locations to the port for transfer. As a result, all ports will typically have either highway/road access, rail access, air access, and/or inland barge access to their port facility; many ports may have more than one inland transportation system.

2. The physical port component: a port's physical and fixed infrastructure varies considerably depending on its size and specialty. The physical port system includes docks, berths, buildings, storage facilities, transfer machines such as cranes and lifts, fabrication capabilities, etc. It also includes channels and their depths, turning basins, and additional amenities and utilities such as electricity, water treatment capabilities, and roads.

3. The offshore component: the actions and operations of the vessels based from a particular port comprise the offshore component. Depending on the port, offshore operations may vary considerably; therefore ports with similar port structural capabilities may have dissimilar offshore components.

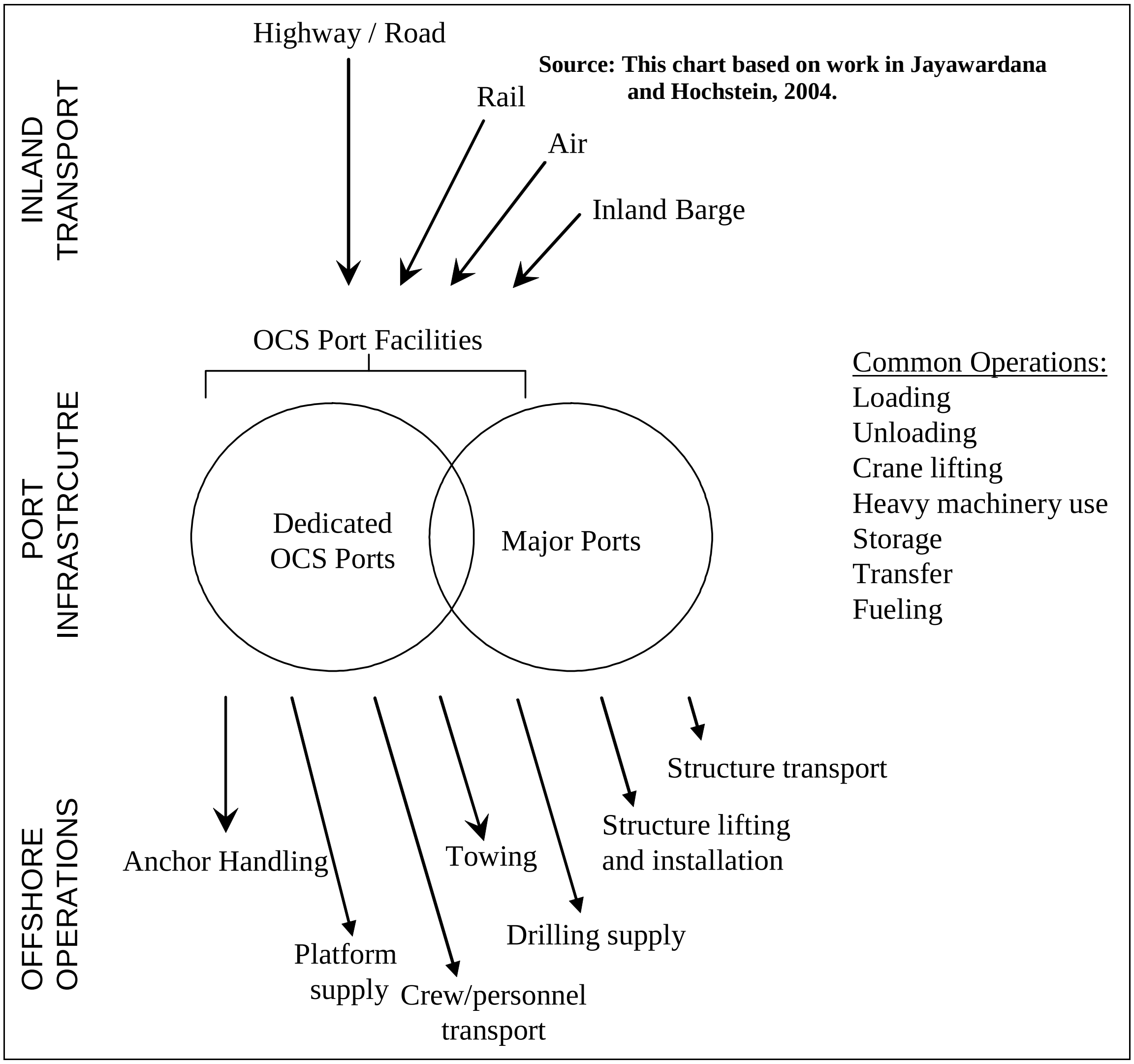


Figure 22. OCS port facilities: Three part logistics system.

A port's inland and physical infrastructure components are responsible to a large extent for the type of offshore operations that are based out of a particular port. Of course, other factors are important as well, such as geography, risk and security, and proximity to supply considerations. The best supply bases typically have more than one of the following important attributes:

1. Strong and reliable transportation systems;
2. Adequate depth and width of navigation channels;
3. Adequate port infrastructure facilities;
4. Existing petroleum industry support infrastructure;
5. Location central to OCS deepwater activities;
6. Adequate worker population within commuting distance; and/or
7. Insightful strong leadership.

Deep and wide navigation channels are also particularly important for the offshore support industry ports, especially as a new generation of larger boats is built to service deepwater installations.

4.2.2. Geographic Distribution

While a large number of offshore support port services are serviced from more conventional, traditional GOM ports, there are a few ports that focus exclusively on offshore activities. In addition, there are numerous small ports along the Gulf of Mexico coast and throughout the Intracoastal Waterway system that may harbor several ocean going support vessels yet have comparatively small infrastructure footprints.

Figure 23 highlights the location of several major ports along the GOM most of which are principally devoted to conventional bulk transport shipping. Figure 24 shows the top 50 GOM ports that have some level of OCS-related offshore activities. There are only four ports: Corpus Christi; Freeport; Lake Charles; and Port Arthur, that are considered both OCS offshore support ports and conventional, major shipping ports.

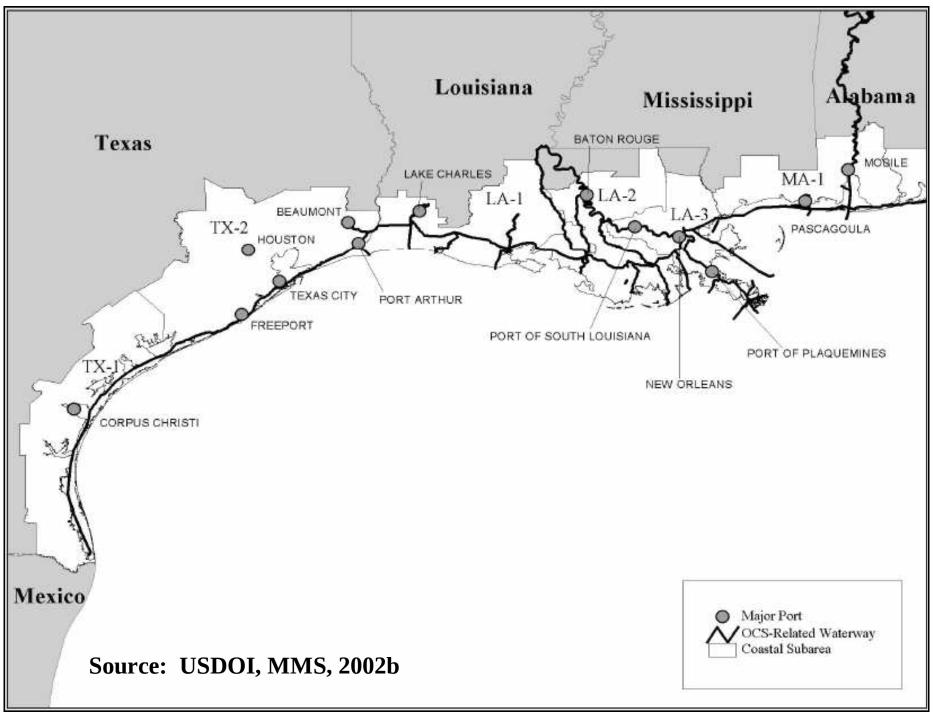


Figure 23. Major shipping ports in the Gulf of Mexico.

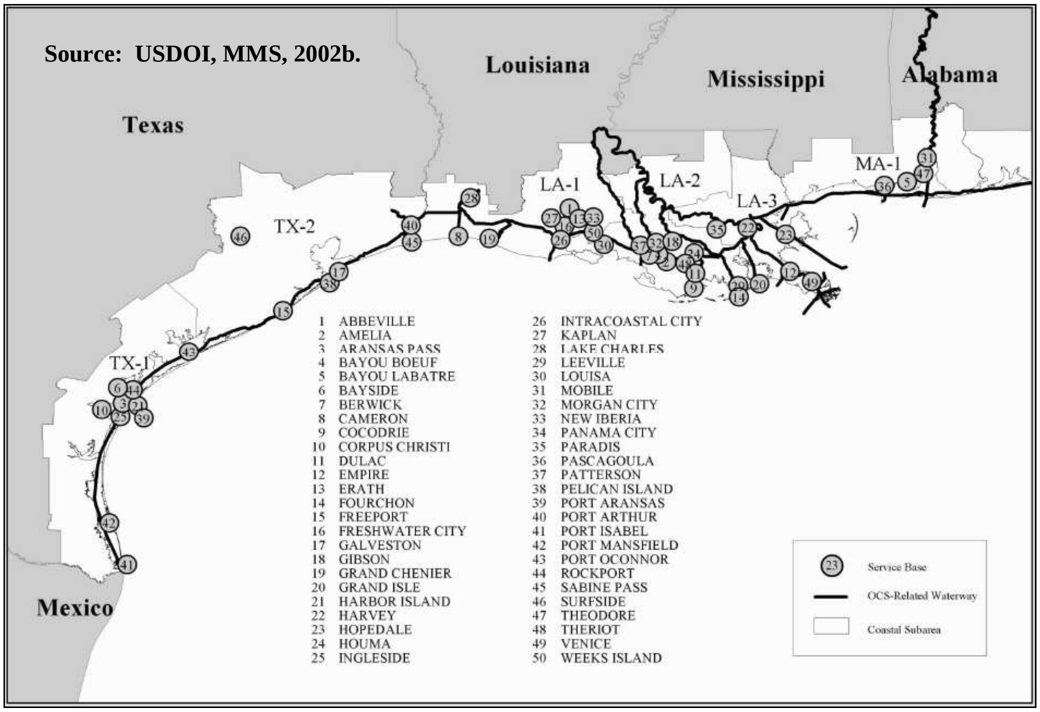


Figure 24. Top 50 offshore support ports in the Gulf of Mexico.

4.2.3. Typical Firms

Major shipping ports such as the Port of New Orleans, South Louisiana, and St. Bernard, (along with other ports such as Houston, Beaumont, Port of Mobile) engage in bulk shipping, among other principal operations. Millions of tons of cargo flow through these ports annually. In fact, the Port of South Louisiana is the largest U.S. port as measured by tonnage, and it is the fifth largest in the world (by tonnage), exporting more than 52 million tons a year, of which more than half are agricultural products (PAL and Louisiana Sea Grant, 2005). Likewise the Port of New Orleans is a transfer and storage point for all sorts of goods. Principal goods that are staged at the Port of New Orleans are steel, rubber, coffee, containers, and manufactured goods.

The extensive network of supply ports includes a wide variety of shore-side operations from intermodal transfer to manufacturing. Their distinguishing features show great variation in size, ownership, and functional characteristics. Supply base functions can be provided by either private or public port facilities. Private ports operate as dedicated terminals to support the operation of an individual company, or possibly a consortium of a few companies. Private ports often integrate fabrication and offshore transport activities. Public ports, however, charge fees and lease space to individual business ventures. Ports can, therefore, be thought of as water-based industrial or manufacturing parks that create economic benefits throughout a local region. Thus the public ports play a dual role by functioning as offshore supply points and as industrial or economic development districts.

Public ports are usually established by state and local governments to develop, manage and promote the flow of waterborne commerce in the area. Ports can also be developed by private companies. A port authority, which can be a state or local government, private agency or firm, is the governing body that oversees the port's operations. In addition to maritime functions, port authority activities may also include jurisdiction over airports, bridges, tunnels, commuter rail systems, inland river or shallow draft barge terminals, industrial parks, Foreign Trade Zones, world trade centers, terminal or shoreline railroads, ship repair, shipyards, dredging, marinas and other public recreational facilities.

The port authority and its management staff also handle the day-in and day-out management activities of the port including all business operations, management, maintenance, safety, and public communications. Most importantly, the port staff, and its executive director, offer advice to the governing body on commercial terms for the port including lease arrangements and fees. The port authority is usually governed by a commission with members that are appointed by city and county governments, or in the case of private ports, by the shareholders and/or port tenants. For instance, the seven-member Port of Houston Commission is the governing body for the Port of Houston Authority. The City of Houston and the Harris County Commissioners Court each appoint two commissioners. These two governmental entities jointly appoint the chairman of the Port Commission. The Harris County Mayors and Councils Association and the City of Pasadena each appoint one commissioner (Port of Houston Authority, 2008).

The Port of Morgan City is located in Morgan City in St. Mary Parish, Louisiana. It is governed by a nine-member Board of Commissioners, who are appointed by the Governor and serve for a nine-year term (PAL, 2006). Centrally located along the Gulf Coast, the port is only 18 miles from the open waters of the Gulf of Mexico. The port handles container, general, and bulk cargo. There are over 200 private dock facilities located in the Morgan City area, most of which are oil and gas related. These facilities have heavy-lift, barge-mounted cranes (5,000 ton capacity), track cranes (300 ton capacity), and mobile cranes (150 ton capacity) (Port of Morgan City, 2007).

Port Fourchon, Louisiana, is under the authority of the Board of Commissioners of the Greater Lafourche Port Commission (GLPC), which consists of nine elected members who serve six-year terms (PAL, 2006). Port Fourchon is a multiuse port primarily servicing the needs of oil and gas development (Figure 25). Port Fourchon has become the primary service base for OCS deepwater drilling. Major tenants of the port include companies that provide logistics support, drilling fluids, food services, rig repair and construction, and helicopter transportation.

Figure 25. Aerial view of Port Fourchon.

4.2.4. Regulation

Ports and Waterways Safety Act

The Ports and Waterways Safety Act (PWSA)[13] is designed to promote navigation, vessel safety, and protection of the marine environment. The PWSA applies to any port or any waterway under U.S. jurisdiction. Waters subject to U.S. jurisdiction are defined as all domestic navigable waters, other waters on lands owned by the U.S., and waters within U.S. territories and possessions.[14]

The PWSA requires the U.S. Coast Guard to promulgate regulations regarding "design, construction, alteration, repair, maintenance, operation, equipping, personnel qualifications and manning of vessels… necessary for the increased protection against hazards to life and property, for navigation and vessel safety and for enhanced protection of the marine environment (USDOC, NOAA, 1998)." The Act also authorizes the U.S. Coast Guard to establish vessel traffic service/separation (VTSS) protocols for ports, harbors, and other waters subject to congested vessel traffic. These protocols help provide order and predictability to vessel movements by establishing lanes with a "separation zone" between opposing vessel traffic similar to the "median" between opposing traffic on the highway system. VTSS apply to commercial ships, other than fishing vessels, weighing 300 gross tons or more (USDOC, NOAA, 1998).

Port and Tanker Safety Act of 1978

The PWSA was amended by the Port and Tanker Safety Act of 1978 (PTSA) under the premise that navigation and vessel safety and protection of the marine environment were matters of major

[13] The PWSA was amended by the Port and Tanker Safety Act of 1978 (PTSA), Public Law 95-474, and the Oil Pollution Act of 1990 (OPA).
[14] Unless otherwise noted, information provided in this section (Section 4) is from USDOC, NOAA, 1998.

national importance. The legislation was also supported by the Congressional finding that vessel traffic in the nation's ports and waterways has the possibility of creating substantial hazard to life, property, and the marine environment, if not regulated appropriately. The amendments included in the PTSA increased supervision of vessel and port operations in order to (USDOC, NOAA, 1998):

1. reduce the possibility of vessel or cargo loss, or damage to life, property, or the marine environment;

2. prevent damage to structures in, on, or immediately adjacent to the navigable waters of the U.S. or the resources within such waters;

3. ensure that vessels operating in the navigable waters of the U.S. comply with all applicable standards and requirements for vessel construction, equipment, manning, and operational procedures; and

4. ensure that the handling of dangerous articles and substances on the structures in, on or immediately adjacent to the navigable waters of the U.S. is conducted in accordance with established standards and requirements.

The Congressional findings included in the PTSA noted that advance planning and consultation (with other federal agencies, state representatives, affected users, and the general public) is critical in determining proper and adequate protective measures for the nation's ports and waterways and the marine environment.

Clean Water Act

Another regulation that is very important to U.S. ports is the Clean Water Act (CWA, Section 404). The CWA requires the USACE to manage programs involving dredging and disposal of dredged material (spoil) from navigation improvement and maintenance projects. In addition to non-Federal projects, permit applicants (e.g., port authorities, pipeline operators, terminal owners, industries, and private individuals) should include all other projects that include a dredge of 100 million cubic yards annually. The USACE reviews potential projects and issues permits for dredging and disposal of the dredged material in accordance with federal regulations. The USACE is also responsible for permitting all requests for the disposal of dredged materials in the ocean, inland or near-coastal waters. If dredged material is disposed of on land, various federal, state, and local regulations may apply.

Security

Security at virtually all major ports has been “dramatically strengthened” through numerous legislative initiatives in the aftermath of the terrorist attacks on September 11, 2001. U.S. port security is overseen by four principal groups: the U.S. Customs and Border Patrol, U.S. Coast Guard, the Terminal Operator, and the Port Authority. The U.S. Customs and Border Patrol has adopted a “multi-layered defense” program at the direction of the federal government. This program consists of several key strategies (USDHS, CBP, 2006) including:

***Screening and Inspection, CSI (Container Security Initiative)* –** also known as the "24-Hour Rule" that requires manifest information be provided 24 hours prior to a sea container being loaded onto a vessel in a foreign port.

C-TPAT (Customs Trade Partnership Against Terrorism) - CBP and partner companies are working together to improve baseline security standards for supply chain and container security.

Use of Cutting-Edge Technology - such as X-ray and gamma ray screening technology.

Programs such as these have changed the landscape of port operations considerably. While these new programs address security concerns, they also place additional stresses on port logistics systems; the integration of efficient intermodal logistics operations and strong security measures at ports is a challenge for port stakeholders in the future.

4.3. Industry Trends and Outlook

4.3.1. Trends

Several new trends along the GOM have resulted in changing needs for the offshore and maritime industry. This, in turn, has placed a burden on OCS ports to provide the necessary infrastructure and support facilities in a timely manner to meet growing industry needs. Important energy trends that have developed over the last decade are:

1. Changing E&P technology from one based on fixed structures, to one more commonly based on a variety of floating/ship-based type of structures;
2. Increasing deepwater and ultra-deepwater drilling;
3. Changes in OSV specifications (i.e., bigger, deeper);
4. Climate change, storm events, and other environmental concerns (i.e. water usage, changing regulations on emissions such NOx, SO2, ozone requirements);
5. Global competition;
6. Changes in energy prices; and
7. LNG development.

Increased port activity creates economic benefits in the form of increased employment, economic output, and other value-added benefits such tax revenue, fee and royalty/proprietor's income growth. The amount of goods and services transferred at ports has increased over the past decade including materials directly related to offshore oil and gas E&P including increasing equipment, drilling fluids, structures, supplies, and crew transfers. The increase of LNG imports through the GOM also has the potential to increase the demand for goods and services located at ports such as tub and barge services.

According to a 1999 Congressional Report assessing the maritime transportation system, commercial demand for marine transportation continues to grow and has been driven in significant part by the increase in international trade, which in turn, has expanded domestic use of the waterways to transport goods and people further upstream to other domestic markets. Continued federal and state port infrastructure investments will be needed to handle these increased port and waterway uses (USDOT, MARAD, 1999).

Ports will also need to enhance efficiency as these increased traffic trends continue. The entire maritime system relies on the successful integration of freight modes – water, truck, and rail – for the smooth transit of cargo from vessels through terminals and to and from inland destinations. Efficient access and the intermodal transfer of goods and cargo will be critical to maximize the returns from increasing terminal investments and will be instrumental in maximizing port competitiveness and growth opportunities (USDOT, MARAD, 2002).

According to an August 2002 MARAD survey the state of the intermodal access for U.S. ports was generally acceptable for handling the existing volume of cargo flows. Yet, more than one-quarter of the ports indicated that channel depths were "unacceptable in federal waterways (USDOT, MARAD, 2002)." A later 2005 MARAD and DOT report found America's port and intermodal freight system is quickly approaching capacity limits as congestion increases in metropolitan areas and passenger/freight corridors are pushing existing infrastructure limits. The report concluded that the Marine Transportation System's (MTS) greatest challenge is accommodating the projected growth in our international trade and the report noted that "Our marine, highway, and rail systems will need to be able to manage the increased volumes of freight shipments that are so vital to our nation's continued economic growth (USDOT, MARAD, 2005a)."

As cargo volumes increase, carriers will see other transport and port alternatives in order to cut time and costs. The primary way of increasing efficiencies and lowering unit transportation costs is to move cargo through increasingly larger vessels. Vessels that began service in the 1960s, with capacities of less than 500 twenty-foot equivalent units (TEUs), have been replaced by vessels with capacities of 6,000 TEUs, and current shippers are beginning to place orders on ships that can carry over 8,000 TEUs.[15] It is possible that by 2010, ships will have capacities of 13,000 TEUs (USDOC, NOAA, 1998). These enormous ships require sophisticated and efficient ports and terminal facilities with first-rate landside intermodal connections. "For a port to service these mega ships, the entire port structure will have to get bigger and more productive. Each channel, berth, and turning basin must be at least 50 feet in depth since 40 to 46 feet will be the maximum draft for the fully-loaded mega ships (USDOC, NOAA, 1998)."

Larger cargo volumes, ships, and operating companies are putting pressure on ports to increase their scale of operations, and channel depth appears to be the most significant factor of consideration in these expansion decisions. Channel depths at most major U.S. ports typically range from 35 to 45 feet. The current generation of new large ships requires channels from 45 to 53 feet. According to a report by the U.S. Army Corps of Engineers finalized in September 2000, container ports around the world are deepening navigation channels down to between 49 and 53 feet. Channel depth issues have been a particular problem for ports along the GOM particularly several smaller ports (like New Iberia, Venice, and Cameron) looking to expand their operations to support greater platform construction and fabrication and deepwater service

[15] It is possible for a shipping company to save $4.5 million per voyage by switching from a 2,500 to 6,000 TEU vessel.

activities. Increases in traffic, larger ships, and larger port infrastructure footprints bring additional challenges, particularly environmental-related challenges. A recent report by MARAD noted that:

> one of the critical challenges confronting the U.S. port industry is meeting the growing demands and diverse needs of waterborne transportation while protecting the environmentally sensitive harbor areas in which ports operate. Protecting the environment and providing an efficient and cost-effective transportation system are critical to the economic future of the United States (USDOT, MARAD, 1998).

In Louisiana, Port Fourchon (Figure 26) is one of the primary port facilities that supports oil and gas E&P activity. Port Fourchon, and the highway system that connects it to the interstate highway system to the north, are protected by the surrounding landscape, which are coastal marshes. These coastal marshes serve as a "marsh barrier," which, if destroyed, would threaten the existing highway system (Battelle Environmental Updates, 2000). The destruction to the primary access way to Port Fourchon could also have implications for oil and gas production in various areas of the GOM, particularly the deepwater GOM. If the essential marsh barrier were destroyed, the existing levees would have to be enlarged and significantly strengthened.

Figure 26. Port Fourchon and a proposed elevated highway system, LA 1.

As noted earlier, channel depth is a critical issue driving port operations and growth opportunities. Channel depth determines the size of ships that will move into and through a given port, these ships' ability to move safely through harbors, breadth of turning basins, and terminal-side water depths. Annual and periodic channel dredging requires the removal of several hundred million cubic yards of sand, gravel and silt each year. These dredging activities can be challenging and controversial because ports are located in, or near, environmentally sensitive areas including wetlands, estuaries and in some instances, fisheries. In addition, there is the potential that materials dredged may uncover toxins or contaminated sediments that have accumulated over time (USDOT, MARAD, 1998). Although the dredging and resurfacing of contaminated sediments is a major topic of debate, only the U.S. DOT has found that "…5 to 10 percent of dredged material is contaminated and some of this material may, in some cases, also be reused in beneficial applications (USDOT, MARAD, 1999)."

Capital expenditures for dredging were 11.1 percent of total port expenditures in the U.S. for 2000 (USDOT, MARAD, 2001). The Gulf Coast Region accounted for 29 percent of these expenditures, exceeded only by the North Atlantic Region at 34 percent. The Gulf Coast Region was followed by the South Pacific region with 27 percent, the North Pacific region with 6 percent, and South Atlantic with 4 percent. Dredging in the Great Lakes accounted for less than 0.1 percent of total dredging expenditures (USDOT, MARAD, 2001).

Total capital infrastructure expenditures for the period 2004 through 2008 at public U.S. ports are estimated at around $10.6 billion. Of this amount, $1.1 billion, or about 10.5 percent, will be spent on dredging. And, of these dredging expenditures, an estimated $100 million will be spent by Gulf Coast Ports, or about 10 percent of total U.S. expenditures on port dredging. In addition, between 1946 and 2003, the Gulf region accounted for an average of 17.3 percent of total U.S. public port infrastructure capital spending (USDOT, MARAD, 2005b).

Improving and maintaining navigation channels is critical to sustaining the rapidly growing marine transport industry. Bottlenecks can occur when channels are not deep enough for ships to safely navigate and dock at berths. Unless ports are dredged, cargo cannot move in the most cost-effective way through the intermodal transportation chain. Also, as ship sizes and volumes of cargo increase, so must the intermodal transfer operations.

Efficient transportation also depends on intermodal connections. In order to move waterborne cargo quickly to or from land based operations, trucks and railroads need to have clear access to ports. According to the APPA, “for some ports, the weakest link in their logistics chain is at their back doors, where congested roadways or inadequate rail connections to marine terminals cause delays and raise transportation costs (AAPA, 2008a).” The AAPA also references a recent Federal Highway Administration (FHA) Report to Congress on the National Highway System (NHS) Intermodal Connectors that found connectors to ports, as opposed to other freight terminals, were in their worst condition and received only minimal levels of federal funding and support over the past several years. The FHA Report also found that port facilities had twice as many miles with pavement deficiencies when compared to non-Interstate NHS routes. Like a pipeline, the nation’s intermodal transportation system is only as efficient as its narrowest, most congested point of the pipeline: for a port, this is often the landside connection. No matter how much ports invest, or how productive their marine terminal facilities, the transportation system cannot operate at maximum efficiency unless cargo can move quickly, and cost effectively, in and out of ports.

The importance of major intermodal marine linkages or connections to surface transportation was recognized in the National Highway System Designation Act of 1995. The Act listed directions for modifications to connections to major ports, airports, international border crossings, public transportation and transit facilities, interstate bus terminals, and rail and other intermodal transportation facilities (USDOT, MARAD, 1998). In 1998, the Transportation Equity Act for the 21st Century (TEA-21) was signed, authorizing highway, highway safety, transit and other subsurface transportation programs for the next 6 years. Within TEA-21, there are a number of programs that could potentially benefit port industry access concerns. Although these programs do not earmark specific funds for port-related projects, they may meet program eligibility requirements (USDOT, MARAD, 1998).

To keep up with changing vessel sizes and industry trends, ports must continuously update, modernize, and expand their facilities. Between 1946 and 2003, U.S. ports have invested $27 billion in capital improvements and related infrastructure. During this period, the Gulf Coast region accounted for 17.3 percent of these expenditures, only to be exceeded by the South Pacific region (33.3 percent) and the North Atlantic (17.6 percent) (USDOT, MARAD, 2005b).

During the five-year period of 2001 through 2005, public port expenditures were estimated at a total of $9.4 billion – an increase of 12.8 percent compared to 2000. The South Pacific region was the focus of investment activity with proposed expenditures of $3.1 billion (33.8 percent). Four other regions projected investment levels in excess of $1 billion – the South Atlantic at $1.7 billion (18.8 percent), the Gulf at $1.6 billion (17.1 percent), the North Atlantic at $1.5 billion (16.6 percent), and the North Pacific at 1.2 billion (12.8 percent). From a coastwise perspective, the West Coast was projected to invest over $4.3 billion with East Coast expenditures at $3.3 billion and the Gulf at $1.6 billion (USDOT, MARAD, 2001). For the time period 2004 to 2008, the public port industry set aside an estimated 10.6 billion in capital improvements, of which 19.1 percent is spent by the Gulf (around $100 million was applied to Gulf dredging during this period). Of the $10.6 billion in port infrastructure investments, an estimated 34.3 percent went to the South Pacific region and 22.2 percent was invested in the South Atlantic (USDOT, MARAD, 2005b).

Offshore support ports have similar logistical considerations as major shipping ports; in Louisiana, where the majority of offshore oil and gas support ports are located; a compilation of five-year capital improvement plans for various Louisiana ports illustrates major areas of perceived and necessary infrastructure improvements. These five-year plans include both shipping ports and offshore support ports in Louisiana.

Cost projections (Figures 27 and 28) show that cargo, dredging, and infrastructure improvements make up the bulk of existing revenue maintenance (excluding MRGO Related Re-locations – a one-time exogenous event). Dredging leads the cost projections for future revenue-generating projects for the period 2007-2011. The implication for offshore support ports is that these ports have recognized changing OCS trends, particularly of bigger boats with deeper drafts, and have recognized the need to expand their infrastructure capabilities accordingly.

One of the ongoing challenges for the support sectors of the offshore industry is the availability of skilled labor. This is a problem being experienced across all energy sectors as the existing labor force ages, and fewer new workers enter the various sectors of the oil and gas industry. Many firms find themselves competing for skilled labor particularly along the GOM between support and transport companies. A report by Amec (a consulting, engineering and project management firm) attributes the small labor pool problem to the fact that oil and gas companies regularly underinvested in their businesses in the 1990s and now they are starting to see the shortage of workers due to the lack of trained employees. Another potential reason for the lack of personnel is the impact of price volatility within the oil and gas industry. When experienced workers leave the industry it is very difficult to entice them back. These shortages have led to a greater emphasis on diversification among contractors, and often result in mergers and acquisitions, leaving fewer contractors (USDOE, OFE, 2000).

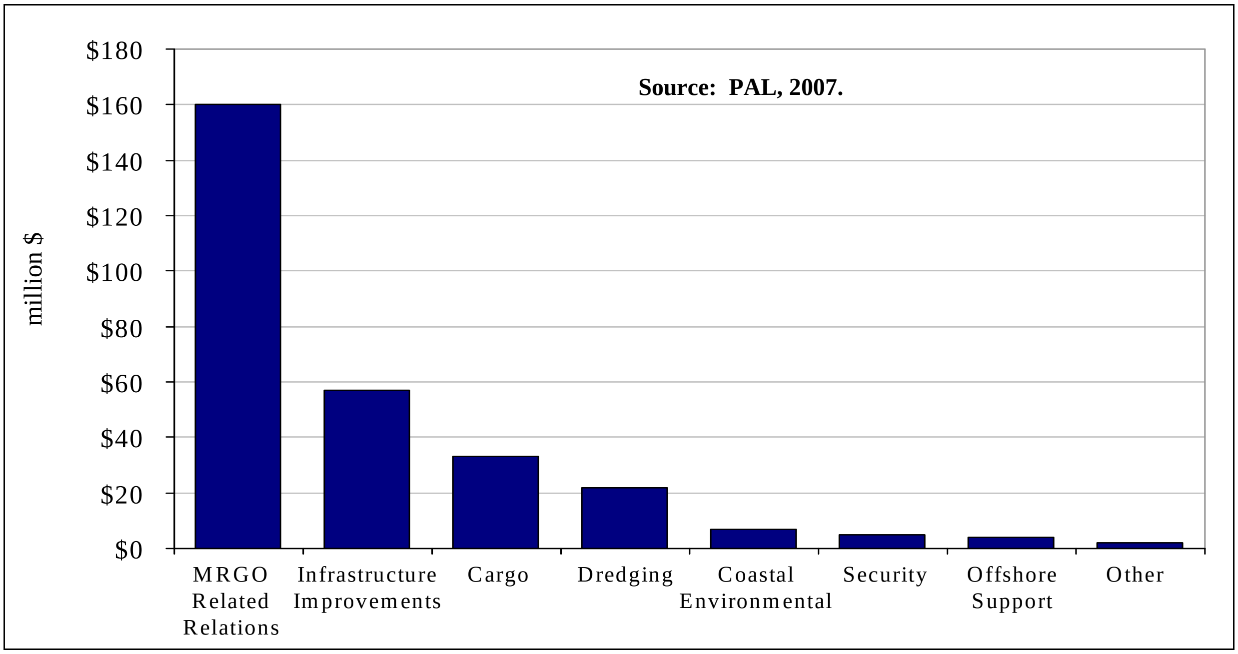


Figure 27. Projected cost allocations for existing revenue maintenance and preservation by project type; Ports Association of Louisiana member ports 2007-2011.

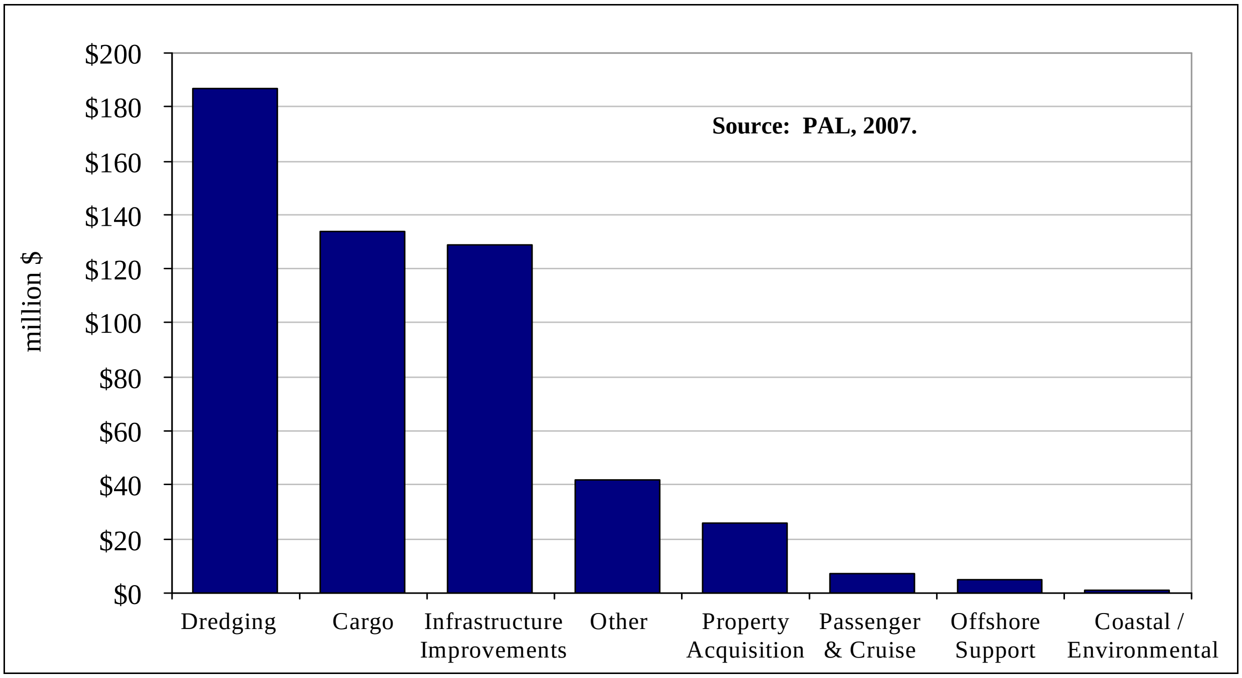


Figure 28. Projected cost allocations for new revenue creation by project type; Ports Association of Louisiana member ports 2007-2011.

4.3.2. Hurricane Impacts

The importance of both major shipping ports and offshore support ports along the GOM is substantial, as highlighted by the 2005 storm season. Like many other types of infrastructure impacted during the 2005 season, port outages and vessel curtailment along the GOM were pervasive and felt throughout the U.S. Both types of ports (shipping, oil and gas support) experienced damage to one or more (or all) components of their logistics systems including: the inland transport modes; port infrastructure; and offshore operations. Particularly hard hit ports were the Port of New Orleans, St. Bernard, Plaquemines, Port Fourchon, South Louisiana, Venice, Cameron, and the Port of Lake Charles. Ports not directly affected by the storm were indirectly affected as water traffic was rerouted to many ports and offshore support operations flooded the operating ports (LA DOTD, 2005a).

Three of Louisiana's deepwater ports (New Orleans, St. Bernard, and Plaquemines) suffered extensive damage due to Hurricane Katrina. Additionally, Hurricane Rita caused damage to the Port of Lake Charles, Port of Iberia, Port Manchaca, Abbeville Harbor & Terminal District, and the West Calcasieu Port. Of the twelve grain transit facilities located throughout the state, only Harvest States in South Plaquemines Parish suffered extensive damage and a few others needed minor repairs (LA DOTD, 2005a).

All of Louisiana's 21 inland and shallow-water river ports, such as the Port of Shreveport-Bossier, Port of Iberia, Port of Lake Providence, and the Alexandria Port Authority, remained fully operational during the hurricanes since they are located inland and away from the brunt of the storms' impacts. The deep draft Port of Greater Baton Rouge was not affected by either hurricane. Baton Rouge and Lake Charles (prior to Hurricane Rita) were accepting ships and diverted cargo until the ports in Southeastern Louisiana were fully operational. According to Joe Accardo, executive director of PAL, "the goal [was] to assist these ports and its customers by providing an alternate location until these ports [were] fully operational. The goal [was] to keep the commerce flowing and retain as much cargo as possible in Louisiana (LA DOTD, 2005a)."

Port of New Orleans

The Port of New Orleans suffered extensive damage during Hurricane Katrina. The port's upriver facilities, accounting for approximately 70 percent of total port activities, fared relatively well in the storm; including the Napoleon Avenue Container terminal, the Nashville Avenue complex, the Louisiana Avenue complex, the First Street Wharf, and the Alabo Street Wharf (LA DOTD, 2005a).

On September 12, 2005, the Port of New Orleans restarted commercial cargo operations. Truck traffic was cleared beginning September 9, 2005, which restored access to the upriver terminals, including the Napoleon and Nashville Avenue terminals. The Louisiana Avenue terminal restarted operations on September 12, 2005 (LA DOTD, 2005a).

There were more lasting impacts, however, at other terminal facilities in the city. All five cranes at the France Road Terminal were still under water at least one full month after Katrina's landfall. A number of terminals and industrial facilities along the Inner Harbor Navigational Canal sustained significant damage during the hurricanes as well. The Mandeville Street Wharf, used for cargo overflow, burned to total destruction in a fire which occurred during the hurricane (LA DOTD, 2005a).

Preliminary damage assessments conducted immediately after Katrina indicated approximately 30 percent of the Port's operating facilities were destroyed, facilities downriver and along the Inner Harbor Navigation Canal (IHNC) were severely damaged, among them the Maersk Sealand terminal and the New Orleans Cold Storage facility at the Jourdan Road terminal. Other damages included the downriver terminals, including the Maersk and Jourdan terminals. To mitigate plant and equipment damages along the IHNC, port commissioners voted to amend 16 leases with industrial tenants, deferring rent up to four months. After the storms, a few new business opportunities emerged in the recovery process through the Port's execution of several new lease agreements with debris removal firms looking for industrial property in New Orleans for hurricane debris staging and transport (Port of New Orleans, 2005).

About seven weeks after Hurricane Katrina, the port was operating at 50 percent of pre-storm volumes. The cargo that had been moving through the port had been redirected to other locations and port officials noted that it is likely some may not return (Curtis, 2007). Port officials also stated that the major obstacle to increasing the Port's capacity is the missing or displaced workforce. Because of the extensive damage to the region and residential areas, many Port employees are unavailable (Curtis, 2007). In February 2006, Port operations were at 80 percent of pre-Katrina levels and port officials were expecting a return to normal levels by mid-2006, which for the most part, the Port was able to attain (Curtis, 2007).

Port of South Louisiana

As of September 2005, the Port of South Louisiana, the nation's largest port by tonnage, operated at near full capacity and was 100 percent operational at the General Cargo Dock, the Bulk Dock, and the Globalplex Intermodal Terminal (LA DOTD, 2005a). Associated Terminals resumed stevedoring operations and worked vessels and barges at the facility. The port experienced significant communications problems due to downed telephone lines, and had persistent problems with its computer system. All grain terminals, chemical facilities, transfer facilities, and the refineries, Motiva-Convent, Motiva-Norco, Valero, and Marathon, were operational (LA DOTD, 2005a). Overall, the port experienced only minor infrastructure and structural damage. Officials with the Port of South Louisiana assessed the damage at approximately $2,000,000 (LA DOTD, 2005a). Moderate additional structural damage was experienced during Hurricane Rita on September 24, 2005 (LA DOTD, 2005b).

Port of Greater Baton Rouge

The Port of Greater Baton Rouge experienced very little damage and made its facility available as staging points to support emergency recovery efforts and to assist other ports during the restoration and recovery process. The Port made its deepwater maritime infrastructure and barge container terminal available to a number of parties in order to accommodate relief supplies for recovery activities, as well serving as an alternative port facility for cargo that was displaced due to the storm. In the aftermath of the storm, some maintenance dredging, up to the project depth of 45 feet was necessary. Other damages at the Port due to the hurricanes were minimal and reported to be about $25,000 in total value (LA DOTD, 2005a).

Venice Port Complex

Hurricane Katrina left Venice in shambles. The road to its port was flooded for more than a month. Venice, which serves about 19 percent of the oil and gas activity in the GOM, was unable to serve as a hub for oil and gas activity near the mouth of the Mississippi and in the central Gulf of Mexico. Even if companies could get to Venice by boat or plane, the docks and yards were covered in lumber, aluminum siding, debris from nearby wetlands and barges and boats tossed there by the storm (Russell, 2007). At the John W. Stone Oil Distributor dock alone, a crew removed 100 dump truck-loads of debris (Russell, 2007).

Two years after the storm, the only remnants of Katrina were a few stranded boats in an isolated corner of the port and a new mountain of trash at the on-site landfill from Katrina related debris and waste (Russell, 2007). All but two of the port's 50 or so tenants have returned, and according to the port manager, those servicing oil and gas companies will be busy with hurricane repair work for at least five more years. As of 2007, the port reported that it had one site out of 61 that was not leased (Russell, 2007). In May 2008, Venice announced plans to begin a new port complex, with the Louisiana State Bond Commission agreeing to issue $300 million in Gulf Opportunity Zone (GO Zone) bonds to help pay for the project (DeGregorio, 2008).

Port Fourchon

The national significance of Port Fourchon has grown considerably in recent years. According to the LSU Sea Grant program:

> With the advent of OCS drilling technology, Port Fourchon has grown from two to 160 companies in the past two decades. Most of that growth has occurred since 1995 when the port was less than a third of its current size. A direct hit on Port Fourchon by a major hurricane could have serious consequences to the U.S. domestic energy sector. Port Fourchon serves as the inter-modal support hub for 75 percent of Gulf of Mexico drilling, 16 percent of U.S. domestic oil and gas production and is the nation’s only offshore oil terminal, the Louisiana Offshore Oil Port (Louisiana Sea Grant, 2005).

While Port Fourchon escaped major water and storm surge damage, it did suffer considerable wind damage from Hurricane Katrina. Some additional wind and flooding damage was created later from Rita. The port credits the “coastal ridges” built during its recent expansion as a defense mechanism that protected it from storm surge during both hurricanes. These coastal ridges were built using dredge spoil and worked to serve as a buffer between the GOM and coastal marshes (Curtis, 2007).

Louisiana Highway 1 (LA 1) was not as lucky as the port facilities themselves. LA-1 serves as the main highway serving the port. Damage to the road can, and did impact port operations considerably (Louisiana Sea Grant, 2005). Overall 2005 damage estimates reported to the state Department of Transportation and Development were over $7 million for public port facilities (LA DOTD, 2005a).

In August 2006 FEMA announced a grant worth $3.8 million to clear the port on Bayou LaFourche of silt and sediment caused by Hurricane Katrina (USDHS, FEMA, 2006). And, the

Louisiana Department of Transportation is replacing a major portion of Louisiana Highway 1 with an 18 mile bridge. It is estimated that this project will cost close to $1.5 billion (Offshore, 2008).

Plaquemines Port, Harbor & Terminal District

The Plaquemines Port facilities (separate from the privately-held Venice Port Complex) suffered substantial damage, which was difficult to estimate as communication problems persisted. By December 15, 2005, the port was 100 percent operational (LA DOTD, 2005b). Initially, MARAD was able to make contact with the Chevron blending facility and marine terminal located within the Parish along the west side of the Mississippi River. According to a Chevron staff member in Texas, their facility was functioning, however the marine terminal was not due to lack of power. Chevron staff conducted repairs and cleaning operations to their facility, which suffered extensive damage. Communications problems continued to persist in Plaquemines parish (LA DOTD, 2005a).

Port of Morgan City

The Port of Morgan City did not experience much damage from Hurricanes Katrina and Rita. Winds at the port reached up to 85 to 90 mile per hour, but there was no significant storm surge. Port officials noted that the port was better protected because of its inland location and the fact that sediment from the Atchafalaya River has been building delta coastal land, as opposed to those areas where erosion is a problem (Curtis, 2007). Within a month of Katrina's landfall, the Port of Morgan City was 100 percent operational, but needed a survey of the waterway due to shoaling caused by the storms (LA DOTD, 2005b). As of September 2005, the U.S. Army Corps of Engineers (USACE) was establishing a schedule to get survey boats on the scene to determine channel depths of waterways essential to offshore oil and gas at Morgan City (LA DOTD, 2005a).

St. Bernard Port, Harbor & Terminal District

The Port of St. Bernard sustained a great deal of wind and water damage. The port operated with limited commercial operations and as a staging area for emergency and FEMA operations in St. Bernard Parish. As of September 19, 2005, Associated Terminals had recommenced cargo operations at the Chalmette slip facility, transloading railroad cars and rail car wheel assemblies (LA DOTD, 2005a).

Port of Lake Charles

The Port of Lake Charles experienced moderate wind damage and flooding. Additionally, the port was without power, water, sewer, and other utilities. The port worked with state and federal officials to procure a MARAD vessel to house port workers. Port cargos were generally not affected but structural damage to warehouse roofs, doors, and siding occurred. Port officials remained at the port throughout the hurricane so they would be ready to recommence operations as quickly as possible to support refineries, liquefied natural gas, agricultural industries, and forest product imports operations (LA DOTD, 2005a).

On September 29, 2005, the Port of Lake Charles met with officials from the Army Corps of Engineers (USACE), FEMA, and the Federal Department of Transportation to assess their needs, such as power generation, water and portable toilets, and fuel. The port hired temporary labor to clean up debris and repair facilities (LA DOTD, 2005a).

Port of West St. Mary

The Port of West St. Mary, located on the Gulf Intracoastal Waterway (GICW) at mile marker (MM) 133, experienced some water damage to port facilities and power outages. The port was out of service for only a few days. The port had water damage in many of the buildings and electrical power was down. A lost ballast along the main railroad and port spur made rail service inoperable (LA DOTD, 2005a).

Port of Iberia

The Port of Iberia experienced extensive flooding in excess of several feet. The port administrative buildings sustained both wind and water damage. As of September 27, 2005, a few areas of the port remained closed due to unstable aluminum oxide drums made volatile by an estimated 9 feet of storm surge (Louisiana Sea Grant, 2006). Businesses affected by the closure included the following: Sea Shell; Allen Processing Systems; Bayou Companies; Natco; Superior Energy Services; Universal Fabricators; Cumings Corp.; and Greg Guidry Enterprises (Louisiana Sea Grant, 2006). As of October 26, 2005, repair work had begun on the port office building, which experienced approximately one foot of flooding (LA DOTD, 2005a).

West Calcasieu Port, Harbor, and Terminal District

The West Calcasieu Port, Harbor, and Terminal District sustained a great deal of wind and water damage. The port was used as a staging area for emergency operations in Calcasieu and Cameron parishes (LA DOTD, 2005a).

Port of Cameron

Hurricane Katrina's damage to Louisiana offshore oil and gas staging areas forced the industry to move its logistical base to Cameron (Inside FERC, 2005b). Then, Hurricane Rita came onshore near Cameron, Louisiana, and inflicted heavy damage to parts of the parish (Inside FERC, 2005a). M-I SWACO's offshore supply base in Cameron was completely destroyed. The base had been in operation since 1958 (Rigzone.com, 2007c). Nabors Offshore reported that a rig it had at the Port of Cameron was damaged: "windows in the pilot house and quarters blown out, resulting in water damage to control system and the quarters (Paganie, 2005)." BP's Grand Chenier gas plant was flooded and early aerial inspections indicated damage to a number of facilities (Energy Trader, 2005).

Offshore, rigs were found submerged and grounded near Cameron. Nabor's Rig 300 was submerged just east of Cameron and Rowan-Louisiana, a jackup was found grounded, with its legs severed (Rach, 2006).

Other companies however, fared much better. Cheniere Energy was in the process of building a 2.6 Bcf per day LNG facility in Cameron Parish. A preliminary examination "found that, due to the site's elevation and the improvements to it, there appears to be no material flooding of the site (Inside FERC, 2005a)."

South Tangipahoa Parish Port Commission

Port Manchaca, of the South Tangipahoa Parish Port Commission, returned to full operability as of September 28, 2005. However, the port did suffer roof damage to three warehouses (LA DOTD, 2005a).

Abbeville Harbor and Terminal District

The Abbeville Harbor and Terminal District was 50 percent operational for the first week following Hurricane Rita and returned to full operational status once power and communications were restored, in early October 2005. The port was one of the few ports between Texas and Mobile, Alabama, that had dry infrastructure following the hurricanes (Louisiana Sea Grant, 2006).

Port of Terrebonne

The Port of Terrebonne experienced little to no damage during Katrina, but did have some damage from Rita. During Rita, water moved up the Houma Navigation Channel and the Gulf Intracoastal Waterway. The water remained elevated for about one week (Curtis, 2007). While the port is protected by a five-foot high levee around its perimeter, there was damage to the floodgates and culverts that separate brackish water from fresh water (Curtis, 2007). The Houma Navigation Canal was closed until a survey of the waterway could be concluded. The port was spared the extreme damage of others as neither hurricane passed directly over the area (Louisiana Speaks, 2008).

The U.S. Gulf Intracoastal Waterway

The Gulf Intracoastal Waterway (GICW) opened to traffic across the hurricane-impacted (Katrina) areas of Louisiana beginning on September 6, 2005, while the IHNC north of the turning basin was re-opened on September 14, 2005. USCG crews worked closely with the Gulf Intracoastal Canal Association to ensure temporary navigation aids were set in the affected areas of the GICW (LA DOTD, 2005a).

Table 6 presents the preliminary damage estimates for a number of ports as of December 2005.

Table 6

Hurricane Katrina Damage Estimates as of December 2005 at Louisiana Ports

Port	Damage Estimate*	Comments
Port of New Orleans	$1,700,000,000	The port is submitting a $1.7 billion relief package to the federal government, which includes repairs, replacing bridges across the Industrial Canal, and fast-tracking the Industrial Canal Lock.
Port Fourchon	$7,000,000	The damage estimate does not include an additional $48 million in damage to privately owned tenant facilities on port property (including a $20 million helicopter).
Port of South Louisiana	$2,000,000	Estimated damages from Hurricane Katrina are approximately $1.5 million for repairs and $350,000 for emergency operations. Additional roof damage was caused by Hurricane Rita.
St. Bernard Port, Harbor & Terminal District	$15,000,000	Damages are significant and while limited commercial operations are underway, the port continues to serve as a staging area for emergency management operations in St. Bernard Parish. Damages are estimated.
Plaquemines Port, Harbor & Terminal District	$10,000,000	Significant damage was experienced. Communication problems continued through December 2005.
Port of Greater Baton Rouge	$25,000	
Port of Iberia	n.a.	Repairs were needed for the port office building which had one foot of water in it.
Port Manchac	n.a.	Port experienced wind damage to three warehouses. Damages to be determined.
Port of Lake Charles	n.a.	The port was 100% operational as of October 5, 2005. It suffered some wind and flood damage.
Abbeville Harbor & Terminal District	$20,000	Hurricane Rita caused both wind and water damage to port facilities. Additional damages are estimated to be $110,000 for the public boat launch at Intracoastal City and the Freshwater Bayou By-Pass at $160,000.
West Calcasieu Port	n.a.	Port facilities experienced minor damage.
Port of Terrebonne	n.a.	The port experienced minor flooding.
TOTAL	$1,734,045,000	

**These damage estimates as of December 2005 were preliminary; and some estimates were not available.*

Source: LA DOTD, 2005a and b.

While Hurricanes Katrina and Rita caused direct damage to several GOM ports, these storms stimulated a significant amount of revenue and incremental work for OCS offshore support ports such as Port Fourchon, Morgan City, and Venice. Specifically, the storms created a large swath of damage that affected numerous platforms, rigs, and wells in the paths of the hurricanes (Figure 29). The subsequent offshore recovery operations were periods of full employment for active offshore support vessels. If ports were able to resume some level of operations, as Fourchon and others were able to do, they were supporting a booming industry over the next months as companies rushed to recover unsecured structures and fix the damages caused by the storms. Reports from private sector offshore support firms indicate that in the months after Katrina, the OSV fleet as a whole was experiencing near 100 percent utilization rates, with day rates (the typical charge schedule) inflated above normal rates. Katrina and Rita illustrate this point: while several key offshore ports were severely damaged, the OSV fleet remained active and busy; favoring undamaged OCS ports for business.

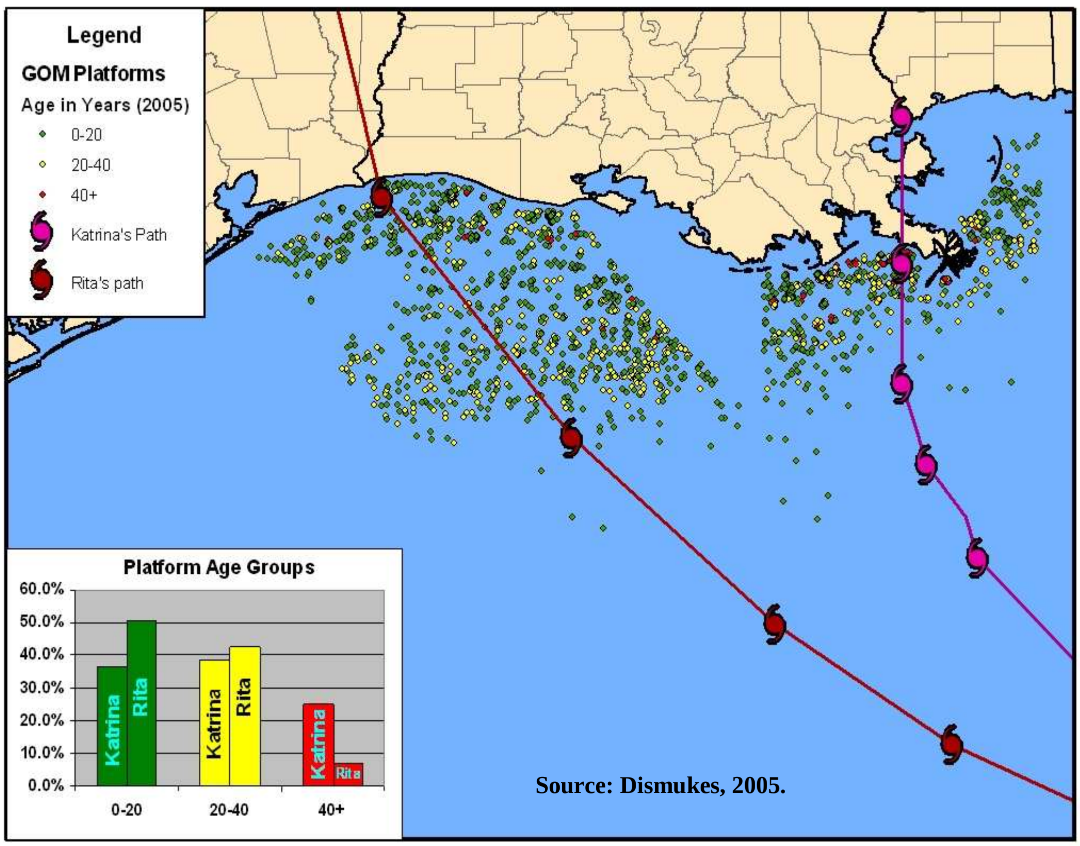


Figure 29. Offshore platforms in the paths of Hurricanes Katrina and Rita.

4.3.3. Outlook

The GOM represents an expanding frontier with extraordinary growth opportunities primarily driven by developments in deepwater (Table 7). More deepwater activity will stimulate the need for support services provided by regional ports. As previously stated, regardless of where the exploration and production equipment, personnel, and supplies originate, at some point these resources must pass through a port to reach the drilling and/or production sites. This point of intermodal transfer is vital to maintaining reliable, uninterrupted production of oil and gas from the Gulf of Mexico.

Table 7

Gulf of Mexico Lease Sale Schedule – Proposed for 2007-2012

Sale No.	Area	Year
204	Western Gulf of Mexico	2007
205	Central Gulf of Mexico	2007
193	Chukchi Sea	2008
206	Central Gulf of Mexico	2008
224	Eastern Gulf of Mexico	2008
207	Western Gulf of Mexico	2008
208	Central Gulf of Mexico	2009
209	Beaufort Sea	2009
210	Western Gulf of Mexico	2009
211	Cook Inlet	2009
212	Chukchi Sea	2010
213	Central Gulf of Mexico	2010
215	Western Gulf of Mexico	2010
216	Central Gulf of Mexico	2011
217	Beaufort Sea	2011
214	North Aleutian Basin	2011
218	Western Gulf of Mexico	2011
219	Cook Inlet	2011
220	Mid-Atlantic	2011
221	Chukchi Sea	2012
222	Central Gulf of Mexico	2012

Source: USDOI, MMS, 2006c.

According to a recently released BOEM report,

> Since the first major deepwater leasing boom in 1995 and 1996, we have entered into a sustained, robust expansion of activity. The Central Gulf of Mexico Sale 198 held this past March [2006] garnered bids on 204 deepwater blocks, confirming continued enthusiasm for exploring the deepwater arena. The total of the high bids in the sale, including shallow- and deepwater leases, was $588 million, the highest in eight years.
>
> As of March 2006, there were 118 deepwater hydrocarbon production projects online. Production from deepwater was an estimated 950 thousand barrels of oil per day and 3.8 billion cubic feet of natural gas per day by the end of 2004. More than 980 exploration wells have been drilled in the deepwater Gulf since 1995. At least 126 deepwater discoveries have been announced since then. Significantly, in the last seven years, there have been 22 industry-announced discoveries in water depths greater than 7,000 feet (2,134 meters), seven in 2004 alone (French et al., 2006).

With increased development comes a need for additional support and port expansion. This need has already been experienced in Manatee County, Florida, with the expansion of Port Manatee and its windfall from the Gulfstream Pipeline Project.

Port Manatee in Manatee County, Florida, is a relatively new port (35 years old) but is already undergoing a considerable expansion effort designed to encourage investments and contracts from industries such as perishable commodities, cruise operations, and containerized cargo (Schultheis, 2005). In 2005, the port announced a $10 million renovation and expansion creating a new berth (Berth 5) designed to add 1,200 feet of new deepwater berthing. In addition, a $42 million dredging project created deeper harbors and berths and $1.65 million was invested in a railroad interchange track expansion project. Total port expansions since 1997 sum to $119 million. The port anticipates continued expansions in future years since its master plan includes $320 million in new construction over the next 20 years (Schultheis, 2005).

Another recent project impacting Florida GOM ports is the Gulfstream Natural Gas Project. Originating near Pascagoula, Mississippi, and Mobile, Alabama, this natural gas pipeline crosses the GOM (with 431 miles of 36-inch diameter pipe) to Manatee County, Florida, encompassing 753 miles of pipeline. The pipeline is estimated to have added $10 million to $12 million to additional revenues for Port Manatee during the construction period. In addition to using the port for import, export, and storage, the project leased 190 acres of port property for pipeline staging and storage (Meinhardt, 2002).

Other port improvements and investments programs that have enhanced GOM port capabilities over the past several years include:

Coastal Impact Assistance Program

The Coastal Impact Assistance Program (CIAP) was created by the Energy Policy Act of 2005. The program will disperse $250 million annually for four years (2007-2010) to six OCS oil and gas producing states: Texas; Louisiana; Mississippi; Alabama; Alaska; and California. The funds are allocated to each state and county using the allocation formula provided in the Act. Each state is allocated its share based on its OCS revenue as a portion of all OCS revenue generated by the six states. The allocations for 2007 and 2008 were done in April 2007 and the allocation for 2009 and 2010 were expected to be calculated in 2009 (USDOI, MMS, 2009b).

According to the Act, a producing state or coastal political subdivision must use the funds received for one or more of the following purposes (USDOI, MMS, 2009a):

- Projects and activities for the conservation, protection, or restoration of coastal areas, including wetland;
- Mitigation of damage to fish, wildlife, or natural resources;
- Planning assistance and the administrative costs of complying with this section;

- Implementation of a federally-approved marine, coastal, or comprehensive conservation management plan; and/or

- Mitigation of the impact of OCS activities through funding of onshore infrastructure projects and public service needs.

In 2007, Louisiana was allocated $172 million. Of this, 65 percent was allocated to the State of Louisiana; and 35 percent was allocated to 19 coastal parishes. Part of the funding would be used for the construction of an elevated highway to replace Louisiana Highway 1 (Sands, 2007). In addition Alabama received $25.6 million, Alaska received $2.4 million, California received $7.4 million, Mississippi received $31 million and Texas received $49 million.

Pinto Island at Mobile, AL

In 2007, Mobile County won a $3.7 billion boon. German steelmaker ThyssenKrupp AG will build its first North American plant at a terminal on the south tip of Pinto Island in Mobile (Wilkinson, 2007). The mill is anticipated to create roughly 29,000 construction jobs and 2,700 permanent positions. With a projected cost of $115 million to build the port terminal, the project will create another 50 to 60 permanent jobs when it reaches full operating capacity in 2010. ThyssenKrupp plans to utilize the plant to convert slab steel into flat carbon and stainless steel for customers in the automotive, electrical, and appliance industries (Wilkinson, 2007).

Port Fourchon

Port Fourchon has established itself over the years as the primary service base for deepwater oil and gas activity. It is estimated that the port services 75 percent of the region's deepwater oil production (LA1 Coalition, 2009). In addition, a recent survey of future activity found that of the 165 existing and pending deepwater projects identified to date, over 50 percent are using, or plan to use, Port Fourchon as their service base (Paganie, 2006c).

After the port's E-slip filled up, Port Fourchon officials began permitting for additional acreage north of the slip, called the Northern Expansion project. Expansion plans were approved and construction started in 2001 (Paganie, 2006c).

Port Fourchon is also expanding waterfront property for lease. An additional 3,000 linear feet of bulkhead along slip B in the Northern Expansion is being constructed (Figure 30). The $12 million project has been funded by Louisiana Port Priority Grants with the local Port Commission funding 10 percent of the cost (Paganie, 2007b). Port Fourchon boasts that the demand for its services were so high that the new port expansions were leased out to Cal Dive International, Deep Marine Technologies, Tiger Tanks, and Expert Riser Solutions some 18 to 24 months before construction even began. The port's Director of Operations noted that "We are building this property as fast as we can to accommodate the needs of the oil and gas industry (Paganie, 2007b)."

In addition, the port is planning construction of a new slip, C. The slip will be approximately 7,000 linear feet long by 700 feet wide. Pending construction and mitigation approvals, slip C is expected to be dredged by 2009. Located on 600 acres, plans are underway to buy 1,000 acres for future expansion (Sullivan, 2007).

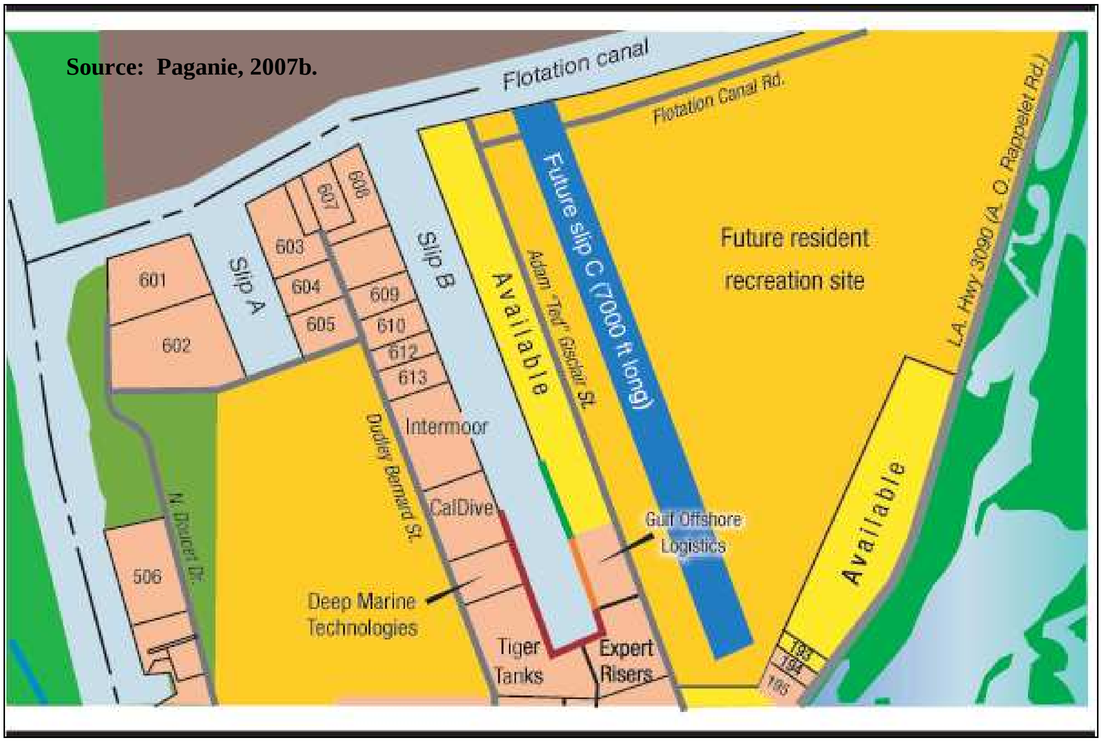


Figure 30. Port Fourchon expansion.

Venice

The Venice Port Complex, which is just east of Fourchon, is marketing its waterfront property to the offshore industry (Paganie, 2007b). According to the port, its 1,500 acre location provides the shortest travel time to well locations in the GOM, particularly the new areas of the eastern GOM that could possibly become open to new E&P activity (Paganie, 2007b). Venice is marketing its developed land in addition to a 38-acre deepwater site with over 3,500 feet of dock space (Paganie, 2007b).

Plans are also underway to dredge navigation channels deeper in the Gulf Coast. Plaquemines officials plan to deepen Baptiste Collette Bayou to facilitate additional oil and gas industry tenants. An estimated $25 million will be needed to deepen Baptiste Collette from 15 to 26 feet. OSVs need at least 16 feet or more of depth (Guillet, 2007b).

The deepened path through the Baptiste Collette from the Mississippi River to the eastern Gulf would be approximately 70 miles compared with the minimum 110 miles from Mississippi. The Baptiste Collette is the only channel available to the eastern Gulf for inland barge and offshore crew boat vessels when the Inner Harbor Navigation Channel locks are down (Guillet, 2007b).

The deepening will help revitalize Venice, which took a significant infrastructure hit after Katrina and Rita. After Katrina disrupted operations in Venice, port facilities at Morgan City and Port Fourchon picked up much of the traffic. The dredging is a last-ditch effort to revive Venice as a player in the oil and gas sector (Guillet, 2007b).

Iberia, Fourchon, and Morgan City

A five-year, $820 million state capital improvement plan was announced in April 2007 for three ports in Louisiana. Most of the state's ports are either shallow-draft inland ports or shallow-draft coastal ports. The importance of Port Fourchon, Port of Venice and the Port of Iberia and Morgan City, was evident after hurricanes Katrina and Rita. Repair crews needed to get out to the Gulf after Katrina and Rita and had to use ports that did not have deepwater channels or go to ports in other states. This increased the cost of transporting the labor and parts needed to repair platforms, rigs and pipelines (Sullivan, 2007).

The three ports dominating the capital improvement plan in 2007 were the Ports of Iberia, Fourchon and Morgan City. Improvements at the Port of Iberia include development of the Acadiana Gulf of Mexico Access Channel, a $158.9 million investment in a deepwater channel that would link the port to the GOM. At the Port of Morgan City, the Atchafalaya Dredging Project is a deepwater channel dredging project that would allow heavier vessels to access the port and the Gulf. The initial budget for the Atchafalaya Project was $160 million, but reports estimate it could cost $300 million (Sullivan, 2007). Projects at the Port of Fourchon were estimated to cost about $50 million (PAL, 2007).

A deepwater channel at the Port of Iberia would allow fabrication yards located there to begin working on structures needed for deepwater. Because of the shallow draft, companies are restricted on the size of the structure they can build (Sullivan, 2007). Increasing the channel size, therefore, greatly enhances Iberia's competitiveness for the deepwater activity market. The same holds true for the Morgan City port: a deeper channel will allow it to support operations into the growing market area of the deepwater support and construction activities.

The Louisiana Recovery Authority (LRA) has approved more than $186 million (93 percent) of the funds for the Long Term Community Recovery Program. As of September 2007, funding allocations and top priorities for local recovery projects for each parish include the following (Louisiana Speaks, 2007):

Jefferson- $14.3 million

* Drainage Master Plan and Improvements for Local Drainage
* Hurricane proof sewage infrastructure
* Hurricane Fortified, Flood Proof Animal Shelter
* Comprehensive Redevelopment Plan for Oakwood Area
* Restoration of Roadway Median Areas

Plaquemines- $12.8 million

* Comprehensive Master Plan
* Emergency Operations Centers
* Flood Gate Safety Measures
* Upgrade of Plaquemines Parish Shipyards
* Tidewater Road Drainage Infrastructure

Cameron- $8.5 million

* Cameron Square Development
* Old River Dredging and Marsh Creation
* Calcasieu River Ship Channel Dredge
* Port Feasibility Study
* Emergency Operations Command Centers in Grand Lake and Hackberry

Calcasieu Parish- $5.6 million

* Construction of the SWLA Entrepreneurial Center
* Construction of the Lake Charles Riverwalk/Parkway
* Revitalization of Downtown Lake Charles
* Establishment of Emergency Services for Public Safety
* Development of Calcasieu Comprehensive Drainage Program
* Comprehensive Wastewater Facilities Projects

St. Mary- $199,000

* Update of Hazard Mitigation Plan
* Improvement of Harry P. Williams Airport Safety and Capacity
* Interconnection of Municipal Potable Water Systems
* Update of St. Mary Emergency Preparedness Plan
* Drainage and Flood Control Improvements

4.4. Chapter Resources

American Association of Port Authorities

The American Association of Port Authorities is a trade association which represents more than 160 public port authorities in the United States, Canada, the Caribbean and Latin America. The Association provides statistics on port cargo tonnage, cargo value, and container traffic. It also has a Knowledge Library with topics such as port administration; development, operations and efficiency; security; dredging; environmental; transportation and safety.
http://www.aapa-ports.org/home.cfm

U.S. Department of Transportation, Maritime Administration (MARAD)

MARAD has a number of reports and statistics on vessel calls and market indicators:
http://www.marad.dot.gov/library_landing_page/data_and_statistics/Data_and_Statistics.htm

It also provides a number of useful publications such as: *MARAD Port Economic Impact Kit;* Public Port Finance Surveys; U.S. Public Port Development Expenditure Report; and Report to Congress on the Performance of Ports and the Intermodal System
http://www.marad.dot.gov/library_landing_page/maritime_publications/Library_Publications.htm

5. SUPPORT AND TRANSPORT FACILITIES

5.1. Description of Industry and Services Provided

Offshore oil and gas activities are supported by a considerable onshore supply and support logistics train. Support activities include providing products and services such as engine and turbine construction and repair, electric generators, chains, gears, tools, pumps, compressors, and a variety of other tools and equipment. Additionally, drilling muds, chemicals, and fluids are necessary daily inputs that have to be transported to offshore structures from onshore support facilities. Many types of transportation vessels and helicopters are used to transport workers, equipment, and materials to and from offshore platforms.

In the past, a large number of support activities were "internal" to offshore oil and gas companies. Today, a large amount of onshore support and transportation services are provided by outside third parties. Downsizing and specialization have been the primary reasons for utilizing these services on a contract basis. Industry downsizing, in particular, has reduced the numerous layers associated with oil and gas operations by many offshore producers. The use of contract services allows producers to utilize supply, transport, and logistics resources on an "as needed basis" rather than providing these support services on a full time, permanent basis. Contract support services create a significant degree of flexibility for offshore operators and allow them to keep costs down during periods of oil and gas commodity price downturns.

Onshore support and transportation services are employed by major and independent producers alike. While the support sector of the industry is very heterogeneous, all firms that operate in this sector share one common element: a large share, if not all of their business activity, profits, and earnings are highly dependent on the cyclical nature of the oil and gas industry. As will be discussed in greater detail later, this dependency has led to two different survival tactics by support and transportation firms in the Gulf: concentration and diversification. Concentration has occurred from general merger and acquisition (M&A) activity, while diversification has resulted from taking on a broader number of support and service activities from other maritime-based industries to dampen earnings impacts from falling oil and gas prices.

5.2. Industry Characteristics

5.2.1. Typical Facilities

It is difficult to characterize any type of support industry as "typical" since they provide a number of difference and specialized products and services. Firms can also take on a variety of sizes from very small, to very large. Land-based supply and fabrication centers, for instance, can be quite large and provide the equipment, personnel, and supplies necessary for the industry to function through intermodal connections at the Gulf of Mexico coast ports. The necessary onshore support segment includes inland transportation to supply bases, equipment manufacturing, and fabrication. The offshore support involves both waterborne and airborne transportation modes.

The physical attributes of a port can determine the number and type of tenants and port users. For example, the Port of Iberia is the Gulf Coast's largest shallow water draft port, with more than 100 companies housed at the port that employ over 5,000 workers (Port of Iberia, 2007).

Port Fourchon is the most significant deepwater port, and according to figures published by Port Fourchon, some 50 percent of current and future deepwater projects plan to service their activities from Fourchon (Greater Lafourche Port Commission, 2006).

General Support Facilities

Support facilities are diverse but there are a number of common features such as being located at or near a port that serves as a point of disembarkment, and tends to have physical attributes that complement support activities. In fact, business practices at most ports are directed at developing and providing the necessary infrastructure for the service sector to support offshore drilling and production activities. Most support/service companies have one or more of the following infrastructure attributes at their respective locations:

- Protected wharfs, docks, and dry-docks (to load and provide temporary storage of materials and crews destined for offshore locations);
- Storage and demurrage facilities (for longer term equipment and material storage);
- Crew housing;
- Access to intermodal transportation access (i.e., roads, inter-coastal waterway, railways);
- Communication facilities/equipment; and
- Workshops and machine and tooling shops.

Repair and Maintenance Yards

A significant portion of repair and maintenance support work that is conducted at platform fabrication facilities and shipyards is associated with maintaining vessels and equipment for drilling and production activities. Specific repair methods vary from job to job in both time and scope and can last from one day to over a year. Repair jobs often have severe time constraints requiring work to be completed as quickly as possible in order to get the equipment back to service. This is particularly true during periods of high oil and gas prices, or hurricane restoration and recovery, where a limited amount of working equipment and personnel is of high value. In many cases, a number of repair-oriented tasks are pre-fabricated and then taken offshore for final assembly and repair. This is often the case with such activities as piping, ventilation, electrical and other machinery. Typical maintenance and repair operations include (USEPA, 1997):

- Blasting and repainting the ship hulls, freeboard, superstructure, and interior tanks and work areas;
- Major rebuilding and installation of machinery such as diesel engines, turbines, generators, pump stations, etc;
- Systems overhauls, maintenance and installation (e.g., piping system flushing, testing and installation);

- System replacement and new installation of systems such as navigational systems, combat systems, communication systems, updated piping systems, etc.;
- Propeller and rudder repairs, modification, and alignment; and
- Creation of new machinery spaces through cut outs of the existing steel structure and the addition of new walls, stiffeners, vertical, webbing, decking, etc.

Supply Bases

Supply bases can range from large yards, offering a range of services from full logistics management, to smaller shops that supply one or many of the items needed on an offshore platform or marine vessel. Larger supply companies (such as Seacor Holdings or Hornbeck Offshore Services) who offer supply chain management services move equipment and supplies from land based supply houses to offshore drilling platforms from various locations along the GOM. Other, smaller suppliers act more or less like a combined retail and equipment rental store, supplying anything from crane rentals, warehouse space, trailer rentals, and dispatch services, to engine parts, fuel, navigation tools, potable water, and lubricants including motor oil, hydraulic oil, natural gas compressor oils, grease, gear oil, and synthetics.

Heliports

Heliports are centralized locations where fixed and rotary wing aircraft (i.e., helicopters) disembark for offshore service. Helicopters move crew and equipment to offshore areas. While supply boats are typically used for short-haul service, helicopters are the primary means of transportation for longer distances as well as instances when speed of delivery (equipment, personnel) may be pressing. For example, the Bell 206L Long Ranger has a fuel capacity of 110 gallons and can travel up to 320 nautical miles (Flight Safety Foundation, 2005). Its cruising speed at sea level is about 130 knots (Flight Safety Foundation, 2005). This would include most deepwater platforms and facilities in the GOM. A supply boat (specifically a crew boat for transporting personnel), on the other hand, has a cruising speed to 20 to 35 knots (Barrett, 2005).

Heliport service providers usually retain a mix of size and quantity of aircraft, with their fleets categorized into small, medium, and large helicopters. The small helicopters are better suited for support of production management activities, daytime flights and shorter routes. These aircraft typically hold four to six passengers. Many of the shallow-water production facilities in the GOM are too small to accommodate anything larger than a small helicopter, making the GOM a strong market for this group of helicopters. Medium helicopters are the most versatile part of an air transportation company’s fleet because they are equipped to fly in a variety of operation conditions and capable of flying longer distances and carrying larger payloads than small helicopters. Medium helicopters hold up to 13 passengers. Large helicopters are also able to fly in a variety of different operations, but they can also perform in harsh weather conditions, carry larger payloads, fly longer distances, and hold up to 25 passengers. Medium and large helicopters are most commonly used for crew changes on large offshore production facilities and drilling rigs. The use of larger helicopters tends to be concentrated in international markets since their drilling locations are typically more remote and they have limited onshore infrastructure support locations (SEC, 2007a).

Crew Services

A number of companies provide services to the crews that live on the offshore rigs. These companies provide catering (delivering and serving hot meals), and laundry (cleaning and maintenance services) for crew barracks. A number of companies also provide on-site paramedics. Paramedics provide more than medical services. They are part of the crew, offering an additional service that improves operational efficiency and productivity (Phudpucker.com, 2009).

Offshore Support Vessels

Any functioning offshore oil and gas production operation requires frequent transportation of personnel, supplies, and materials to and from offshore platforms. The large scale of operations in the GOM has led to the development of a specialized fleet of OSVs that were discussed in a prior chapter.

OSVs are required in virtually every stage of the offshore drilling process. In some instances, support vessels may be solicited and bid for particular activities or projects. In some cases, these solicitations will require the offshore support company to design and build a support vessel to particular specifications in order to meet the requirements of the exploration or production project (SPO, 2007).

Support vessels are also needed to assist in the construction phase of field development including the supply and installation of platforms, the laying of pipelines to shore-based storage facilities, and the installation of associated offshore loading facilities. Once the necessary infrastructure is in place, there is a continuing requirement for the transportation of food, stores, personnel, and maintenance equipment to the platforms. OSVs can also perform fire fighting as well as oil recovery operations in case of an oil spill at an offshore platform.

Accommodation management of platforms includes laundry and housekeeping services, including maintenance of living quarters. Offshore accommodations can drive operating costs up substantially, but these costs are typically unavoidable given new safety regulations and the need to attract skilled labor through comfortable accommodations and other non-salary work environment benefits. Some companies are even building accommodation barges, such as the one pictured in Figure 31 called a “floatel.” This particular facility is named the “Offshore Olympia,” and can hold up to 500 people and can be moored alongside a deepwater production facility.

Figure 31. Offshore accommodations.

Other services often provided by support companies include, but are not limited to security, medical services, waste management, and entertainment. One of the most critical offshore support services provided is that of potable water transportation and waste management. Waste disposal is important since numerous federal and state laws require the safe disposal of offshore drilling wastes, some of which are returned to land for disposal. Many of the offshore supply companies transport the wastes in special tanks on OSVs from the offshore site to onshore transfer facilities. From there the wastes are transferred to another transportation mode and sent to a final point of disposition. These details are discussed in greater detail in the chapter on Waste Disposal Facilities.

A barometer of OCS service base significance is found in private sector platform plans submitted to the BOEM. While actual OSV vessels may be registered to a specific port, and use this port as their home mooring/berth, these same vessels may in fact actually use other ports for picking up supplies, refueling, transferring crew and cargo, etc. Platform plans specify the specific service base from which supplies and necessary equipment are being loaded and transported en route to the platform; these plans highlight ports that may be underrepresented from the USACE registry databases.

5.2.2. Geographic Distribution

There are many onshore facilities that support the offshore industry along the Gulf Coast. Figure 24 identifies major support bases along the coast that are key supply points for goods and services for OCS installations such as wells, rigs, platforms, pipe laying operations, and many additional energy projects in the Gulf of Mexico. From these ports, a variety of ships and support vessels together make thousands of trips annually to provide this support. Although operations are spread all along the Gulf Coast, most producing deepwater fields have service bases in southeast Louisiana (French et al., 2006).

Exploration and production in the Gulf is concentrated in three areas (Figure 32): Western, Central and Eastern Gulf regions. Located adjacent to these three regions are hundreds of contractors operating ports, maintenance and shipbuilding facilities, as well as crew bases, and other supporting industries such as pipe-making and pipe-laying.

Western GOM

The Western Gulf of Mexico Planning Area extends from South Padre Island, Texas, to the Sabine River, on the Texas – Louisiana border. According to December 2003 BOEM estimates, the western Gulf area has approximately 427 million barrels of oil and 5.9 Tcf of gas of remaining proved reserves (USDOI, MMS, 2006d). The major onshore key ports and facilities are located near the Corpus Christi, Galveston, and Port Arthur areas.

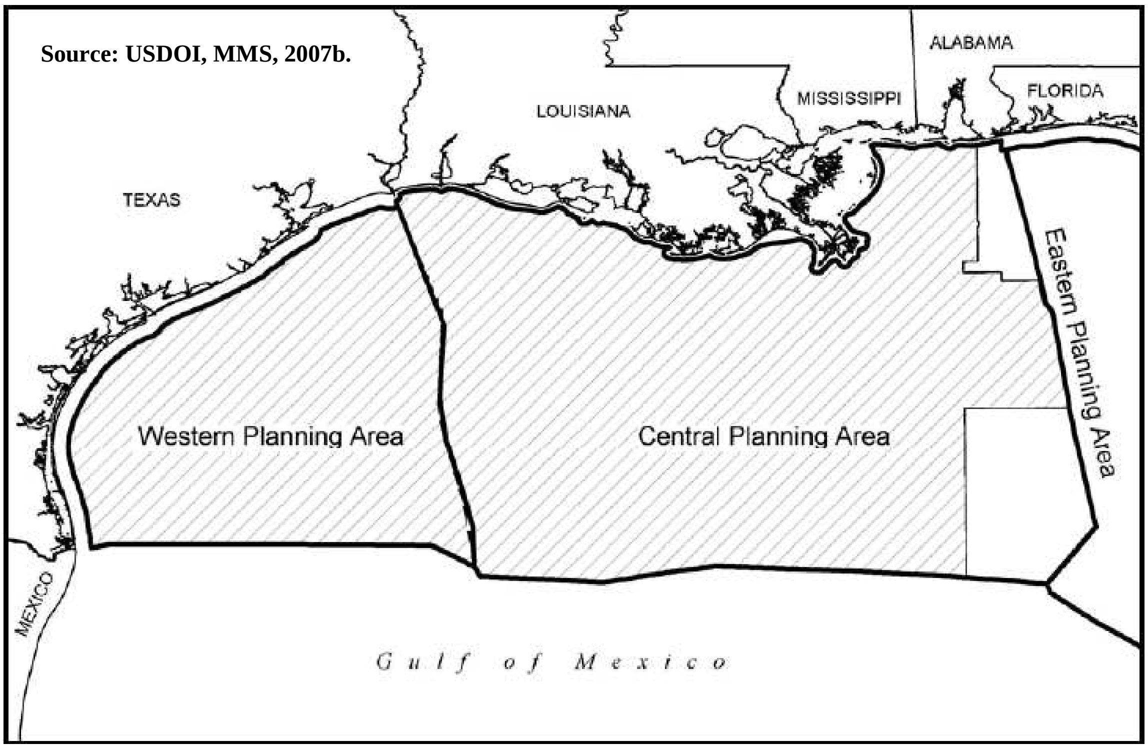


Figure 32. Gulf of Mexico planning areas.

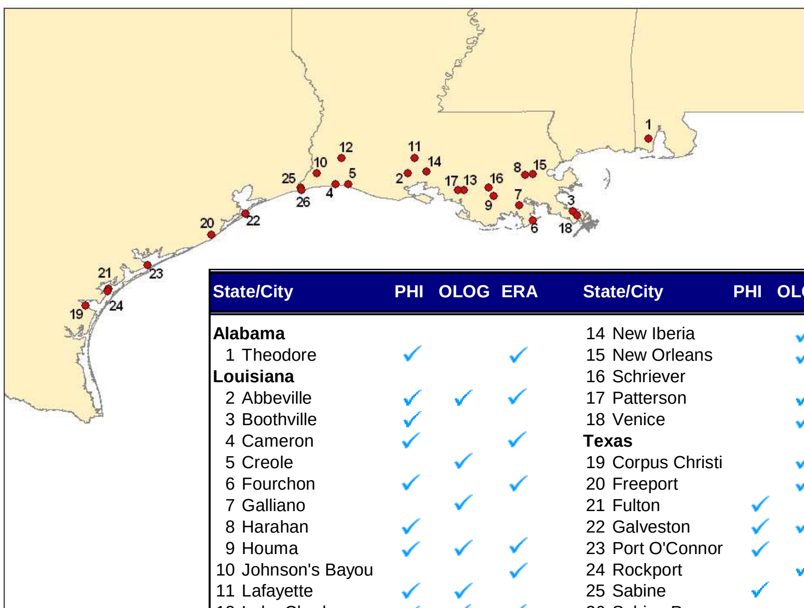
Central GOM

The Central Gulf of Mexico Planning Area extends from the Sabine River to Baldwin County, Alabama. According to December 2003 BOEM estimates, the Central Gulf area has approximately 4,443 million barrels of oil and 15.5 trillion cubic feet of natural gas of remaining proved reserves (USDOI, MMS, 2006d). Major ports and facilities are located in Morgan City, Venice, Intracoastal City, Cameron and Fourchon in Louisiana. Additional facilities are located near Biloxi, MS.

Eastern GOM

The eastern GOM Planning Area extends along the Gulf's northeastern coast for some 700 miles, from Baldwin County, Alabama, southward about 300 miles to the Florida Keys. The area encompasses approximately 76 million acres, with water depths ranging from tens of feet to over 9,900 feet. Since the late 1980s, a limited amount of OCS activity has taken place in this planning area because of administrative deferrals and annual congressional moratoria. However, recent legislation has allowed the development of 8.3 million acres within the Eastern area of the Outer Continental Shelf, therefore some development is imminent. In 2000, BOEM estimated that between 6.95 and 9.22 trillion cubic feet of natural gas and between 1.57 and 2.78 billion barrels of oil and condensate are contained in the Eastern Gulf of Mexico Planning Area (USDOI, MMS, 2007c).

Heliports are typically located at small and medium sized regional airports throughout the GOM and can be main and auxiliary (or remote) heliport facilities. Main facilities, usually located at regional airports, host most of the main aircraft hangers, aircraft repair yards, as well as administrative offices. Figure 33 shows the locations in which the largest three providers operate. Almost any location in the Gulf of Mexico can be reached by any one of these locations. For instance, both PHI and ERA operate out of Fourchon, Louisiana, as indicated by the checkmarks in the table. Fourchon is labeled as point 6 on the map.



State/City	PHI	OLOG	ERA	State/City	PHI	OLOG	ERA
Alabama				14 New Iberia		✓	
1 Theodore	✓		✓	15 New Orleans		✓	
Louisiana				16 Schriever			✓
2 Abbeville	✓	✓	✓	17 Patterson		✓	
3 Boothville	✓			18 Venice		✓	✓
4 Cameron	✓		✓	**Texas**			
5 Creole		✓		19 Corpus Christi		✓	
6 Fourchon	✓		✓	20 Freeport		✓	
7 Galliano		✓		21 Fulton	✓		
8 Harahan	✓			22 Galveston	✓	✓	✓
9 Houma	✓	✓	✓	23 Port O'Connor	✓		
10 Johnson's Bayou			✓	24 Rockport		✓	
11 Lafayette	✓	✓		25 Sabine	✓		
12 Lake Charles	✓	✓	✓	26 Sabine Pass			✓
13 Morgan City	✓		✓				

Source: PHI, Inc., 2008; SEC, 2005c; SEC, 2005d.

Figure 33. Locations of major helicopter service providers.

5.2.3. Typical Firms

There are numerous and varied companies within the GOM offshore support and transport sector. The Atlantic Communications 2008 *Gulf Coast Oil Directory's* section on Marine Supply Bases – Expediters & Chandlers lists 56 companies with 87 locations along the Gulf Coast. Figure 34 shows the locations of these supply base companies.

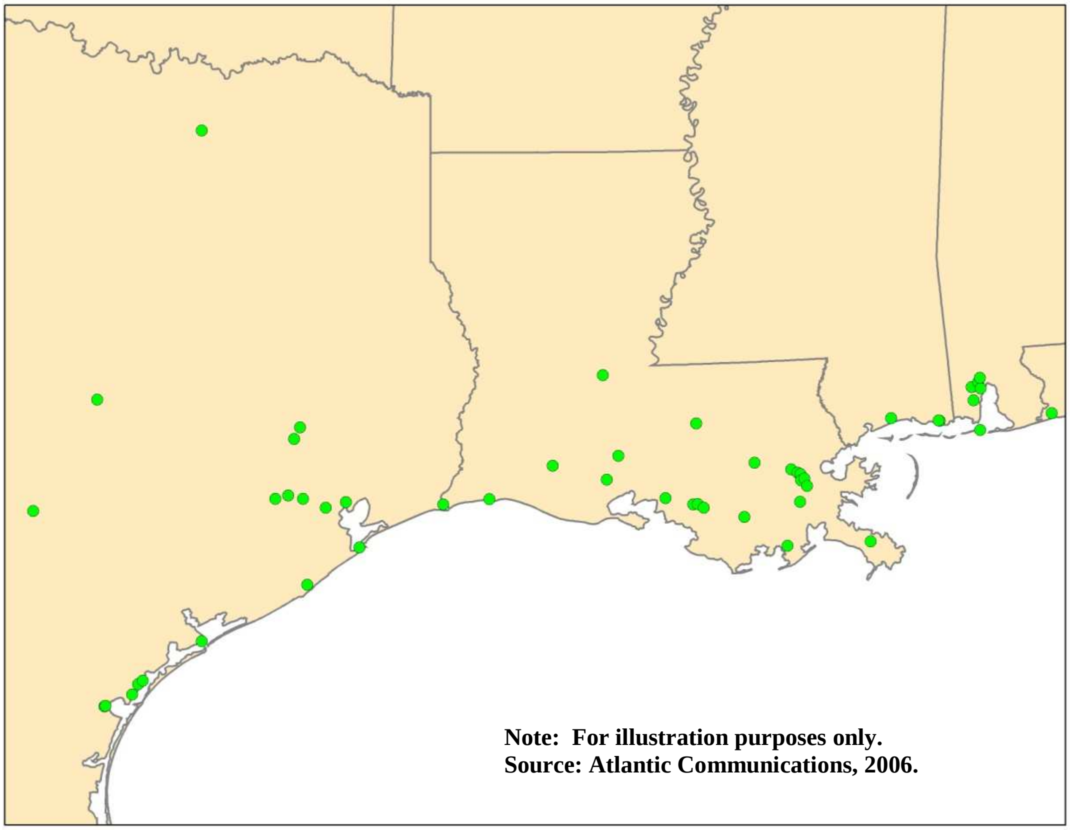


Figure 34. Locations of marine supply bases.

Companies range in size from less than 25 employees and one location, to over 100 employees at several locations (Atlantic Communications, 2006). These supply bases can range from large yards, offering multiple services including full logistics management, to smaller shops that supply one or many of the items needed on an offshore platform or marine vessel. The following list is an example of just some of the services or products listed by these companies:

- Electrical cables for offshore marine applications.
- Navigational supplies and weather instruments.
- Broker of tugs, offshore boats, crewboats, barges.
- Marine supplies, dock, harbor and vessel mooring, hardware.
- Temporary accommodation cabins.
- Living quarters and temporary accommodations, galleys, diners, utility buildings.
- Wire rope, marine and lifting equipment.
- Marine diesel fuel and lubricants (purchase, sell, store and deliver).
- Loading and offloading dock, crane service, pipe storage, office space.
- Dispatchers, material expediters, rig clerks, computer sales and rentals.

- Complete galley, deck and engine supplier.
- Rig and vessel fueling.

In addition to the supply bases, there are 23 catering companies listed in Atlantic Communications' Gulf Coast Oil Directory. Some of the largest food management companies with operations in the GOM include Delta Catering, Sodexho Alliance (via Delta Catering, and Energy Catering Services, Inc.), the Craig Group, Compass Group (via Eurest Support Services), Sunoco, Trinity Catering, and Taylor's International. All have offices, or affiliates, working in the GOM.

Delta Catering, of Harahan, Louisiana, works exclusively in the GOM region and focuses its efforts on servicing a small number of customers (Delta Catering, 2008). Delta, along with Energy Catering Services, Inc., is now part of Sodexho Alliance, a $14 billion worldwide company. One of their biggest clients is ConocoPhillips, which operates the Magnolia Blossoms deepwater rig that houses 92 people. The company provides meals, as well as laundry and cleaning services. The Sodexho crew consists of 12 cooks, galley hands, and others (Universal Sodexho, 2008a and 2008b).

Other catering companies include

- Eurest Support Services, a division of the Compass Group, is the leading provider of specialist foodservice and related support services in the offshore industry.

- Sunoco, of Houma, LA, is a private company that provides catering, housekeeping and grocery sales exclusively for the offshore industry.

- Taylor's International, of Lafayette, LA, is an international company with over 10,000 employees in 25 countries (Taylors International Services, Inc., 2007).

There are three main independent providers of air transportation services. These include: Bristow Group (formerly Offshore Logistics); PHI, Inc. (formerly Petroleum Helicopters, Inc.); and Seacor (formerly ERA Aviation) (Figure 35). Each company operates numerous locations (as shown in Figure 34) along the Gulf in addition to those activities conducted at their main headquarters. The primary business of all three is to provide crew and equipment transportation services to offshore oil and gas companies. Together, these three companies account for nearly 80 percent of the aircraft available in the Gulf. Other competitors in this sector are smaller, privately-owned businesses or subsidiaries of larger companies. Among the smaller companies are Evergreen, Houston Helicopters and Rotorcraft Technologies.

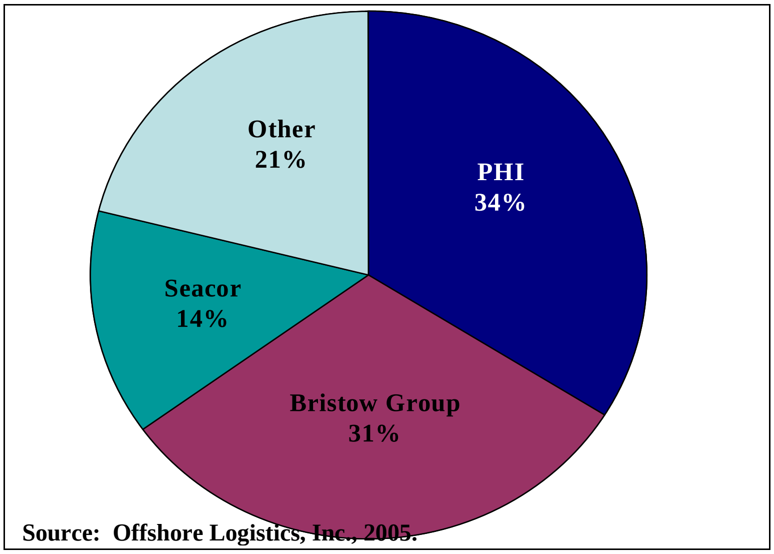


Figure 35. Market shares of major helicopter service providers in the Gulf.

The largest OSV companies in the GOM market include Seacor Holdings with 107 vessels operating in the GOM; Trico operates 68 vessels (including 44 supply vessels and 7 crew boats); Hornbeck Offshore Services operates 25 new generation (i.e. deepwater) OSVs; Tidewater, Inc. has 57 vessels; and Hercules Offshore, Inc. operates 9 jackup rigs and 64 lift boats (SEC, 2006d; SEC, 2006e; SEC, 2006f; SEC, 2006g; SEC, 2006h). There are also numerous smaller entities, with over 150 boat owners operating over 850 boats in the Gulf of Mexico (Barrett, 2005).

Competition is usually strong for the support and transport sectors. For example, an oil and gas company will select one helicopter provider for all services provided in the Gulf. Bristow Group's annual report explains that 18 percent of their Helicopter Services' revenues were from Shell Oil Company in fiscal year 2007. During their fiscal year ending in March 2007, their top ten customers accounted for more than 55 percent of gross revenue (SEC, 2007a). PHI's largest customer provides the company with 17 percent of its operating revenues (SEC, 2006i). And, ERA Aviation's (now part of Seacor) ten largest customers account for 46 percent of its operating revenues (SEC, 2006e). The loss of any one customer could have a significant impact on any company's operations. While many contracts are awarded through a competitive bidding process, customers will usually make their decision based on price and aircraft preference (SEC, 2006e).

5.2.4. Regulation

The numerous regulations surrounding the oil and gas industry affect those companies who offer support and transport services. The regulations extend to local, state, federal, and international levels. Among the U.S. governmental agencies who have jurisdiction over the operations are the U.S. Department of Transportation, Department of Homeland Security and agencies under its auspices (such as the U.S. Coast Guard and the U.S. Customs and Border Protection), Environmental Protection Agency and the National Transportation Safety Board. In addition, private industry associations, such as the American Shipping Bureau or the American Association of Port Authorities also oversee certain aspects of the business (SEC, 2006d).

Regulations that are specifically built just for an oil and gas company will also affect the support and transport companies. For example, the Outer Continental Shelf Lands Act (OSCLA) gives the government broad discretion in regulating the release of offshore resources of oil and natural gas. If the government were to decide to restrict the availability of leases in the GOM, then all the support and transport companies would be strongly affected (SEC, 2006d).

Although onshore support services are not economically regulated, they are subject to numerous environmental and safety statutes and guidelines. Repair and maintenance, because it is a part of, and often referred to in conjunction with, the shipbuilding industry, is subject to the same regulations as discussed in Chapter 2, in the Regulations section. This includes the Resource Conservation and Recovery Act, United States Code, Title 10, Section 7311, the Clean Air Act, the Clean Water Act, the Comprehensive Environmental Response, Compensation, and Liability Act, and the Jones Act.

Other regulations that affect the onshore support industries may include (unless otherwise noted, the remainder of this section is from USEPA, 1997):

Emergency Planning and Community Right-To-Know Act

The Superfund Amendments and Reauthorization Act (SARA) of 1986 created the Emergency Planning and Community Right-to-Know Act (EPCRA, also known as SARA Title III). This statute is designed to improve access to the public on information about chemical hazards. It also helps to facilitate the development of chemical emergency response plans by state and local governments. EPCRA required the establishment of state emergency response commissions (SERCs). These commissions are responsible for coordinating certain emergency response activities and for appointing local emergency planning committees (LEPCs). EPCRA and the EPCRA regulations establish four types of reporting obligations for facilities that store or manage specified chemicals:

- EPCRA §302 requires facilities to notify the SERC and LEPC of the presence of any extremely hazardous substance (the list of such substances is in 40 CFR Part 355) if it has such substance in excess of the substance's threshold planning quantity, and directs the facility to appoint an emergency response coordinator.

- EPCRA §304 requires the facility to notify the SERC and the LEPC in the event of a release equaling or exceeding the reportable quantity of a CERCLA hazardous substance or an EPCRA extremely hazardous substance.

- EPCRA §311 and §312 require a facility at which a hazardous chemical, as defined by the Occupational Safety and Health Act, is present in an amount exceeding a specified threshold to submit to the SERC, LEPC, and local fire department material safety data sheets (MSDSs) or lists of MSDSs and hazardous chemical inventory forms (also known as Tier I and II forms). This information helps the local government respond in the event of a spill or release of the chemical.

- EPCRA §313 requires manufacturing facilities included in SIC codes 20 through 39, which have ten or more employees, and which manufacture, process, or use specified chemicals in amounts greater than threshold quantities, to submit an annual toxic chemical release report. This report, known commonly as Form R, covers releases and transfers of toxic chemicals to various facilities and environmental media, and allows EPA to compile the national Toxic Release Inventory (TRI) database (USEPA, 1997).

All information submitted pursuant to EPCRA regulations is publicly accessible, unless protected by a trade secret claim.

Safe Drinking Water Act

Under the Safe Drinking Water Act (SDWA), the EPA is required to establish regulations to protect human health from contaminants in drinking water. The SDWA authorizes EPA to develop national drinking water standards and create a joint Federal-State system to ensure compliance. It also directs EPA to protect underground sources of drinking water through the control of underground injection of liquid wastes. EPA and authorized states enforce the primary drinking water standards and the contaminant-specific concentration limits that apply.

Toxic Substances Control Act

The Toxic Substances Control Act (TSCA) gave the EPA authority to create a regulatory framework to collect data on chemicals in order to evaluate, assess, mitigate, and control risks that may be posed by their manufacture, processing, and use.

Under TSCA §5, EPA has established an inventory of chemical substances. If a chemical is not already on the inventory, and has not been excluded by TSCA, a pre-manufacture notice (PMN) must be submitted to EPA prior to manufacture or import (USEPA, 1997). The PMN must identify the chemical and provide available information on health and environmental effects. If available data are not sufficient to evaluate the chemical's effects, EPA can impose restrictions pending the development of information on its health and environmental effects (USEPA, 1997). EPA can also restrict significant new uses of chemicals based upon factors such as the projected volume and use of the chemical. Under TSCA §6, EPA can ban the manufacture or distribution in commerce, limit the use, require labeling, or place other restrictions on chemicals that pose unreasonable risks. Among the chemicals EPA regulates under §6 authority are asbestos, chlorofluorocarbons (CFCs), and polychlorinated biphenyls (PCBs).

Under TSCA §8, EPA requires the producers and importers of chemicals to report information on chemicals' production, use, exposure, and risks. Companies producing and importing chemicals can be required to report unpublished health and safety studies on listed chemicals and to collect and record any allegations of adverse reactions or any information indicating that a substance may pose a significant risk to humans or the environment (USEPA, 1997).

Heliports are regulated by a number of different federal and state agencies. All flight operations, for instance, are regulated by the Federal Aviation Administration (FAA). Aircraft accidents are regulated by the National Transportation Safety Board (NTSB). Standards related to workplace health and safety are regulated by the federal Occupational Safety and Health Act (OSHA).

The FAA holds jurisdiction over most aspects of the air transportation business. This includes oversight of flight operations, personnel, aircraft, and ground facilities. Air transportation providers must obtain an Air Taxi Certification from the FAA, to transport personnel and equipment to offshore regions. The FAA requires air transportation companies to file periodic reports associated with flight operations.

Most air transportation companies are also subject to certain regulations associated with the Communications Act of 1934 because of ownership and operation of radio and communications equipment used for flight operations.

5.3. Industry Trends and Outlook

5.3.1. Trends

According to the FAA, there are 599 heliports in the Gulf Economic Impact Areas.

Offshore support and transportation facilities are highly dependent upon drilling and production activities, which, in turn, are highly dependent upon oil and gas commodity prices. To survive changes within the oil and gas industry, such as further exploration to deeper waters, support and transport companies must be dynamic and seek diversification opportunities where possible. The supply and transport side of the offshore industry is very cyclical and can be one of the first to feel the sting of price-induced industry downturns. During periods of E&P contraction, discretionary supply, repair, and maintenance activities are one of the first to be cut to reduce E&P costs. The offshore support sector's main defense to these downturns is through efficiency/innovation, diversification, and/or consolidation (i.e., mergers or acquisitions). The 1990s was a decade in which oil and gas companies, seeking to protect shareholder value, consolidated and formed alliances. This process also resulted in an increase and realignment in contract support services.

Oil and gas service companies of all types have had to seek diversification in both the types of industries they serve, and the regions they serve. For instance, in the early 1990s, 75 to 80 percent of PHI's operating revenues were generated by oil and gas transportation services in the GOM (SEC, 1994). This number has declined to just 62 percent in 2004 and 60 percent in 2006 (SEC, 2006i). After the 1986 oil price decrease, Evergreen Helicopters turned its attention to diversifying into spraying crops and other agricultural applications. Evergreen, as well as PHI, Inc. has also turned to emergency medical transportation as a means for revenue diversification. The share of PHI's operating revenues from these services has increased from 27 percent in 2004 to 32 percent in 2006 (SEC, 2006i).

Increasing activity in deepwater offshore activity is forcing many in the service sector of the industry to adopt more innovative methods and new technologies to remain competitive. Domestic and international competition, in addition to a general shortage in skilled labor, are also forcing the service support activities to use more advanced technologies. One example of new support technologies being utilized in offshore operations is the deployment of undersea fiber optic cable. A fiber optic network can increase productivity, reliability, and safety, allowing companies to use digital information and manage offshore operations collaboratively with personnel onshore (Munier and Haaland, 2008). BP has recently installed and deployed a new fiber optic network in the GOM called the "BP BoM FON." The BP network includes a 1,100 kilometer, two optical fiber pair trunk cable between Pascagoula, Mississippi, and Freeport, Texas (Munier and Haaland, 2008). There are strategically located branches that serve the platforms. The network also has expansion modes that will allow it to serve existing platforms as well as any new platforms (Munier and Haaland, 2008). In addition to more efficient operations and better communication, the network may be used during storm events. Platforms could possibly remain operational, or if evacuated, stay online longer and return to production faster using this network (Munier and Haaland, 2008).

Technological developments can also allow for safer flying and improved general performance. For instance, a new memory card, called ALERTS, was developed by Air Logistics and Appareo Systems in 2007 to store flight data. This information can be uploaded onto a PC and will be available within some helicopters including those in the GOM. By reviewing the data from each flight, flight crews can use the information to fly safer, help in training, and in accident investigations (Bristow Group, 2007).

Greater total (and relative) deepwater activities in the GOM are forcing significant changes on the transportation industry in the region. For example, the helicopter and vessel industries must have the capability of traversing longer distances with more cargoes that were necessary even a decade ago. Upgrading vessels will be important, particularly given the current age of the OSV fleet. Today, the useful life of OSVs is considered to be around 20 to 25 years yet the average age of conventional (180' or less) OSVs is around 26 years (December 2005), meaning that a significant transformation from older, smaller vessels to new larger and deepwater capable vessels should occur if industry is going to remain competitive (SEC, 2006d).

Onshore support facilities have also had to change their configurations in order to support deepwater vessels that require more draft. Since fewer ports have such access, dredging operations at existing facilities and contractor expansion to areas that can handle such vessels have occurred. This has led to heated competition between port facilities. Many support companies have multiple locations among the key port facilities. For instance, Bollinger Shipyards has locations in Texas City, Calcasieu, Morgan City, Lockport, Fourchon, as well as other locations in the Central Gulf Region (Bollinger Shipyards, 2008).

According to a recent report by the BOEM, onshore service bases for deepwater production will continue to grow in southeastern Louisiana. Pending exploration plans and development operations coordination documents filed with BOEM indicate that southeastern Louisiana will remain the concentrated location for shore-based support, with additional support coming from southwestern Louisiana, Mississippi and the Texas coast. Figure 36 shows future development plans for service bases (USDOI, MMS, 2006d).

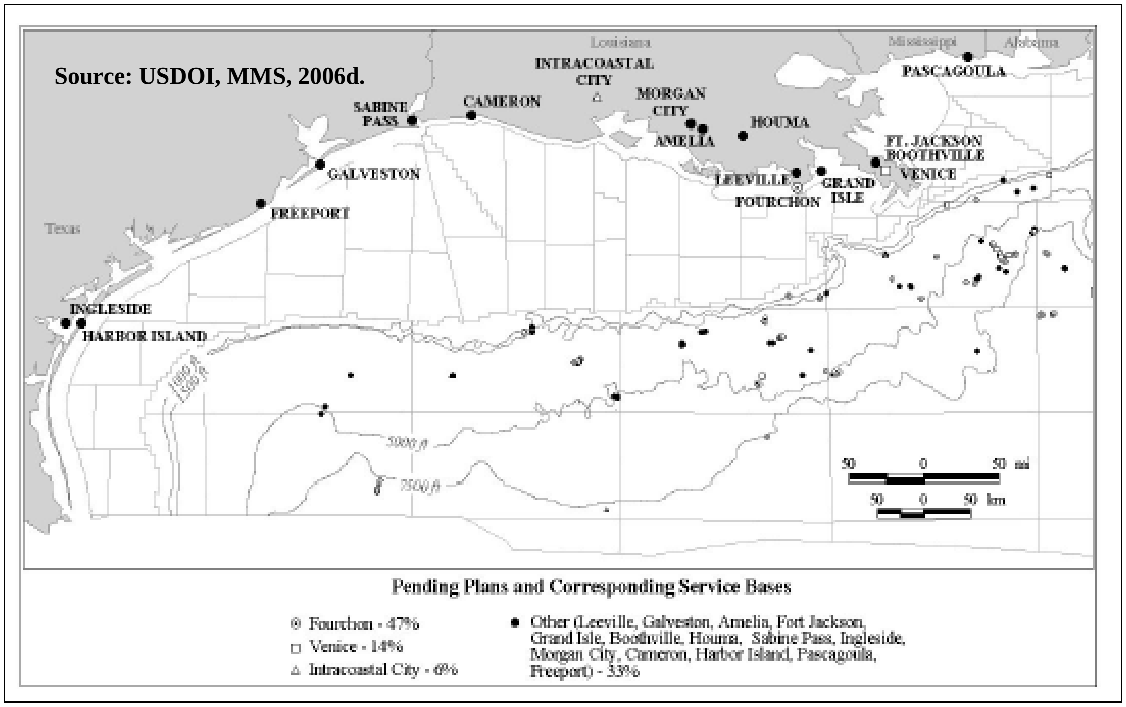


Figure 36. Pending plans and corresponding service bases.

5.3.2. Hurricane Impacts

The 2005 hurricanes caused extensive damage to the oil and gas industry in general, but in particular, the support and transport sector was severely hurt. According to Michael Kearns, a spokesperson for the National Ocean Industry Association (NOIA) in Washington, onshore support infrastructure took some of the hardest hits during the 2005 season of hurricanes. NOIA noted that while offshore platforms may have survived, the people onshore who run them, and the facilities and supply boats and everything connected to those support activities "took a significant beating (McCulley, 2006)."

The damage from the hurricanes was quite severe for some service-related companies. Due to Hurricane Katrina, Bristow Group suffered a total loss of its Venice, Louisiana, shore base facility. Further, Hurricane Rita severely damaged the Bristow's Creole, Louisiana, base and flooded its Intracoastal City, Louisiana, base. The destruction required the company to make $2.8 million in insurance recoveries that were offset by $2.6 million in involuntary conversion losses. Ultimately, the Intracoastal base was reopened in December 2005, the Venice base was reopened in March 2006, and the Creole base was back in business in April 2006 (SEC, 2007a).

While the 2005 hurricanes resulted in significant damage for some offshore support companies, many saw an increase in operations and overall revenues and profitability. This increase in activity was driven in large part by the 2005 storms as well as the high crude oil and natural gas price environment that existed after the storms' departure. Seacor's operating revenue in the GOM region increased $46 million as compared to the prior year's quarter (SEC, 2006e). Trico Marine Services reported that for its GOM supply vessels, average day rates increased 71 percent for the year ended December 31, 2006, compared with the same period in 2005. Utilization also increased six percent for these vessels during the year ended December 31, 2006, compared with the same period in 2005, inclusive of their stacked vessel fleet. The increase in both day rates and utilization was a result of the increased demand due to decreased vessel supply and work related to assessment and repair of damage from hurricanes in 2005 (SEC, 2006f).

5.3.3. Outlook

It is apparent that the oil and gas industry continues to thrive in the Gulf of Mexico in large part due to the recent, post-2005 increase in fossil fuel prices. Support activities for the industry come from a logistical value-chain that links all phases of the operation to its corresponding support needs, and in turn, to the local communities providing that support in the form of products or services. Land-based supply and fabrication centers provide the equipment, personnel, and supplies necessary for the industry to function through intermodal connections at the Gulf Coast ports. The necessary onshore support segment includes inland transportation to supply bases, equipment manufacturing, and fabrication. The offshore support involves both waterborne and airborne transportation modes.

As demand for the oil and gas industry intensifies, so does the demand for those companies providing support and transport facilities. In a BOEM report on oil and gas production forecasts for 2004 to 2013, it was estimated that oil production would reach about 2 million barrels per day for a number of years, although there would be a short-term decline in total GOM production (USDOI, MMS, 2004b). The oil and gas industry was expected to spend about $291 billion in 2007, compared to $268 in 2006, an increase of nine percent. Although much of that increase will be spent outside of North America, the outlook for North America still sees a gain (Snieckus, 2007).

Any expected increase in activity in new areas of the GOM, including those in the Eastern Planning Region, would lead to more services needed by the oil and gas industry, thus driving the support and transport sector as well. Most offshore service industries tend to be cyclical, depending upon the price of oil and gas, which drives exploration efforts, and the extent of economic growth, which drives the construction market.

The outlook for the helicopter transportation industry continues to look favorable so long as crude oil and natural gas prices continue to be robust. Resilient prices result in continued activity in both deepwater regions and traditional producing areas of the GOM. High and sustained demand increases effective utilization that allows helicopter companies to increase their rates, which in turn allows them to grow their fleets. These conditions are expected to continue for a number of years. Both Bristow and PHI have deliveries scheduled for new helicopters throughout 2007 to 2013. Bristow is acquiring 15 new medium-sized helicopters between 2007 and 2013, and PHI ordered 30 additional medium and light aircraft for service, plus two additional transport category aircraft, to be delivered in 2007 to 2008 (SEC, 2007a and 2006i).

5.4. Chapter Resources

Atlantic Communication's Gulf Coast Oil Directory
Includes a wide range of data from company name, address, web and email addresses to contact names with titles, direct phone numbers, and email addresses all organized alphabetically by industry categories. Also included is "Company Detail" information such as company size, revenue, areas operated in last 12 months, operations onshore or offshore, and stock information for publicly traded companies.
http://www.oilonline.com/Directory/DirectoriesDatabases.aspx

U.S. Securities and Exchange Commission
Quarterly and annual reports of operations for publicly traded companies are filed with the Securities and Exchange Commission.
http://www.sec.gov/edgar/searchedgar/companysearch.html

Workboat.com
Provides daily news reports and a weekly newsletter for the commercial marine industry. It also provides historic industry statistics on day rates and fleet utilization.
http://www.workboat.com/

6. WASTE MANAGEMENT FACILITIES

6.1. Description of Industry and Services Provided

A variety of different types of wastes are generated by offshore oil and gas E&P activities along the GOM. Some wastes are common to any manufacturing or industrial operation (e.g., garbage, sanitary waste (toilets), and domestic waste (sinks, showers)), while others are unique to the oil and gas industry (e.g., drill fluids and produced water). Most waste must be transported to shore-based facilities for storage and disposal. The different types of waste generated as a result of offshore exploration and production activity include:

- Solids, such as drill cuttings, pipe scale, produced sand, and other solid sediments encountered during drilling, completion, and production phases.

- Drilling muds, either oil-based, synthetic, or water-based.

- Aqueous fluids having relatively little solids content, such as produced waters, waters separated from a drilling mud system, clear brine completion fluids, acids used in stimulation activities, and wash waters from drilling and production operations.

- Naturally Occurring Radioactive Materials (NORM), such as tank bottoms, pipe scale, and other sediments that contain naturally high levels of radioactive materials.

- Industrial hazardous wastes, such as solvents and certain compounds with chemical characteristics that render them hazardous under Subtitle C of the Resource Conservation and Recovery Act and thus not subject to the exemption applicable to wastes generated in the drilling, production, and exploration phases of oil and gas activities.

- Non-hazardous industrial oily waste streams generated by machinery operations and maintenance, such as used compressor oils, diesel fuel, and lubricating oils, as well as pipeline testing and pigging fluids.

- Municipal solid waste generated by the industry's personnel on offshore rigs, platforms, tankers, and workboats.

The onshore infrastructure network needed to manage the spectrum of waste generated by offshore E&P activities can be divided into three categories:

- Transfer facilities at ports, where the waste is transferred from supply boats to another transportation mode, either barge or truck, toward a final point of disposition;

- Special-purpose waste management facilities that are dedicated to handling particular types of waste; and,

- Generic waste management facilities that receive waste from a broad spectrum of American industry, of which waste generated in the oil field is only a small part.

This chapter presents a comprehensive inventory of GOM waste management facilities and their capacities for the first two categories: these two categories are unique and important in handling GOM wastes. A specific analysis of generic waste management facilities, however, has not been included for several reasons. First these generic waste management facilities have unique permit terms that render physical capacity only a small factor in a site's longevity. Second, solid waste landfills receive only a small fraction of their total loading from OCS oil and gas activities. Generic waste management facilities will be discussed, but only in a general fashion as they relate to general waste disposal.

6.2. Industry Characteristics

6.2.1. Typical Facilities

The EPA has established a hierarchy of waste management methods that protect the environment. EPA identifies the following general waste management techniques for the disposal of wastes associated with oil and gas activities (USEPA, 1995a):

- *Recycle/re-use:* Re-usable components, such as oil or drilling mud, can be recovered from a waste stream and reused in order to reduce potential burdens on the environment and potential waste from the manufacturing of new replacement resources .

- *Treatment/detoxification:* When a waste cannot be recycled or re-used it can sometimes be treated to remove or detoxify a particular constituent prior to disposal. Neutralization of pH and removal of sulfides are examples of technologies that are used with oil and gas wastes.

- *Thermal treatment/incineration:* Wastes with organic content can be burned, resulting in a relatively small amount of residual ash that can be incorporated into a product or sent to disposal. This technology results in air emissions, but the residuals are generally free of organic constituents.

- *Subsurface land disposal:* This disposal methodology places waste below usable drinking water resources and is viewed as superior to land filling due to the low potential for waste migration. Injection wells and salt cavern disposal are examples of this type of technology.

- *Surface land disposal/treatment:* This disposal methodology involves placement of wastes into a landfill or onto a land farm. Although well-designed and constructed landfills minimize the potential for waste migration, generators remain concerned about migration of contaminants into water resources and avoid it whenever practical. EPA classifies surface land disposal as the least desirable disposal method.

Each of these waste disposal options has a different set of environmental impacts, regulatory constraints, costs, and capacity limitations. For example, industrial non-hazardous oily waste streams are managed at facilities that manage oily wastes for a broad range of industries. The same is true for municipal solid waste and hazardous waste. Most NORM and non-hazardous wastes (NOW) are only handled by specialized waste facilities in the Gulf Coast area, although there are exceptions. The most common waste management methods are provided in the rest of this section.

Offshore Marine Discharge

In early offshore oil and gas development, drilling wastes were usually dumped from the platforms directly to the ocean. During the 1970s and 1980s, however, increasing evidence showed that some drilling waste discharges could harm the local ecology, particularly in shallow water. Water-based muds (WBMs) resulted in limited environmental harm, but oil-based muds (OBMs) typically used in wells drilled on deeper well sections create cuttings piles that can impair zones beneath and around offshore platforms. Oil-based cuttings can affect the local ecosystem in three ways: (1) by smothering organisms, (2) by direct toxic effect of the drilling waste, and (3) by anoxic conditions caused by microbial degradation of the organic components in the waste (USDOE, DWMIS, 2008a).

In the late 1970s, the EPA began restricting ocean discharges of drilling muds and cuttings through National Pollutant Discharge Elimination System (NPDES) permits. The first restrictions included prohibitions on the discharge of OBMs and cuttings. In 1993, the EPA adopted further discharge standards for the offshore oil and gas industry. These established additional requirements for marine discharging of WBMs and cuttings from wells drilled at least 3 miles from shore but prohibited WBM discharges within 3 miles of shore (USDOE, DWMIS, 2008a).

During the mid-1990s, synthetic-based muds (SBMs) were developed and promoted to offer strong drilling performance like OBMs but with less in environmental impact. However the 1993 regulations did not include SBMs, resulting in considerable uncertainty about whether offshore operators could discharge the resulting cuttings and SBMs. The EPA, DOE, BOEM, and numerous companies and industry associations collaborated to finalize new effluent limitations guidelines (ELGs) for SBMs in 2001. A summary of the 1993 and 2001 discharge requirements are shown below (USDOE, DWMIS, 2008a):

Baseline Requirements

- No discharge of free oil (using a static sheen test) or diesel oil.
- Acute toxicity must have a 96-hour LC50 > 30,000 ppm (using EPA's mysid shrimp toxicity text).
- Metals concentrations in the barite added to mud must not exceed:
    - 1 mg/kg for mercury;
    - 3 mg/kg for cadmium.

- No discharge of drilling wastes allowed within three miles of shore (except for Alaskan facilities in the offshore subcategory).

Additional Requirements for Synthetic-Based Muds (SBMs)

- SBMs themselves may not be discharged.
- Cuttings coated with up to 6.9 percent SBMs may be discharged.
    - Ester SBMs can have up to 9.4 percent SBM on cuttings.
- Polynuclear aromatic hydrocarbon (PAH):
    - Ratio of PAH mass to mass of base fluid may not exceed 1×10^{-5} .
- Biodegration rate of chosen fluid shall be no slower than that for internal olefin:
    - Base fluids are tested using the marine anaerobic closed bottle test.
- Base fluid sediment toxicity shall be no more toxic than that for internal olefin base fluid:
    - Base fluid stocks are tested by a 10-day acute solid-phase test using amphipods (*Leptocheirus plumulosus*).
    - Discharged cuttings are tested by a 4-day acute solid-phase test using amphipods (*Leptocheirus plumulosus*).
- No discharge of formation oil:
    - Whole muds are tested onshore by GC/MS analysis.
    - Discharged cuttings are tested for crude oil contamination by fluorescence method.
- Conduct seabed survey or participate in industry-wide seabed survey.

Drill cuttings are pieces of ground rock from the well and are coated with a layer of drilling fluid. Most drill cuttings are managed through disposal, although some can be treated and beneficially reused. Before cuttings can be reused, the hydrocarbon content, moisture content, salinity, and clay content of the cuttings must be examined to ensure they are suitable for the intended use of the material (USDOE, DWMIS, 2008e).

After coming to the surface, drilling wastes are placed on a series of vibrating screens called shale shakers (Figure 37). Each successive shale shaker uses finer mesh screen to collect smaller and smaller particles. The liquid mud passes through the screens and is returned to mud pits on the platform to be reused. If the recycled mud still contains fine particles that could interfere with drilling performance, the muds are treated using mud cleaners or centrifuges. At the end of a drilling job or at the end of a particular interval that uses a specialized mud, the bulk mud will either be returned to shore for recycling or discharged to the sea (USDOE, DWMIS, 2008a).

Figure 37. Shale shaker.

Discharge into the sea has a considerable cost advantage because there are no transportation costs. A simple, continuous stream of produced water, for example, costs next to nothing to dispose, while the setup to treat a difficult intermittent stream could cost over a million dollars. Cost per barrel depends on the nature of the waste stream and life span of the wells served by the installation.

Subsurface Injection[16]

Subsurface injection is the management method used for more than 90 percent of the 16 billion barrels of saltwater produced by onshore oil and gas production each year in the U.S. (ICF, 2000). An injection well can best be envisioned as a producing well operating in reverse, with very similar drilling and completion procedures. In fact, depleted producing wells are sometimes converted to injection wells. Subsurface injection of aqueous fluids into a porous rock formation is the oldest and most established technology for disposal of produced waters onshore or when discharge is not allowed offshore.

About 70 percent of the water volumes injected in the U.S. serves the dual purpose of water flooding the field, also known as "secondary recovery," which is essentially pushing residual hydrocarbons to selected wells in a secondary oil recovery project (ICF, 2000). Alternatively, the injection zone is associated with either a depleted reservoir or non-productive zone. Underground injection is most suitable for relatively solids-free liquids. Fluids that are injected underground are often filtered since many injection formations can become plugged with solids. In streams with high levels of solids, the filtrate and sometimes the filters themselves, then

[16] The term "subsurface injection" of waste is used in its more traditional sense, meaning injection into a porous rock formation as opposed to the newer waste management method of salt cavern disposal, which is also technically subsurface injection but significantly different from this method both technically and legally.

become a solid-form waste stream that must be managed.[17] Some formations, on the other hand, are sufficiently porous and tolerant of solids and can serve as a viable method of sludge disposal. The most prominent example of the latter is the Newpark facility located near Fannett, Texas in Jefferson County.

As shown in Table 8 and Table 9, the costs of fluids disposal range from $0.40 to $10 per barrel. Solids or sludges have a higher disposal fee of $5 to $10.50 per barrel. Newpark Environmental Services offer NORM disposal for $150 to $300 per barrel. In addition, transportation costs for injections disposal ranges from $65 per hour to $90 per hour and are also subject to additional fuel surcharges of up to 16 percent. Other transportation costs, such as use of a Bobcat, crane, forklift or track hoe, may result in an additional charge (Puder and Veil, 2006).

All facilities employing a form of underground injection rely on the availability of a suitable underground formation or structure for emplacement of wastes. To be suitable for injection, a geologic formation must be of sufficient thickness and permeability to accept reasonable amounts of fluid as well as the residual solids that escape filtration. The injection zone must also be situated with sufficiently impermeable formations above and below it to isolate the injected material from usable groundwater and other resources. The most porous and permeable formations can be extremely tolerant of solid particles. However, slurried solids that are disposed in the formations must be uniformly small enough to pass through formation pore spaces or else plugging and fouling will occur.

Subsurface injection wells are regulated as Class II injection wells under the EPA's underground injection control program authorized by the Safe Drinking Water Act and pursuant to regulations set forth in 40 CFR Part 144 that were first promulgated in 1983. EPA directly regulates injection wells in federal waters and delegates authority for the state programs to the Texas Railroad Commission, the Louisiana Department of Natural Resources, Mississippi Oil and Gas Board, and the Alabama Department of Environmental Management. The regulatory program is mature and the technology has an established record of good performance, despite decades of operations under considerably less protective regulation than those that exist today.

Waste is isolated in the injection zone by other surrounding geologic zones that form a seal or barrier to the zone holding the injected waste materials. These formations typically do not have well-defined "edges" that would help in identifying the zone as a "container" for the waste materials. This lack of "containing sides" is the reason most injection zones do not have well-defined capacity limits that can be meaningfully measured against the relatively finite amount of waste that may be generated within the local area.

[17] A similar technology, annular injection, is used at the point of generation and sometimes used onshore in a commercial mode, but has generally been less accepted due to concerns about the fate of the waste once injected. Some newer approaches involve extensive characterization of the receiving formation and seem to hold the promise of broader acceptance, especially for offshore applications.

Table 8

Injection Wells

Waste Type / State	Disposal Company and Facility	Disposal Cost ($ per barrel)
WBMs and cuttings		
Alabama		
	Wastewater Disposal Service Inc.	$ 0.50
Produced water		$ 0.50
Alabama		
	Wastewater Disposal Service Inc.	$ 0.50
	Zinn Petroleum Company	$ 0.45
Louisiana		
	Charles Holston, Inc.	$ 0.50
	Guillory Tank Truck Service	$ 0.50
	Habetz Oilfield Saltwater Service	$ 0.67
	Hallar Enterprises Inc. Disposal Site	$ 1.00
	Houma Salt Water Disposal Corp. - Off LA Hwy 316	$ 0.60
	Key Energy Services, Inc. – Athens	$ 0.75
	Key Energy Services, Inc. - Oil City	$ 0.75
	Louisiana Tank, Inc.	$ 0.50
	O'Brian Energy Co.	$ 0.75
	Philip Environmental Services (PSC Industrial Outsourcing, Inc.) - Morgan City Facility	$ 0.65
	Pool Company – Minden	$ 0.85
	Saline Injection Systems Co.	$ 0.50-
	US Liquids of Louisiana LP - Bateman Island (Direct)	$ 7.00
	US Liquids of Louisiana LP - Berwick (Transfer)	$ 3.00- 7.00
	US Liquids of Louisiana LP - Bourg (Direct)	$ 7.00
	US Liquids of Louisiana LP - Cameron (Transfer)	$ 3.00- 7.00
	US Liquids of Louisiana LP - Elm Grove (Direct)	$ 1.00
	US Liquids of Louisiana LP - Fourchon (Transfer)	$ 3.00- 7.00
	US Liquids of Louisiana LP - ICY (Transfer)	$ 3.00- 7.00
	US Liquids of Louisiana LP - Mermenteau (Transfer)	$ 3.00
	US Liquids of Louisiana LP - Venice (Transfer)	$ 3.00- 7.00
Mississippi		
	Earth Resources	$ 0.60
	Radzewicz Operating Corporation	$ 0.37
Texas		
	Key Energy Services, Inc. - Amando, Webb County School Land, Mckendrick, and Barker	$ 0.75
	Key Energy Services, Inc. - Bettie Unit, Porter/Holland and Sebesta Earl	$ 0.75
	Key Energy Services, Inc. - Bloes, and Thornton/Henry	$ 0.75
Produced Water - Texas (continued)		
	Key Energy Services, Inc. - BrowNAlma, and Jeter-Farmer	$ 0.75
	Key Energy Services, Inc.-Burns and Hanselman Unit 1	$ 0.75
	Key Energy Services, Inc.-Carthage Loop, Deberry, Panola County Disposal, Reed, and Singlton	$ 0.75
	Key Energy Services, Inc. - Case	$ 0.75
	Key Energy Services, Inc. - Cashburn	$ 0.75
	Key Energy Services, Inc. - Cooper	$ 0.75
	Key Energy Services, Inc. - Dasani	$ 0.75
	Key Energy Services, Inc. - Early	$ 0.75
	Key Energy Services, Inc. - Freestone County (2)	$ 0.75
	Key Energy Services, Inc. - Gangl Unit	$ 0.75
	Key Energy Services, Inc. - Gayle (2)	$ 0.75
	Key Energy Services, Inc. - Gutierrez (2), Leonard, Medina/Lozano, Villareal (3), and Ramirez, Maria	$ 0.75
	Key Energy Services, Inc. - Hunt/William, and Brushy Creek Gas Unit	$ 0.75
	Key Energy Services, Inc. - Hutson	$ 0.75
	Key Energy Services, Inc. - Joaquin	$ 0.75
	Key Energy Services, Inc. - Kinder/George	$ 0.75
	Key Energy Services, Inc. - Kristina	$ 0.75
	Key Energy Services, Inc. - Live Oak County	$ 0.75
	Key Energy Services, Inc. - Mckeown and Meisenheimer	$ 0.75
	Key Energy Services, Inc. - Moser (2)	$ 0.75
	Key Energy Services, Inc. - Nichols Unit	$ 0.75
	Key Energy Services, Inc. - Peterson, T.M.	$ 0.75
	Key Energy Services, Inc. - South Texas Disposal	$ 0.75
	Key Energy Services, Inc. - Standifer	$ 0.75
	Key Energy Services, Inc. - Teeters	$ 0.75
	Key Energy Services, Inc. - Vick and Lisa	$ 0.75
	Key Energy Services, Inc. - Washington County, Clay Creek East Unit, and Linda	$ 0.75
	Key Energy Services, Inc. - Youngblood	$ 0.75
	Mo-Vac Service Co. Inc. - Andrews	$ 0.50
	S & D Services – Floyd	$ 0.40-
	Taylor Disposal Operating Inc. - Butler	$ 0.70
	Wasson Solid Waste Disposal System LLC - RCC District 8A/Yoakum County	$ 0.50

Source: Puder and Veil, 2006.

Table 9

Injection Wells (Sludges)

Disposal Company and Facility	Disposal Cost ($ per barrel)	Disposal Company and Facility	Disposal Cost ($ per barrel)
Contaminated Soils		**Proudced Water (continued)**	
Louisiana		**Texas**	
Newpark Environmental Services - Cameron (Transfer)	$ 5.50-10.00	Newpark Environmental Services - Fannett (Direct)	$ 5.00-10.00
Newpark Environmental Services - Fourchon I (Transfer)	$ 5.50-10.00	Newpark Environmental Services - Galveston (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Fourchon II (Transfer)	$ 5.50-10.00	Newpark Environmental Services - Ingleside (Transfer)	$ 5.50-10.50
Newpark Environmental Services - ICY (Transfer)	$ 5.50-10.00	Newpark Environmental Services - Port Arthur (Transfer)	$ 5.00-10.00
Newpark Environmental Services - Morgan City (Transfer)	$ 5.50-10.00	**Tank bottoms**	
Newpark Environmental Services - Venice (Transfer)	$ 5.50-10.00	**Louisiana**	
Texas		Newpark Environmental Services - Cameron (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Fannett (Direct)	$ 5.00-10.00	Newpark Environmental Services - Fourchon I (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Galveston (Transfer)	$ 5.50-10.50	Newpark Environmental Services - Fourchon II (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Ingleside (Transfer)	$ 5.50-10.50	Newpark Environmental Services - ICY (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Port Arthur (Transfer)	$ 5.00-10.00	Newpark Environmental Services - Morgan City (Transfer)	$ 5.50-10.50
NORM		Newpark Environmental Services - Venice (Transfer)	$ 5.50-10.50
Texas		**Texas**	
Newpark Environmental Services - Big Hill (Direct)	$ 150-300.00	Newpark Environmental Services - Fannett (Direct)	$ 5.00-10.00
OBMs and cuttings		Newpark Environmental Services - Galveston (Transfer)	$ 5.50-10.50
Louisiana		Newpark Environmental Services - Ingleside (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Cameron (Transfer)	$ 5.50-10.50	Newpark Environmental Services - Port Arthur (Transfer)	$ 5.00-10.00
Newpark Environmental Services - Fourchon I (Transfer)	$ 5.50-10.50	**WBMs and cuttings**	
Newpark Environmental Services - Fourchon II (Transfer)	$ 5.50-10.50	**Louisiana**	
Newpark Environmental Services - ICY (Transfer)	$ 5.50-10.50	Newpark Environmental Services - Cameron (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Morgan City (Transfer)	$ 5.50-10.50	Newpark Environmental Services - Fourchon I (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Venice (Transfer)	$ 5.50-10.50	Newpark Environmental Services - Fourchon II (Transfer)	$ 5.50-10.50
Texas		Newpark Environmental Services - ICY (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Fannett (Direct)	$ 5.00-10.00	Newpark Environmental Services - Morgan City (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Galveston (Transfer)	$ 5.50-10.50	Newpark Environmental Services - Venice (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Ingleside (Transfer)	$ 5.50-10.50	**Texas**	
Newpark Environmental Services - Port Arthur (Transfer)	$ 5.00-10.00	Newpark Environmental Services - Fannett (Direct)	$ 5.00-10.00
Produced water		Newpark Environmental Services - Galveston (Transfer)	$ 5.50-10.50
Louisiana		Newpark Environmental Services - Ingleside (Transfer)	$ 5.50-10.50
Newpark Environmental Services - Cameron (Transfer)	$ 5.50-10.50	Newpark Environmental Services - Port Arthur (Transfer)	$ 5.00-10.00
Newpark Environmental Services - Fourchon I (Transfer)	$ 5.50-10.50		
Newpark Environmental Services - Fourchon II (Transfer)	$ 5.50-10.50		
Newpark Environmental Services - ICY (Transfer)	$ 5.50-10.50		
Newpark Environmental Services - Morgan City (Transfer)	$ 5.50-10.50		
Newpark Environmental Services - Venice (Transfer)	$ 5.50-10.50		

Source: Puder and Veil, 2006.

Subsurface injection facilities can have two limitations. First, any given injection zone will accept fluid at a certain rate, depending on porosity, permeability, and thickness of the formation. This tends to govern the maximum amount of waste that may be disposed of daily in a given well. Second, any given injection well can be subject to irreparable failure of the casing or the cement around the casing as well as to "skin damage" to the formation at its interface with the wellbore. With proper design and operation, however, most disposal wells can be expected to last 15 or 20 years if not longer. When a well fails, re-drilling within a few hundred feet is often a viable solution to the well failure. Life-of-site capacity at a given location is less of a concern than is the duration of saltwater production from nearby wells.

Salt Cavern Disposal

Salt caverns, utilized for a variety of underground storage purposes, are created by a process called solution mining. Under a typical solution mining approach, a hole is drilled to the depth of the salt formation and a small diameter pipe is lowered into the well. To form the cavern, water is pumped through one of the pipes. As the water comes in contact with the salt formation, the salt dissolves. When the solution is removed from the hole, a cavern is created by the removal of this brine (USDOE, DWMIS, 2008b).

Salt caverns have been used for decades to store different types of hydrocarbon products. More recently, their use for disposal of wastes has received increased attention (Figure 38). In the early 1990s, several Texas brine companies obtained permits to receive waste, much of which was drilling waste, for disposal into salt caverns they had previously developed as part of their brine production operations. As of August 2002, permits were granted for 11 caverns at seven Texas locations. The disposal of offshore wastes into disposal caverns near the coast is becoming more popular. In 2003, Texas was the only state to issue permits for disposal of wastes in salt caverns in the United States. Louisiana adopted cavern disposal regulations in May 2003 but had not yet permitted any disposal caverns. Several disposal caverns are operated in Canada. In 2004, Mexico announced that it was developing regulations for disposal of oil-based muds and cuttings in salt caverns (USDOE, DWMIS, 2008b).

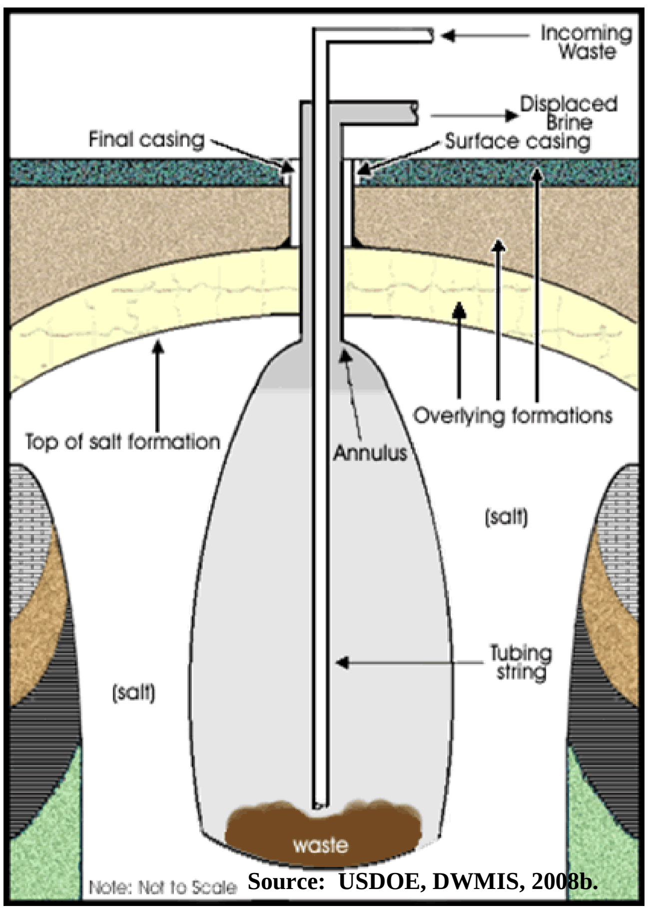


Figure 38. Schematic of a cavern in domal salt.

Wastes are transported to the cavern site in trucks and unloaded into mixing tanks, where they are blended with water or brine to make a slurry. E&P wastes that are suitable for disposal in caverns include drilling muds, drill cuttings, produced sands, tank bottoms, contaminated soil, and completion and stimulation wastes. The waste slurry is then pumped into the caverns. The incoming waste displaces the brine, which is brought to the surface. The brine is either sold or injected into a disposal well. Inside the cavern, the solids, oils, and other liquids separate into distinct layers: solids sink to the bottom, the oily and other hydrocarbons float to the top, and brine and other watery fluids remain in the middle (USDOE, DWMIS, 2008b).

The surface footprint of an underground salt cavern is considerably lower than traditional surface disposal. Further, the chance of any waste-related problems resulting from cavern storage tends to be lower than land treatment or landfill operation. Wastes in a salt cavern are contained underground in an impermeable and self-healing matrix of salt. No leaks or releases have been observed from the limited number of salt caverns used for disposal (USDOE, DWMIS, 2008b).

Table 10 shows that the disposal cost for produced water in a salt cavern ranges between $0.30 and $10 per barrel. Other types of waste, contaminated soil, WBM, OBM and tank bottoms, cost $2 to $15 per barrel. NORM prices at Lotus, L.L.C. (a commercial salt dome in Andrews County, Texas) are approximately $150-$300 per barrel.

Other fees disposal companies may charge:

- Transportation fees: $55-$75 per hour.
- Cost to clean container: $150 per hour or $150 per job.
- Cost of laboratory analysis: $110 to $150.

Table 10

Salt Cavern Waste Disposal

Waste Type / State	Disposal Company and Facility	Disposal Cost ($ per barrel)
Contaminated Soils		
Texas		
	CCS Energy Services LLC - Kiva (Direct)	$ 6.00-15.00
	CCS Energy Services LLC - Moss Bluff (Direct)	$ 6.00-15.00
	Coastal Caverns Inc.	$ 2.00-7.00
	Newpark Environmental Services - Permian Basin - Andrews (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Big Spring (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Fort Stockton (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Plains (Direct)	$ 5.00-10.00
	Taylor Disposal Operating Inc. - Caverns 1 & 2	$ 6.00
	Wasson Solid Waste Disposal System LLC	$ 3.50
NORM		
Texas		
	Lotus LLC	$ 150-
OBMs and cuttings		
Texas		
	CCS Energy Services LLC - Kiva (Direct)	$ 6.00-
	CCS Energy Services LLC - Moss Bluff (Direct)	$ 6.00-
	Coastal Caverns Inc.	$ 2.00-7.00
	Newpark Environmental Services - Permian Basin - Andrews (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Big Spring (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Fort Stockton (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Plains (Direct)	$ 5.00-10.00
	Taylor Disposal Operating Inc. - Caverns 1 & 2	$ 6.00
	Wasson Solid Waste Disposal System LLC	$ 3.50
Produced water		
Texas		
	CCS Energy Services LLC - Kiva (Direct)	$ 0.50-3.00
	CCS Energy Services LLC - Moss Bluff (Direct)	$ 0.50-3.00
	Coastal Caverns Inc.	$ 0.30-0.40
Produced Water - Texas (continued)		
	Newpark Environmental Services - Permian Basin - Plains (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Big Spring (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Fort Stockton (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Andrews (Direct)	$ 5.00-10.00
Tank bottoms		
Texas		
	CCS Energy Services LLC - Kiva (Direct)	$ 6.00-15.00
	CCS Energy Services LLC - Moss Bluff (Direct)	$ 6.00-15.00
	Coastal Caverns Inc.	$ 2.00-7.00
	Newpark Environmental Services - Permian Basin - Andrews (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Big Spring (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Fort Stockton (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Plains (Direct)	$ 5.00-10.00
	Taylor Disposal Operating Inc. - Caverns 1 & 2	$ 6.00
	Wasson Solid Waste Disposal System LLC	$ 3.50
WBMs and cuttings		
Texas		
	CCS Energy Services LLC - Kiva (Direct)	$ 6.00-15.00
	CCS Energy Services LLC - Moss Bluff (Direct)	$ 6.00-15.00
	Coastal Caverns Inc.	$ 2.00-7.00
	Newpark Environmental Services - Permian Basin - Andrews (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Big Spring (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Fort Stockton (Direct)	$ 5.00-10.00
	Newpark Environmental Services - Permian Basin - Plains (Direct)	$ 5.00-10.00
	Taylor Disposal Operating Inc. - Caverns 1 & 2	$ 6.00
	Wasson Solid Waste Disposal System LLC	$ 3.50

Source: Puder and Veil, 2006.

The use of these facilities is obviously only possible in parts of the country where salt deposits are found, in either dome or bedded formations.[18] The Gulf Coast region, both onshore and offshore, has an abundance of salt caverns, many with barge access. As discussed in Chapter 10, many Gulf Coast salt domes are already in service for hydrocarbon storage. Salt caverns otherwise introduce no particular siting criteria except the need to maintain a sensible buffer from residential and commercial areas for reasons associated with odors and equipment noise.

[18] A salt dome is a structural dome that is created from natural salt deposits that have leached up through overlying sedimentary layers. These thick formations can be as large as a mile in diameter, and 30,000 feet in height. Salt beds are shallower and thinner formations that are usually no more than 1,000 feet in height (NaturalGas.org, 2007b).

Land Application

Drilling muds, produced sand, and other fine solids are candidates for land application, often called land farming. Land farming can be a relatively low-cost approach to managing offshore drilling wastes (USDOE, DWMIS, 2008c). Under a land farming disposal method, muds and other solids are spread on land and mixed with earth to be incorporated into the soil, or deposited into dedicated pits. This is a common form of waste disposal across the GOM. Studies indicate that land farming does not adversely affect soils and may even benefit certain sandy soils by increasing their water-retaining capacity and reducing fertilizer losses (USDOE, DWMIS, 2008c).

Land utilized in a land farming approach can become depleted of organic material. In order to increase biological activity and aeration of the soil, waste disposal firms will add water, nutrients, and other amendments (e.g., manure, straw) into the soil during land farming operations. The introduction of additional organic matter also helps prevent the development of conditions that might promote leaching and mobilization of inorganic contaminants. During periods of extended dry conditions, moisture control may also be needed to minimize dust (USDOE, DWMIS, 2008c).

Land farming advantages include its simplicity and low capital cost, the ability to apply multiple waste loadings to the same parcel of land, and the potential to improve soil conditions (Table 11). Some of the reported disadvantages include its high maintenance costs (e.g., for periodic land tilling, fertilizer); potentially large land requirements; and required analysis, testing, demonstration, and monitoring. Elevated concentrations of hydrocarbons in drilling wastes can limit the amount of waste that can be applied on a site. Land farming approaches must be mindful of applying wastes to any soils if they contain salt. Unlike hydrocarbons, salt does not biodegrade but can accumulate in soils. If salt levels become too high, the soils may be damaged and treatment of hydrocarbons can be inhibited. Another concern with land farming is that while lower molecular-weight petroleum compounds biodegrade efficiently, higher molecular-weight compounds biodegrade more slowly. Thus, repeated applications can lead to accumulation of high molecular weight compounds which can increase soil-water repellency, affect plant growth, reduce the ability of the soil to support a diverse community of organisms, and render the land farm useless (USDOE, DWMIS, 2008c).

Several factors are considered in choosing land farming approaches to oilfield waste management including:

- site topography;
- site hydrology;
- neighboring land use; and
- the physical (texture and bulk density) and chemical composition of the waste and the resulting waste-soil mixture.

Disposal costs typically include a transportation fee that has recently been reported around $73.50 per hour as well as an insurance and a fuel surcharge of 14 percent.

Table 11

Land Application

Waste Type / State	Disposal Company and Facility	Disposal Cost
WBMs and Cutting		
Texas		
	Basic Energy Services – Jackson	\$2.50/bbl (WBMs) \$7.50/yd^3 (cuttings)
	Basic Energy Services - Jefferson	\$2.50/bbl (WBMs) \$7.50/yd^3 (cuttings)

Source: Puder and Veil, 2006.

Land farming regulations along the GOM depend on site-specific permits except for onsite disposal of onshore drilling waste. Land farming carries a risk of long-term liability from either leakage of the monofill or liability from use of the recycled material. While any method has its risks, land farming is perceived as riskier than underground injection methods.

Landfilling

A modern landfill is an engineered facility with protective liners and caps to isolate the waste from the larger environment (Figure 39). Municipal solid waste (MSW) is placed in an excavated cell, usually lined with high-density polyethylene to prevent leakage into the groundwater. MSW must be covered daily to control odors, birds, and vermin brought about by rotting food wastes.

Cuttings, muds or watery waste streams can be treated by mixing them with a stabilizing agent such as cement kiln dust, lime, or often even a simple bulking agent such as sawdust or waste from papermaking processes. These materials will be introduced in a mixing vessel at the landfill and stirred with a track hoe until it has a desired consistency. Depending on the solids content of the original waste stream as well as the bulking agent, the growth in volume will vary; a cubic yard of fresh water could become two cubic yards of landfillable waste.[19] Thus, an incoming cubic yard (approximately five barrels) of waste will occupy the landfill space of as much as four gate yards of MSW, which will be compacted in the landfill to half of its volume at the gate.

[19] Five barrels is equivalent to one cubic yard. Two cubic yards of MSW in place is equivalent to four cubic yards of MSW at the gate.

Figure 39. Commercial waste landfill.

A landfill must apply cover material of earth or some kind of non-decomposing material to the working face of the MSW daily. Drilling muds and wastewater streams that have been solidified can be used as a daily cover. Use of this type of material often improves a site's soil balance, meaning the volume of soil required over the life of the landfill for its construction and operation will be less than it would be if these materials were not available and other soils had to be hauled in at a cost (USDOE, DWMIS, 2008c). Up to a point, the materials consume no airspace since they are merely displacing soils that would be used for cover in any event (USDOE, DWMIS, 2008c). For this reason, landfills will often accept these materials at a reduced price, or even at no charge. Once a site has its daily cover requirements being met from revenue-positive gate receipts, its management would look differently at incremental volumes of such materials.

Transportation fees can range from \$85 to \$112 per hour and are subject to fuel surcharges. Disposal fees are charged by the barrel or ton and can cost \$2.61 to \$12.75 per barrel or \$28 to \$250 per ton (Puder and Veil, 2006) Waste Management Inc. - Chastang Landfill in Alabama accepts NORM waste below regulatory thresholds and charge \$70 per ton (Table 12).

Table 12

Landfilling

Waste Type	Disposal Company and Facility	Disposal Cost
Contaminated Soils		
	BFI Timberlands Sanitary Landfill	$ 32.00 per ton
	Waste Management Inc. - Chastang Landfill	$ 70.00 per ton
	Perdido Landfill Escambia County	$ 28.00 per ton
	Chemical Waste Management Inc.	$ 75- per ton
	MacLand Disposal Center	$ 20- per ton
	Waste Management - Central Landfill	$ 38.00 per ton
	Waste Management Inc. - Pecan Grove Sanitary Recycling and Disposal Facility	$ 38- per ton
	US Liquids of Louisiana LP - Galveston (Transfer)	$ 14.00 per bbl
	US Liquids of Louisiana LP - Rincon (Direct)	$ 7.71 per bbl
	US Liquids of Louisiana LP - Zapata (Direct)	$ 6.67 per bbl
Non-injectable dirt water		
	US Liquids of Louisiana LP - Rincon (Direct)	$ 3.25-9.25 per bbl
	US Liquids of Louisiana LP - Zapata (Direct)	$ 3.25-9.25 per bbl
NORM		
	Waste Management Inc. - Chastang Landfill	$ 70.00 per ton
OBMs and cuttings		
	Waste Management Inc. - Chastang Landfill	$ 70.00 per ton
	MacLand Disposal Center	$ 20- per ton
	Waste Management - Central Landfill	$ 38.00 per ton
	Waste Management Inc. - Pecan Grove Sanitary Recycling and Disposal Facility	$ 38- per ton
	US Liquids of Louisiana LP - Galveston (Transfer)	12.75 per bbl
	US Liquids of Louisiana LP - Rincon (Direct)	7.71-9.25 per bbl
	US Liquids of Louisiana LP - Zapata (Direct)	6.67-8.50 per bbl

Waste Type	Disposal Company and Facility	Disposal Cost
Produced water		
	Chemical Waste Management Inc.	$ 75- per ton
	MacLand Disposal Center	$ 55- per ton
	Waste Management - Central Landfill	$ 38.00 per ton
	Waste Management Inc. - Pecan Grove Sanitary Recycling and Disposal Facility	$ 38- per ton
Tank bottoms		
	Waste Management Inc. - Chastang Landfill	$ 70.00 per ton
	Chemical Waste Management Inc.	$ 75- per ton
	MacLand Disposal Center	$ 55- per ton
	Waste Management - Central Landfill	$ 38.00 per ton
	Waste Management Inc. - Pecan Grove Sanitary Recycling and Disposal Facility	$ 38- per ton
	US Liquids of Louisiana LP - Galveston (Transfer)	$ 14.00 per bbl
	US Liquids of Louisiana LP - Rincon (Direct)	$ 10.50 per bbl
	US Liquids of Louisiana LP - Zapata (Direct)	$ 10.50 per bbl
WBMs and cuttings		
	Waste Management Inc. - Chastang Landfill	$ 70.00 per ton
	Chemical Waste Management Inc.	$ 75- per ton
	MacLand Disposal Center	$ 20- per ton
	Waste Management - Central Landfill	$ 38.00 per ton
	Waste Management Inc. - Pecan Grove Sanitary Recycling and Disposal Facility	$ 38- per ton
	US Liquids of Louisiana LP - Galveston (Transfer)	$ 10.75 per bbl
	US Liquids of Louisiana LP - Rincon (Direct)	$ 3.25 per bbl
	US Liquids of Louisiana LP - Zapata (Direct)	$ 2.61 per bbl

Source: Puder and Veil, 2006.

Landfill siting criteria can be vague. Nearly every landfill siting application results in an evidentiary hearing or is otherwise the subject of an administrative hearing process. Certain qualitative factors describe the spirit of what a successful application for a new landfill must contain. A new landfill should have the following characteristics based on 40 CFR Part 258:

- Not in the 100-year floodplain;
- Away from population centers;
- More than six miles from an airport (for landfills that receive putrescible waste);[20]
- Accessible by public roads built to withstand maximum legal truckloads with significant excess capacity;
- Geologically simple and well-understood subsurface stratigraphy characterized by an absence of faulting, fracturing or folding;
- Groundwater deeper than maximum depth of excavation;
- Large enough tract of land for minimum of 20-year site life at expected opening fill rates (usually a minimum of 250 acres); and
- Established or expected use of neighboring land is industrial.

[20] This standard is for landfills that receive putrescible waste and can be relaxed with Federal Aviation Administration consent.

Environmental issues raised by landfills ultimately come down to: 1) potential threats to local groundwater; 2) impacts on local traffic; and 3) aesthetic considerations associated with truck traffic, nuisance odors, equipment noise, visual impairment of the landscape, and trash blown offsite. All of these issues are generally confined to a very small area relative to the trade area of the modern landfill, which is typically at least a fifty-mile radius. Impacts can be minimized if a landfill is properly sited, engineered, and operated.

Recycling of Drilling Wastes

Most WBMs are disposed at the conclusion of a drilling job. OBMs and certain SBMs can be recycled when possible. Sometimes the physical and chemical properties of the used muds degrade limiting their ability to be recycled necessitating some different type of reuse or disposal (USDOE, DWMIS, 2008d and e).

The left-over cuttings from drilling operations can be used to stabilize surfaces like roads or drilling pads. Oily cuttings can serve as a substitute for traditional tar-and-chip road surfacing; however, not all regulatory agencies will allow the use of these left-overs. Some jurisdictions limit road spreading to dirt roads on onshore oil and gas leases, while others may allow cuttings to be spread on a limited basis on public dirt roads. Operators must obtain prior permission from the regulatory agency, as well as the private landowner, before spreading cuttings. Operators are typically required to ensure that cuttings are not spread close to stream crossings or on steep slopes. Application rates should be controlled so that no free oil appears on the road surface (USDOE, DWMIS, 2008e).

Treated cuttings have been used in various ways:

- fill material;
- daily cover material at landfills; and
- aggregate or filler in concrete, brick, or block manufacturing.

Other possible construction applications for treated cuttings include use in road pavements, bitumen, and asphalt or use in cement manufacture. Drilling waste can be used as a filler or base material to make other products; however, the legal liability stays with the initial producer of the waste (USDOE, DWMIS, 2008e).

A new potential use for drilling wastes is to use treated cuttings as a substrate for vegetation and restoration of coastal wetlands. The U.S. Department of Energy has provided funding to test the possibility of pursuing and developing this restoration strategy (Veil, et al., 2000). The first phase of these research and pilot projects was based upon “greenhouse mesocosm experiments,” where several species of wetlands plants were grown in treated cuttings, topsoil, and dredged sediments. The results were positive and proved that wetlands vegetation could be grown in properly treated cuttings as well as the dredged material. However, neither the U.S. Army Corps of Engineers nor the EPA would issue a permit to conduct a field demonstration of the approach. To date, no field demonstrations of this waste management approach have been tried in the U.S. or elsewhere (USDOE, DWMIS, 2008e).

Separation and Recycling of Industrial Wastes

Certain industrial wastes generated in the course of oil and gas development do not fall under a waste exemption under RCRA Subtitle C. If they are not uniquely wastes, then the oil and gas waste exemption does not apply (RRC, 2009). Examples of such streams are lubricating oils for drilling machinery, oil filters, oil based paint solvents, and parts degreasers. These activities are characteristic of painting metal and maintaining machinery, and are not unique to the oil field. Generation of hazardous wastes has declined markedly in recent years as more environmentally friendly products have replaced them and the use of hazardous materials has been minimized in other ways.

Table 13 presents a range of costs for the different industrial wastes that fall into this category.

Table 13

Disposal Costs for Various Industrial Wastes

Waste Type	Disposal Price Range
Industrial organic hazardous wastes	$75 to $150 /gal
Inorganic liquid hazardous wastes	$50 to $01.25 /gal
Oil filters	$8 to $15 per 55 gallon drum
Used oil	$ 0 to $0.15 per gallon
Oily wastewater	$0.10 to $0.25 per gallon

Source: Puder and Veil, 2006.

6.2.2. Geographic Distribution

Argonne National Laboratory reported that there were 46 waste management facilities that serviced the oil and gas industry along the GOM with 18 in Louisiana, 18 in Texas, 5 in Mississippi, 4 in Alabama and 1 in Florida (Table 14).

Table 14

Waste Management Facilities in Gulf that Support Oil and Gas Industry

Alabama	**Mississippi**
BFI Timberlands Sanitary Landfill	Earth Resource
Waste Management Inc. - Chastang Landfill	MacLand Disposal Center
Wastewater Disposal Service Inc.	Radzewicz Operating Corporation
Zinn Petroleum Company	Waste Management - Central Landfill
Florida	Waste Management Inc. - Pecan Grove Sanitary
Perdido Landfill Escambia County	Recycling and Disposal Facility
Louisiana	**Texas**
Charles Holston, Inc.	CCS Energy Services LLC - Kiva (Direct)
Chemical Waste Management Inc.	CCS Energy Services LLC - Moss Bluff (Direct)
Guillory Tank Truck Service	Coastal Caverns Inc.
Habetz Oilfield Saltwater Service	Key Energy Services, Inc.
Hallar Enterprises Inc. Disposal Site	Lotus LLC
Houma Salt Water Disposal Corp	Mo-Vac Service Co. Inc. - Andrews
Key Energy Services, Inc. - Athens	Newpark Environmental Services - Big Hill (Direct)
Key Energy Services, Inc. - Oil City	Newpark Environmental Services - Fannett (Direct)
Louisiana Tank, Inc.	Newpark Environmental Services - Galveston (Transfer)
Newpark Environmental Services - Cameron (Transfer)	Newpark Environmental Services - Ingleside (Transfer)
Newpark Environmental Services - Fourchon I (Transfer)	Newpark Environmental Services - Permian Basin - Andrews (Direct)
Newpark Environmental Services - Fourchon II (Transfer)	Newpark Environmental Services - Port Arthur (Transfer)
Newpark Environmental Services - ICY (Transfer)	S & D Services - Floyd
Newpark Environmental Services - Morgan City (Transfer)	Taylor Disposal Operating Inc. - Caverns 1 & 2
Newpark Environmental Services - Venice (Transfer)	US Liquids of Louisiana LP - Galveston (Transfer)
O'Brian Energy Co.	US Liquids of Louisiana LP - Rincon (Direct)
Saline Injection Systems Co.	US Liquids of Louisiana LP - Zapata (Direct)
US Liquids of Louisiana LP - Mermenteau (Transfer)	Wasson Solid Waste Disposal System LLC

Source: Puder and Veil, 2006.

6.2.3. Typical Firms

Waste management companies have seen a number of changes over the past several years. Most of the changes in industry structure have been associated with diversification and consolidation. Waste companies are unique in that many of them have developed their own proprietary methods for environmentally safe waste disposal and recycling. Using different methods is a form of differentiation that increases efficiency and profitability.

Newpark Resources, founded in 1932, is a waste services company that operates along the GOM and offers a diverse range of waste disposal services to the oil and gas exploration and production industry. The division concentrating on oilfield waste management is called U.S. Environmental Services (Figure 40) and specializes in producing recycled and reusable products from a range of different wastes. Materials that cannot be recycled are processed to provide permanent isolation from the environment. U.S. Environmental Services uses non-hazardous injection well technologies in secure geologic formations that include low-pressure injection wells or caverns. Their business operates in a number of producing basins including the Gulf Coast, the Permian, the Rockies and Canada. The company holds several U.S. patents on waste disposal and processing methods for oilfield waste, including NORM waste. The Company leases a fleet of 48 double-skinned barges to transport waste to processing stations and seven transfer facilities located along the Gulf Coast.

Figure 40. Newpark Resource's E&P waste disposal site at Fannett, Texas.

Trinity Storage Services, L.P. operates as a commercial waste management company in the Gulf Coast area and has been in business since 1999. The company's process for underground waste disposal is to use salt caverns as well as other technologies to reduce the customer's liability. The company owns the Moss Bluff Facility located near Liberty, Texas. The facility is able to dispose and recycle many types of non-hazardous wastes that include produced salt water, mud, and cuttings used in the drilling process (Trinity Storage Services, 2008). In 2002, the company sold six of their oil field transfer stations along the Gulf Coast to U.S. Liquids Inc. (Houston Business Journal, 2002).

Four of these transfer stations sold by Trinity Storage Services are in Louisiana and two are in Texas. These facilities are located to provide a variety of different collection points to receive offshore waste from GOM clients. U.S. Liquid's acquisition of these four facilities allowed the company to further expand into the GOM oilfield waste disposal and treatment market (Houston Business Journal, 2002). In July 2003, a division of U.S. Liquids, U.S. Liquids of Louisiana (USLL), was purchased by Three Cities Research, Inc.

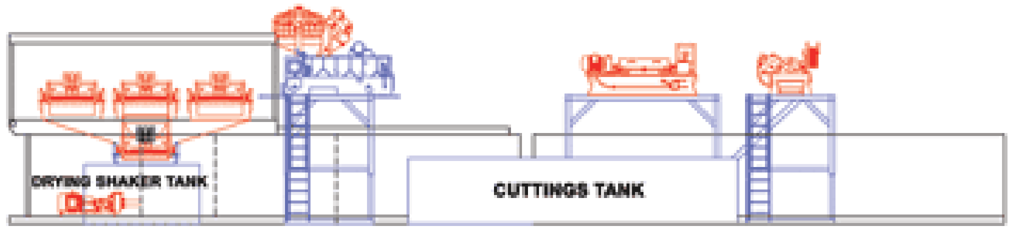
USLL, which began operations in 1980, is headquartered in Houston, Texas. USLL operates throughout the Gulf Coast area, and is the leading independent provider of oilfield E&P waste treatment and disposal services. USLL offers two E&P waste management processes that includes low-pressure injection into fully permitted salt caverns and land treatment. USLL's patent-pending R3 technologies are innovative, converting E&P waste into beneficial reuse products such as road base and levee materials. These technologies are further discussed in Section C.1 below. USLL operates six transfer facilities, six treatment facilities, ten injection wells and salt cavern disposal facilities. Loads are received, sampled, and tested per regulation at Bateman Island, Bourg, Elm Grove and Mermentau in Louisiana, and Rincon and Zapata in Texas. The company also treats waste from Mexico's growing oil and gas industry (USLL, 2008).

CCS Corporation is a recognized industry leader in environmental services to the oil and gas industries in Canada and the U.S. and is a major service provider along the GOM. CCS Corp was formed in 1986 and is headquartered in Calgary, Alberta. In 2006, they acquired Environmental Treatment Team and renamed it CCS Energy Services, Inc. with the goal of providing waste treatment and disposal services to the offshore Gulf Coast and Canada (CCS Income Trust, 2006). CCS Energy Services was recently rebranded to CCS Midstream Services (Canada NewsWire, 2007) and concentrates its business activities on owning and operating treatment, recovery, and disposal (TRD) cavern facilities. Services offered by CCS Midstream includes emulsion treatment, water treatment and disposal, waste processing, NORM processing, drilling mud disposal and crude oil terminalling.

In 2006, CCS's U.S. operations, along with ARKLA, an acquired industrial waste treatment center, generated $34.5 million in revenue. However, their fourth quarter 2006 revenue declined due to a reduction in GOM drilling activity which was blamed on a mild hurricane season that enabled drilling programs to finish earlier than anticipated. In 2007, CCS announced an expansion in the U.S. market by acquiring two companies located on the U.S. Gulf Coast, Mobley Oilfield Services and Pride Oilfield Services. Both companies operated within the waste disposal industry; Mobley managed and disposed of a variety of liquids in upstream operations and Pride collected produced water from various generators to haul for disposal (CCS Income Trust, 2007). CCS is also in the midst of developing a salt cavern facility at Weeks Island, Louisiana (Canada NewsWire, 2007). They have developed a unique design that allows for an efficient and reliable method of processing waste materials with brine water before injecting them into salt caverns (CCS Midstream, 2008).

Stallion Oilfield Services Ltd. is a private company with 2,400 employees that provide integrated solids and fluids waste management services. Headquartered in Houston, Texas, with 55 locations, they service South Texas, the Gulf Coast, the Ark-La-Tex area, North Texas, the Permian Basin, the Mid-Continent and Rocky Mountain regions as well as the global offshore industry. Stallion is a well-known leader in efficient solids control equipment design. For instance, their Shale Shaker uses a unique motion technique that allows for increased g-force and reduced solids conveyance friction, resulting in longer screen life and drier discards.

Stallion's stated business goals are to lower customer costs through planning, assisting, and/or managing solids control equipment, waste minimization and fluid recovery. To achieve this goal, Stallion uses closed loop systems, centrifuges, shale shakers, mud conditioners, drying shakers, and peripheral backside equipment (Figure 41) (Stallion Oilfield Services, 2008). Stallion uses centrifuges for solids removal, dewatering and barite recovery applications. Stallion units operate with VSD (variable speed driven) motors that, in addition to being more energy efficient, optimize bowl speed for finer separation of ultra-fine solids from the drilling mud (Stallion Oilfield Services, 2008). Since 2006, Stallion has actively been acquiring companies to expand business in all their sectors. Acquisitions of Pioneer RSC in 2006 and Bayou Tank Services and Patriot Liquid Services in 2007 added to their waste management division (Rigzone.com, 2008b).



Source: Stallion Oilfield Services, 2008.

Figure 41. Stallion's design of their close loop mud system.

PROwaste is an example of a smaller waste disposal company operating along the GOM that is located in Baytown, Texas. PROwaste is a full-service environmental, waste management, and industrial services company. PROwastes' services include hydrocarbon recovery, waste disposal, consultation, and transportation of waste. PROwaste developed an innovative hydrocarbon recovery and recycling facility which can accommodate waste stream recycling and off-spec product. Waste disposal is further enhanced through a network of disposal facilities, which include deep well injection, oil and filter recycling, incineration and fuels blending (PROwaste, 2008).

6.2.4. Regulation

Several different types of wastes are generated through offshore oilfield activities along the GOM. The removal and storage of these wastes are governed by a variety of state and federal statutes, rules, and regulations.

The major federal laws governing waste materials and management activities include the Resource Conservation and Recovery Act (RCRA), the Clean Water Act (CWA), and the Safe Drinking Water Act (SDWA). Table 15 provides a quick summary of the major federal laws governing waste materials and management activities.

Table 15

Federal Laws Governing Waste Materials and Management Activities

Law	Material Subject of Regulation	Activity Subject to Regulation
Clean Water Act	Aqueous waste streams	Surface discharge
Resource Conservation and Recovery Act	Solid and hazardous wastes (unless excluded or exempted)	Generation, transportation and treatment; storage and disposal
Safe Drinking Water Act	Waste fluids or slurries	Underground injection

Source: Puder and Veil, 2006.

In October, 1976, Congress passed the Resource Conservation and Recovery Act (Public Law 94-580) requiring the EPA to develop regulations governing the identification and management of hazardous waste (USEPA, 2008b). Two years later, the EPA published the first set of proposed hazardous waste management standards in the Federal Register (43 FR 58946). This Federal Register notice included a proposal to exempt six categories of "special wastes" from the RCRA until further study could be completed. Oil and gas drilling muds and oil production brines were included as one of the six special waste categories (USEPA, 2008b).

In 1980, Congress conditionally exempted oil and gas E&P wastes, including produced water, from the hazardous waste management requirements of Subtitle C of RCRA. Among the amendments, Section 3001(b)(2)(A)—frequently referred to as the Bentsen Amendment—temporarily exempts "drilling fluids, produced waters, and other wastes associated with the exploration, development, and production of crude oil or natural gas (USEPA, 2008b)." The EPA was directed to study these wastes and submit a report to Congress on the status of their management. Congress also required the agency either to promulgate regulations under Subtitle C of RCRA or make a determination that such regulations were unwarranted (Puder and Veil, 2006).

In 1988, the EPA published its regulatory determination on oilfield wastes in the Federal Register (53 FR 25447 July 6, 1988). The publication included a long list of wastes determined to be either exempt (e.g., produced water, drilling fluids, and drill cuttings) or nonexempt (unused fracturing fluids or acids, waste solvents, and hydraulic fluids). The EPA rearticulated the exemption in the Code of Federal Regulations (40 CFR §261.4(b)(5)). In 1993, the EPA published a clarification of its regulatory determination in the Federal Register (58 FR 15284, March 22, 1993) (Puder and Veil, 2006).

In 2002, EPA issued a publication titled *Exemption of Oil and Gas Exploration and Production Wastes*. The document explains the exemption of certain oilfield wastes from regulation as hazardous wastes under RCRA Subtitle C. The report includes background on the E&P exemption, basic rules for determining the exempt or non-exempt status of wastes, examples of exempt and non-exempt wastes, the status of E&P waste mixtures, and clarifications of several misunderstandings about the exemption (USEPA, 2008b). A subsequent analysis summarizing the findings of the report noted:

> With respect to petroleum production, primary field operations include activities occurring at or near the wellhead or production facility, but before the point where the custody of the petroleum is transferred from an individual field activity or centrally located facility to a carrier for transport to a refinery. Without a transfer of custody, the primary field operation ends at the last point of separation. Crude oil stock tanks are considered separation devices (Puder and Veil, 2006).

In addition to specific oilfield waste regulations, the report noted that wastes that are a product of treatment of an exempted waste usually remain exempt, and offsite transportation does not negate the exemption. However, this exemption does not include those wastes that are not uniquely associated with an E&P activity. Any waste that is not associated with primary field operations is subject to further scrutiny for purposes of classification. Table 16 presents examples of exempt and nonexempt E&P wastes (Puder and Veil, 2006).

Clean Water Act - Surface Discharge Regulation

All discharges of pollutants to surface waters (streams, rivers, lakes, bays, and oceans) must be authorized by a permit issued under the National Pollutant Discharge Elimination System (NPDES) program. These permits outline the frequency for collecting wastewater samples, the location for sample collection, the pollutants to be analyzed, and the laboratory procedures to be used in conducting the analyses. A facility must retain the detailed records of these "self-monitoring" activities for at least three years. And, each facility is required to submit the results of these analyses to regulators on a periodic basis. NPDES permits may also require operational or environmental effects monitoring. This includes the preparation of best management practice plans or spill prevention plans (Puder and Veil, 2006).

Discharges associated with offshore oilfield wastes are regulated under the Clean Water Act's National Pollutant Discharge Elimination System program. EPA Region 4 issues individual and general permits covering facilities that discharge beyond the offshore three-mile limit defining territorial seas in the Eastern Planning Area and in the Mobile and Viosca Knoll Blocks of the Central Planning Area. Permits issued by the regional EPA offices must meet all CWA requirements, as well as EPA's guidelines for determining the degradation of marine waters (Ocean Discharge Criteria Evaluation). The final NPDES general permit for existing and new source discharges in the Eastern Portion of the OCS on the GOM (GMG460000) was issued on December 9, 2004 and expires on December 31, 2009. The permit applies to operators of leases seaward of the 200-meter water depth for offshore Alabama and Florida in the Eastern Planning Area and offshore Mississippi and Alabama in the Mobile and Viosca Knoll lease blocks in the Central Planning Area (USEPA, 2008c).

Table 16

Examples of Exempt and Nonexempt Exploration and Production Waste Streams

Exempt E&P Waste Streams	Nonexempt E&P Waste Streams
Caustics if used as drilling fluid additives Cement slurry returns and cement cuttings Debris, crude-oil soaked/crude-oil stained Drill cuttings/solids Drilling fluids/muds Drilling fluids and cuttings from offshore operations disposed of onshore Liquid hydrocarbons removed from the production stream Liquid and solid wastes generated by crude oil and tank bottom reclaimers Pit sludges and contaminated bottoms from storage or disposal of exempt wastes Produced sand Produced water Produced water constituents removed before disposal Soils, crude-oil contaminated Tank bottoms and basic sediment from storage facilities that hold product and exempt waste (including accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments) Volatile organic compounds from exempt wastes in reserve pits or impoundments or production equipment Well completion, treatment, and stimulation, and packaging fluids Workover wastes (blowdown, swabbing and bailing wastes)	Batteries (lead-acid and nickel-cadmium) Caustic or acid cleaners Cement slurries, unused Chemicals, surplus/unusable Compressor oil, filters, and blowdown waste Debris, lube oil (contaminated) Drilling fluids (unused) Drums/containers, containing chemicals/ lubricating oil Drums, empty and rinsate Hydraulic fluids (used) Oil, equipment lubricating (used) Sandblast media Scrap metal Soil, chemical-contaminated, lube oil-contaminated and mercury-contaminated Solvents, spent (including waste solvents) Thread protectors, pipe dope-contaminated Vacuum truck rinsate (from tanks containing nonexempt waste) Well completion, treatment and stimulation fluids (unused)

Source: Puder and Veil, 2006.

EPA Region 6 encompasses Arkansas, Louisiana, New Mexico, Oklahoma, and Texas as well as the western GOM. EPA Region 6 works closely with the BOEM whose inspectors perform most of the NPDES offshore platform compliance inspections for EPA. Additionally, the U.S. Coast Guard Marine Safety Office conducts inspections. The final NPDES General Permit for New and Existing Sources and New Discharges in the Offshore Subcategory of the Oil and Gas Extraction Category for the Western Portion of the OCS of the GOM (GMG290000) and Notice of a Proposed Modification to that permit was published at 69 CFR 194 on October 7, 2004, effective November 6, 2004, and expired midnight November 5, 2007. The permit was reissued with an effective date of October 1, 2007, expiring at midnight of September 30, 2012 (USEPA, 2008d).

<u>Safe Drinking Water Act (SDWA) - Underground Injection Control</u>

Under the SDWA, the EPA has the authority over underground injection control (UIC) regulation. The UIC program is designed to protect underground sources of drinking water. Underground injection is grouped into five classes of injection wells. This is defined by the EPA as follows:

> An injection well is defined as any bored, drilled or driven shaft or dug hole, where the depth is greater than the largest surface dimension that is used to inject fluids underground. Class I wells are used for the emplacement of hazardous and non-hazardous fluids (industrial and municipal wastes) into isolated formations beneath the lowermost underground source of drinking water. Class II wells inject brines and other fluids associated with oil and gas production. Class III wells inject fluids associated with solution mining of minerals. Class IV wells, which involve the injection of hazardous or radioactive wastes into or above an underground source of drinking water, are banned unless authorized under other statutes for groundwater remediation. Class V wells include underground injection wells not included in Classes I through IV. Wells used for injecting waste materials associated with E&P operations are considered Class II wells. Class II subclasses include disposal wells (Class II-D) and enhanced recovery wells (Class II-R) (Puder and Veil, 2006).

The EPA's regulations establish minimum standards for state programs allowing each individual state to chose more stringent requirements if warranted. In 1981, Congress added Section 1425 to the SDWA, that relieves oil- and gas-related injection well programs in the states from having to meet the technical requirements in the federal UIC regulations. Instead, the demonstration can be made that the state has an effective program (including adequate oversight, record keeping, and reporting) in place to prevent the endangerment of underground sources of drinking water by underground injection operations (Puder and Veil, 2006).

6.3. Industry Trends and Outlook

6.3.1. Trends

There are approximately 86 waste facilities in the Gulf Economic Impact Areas.

Newpark Resources noted in a recent annual SEC filing that several factors are driving the demand for its services, including: (i) supply, demand, and pricing of oil and gas commodities which drive E&P development activity; (ii) a trend toward deeper and otherwise more complex drilling that drives drilling fluid consumption and increasing technical requirements; (iii) the continued trend of E&P development into more environmentally sensitive areas; and (iv) the use of increasingly complex drilling techniques that tend to generate more waste. Demand for most services is related to the level, type, depth, and complexity of oil and gas drilling (SEC, 2006j).

The waste disposal industry is also highly dependent upon environmental laws and regulations. The more stringent the regulations, the more demand for waste services as E&P companies take steps to comply with the more stringent regulations. Conversely, the industry could be adversely affected by new regulations or changes in current regulations (SEC, 2007b).

Currently, oilfield waste that is not contaminated with NORM is exempt from the principle federal statute governing the handling of hazardous waste. However, in recent years proposals have been made to retract this exemption (SEC, 2007b).

The storage pits and land around Port Fourchon, Louisiana, have accumulated large deposits of non-hazardous drilling and production waste containing NORM (Reed et al., 2001). In order to remediate the site, Chevron chose to re-inject the material into the deep subsurface using a process known as on-site Slurry Fracture Injection (SFI) (Reed et al., 2001). SFI is a method which provides greater environmental security, reduces the long-term liability risk to the waste generator and reduces transportation and disposal costs (Reed et al., 2001). Through SFI, the waste material is screened to a specified injection criteria and then slurried in a stream of water as required. The slurry is made with as high a waste concentration as possible and then pumped down a waste disposal well at fracturing pressures (TTI, 2008).

Numerous companies within the waste management industry have developed innovative methods to handle waste. For example, PROwaste built a hydrocarbon recovery/recycling facility that is located in Baytown, Texas and processes off-spec refinery products, hydrocarbon streams, lube oils and tank pipeline clean out materials (PROwaste, 2008).

Another example is USLL's R3 technologies, several of which have been implemented to reduce, reuse, and recycle E&P waste. Their land treatment process decreases soluble salt content, reduces oil concentration through recovery or degradation, and can clean cuttings or reuse materials which are stored in secure onsite stockpiles. The stock piles are able to be safely eliminated through two new reuse programs to make the waste usable as road base or levee fill.

The R3 road base program was developed at USLL's South Texas facilities, and the goal of the program has been to convert stockpile materials to an environmentally safe road base material. Tests have proved that the material is cleaner, more affordable, and has more comparative strength than asphalt. In fact, regulatory agencies have recently approved R3 road base to be used in building both public and private roads. The clean reuse material is also being considered for levee material. USLL is currently working with the ACE and the Louisiana Department of Natural Resources (LDNR) to ensure that the liability to the generator ends when the stockpile material leaves the facility to be used for a levee reconstruction project (USLL, 2008).

USLL is also pushing for higher land and water use efficiencies through two patent-pending innovations. The company currently has a pilot project at their Mermantau facility in Louisiana that is using a newly developed waste segregation technique that segregates different waste streams into differing "mini-cells," The goals of this program are to reduce treatment time, improve oil recovery levels, and reduce the number and duration of water washings. The second patent-pending method under development by USLL is referred to as "active water evaporation," and has been developed in cooperation with LDNR and the Louisiana Department of Environmental Quality (LDEQ). The process is continuing to be tested and put through trials (USLL, 2008).

6.3.2. Hurricane Impacts

Most of the waste disposal facilities along the GOM suffered little reported damage as the result of the 2005 hurricane season. None of the regional operators referenced earlier in this chapter reported any constraints associated with landfills or oil and gas disposal sites along the GOM n the aftermath of the 2005 hurricanes. No capacity constraints have been identified for the future, and no capacity constraints have been identified as being specifically created by OCS oil and gas activities. This included pre-hurricane and post-hurricane activities.

6.3.3. Outlook

Oilfield waste services are highly dependent upon the general business environment for the oil and gas industry. The risks involved in oilfield waste management encompass overall demand for services, oil and gas prices, environmental requirements, and general competition (Canada NewsWire, 2007).

Treatment and waste disposal services are largely dependent on the willingness of customers to outsource their waste management activities. Although environmental regulations can be a significant hurdle for new entrants in the waste business environment, they do not prohibit companies from developing their own "internal" alternatives to third-party service. These options include bioremediation, land spreading, road spreading, and deep well disposal options (Canada NewsWire, 2007).

Waste disposal firms along the GOM also face relatively significant competition forcing some to reduce prices in order to maintain market share. For example, CCS reported that its Gulf Coast Waste Disposal business unit experienced 2007:Q3 revenues that were 16 percent below prior year levels due to competition (Canada NewsWire, 2007).

Oilfield waste volumes are closely correlated with offshore drilling and production activity. Waste volume activities in 2007 were strong due to continued strong drilling activity along the GOM (onshore and offshore) (Canada NewsWire, 2007).

6.4. Chapter Resources

Drilling Waste Management Technology
Drilling Waste Management Technology is an online resource for technical and regulatory information on practices for managing drilling muds and cuttings, including current practices, state and federal regulations, and guidelines for optimal management practices. The pages on Technology Descriptions provide basic information about practices that are currently employed to manage drilling wastes. The Federal and State Regulations section provides existing state and federal regulations that form the regulatory context for drilling waste management practices. The Technology Identification section has an interactive tool to determine optimal management practices for a given geographical or environmental setting.

http://web.ead.anl.gov/dwm/index.cfm

U.S. Environmental Protection Agency (USEPA)
The regional sites for the USEPA's Division 4 and Division 6 provide current information on the regulation of discharges associated with offshore oil and gas exploration, development, and production activities on the Outer Continental Shelf (OCS) under the Clean Water Act's National Pollutant Discharge Elimination System (NPDES) program.

http://www.epa.gov/region04/water/permits/oil_gas.html
http://www.epa.gov/earth1r6/6en/w/offshore/home.htm

7. PIPELINES

7.1. Description of Industry and Services Provided

After raw natural gas is brought to the earth's surface, it is processed to remove impurities such as water, carbon dioxide, sulfur, or inert gases that can damage or destroy various pipeline systems made primarily of a combination of metals that include steel and cast iron. Processed natural gas is then moved from its original location of production (producing region) into a pipeline system for transportation to an area where it is sold (consuming region). Because natural gas reserves are not evenly spaced across the continent, an efficient, reliable gas transportation system is essential in order to deliver natural gas reliability and efficiently to consumers.

Over 300,000 miles of steel pipe, ranging in diameter from 20 to 42 inches, serve as the "interstate highway" system for natural gas (USDOE, EIA, 2008a). Natural gas is transmitted through pipeline systems at higher than atmospheric pressures in order to reduce volumes and provide a source of propulsion. Pressure is maintained through a system of over 1,400 compressor stations along various segments of inter- and intrastate pipeline systems (USDOE, EIA, 2008a).

Pipelines can be characterized as interstate or intrastate (Figure 42). Interstate pipelines carry natural gas across state boundaries whereas intrastate pipelines transport natural gas within a particular state. The distinction between inter- and intrastate pipeline systems is important for regulatory and pricing purposes and will be discussed in greater detail in the Regulation section of this chapter.

A major portion of the U.S. is dependent on the interstate pipeline system for its supplies of natural gas. Large-diameter (20 to 42 inch) pipelines, with high capacities, transport most of the gas on the national network. Some of the systems with the highest capacity are those originating in the various U.S. producing basins (USDOE, EIA, 2008a).[21] Figure 43 highlights the order of magnitude of gas production from the lower 48 states.

In addition to natural gas pipelines, there are petroleum or oil pipelines that carry nearly two-thirds of the ton-miles of oil transported in the U.S. There are approximately 200,000 miles of oil pipelines that move crude from producing areas like the GOM, California, the Rockies and West Texas to refining areas that tend to be in relatively close proximity. Crude pipelines also move gas from offshore import terminals and ports to various refining centers across the U.S. (USDOE, EIA, 2008b). Pipelines are a more cost-effective means of transporting crude oil than rail, barge, or road. For instance, a typical 150,000 Bbl/d pipeline moves the equivalent of some 750 tanker truckloads per day while a 75-car train would be needed to move 2,000 Bbls of crude oil alone (AOPL, 2008).

[21] The EIA defines the Southwest region as Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.

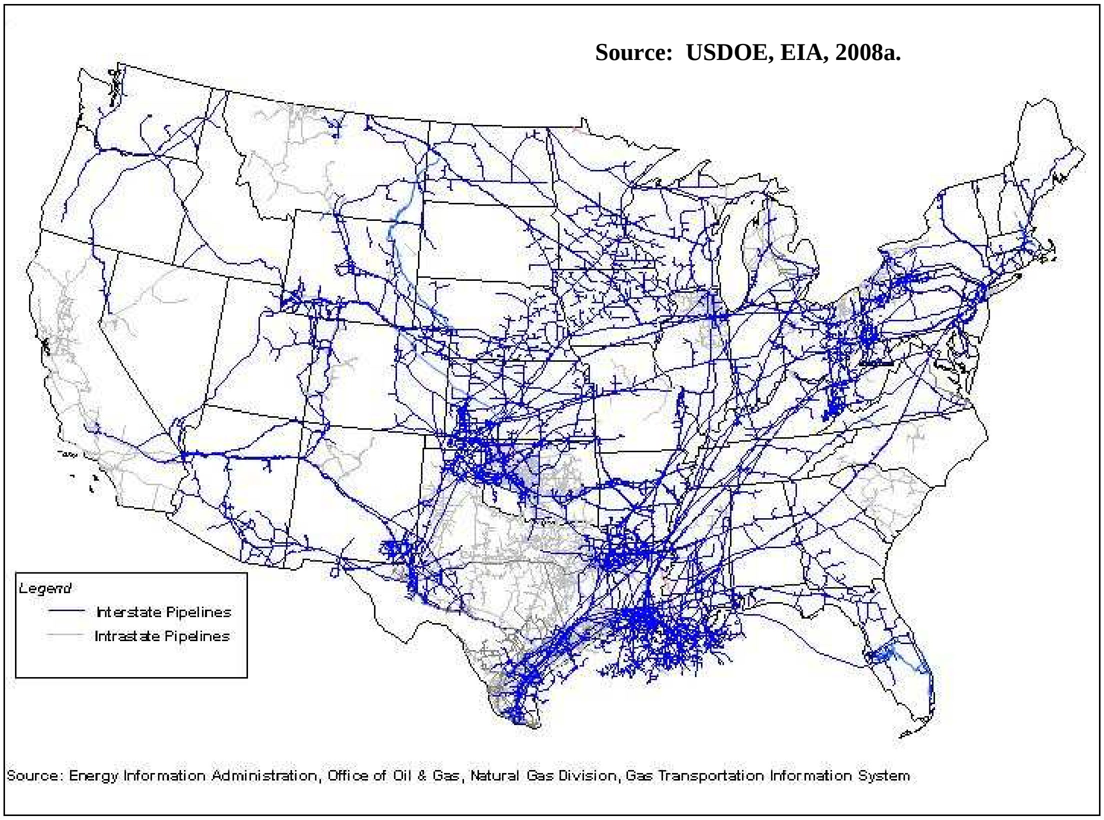


Figure 42. U.S. natural gas pipeline network.

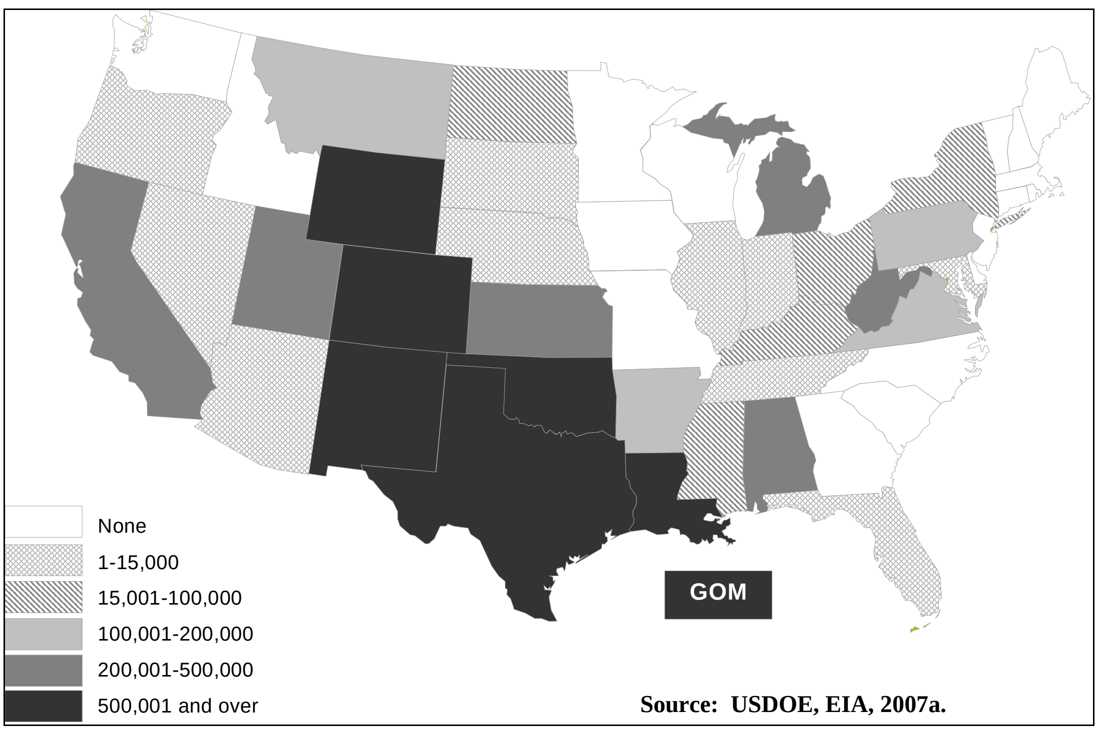


Figure 43. Marketed production of natural gas in the U.S. (MMcf), 2006.

7.2. Industry Characteristics

7.2.1. Typical Facilities

Natural gas pipelines can be disaggregated into three different components that include (1) gathering systems, (2) interstate and intrastate pipeline systems, and (3) distribution systems (Figure 44) (NaturalGas.org, 2007a and c). Gathering systems use low pressure, low diameter pipelines to move raw natural gas from the wellhead to the processing plant. Transportation pipelines (interstate, intrastate), transport natural gas from areas of production to areas of consumption, or demand (NaturalGas.org, 2007a).

Natural gas is delivered to end-users through the distribution system. Most users receive natural gas from a local distribution company or LDC. However, some large industrial and power generation customers receive natural gas directly from the interstate and intrastate transportation pipelines (often referred to as direct connects).

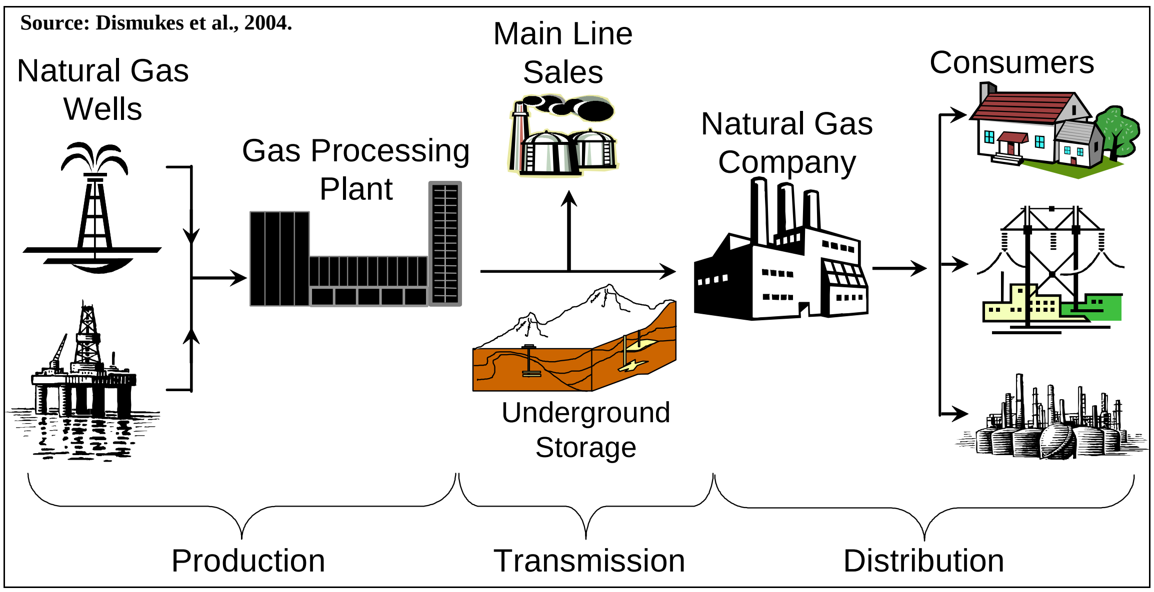


Figure 44. Natural gas chain.

Most natural gas pipelines measure anywhere from 6 to 48 inches in diameter (Figure 45). However, some pipe sections, such as those connecting distribution mains to customer premises, can consist of smaller diameter pipe, as small as 0.5 inches in diameter. Main transportation pipes are usually between 16 and 48 inches in diameter, while lateral pipelines, which deliver natural gas to or from the mainline, are typically between 6 and 16 inches in diameter. The actual pipeline itself, commonly called line pipe, consists of a strong carbon steel material, engineered to meet standards set by the API as well as the U.S. Department of Transportation, Office of Pipeline Safety (NaturalGas.org, 2007a).

Figure 45. Pipeline installation.

Modern large-diameter pipelines are typically produced in steel mills under two different production techniques. The first, usually associated with small diameter pipes (less than 20 inches in diameter), is comprised of a relatively seamless process that involves high temperature heating of a fixed-size metal bar (corresponding closely with the ultimate pipe diameter). The central section of the bar is “punched out” to produce a seamless, hollow pipeline segment.

The second pipeline production method is associated with large diameter pipes (larger than 20 inches in diameter) that are produced from sheets of metal that are folded into a tubular shape. The ends are then welded together along a seam to form a contiguous pipe section (Figure 46) (NaturalGas.org, 2007a).

Figure 46. Pipe in the steel mill.

Compressor Stations

The compressor stations can be thought of as the "engine" that powers the pipeline. This engine compresses the natural gas (increasing the pressure) thereby providing the energy to move the gas through the pipeline (INGAA, 2009). Compressor stations are installed approximately every 40 to 100 miles along a pipeline route, depending on the size of the pipe and volume of gas (INGAA, 2009). Most compressor stations are completely automated, so the equipment monitored and controlled from a pipeline's central control room (AGA, 2005). The control center also can remotely operate shut-off valves along the transmission system. Pipeline operators have continuous and detailed operating data on each compressor station, and will make adjustments to maximize efficiency and safety (AGA, 2005).

When transmission pipelines deliver gas to utilities, the fuel passes through what is commonly referred to as a "gate station" or "city gate" at which point the LDC takes control of the natural gas and its further distribution. The pressure in the pipeline is reduced at the city gate from transmission levels, usually between 200 to 1,500 pounds per square inch (psi) to pressure levels commonly found at distribution levels that range between ¼ to 200 psi (AGA, 2005). Meters at the gate measure how much gas is being received by the utility, and a sour-smelling odorant (usually t-butyl mercaptan or thiophane) is added to help customers smell even small quantities of leaked natural gas. The local utility then uses distribution pipes, or mains, to bring natural gas service to homes and businesses.

Monitoring and Maintenance of Pipelines

Transportation company investments in pipes, pumps, compressors, drivers, dehydration units, meters, control systems, and other equipment are significant. Large investments of this nature require non-trivial levels of monitoring and maintenance in order to maintain their operational performance. Pipeline owners and operators often use a combination of preventative maintenance (such as cathodic protection and pipeline coating, discussed further in Chapter 7), planned and scheduled maintenance, along with frequent inspection to ensure pipeline asset integrity.

Traditionally, pipelines were inspected visually by going over the route on the ground or patrolling the pipeline route in aircraft. Aerial inspection is still done today, but inspections are more likely to be conducted through digital and computerized instrumentation and monitoring equipment provide more rapid and precise identification of leaks or potential leaks.

Electronic data acquisition systems, commonly referred to as "Supervisory, Control, and Data Acquisition" systems or "SCADA," allow pipeline operators to keep accurate, constant information on sections of pipeline. Information can be retrieved from remote sections of pipeline and the flow of gas can be controlled using computers that are linked to satellite communication and telephone communication systems. SCADA systems not only allow pipeline operators to obtain timely information, but in some instances can allow producers (or pipeline shippers) to have access to delivery information in order to efficiently schedule pipeline deliveries (NaturalGas.org, 2007a).

An important piece of equipment used in pipeline inspection and maintenance includes the use of intelligent robotic inspection devices, known as a pipeline inspection guide or “PIG” (Figure 47) which travel through a pipeline, inspecting the interior walls for corrosion and defects, measuring the interior diameter of a section of pipe, and removing accumulated debris from a section of pipeline. PIGs are about the same diameter of the pipe, are carried through the pipe by the flow of the liquid or gas, and can travel and perform inspections over very large distances. They may be put into the pipeline on one end and taken out at the other. The PIG uses sensors to take thousands of measurements that can later be analyzed by computers to show possible problems. Magnetic-flux leakage PIGs are used to detect metal loss (from corrosion) in pipeline walls, locating potential problems without the cost and risk of using other methods. In 1997, a PIG set a world record when it completed a continuous inspection of the Trans Alaska crude oil pipeline, covering a distance of 1,055 km in one run (NDT Resource Center, 2008).

Source: Pipeline Pigging Technology Ltd, 2008.

Figure 47. Pipeline PIG.

<u>Pipeline Repair</u>

Pipeline leaks can be repaired under a variety of methods that can be a function of the magnitude and location of the leak. A short length of pipe may be inserted where the leak is found (called a pup joint), or the entire joint of the pipe may be replaced. Onshore pipelines may also be plugged temporarily on either side of a problem area, and flow is redirected through a bypass so work can be done on the isolated area. A variety of plugging equipment is available, and can be applied in a wide range of situations.

The repair of offshore pipelines, however, is much more complex and costly. Each repair alternative is reviewed to ensure the selection of the method that is most compatible with the overall requirements of each situation. A number of factors influence offshore pipeline repair methods that can include pipeline diameter, rupture location and gas volumes being transported, water depth, rupture coverage, pipeline segment age, as well as any other special hazards (i.e., mud slides, unusual currents, severe weather conditions, etc.) (Woods, 1982).

To minimize the downtime of an out-of-service line, formal emergency repair plans are often made for offshore pipelines. There are a variety of methods available for repairing underwater pipelines, but they generally fall into three categories (Woods, 1982):

- Surface repair: This method involves lifting the pipeline to the surface and repairing it completely by welding a new section of pipe to replace the damaged area or by welding flanges, misalignment fittings, etc. onto each end of the pipe after removal of the damaged area. The pipe is then lowered back to the sea floor and carefully reconnected. Since this method relies upon all major work being performed on the surface, it is probably the most weather sensitive of the three types of repair methods.

- Underwater hyperbaric welding: If a totally welded repair without lifting the pipe is the most desirable solution, then this can be achieved on the bottom, eliminating the necessity of raising the pipeline to the surface. The variations on this method allow for a welder-diver to weld the pipe either completely enclosed in a dry habitat or with the welder-diver working in the wet while the weld point on which he is working is enclosed in a dry, environmentally controlled chamber. Although not as weather sensitive as surface repairs, underwater welding is probably the most skill-sensitive method due to the fact that specific qualification levels for welding the pipe material at a given water depth must be present in the welding team.

- Mechanical connectors: There are a number of these types of products currently available which allow for the repair of pipelines in place without the necessity of lifting them to the surface or performing underwater welding. These products are available in a variety of configurations and degrees of sophistication ranging from the containment of a pin-hole leak with a simple split-sleeve clamp through a complete spool-piece repair in deepwater either through diver intervention or in an automatic, diver-less profile. Generally, this method is not as weather or skill-sensitive as the other two, but due to the manufacturing lead time of many of these items, it is almost imperative that they be purchased and stocked well in advance of any requirement.

7.2.2. Geographic Distribution

Natural Gas Pipelines

The U.S. has a complex and extensive pipeline system for transporting natural gas from production areas to ultimate consumers. However, most of the major transportation routes can be categorized into 11 distinct corridors or flow patterns (USDOE, EIA, 2008a). Figure 48 shows these major corridors, while Figure 49 shows the estimated region-to-region natural gas pipeline capacity.

- Five major routes extend from the producing areas of the South. More than 20 of the major interstate pipelines originate in the GOM and Texas region. Texas and the GOM exports about 45 percent (6.0 trillion cubic feet in 2005) of its production, which is 46 percent of the total natural gas consumed elsewhere in the lower 48 states. The pipeline capacity exiting the region is over 40.7 Bcf per day: 58 percent of which travels to the Southeast Region, 24 percent goes to the Central Region, 15 percent goes to the Western Region, and the remainder is exported to Mexico. A lot of the capacity directed toward the Southeast crosses the region moving gas to Midwestern and Northeastern markets (USDOE, EIA, 2008a).

- Four routes enter the U.S. from Canada. These include the pipes that flow from (1) Western Canada to western markets in the U.S., mainly California, Oregon, and Washington State; (2) Western Canada to Midwestern markets in the U.S.; (3) Western Canada to Northeastern markets of the U.S.; and (4) offshore eastern Canada (Sable Island) to New England markets in the U.S. (USDOE, EIA, 2008a).

- There are two routes that start in the Rocky Mountain area. In the Central Region, only one major interstate pipeline originating within the region provides transportation services directly to another region, Kern River Transmission Company. All the others operate primarily within the region or come from other regions (USDOE, EIA, 2008a).

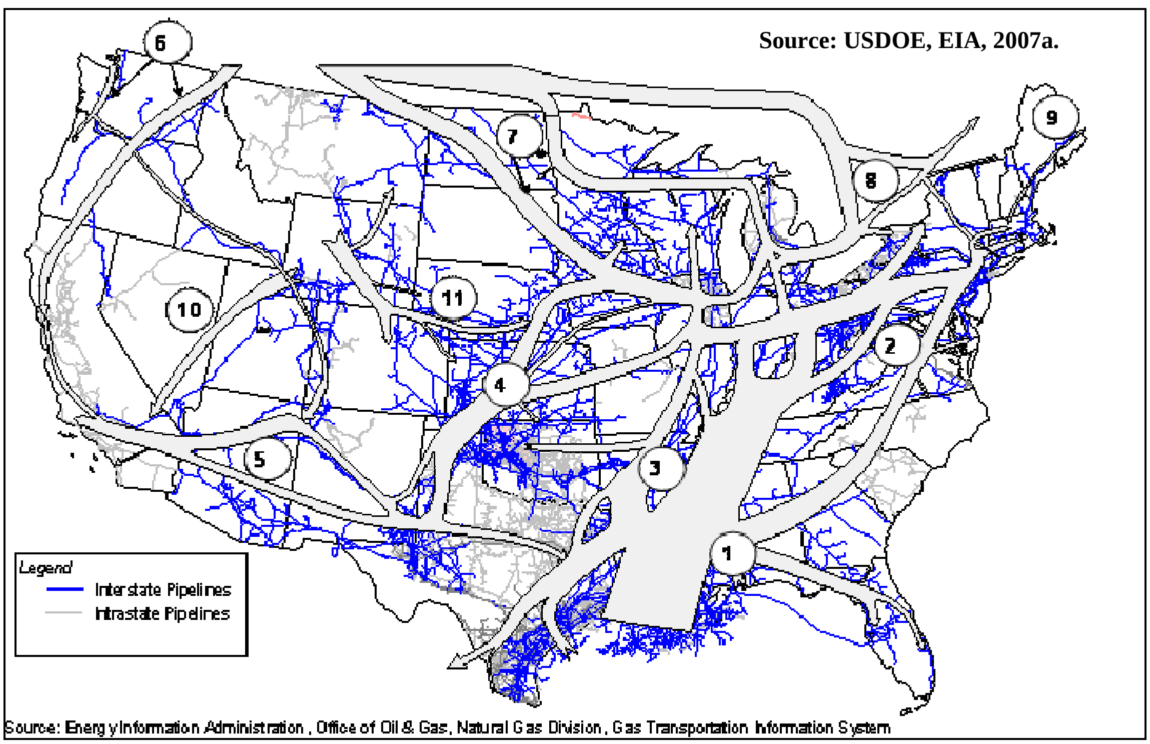


Figure 48. Major U.S. natural gas transportation corridors.

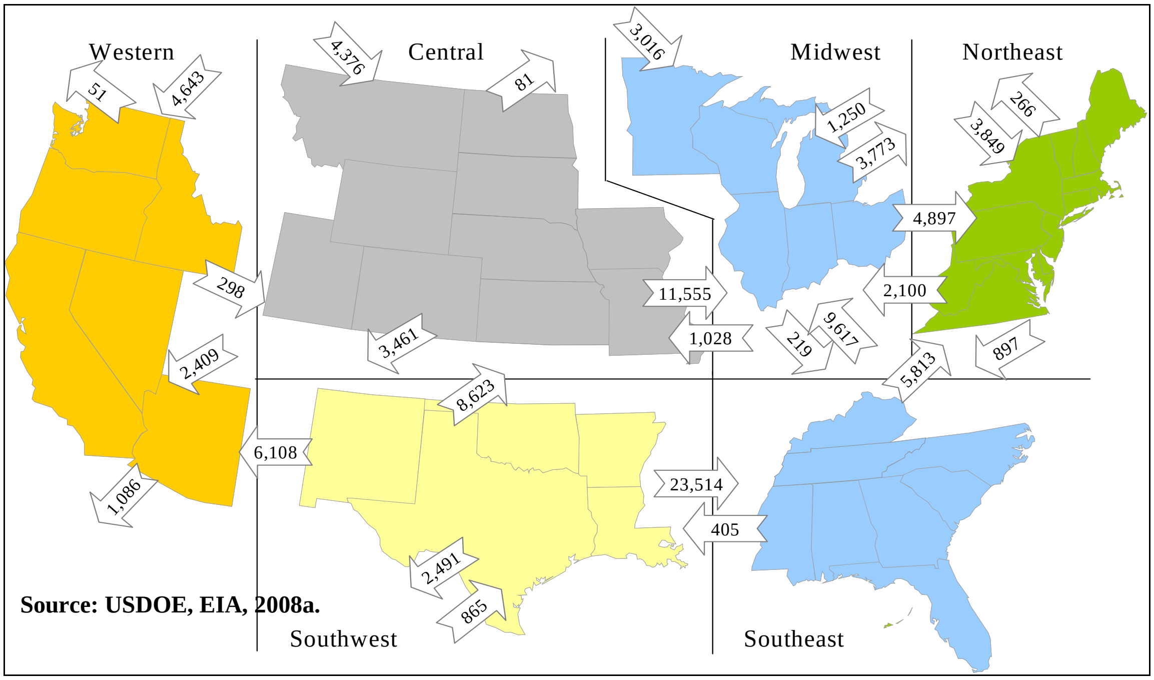


Figure 49. Estimated region-to-region natural gas pipeline capacity (MMcf/day).

Oil Pipelines

Interstate oil pipelines deliver over 13 billion barrels of petroleum each year. About 59 percent of the petroleum transported by pipelines is crude oil, the remainder is in the form of refined petroleum products (AOPL, 2008). Like natural gas, the oil market's infrastructure moves oil from the producing regions to consuming regions (Figure 50).

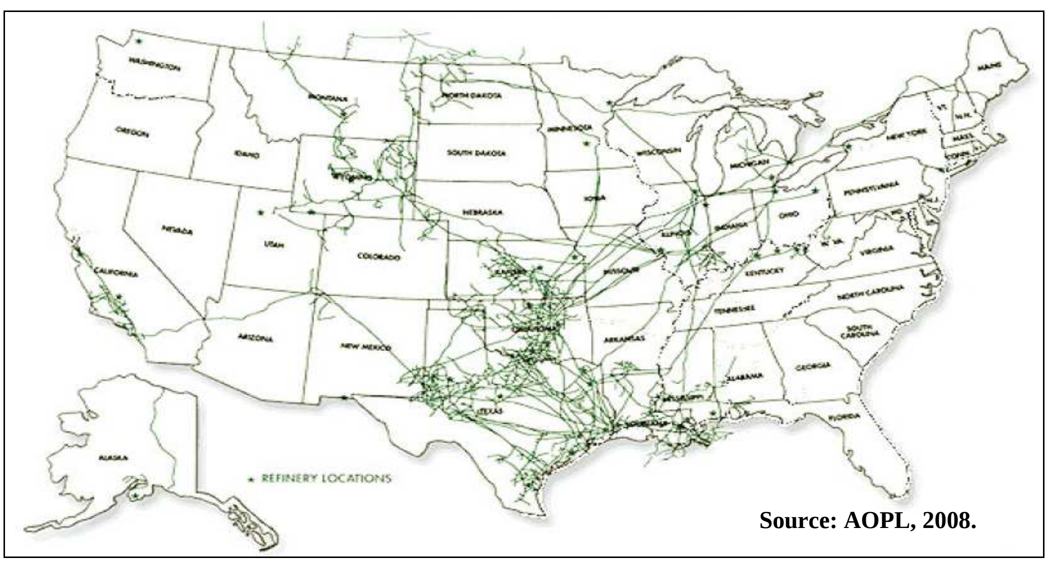


Figure 50. Major crude oil pipelines.

The profiles below and accompanying Figure 51 and Table 17 display the inter-regional flows in the U.S (Allegro Energy Group, 2001; USDOE, EIA, 2008c):

- ***The Gulf Coast (PADD[22] 3)*** is the largest supply area of the U.S. accounting for 56 percent of the nation's crude oil production and 46 percent of its refined product output. It is the largest oil supplier in interregional trade, accounting for 85 percent of the crude oil shipments and 78 percent of the refined petroleum production shipments among PADDs. Most of the crude oil goes to refineries in the Midwest, while most refined products go to the East Coast and, to a lesser extent, to the Midwest.

- ***The East Coast (PADD 1)*** has virtually no indigenous crude oil production, limited refining, and the highest regional, non-feedstock demand for refined products. Its refineries process predominately foreign crude oil. To meet regional demand, their output is augmented by refined product shipments from the Gulf Coast as well as imports from abroad. The East Coast receives more than 55 percent of the refined products shipped among regions and almost all of the refined product imported into the U.S.

- ***The Midwest (PADD 2)*** has significant regional crude oil production, but also processes crude oil from outside of the region: Canadian crude oil imported directly via pipeline, crude oil imported from other nations and then shipped to the Midwest via the Gulf Coast, and crude oil produced in the Gulf Coast region. These supplies from outside of the region – imports and domestic – account for 88 percent of its refinery input. Refined product output from regional refineries is also supplemented with supplies from outside the region, primarily shipments from the Gulf Coast.

- ***The Rocky Mountain Region (PADD 4)*** has the lowest petroleum consumption, but has shown relatively rapid regional growth in recent years. It imports crude oil from Canada to augment local production for its refineries. Its distances are long, its topography steep and its infrastructure thin, however. Therefore, the inter-regional trade, while small in nationwide standards, is an important factor in keeping the region's supply and demand in balance.

- ***The West Coast (PADD 5)*** is logistically separate from the rest of the country. Its crude oil supply is dominated by production from the Alaskan North Slope oil fields, which now accounts for 51 percent of PADD 5 production, down from 65 percent when those fields were in peak production in the late 1980s. Essentially all of the rest of the region's production comes from California.

[22] The five regions referred to as "Petroleum Administration for Defense Districts" or PADDs are successor regional designations that were created during World War II to organize the allocation of fuels. While the original PADDs were abolished in 1946 after the war, they were re-activated during the Korean War and ultimately taken over by the U.S. Department of the Interior (Oil and Gas Division) and then later by the DOE.

Because of unique product quality requirements in California, the largest consuming state, essentially all of that state's refined product demand is met by output from the state's refineries.

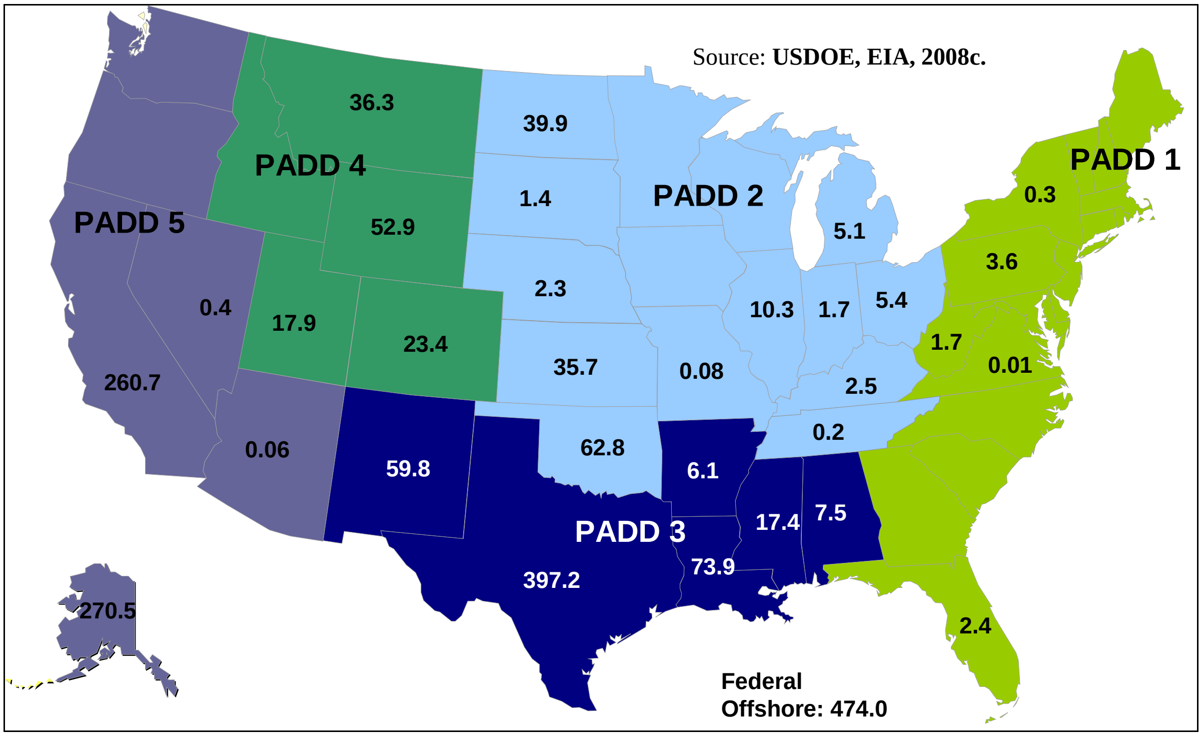


Figure 51. Production of crude oil by PADD district and state (million barrels).

Table 17

Movements of Crude Oil and Petroleum Products by Pipeline between PADD Districts, 2006

	Crude Oil	Petroleum Products	Total
	---------- (thousand barrels) ----------		
From PADD 1 to:			
PADD 2	-	121,538	121,538
PADD 3	4,712	-	4,712
From PADD 2 to:			
PADD 1	2,216	12,581	14,797
PADD 3	22,544	67,759	90,303
PADD 4	16,628	26,915	43,543
From PADD 3 to:			
PADD 1	2,978	894,920	897,898
PADD 2	594,064	365,272	959,336
PADD 4	-	10,210	10,210
PADD 5		40,250	40,250
From PADD 4 to:			
PADD 2	56,356	19,937	76,293
PADD 3	1,469	50,510	51,979
PADD 5		10,035	10,035
From PADD 5 to:			
PADD 3	-	-	-
PADD 4		-	-

Source: USDOE, EIA, 2008c.

Gulf of Mexico

The pipeline system within the GOM region is made up of approximately 33,000 miles of pipelines that link the estimated 4,000 operating platforms to facilities onshore (USDOE, OFE, 2006). The pipeline system is complicated and includes surface-level piping, valves, metering points, compressors, and dehydration and separation facilities, as well as sub-sea piping and valves. Secondary lines (typically less than 20 inches), comparable to the areas "gathering system," feed natural gas into the main the larger diameter primary lines (typically greater than 20 inches in diameter) that transport the natural gas directly to points onshore and in many instances directly into systems bound for the consuming areas of the northeast, Midwest, and southeastern U.S. (USDOE, OFE, 2006). The following discussion highlights a number of the larger subsea pipeline systems and segments that bring oil and gas onshore from the GOM.

Manta Ray Pipeline System

Owned by Neptune Pipeline Company (which is owned by Enbridge Offshore and Enterprise Productions Operating L.P.) and operated by Shell, the Manta Ray system is comprised of 250 miles of 14-, 16- and 24-inch pipeline. The system extends southward from Ship Shoal 207 into parts of the South Timbalier, Ewing Banks, Grand Isle, and Green Canyon blocks of the Central Planning Area. The Manta Ray system has a capacity of 800 MMcf per day and interconnects with ANR Natural Gas Pipeline, Nautilus Pipeline Company, Transcontinental Gas Pipeline Line, and Trunkline Gas Company (Enbridgeus.com, 2009a).

Viosca Knoll Gathering System

Owned and operated by Enterprise Products Partners, this 162-mile natural gas transmission system is located off the coast of Louisiana primarily into the Main Pass, South Pass, and Viosca Knoll blocks of the Central Planning Area. Viosca Knoll Gathering System pools gas production into several major interstate pipelines including Tennessee, Columbia Gulf, Southern Natural, Transco, and Destin (EPP, 2008a).

Phoenix

Owned and operated by Enterprise Products Partners, Phoenix Gathering System is a 78-mile offshore natural gas pipeline that connects the Red Hawk platform in the Garden Banks area of the Central Planning Areas in the GOM to the ANR pipeline system (EPP, 2008a). ANR makes landfall near Morgan City, Louisiana, and Grand Chenier, Louisiana.

Green Canyon Laterals

This is a group of 28 laterals (136 miles) that are extensions of natural gas pipelines located in the GOM offshore Texas and Louisiana. This system delivers to numerous downstream pipelines including the High Island Offshore System (EPP, 2008a).

Nautilus Pipeline System

Owned by Neptune Pipeline Company (which is owned by Enbridge Offshore and Enterprise Productions Operating L.P.) and operated by Shell, the Nautilus system is a 101-mile, 600 MMcf per day, FERC-regulated natural gas pipeline extending from Ship Shoal Block 207 to onshore Louisiana. The system interconnects with four interstate and three intrastate pipelines and is straddled by the Neptune Gas Plant (Enbridgeus.com, 2009b).

High Island Offshore System (HIOS)

Owned and operated by Enterprise Products Partners, HIOS is a FERC-regulated offshore natural gas transmission system that transports production from fields in the Western Gulf of Mexico to numerous downstream pipelines off the coast of Louisiana including ANR and Tennessee Gas Pipeline, UTOS, and Stingray. High Island Offshore System is 204 miles (EPP, 2008a).

Poseidon System

Owned and operated by Enterprise Products Partners, the Poseidon System is a 324-mile offshore crude oil pipelines system that gathers crude oil production from the OCS in the GOM and transports it onshore to Houma, Louisiana (EPP, 2008b). A number of wells feed into the Poseidon system including the Front Runner Field owned by Murphy Exploration and

Production, Dominion Exploration and Production, and Spinnaker Exploration and Production; and the Tarantula Field which is owned by Apache Corporation (EPP, 2005).

Cameron Highway Oil Pipeline System

Owned and operated by Enterprise Products Partners, the 390-mile system is designed to gather deepwater trend production, primarily from the South Green Canyon area of the GOM, for delivery to refineries and terminals in Port Arthur and Texas City, Texas (EPP, 2008b).

Stingray Pipeline Company

Owned and operated by Starfish Pipeline Company, L.L.C., (a limited liability company owned 50% by Enbridge Offshore (Gas Transmission) L.L.C. and 50% by MarkWest Energy Partners, L.P.), the Stingray Pipeline system is comprised of 325 miles of 36-inch diameter pipe. The system extends from the High Island, West Cameron, East Cameron, Vermillion, and Garden Banks blocks to onshore southern Louisiana connections with the West Cameron Dehydration Plant, the Targa-owned Barracuda and Stingray gas processing plants, and one intrastate and three interstate pipelines (Enbridgeus.com, 2009c).

Enbridge Offshore Pipelines (UTOS)

Owned and operated by Enbridge Offshore, the UTOS system is composed of 30 miles of 42-inch diameter pipe. UTOS extends from an interconnection with the HIOS system at West Cameron Block 167 to the Johnson Bayou production handling facility, owned by UTOS. The UTOS system is essentially an extension of the El Paso's HIOS System as almost all the natural gas transported through the UTOS system comes from the HIOS system. The Johnson Bayou facility provides primarily natural gas and liquids separation and gas dehydration services for natural gas transported on the UTOS system (Enbridgeus.com, 2009d).

Independence Trail

Owned and operated by Enterprise Products Partners, the system connects the Independence Hub platform in Mississippi Canyon Block 920 to Tennessee Gas Pipeline in the West Delta area of the Gulf of Mexico. The system comprises 140 miles of 24-inch pipe (Offshore-Technology.com, 2009b). The Independence Hub and Trail projects process and gather natural gas and condensate production from the Atwater Valley, DeSoto Canyon, Lloyd Ridge, and Mississippi Canyon areas located in the eastern region of the deepwater Gulf of Mexico (Rigzone.com, 2006c).

Louisiana Offshore Oil Port (LOOP)

Owned by Marathon Pipe Line LLC, Murphy Oil Corporation, and Shell Oil Company, the LOOP is an offshore port facility located eighteen miles south of Grand Isle, Louisiana. LOOP is the only port in the U.S. capable of offloading deep draft tankers known as Ultra Large Crude Carriers (ULCC) and Very Large Crude Carriers (VLCC) (LOOP.com, 2009). LOOP offloads small tankers as well. LOOP is connected via a 48-inch pipeline to the Clovelly onshore oil storage facility which is 25 miles inland, near Galliano, Louisiana. The Clovelly facility provides interim storage for the crude oil before it is delivered to refineries on the Gulf Coast and in the Midwest (LOOP.com, 2009).

The Clovelly storage facility is made up of eight underground salt caverns with a total storage capacity of 50 million barrels (LOOPLLC.com, 2009). The Exxon-Mobil, Shell, Clovelly-to-Meraux (CAM) pipelines all connect the Clovelly facility to refineries in Louisiana and the Gulf Coast. LOOP also operates 53 miles of 48-inch pipe that connects the Clovelly facility to the St. James, Louisiana terminal and the Capline pipeline system (Sprehe, 2003). The Capline system transports crude oil to several refineries in the Midwest. The LOOP system handles up to 50 percent of the U.S. refining capacity (LOOPLLC.com, 2009; Sprehe, 2003).

7.2.3. Typical Firms

Two-thirds of the lower 48 states are almost totally dependent upon the interstate pipeline system for their supplies of natural gas. In 2005, 85 percent of the 48 trillion cubic feet (Tcf) of gas transported throughout the U.S. moved through facilities owned by the major interstate pipeline companies (USDOE, EIA, 2008a). The 30 largest companies own about 77 percent of all interstate natural gas pipeline mileage and about 83 percent of the total capacity (148 billion cubic feet) available within the interstate natural gas pipeline network (Table 18) (USDOE, EIA, 2008a). These pipelines also account for the largest levels of pipeline capacity. Sixteen of the thirty largest U.S. natural gas pipeline systems originate in the Southwest Region, with four additional ones depending heavily upon supplies from the region (USDOE, EIA, 2008a).

The largest system-wide capacity is found on the Columbia Gas Transmission system, which has primary operations in seven states in the Northeast and limited operations in Kentucky, North Carolina, and Ohio (USDOE, EIA, 2006a). Northern Natural Gas Pipeline system, which transports natural gas supplies from the Southwest to the Central and Midwest regions, consists of 15,854 pipeline miles, the most number of miles for a single natural gas pipeline company (USDOE, EIA, 2006a).

While interstate pipelines transport gas throughout the U.S., intrastate pipelines operate within state borders, connecting natural gas production to local markets and to the interstate pipeline network (Table 19). Intrastate pipelines account for approximately 29 percent of the total miles of natural gas pipeline in the U.S. (USDOE, EIA, 2008a). Although an intrastate pipeline system is defined as operating within a state, it may have operations in more than one state. If these operations are separate, and do not physically interconnect, they are considered intrastate, and are not subject to the jurisdiction of the FERC. More than 90 intrastate natural gas pipelines operate in the lower 48 states (USDOE, EIA, 2008a).

Table 18

Thirty Largest U.S. Interstate Natural Gas Pipeline Systems, 2005

Pipeline Name	Market Regions Served	Primary Supply Regions	States in which Pipeline Operates	Transported (billion dth)	System Capacity (MMcf/d)	System Mileage
Columbia Gas Transmission Co.	Northeast	Southwest, Appalachia	DE, PA, MD, KY, NC, NJ, NY, OH, VA, WV	3,431	8,700	10,354
Transcontinental Gas Pipeline Co.	Northeast, Southeast	Southwest	AL, GA, LA, MD, MS, NC, NY, SC, TX, VA, GOM	3,338	8,161	10,469
Northern Natural Gas Co.	Central, Midwest	Southwest	IA, IL, KS, NE, NM, OK, SD, TX, WI, GOM	1,195	7,923	15,854
ANR Pipeline Co.	Midwest	Southwest	AR, IA, IL, IN, KS, KY, LA, MI, MO, MS, NE, OH, OK, WI, GOM	2,815	6,844	9,616
Tennessee Gas Pipeline Co.	Northeast, Midwest	Southwest, Canada	AR, KY, LA, MA, NY, OH, PA, TN, TX, WV, GOM	1,920	6,686	13,302
Texas Eastern Transmission Corp.	Northeast	Southwest	AL, AR, IL, IN, KS, KY, LA, MI, MO, MS, NJ, NY, OH, OK, PA, TX, WV, GOM	1,364	6,523	9,179
El Paso Natural Gas Co.	Western, Southwest	Southwest	AZ, CO, NM, TX	4,864	6,152	10,661
Dominion Transmission Co.	Northeast	Southwest, Appalachia	PA, MD, NY, OH, VA, WV	1,344	5,734	3,142
Northwest Pipeline Corp.	Western	Canada, Central	CO, ID, OR, UT, WA, WY	700	4,500	4,046
Natural Gas Pipeline Co. of America	Midwest	Southwest	AR, IA, IL, KS, LA, MO, NE, OK, TX, GOM	2,690	4,485	9,111
Southern Natural Gas Co.	Southeast	Southwest	AL, GA, LA, MS, SC, TN, TX, GOM	937	3,365	7,671
Centerpoint Gas Trans. Co.	Southwest	Southwest	AR, KS, LA, OK, TX	928	3,339	6,182
Gulf South Pipeline Co.	Southeast, Southwest	Southwest	AL, FL, LA, MS, TX, GOM	1,015	3,038	6,580
Colorado Interstate Gas Co.	Central	Central, Southwest	CO, KS, OK, TX, WY	939	3,000	3,996
Texas Gas Transmission Corp.	Midwest	Southwest	AR, IN, KY, LA, MS, OH, TN	2,178	2,979	5,643
Great Lakes Gas Trans. Co.	Midwest	Canada	MI, MN, WI	958	2,859	2,115
Panhandle Eastern Pipeline Co.	Midwest	Southwest	IL, IN, KS, MI, MO, OH, OK, TX	709	2,840	6,445
Gas Trans. Northwest Corp.	Western	Canada	ID, OR, WA	767	2,636	1,356
Northern Border Pipeline Co.	Midwest, Central	Canada	IA, IL, IN, MN, MT, ND, SD	898	2,496	1,399
Southern Star Central Pipeline Co.	Central	Central	CO, KS, MO, NE, OK, TX, WY	354	2,451	5,788
National Fuel Gas Supply Co.	Northeast	Canada, Appalachia	NY, PA	417	2,312	1,504
Questar Pipeline Co.	Central	Central	CO, UT, WY	379	2,192	1,745
Florida Gas Transmission Co.	Southeast	Southwest	AL, FL, LA, MS, TX, GOM	757	2,190	4,867
Algonquin Gas Transmission Co.	Northeast	Southwest	CT, MA, NJ, NY, RI	346	2,174	1,103
Columbia Gulf Transmission Co.	Southeast, Northeast	Southwest	KY, LA, MS, TN, GOM	2,041	2,156	4,105
Alliance Pipeline Co. (US)	Midwest	Canada	ND, MN, IA, IL	652	2,053	888
Wyoming Interstate Gas Co.	Central	Central	CO, WY	594	1,997	585
Kern River Gas Transmission Co.	Western	Central	CA, NV, UT, WY	718	1,833	1,680
High Island Offshore System	Southwest	Gulf of Mexico	LA, GOM	234	1,800	212
Trunkline Gas Co.	Midwest	Southwest	AR, IL, IN, KY, LA, MS, OH, TN, TX	606	1,680	3,558
Subtotal				**40,088**	**115,098**	**163,156**
Other Interstate Systems (79)				10,242	33,235	49,531
Total				**50,330**	**148,333**	**212,687**

(Ranked by system capacity, million cubic feet per day, (MMcf/d).
Source: USDOE, EIA, 2008a.

Table 19

U.S. Intrastate Natural Gas Pipeline Systems

Pipeline Name	State(s) in which Pipeline Operates	System Capacity (MMcf/d)	System Mileage
Central Region			
Missouri Gas Co	MO	n.a.	65
Missouri Pipeline Co	MO	n.a.	181
NorthWestern Energy Co	MT, WY, SD, NE	73	2,819
Overland Trail Transmission Co	WY	n.a.	238
Rocky Mountain Natural Gas Co	UT, CO	n.a.	731
Midwest Region			
Battle Creek Pipeline Co	MI	n.a.	NA
Bluewater Pipeline	MI	100	30
Cardinal Pipeline System	IN	100	12
Cobra Pipeline Co	OH	n.a.	217
Dominion East Ohio Gas Co	OH	n.a.	1,281
Dominion West Ohio Gas Co	OH	n.a.	199
Heartland Pipeline	IN	80	25
North Coast Gas Trans. Co	OH	82	185
Northern Illinois Gas Co	IL	n.a.	2,613
Saginaw Bay Pipeline South	MI	135	59
Northeast Region			
AGL/Elizabethtown Gas Div.	NJ, PA	n.a.	4
Cranberry Pipeline Corp	WV	n.a.	NA
Dominion Hope Gas co	WV	n.a.	160
Empire Pipeline Co	NY	525	157
KeySpan Energy Delivery	NH	n.a.	NA
KeySpan Energy Delivery Co	NY	n.a.	220
KeySpan LNG LP	MA	n.a.	NA
NORA Gas Transmission Co	VA	50	16
National Fuel Gas Dist.Co	NY	n.a.	1,268
Norse Pipeline Co	PA, NY	n.a.	350
North Penn Gas Co	PA	n.a.	647
Northern Utilities Inc (ME)	ME	n.a.	103
Spectra Virginia Pipeline Co	VA	n.a.	244
Southeast Region			
Alabama Intrastate System	AL	200	450
Atmos Energy -- Mississippi	MS	n.a.	335
Cardinal Pipeline Co	NC	263	67
Eastern N.C. Gas Pipeline Co	NC	72	140
Enbridge Pipelines (AL Intra)	AL	n.a.	111
Kentucky-West Virginia Gas Co	KY, WV	100	516
Mississippi Fuel Co	MS	n.a.	395
Pub Svc Co of North Carolina	NC	n.a.	559
Sandhill Pipeline Co	NC	300	84
Tengasco Pipeline Co	TN	25	30
Union Light Heat & Power	KY	n.a.	70
Western Region			
Coos Bay Pipeline Co	OR	70	57
Northwest Natural Gas Co	OR, WA	n.a.	NA
PG&E Transmission Co	CA	3,200	3,477
San Diego Gas & Electric Co	CA	900	830
Southern California Gas Co	CA	4,050	1,887
Southwest Gas Co	AZ, CA, NV	n.a.	226
Southwest Region			
Acadian Gas Pipeline System	LA	1,000	438
Amoco Pipeline Co	TX	n.a.	368
Arkansas Western Pipeline Co	AR	27	NA
Atmos Pipeline - Texas	TX	1,300	6,162
Barnett-Texoma Pipeline	TX	700	264
Bossier Pipeline	TX	500	78
Bridgeline Gas Systems Inc	LA	1,500	1,024
Buffalo Wallow System	OK, TX	n.a.	100
CCNG Transmission System	TX	350	590
Calpine Texas Pipeline	TX	n.a.	17
Channel Indus. Gas Pipeline Co	TX	1,300	733
Cornerstone Pipeline Co	TX	n.a.	15
Crosstex North Texas Pipeline	TX	250	140
Cypress Gas Pipeline Co	LA	100	577
DCP Intrastate Pipeline Co	TX	n.a.	161
Dow Pipeline Co (LA)	LA	n.a.	184
Dow Pipeline Co (TX)	TX	n.a.	338
ET Fuel System	TX	1,300	2,000
ETP Katy Pipeline Co	TX	n.a.	148
Enbridge Pipelines (East Texas)	TX	500	2,369
Enbridge Pipelines (LA Intra)	LA	115	44
Enbridge Pipelines (Palo Duro)	TX	75	400
Energy Transfer - Oasis Pipeline	TX	1,200	583
Enogex Inc	OK	n.a.	2,311
Enterprise Texas Pipeline LP	TX	410	7,489
Evangeline Gas Pipeline Co	LA	n.a.	27
Fort Worth Basin Pipeline	TX	400	54
Fort Worth Basin Pipeline	TX	250	122
Guadalupe Pipeline Co	TX	n.a.	882
Gulf Coast Pipeline System	TX	250	484
Hallmark Laterals System	TX	n.a.	70
Houston Gas Pipeline System	TX	2,400	4,200
KM Rancho Pipeline	TX	320	424
KM Tejas Pipeline System	TX	3,500	3,400
Kinder Morgan TX Pipeline Co	TX	n.a.	2,500
Louisiana System	LA	600	2,000
MarkWest Intrastate Pipeline Co	TX	70	135
MarkWest New Mexico LP	NM	162	5
Matagorda Island Pipeline Co	TX	n.a.	50
Monterey Pipeline Co	LA	n.a.	439
North Side Loop Line	TX	200	22
North Texas Pipeline	TX	325	86
Oklahoma Natural Gas Co	OK	2,000	4,537
Oklahoma Texas Gas Co	TX	n.a.	29
Peoples Gas Co (TX)	TX	n.a.	148
Public Service Co of New Mexico	NM	n.a.	1,213
Red River Pipeline Co	TX	n.a.	342
Regency Intrastate Pipeline Sys.	LA	615	320
Snyder Pipeline	TX	n.a.	132
South Shore Pipeline Co	TX	10	23
Southern Union Intra. Pipelines	TX, NM	n.a.	4,000
Southwestern Energy Pipeline Co	AR	34	18
Tidelands Pipeline System	TX	n.a.	5
Tuscaloosa Pipeline Co	LA	n.a.	30
Vanderbuilt Pipeline System	TX	60	200
West Texas Gas Pipeline Co	TX	134	566
Westex Pipeline Co	TX	n.a.	2,656

Note: n.a. is not available.
Source: USDOE, EIA, 2008a.

7.2.4. Regulation

Natural Gas Pipelines

The FERC regulates both the construction of pipeline facilities and the transportation of natural gas engaged in interstate commerce. FERC does not have direct jurisdiction over all gas pipelines and does not directly regulate intrastate pipelines nor does it regulate onshore gathering lines. The Natural Gas Act of 1938 (NGA) is the primary federal legislation outlining the jurisdiction of the Federal Power Commission (the predecessor regulatory agency to the FERC). Companies providing services, constructing, and/or operating interstate pipelines must first obtain commission certificates of public convenience and necessity. FERC approval is required to abandon regulated transportation and storage facility use and services. FERC also sets rates and governs the terms and conditions of providing services through a set of price and term sheets referred to as "tariffs." FERC also regulates the construction and operation of facilities needed by pipelines at the U.S. point of entry or exit to import or export natural gas.

The Regulatory Transformation of the Pipeline Industry

Prior to the mid-1980s, interstate pipeline systems brought natural gas from producers, transported it along their pipelines, and then resold it to local distribution companies (LDCs) in consuming areas. Order 436, promulgated in 1985, began a series of regulatory reforms opening access of the interstate transportation system to third parties that culminated in 1992 with the precedent setting policy referred to as Order 636 in 1992. Cumulatively, the FERC Orders starting in the mid-1980s and ending with Order 636, started a process of competition based upon the "unbundling" of interstate natural gas transportation services. This process separated, or "unbundled," the ownership of natural gas and the transportation of natural gas into two different components. Natural gas pipelines, after Order 636, were prohibited from directly owning natural gas commodity and were only allowed to be "transporters" of natural gas commodities for third parties. This increased competition allowed natural gas purchasers to separately negotiate price provisions and contract durations with various suppliers as well as interstate transportation companies to attain the best deal possible on both "ends" of their service provision (e.g. commodity natural gas and transportation).

The process of natural gas unbundling started with Order 436 which allowed pipelines to choose "open-access" (or competitive) status by allowing transport-only service to any willing customer on its interstate pipeline system. Customers not choosing to facilitate this new competitive transportation service could continue to use its bundled services (i.e., combined gas commodity and transportation) previously offered by the pipelines. Pipelines that did declining open-access status, were required to provide bundled service only and were not allowed to transport any third party gas (on transportation basis alone). FERC attempted to entice pipelines to participate in this open access policy by offering to grant participants an "optional expedited certificate" for the development of new transmission facilities. At the time, obtaining a permit to build new facilities was costly, contested, and long FERC processes often took several years.

Within months of the promulgation of Order 436, every major interstate pipeline, including those in the GOM region, had applied for open access status. Within two years, 75 percent of all interstate throughput was transported rather than sold through a bundled service (Michaels, 2002a). Order 436 was a successful start in the introduction of competition in natural gas markets, but it had its shortcomings primarily in its failure to address important "take-or-pay" issues.[23] The DC Court of Appeals wanted to resolve the outstanding issues by requiring FERC to tie producer's access to a pipeline to take-or-pay contracts. The court sympathized with FERC's reluctance to alter contracts, however, these contracts had been written in a different era which required resale-only pipelines to find adequate gas supplies during a shortage period. The court concluded the FERC should have the power to modify these contracts.

In August, 1987, the FERC issued Order 500 in response to the Court of Appeals remand. Order 500 required producers to credit any gas transported for it against the transporting pipeline's take-or-pay liability. To minimize the intrusion, Order 500 mandated cross-crediting only on a subset of all contracts that had been written during a two-year period (1986 to 1987). To force rapid settlements, Order 500 imposed a sunset deadline of December 31, 1988, and the Order also adopted the ratemaking principle of a "gas inventory charge" that would compensate the pipeline for providing capacity to serve resale customers' requirements.

Pipeline companies entered the early 1990s with a myriad of responsibilities as a result of the changing FERC Orders and Court decisions. Pipelines also remained responsible for the reliable operation and coordination of transportation receipts, deliveries, and storage, both for their own transactions and for those of third-party transporters. Most pipelines had marketing affiliates that sold gas in competition with producers and brokers. Shippers and other marketers of natural gas services were concerned that a pipeline could use its operational knowledge and transaction-specific information to create a competitive advantage for itself as a gas merchant, particularly during peak periods. Conversely, pipeline re-sales were disadvantaged by burdensome abandonment regulations that did not apply to transport service.

The concerns about the ability to exercise vertical market power motivated the FERC to issue Order 636 in April 1992. This Order represented the most comprehensive restructuring of the pipeline transportation industry to date. Order 636 is important because it mandates that natural gas transportation be provided on a "basis that is equal in quality for all gas supplies whether purchased from the pipeline or from any other gas supplier." Order 636 requirements also issued blanket sales certificates to pipelines so that they can offer unbundled firm and interruptible sales services at market-based or competitive rates. In addition, pipelines are required to provide a variety of transportation services to their shippers including a new unbundled "no-notice" firm transportation service, a firm transportation service that is unbundled and improved in quality, unbundled storage services, and interruptible transportation services, among others. Order 636 permits gas purchasers and sellers to choose their own customized transportation service and service provider. Order 636 also loosened requirements that a pipeline continue to provide what were considered to be uneconomic services by requiring pipelines to conform to what is referred to as a straight-fixed-variable (SFV) pricing mechanism that puts all fixed-costs in a capacity charge, and all variable costs in a variable, volumetric transportation charge. This new pricing methodology was developed to make users responsible for the costs of capacity that they actually use during peak periods. All of these changes, in conjunction, changed the nature of pipeline transportation services. Rather than being passive purchasers of bundled, delivered supply,

[23] Take-or-pay contracts have a clause that provides a minimum quantity of gas that must be paid for, whether or not delivery is accepted by the purchaser.

customers have, since Order 636, been able to choose their pipeline service provider and their own respective sources of supply. The use of pipeline capacity release, that is, allowing customers to re-sell capacity rights secured on pipeline services, has added an additional layer of competition in pipeline transportation markets. According to industry experts, the advent of open access transportation and a market in released capacity provided an important lesson in economics: although a pipeline is technologically a natural monopoly, a market is arising in which the services of that monopoly will be allocated competitively (Michaels, 2002b).

Since Order 636, numerous new services have been introduced as companies positioned themselves to take advantage of new market opportunities. In response to new market conditions, many pipeline companies have consolidated or formed strategic alliances to increase market share and gain access to new customers. For example, the gas industry has seen a strong growth in the number of gas marketing affiliates and "all energy" service companies. Some examples of these "all energy" service companies arising from pipeline company origins, include El Paso Energy, Williams Energy, and Kinder Morgan.

The new natural gas market design allows natural gas purchasers to negotiate price provisions and contract terms with many different suppliers, while contracting separately with pipeline companies for transportation, storage, and various other services, selected and combined, to satisfy their needs. To facilitate this, a new type of industry player has emerged, the independent gas marketer, who, in addition to marketing gas supply, can serve as the purchaser's agent in making all the arrangements necessary to get the gas delivered to the end user. This service includes what is effectively a "packaging" or "bundling" of various types of supply and transportation services. Deregulation and market restructuring have also directly contributed to growth in gas storage for managing seasonal inventories, the development of a secondary transportation markets, and better information about commodity and transportation prices via commodity markets, electronic bulletin boards, and more recently, the internet (NaturalGas.org, 2007a).

Oil Pipelines

Like natural gas pipelines, most interstate liquid petroleum pipelines operate as "common-carriers," which are pipelines that must allocate space to all shippers who meet their service conditions requirements. The FERC loosely regulates oil pipeline rates for interstate services on these pipelines. States, on the other hand, tend to regulate rates that are charges for interstate crude oil and product transportation. Prior to FERC rate regulation, the Interstate Commerce Commission (ICC) held primary rate regulation authority over an oil pipeline's "tariffed" or posted rates. Like natural gas companies, rate regulation on oil pipelines was based upon a regulatory premise of setting rates at a "just and reasonable" level, based on an allowed rate of return, and on the "valuation" of the pipeline's common carrier assets. When the FERC assumed jurisdiction, it explored a number of different methods for determining "just and reasonable" rates.

FERC's revised oil pipeline regulatory model was established in 1995 and is based upon a variety of methods to set just and reasonable transportation rates (Allegro Energy Group, 2001). These methods include allowing pipelines to change rates according to a quasi-price cap formula that allowed rate increases up to percentage change of a pre-defined government-set economic index. Another pricing method, more commonly utilized along the Gulf Coast region, includes a market-determined (i.e., market-based) rate if competitive alternatives can be proven. In other parts of the country, application of the former cost of service standard still exists for pricing oil transportation services as well as formerly negotiated rates for service that have been agreed to between the oil pipeline carrier and relevant shippers. The vast majority of oil pipeline industry tariff rates now in effect were set under the economic index method. (Allegro Energy Group, 2001). The second most used method of tariff rate justification is agreement on negotiated rates between the pipeline and its shippers. The fastest growing application is market-based rates, which requires the Commission to determine that the pipeline lacks market power (i.e., there are competitive substitutes and alternatives) in the applicable regional market (Allegro Energy Group, 2001).

In addition to economic regulation, the design, construction, operation, and maintenance of interstate liquid petroleum pipelines is regulated by the Department of Transportation's Office of Pipeline Safety (OPS). If the pipeline is an intrastate pipeline and the state has established an office overseeing pipeline safety, there may be additional state regulatory requirements. In some cases, states have received approval from the federal OPS to inspect interstate pipelines for compliance with federal pipeline safety regulations, although enforcement authority remains under the jurisdiction of the federal OPS to assure continuity in interstate commerce. Offshore pipelines (e.g., in the Gulf of Mexico) are regulated by the BOEM.

Pipeline safety regulations govern the entire life of pipeline operations, including design, construction, inspection, record-keeping, worker qualification, and emergency preparedness. Other agencies that have supporting regulatory roles related to pipeline safety include:

- ***National Transportation Safety Board*** for investigation of certain pipeline accidents;
- ***Occupational Safety and Health Administration*** for worker safety and hazardous material emergency response;
- ***Environmental Protection Agency*** (and/or corresponding state environmental agencies) for permitting of emissions from tanks and some other facilities and response and remediation of liquid petroleum spills;
- ***U.S. Coast Guard*** relative to preparedness and response to spills in navigable waters; and
- ***State and County Emergency Management Agencies*** may have regional emergency planning and notification requirements and, along with local emergency responders, would be involved in oversight of the company's response to a pipeline incident.

7.3. Industry Trends and Outlook

7.3.1. Trends

Between 2000 and 2005, over 13,000 miles of pipeline totaling 55,000 million cubic feet per day of capacity were added to the U.S. network (USDOE, EIA, 2003a and 2006a). From 2000 through 2003, the annual level of capacity additions grew steadily and then leveled in 2004 and 2005. As seen in Table 20, the majority of the capacity additions were in the Southwest region and most of the added mileage was in the West.

Table 20

Recent Natural Gas Pipeline Additions and Expansions

	Additional Capacity (MMcf/day)					
	2000	**2001**	**2002**	**2003**	**2004**	**2005**
Central	853	1,429	1,876	1,162	1,424	1,977
Midwest	2,398	1,236	2,058	651	1,063	599
Northeast	345	2,163	1,500	1,318	837	620
Southeast	510	1,822	3,056	1,532	545	425
Southwest	1,400	2,157	882	2,480	2,744	4,357
Western	157	310	2,852	2,368	1,023	502
to Mexico/Canada	1,320	145	624	912	25	-
Total Capacity	**6,983**	**9,262**	**12,848**	**10,423**	**7,661**	**8,480**
	Additional Miles					
	2000	**2001**	**2002**	**2003**	**2004**	**2005**
Central	243	384	340	409	489	253
Midwest	1,270	87	236	129	51	51
Northeast	26	191	189	82	116	22
Southeast	182	408	915	463	58	113
Southwest	234	316	145	264	568	447
Western	22	922	1,660	885	168	88
to Mexico/Canada	200	84	86	11	9	-
Total Miles	**2,177**	**2,392**	**3,571**	**2,243**	**1,459**	**974**
	Estimated Cost (Million $)					
Region	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
Central	86	319	234	182	550	391
Midwest	1813	155	374	132	90	103
Northeast	39	371	611	346	543	74
Southeast	175	499	1842	905	136	240
Southwest	161	204	331	266	465	539
Western	29	96	830	1693	342	31
to Mexico/Canada	31	32	148	41	2	0
Total Cost	**2,334**	**1,676**	**4,370**	**3,565**	**2,128**	**1,378**

Source: USDOE, EIA, 2003a and 2006a.

In 2007 at least 50 natural gas pipeline projects were completed in the U.S., 4 more than were completed in 2006. These projects added close to 1,674 miles of pipeline and more than 14.9 Bcf per day of new capacity to the national natural gas pipeline grid (USDOE, EIA, 2008e). As seen in Table 20, the southeast region, that includes the GOM region, is one of the faster growing areas for pipeline capacity in the U.S. For the period, 2000 to 2005, the Southeast region accounted for 14 percent of the total pipeline capacity additions, 17 percent of the new pipeline miles constructed, and 25 percent of total incremental pipeline investment costs.

Thirty-six of the 50 projects completed in 2007 involved expansions of interstate networks. The other projects either increased capacity on intrastate systems or added to gathering systems to transport new natural gas production from expanding natural gas fields (USDOE, EIA, 2008e).

The following is a summary of some of the recent natural gas pipeline developments in the Southeast and Southwest and one in the Northeast:

- In 2002 the Gulfstream Pipeline system went into service. The 1.1 Bcf per day pipeline is one of the most significant developments in the region. The Gulfstream Natural Gas Project is a 691 mile pipeline that originates near Pascagoula, Mississippi, and Mobile, Alabama, crosses the GOM (with 419 miles of 36 inch diameter pipe) to Manatee County, Florida. Onshore, about 270 miles of pipeline, ranging in diameter from 36 to 16 inches, stretches across south and central Florida, terminating in Palm Beach County (Gulfstream Natural Gas System, 2008).

- In 2004 and 2005, the Gulfstream Pipeline system was expanded. A 110-mile, 175-MMcf per day extension to Florida Power and Light Company's Martin power plant near Florida's east coast was placed in service. A 350-MMcf per day Martin interconnect will also deliver natural gas to the third phase of the project, extensions to St. Lucie and Palm Beach counties (USDOE, EIA, 2005a).

- Also completed in 2004 was the final phase of Southern Natural Gas Company's South System expansion, originally proposed as one project to be completed in 2002. But owing to shifts in natural gas demand in the various markets encompassed by the project, it was divided into five separate phases, covering discrete expansions in Louisiana, Mississippi, Alabama, and Georgia. These five phases increased overall capacity on the southern portion of the system by 760 MMcf per day over the 3 years. A 33-MMcf per day expansion on its North System was completed in 2003 (USDOE, EIA, 2005a).

- In 2004 in the Gulf of Mexico, six offshore deepwater projects added 311 miles of pipeline and 1.8 Bcf per day of capacity. None of these projects transport natural gas directly onshore, but rather interconnect with existing systems, such as the Destin and Nautilus pipelines (USDOE, EIA, 2005a).

- Five new intrastate natural gas pipelines, comprising almost 1.6 Bcf per day of capacity, were installed in east Texas in 2005. These new natural gas pipelines were installed to facilitate the transportation of expanding natural gas production from the East Texas and Fort Worth basins, particularly the Barnett Shale formation area found in the latter. The largest project, Energy Transfer Company's 650-MMcf per day Fort Worth Basin Pipeline, improved transportation services between the Fort Worth Basin and interconnections with other area natural gas pipelines. Demand for new capacity on this and other area natural gas pipelines prompted Energy Transfer to begin looping this new system almost immediately after placing it in service, to increase its capacity by an additional 400 MMcf day by the end of 2006 (USDOE, EIA, 2006a).

- Also in 2005, in the GOM, the first new U.S. LNG import terminal in over 20 years was completed, as well as an 8-mile natural gas pipeline lateral linking it to existing offshore-to-onshore systems. The Excelerate Energy Bridge LNG facility, located 116 miles south of Louisiana in the Gulf of Mexico, can deliver up to 690 MMcf per day of vaporized LNG onshore via either the Sea Robin or Bluewater offshore-to-onshore natural gas pipeline systems through its associated 20-inch diameter, 8-mile connecting lateral (USDOE, EIA, 2006a).

- On May 1, 2007, Southern Natural Gas, a subsidiary of El Paso Corporation began commercial operation of its 167-mile Cypress Pipeline. The 220-MMcf per day pipeline connects with Florida Gas Transmission and transports natural gas from the Elba Island, Ga., LNG terminal to power plants, local distribution companies, large industrial plants and municipal customers in Georgia and Florida. The pipeline has increased its customers' supply diversification and access to storage. Previously, gas customers in Florida, mainly power generators, depended solely on Gulf of Mexico supply that is regularly threatened during tropical storms and hurricanes (FERC, 2008a).

- The largest natural pipeline project completed in 2007, the 1.2-Bcf per day, 172-mile Centerpoint Energy Company's Perryville expansion project, was constructed principally to link the expanding natural gas production flowing on Texas intrastate pipeline systems to the interstate system of natural gas pipelines found in northern Louisiana (USDOE, EIA, 2008e).

- The second-largest pipeline project completed in 2007 was the Tenneco Deepwater Link Project at 1 Bcf per day, which connects the Independence Trail deepwater offshore gathering system and the Tennessee Gas Pipeline (USDOE, EIA, 2008e).

Figure 52 and Figure 53 show the total capacity and mileage additions in the U.S. as well as the southeastern U.S. that includes the better part of the GOM region.

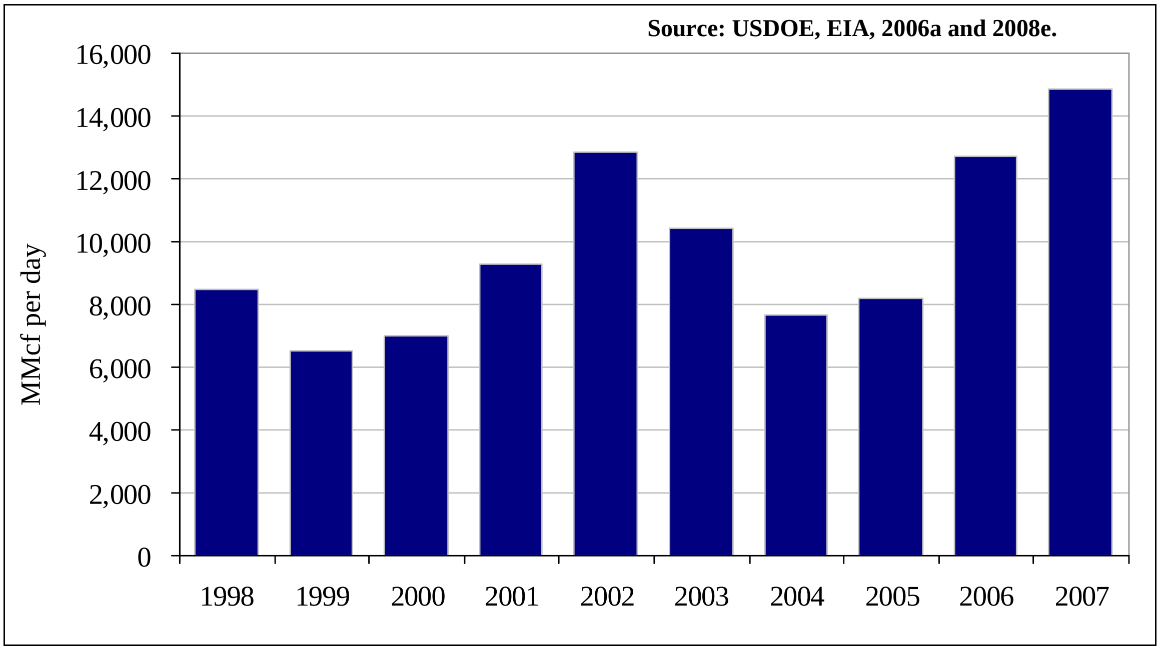


Figure 52. Natural gas pipeline capacity additions, 1998 to 2007.

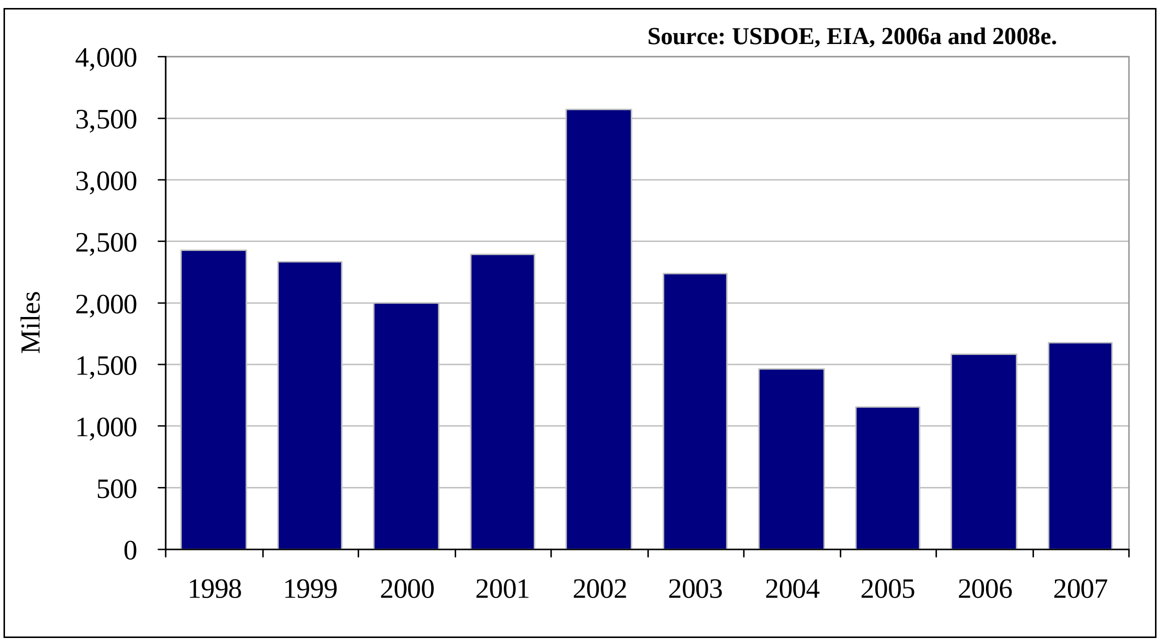


Figure 53. Natural gas pipeline mileage additions, 1998 to 2007.

<u>Oil Pipelines</u>

Crude oil and petroleum products carried in domestic transportation in 2004 totaled 902.5 billion ton-miles. Of this, over 66 percent, or 600 billion ton-miles was transported by pipeline. The rest was carried by water carriers, motor carriers, or rail. For crude oil alone, in 2004, pipelines carried 76 percent of the total 374.1 billion ton-miles transported. This is a much greater percentage than the prior ten years. In 1994, while there was a greater amount of crude oil transported (581.8 billion ton miles), only 56 percent of this was transported by pipeline. Figure 54 shows that although the total ton-miles of crude oil and petroleum products transported by pipeline has been decreasing since the late 1980s, the transportation by pipeline (as opposed to water, motor or rail) has increased significantly (AOPL, 2006).

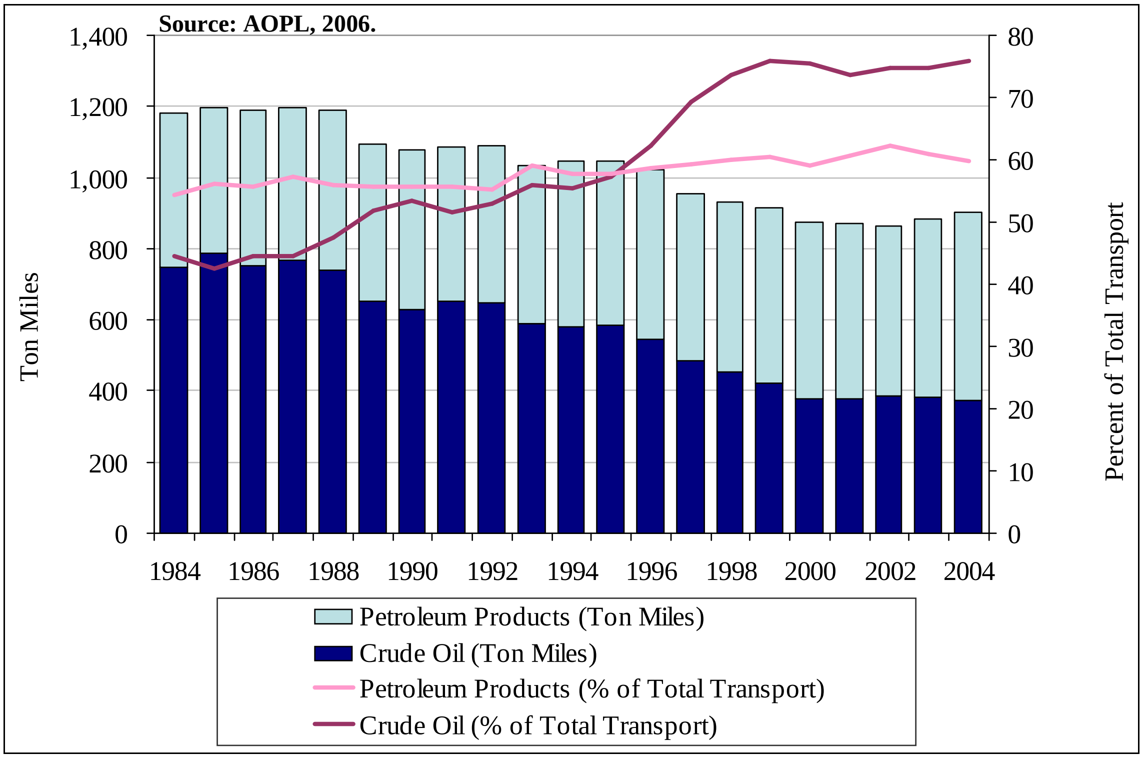


Figure 54. Transportation of crude oil and petroleum products.

7.3.2. Hurricane Impacts

Hurricane-created pipeline damage and outages was the result of a number of different factors. First, some pipelines, while not physically damaged, were out of service due to supply interruptions at the wells connected to, or upstream of, the facility. As long as production was shut-in, many pipelines would be under- or un-utilized. Physical damage to facilities was varied and could include displacement, partial or complete severing, or punctures/breaches. This damage could result from riser damage and separation, movement stress, collision with other operating equipment in the Gulf (such as drilling rigs dragging mooring anchors), mudslides, and sea floor movement.

Onshore

Onshore, damage was minimal from the 2005 tropical season. Most natural gas transmission pipelines in the path of Katrina survived with minimal damage or impacts (USDOE, OE, 2005b). For most, there were temporary power outages and reduced operating capacity due to constraints in the supply chain. Some pipelines declared force majeure and limited service due to downstream power outages and flooded compression stations. For instance, Transcontinental Gas Pipe Line was limiting supply to primary firm service-only capacity through its compressor station 40 in Hardin County, Texas, due to continued downstream power outages and other Rita-related damage in the Lake Charles and Eunice, Louisiana, areas (Coal Trader, 2005). Columbia Gulf Transmission was also under force majeure for meters upstream due to high water at and around the Pecan Island compressor and separation station in southern Louisiana resulting from Rita (Coal Trader, 2005).

Sabine Pipe Line's Henry Hub, which serves as the benchmark NYMEX delivery point and as a basis reference for spot gas deals in the Gulf Coast, imposed a force majeure on September 22 that lasted for nearly 2 weeks as a result of localized flooding that occurred in the aftermath of Hurricane Rita. Once the force majeure was lifted, six of the 13 pipelines that run through the hub were back in operation. However, in early October the hub's main complex was still without electricity and parts of the facility were still underwater (Inside FERC's Gas Market Report, 2005).

Colonial and Plantation petroleum product pipelines, which provide most of the gasoline, diesel fuel, and jet fuel to the Southeast, Mid-Atlantic, and Northeast states, lost power at critical pump stations in Louisiana and Mississippi. Dixie Pipeline (the propane line) was also shut down, as was Capline, the crude oil pipeline that serves the Midwest (USDOE, OE, 2005a). At the time, it was reported that power interruptions and other outages put both pipeline systems within days of running out of gasoline and product supplies to the Eastern U.S. (USDOE, OE, 2005b). Figure 55 shows some of the Gulf Coast crude and project pipelines and their proximity to Hurricane Katrina's wind fields.

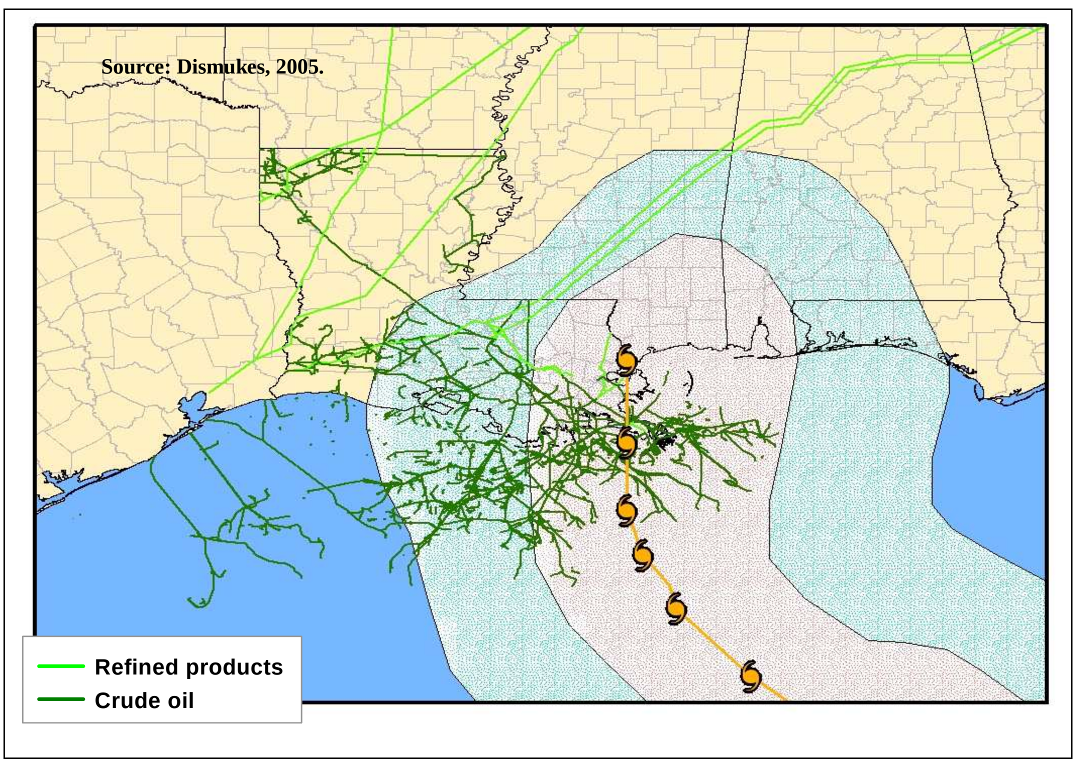


Figure 55. Crude and product pipelines impacted by Hurricane Katrina.

Figure 56 shows the path of Hurricane Rita and the pipelines that were impacted.

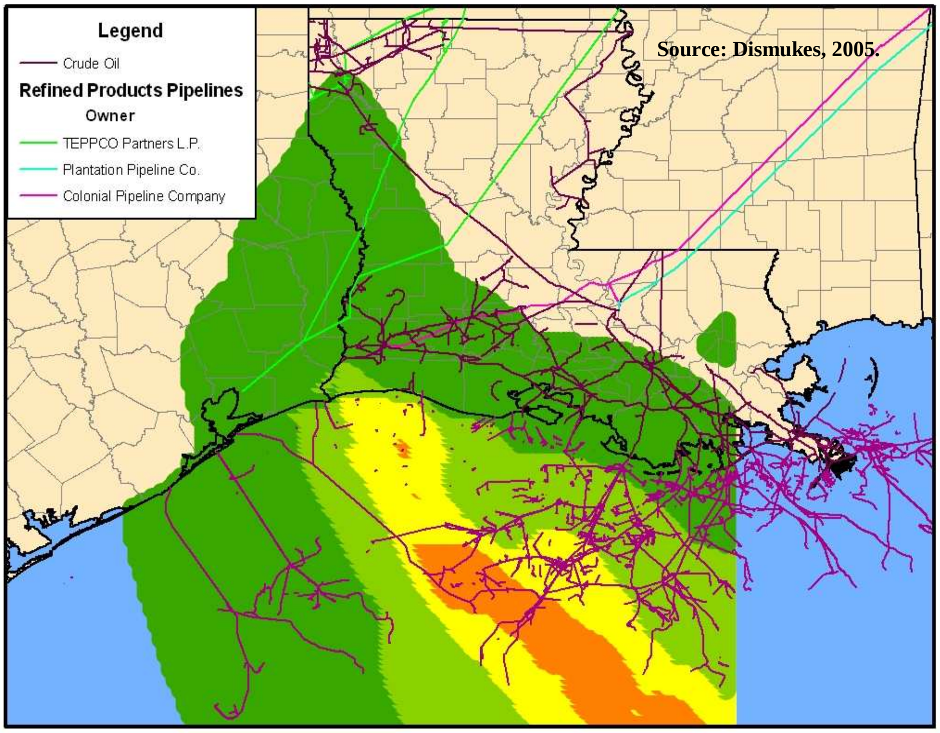


Figure 56. Crude and product pipelines impacted by Hurricane Rita.

Offshore

It is estimated that 22,000 miles of GOM offshore pipeline were in the direct path of Hurricanes Katrina and Rita (USDOE, OFE, 2006). These pipelines transport approximately 67 percent of the natural gas produced in the Gulf. Over 35 pipelines transport natural gas from the Gulf to the shorelines of Louisiana, Texas, Mississippi, and Alabama. Two-thirds of these lines move through Louisiana and therefore were within the hurricane impact area. Most primary lines in the hurricane impact area experienced damage from the storms that either limited or completely halted operations (USDOE, OFE, 2006).

In January 2006, BOEM estimated that Hurricane Katrina damaged 100 pipelines with 211 minor pollution incidents (USDOI, MMS, 2006a). Included in the 100 damaged pipelines in Federal waters were 36 large diameter pipelines (10 inches or larger) (USDOI, MMS, 2006a). Twelve of these 36 were returned to service by January 2006 (USDOI, MMS, 2006a).

In addition, it was reported that Hurricane Rita damaged 83 offshore pipelines, of which 28 were large diameter pipelines. Ten of these were returned to service by January 2006 (USDOI, MMS, 2006a). In addition 207 minor pollution incidents were reported to the BOEM (USDOI, MMS, 2006a). Much of the damage to offshore pipelines was caused by drifting offshore drilling units and platforms dragging their anchors (Sullivan, 2006).

In May 2006, the BOEM revised the number of pipelines damaged. Based on additional industry assessments, investigations and reports, the number of pipelines damaged increased from 183 to 457. The number of larger diameter pipelines (10 inches or greater) that were damaged rose from 64 to 101. As of May, thirty-two of these pipelines had returned to service. Table 21 lists the major pipelines that were damaged by Hurricane Katrina.

Table 21

Natural Gas Pipelines Damaged by Hurricane Katrina

Operator	Map Area	Diameter (inches)	Product	Status	Operator	Map Area	Diameter (inches)	Product	Status
Destin Pipeline Company	Main Pass	36	Gas	In Service	Shell Oil Company	South Pass	12	Oil	In Service
Venice Energy Services Co	South Timbalier	26	G/C	In Service	Noble Energy Inc	Main Pass	12	Oil	Shut-in
Southern Natural Gas Co	Main Pass	26	Gas	In Service	SPN Resources	South Pass	12	Gas	In Service
Tennessee Gas Pipeline Co	Ship Shoal	26	Gas	Shut-in	BP America Production Co	West Delta	12	GasH	Shut-in
Venice Gathering System	West Delta	26	Gas	In Service	Noble Energy Inc	MS Canyon	12	G/C	Shut-in
Tennessee Gas Pipeline Co	Ship Shoal	26	Gas	Shut-in	Chevron USA Inc	MS Canyon	12	Bulk Gas	In Service
Trunkline Gas Company	Grand Isle	24	Gas	In Service	Chevron USA Inc	MS Canyon	12	Bulk Gas	In Service
Venice Gathering System	West Delta	20-22	Gas	In Service	Southern Natural Gas Co	West Delta	12	Gas	Shut-in
Tennessee Gas Pipeline Co	South Timbalier	20	Gas	Shut-in	Tennessee Gas Pipeline Co	South Timbalier	12	Gas	Shut-in
Equilon Pipeline Company	Green Canyon	20	Oil	In Service	Tennessee Gas Pipeline Co	Grand Isle	12	Gas	Shut-in
Enterprise Field Services	Viosca Knoll	20	Gas	Shut-in	Gulf South Pipeline Co	South Timbalier	12	Gas	In Service
Southern Natural Gas Co	South Pass	20	Gas	Shut-in	BP America Production Co	West Delta	10	Gas	Shut-in
Tennessee Gas Pipeline Co	Ship Shoal	20	Gas	Shut-in	Noble Energy Inc	Main Pass	10	Gas	Shut-in
Southern Natural Gas Co	Main Pass	18	Gas	In Service	Chevron USA Inc	South Timbalier	10	Bulk Gas	In Service
Equilon Pipeline Company	MS Canyon	18	Oil	Shut-in	SPN Resources	South Pass	10	Gas	In Service
Equilon Pipeline Company	MS Canyon	18	Oil	In Service	Apache Corporation	South Timbalier	10	Gas	Shut-in
Equilon Pipeline Company	MS Canyon	18	Gas	In Service	Exxon Mobil Corporation	South Pass	10	Gas	Shut-in
Centana Gathering	Grand Isle	16	G/C	Shut-in	Transcontinental Gas Pipeline	Ship Shoal	10	Gas	In Service
BP America Production Co	West Delta	16	GasH	Shut-in	BP America Production Co	West Delta	10	G/O	Shut-in
Chandeleur Pipeline Co	Main Pass	16	Gas	In Service	Apache Corporation	West Delta	10	Gas	Shut-in
Equilon Pipeline Company	MS Canyon	14	Gas	Shut-in	Transcontinental Gas Pipeline	Ship Shoal	10	Gas	In Service
Southern Natural Gas Co	South Pass	14	Gas	Shut-in	Total E&P USA	MS Canyon	10	Gas	Shut-in
Marlin Energy Offshore	South Timbalier	14	Gas	Shut-in	Chevron USA Inc	South Pass	10	Bulk Oil	In Service
Southern Natural Gas Co	Main Pass	12-24	Gas	In Service	Chevron USA Inc	South Timbalier	10	Bulk Oil	In Service
Chandeleur Pipeline Co	Main Pass	12	Gas	In Service	Chevron USA Inc	South Pass	10	Bulk Oil	Shut-in
BP America Production Co	West Delta	12	GasH	Shut-in	Chevron Pipeline Co	Main Pass	10	Oil	In Service
Equilon Pipeline Company	West Delta	12	Oil	Shut-in	Apache Corporation	South Pass	10	Lift	Shut-in
Shell Offshore, Inc	Main Pass	12	Oil	In Service	Apache Corporation	South Pass	10	Gas	Shut-in
Southern Natural Gas Co	Main Pass	12	Gas	In Service	Chevron USA Inc	South Timbalier	10	Bulk Gas	Shut-in
Chandeleur Pipeline Co	Mobil	12	Gas	In Service	BP America Production Co	West Delta	10	Bulk Oil	Shut-in
Apache Corporation	West Delta	12	Bulk Oil	Shut-in					

Note: Status is as of May 1, 2006; G/C is gas condensate; Gas H is gas hydrogen sulfide and G/O is Gas/Oil.
Source: USDOI, MMS, 2006b.

Table 22 lists the major pipelines that were damaged by Hurricane Rita.

Table 22

Natural Gas Pipelines Damaged by Hurricane Rita

Operator	Map Area	Diameter (inches)	Product	Status	Operator	Map Area	Diameter (inches)	Product	Status
Tennessee Gas Pipeline Co	East Cameron	26	Gas	In Service	Tennessee Gas Pipeline Co	Eugene Island	12	Gas	Shut-in
ANR Pipeline Co	Vermilion	24	Gas	Shut-in	Enterprise Field Services	Green Canyon	12	Oil	In Service
ANR Pipeline Co	S. Marsh Island	24	Gas	Shut-in	ANR Pipeline Co	S. Marsh Island	12	Gas	Shut-in
ANR Pipeline Co	S. Marsh Island	24	Gas	Shut-in	Equilon Pipeline Company	East Cameron	12	Oil	Shut-in
Equilon Pipeline Company	South Timbalier	24	Oil	In Service	Equilon Pipeline Company	Garden Banks	12	Gas	In Service
Enterprise Field Services	Green Canyon	20	Gas	Shut-in	Dynegy Midstream Services	West Cameron	12	Gas	Shut-in
Transcontinental Gas Pipline	Ship Shoal	20	Gas	In Service	Texas Eastern Transmission	East Cameron	12	Gas	Shut-in
Trunkline Gas Company	Grand Isle	20	Gas	In Service	Dynegy Midstream Services	West Cameron	12	Gas	In Service
Transcontinental Gas Pipline	West Cameron	16	Gas	Shut-in	Shell Oil Company	S. Marsh Island	12	Oil	In Service
Tennessee Gas Pipeline Co	South Timbalier	16	Gas	Shut-in	Equilon Pipeline Company	Grand Isle	12	Oil	In Service
Tennessee Gas Pipeline Co	South Timbalier	16	Gas	Shut-in	Enterprise Field Services	MS Canyon	12	Gas	In Service
Chevron USA Inc	Eugene Island	16	Bulk Oil	In Service	Chevron USA Inc	Eugene Island	12	Gas	Shut-in
Manta Ray Gathering Co	Garden Banks	16	Oil	In Service	Transcontinental Gas Pipline	Ship Shoal	10	G/C	Shut-in
Tennessee Gas Pipeline Co	East Cameron	16	Gas	Shut-in	Devon Energy Production	Eugene Island	10	G/O	Shut-in
Texas Eastern Transmission	East Cameron	16	Gas	In Service	Gulf South Pipeline Company	Eugene Island	10	Gas	In Service
Williams Field Services	Ship Shoal	16	Gas	In Service	Apache Corp	Eugene Island	10	Oil	Shut-in
Devon Energy Production	Eugene Island	14	Oil	Shut-in	Devon Energy Production	Eugene Island	10	G/O	Shut-in
Gulf South Pipeline Company	Eugene Island	14	Gas	Shut-in	Marlin Energy Offshore	South Timbalier	10	Bulk Oil	Shut-in
Shell GOM Pipeline Compan	Ship Shoal	12	Oil	In Service	Trunkline Gas Company	East Cameron	10	Gas	Shut-in
Stingray Pipeline Company	Vermilion	12	Gas	Shut-in	ANR Pipeline Co	West Cameron	10	Gas	Shut-in

Note: Status is as of May 1, 2006; G/C is gas condensate; Gas H is gas hydrogen sulfide and G/O is Gas/Oil.
Source: USDOI, MMS, 2006b.

Although the pipeline damage from the two storms varied in pattern, there was a degree of similarity. For the most part, approximately half of the pipeline breaches occurred within an area that also experienced damaged or destroyed platforms. All but six of the pipeline breaches occurred in the waters of the continental shelf (i.e., in water depths of 200 feet or less). Half of the continental shelf breaches were located within 25 miles of the transition from deepwater. Approximately half of the breaches within the eastern impact area occurred within 25 miles of the shoreline in South Timberline and Main Pass areas or in the waters surrounding the Plaquemines Peninsula and Lafourche Parish given their closer relative proximity to the shoreline (USDOE, OFE, 2006).

According to the USDOE, Katrina caused almost double the number of natural gas pipeline breaches caused by Rita. Katrina's breaches, being in the eastern portion of the damage area, generally occurred closer to the shore, while the pipeline breaches caused by Rita were more randomly distributed along the path of the hurricane (USDOE, OFE, 2006).

In 2007, four U.S. GOM pipeline operators announced that they had formed a partnership to speed up emergency repairs. The four companies, Enterprise Products Partners, Enbridge, BP and Eni have formed a partnership that will allow them to dramatically expedite deepwater pipeline repairs after hurricanes or other emergency disruptions (Porretto, 2007). The four companies represent 25 percent of the deepwater pipeline capacity in the GOM. They have agreed to purchase $12 billion of equipment to fix damaged pipelines. Stress Engineering Services will manage the project. Having the equipment readily available could reduce the time that a pipeline is out of service by 50 to 75 percent (Porretto, 2007).

7.3.3. Outlook

U.S. natural gas prices remain strong and will most likely keep large infrastructure projects such as pipelines moving forward (Smith, 2007). In 2007 the EIA reduced projected 2030 U.S. energy consumption by 2 percent to 131.2 quadrillion Btu. Despite the reduced forecast, EIA still anticipates energy consumption growing more rapidly than production, with increasing imports playing a more import role in supplies (Smith, 2007). EIA anticipates that most of these imports will come in the form of LNG. Total net imports of LNG to the U.S. in the EIA's 2007 reference case will increase to 4.5 Tcf in 2030 from 0.6 Tcf in 2005. Regardless of how natural gas enters the country however, it will have to be brought to the end-user via pipeline (Smith, 2007).

For the period 2006 through 2008, 19 natural gas pipeline projects have been proposed, most all are anticipated to support new LNG import capabilities. Most of the recently-announced LNG import facilities are designed to regasify volumes at a high daily rate, 1 Bcf per day to 2.5 Bcf per day or greater. The natural gas pipelines built to transport their output to interconnections with the existing natural gas pipeline grid are also designed for similar load capacities. Table 23 lists the new pipeline projects that have been announced recently with newly proposed LNG regasification facilities. Many of these pipeline projects are quite large with 32-inch or larger pipeline diameter extensions/expansions.

Table 23

Proposed LNG Facilities and Associated Pipelines

			Capacity	Installed Pipeline	
Project	Company	Location	(Bcf)	Miles	Diameter
Onshore					
Cameron LNG	Sempra Energy	Hackberry, LA	1.5	35.4	36
Freeport LNG	Cheniere	Quintana Is., TX	1.5	9.4	36
Sabine Pass	Cheniere	Sabine Pass, LA	2.6	16.0	42
Corpus Christi	Cheniere	Corpus Christi, TX	2.6	24.0	48
Vista Del Sol	Exxon Mobil	Corpus Christi, TX	1.0	25.0	36
Golden Pass	Exxon Mobil	Sabine Pass, LA	1.0	119.7	36
Corpus Christi	Occidental	Corpus Christi, TX	1.0	26.4	26
Port Arthur	Sempra	Port Arthur, TX	1.5	73.0	36
Creole Trail	Cheniere	Cameron, LA	2.6	287.3	42
Sabine Pass - Phase II	Cheniere	Sabine Pass, LA	1.4	16.0	42
Freeport LNG - Phase II	Cheniere	Quintana Is., TX	2.9		
Cameron LNG - Expansion	Sempra Energy	Hackberry, LA	2.7		
Gulf LNG Energy		Pascagoula, MS	1.0	5.0	36
Bayou Cassotte	ChevronTexaco	Pascagoula, MS	1.6	-	-
Calhoun LNG	Gulf Coast LNG	Port Lavaca, TX	1.0	27.0	36
Offshore					
Port Pelican	ChevronTexaco		1.6	42.5	42
Main Pass	McMoRanExp		1.6	192.0	36
Bienville	TORP		1.4	25.0	36
Port Dolphin	Hoegh LNG		1.2	42.0	36

Source: FERC, 2008b, daily trade press and company websites and FERC filings.

In addition the following is a summary of selected upcoming pipeline projects related to the GOMR:

- Kinder Morgan Energy Partners LP and Energy Transfer Partners LP will jointly develop the Midcontinent Express Pipeline. The 1.4-Bcfd pipeline will be about 500 miles long, originating near Bennington, Oklahoma. It will run through Perryville, Louisiana, and terminate at an interconnect with Transco in Butler, Alabama. Pending regulatory approvals, the $1.25 billion project will be in service by February 2009 (Smith, 2007).

- Enterprise Products Partners LP signed definitive agreements with producers to construct, own, and operate an oil export pipeline to provide firm gathering services from BHP Billiton-operated Shenzi field located in South Green Canyon, Gulf of Mexico. The 83 mile, 20-in. pipeline will have the capacity to transport 230,000 barrels per day and will connect the field to the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline systems (Smith, 2007).

- Also in Green Canyon, Chevron USA Inc. approved construction of a 55-mile deepwater oil pipeline for its Tahiti project. The company also approved expanding the pipeline from an initially planned 20-in. to 24-in. to handle 300,000 barrels per day of oil and accommodate additional discoveries in the Walker Ridge and Green Canyon areas (Smith, 2007).

- Colonial Pipeline Co. received assurance from FERC encouraging it to invest $1 billion in expanding its mainline petroleum products pipeline. To ease constraints on its system, Colonial plans to construct and operate 500 miles of 36-in. pipeline between Louisiana and Georgia to transport at least 800,000 barrels per day, a 30 percent increase in capacity. Colonial estimates the project will enter service in 2010 (Smith, 2007).

7.4. Chapter Resources

Federal Energy Regulatory Commission – Natural Gas Industry
The FERC website provides a list of approved pipeline projects since 2003; major pending pipeline projects; and major pipeline projects on the horizon.
http://ferc.gov/industries/gas/indus-act/pipelines.asp

Federal Energy Regulatory Commission – eLibrary
On the FERC's eLibrary, documents filed in a particular docket can be downloaded and viewed. This includes both documents that are filed, and issued.
http://ferc.gov/docs-filing/elibrary.asp

Federal Energy Regulatory Commission – Market Oversight
An overview of natural gas markets by region can also be found at FERC.
http://ferc.gov/market-oversight/mkt-gas/overview.asp

Department of Energy, Energy Information Administration
On the EIA's Natural Gas Navigator, natural gas pipeline statistics can be found, such as imports, exports, and interstate movements of natural gas.
http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

On the EIA's website, a section titled About U.S. Natural Gas Pipelines provides statistics on interstate and intrastate pipelines; network design, capacity and usage; regulatory authorities; transportation corridors; and development and expansion. It also provides natural gas pipeline maps of several U.S. geographic regions. Internet website: http://tonto.eia.doe.gov/dnav/ng/ng_pub_analysis_move.asp

A number of analysis reports can also be found at the EIA.
http://tonto.eia.doe.gov/dnav/ng/ng_pub_analysis_move.asp

The Association of Oil Pipelines
The Association of Oil Pipelines' website provides industry statistics, maps of major crude oil pipelines, safety statistics, as wells as industry facts.
http://www.aopl.org/

8. PIPE COATING FACILITIES

8.1. Description of Industry and Services Provided

Pipelines that transport oil and gas are coated on the exterior to protect against corrosion and other damage. Pipes may also be coated on the inside to protect against corrosion from the fluids being transported or to improve the flow. In addition to corrosion protection, many pipes that will be used offshore are also coated with a layer of concrete to increase the weight of the line to ensure it stays on the seabed.

Significant threats to pipeline integrity often include third-party damage, geological activity, and corrosion. The most common threat, external corrosion, is recognized as the main deterioration mechanism that can reduce the structural integrity of buried pipelines. In fact, corrosion ranks only second to human error as a cause of pipeline failure (Taylor and Werner, 1994). Because coatings are the first line of defense in protecting pipelines against corrosion, they must be well bonded, continuous, and resist the effects of their environments (Figure 57). According to one industry analyst, "the application of corrosion-protective coatings to pipelines has emerged as an industry because it is a cost-effective means of extending the life of a pipeline (McConkey, 1982)."

Figure 57. Stacks of pipes.

To be effective, pipeline coating must satisfy several properties that include (Kennedy, 1993):

1. easy to apply;
2. adheres well to pipe;
3. resists impact;
4. is flexible;
5. resists soil stress;
6. resists flow (of coating);
7. is resistant to water;
8. is resistant to electricity;
9. is chemically and structurally stable; and
10. resists bacteria, marine organisms, and cathodic disbondment.

8.2. Industry Characteristics

8.2.1. Typical Facilities

Pipeline corrosion coating can be applied either before the pipe is delivered (yard applied) or after the pipe lengths are welded together and suspended above the trench, as shown below in Figure 58. When pipe lengths are coated and wrapped at a coating yard before being delivered to the job site, a short distance at each end of each length of pipe is left bare so the joints can be welded together. When field welding is complete, coating and wrapping material is applied to the bare pipe sections.

Figure 58. Pipe coating.

When all coating and wrapping is done at the job site, individual lengths are first welded together and the pipeline is suspended over the trench. Special machines then move along the pipeline and apply coating to the entire pipe. Tape is wrapped over the coating by a tape machine in a spiral. The wrapping machine maintains tension on the tape so it fits tightly over the coating (Kennedy, 1993).

Pipeline construction

Pipeline construction methods differ depending on the geographical area, the terrain, the environment, the type of pipeline, and the restrictions and standards imposed by governments and regulatory agencies. The biggest differences exist between land construction and offshore construction; however, all pipeline construction projects have a number of features in common (Kennedy, 1993):

1. The methods of designing the system include arriving at the optimum pipe diameter, determining the amount of horsepower required for pumping or compression, and meeting safety standards.
2. There are a number of design criteria that are set by government or regulatory agencies to insure safe operation of a pipeline and the safety of personnel and property near the pipeline. These standards vary depending on the location of

the pipeline, both geographically and in relation to populated areas and other facilities.

3. Comprehensive environmental impact studies are required in many countries before construction permits can be issued. Construction plans must provide for the protection of scenery, wildlife, archeological sites, and other historic assets.
4. Most oil, gas, and products pipelines are constructed by welding short lengths, or *joints*, of pipe together. There are a few exceptions to the use of welded connections, but these are in short lines within a producing field or in similar applications.
5. Extensive testing of welders and the welds they produce is an important part of the construction of all long-distance petroleum pipelines.
6. Almost all oil and gas pipelines are buried below ground level; even most offshore pipelines are buried below the sea bed for protection. There are cases in which large segments of a major pipeline are not buried. The most notable example of this is the trans-Alaska crude pipeline where above-ground sections were installed to protect permafrost areas.
7. All pipelines are tested for leaks following construction before the line is put in service. Several techniques can be used, but the most common is hydrostatic testing, which involves filling the line with water and subjecting it to a pressure greater than the designed operating pressure.
8. Most pipelines are coated on the exterior to prevent corrosion. Offshore pipelines are also “weight-coated” with a concrete coating to overcome the force of buoyancy and to prevent the pipe from floating to the surface.
9. Most pipelines must have one or more pumping stations or compressor stations along the route to provide energy to overcome pressure loss and keep the fluid in the pipeline moving.
10. The construction of all pipelines follows this general sequence: design and route selection, obtaining rights-of-way, installation, tie-in to origin and destination facilities and pumping or compressor stations, and testing.

The following is a discussion of corrosion and the major types of coatings used today.

Corrosion

Corrosion is an electrochemical process involving an area of higher potential – the anode (a piece of metal that readily gives up electrons) and an area of lower potential – the cathode (a piece of metal that readily accepts electrons). The electrolyte is a liquid or some conveyor that helps the electrons move from the anode to the cathode. The anode will become corroded, while the cathode will not be subject to damage. When a piece of metal corrodes, the electrolyte helps provide oxygen to the anode. As oxygen combines with the metal, electrons are liberated. When they flow through the electrolyte to the cathode, the metal of the anode disappears and is swept away by the electrical flow or converted into metal cations in a form such as rust. In the case of a buried pipeline, the soil is the electrolyte. Areas of different potential exist along a pipeline. The magnitude of the potential difference depends on soil conditions, among other factors.

The electrical potential between the anode and cathode is what causes the corrosion current to flow (Allied Corrosion Industries, 2006). The anode is the area that is subject to corrosion and the severity of which is directly proportional to the amount of current flow. There are many types of corrosion. Some common industry types include:

- ***Dissimilar metal corrosion (or galvanic corrosion)*** occurs when two metals with different compositions are metallically contacting each other in a common current flow. The negative potential composition of each metal determines which metal acts as the anode and the rate of corrosion.
- ***Differential Aeration Corrosion*** occurs when part of the pipe is exposed to well-aerated soil (cathode region) and the other part exposed to a poor supply of oxygen.
- Corrosion can also occur when new sections are used and welded with old sections in repairs and additions. In this situation, the newer structure normally becomes the anode.

Cathodic Protection

Cathodic protection refers to the method of preventing corrosion in metal structures that involves using electric voltage to slow or prevent corrosion. It is used along natural gas pipelines, as well as in certain bridges or other large metal structures that need to resist corrosion over an extended period of time. In a cathodic protection system, anodes are installed and an electrical current is made to flow between the pipe and the anodes through the soil. The pipeline becomes the cathode of the system, and corrosion is decreased. The anodes, the part of the system that is corroded, are "sacrificed."

Cathodic protection eliminates anodic areas on an underground metallic structure. Constant surveying of how the cathodic protection is holding up, whether it is disbondment of the coating or if new coating faults arise, is a significant implementation that has arisen in the industry (Kennedy, 1993). During pipeline fabrication, all possible measures are taken to detect and repair coating faults.

It is possible to calculate the electrical resistance of a coated pipeline, given the coating specifications and pipeline dimensions, but it is impossible to calculate the actual resistance of the total pipeline over time with varied external conditions affecting the structure (Kennedy, 1993). The magnitude of the corrosion currents for a given potential difference between two electrodes (cathode and anode) depends on several factors (Kennedy, 1993):

1. Soil resistivity. This is determined by temperature, moisture content, and the concentration of ionized salts present. Generally, corrosion is high in low-resistivity soils and can be low in high-resistivity soils.

2. Chemical constituents of the soil. The type of salts in the soil affect the rate of corrosion.

3. Separation between anode and cathode. Corrosion is more likely to occur when the anode and cathode are close together. Increasing the distance between two dissimilar metals (electrodes) reduces corrosion current intensity.

4. Anode and cathode polarization. Protective films formed at the anode and cathode affect corrosion rate.

5. Relative surface areas of cathode and anode. For a given magnitude of corrosion current, the depth of corrosion on the anode will be inversely proportional to anode area.

External Corrosion Coating

Pipeline coating inhibits the flow of electric current from the pipe and the resulting loss of steel. Once the coating is applied, tape is wrapped around the pipe in a spiral pattern with the edges overlapping slightly so that all of the pipe coating is covered. Wrapping tape, normally either heavy paper or plastic, protects the coating from damage.

The earliest anti-corrosion coatings for buried pipelines were bitumen-type coatings, or asphalt mastic and enamel and coal tar enamel (Aalund, 1992). Historic experience found that these types of coatings were subject to cracking, leading to contact of water with the pipe and coating disbondment. Asphalt coatings were also found to absorb water to a greater degree than other coatings. Developments in epoxy-based adhesives have lead to more desirable coatings such as fusion-bonded epoxy, polyethylene, and polypropylene (Figures 59 and 60). Traditional pipeline anti-corrosion coatings are being progressively replaced by complex multi-layer composite systems. These new coatings start with a fusion-bonded epoxy layer, combined with a robust shield of thick extruded polyethylene or polypropylene (Aalund, 1992).

The ability of a coating system to perform as a corrosion barrier depends upon the resistance to damage exhibited by the coating as well as its inherent corrosion-protective properties as determined by adhesion to the steel and resistance to the corrosive environment (McConkey, 1982). These capabilities, in turn, are a function of the properties of the coating material combined with the application process which defines the overall coating system (McConkey, 1982).

Fusion-Bonded Epoxy

One of the most popular coatings used today is the fusion-bonded epoxy. Application of fusion-bonded epoxy pipe coatings began in the early 1980s and has expanded rapidly due to its numerous perceived advantages that include high-temperature performance, chemical resistance, resistance to soil stress, and excellent resistance to cathodic disbondment in comparison to traditional coatings (McConkey, 1982). Fusion-bonded epoxy coatings have become more attractive due to several advances in both the application process and in the raw material (McConkey, 1982). Fusion-bonded epoxy coatings provide a more controllable application process and a product whose quality can be assured before the laying of the pipeline (McConkey, 1982).

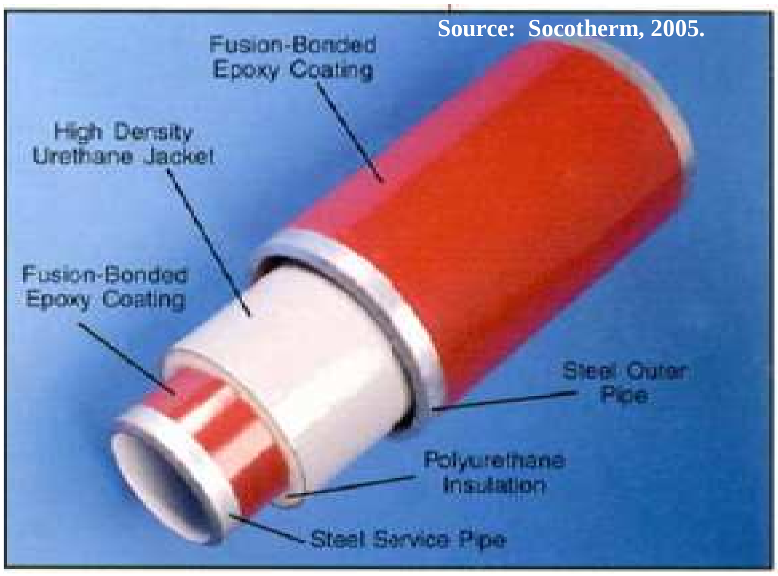


Figure 59. Types of coating protection.

Source: Socotherm, 2005.

Figure 60. Internal coating called Tubokote and external coating with fusion bonded epoxy called Powderkote.

Application of Fusion-Bonded Epoxies

The process of applying fusion-bonded epoxy coating to pipelines involves four major steps: surface preparation; heating; powder application; and curing (Figure 61). Proper surface preparation assures that maximum adhesion will develop at the interface between the pipe and the coating. The steel is blast-cleaned to a near white metal finish using abrasive grit which cleans the pipe of contaminants, mill scale, and rust. The surface preparation process also roughens the surface to give it a textured profile in order to facilitate adhesion by increasing the exposed surface area of the steel and by providing more opportunity for the coating to chemically bond. After blast-cleaning, the steel is heated to approximately 450 degrees Fahrenheit using electrical induction heaters.

The heated pipes are then passed through a powder spray booth where dry epoxy powder is emitted from a number of spray nozzles. As the powder leaves the spray nozzle, an electrical charge is imparted to the particles. These electrically-charged particles are attracted to the grounded steel surface, providing an even coverage of the coating. When the dry powder hits the hot steel, it melts and flows into the textured profile and conforms to the ribs and deformations of the pipe. The heat also initiates a chemical reaction that causes powder molecules to form the complex cross-linked polymers that give the epoxy coating its beneficial properties. Following powder application, the coating is allowed to cure for a short period (approximately 30 seconds), during which it hardens. To facilitate handling, the curing period is often followed by an air or water quench that quickly reduces the bar temperature.

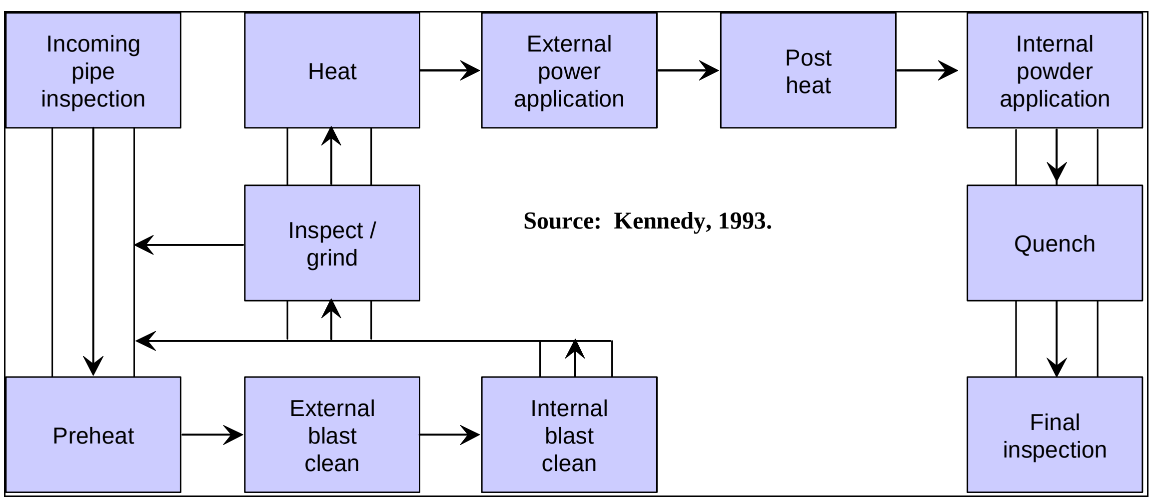


Figure 61. External/internal fusion bonded epoxy coating plant.

Concrete Coating for Offshore Pipe

Offshore pipelines are coated with concrete in addition to the corrosion coating to provide negative buoyancy (a weight greater than the buoyant force of the water) to the pipeline. This added weight is necessary for the pipeline to sink to the ocean floor and remain in position on the seabed (Figure 62). To be effective, a concrete coating must resist damage during installation and after it is in place. In addition to providing needed weight, the concrete coating protects the underlying corrosion coating.

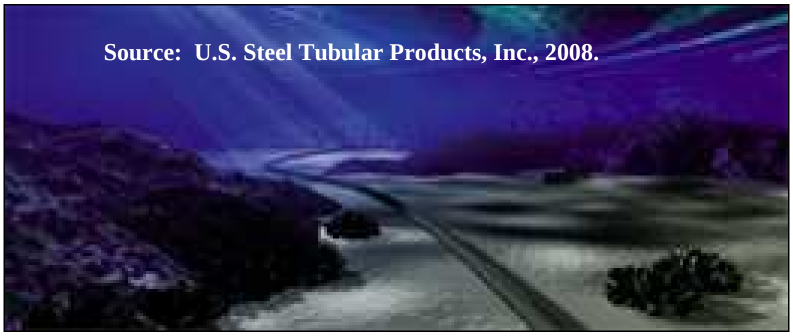


Figure 62. Pipeline on the ocean floor.

There are 3 major requirements of concrete coating in maintaining the stability of pipeline on the seabed (Kiernan, 1982):

1. Negative buoyancy – Originally, the chief function of negative buoyancy was to add sufficient weight to the pipeline to achieve the required negative buoyancy, hence the term “weight coating.” This primary function has not changed over the years since the first offshore lines were laid in the Gulf of Mexico in the late 1940s.
2. Resistance to damage – To remain in position during pipeline life, a concrete coating must resist damage during laying and trenching operations, natural environmental hazards during the life of the pipeline at the bottom of the sea, and the effects of human hazards, such as fishing trawls and trailing cables from floating vessels.
3. Protection of anti-corrosion coating – All presently used techniques of anti-corrosion coating are subject to damage when exposed to trawl gear or trailing cables.

Design of the concrete coating is critical if it is to withstand laying stresses and resist damage from anchors, fishing gear, and other hazards during operation. Considerable research has been aimed at the improvement of concrete coatings and application methods, based in part on the performance of early concrete-coated pipelines. One of the most critical considerations in concrete coating design is the over-bend area where the pipe leaves the lay barge’s pipe ramp during installation. If laying stresses are not properly calculated and maintained within design limits, concrete coating can crack during installation (Kennedy, 1993).

8.2.2. Geographic Distribution

The *Atlantic Gulf Coast Oil Directory* lists 145 different companies, with a total of 198 locations, under its Corrosion Control/Cathodic Protection section (Figure 63). Texas contains 125 locations. Another 60 are in Louisiana. The remaining locations are throughout GOMR including Mississippi (five facilities), Alabama (seven facilities) and Florida (one facility) (Atlantic Communications, 2006).

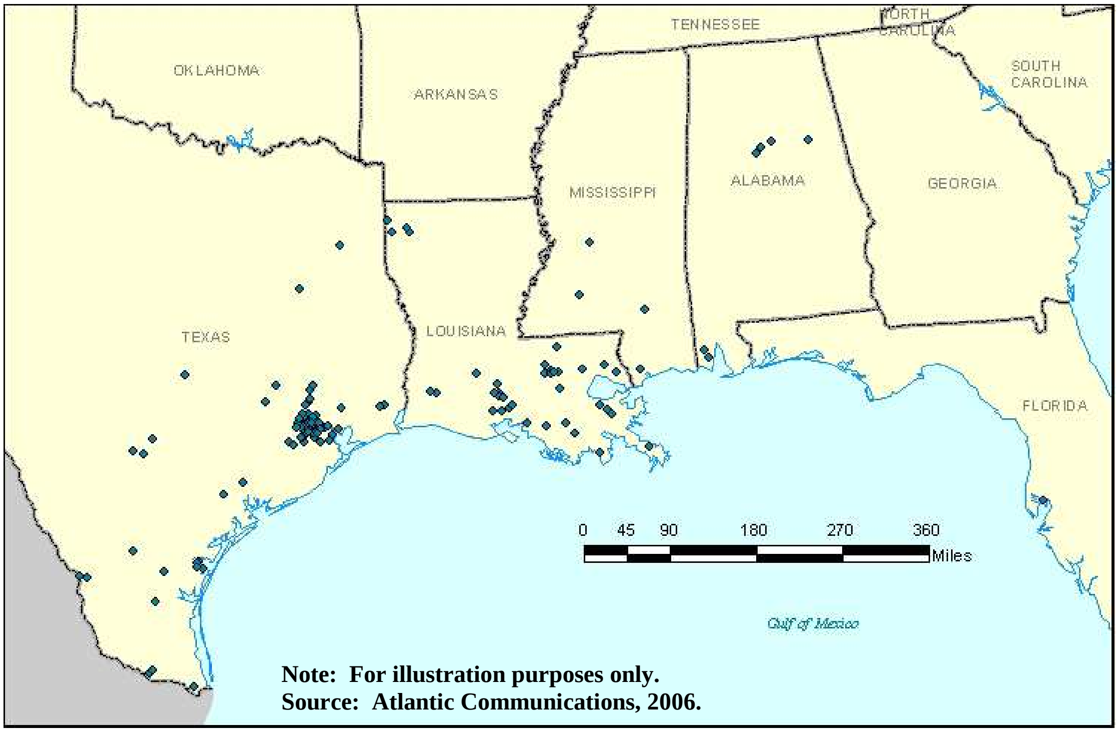


Figure 63. Location of Gulf Coast pipe coating and pipe services yards.

8.2.3. Typical Firms

The levels of activity experienced by pipe coating companies depend on the requirement for new pipeline infrastructure, which is driven by investment in energy supply. The strongest trends in energy supply which effect demand are energy prices, world economic growth, advances in technologies, and future public policy decisions (ShawCor, 2005). Much of the pipe coating that takes place is done by companies that also produce the pipes themselves. If the coating company is a separate entity, it is often located near a pipe facility. Below are introductions to a few of the major players in the industry.

Bredero Shaw is a division of ShawCor Ltd., a company which is focused on technology-based products for the energy industry. Bredero Shaw, which began in the 1930s in Houston, Texas, has grown to be the world's leader in the development and manufacturing of pipe coating solutions for the oil, gas, and water industries. Over the course of their history, they have protected over 250,000 kilometers of pipelines around the world (Bredero Shaw, 2008b). Their operations have grown to 27 different facilities employing the largest team of technical and service specialists in the business. Much of their efforts are spent on technological solutions for coatings for both onshore and offshore applications (Bredero Shaw, 2007). One of Bredero Shaw's most recent large contracts, announced in October 2005, was in the GOMR and associated with Noble Energy's Lorien discovery. The contract calls for ThermoFlo Flow Assurance Coatings to be applied at their Pearland, Texas facility. ThermoFlo is a polyurethane-based insulation designed by Bredero for offshore flow assurance (Canada News Wire, 2005).

The Bayou Companies, LLC began operating in the pipe coating industry in the 1970s with Bayou Pipe Coating (Figure 64) and is located in New Iberia, Louisiana. Throughout the years, Bayou Companies have evolved from operating out of one fusion-bonded epoxy pipe coating plant to adding an adjacent larger diameter coating plant in the 1980s. The Bayou facilities offer FBE coating, concrete coating, thermal spray aluminum, custom coatings, and glass synthetic polyurethane insulation (GSPU) coating. Bayou has recently extended its capabilities into the field joint and custom coating business by buying majority shares in Commercial Coating Services, Inc. and C&L Pipeline Equipment (The Bayou Companies, 2008a). In 2006, the company began working to rebuild their initial plant into a state of the art fusion-bonded epoxy pipe coating plant capable of coating heavier pipe at spreads greater than currently possible at existing facilities (Landry, 2006).

Source: The Bayou Companies, 2008b.

Figure 64. The Bayou Company.

Commercial Coating Services, Inc. is an affiliate of The Bayou Companies, offering a full range of custom coating solutions to the oil and gas industry. The company began operations in 1983 and has grown to three U.S. locations (two of which are in the GOMR) and numerous locations around the world. It has one of the largest fleets of field joint coating systems in the world, the ability to serve more than 50 working spreads at one time, and expertise from coating over two million field joints around the globe (The Bayou Companies, 2008c).

Tenaris is a global steel pipe manufacturer with a strong focus on manufacturing products and related services for the oil and gas industry. Its U.S. headquarters are in Houston, with additional facilities in Arkansas, Texas, and Tennessee. The company's main facility in Hickman, Arkansas covers an area of 78 hectares and includes a coating facility that can coat up to 16 inches. Its Houston operations are capable of producing coiled tubing products in various grades, sizes, and wall thickness (SEC, 2006k). In addition, Tenaris offers external and internal anti-corrosion, weight coating, and thermal insulation (Tenaris, 2008).

Another major global leader is Socotherm. Socotherm has two head offices in two different geographical areas. One is in Italy and the second, which operates their business in the Americas, is in Argentina and is called Socotherm Americas. They are one of the worldwide operators in the anti-corrosion pipe coating field for oil, gas, and water transportation industries. In addition, they are world leaders in deepwater pipe insulation and coating technology. The group also operates in designing and assembling anti-corrosion and insulation pipe coating plants (Subsea Oil & Gas Directory, 2008). Socotherm Americas, through its research and development unit, has developed a pipe thermal insulation system for the deepwater industry, called the Multipass System (Socotherm, 2008). According to Socotherm, the international pipe coating market is divided between about eight large companies and 20 percent is taken up by other, smaller companies. Figure 65 illustrates this division.

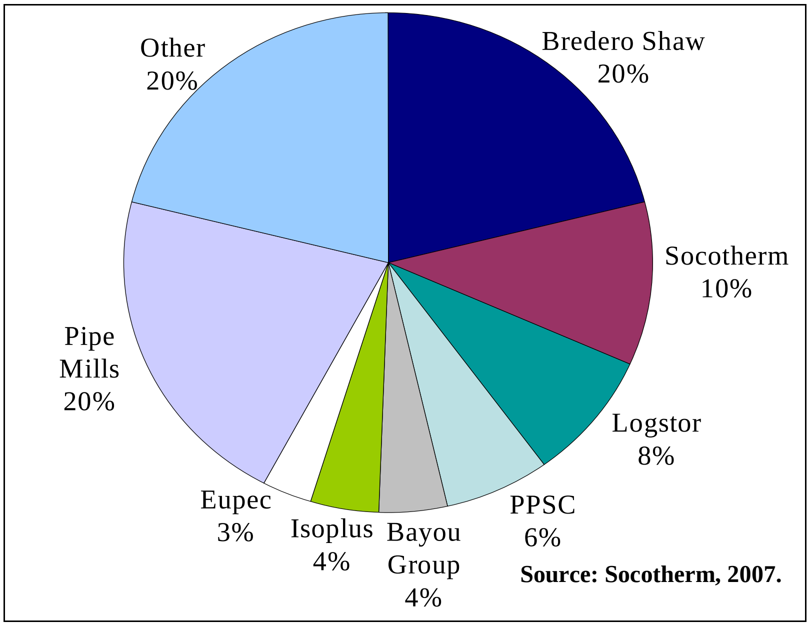


Figure 65. Market share divisions as of October 2007.

8.2.4. Regulation

Although not economically regulated like other segments of the natural gas industry, pipe coating techniques do have to meet industry specifications as established by the Department of Transportation and recommended by the National Association of Pipe Coating Applicators.

Part 195, under Title 49 (Transportation) of the Code of Federal Regulations is titled "Transportation of Hazardous Liquids by Pipeline." Sections 195.557 through 195.561 lists the requirements for external coatings (49 CFR §195, 2008):

- Each buried or submerged pipeline must have an external protective coating for external corrosion if the pipeline is:
    - Constructed, relocated, replaced or otherwise changed after the applicable date;
    - Has an external coating that substantially meets allowable coating before the pipeline is placed in service;
    - Is a segment that is relocated, replaced, or substantially altered.

- All pipe coating must be inspected just prior to lowering the pipe into the trench or submerging the pipe, and any damage discovered must be repaired.

- Allowable coating materials for external corrosion control include materials that:

  - Are designed to mitigate corrosion of the buried or submerged pipeline;
  - Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
  - Are sufficiently ductile to resist cracking;
  - Have enough strength to resist damage due to handling and soil stress;
  - Are supportive of any supplemental cathodic protection;
  - If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

Regulations for cathodic protection systems are also included in Sections 195.563 and 195.567. A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A cathodic protection system must be installed no later than one year after completing the construction. Except for offshore pipelines, electrical test leads used for corrosion control is required for all buried or submerged pipeline or segment of pipeline. Requirements for how to test are described in the code.

External Corrosion Control

According to the CFR, every pipeline operator must, at least once each calendar year but with intervals not exceeding 15 months, conduct tests on each buried, in contact with the ground, or submerged pipeline facility in its pipeline system to determine whether the cathodic protection is adequate. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every three calendar years but with intervals not exceeding 39 months.

Once every three years, an operator must inspect the bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is needed. Whenever any buried pipe is exposed for any reason, the operator must examine the pipe for evidence of external corrosion. If any active corrosion is found, the area should be examined for leaks. Also, leak repair and inspection records, corrosion monitoring records, and exposed pipe inspection records should be reviewed.

Internal Corrosion Control

An operator may not transport any hazardous liquid or carbon dioxide that would corrode a pipe or other components of a pipeline system, unless it has investigated the corrosive effect of the hazardous liquid or carbon dioxide on the system and has taken adequate steps to mitigate corrosion. If corrosion inhibitors are used to mitigate internal corrosion, the pipeline operator must use inhibitors in sufficient quantity to protect the entire part of the system that the inhibitors are designed to protect, and shall also use coupons or other monitoring equipment to determine their effectiveness.

Twice each calendar year, the monitoring equipment must be examined to determine the effectiveness of the inhibitors or the extent of any corrosion, but with intervals not exceeding seven and one-half months.

Whenever any pipe is removed from the pipeline for any reason, the operator must inspect the internal surface for evidence of corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the operator shall investigate adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced with pipe that meets industry requirements, or based on the actual remaining wall thickness, the operating pressure must be reduced to be commensurate with the limits on operating pressure.

Corrosion control information must be maintained. Maps must be kept of cathodically protected pipelines, cathodic protection facilities installed after January 28, 2002, and maps showing a stated number of anodes. The required information also includes records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or to indicate that corrosion requiring control measures do not exist. The records must be retained for at least five years, except, in some instances, the records must be kept for the life of the pipeline.

8.3. Industry Trends and Outlook

8.3.1. Trends

The pipe coating industry is dependent on the oil and gas market. During the 1980s, the coatings business experienced significant growth. The 1990s saw additional change with a push for companies to research new products for growing deepwater GOM exploration activities (The Bayou Companies, 2008a). Pipe coatings have evolved from simple coal-tar applications to more sophisticated fusion-bonded epoxies and polypropylene coatings. Companies continue to try new, cost-effective methods and materials in the battle against corrosion and extreme environmental effects. Sometimes the new methods involve using multiple types or layers of protection, and at other times, innovative processes use new materials. The advantages and disadvantages, particularly costs, of each type of coating needs to be taken into account in the development of different coating products.

According to industry reports to investors, technology and environmental trends are pushing design temperatures at both ends of the temperature spectrum, requiring considerable product and process innovations to meet client needs. Higher temperatures are often used in ultra-deepwater applications, whereas lower temperatures are utilized to support LNG transportation and internal site distribution. Environmental standards are also becoming more stringent and have eliminated some formerly-acceptable products from the pipeline coating market (ShawCor, 2005).

As the oil and gas industry moves to deeper water exploration, the pipe coating industry has to remain dynamic to changing needs. For instance, Jotun Powder Coatings recognized in the last decade that the move toward more demanding and difficult environments, such as the deeper subsea pipelines in the GOM, would surpass the capabilities of many of the industry's conventional products. Jotun, through their technical development center's innovation, developed new products that are able to meet these demands, including a high temperature powder technology that allows FBE coatings to withstand operating temperatures of up to 150 degrees Celsius (Carlson et al., 2005).

Socotherm Americas and La Barge Pipe and Steel Co. plan to serve the deepwater market through a new pipe coating facility in Channelview, Texas. In January of 2007, both companies announced a joint venture to build the pipe coating facility with the primary goal of serving the new deepwater developments in the GOM. Among the products that will be available from the JV facility are a modified polypropylene matrix filled with hollow glass microspheres and three-layer polyolefin external anti-corrosion coatings on pipes up to 48-inches in diameter (Quest Offshore Resources, Inc., 2007a). The new plant was expected to start operations in the first quarter of 2008. The company reports that demand was so high that by November of 2007, the joint venture was able to announce a backlog of work worth $52 million for 2008. One of their large projects is work for the Thunder Hawk Project, said to be worth about $15 million (Quest Offshore Resources, Inc., 2007b). In addition, Socotherm teamed up with Tenaris on a contract which calls for the application of 80 millimeter thick coating of Weisokote, their product for deepwater from the new plant (Socotherm, 2006).

In 2006, the Bayou Companies began construction on a 50,000-square-foot fusion-bonded epoxy pipe coating plant to replace the one that was built in the early 1970's for $300,000 (Landry, 2006). The new all-steel plant will coat heavier pipe at speeds greater than currently possible in the company's existing facilities.

In 2006, a brand new pipeline heat and coat field joint technology was used for the first time for BP's Thunderhorse project in the Gulf of Mexico (this is one of the largest projects to date in the GOM). The needs were for induction heat and coat technology that would result in a solution that would scan, heat, and coat in a vertical plane in the J-lay tower, as well as treat hang-off collars located on the pipe. In applying the new solution, a computer-controlled robotic arm was used to ensure even application. Future developments of new scan-heat coat solutions are being specifically developed to reduce powder waste and to improve operator health and safety by preventing FBE powder from entering the environment where coatings are applied (Lee, 2006).

Technology is also continually expanding the pipe coating industry aside from deepwater needs. In January 2007, a new sleeve, called the CCB sleeve, was installed for the first time in a long, large-diameter pipeline. This sleeve offers new standards in internal corrosion protection (Pipeline & Gas Journal, 2007).

Another recent technology breakthrough in the pipe coating industry came in 2007 with the idea of utilizing nanotechnology to create a protective layer on pipelines. Nansulate, developed by Industrial Nanotech, Inc. (INI), has been used in the past for numerous applications in other industries such as textiles and automotives (INI, 2008). Currently, the technology is being used in Brazil on a 105-mile project (INI, 2007a), and in November 2007 Socotherm announced their intention to join forces with INI to integrate the technology into their GOMR projects (INI, 2007b). This product is a revolutionary breakthrough in the science of thermal insulation.

Nansulate is a liquid-applied insulation protective coating. When the product dries, it leaves a thin layer and provides exceptional insulation, corrosion protection, and prevents condensation and rust (INI, 2008).

Most of the new developments in pipe coating are found through a specific company's research and development centers. The largest companies have the greatest abilities to conduct research. For example, Tenaris, the world's leading suppliers of tubes and related services, has a global network of research centers employing over 200 scientists and engineers (Tenaris, 2006). Their largest research center, located in Argentina, focuses on, among other things, steel metallurgy, forming and furnace technology, and surfaces and coating chemistry. Tenaris is also responding to customer technical needs by participating in joint industry programs with customers to develop new product capabilities, such as research into fatigue corrosion in sour environments (Tenaris, 2006).

Quality control and consistency is a major concern for pipe coating companies and advances in technology has helped to solve these concerns. For example, Commercial Resins reports that real-time video monitoring of the coating process becomes part of the customer's permanent project files. One effective method of quality control reported by Applied Coatings is the development of international pipe coating and material specifications, such as ISO 9001-2000, which is certification as an international reference for quality requirements in business-to-business dealings (Applied Coatings and Linings, Inc., 2008). Such companies as Commercial Coating Service advertise that they operate following a Quality Management System that is in compliance with ISO 9001-2000 (CCSI, 2008). One of the major challenges of the coating application industry has been having to use completely different material and quality standards from project to project. Yet, with the issuance of industry standards, consistency could become more prevalent. For example, in Canada, a National Material Specification and a Quality Management Standard has been invoked. According to Keith Coulson, chairman of the CSA Pipeline Coating Committee, using international specifications has a major influence in improving the relationships in the pipe coating industry between the applicator, material suppliers, and the customers (Carlson et al., 2005).

The National Association of Pipe Coating Applicators (NAPCA) is an organization representing plant-applied pipe coating companies, and it promotes standardized protective coating practices. A NAPCA Specifications and Plant Coating Guide has been published outlining, among other things, recommended specifications and suggested procedures (NAPCA, 2008).

With increases in natural gas demand and promising developments in the Gulf of Mexico, transmission capacity will also need to expand, and thus the need for pipeline coatings increases. In turn, pipeline coating companies have increased output to meet the increased demand for services.

8.3.2. Hurricane Impacts

A personal account of the damage experienced by James T. Shea, President of the Bayou Companies stated, "In my 30 years in the coating industry, I have never experienced the extent of damage to our industry that has occurred through these two disasters." He went on to explain the damage his own facility experienced and its association with vendors of National Association of

Pipe Coating Applications (NAPCA) that enabled their facility to be put back in operation (Shea, 2006).

8.3.3. Outlook

As a whole, the future outlook for the pipe coating industry is both challenging and competitive as companies vie for market share while trying to keep pace with rapid advances in testing and technology. In addition, offshore cycle times are reducing and there are ever more stringent specifications for more tough operating conditions. The industry as a whole must focus on timely and efficient applications. Most companies within the industry offer solution-based services, meaning that the companies must invest heavily in research and development to meet their clients' needs (PIH, 2008). Research and development continue to play a major role in the pipe coating industry, especially as environmental constraints become more pronounced and the oil and gas industry moves further into deepwater exploration.

Activity for the pipe coating industry is expected to grow. Bredero Shaw has expanded their facilities worldwide in order to keep up with the demand they see as imminent within the next few years (Tiflis, 2007). In addition, the company is consistently pushing new technology solutions within the field of pipe coating. Their three research and development facilities are very active. As of April 2007, they had 40 patents on application processes, polymer technology and other solutions (Tiflis, 2007).

Another world leader in the industry, Socotherm, is also expecting strong growth in the coming years. In 2005 they anticipated strong growth, particularly in North America and the GOMR. Socotherm estimated that from 2005 to 2010, $15 billion would be invested in pipelines alone, of which 21 percent would be spent in the Gulf of Mexico (Socotherm, 2005). To capture some of this market, Socotherm has invested heavily over the past years, with investments increasing from 3.5 million Euros in 2002 to 11 million Euros in 2007 (Socotherm, 2007). Socotherm reported 26 percent of their revenue was derived from offshore energy transportation in June 2005. By October 2007, that percentage had jumped to 37 percent (Socotherm, 2005 and 2007).

Socotherm views the GOMR as one of the largest offshore, deepwater market in the world, with much more room for innovation and growth for pipeline coating companies (Socotherm, 2007). The increased activity in the GOMR should continue to push the development of new products and services that increase pipeline life and repair. Companies with GOMR facilities capable of accommodating large, deepwater projects, and the research and development capabilities needed to support these projects, stand to be the major benefactors of the current pipeline marketplace.

8.4. Chapter Resources

Atlantic Communication's Gulf Coast Oil Directory
Includes a wide range of data from company name, address, web and email addresses to contact names with titles, direct phone numbers, and email addresses all organized alphabetically by industry categories. Also included is "Company Detail" information such as company size, revenue, areas operated in last 12 months, operations onshore or offshore, and stock information for publicly traded companies.
http://www.oilonline.com/Directory/DirectoriesDatabases.aspx

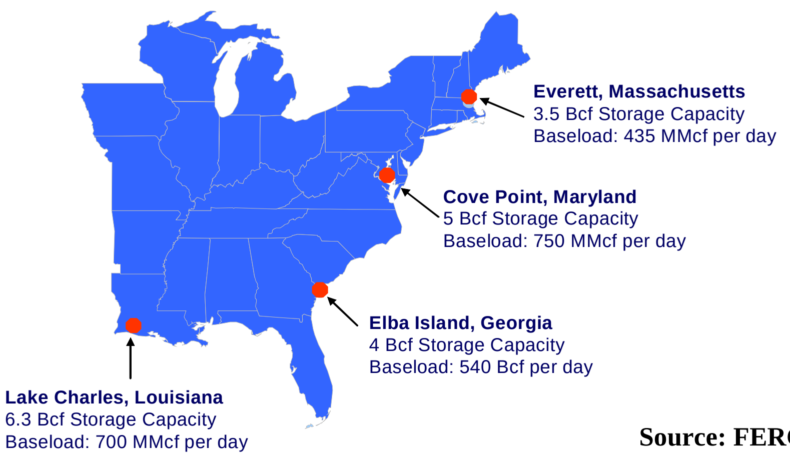
U.S. Securities and Exchange Commission
Quarterly and annual reports of operations for publicly traded companies are filed with the Securities and Exchange Commission.
http://www.sec.gov/edgar/searchedgar/companysearch.html

9. LNG

9.1. Description of Industry and Services Provided

Liquefied Natural Gas (LNG) is natural gas converted to liquid form by cooling it to a temperature of -256°F, the point at which gas becomes liquid. This simple process allows natural gas to be transported from an area of abundance to an area where it is needed. Once the LNG arrives at its destination, it is either stored as a liquid, or converted back to natural gas and delivered to end-users. Liquefying gas is not a new process or technology, it is simply a process by which the physical properties of natural gas, primarily methane, are altered in order to transport the commodity from markets where it is abundant to those more limited in supply (Dismukes, 2008).

The natural gas price controls and production shortages of the late 1960s led many U.S. energy planners to look at alternative sources of natural gas to meet domestic energy needs. The crisis of the early 1970s, continuing on for much of the decade, provided the impetus for the first generation of LNG regasification facilities in the U.S. During this period, four different LNG facilities were developed in various locations in the eastern U.S., as shown in Figure 66.



Source: FERC, 2008b.

Figure 66. U.S. LNG terminals and original capacity.

Despite the initial growth of LNG in the late 1970s, policies, markets and the underlying economics of natural gas production changed relatively quickly and left these newly developed facilities economically stranded for almost 20 years. It has not been until the most recent decade that the dynamics of natural gas supply and demand have lead to increased interest and investment in LNG. In 2002, FERC issued what became known as the "Hackberry decision" which granted preliminary approval, the first in over 20 years, for the construction of Dynegy's Hackberry LNG facility, located in Hackberry, Louisiana (USDOE, EIA, 2005b).

The overall size of the U.S. natural gas market is forecasted to increase substantially over the next decade with the expectation that LNG import capabilities will need to increase by 50 percent by the year 2030 (USDOE, EIA, 2007b). These increased LNG capabilities are anticipated to serve as a supplement, not a substitute, for domestic U.S. natural gas production.

The degree to which LNG supplements domestic U.S. production will be heavily influenced by future domestic natural gas production and reserve additions in conjunction with end-use demand requirements.

Natural gas is a vital component for many industries in the GOMR and while the importance of production is commonly associated with the area, the significance and scope of natural gas consumption is not always recognized. The GOMR is home to two of the largest and most intensive natural gas end-uses in the U.S. economy: power generation and industrial usage.

Natural gas is a important fuel for power generation for many of the states along the GOMR, particularly Texas, Louisiana, and Florida. Power generators use natural gas for boilers, which creates steam, which, in turn, is used to power large generators. Alternatively, natural gas can be burned directly in a combustion turbine that can directly spin a generator to create electricity. Given the affordability of natural gas and its close proximity to the Gulf Coast producing basin, utilities across the region have historically used natural gas as a fuel for power generation.

Industrial uses of natural gas are equally important, yet more complex. Figure 67 provides an outline of the means by which natural gas is often used at an industrial facility along the GOMR. These processes include using natural gas to fuel furnaces to create process heat; boilers to create processed steam; electricity generation (in a fashion similar to utilities); and feedstock. The feedstock use of natural gas is one of the unique and defining characteristics of industrial use of natural gas along the Gulf Coast and is primarily associated with the large number of regional petrochemical facilities.

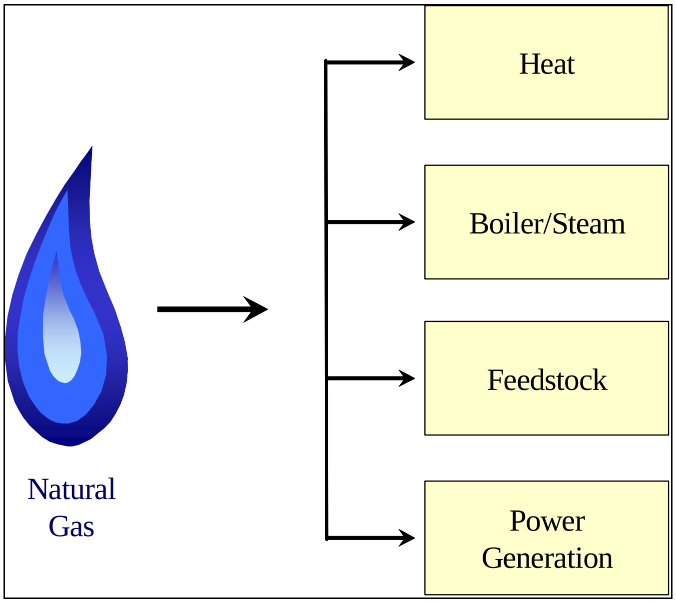


Figure 67. Industrial natural gas usage.

There is an exceptional amount of proved natural gas reserves around the world. Recent estimates have these reserves somewhere around 6,400 trillion cubic feet (Tcf) (USDOE, EIA, 2008d). While natural gas is abundant worldwide, these reserves are located in areas that do not have significant natural gas demand. In addition, much of the gas is located in and around politically instable areas such as Nigeria and the Persian Gulf. In order to move this gas from these areas of supply abundance, to areas with higher demand, a mode of transportation needs to be engaged. Since pipeline transportation over long distances is cost prohibitive, liquefaction of natural gas has been the preferable technological means of rendering natural gas into a transportable form to move over long distances.

9.2. Industry Characteristics

9.2.1. Typical Facilities

The LNG "value chain" (see Figure 68) shows the various stages that natural gas is converted to LNG and delivered to end-users. Exploration and production is the first stage of the process. Here, natural gas reserves are developed, wells are drilled, and production is initiated in order to extract the hydrocarbon and transport it locally to a liquefaction facility for super-cooling. Insulated tankers serve as intermediate storage facilities before the gas is transported internationally.

Exploration and Production: World natural gas reserves are large, estimated at 6,000 tcf or 60 times the volume of natural gas used in 2004. Much of this gas is considered "stranded" because it is located in areas distant from consuming markets.

Liquefaction: Gas from the producing field comes to the liquefaction plant. Contaminants are removed and the gas is cooled to a temperature of -256°F. By liquefying the gas, its volume is reduced by a factor of 600.

Storage: LNG is stored in double walled, insulated tanks at atmospheric pressure. These tanks are designed to prevent any leaks. There is also a dike around the tank that is capable of containing the entire volume of the tank in case of a spill.

Shipping: The typical LNG carrier can transport 125,000 to 138,000 cubic meters of LNG, which will provide 2.6 to 2.8 bcf of natural gas. The typical carrier measures 900 feet in length, 140 feet in width and 36 feet in water draft, and costs $160 million.

Regasification and Delivery: LNG is pumped from the ship to insulated storage tanks at a specially designed terminal. It is then fed into a regasification plant to return the LNG to a gaseous state. The LNG is warmed by passing it through heated pipes and various terminal components. The vaporized gas is then regulated for pressure and enters the pipeline system to be transported to end-users.

Source: Dismukes, 2008.

Figure 68. LNG schematic – production to end-user.

LNG tankers are specialized ships with insulated storage to keep the gas in its cooled and liquefied state until it is delivered to its destination market. Any gas that naturally regasifies during the transport process (known as boil-off) is used as transportation fuel during the trip. Tankers are large and can typically hold as much as 2.9 Bcf of natural gas. One tanker holds enough natural gas to fuel: (1) a typical GOMR steam electricity plant for one to two months, 51,000 typical residential natural gas customers in the GOMR; or 5 typical GOMR industrial facilities (using average consumption) (Dismukes, 2008). As of January 2008, there were 258 LNG carriers worldwide and 122 on order (Colton Company, 2008).

The last step in the process is what is referred to as "regasification." A regasification facility heats the liquefied natural gas and delivers it to local destination markets or intermediate storage for future delivery to end-users. The facilities that have been proposed for development along the Gulf Coast are the regasification facilities shown in Figure 70. The first three steps of the parts of the LNG "value chain" (production, liquefaction, and transportation) originate in other locations.

Figure 69 presents a general schematic of the LNG regasification process. The process does not differ much between onshore and offshore receiving terminals. The first step of the regasification process consists of unloading LNG from ships into a series of intermediate storage tanks. The physical process of offloading the LNG cargo usually takes about 12 hours, but can vary depending on the capacity of the regasification facility. The typical capacity for an onshore facility ranges between 1 Bcf per day to 3 Bcf per day. For an offshore facility, the typical capacity ranges from 0.5 Bcf per day to 1.5 Bcf per day.

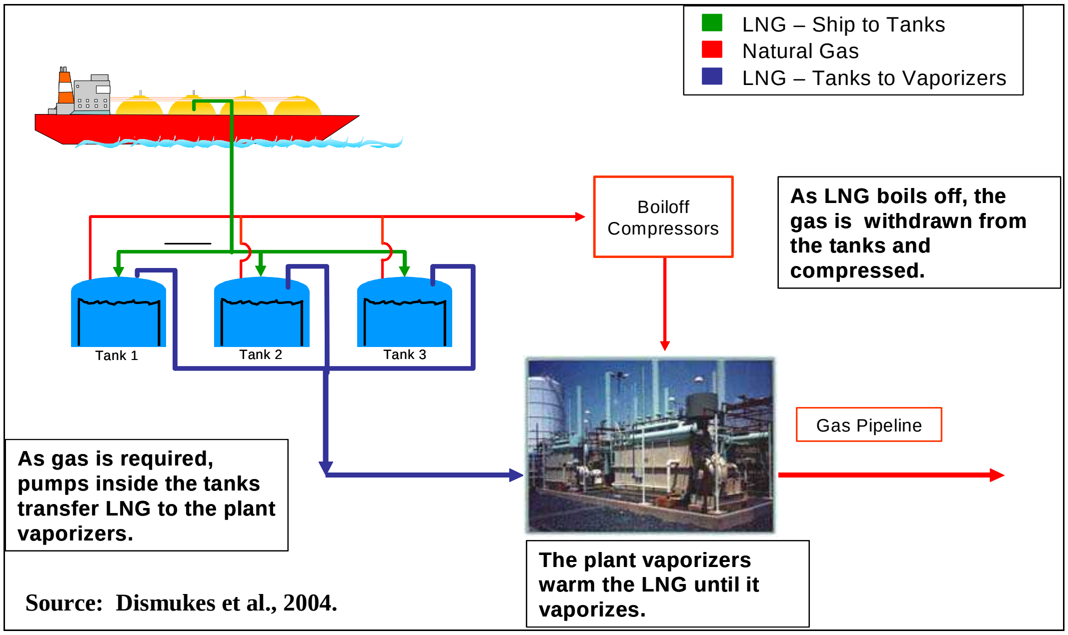


Figure 69. Receiving terminal – LNG gas flow.

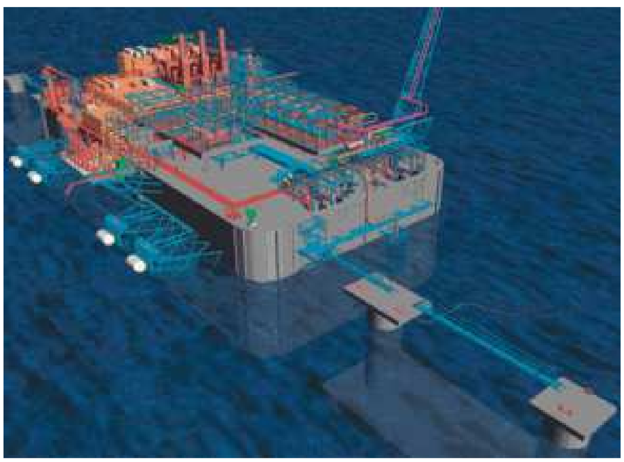
The next step in the regasification process is to heat, or vaporize, the LNG. The primary means is to use heat treaters or vaporizers to warm the gas and convert it from a liquid to a gaseous state. From there, the gas is injected into large interstate and/or intrastate pipelines for delivery to markets (end-users) or intermediate storage facilities.[24] Any boil-off associated with the liquid

[24] These intermediate storage facilities are typically underground natural gas storage facilities which are developed from various geological formations such as abandoned aquifers, oil and gas reserves and salt caverns.

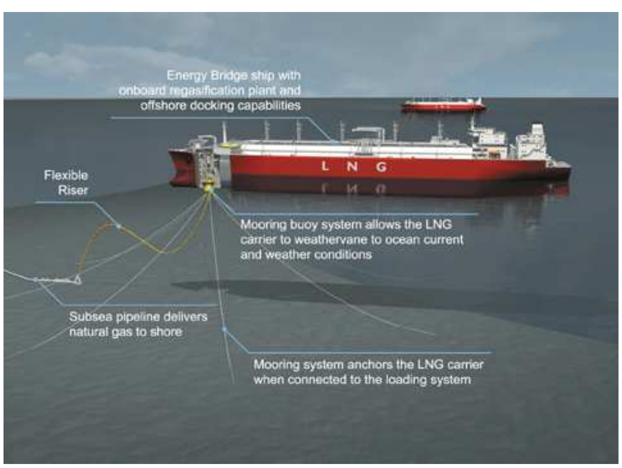
natural gas in storage is captured, compressed, and then combined with gas from the vaporizers to feed into pipelines for delivery to end-users or intermediate storage facilities.

Two types of regasification facilities, offshore and onshore facilities, are currently in operation or development along the GOM. Onshore regasification facilities have existed for over 40 years. The only real difference between the onshore facilities of today and those of the past are the capacity levels of the facilities. The current facilities are located at or near major ports, where LNG tankers arrive and unload their cargoes. Because of their port locations, they are referred to as "marine" facilities. Due to recent security concerns, there has been greater interest in locating these facilities offshore, where large LNG tankers can offload their cargoes. The gas will be injected into pipelines and moved onshore, eventually reaching the downstream markets.

Offshore facilities, however, are different than their onshore counterparts. They are much newer and have virtually no comparable technological applications on the GOM. The following lists some of the various types of offshore LNG regasification facilities proposed over the past several years.


Source: True and Sen, 2007.

A **Gravity-Based Structure (GBS)** consists of two large concrete caissons that are floated to the site and lowered to rest on the sea floor. LNG carriers will offload cargoes into storage tanks on the GBS. The topside of the GBS houses vaporizers and other equipment to warm the LNG and return it to its gaseous state. The gas is then transported by subsea pipeline to processing facilities on land for delivery to end-users.



Source: Northeast Gateway, 2008.

At a **Buoy or Energy Bridge**, specially designed regasification vessels dock with a subsurface buoy that is permanently anchored offshore. The LNG is returned to its gaseous state onboard the regasification vessel and delivered to the buoy. The natural gas is then sent through the buoy and flexible rise to a subsea pipeline. The offshore pipeline brings the gas onshore and delivers it to end-users.


Source: AMOG Consulting, 2008.

Floating Storage and Regasification Units (FSRU) or **Floating Production, Storage, and Offloading** (FPSOs) are floating regasification systems where the vaporizer, storage, and other equipment is housed on the vessel itself. The vessel tethers to a buoy-based system during the regasification process. The tether connects the ship and vaporization equipment to the subsea pipeline system. Regasified LNG (natural gas) is then delivered to end-user markets or intermediate storage. When the offload is complete, the ship can leave the system to obtain additional cargoes. The FSRU system would be permanently moored to a tether system and would serve as an intermediate station for offloading LNG.

9.2.2. Geographic Distribution

LNG is not a new means of exporting and importing natural gas from and to the U.S. In addition to the marine terminals developed for importing LNG, there are numerous small LNG liquefaction and regasification facilities throughout the U.S. These small facilities have been in operation for several decades and have been used by LDCs as storage facilities for "peak shaving" purposes. LNG peak-shaving facilities are used for storing natural gas to meet the requirements of peak consumption during high demand typically during the winter season for North America. Each peak-shaving facility has a regasification unit attached, but not all have a liquefaction unit. These facilities depend on tank trucks to deliver LNG from other producing or transportation terminal areas. Figure 70 provides a map with the location of several different types of LNG facilities located throughout the country. As shown in the figure, about half of the LNG facilities in the U.S. are peak-shaving facilities.

These small-scale LNG facilities can also be used by what is referred to as a "stranded utility," or one with no interstate or intrastate transmission pipeline interconnection. These stranded utilities need truck delivery of natural gas to supply their customers. Lastly, the map shows a number of Nitrogen Rejection Units (NRU) that liquefy gas for special processing purposes. At NRU facilities, the entire gas stream is liquefied to remove impurities, then regasified and sent on as pipeline-quality gas.

The types of LNG facilities that are getting the most attention today are the large marine terminals located on the U.S. coasts. There are four "original" LNG import facilities located along the Atlantic and GOM coast. Figure 71 provides an expanded view of these facilities, along with their locations, and capacities, many of which are expansions from the original design capacities of the late 1970s. As seen from the figure, all four are located in the eastern half of the

U.S. Two of these facilities (Everett and Cove Point) were developed in the late 1970s. The other two facilities (Elba Island and Lake Charles) were developed in the late 1970s and early 1980s. All four facilities have been expanded in recent years and each have a peak sendout of one Bcf per day or more. Together, the four facilities had an annual capacity of just over 1 Tcf in 2002.

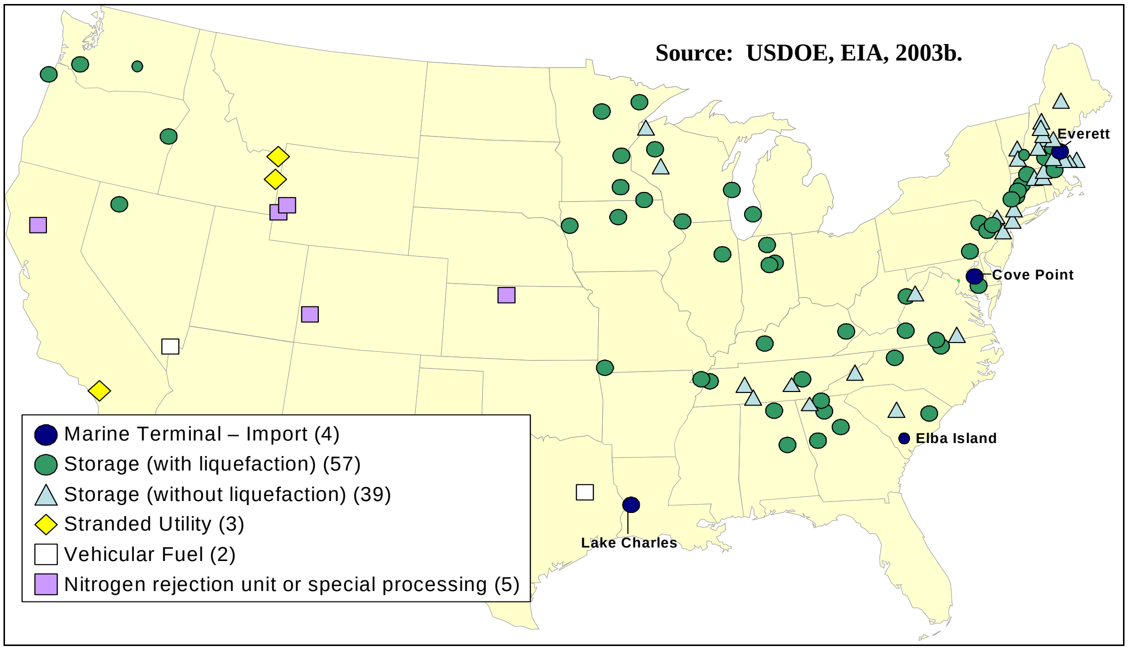


Figure 70. U.S. LNG facilities.

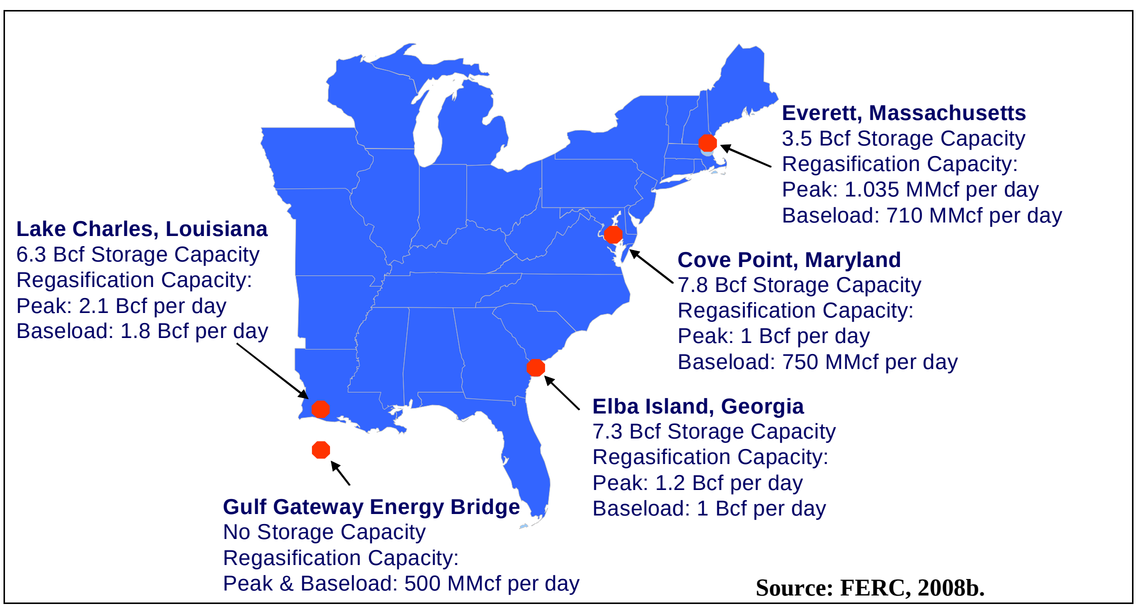
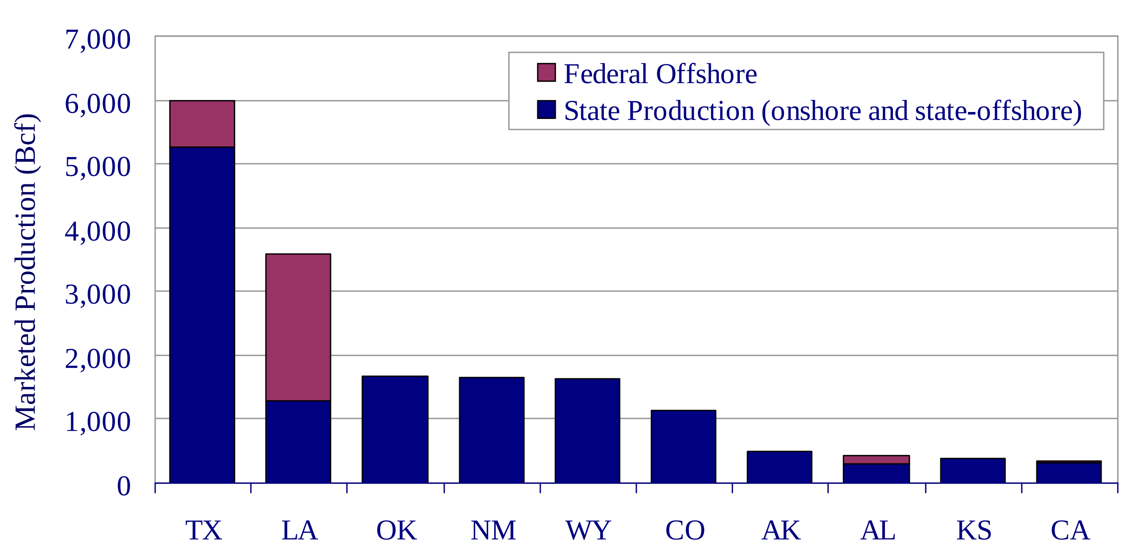


Figure 71. Current U.S. LNG import terminals.

A fifth facility, the Gulf Gateway Energy Bridge, commenced operations in 2005. The Energy Bridge was the world's first deepwater LNG port. It is located 116 miles off the south coast of Louisiana in 298 feet of water and delivers about 3 Bcf of regasified LNG into the pipeline grid through the Sea Robin and Blue Water subsea systems at a rate of about 500 MMcf per day (Excelerate Energy, 2008a).

The GOM region has one of the largest and most comprehensive energy economies in the world. Energy activities span across all areas, from production, processing, and transportation, to distribution and sales. Further, the GOM is also one of few regional economies around the globe that has such a pervasive degree of horizontal and vertical linkages between all types of energy infrastructure and activities. Natural gas is an important and integral part of the GOM energy economy.

Infrastructure is the primary reason why the GOM is the best suited location in the U.S. for the development of LNG regasification facilities. As seen in Figure 72, Texas and Louisiana are the largest two producers of natural gas in the U.S.



Source: USDOE, EIA, 2008d and LDNR, 2008.

Figure 72. U.S. natural gas production by state, 2005.

The region is perhaps one of the most unique in the world for its breadth and depth of energy assets, most all of which are supportive of LNG imports (Figure 73). The GOM has some of the largest refinery, petrochemical, and paper-pulp facilities in the world, all of which either consume significant quantities of natural gas for production purposes or transform this raw material into high quality fuels or products. The region also has the largest amount of natural gas processing, storage, and most importantly, transportation assets of anywhere in the U.S. It is these transportation assets (pipelines) that are critical in moving LNG from its source of production to its source of consumption, much like these assets have done for domestic production over the past 50 years.

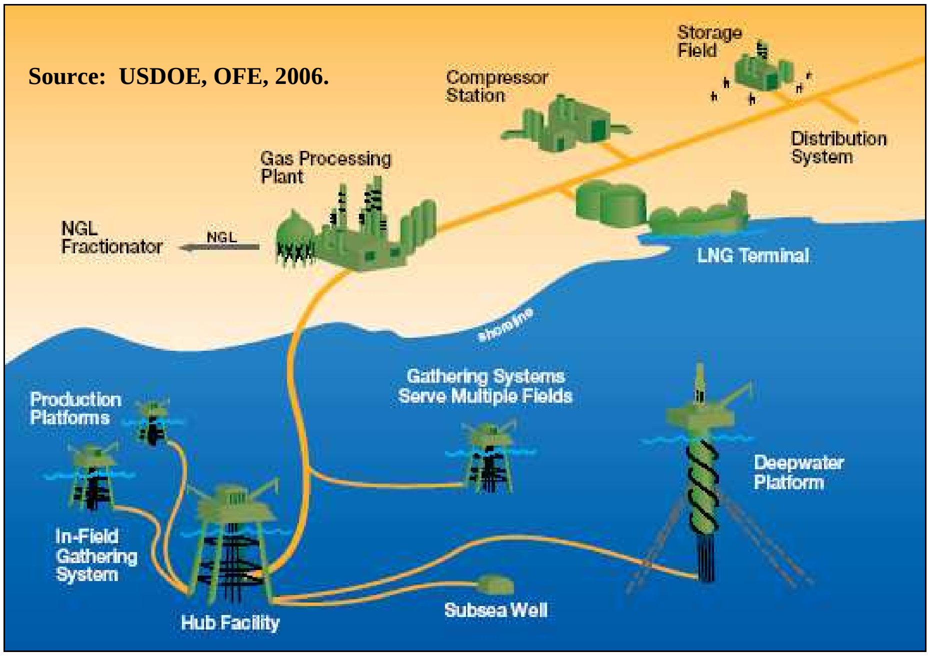


Figure 73. GOM gas supply schematic.

The wide variety of pipeline systems and delivery markets makes the GOM attractive for LNG developers. In Texas, numerous large interstate pipelines parallel the Gulf Coast shoreline en-route to Louisiana and downstream markets. This allows LNG projects to tie into multiple interstate pipeline systems, with much shorter pipeline construction needs. The capital cost savings could help to mitigate the potential for Gulf Coast prices to trade at discounts to Louisiana. An LNG regasification facility can take advantage of this diverse pipeline system to move natural gas much like producers do today.

9.2.3. Typical Firms

A number of companies have proposed LNG facilities in recent years. The following is an introduction to some of the major players in the market, many of whom utilize the LNG industry in different ways, such as marketing, supply management or midstream play.

Sempra Energy is one of the largest energy services companies in the U.S., that includes an LNG affiliate named "Sempra LNG," which develops, builds, and operates LNG receiving terminals and sells regasified LNG throughout the U.S. (SEC, 2006l). The company's business model is based upon securing long-term capacity contracts for its regasification terminals on a fee basis, with incremental charges to regasify the customer's LNG. In this model, Sempra would not own the natural gas, but serve more as a "toll booth" for moving imported natural gas into the U.S. pipeline system. Sempra LNG is also looking into arrangements to own natural gas through long-term supply agreements in foreign countries. This gas would be liquefied and sent direct to Sempra-owned facilities for sale to other parties. Aside from operations in Mexico, Sempra LNG has an agreement for 40 percent of the send-out capacity of the Cameron LNG receipt terminal, which began commercial operations in July 2009 (Sempra LNG, 2009a). Located on the Calcasieu Channel in Hackberry, Louisiana, the new facility has 1.5 Bcf per day of send out capacity (Sempra LNG, 2009a). In addition, Sempra LNG plans to build another facility along the Port Arthur Ship Canal in Texas. Port Arthur LNG would have a capacity of 1.5 to 3 Bcf per day and has been approved by FERC. Sempra plans to begin construction once commercial arrangements have been finalized (Sempra LNG, 2009b).

Excelerate Energy, LLC is a LNG importer and marketer based in The Woodlands, Texas. The company began in 2003 to utilize proprietary technology called the "Energy Bridge," which allows LNG to be regasified on specifically-designed regasification vessels. Within five years, Excelerate has developed three LNG facilities. In February 2008, Excelerate announced a 50-50 percent partnership with RWE Group, a major European electricity and natural gas company (Excelerate Energy, 2008b). Excelerate's major achievement has been the development and operation of the world's first, and only, offshore LNG receiving facility off the coast of Louisiana in the GOM. The facility, Gulf Gateway Deepwater Port (Gulf Gateway), is located 166 miles offshore, just due south of Lake Charles, Louisiana. Excelerate uses their proprietary technology, "Energy Bridge" to regasify imported LNG. Peak capacity is at 690 MMcf per day, although the facility has the ability to increase throughput should Energy Bridge vessels increase their respective regasification capacity (Excelerate Energy, 2008a).

ExxonMobil began their involvement in the LNG business in the 1970s in Indonesia. Today, the company is the world's largest non-governmental marketer of equity natural gas, using 23 gas offices for the support of selling natural gas, LNG, and related products. ExxonMobil has focused on developing LNG technologies, and have found ways to boost production and operating efficiencies. The company manages about 1 MMBbls of natural gas liquids (ExxonMobil, 2008). ExxonMobil has a significant LNG presence in Qatar. In the U.S., the company is currently building a regasification terminal 10 miles south of Port Arthur and two miles north of Sabine Pass, Texas. The Golden Pass LNG Project will have the capacity to supply 2 Bcf per day of natural gas and is expected to be operational in mid-2010 (Golden Pass LNG, 2009). State Qatar owns 70 percent of the venture, Exxon owns 20 percent, and 10 percent is owned by ConocoPhillips. Qatar is expected to provide the natural gas supply for the facility (SEC, 2007c).

Freeport LNG Development, L.P. operates a storage and regasification facility located on Quintana Island, about 70 miles south of Houston, Texas (Figure 74). The Freeport LNG site is located about six miles from open water off a ship channel that is maintained at a depth of 45 feet (Freeport LNG, 2009). The facility is being built in phases. Phase I was designed to have a send-out capacity of 1.75 Bcf per day. Construction began in January 2005 and the facility became operational in October 2008 (Freeport LNG, 2009). The facility's capacity is fully contracted under two long-term terminal use agreements with ConocoPhillips Company for 1 Bcf per day and The Dow Chemical Company for 0.5 Bcf per day (Foster Natural Gas Report, 2006). Permitting work for Phase II has been completed and all state and federal permits are in place (Freeport LNG, 2009). Phase II will increase the capacity of the terminal by up to 1.15 Bcf per day. Phase II construction will begin when additional customer capacity sales needed to finance the expansion are finalized (Freeport LNG, 2009).

Figure 74. Schematic design of Phase I of Freeport LNG.

ConocoPhillips operates LNG facilities around the world, including an LNG liquefaction facility in Alaska, with additional facilities in Venezuela, Nigeria, Qatar, Australia and Timor Sea. ConocoPhillips owns a 70 percent interest in the U.S.'s only export terminal in Alaska at the Kenai LNG plant, which sold 41.3 net billion cubic feet, primarily to Asian markets. In 2006, the company withdrew their license applications for the Compass Port and Beacon Port Terminals, located in various places along the GOMR (SEC, 2006m). The application for Compass Port, proposed to be located 11 miles off the coast of Alabama, was withdrawn due to concerns about the technology the company uses for the vaporization process, called "Open Loop Vaporization" (this technology is discussed in the Trends section) (Rigzone.com, 2006b). If the company changes their system to Closed Loop Vaporization, then the application could be considered once again (Rigzone.com, 2006b). The application for Beacon Port, proposed to be located in lease block High Island Area 27 was withdrawn due to concerns about over capacity for their company (Rester, 2006).

Freeport-McMoRan Energy had plans to develop the "Main Pass Energy Hub" offshore in the Gulf of Mexico, 38 miles east of Venice, Louisiana. The application was filed with the Coast Guard and MARAD in 2004 and by March 2006, the Coast Guard issued a final Environmental Impact Study, concluding that the project would only have minor impacts on the environment. However, in May 2006, the Governor of the State of Louisiana vetoed the approval of Freeport's facility since its vaporization technology was proposed to be based upon an Open Loop technology. The company revised their plan to use Closed Loop technology, and as of January 2007, Freeport-McMoRan had received a Deepwater Port license. The terminal was estimated to cost $440 million and would be capable of regasifying LNG at 1 Bcf per day (SEC, 2006n). Since receiving their Deepwater Port Permit in 2007, the company has been pursuing commercial arrangements for the project (MPEH, 2009). However, Freeport reports that market conditions have prevented the project from obtaining long-term agreements required to finance the construction of the project. Freeport-McMoran is currently “spending limited amounts to continue to pursue the project’s long-term potential, although current market conditions make near-term development unlikely (MPEH, 2009).”

Royal Dutch Shell (Shell) is one of the largest suppliers of LNG, with terminals located throughout the world. Shell’s U.S. operations include capacity rights to import terminals, natural gas and power marketing, trading and storage, long-term gas transportation contracts, and energy management services. In 2006, Shell contracted for 45 percent of the capacity rights at the Elba Island LNG regasification facility, as well as 45 percent of the facility’s proposed capacity expansion. In 2006, Shell owned six LNG carriers and time-shared 4 other carriers, bringing their total LNG shipping capacity to 1.370 Bcf (SEC, 2006o). Shell has proposed the Broadwater LNG regasification import terminal be located on the Long Island Sound. Shell will own 50 percent of the proposed facility, but will contract for 100 percent of the facilities import capacity.

9.2.4. Regulation

Permitting LNG facilities is a lengthy, expensive process that can take years before approvals are given. In addition, the permitting process differs depending upon whether the proposed LNG regasification facility is developed onshore or offshore. Both onshore and offshore projects will engage both federal and state agencies. The FERC is the leading agency for the regulatory review of proposed onshore facilities[25] and the U.S. Coast Guard is the supervising agency for proposed offshore facilities. Both federal agencies work closely together with the U.S. Department of Transportation and other federal and state agencies to review LNG permit applications.

For onshore regasification facilities, the FERC has authority over entry and exit, siting, construction, and operation of new LNG terminals, as well as modifications or extensions of existing LNG terminals. The FERC also has jurisdiction over the existing import terminals and 15 peak-shaving plants engaged in interstate natural gas trade. Every two years, FERC officials inspect LNG facilities to monitor the condition of the plant.

For offshore LNG regasification facilities, the Ports and Waterways Safety Act of 1972 and the Maritime Transportation Security Act of 2002 (which amended the Deepwater Port Act of 1974) gives the Coast Guard the responsibility of assuring marine safety in coastal waterways. The Coast Guard process is designed to render a decision for the construction of an offshore LNG terminal within one year of receipt of application. The Coast Guard also regulates the design, construction, and operation of LNG ships and the duties of LNG ship officers and crews (USDOE, OFE, 2005).

[25] The Natural Gas Act (NGA) gave the Federal Power Commission (FPC) (subsequently the Federal Energy Regulatory Commission (FERC)) the authority to grant certificates allowing construction and operation of facilities used in interstate gas transmission and to authorize the provision of services. A "certificate of public convenience and necessity" is issued under Section 7 of the NGA, and permits pipeline companies to charge customers for some of the expenses incurred in pipeline construction and operation. The NGA also requires Commission approval prior to abandonment of any pipeline facility or services. Section 3 of the NGA requires approval by FERC for the siting, construction, and operation of onshore LNG import and export facilities.

The Pipeline Safety Act of 1994 gives the U.S. Department of Transportation's Office of Pipeline Safety (OPS) the authority to regulate the siting and safety of LNG pipeline facilities, including LNG peak-shaving plants. The OPS is also responsible for developing and maintaining operating, maintenance, fire protection, and safety standards for facilities under its authority and to ensure that LNG facilities are in compliance with these standards. The Department of Energy's Office of Fossil Energy (OFE) coordinates across federal agencies that have regulatory and policy authority for LNG. The Natural Gas Act of 1938 (NGA) requires that anyone seeking to import or export natural gas across U.S. borders to be authorized by the OFE. OFE monitors and certifies LNG shipments and also funds LNG research (USDOE, OFE, 2005).

Finally, the National Environmental Policy Act (NEPA) requires that federal agencies must consider the environmental impact of all proposals for major federal actions and, when appropriate, consider alternatives. FERC is the lead agency in implementing NEPA requirements for onshore facilities, though other agencies are also involved, including the EPA. However, FERC approves or disapproves the actual Environmental Impact Statement (EIS). The Coast Guard is the lead NEPA agency for offshore terminals (USDOE, OFE, 2005). There are as many as 13 in-depth resource reports that make up the EIS for each site (Table 24).

Table 24

Environmental Impact Statement for Onshore LNG Terminals

Topics Included in the Environmental Impact Statement (EIS) for Onshore LNG Terminals	
• General Project Description	• Land Use, Recreation & Aesthetics
• Water Use & Quality	• Air & Noise Quality
• Fish, Wildlife & Vegetation	• Alternatives
• Cultural Resources	• Reliability & Safety
• Socioeconomics	• PCB Contamination (pipelines only)
• Geological Resources	• LNG Engineering & Design Details
• Soils	

Source: FERC, 2005.

The EPA is also involved in the siting process and can offer key input in the following areas (USEPA, 2006c):

- Project approval and environmental review process;
- Requirements and decision making related to air emissions;
- Requirements related to water quality; and
- Other permitting requirements and considerations.

State agencies are also involved in the LNG terminal permitting process, and in some instances local governments, including police and fire departments, may also be involved in the process.

Over the past several years, there have been several regulatory disagreements over the different review processes for onshore and offshore projects. In 2004, the U.S. Department of Commerce, Department of Defense, Department of Energy, Homeland Security, Department of the Interior, Department of Transportation, EPA, FERC, Corps of Engineers, and the Council on Environmental Quality signed a final memorandum of understanding (MOU) for interagency coordination on licensing of deepwater ports in an attempt to streamline the process (USDOE, OFE, 2005). Nevertheless, as many as 100 permits may be required from various federal, state, and local government agencies for a new onshore LNG regasification facility (USDOE, OFE, 2005). Without significant delays, it could take up to seven years for the typical LNG import terminal to be brought online from initial design to the first LNG delivery, including up to three years for obtaining the necessary permits (USDOE, OFE, 2005).

In addition to federal agency oversight and approval, some states have also asserted their influence over both onshore and offshore LNG proposals. Recently, the governors of impacted states were granted additional authority over proposed onshore facilities through the Energy Policy Act of 2005 (EPAct). EPAct allows a state governor with a proposed onshore terminal to designate a state agency to consult with FERC regarding applications which subsequently consults with the named agency regarding state and local safety considerations. EPAct also allows a state agency to furnish an advisory report on state and local safety considerations to FERC. For offshore projects, federal law, under the Deepwater Port Act, allows governors to approve, approve with conditions, or veto proposed projects. For example, in 2006, Louisiana Governor Blanco vetoed Freeport McMoRan's proposed open loop Main Pass Energy Hub project offshore its coast. Federal law states that a state's lack of action within 45 days of a final federal hearing is the equivalent of license approval (Kennedy, 2006). Thus, if the state fails to take any type of protest action in 45 days, a LNG facility can move forward with its potential license.

9.3. Industry Trends and Outlook

9.3.1. Trends

In the past, LNG imports have represented a very small share of total U.S. natural gas supply. The overwhelming majority of U.S. gas supplies used to meet demand have come from producing fields in the lower 48 states. The limited amount of natural gas that has been imported into the country, outside of LNG, has been through pipeline imports from Canada. Figure 75 shows overall natural gas import trends over the past two decades. The left axis graphs total imports and pipeline imports (the difference between the two series being LNG). The right side of the figure shows the growing share of LNG as a percent of total consumption. As of 2006, LNG imports had increased over 650 percent since 1997 and 155 percent since 2002. However, today, those shares are just 1.5 percent of total U.S. natural gas supplies.

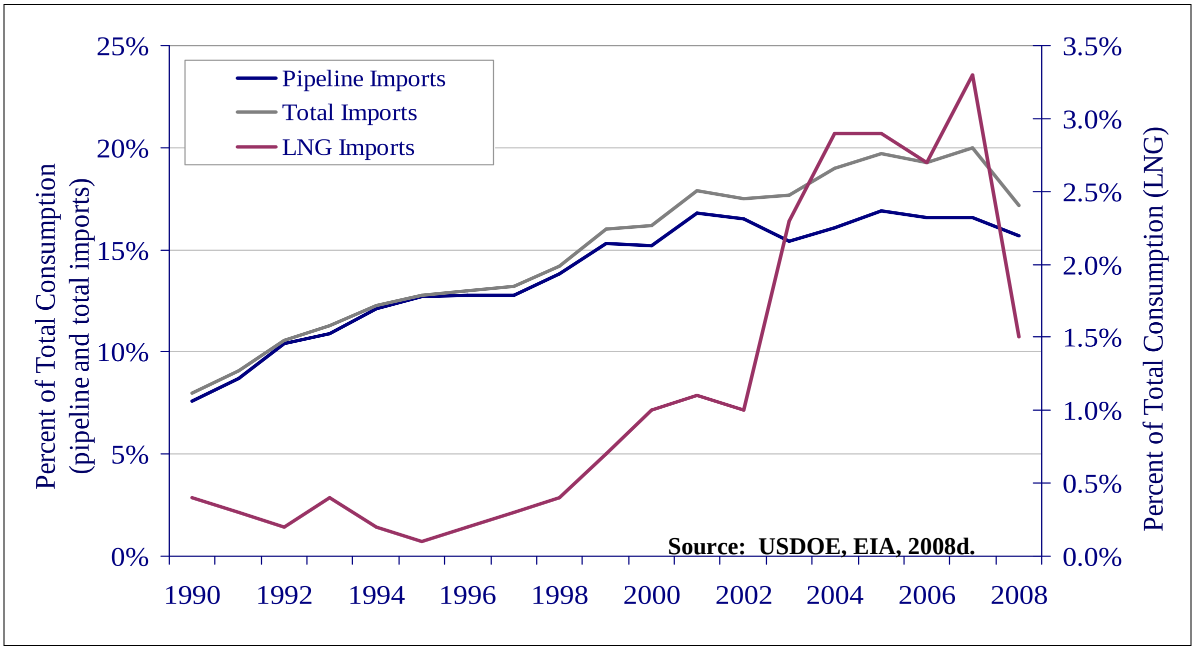


Figure 75. U.S. natural gas imports as a percent of total consumption, 1990 - 2008.

Figure 76 shows historic LNG imports per facility since the mid-1990s. The left side of the graph measures total LNG imports (in Bcf) and the right side compares those imports to trends in Henry Hub natural gas prices (i.e., wholesale prices). The graph shows the increase in imports from all three terminals starting in 2001, when Elba Island became operational. Clearly, the import trend has increased considerably since natural gas prices began their climb in 2000, though it actually slowed during 2005 and 2006 due to European and Asian competition.

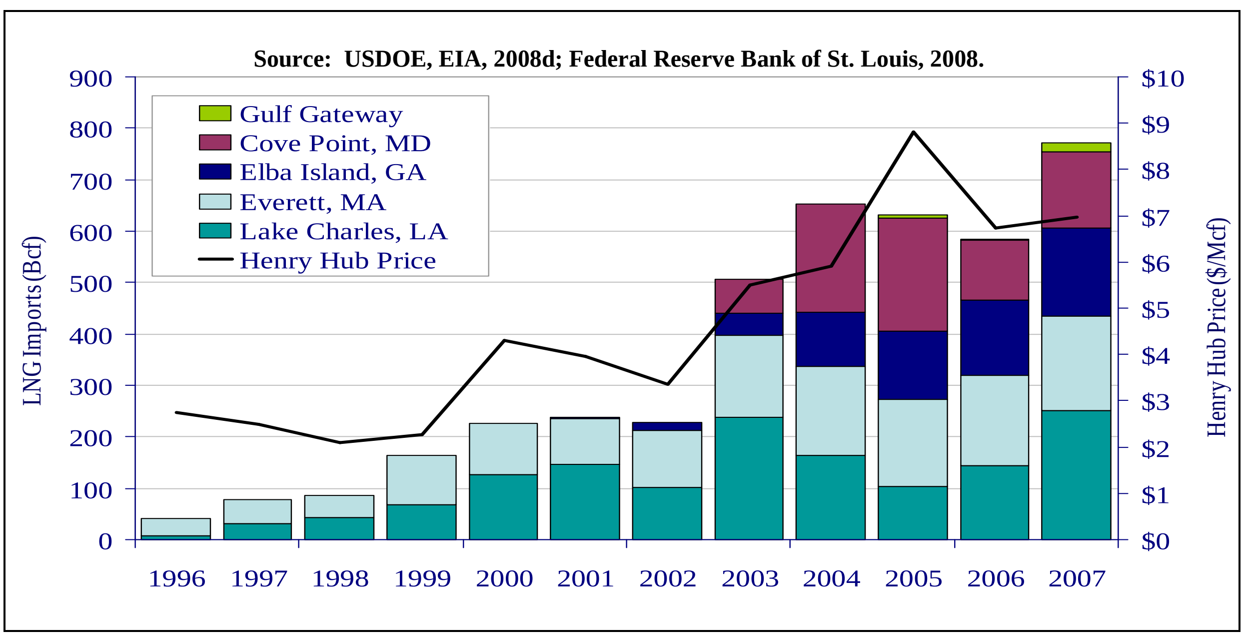


Figure 76. LNG imports and natural gas price.

In 2006, the U.S. imported an estimated 580 Bcf, or approximately 8 percent less than the 631 Bcf imported in 2005. Through October 2006, the offshore facility, Gulf Gateway, received only one partial shipment of LNG. In 2008 however, the facility received over 17 Bcf. As shown in Figure 75, LNG imports grew significantly but fell in 2008. Much of this decline was due to increased U.S. natural gas production (USDOE, EIA, 2009a). The drop in total imports occurred despite an increase in domestic consumption (USDOE, EIA, 2009a).

The economics of new development opportunities strongly favor expansion at existing sites and is one of the reasons onshore facilities have such favorable economics relative to their offshore counterparts. Expansions have recently been completed at a number of LNG facilities.

In April 2006, Trunkline LNG completed Phase I of its terminal expansion, by adding a new storage tank and a second ship berth. Phase I increased the facility's storage capacity from 6.3 Bcf to 9 Bcf. Phase II of the expansion was completed in July 2006. This expansion increased the facility's send-out capacity from 1.2 Bcf per day to 1.8 Bcf per day (Panhandle Energy, 2009).

In 2006, FERC approved expansion plans at Dominion's Cove Point facility in Maryland. The expansion, completed in 2009 increased the terminal's daily output capacity from 1 Bcf per day to 1.8 Bcf per day and increased its storage capacity from 7.8 Bcf to 14.6 Bcf. In addition, the expansion added two storage tanks and two electric generating units (Dominion Transmission, 2009).

An expansion at El Paso's Elba Island facility in Georgia is currently under construction. The project will add 900 MMcf per day of send-out capacity and 8.4 Bcf of storage capacity, effectively doubling the facility's capacity (El Paso.com, 2009). El Paso expects the first phase of the project, installation of a new 4.2 Bcf storage tank and enhancements to the docking facilities, to accommodate new, larger delivery vessels to be complete by mid-2010. The second phase will add another 4.2 Bcf storage tank and is expected to be finished in 2012 (El Paso.com, 2009).

In January 2007, FERC approved Sempra Energy's plan to expand its Cameron LNG terminal. The new facility started operations of with 1.5 Bcf of capacity in July 2009 and is planning to expand the facility by another 1.5 Bcf. The expansion project is expected to be completed by October 2010 (FERC, 2007).

In addition to the expansions at existing facilities, there has been a plethora of announcements for new regasification facilities in various parts of the coastal U.S. Figure 77 provides a map of these facilities concentrated in areas along the Atlantic seaboard, the west coast, the Gulf Coast, and Mexico as of January 14, 2008. Table 25 lists the company and facility name for each of these terminals, as well as their location and capacity.

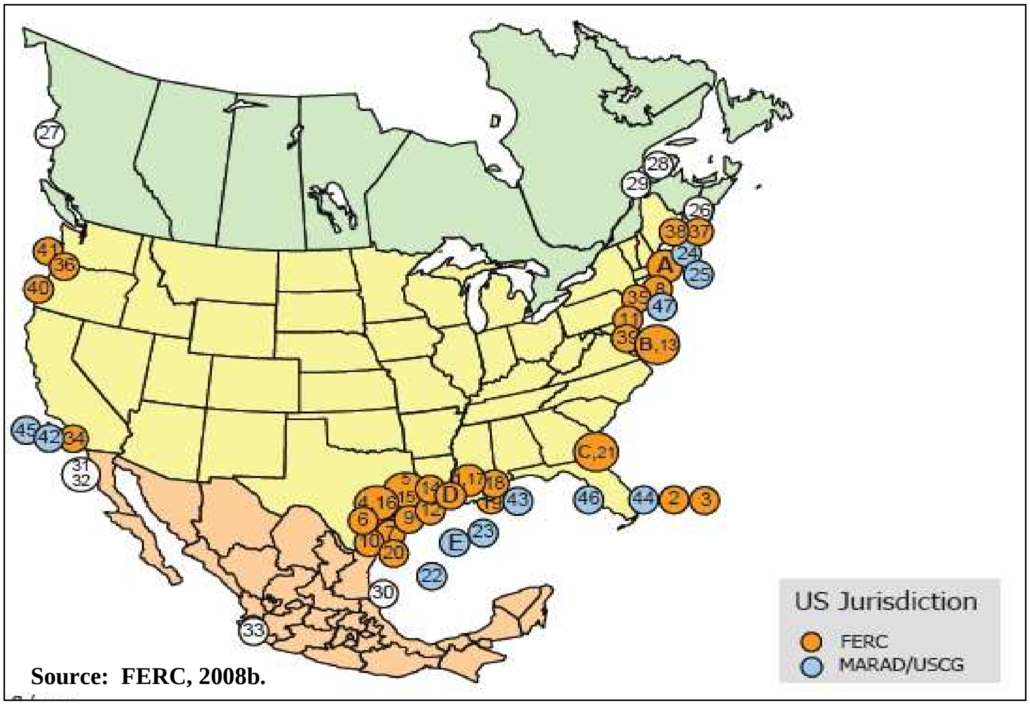


Figure 77. Existing and proposed North American LNG terminals.

Table 25

Existing and Proposed North American LNG Terminals

	Company / Facility	Location	Capacity (Bcf/d)
OPERATING			
A.	DOMAC / Everett	Everett, MA	1.0
B.	Dominion / Cove Point LNG	Cove Point, MD	1.0
C.	El Paso / Elba Island	Elba Island, GA	1.2
D.	Trunkline LNG / Lake Charles	Lake Charles, LA	2.1
E.	Excelerate Energy / Gulf Gateway	Gulf of Mexico	0.5
PROPOSED			
Approved by FERC			
1.	Sempra / Cameron LNG	Hackberry, LA	1.8
2.	AES / Ocean Express	Bahamas	0.8
3.	Calypso / Calypso Pipeline	Bahamas	0.8
4.	Cheniere / Freeport LNG	Freeport, TX	1.5
5.	Cheniere / Sabine Pass	Sabine, LA	2.6
6.	Cheniere / Corpus Christi	Corpus Christi, TX	2.6
7.	4Gas / Vista del Sol	Corpus Christi, TX	1.1
8.	Hess LNG / Weaver's Cove Energy	Fall River, MA	0.8
9.	ExxonMobil / Golden Pass	Sabine, TX	2.0
10.	Occidental / Ingleside Energy	Corpus Christi, TX	1.0
11.	BP / Crown Landing LNG	Logan Township, NJ	1.2
12.	Sempra / Port Arthur	Port Arthur, TX	3.0
13.	Dominion / Cove Point LNG Expansion	Cove Point, MD	0.8
14.	Cheniere / Creole Trail LNG	Cameron, LA	3.3
15.	Cheniere / Sabine Pass Expansion	Sabine, LA	1.4
16.	Cheniere / Freeport LNG Expansion	Freeport, TX	2.5
17.	Sempra / Cameron LNG Expansion	Hackberry, LA	0.9
18.	Gulf LNG Energy LLC / Pascagoula	Pascagoula, MS	1.5
19.	ChevronTexaco / Bayou Casotte	Pascagoula, MS	1.3
20.	Gulf Coast LNG Partners / Calhoun LNG	Port Lavaca, TX	1.0
21.	El Paso / Elba Island Expansion	Elba Island, GA	0.9
Approved by MARAD/Coast Guard			
22.	ChevronTexaco / Port Pelican	GOM	1.6
23.	McMoRan Exp / Main Pass	Offshore Louisiana	1.0
24.	SUEZ LNG / Neptune LNG	Offshore Boston	0.4
25.	Excelerate Energy / Northeast Gateway	Offshore Boston	0.8
Canadian Approved Terminals			
26.	Irving Oil, Repsol / Canaport	St. John, NB	1.0
27.	Galveston LNG / Kitimat LNG	Kitimat, BC	1.0
28.	TransCanada, PetroCanada / Cacouna	Riviere-du-Loup, QC	0.5
29.	Enbridge,GazMet,Gaz de France	Quebec City, Quebec	0.5
Mexican Approved Terminals			
30.	Shell, Total, Mitsui / Altamira	Altamira, Tamulipas	0.7
31.	Sempra / Energia Costa Azul	Baja California, MX	1.0
32.	Sempra / Energia Costa Azul (expansion)	Baja California, MX	1.5
33.	n.a.	Manzanillo, MX	0.5
Proposed to FERC			
34.	Mitsubishi, ConocoPhillips / Sound Energy	Long Beach, CA	0.7
35.	TransCanada, Shell / Broadwater Energy	LI Sound, NY	1.0
36.	Northern Star / Northern Star LNG	Bradwood, OR	1.0
37.	Quoddy Bay LLC / Pleasant Point	Pleasant Point, ME	2.0
38.	Kestrel Energy / Downeast LNG	Robbinston, ME	0.5
39.	AES / Sparrows Point	Baltimore, MD	1.5
40.	Jordon Cove Energy Project	Coos Bay, OR	1.0
41.	Oregon LNG	Astoria, OR	1.5
Proposed to MARAD/Coast Guard			
42.	Northern Star / Clearwater Port	Offshore California	1.4
43.	TORP / Bienville Offshore Energy Terminal	GOM	1.4
44.	SUEZ LNG / SUEZ Calypso	Offshore Florida	1.9
45.	Woodside Natural Gas / OceanWay	Offshore California	1.2
46.	Hoegh LNG / Port Dolphin Energy	Offshore Florida	1.2
47.	ASIC / Safe Harbor Energy	Offshore New York	2

Source: FERC, 2008b.

More than 62 percent of capacity of proposed U.S. facilities (not including those in Bahamas, Canada or Mexico), comprising 33.9 Bcf per day, are located along the Gulf Coast. This represents the single highest concentration of proposed capacity anywhere in the U.S. Of the Gulf Coast proposed facilities, 81 percent, or 27.5 Bcf per day of capacity, is proposed to be developed onshore in the region, while the remaining 6.4 Bcf per day is proposed to be located offshore in the Gulf of Mexico.

Figure 78 provides a graph showing the potential LNG capacity additions, by year, based upon their reported online dates.

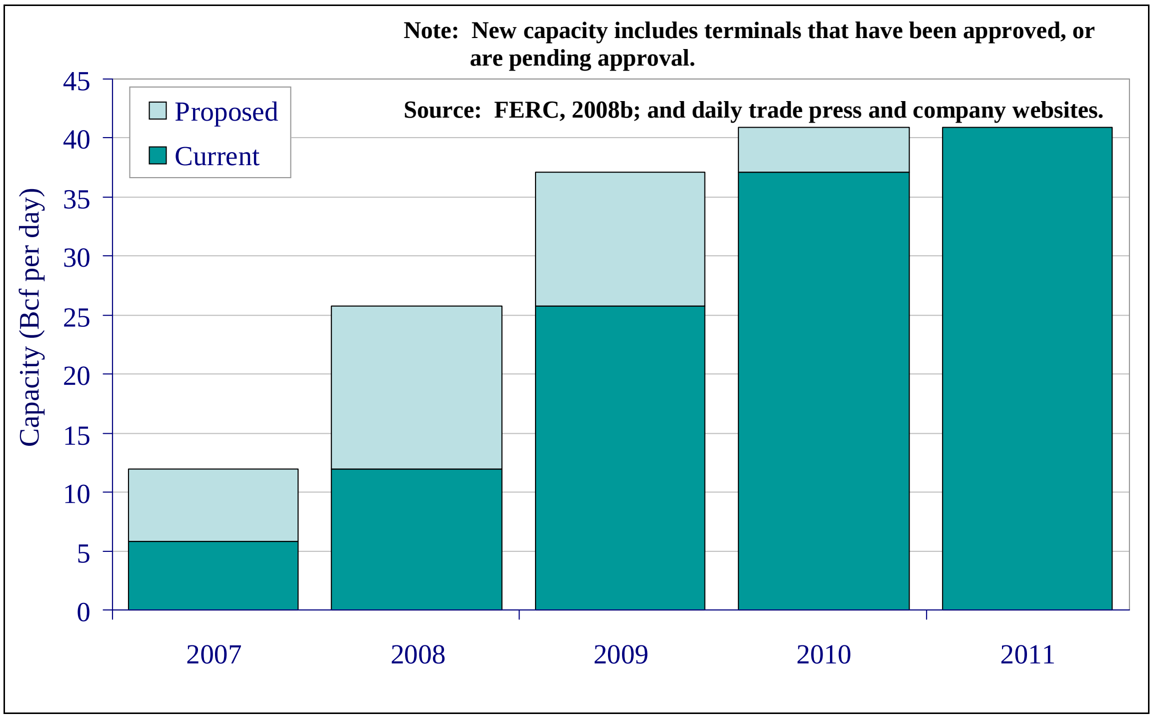


Figure 78. Planned LNG capacity additions and expansions, 2007-2011.

9.3.2. Hurricane Impacts

Storm surge associated with hurricanes and tropical storms is often the most significant cause of damage to facilities and property in low-lying areas, and poses a risk to onshore LNG facilities. The 2005 hurricane season produced two powerful hurricanes in the Gulf, Katrina and Rita, that did have some moderate impacts on local LNG facilities.

The nation's only operating offshore terminal, Excelerate Energy's Gulf Gateway Energy Bridge, located 116 miles off the Louisiana coast, narrowly avoided a direct hit by Hurricane Rita on September 23, 2005 (Figure 79). Rita's eye passed just 25 nautical miles north of the Excelerate facility. Gulf Gateway suffered no major damage (the facility was designed using 100-year Gulf of Mexico storm conditions), despite wind-driven seas near the eye of the storm estimated to have reached 70 feet. No specific wave condition data for the area near the Excelerate facility are available since the Ocean Data Acquisition System buoys along the path of the storm were destroyed (Sullivan and Jura, 2005; Marron, 2005). No damage was suffered at the Excelerate facility, though pipelines serving the facility were affected and were not fully operational until mid-November (USDOE, OFE, 2006).

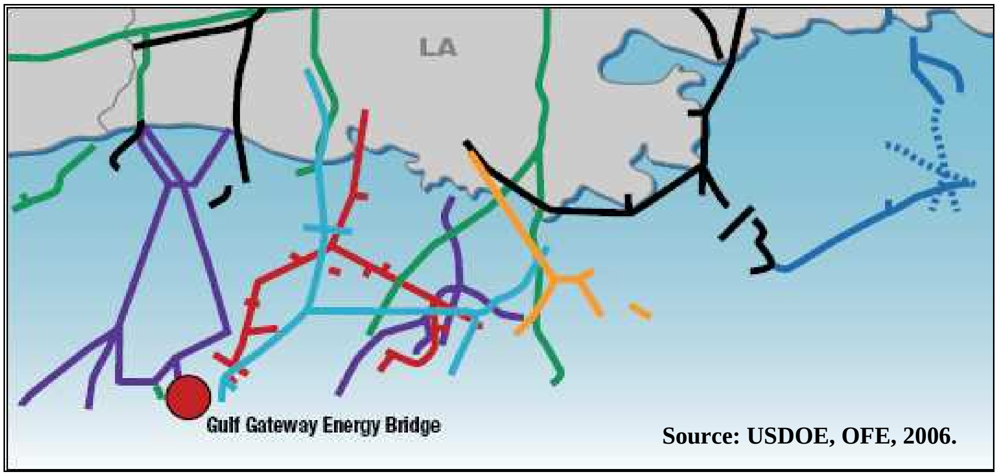


Figure 79. Gulf Gateway LNG facility and surrounding pipelines.

The Lake Charles LNG import facility was also in the path of Hurricane Rita, but suffered little damage (Figure 80). However, the navigation channel to the terminal was closed for several days after the storm due to debris in the shipping channel and a lack of commercial power availability. The facility was 100 percent operational by October 5, 2005 (USDOE, OFE, 2006).

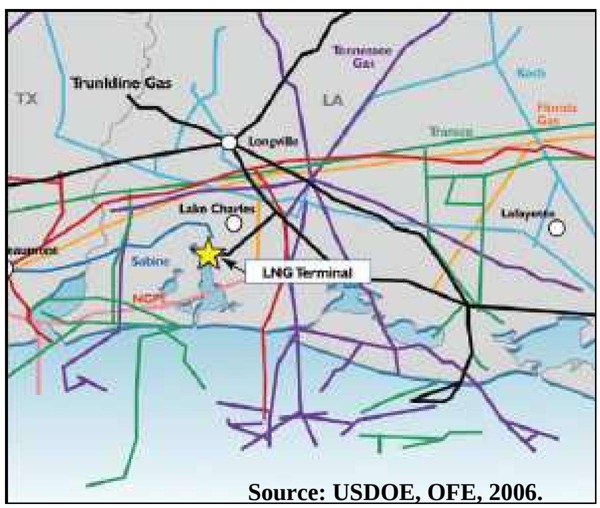


Figure 80. Lake Charles LNG facility and surrounding pipelines.

To plan for, and mitigate, the effects of hurricanes on LNG facilities, designers use a variety of tools to evaluate potential surge damage. For instance, following the 2005 hurricanes, planners for the Chevron Gulf LNG facility near the port of Pascagoula, MS used two computer models to evaluate future hurricane surge events. After comparing actual hurricane surge data along the Mississippi coast to the models, designers determined that facility protection sufficient to withstand a Category 4 hurricane would provide the most benefit. This has resulted in a planned dike wall 45 feet wide and 27 feet high to surround the entire 33.3-acre site (FERC, 2006a).

Besides physical damage, the hurricanes caused prices to increase during 2005, from August to the end of the year, as a result of extensive supply disruptions (SEC, 2005e). The disruptions also caused imports to surge. LNG imports rose 0.1 Bcf per day in September and October, and continued to rise into November (Gas Processors Report, 2006).

9.3.3. Outlook

U.S net imports of natural gas are expected to decline from 16 percent of supply to 3 percent in 2010 (USDOE, EIA, 2009b). The reduction is not only a result of lower imports from Canada and Mexico because of growing demand in those countries, but also the potential for U.S. domestic natural gas production (particularly from unconventional sources) increases, providing a competitive alternative to imports of LNG (USDOE, EIA, 2009b).

In the U.S., LNG imports are expected to reach 1.1 Tcf in 2015 and peak at 1.5 Tcf in 2018. LNG imports, however, will then decline to 0.85 Tcf in 2030 (Figure 81). The Energy Information Administration cites growth in world liquefaction capacity as the reason for near-term growth. However, in the longer term, high LNG prices (which are tied to oil prices in many markets) and ample domestic natural gas supplies, particularly from unconventional resources, will reduce U.S. demand for LNG imports (USDOE, EIA, 2009b).

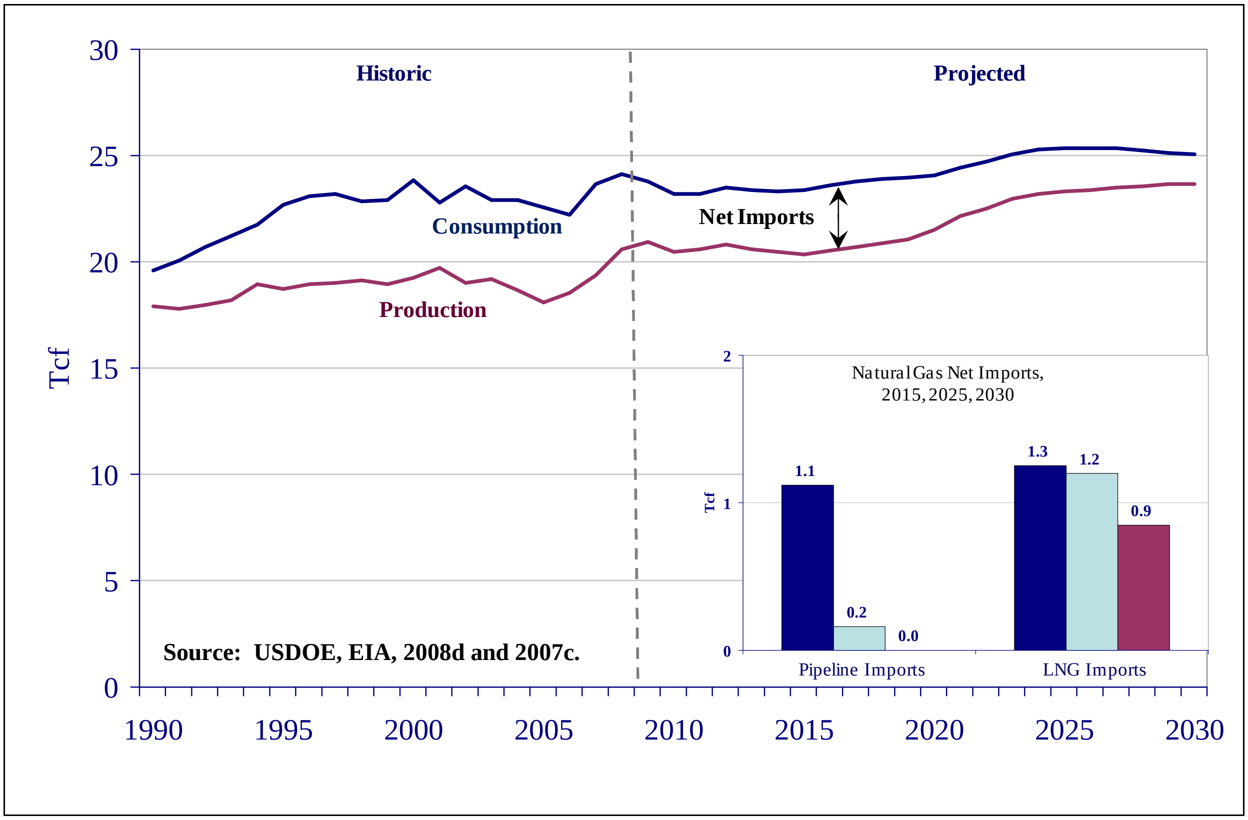


Figure 81. Natural gas production, consumption, and imports, 1970-2030.

9.4. Chapter Resources

Federal Energy Regulatory Commission – LNG Industry
The FERC website provides a list of existing and proposed LNG terminals as well as links to certification filings.
http://ferc.gov/industries/lng.asp

Federal Energy Regulatory Commission – eLibrary
On the FERC's eLibrary, documents filed in a particular docket can be downloaded and viewed. This includes both documents that are filed, and issued.
http://ferc.gov/docs-filing/elibrary.asp

Federal Energy Regulatory Commission – Market Oversight
An overview of natural gas markets by region can also be found at FERC.
http://ferc.gov/market-oversight/mkt-gas/overview.asp

Department of Energy, Energy Information Administration
On the EIA's Natural Gas Navigator, LNG imports are provided by country (originated), state and point of entry. http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

A number of analysis reports can also be found at the EIA.
http://tonto.eia.doe.gov/dnav/ng/ng_pub_analysis_move.asp

10. NATURAL GAS PROCESSING

10.1. Description of Industry and Services Provided

Natural gas, as it is produced from a reservoir rock, is typically a mixture of light hydrocarbon gases, impurities and liquid hydrocarbons. Natural gas processing removes the impurities and separates the light hydrocarbon mixture into its useful components.

Natural gas is found below the earth's surface in three principal forms:

- *Associated gas* is found in crude oil reservoirs, either dissolved in the crude oil, or combined with crude oil deposits. Associated gas is produced from oil wells along with the crude and is separated from the oil at the head of the well.

- *Non-associated gas* is found in reservoirs separate from crude oil – its production is not a result of the production of crude oil. It is commonly called "gas-well gas" or "dry gas." Today about 75 percent of all U.S. natural gas produced is non-associated gas (USDOE, EIA, 2006b).

- *Gas Condensate* is a hydrocarbon that is neither true gas nor true liquid. It is not a gas because of its high density, and it is not a liquid because no surface boundary exists between gas and liquid. Gas condensate reservoirs are usually deeper and have higher pressures, which pose special problems in the production, processing, and recycling of the gas for maintenance of reservoir pressure.

The quality and quantity of components in natural gas varies widely by the field, reservoir, or location from which the natural gas is produced. Although there really is no "typical" make-up of natural gas, it is primarily composed of methane (the lightest hydrocarbon component) and ethane. Figure 82 shows the common components of a natural gas production stream.

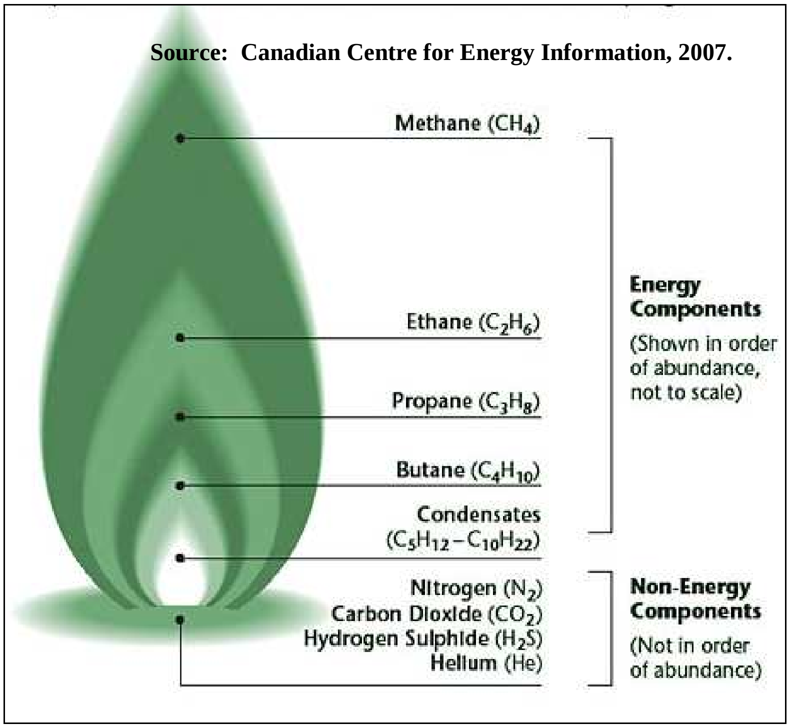


Figure 82. Common components of natural gas.

In general, there are four types of natural gas – wet, dry, sweet, and sour. Wet gas contains some of the heavier hydrocarbon molecules and water vapor. When the gas reaches the earth's surface, a certain amount of liquid is formed. The water has no value; however, the remaining portion of the wet gas may contain five or more gallons of recoverable hydrocarbons per thousand cubic feet (Berger and Anderson, 1992). If the gas does not contain enough of the heavier hydrocarbon molecules to form a liquid at the surface, it is a dry gas. Sweet gas has very low concentrations of sulfur compounds, while sour gas contains excessive amounts of sulfur and an offensive odor. Sour gas can be harmful to breathe or even fatal (Berger and Anderson, 1992).

Hydrocarbons have a distinctive weight, boiling point, vapor pressure, and other physical properties that make the removal and separation of individual hydrocarbons possible.[26] Each hydrocarbon has a specific combination of pressure and temperature at which it will change from liquid to gas – the heavier the component, the higher the temperature, or boiling point (Berger and Anderson, 1992).

10.2. Industry Characteristics

10.2.1. Typical Facilities

All natural gas is processed in some manner to remove unwanted water vapor, solids, and/or other contaminants that would interfere with pipeline transportation or marketing of the gas.

[26] "Boiling point" is when a liquid will boil whenever the vapor pressure of a liquid is equal to the pressure being exerted on it.

Typical contaminants include water, hydrogen sulfide, carbon dioxide, nitrogen, and helium. Centrally located to serve different fields, natural gas processing plants have two main purposes: (1) remove the impurities from the gas; and (2) separate the gas into its useful components for eventual distribution to consumers (Figure 83).

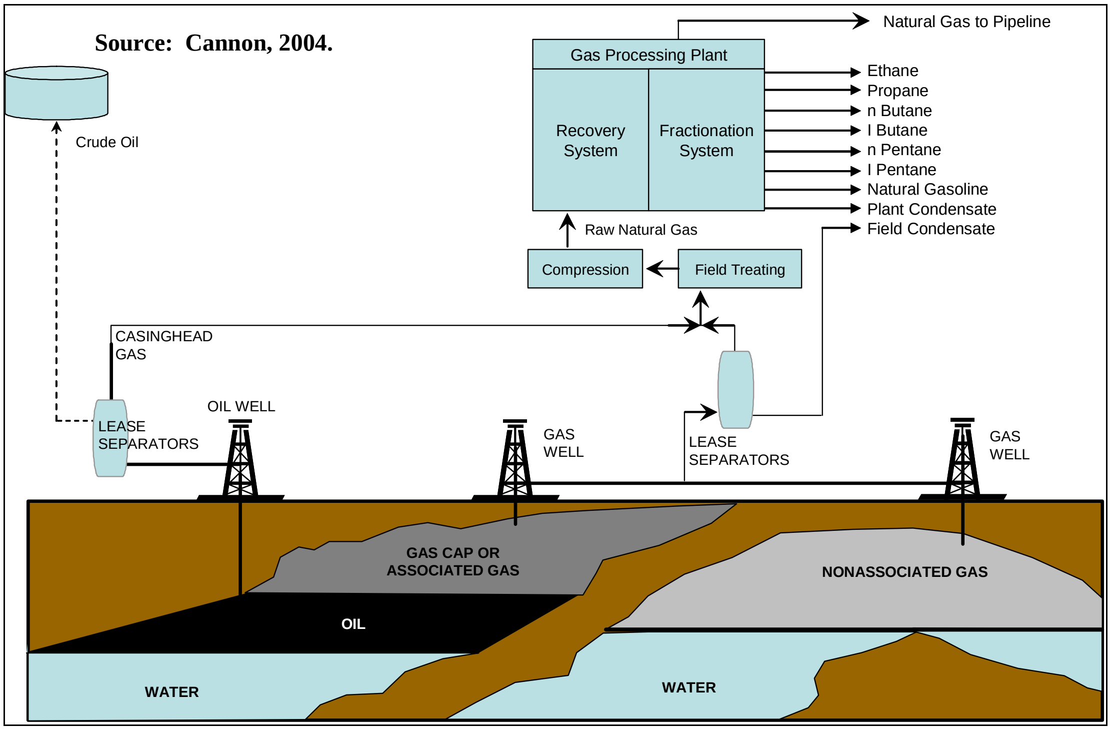


Figure 83. Natural gas processing.

The number of steps and the type of techniques used in the process of creating pipeline-quality natural gas most often depends upon the source and makeup of the specific natural gas production stream. In some cases, several of the steps shown in Figure 84 may be integrated into one unit or operation, performed in a different order, or at alternative locations (lease/plant), or not required at all.

There are several stages (as shown in Figure 84) in natural gas processing/treatment that include (USDOE, EIA, 2006b):

- Gas-Oil Separators: The release of pressure at the wellhead often causes a natural separation of gas and oil (using a conventional closed tank, where gravity separates the gas hydrocarbons from the heavier oil). However, in some cases, a multi-stage gas-oil separation process is needed to physically separate the gas stream from the crude oil. These gas-oil separators are commonly formed from closed cylindrical shells, horizontally mounted with inlets at one end, an outlet at the top for removal of gas, and an outlet at the bottom of the tank for removal of oil. The process includes alternating heating and cooling (by compression) in order to separate gas from the flow stream as well as any water and condensate, if present.

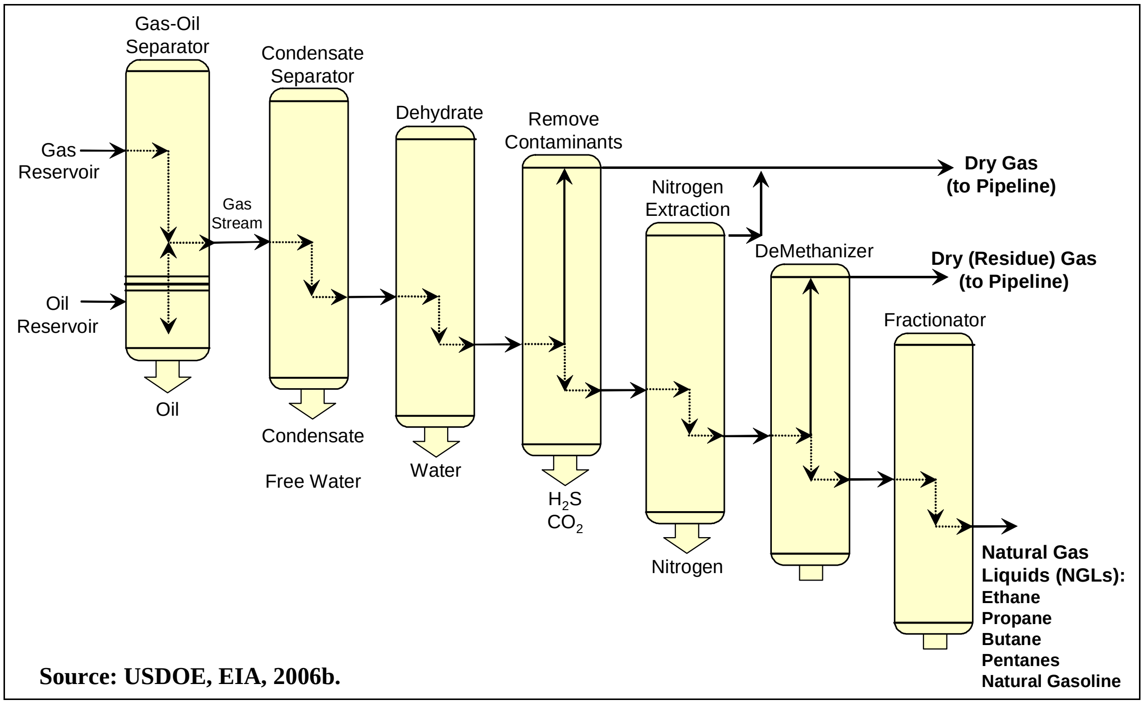


Figure 84. General natural gas processing schematic.

- Condensate Separator: For the most part, condensates are usually removed from the gas stream at the wellhead through mechanical separators. The natural gas production stream enters the separator directly from the wellhead eliminating the need for a gas-oil separation process. In order to remove additional condensates, the gas stream will enter the processing plant at high pressure (600 pounds per square inch gauge (psig) or greater) through an inlet slug catcher where free water is removed from the gas, and directed to a condensate separator. The extracted condensate is routed to storage tanks.

- Dehydration: The dehydration process is needed to eliminate water that may cause the formation of hydrates. Hydrates form when a gas or liquid containing free water experiences specific temperature/pressure conditions. Dehydration is the removal of this water from the produced natural gas and is accomplished through several methods. Ethylene glycol (glycol injection) systems can be used as an absorption mechanism to remove water and other solids from the gas stream.[27] Or, adsorption dehydration may be used. This method uses dry-bed dehydrators towers, which contain desiccants such as silica gel and activated alumina, to perform the extraction.

[27] Adsorption is the binding of molecules or particles to the surface of a material, while absorption is the filling of the pores in a solid. The binding to the surface is usually weak with adsorption, and therefore, usually easily reversible.

- Contaminant Removal: Contaminates that need to be removed from the gas stream can include hydrogen sulfide, carbon dioxide, water vapor, helium, and oxygen. The most commonly-used technique for contaminant removal is to first direct the flow of gas though a tower containing an amine solution. Amines have the advantage of absorbing sulfur compounds from natural gas and they can be reused repeatedly. The next processing step can include a series of filter tubes. As the flow of gas slows, the separation of remaining contaminants tends to occur due to gravity. Smaller particles fall out of the gas flow as the gas moves through these separator tubes. The contaminants combine with larger particles that flow to the lower section of the unit. As the gas stream continues through the series of tubes, a centrifugal force is generated which further removes any remaining water and small solid particulate matter.

- Nitrogen Extraction: Once the contaminants are removed, the stream is routed to a Nitrogen Rejection Unit (NRU). There it is further dehydrated using molecular sieve beds. The gas stream is routed through a series of passes through a column and a brazed aluminum plate fin heat exchanger. The nitrogen is cryogenically separated and vented using thermodynamics. Another type of NRU unit separates methane and heavier hydrocarbons from nitrogen using an absorbent solvent. The absorbed methane and heavier hydrocarbons are flashed off from the solvent by reducing the pressure on the processing stream in multiple gas decompression steps. The liquid from the flash regeneration step is returned to the top of the methane absorber as lean solvent. Helium, if any, can be extracted from the gas stream through membrane diffusion in a Pressure Swing Adsorption (PSA) unit.

- Methane Separation: Demethanizing the gas stream can occur as a separate operation in the gas plant or as part of the NRU operation. Some of the ways to separate methane from natural gas liquids (NGLs) include cryogenic processing and absorption methods. The cryogenic method is better at extraction of the lighter liquids, such as ethane. With this method the temperature of the gas stream is lowered to around -120 degrees Fahrenheit. The quick drop in temperature condenses the hydrocarbons in the gas stream, but maintains methane in its gaseous form. The absorption method uses a “lean” absorbing oil to separate the methane from the NGLs. The gas stream is passed through an absorption tower and the absorption oil soaks up a large amount of the NGLs. The “enriched” absorption oil with the NGLs exits through the bottom of the tower. The enriched oil is fed into distillers where the blend is heated to above the boiling point of the NGLs, while the oil remains fluid. The oil is recycled while the NGLs are cooled and directed to a fractionator tower.

- Fractionation: Fractionation is the process of separating the various NGLs present in the remaining gas stream into their respective components. This process uses the different boiling points of the individual hydrocarbons in the stream, by now virtually all NGLs, to achieve that task. The process occurs in stages as the gas stream rises through several towers where heating units raise the temperature of the stream, causing the various liquids to separate and exit into specific holding tanks, which in turn are then sold as individual commodities for energy and feedstock purposes along the Gulf Coast.

10.2.2. Geographic Distribution

In 2007, there are 571 gas processing plants in the U.S. listed as being operational. Most of the processing capacity is located in six states: Texas; Louisiana; Oklahoma; Colorado; Wyoming; and California (Figure 85). New Mexico and Michigan also have a large number of processing facilities. These eight states account for 83 percent of the total number of U.S. gas processing plants, 71 percent of processing capacity, and 68 percent of throughput (Oil & Gas Journal, 2007). More than half of the natural gas processing plant capacity in the U.S. is located along the GOMR and available for supporting federal offshore production (USDOE, EIA, 2006b). Four of the largest capacity natural gas processing and treatment plants are found in Louisiana, while the greatest number of individual natural gas plants is located in Texas (USDOE, EIA, 2006b).

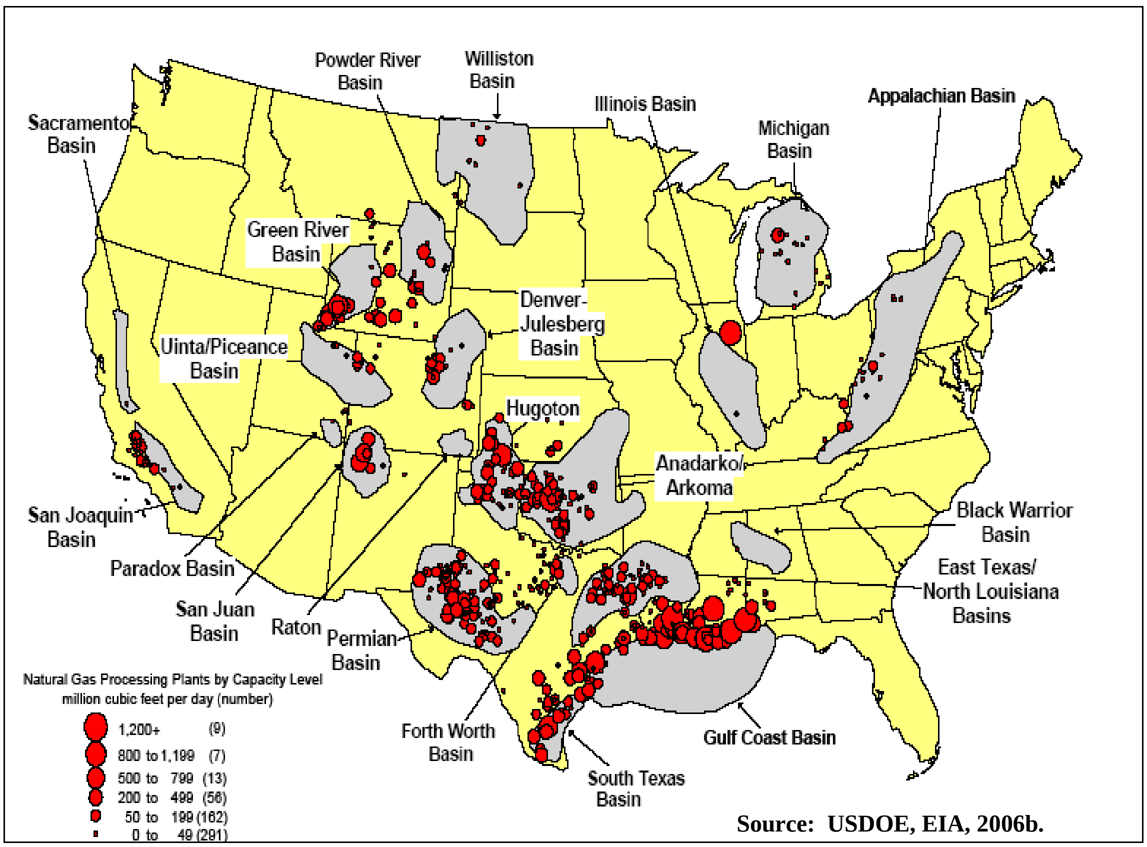


Figure 85. Concentrations of natural gas processing plants.

As shown in Table 26, some states have processing facilities with higher capacities than those in others. For instance, Texas has 187 gas processing plants and Louisiana has only 72 gas processing plants; however, Louisiana's processing capacity is 21 percent higher than Texas.

Total U.S. gas processing capacity is over 70,000 MMcf per day and current throughput represents about 65 percent of capacity (Oil & Gas Journal, 2007).

With more than 18.6 Bcf per day in gas-processing capacity (down slightly from 18.8 Bcf per day in 2006), Louisiana continues to lead other U.S. states, followed closely by Texas with almost 15.5 Bcf per day. Between them, the two states hold nearly 50 percent of the nation's capacity (Oil & Gas Journal, 2007).

Table 26

Natural Gas Processing Plants in the U.S. as of January 1, 2007

State	Number of Plants	Gas Capacity	Gas Throughput
		----- (MMcfd) -----	
Texas	187	15,462	10,879
Louisiana	72	18,675	9,607
Oklahoma	56	3,416	2,268
Colorado	41	1,483	1,200
Wyoming	39	5,306	3,055
California	31	1,118	842
New Mexico	26	3,262	2,492
Michigan	22	1,549	626
Alabama	14	1,363	470
Utah	14	531	243
Kansas	13	2,909	1,221
Pennsylvania	8	43	33
West Virginia	8	585	304
North Dakota	7	203	167
Alaska	5	9,525	9,298
Arkansas	5	874	507
Montana	5	16	11
Kentucky	4	120	106
Mississippi	4	1,603	760
Ohio	4	25	10
Tennessee	2	8	2
Florida	1	32	4
Illinois	1	2,100	1,426
Nebraska	1	10	8
Wisconsin	1	0	0
Total U.S.	**571**	**70,218**	**45,539**

Source: Oil & Gas Journal, 2007.

In terms of throughput, Texas leads the U.S., with almost 4.0 Tcf of natural gas processed in 2006, followed closely by Alaska and Louisiana (see Figure 86). Louisiana processed 2.5 Tcf of natural gas in 2005. Together Texas and Louisiana account for 44 percent of the natural gas processed in the U.S., and over 54 percent of natural gas processed in the lower 48 states (USDOE, EIA, 2008d).

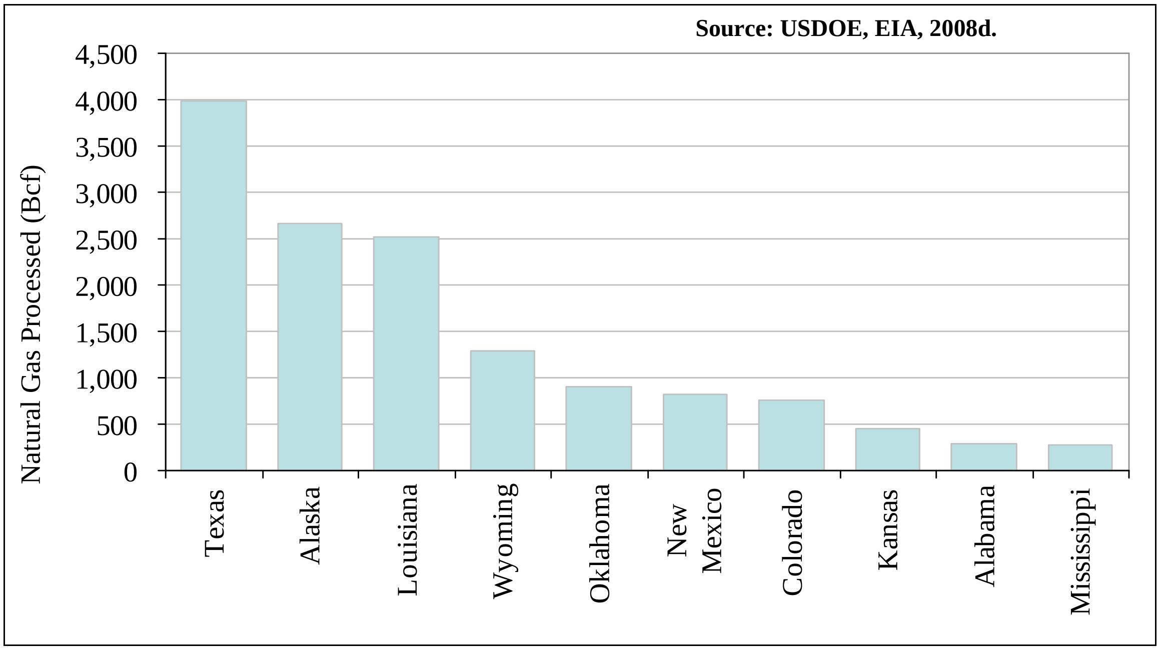


Figure 86. Natural gas processed by top 10 states, 2006.

10.2.3. Typical Firms

The natural gas processing business includes a wide range of company types, such as fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each company type has varying levels of financial and personnel resources. Competition in the market generally revolves around price, service, and location (SEC, 2006q).

Enterprise Products Partners (EPP), one of the largest North American processers, is an integrated midstream company with assets that include natural gas gathering, processing, transportation, and storage; NGL fractionation (or separation), transportation, storage, and import and export terminalling; crude oil transportation; offshore production platform services; and petrochemical pipeline and services. EPP owns 23 processing plants located in Texas, Louisiana, Mississippi, New Mexico, and Wyoming (Figure 87) (SEC, 2006q). Another large integrated midstream company and the largest NGL producer in North America is DCP Midstream (formerly Duke Energy Field Services). DCP Midstream processes natural gas at 52 owned or operated natural gas processing plants (DCP Midstream, 2008).

Crosstex Energy is an independent midstream company with a significant presence in the GOM region. Crosstex's primary midstream assets include approximately 5,000 miles of natural gas gathering and transmission pipelines, 12 natural gas processing plants and four fractionators – the majority of which are located in the GOM region (SEC, 2006r).

Figure 87. Enterprise natural gas processing plant.

Another natural gas processor with a significant presence in the GOM is DCP Midstream Partners, LP. DCP Midstream is a joint venture between Spectra Energy and ConocoPhillips. DCP Midstream's Northern Louisiana system is an integrated pipeline system located in northern Louisiana and southern Arkansas that gathers, compresses, treats, processes, transports, and sells natural gas, and that transports and sells NGLs and condensate. This system consists of:

- the Minden processing plant and gathering system, which includes a 115 MMcf per day cryogenic natural gas processing plant supplied by approximately 725 miles of natural gas gathering pipelines, connected to approximately 460 receipt points, with throughput and processing capacity of approximately 115 MMcf per day (DCP Midstream, 2008);

- the Ada processing plant and gathering system, which includes a 45 MMcf per day refrigeration natural gas processing plant supplied by approximately 130 miles of natural gas gathering pipelines, connected to approximately 210 receipt points, with throughput capacity of approximately 80 MMcf per day (DCP Midstream, 2008); and

- the Pelico Pipeline, LLC system, or Pelico system, an approximately 600-mile intrastate natural gas gathering and transportation pipeline with throughput capacity of approximately 250 MMcf per day and connections to the Minden and Ada processing plants and approximately 450 other receipt points (DCP Midstream, 2008). The Pelico system delivers natural gas to multiple interstate and intrastate pipelines, as well as directly to industrial and utility end-use markets (DCP Midstream, 2008).

Targa Resources is a provider of midstream natural gas and NGL services throughout several producing basins in the U.S. Its gathering and processing assets are located in the Permian Basin in west Texas and southeast New Mexico, the Louisiana Gulf Coast primarily accessing the offshore region of Louisiana, and, through the Partnership, the Fort Worth Basin in north Texas, the Permian Basin in west Texas and the onshore region of the Louisiana Gulf Coast.[28] Targa's NGL logistics and marketing assets are located primarily at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana, with terminals and transportation assets across the United States. Most of the NGLs processed by Targa are supplied through their gathering systems, which in aggregate consist of approximately 11,000 miles of natural gas pipelines. The remainder is supplied through third party owned pipelines. Targa's processing plants include 16 facilities that it owns (either wholly or jointly) and operates, as well as 6 facilities in which it has an ownership interest but are operated by others. In 2007, they processed an average of approximately 2.0 Bcf per day of natural gas and produced an average of approximately 107 million barrels per day of NGLs (SEC, 2007d).

DCP Midstream's equity interests also consist of a 40 percent interest in Discovery Producer Services LLC, or Discovery, which operates a 600 MMcf per day cryogenic natural gas processing plant, a natural gas liquids fractionator plant, an approximately 280-mile natural gas pipeline with approximate throughput capacity of 600 MMcf per day that transports gas from the Gulf of Mexico to its processing plant, and several onshore laterals expanding its presence in the Gulf. It also has 25 percent interest in DCP East Texas Holdings, LLC, or East Texas, which operates a 780 MMcf per day natural gas processing complex, a natural gas liquids fractionator and an 845-mile gathering system with approximate throughput capacity of 780 MMcf per day, as well as third party gathering systems, and delivers residue gas to interstate and intrastate pipelines (SEC, 2007g).

10.2.4. Regulation

Natural gas producers and marketers are not directly regulated from an economic perspective. This is not to say that there are no rules governing their conduct, but there is no government agency charged with the direct oversight of their day-to-day business. Production and marketing companies must still operate within the confines of the law; for instance, producers are required to obtain the proper authorization and permitting before beginning to drill, particularly on federally-owned land. However, the prices they charge are a function of competitive markets, and are no longer regulated by the government.

Natural gas processors are subject to the federal Clean Air Act and any comparable state laws or regulations (SEC, 2008). Air pollutants from processing facilities are regulated and monitored. Emissions laws may also require companies to obtain pre-approval for any construction or modification to facilities that will increase air emissions. Similarly, natural gas processors are subject to environmental laws related to the management and release of hazardous substances or solid wastes (SEC, 2008). For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, imposes liability on any current or prior owners or operators of a property that contributed to the release of a hazardous substance into the

[28] In October 2006, Targa Resources, Inc. formed a master limited partnership, Targa Resources Partners LP.

environment. Under the Act, these owners or operators could be responsible for the cost of cleaning up the hazardous substances that have been released. The parties may also be held responsible for the cost of damages to any natural resources and for the cost of health studies (SEC, 2008).

10.3. Industry Trends and Outlook

10.3.1. Trends

According to *Oil and Gas Journal*, there are 100 gas processing plants with approximately 100 Bcf per day of capacity in the Gulf Economic Impact Area.

As seen in Figure 88, the total number of gas processing plants operating in the U.S. has been declining over the past several years as companies merge, exchange assets, and close older, less efficient plants. The decade between 1995 and 2004 saw the number of gas processing plants decreased from 727 to 530 (USDOE, EIA, 2006b). However, average daily processing capacity has increased by 49 percent. In Texas, the number of plants and overall processing capacity has decreased, but the average capacity per plant has increased from 66 MMcf per day to 95 MMcf per day as newer plants were added and old, less efficient plants were shut down. The average plant capacity increased significantly in Alabama, Mississippi, and the eastern portion of South Louisiana as new larger plants and plant expansions were built to serve offshore production (USDOE, EIA, 2006b). Thus, there has been a clear movement to efficiency and economies of scale in the gas processing industry over the past several years.

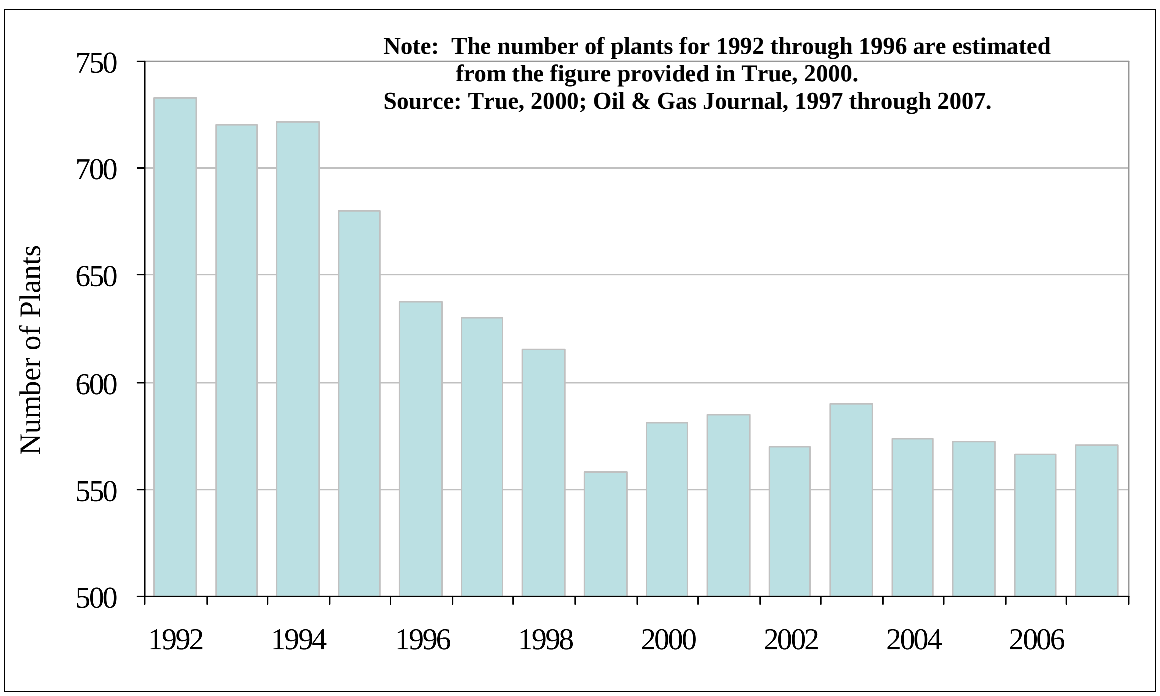


Figure 88. U.S. natural gas processing plants.

Recent GOM processing trends have followed decreases in offshore rig counts which have been dropping over the past few years. In 2001, the Texas and Louisiana Gulf Coasts accounted for 26 percent of all NGLs extracted, while in 2007 that market share dropped to 20 percent (Graham, 2007). Gas Processors Report estimates that the Louisiana Gulf Coast Region NGL extraction has been decreasing at a year-over-year rate of 7.5 percent. Similarly, the Texas Gulf Coast Region shows a 5.1 percent yearly decrease rate (Graham, 2007).

The decrease in extraction volumes may be halted temporarily, as BP and BHP recently announced the commissioning of their GOM Atlantis project. The Atlantis project is estimated to produce 200 million barrels per day of crude and 180 million cubic feet per day of natural gas (Graham, 2007).

One major development, possibly setting a new trend in processing, is the installation and operation of the Independence Hub. The semisubmersible production facility, anchored in 8,000 feet of water in the Mississippi Canyon block, processes production from 10 fields. All of these fields are developed with subsea infrastructure and connected to the Hub through 1,100 miles of umbilical and 210 miles of flow lines (Paganie, 2007a). Independence Hub has the capacity to process 1 Bcf per day of gas, 5,000 barrels per day of condensate, and 3,000 barrels per day of water (Paganie, 2007a). The product then moves to West Delta Block 68 through 134 miles of 24-inch pipe called Independence Trail. From West Delta Block 68 the gas flows to shore (Paganie, 2007a). It has been reported that "once the project reaches full processing capacity, it will represent 10 percent of all natural gas production in the Gulf of Mexico and comprise 1.5 percent of overall U.S. gas supply (Paganie, 2007a)."

10.3.2. Hurricane Impacts

Although the processing/treatment segment of the natural gas industry generally receives little public attention, its overall importance to the natural gas industry became readily apparent in the aftermath of hurricanes Katrina and Rita in August and September 2005 (USDOE, OFE, 2006). Damage caused by the hurricanes resulted in a number of shut-in gas processing plants.

Causes of the shut-ins varied based on either internal or external conditions. Internal conditions refer to damage directly affecting the gas processing plants, including flooding, debris, and destruction of equipment (Figure 89). External conditions refer to closures caused by lack of electricity, inaccessibility of the plant site because of road damage or other problems, lack of upstream supplies to the processing plant caused by production shut-ins or pipeline problems, and downstream problems related to the disposal of natural gas liquids or Y-grade liquids (USDOE, OFE, 2006).

After Hurricane Katrina made landfall in late August, at least eight gas processing plants were known to have been inoperable. These eight plants represented 6,615 MMcf per day of capacity that had a pre-hurricane flow of 4,158 MMcf per day. When Hurricane Rita struck less than a month later, the cumulative damage from both storms was much greater (USDOE, OFE, 2006).

By the end of September 2005, 27 gas processing plants or 16,796 MMcf per day of capacity were shut-in. This represented almost 75 percent of total capacity for major plants in the region. The shut-in plants included most of the large plants in the area from Galveston Bay, Texas, through Mississippi. Only 20 of the major plants, with a capacity of 6,045 MMcf per day, were active by the end of September (USDOE, OFE, 2006).

Source: OMB, 2007.

Figure 89. Natural gas processing plant flooded by Hurricane Katrina.

Internal problems shut-in 11 of the 27 plants, or 7,665 Bcf per day of capacity. These internal problems were mostly due to flooding from either storm surge or rain penetration. The flooding at some facilities, and the roads and areas leading into these facilities, was so bad that inspections were not conducted or completed for weeks. The major restoration challenges were associated with debris removal and repair to damaged equipment, especially controls and electrical equipment. In addition to damage-created shut-ins, an even larger amount of processing capacity was off-line due to other factors that, if corrected, would have made the plants operational. DOE reported that at the end of September 2005, there were 16 gas processing plants that were reported as operational but not active because of problems outside the plant that included: lack of power (6 plants); upstream supplies being unavailable (10 plants); problems with disposal of co-products downstream (6 plants); and one case of bypass because of market conditions (USDOE, OFE, 2006).

One of the single most important and unique aspects of Katrina was the damage she imposed on several large and important natural gas processing stations located in the GOM region, particularly those serving natural gas production in the New Orleans District of the OCS. Table 27 lists the immediate damage inflicted on several large and important facilities along the coast. Of particular importance are the large facilities taken off-line that have gas processing capacities in excess of 1.0 Bcf per day. These include two facilities which, at the time, were owned by Dynegy (Yscloskey, Venice), one Enterprise facility (Toca), and one relatively new BP facility in Pascagoula.

Table 27

Natural Gas Processing Facilities

Plant	Location	Capacity as of Jan 1, 2005	2004 Average Throughput	Status (as of September 10)
		--------- (MMcf/d) ---------		
Duke Energy	Bay, AL	600	172	available for service, waiting on pipeline outlet for liquids
BP	Pascagoula, MS	1,000	768	power restored. waiting for pipelines to deliver gas
Dynegy	Venice, LA	1,300	997	seawater damage. Could take 3-6 months to repair
Dynegy	Yscloskey, LA	1,850	1,343	seawater damage. Could take 3-6 months to repair
Enterprise Prod.	Toca, LA	1,100	468	assessment ongoing
ExxonMobil	Garden City, LA	630	n.a.	waiting on power
ExxonMobil	Grand Isle, LA	115	72	waiting on power
Marathon	Burns Point, LA	200	60	waiting on power

Source: USDOE, OE, 2005a through 2005f and 2006a.

The plants affected by external problems were reactivated quickly – about two-thirds of them were back online by the end of October 2005. It was the plants with internal problems that required the longest recovery periods. By as late as December of 2005, 7 of the 11 originally-damaged facilities remained inactive (USDOE, OFE, 2006).

October 2005 was the most active month for facility restoration during the post-Katrina/Rita restoration and recovery period. The number of inactive plants declined from 27 at the end of September to 15 by the end of October. At the end of October, 8,335 MMcf per day of capacity was inactive, with 14,506 MMcf per day active (USDOE, OFE, 2006).

By the end of November, the number of inactive gas processing plants fell from 15 to 8. Seven of these gas processing plants were inactive because of internal problems. By the end of November, 39 active plants with capacity of 17,366 MMcf per day were active compared to the inactive capacity of 5,475 MMcf per day. Although no additional plants were activated during December, flows through the active plants, which were operational at reduced levels, did increase. In January, four more plants with a capacity of 2,425 MMcf per day were restored back to active status. The four gas processing plants that were still inactive by the end of January included BP's Grand Chenier plant with capacity of 950 MMcf per day, which was being decommissioned. As of March 8, 2006, 45 of the 47 plants were restored to active status. The final reactivation of a major processing plant occurred on April 2, 2006, when the Stingray plant resumed processing, bringing capacity of all major active plants to 21,891 MMcf per day (USDOE, EIA, 2007i; USDOE, OFE, 2006).

EPP reported that "[i]n general, the disruptions in natural gas, NGL, and crude oil production along the U.S. Gulf Coast resulted in decreased volumes for some of [its] pipeline systems, natural gas processing plants and NGL fractionators, which in turn caused a decrease in [its] gross operating margin from certain operations (SEC, 2006q)." Although DCP did not suffer any significant damage to its properties, it did experience operational disruptions for several days as a result of the impact of Hurricane Rita on the energy industry in its areas of operations. These disruptions reduced DCP's total operating revenues by approximately $10.1 million, purchases by approximately $9.5 million, and its gross margin by approximately $0.6 million in September 2005 (SEC, 2006s).

10.3.3. Outlook

Gas processors' profits are dependent on both the price and supply of natural gas. As production in the GOM declines, competition between gas processors increases, as does the struggle for new sources of supply. This leaves some midstream companies looking to other regions of the country for growth and new investment opportunities. At an analyst meeting in spring 2007, EPP President Bob Phillips stated that unconventional gas plays represent the biggest sources of supply for both natural gas and NGLs and noted that:

> we're seeing a shift in NGL production from the East offshore Louisiana where it is declining slightly to the Rockies. We're investing heavily to be there in the next decade, to bring the increased NGLs out of the Rockies into the market.

"For the next couple of years, EPP does not anticipate any significant new strategic opportunities in the Gulf and anticipates focusing its development strategy more on the Rockies," Phillips said. The company has $1.9 billion in new projects for the Rockies. In essence, the Independence Hub represents the culmination for Enterprise's investment in the deepwater Gulf and a good stopping point for the company's multiyear strategy there. "The Rocky Mountain Region has become Enterprise's next big regional growth strategy," Phillips said (Gas Processors Report, 2007a and b).

While Crosstex officials are hoping that new technologies will yield more gas from deeper underground formations in the shallow waters of the Gulf, it too is investing in other parts of the country. In particular, Crosstex is investing in assets near the Barnett Shale in North Texas, one of the largest U.S. onshore natural gas fields (Prezioso, 2007).

DCP Midstream Partners notes in its annual report that a number of factors have had a moderating effect on the levels of drilling activity. These factors include: the softening of natural gas prices; reduced demand for natural gas and natural gas liquids; potential reduction in available capital; and the recent downturn in the economy (SEC, 2008). In general, the company saw a decrease in drilling levels in the first three quarters of 2009 compared to the same period in 2008 (SEC, 2009). DCP Midstream has also experienced lower gas throughput volumes and notes that these volumes could continue to fall if natural gas prices and reduced drilling levels stay at current levels (SEC, 2009). Over the long-term however, DCP Midstream Partners expects natural gas prices to return to a level that will support higher levels of drilling and thus higher levels of processing (SEC, 2008).

10.4. Chapter Resources

Department of Energy, Energy Information Administration
The EIA's Natural Gas Navigator, includes U.S. and State level statistics for natural gas processed, total liquids extracted, extraction loss, and heat content of extraction loss.
http://tonto.eia.doe.gov/dnav/ng/ng_prod_top.asp

In addition, in 2006, the EIA published a report, "Natural Gas Processing: The Crucial Link between Natural Gas Production and its Transportation to Market." The report examines the processing/treatment segment of the natural gas industry. It provides a discussion and an

analysis of how the gas processing segment has changed following the restructuring of the natural gas industry in the 1990s and some of the trends that have developed during that time.
http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngprocess/ngprocess.pdf

Gas Processors Association
GPA is an incorporated nonprofit trade association. Its corporate members are engaged in the processing of natural gas into merchantable pipeline gas, volume movement, or further processing of liquid products from natural gas. Member companies represent approximately 92 percent of all natural gas liquids produced in the U.S. and operate approximately 190,000 miles of domestic gas gathering lines.
http://www.gasprocessors.com/

Gas Processors Report
GPR is a subscription-based weekly publication that analyzes market trends, based on inside information from the operators, key consultants and financial players.

Oil and Gas Journal
This is a subscription-based publication. It publishes an annual survey that shows plant-by-plant details combined with an analysis of global gas processing trends. Capacity, throughput, and production details for more than 1,500 individual plants around the world are included.
http://www.ogj.com/index.cfm

U.S. Securities and Exchange Commission
Quarterly and annual reports of operations for publicly traded companies are filed with the Securities and Exchange Commission.
http://www.sec.gov/edgar/searchedgar/companysearch.html

11. NATURAL GAS STORAGE

11.1. Description of Industry and Services Provided

Natural gas storage serves two primary functions: to meet seasonal demands for gas (base-load storage), and to meet short-term peaks in demand (peaking storage). Peaks in natural gas demand can range from a few hours to a few days. To ensure that adequate natural gas supplies are available to meet seasonal base-load customer requirements, underground natural gas storage facilities are filled during low utilization periods in what is commonly called the "injection season," typically between April through October of any given year. Natural gas that is placed into storage is ultimately moved to markets to supplement domestic production and imports during what is referred to as the "withdrawal season" between the fall/winter peak usage months of November to March.

Underground storage is a capacity investment that facilitates market efficiency and reduces need for larger capacity investments in pipeline systems. If not for storage, pipeline operators would need to construct additional pipelines, and/or larger pipelines, to meet peak localized demands during winter months. Shippers and other market participants would have to pay capacity fees to utilize these assets that would more than likely sit idle for large periods of the year. The benefit of using storage instead of expensive pipeline capacity is passed along to customers through lower rates and more reliable service.

Underground storage is also quickly becoming an important asset in meeting new regulatory and market requirements in competitive natural gas markets. Storage facilities have quickly become varied and complex value-added services that create opportunities for competitive sales revenues that differ considerably from its old regulatory functions of offering relatively simple back-up and balancing service priced on a cost-of-service basis. Today, underground storage services facilitate (FERC, 2004):

- The avoidance of imbalance penalties and facilitate daily nomination changes, parking and lending (PAL) services, and simultaneous injections and withdrawals.
- Ensure liquidity at market centers to contain price volatility.
- Offset the reduction in traditional supplies that were relied upon to meet winter demand.
- Create trading opportunities by facilitating arbitrage gains from seasonal and regional differences in gas prices.
- Managing price risk for regulated natural gas and electric utilities, as well as large industrial customers that can contract directly with storage operators or indirectly through marketers.
- Facilitate competitive electric generation markets by providing quick service to natural gas-fired generation facilities that provide power during load fluctuations in any given day, hour, or season.

11.2. Industry Characteristics

11.2.1. Typical Facilities

There are three main types of underground natural gas storage facilities (Figure 90):

1. Depleted reservoirs in oil and/or gas fields;
2. Aquifers; and
3. Salt cavern formations.

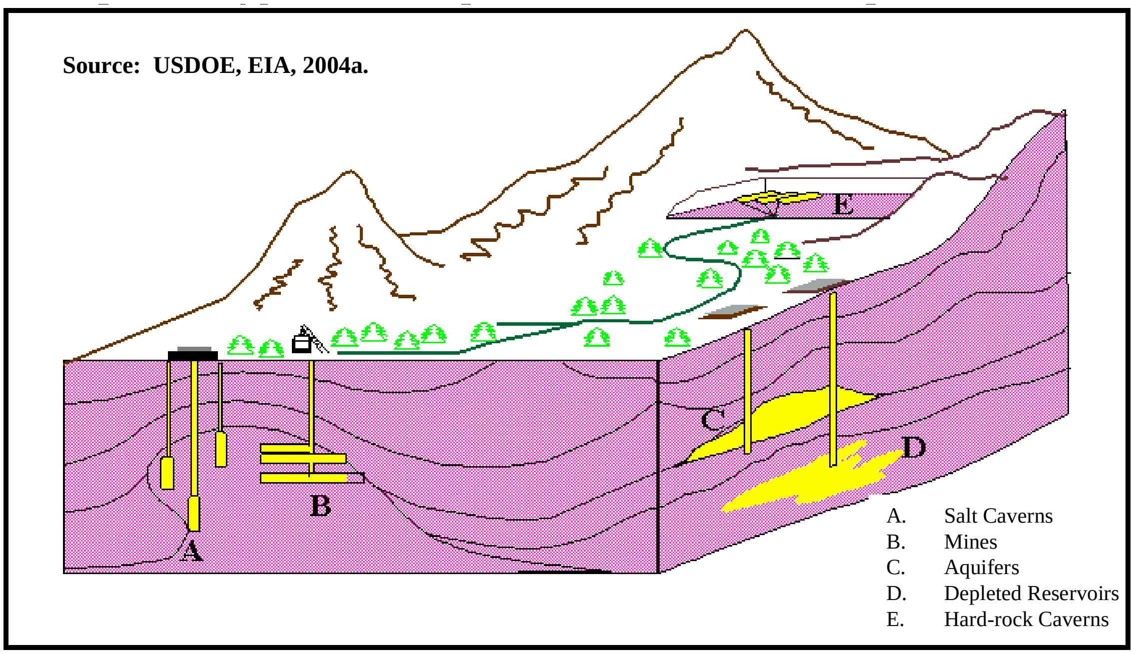


Figure 90. Types of underground natural gas storage facilities.

Each type of storage facility has its own physical characteristics that include porosity, permeability and retention capability. Each type of storage facility also has its own economic characteristics that include capacity development costs, location, deliverability rates, and cycling capability. As shown in Table 28, salt caverns have certain cost benefits since they have lower base or "cushion gas" requirements than reservoirs and aquifers. Cushion gas is the term used to describe the minimum amount of gas that is needed in an underground storage facility to maintain operating pressures and in the case of salt, maintain cavern integrity. In today's markets, facilities that have large cushion gas requirements can be more expensive since they tie up large amounts of highly valued gas in limited revenue generating activities. Thus, salt has an advantage relative to other types of underground storage since it typically requires considerably less cushion gas. However, salt's advantage over reservoir storage has to be balanced against its increased initial capital development cost. Reservoir storage is much cheaper on a capacity-developed basis.

Injection flexibility is becoming an increasingly important characteristic for underground storage facilities. Quick delivery times are much more important in today's competitive markets than they were in past decades where storage service deliverability was limited to steady seasonal requirements. Today, storage services are needed in an instant to meet the unanticipated demand for a power generation facility that is being dispatched to meet a surge in load, or provide injection service to a large LNG tanker arriving to offload supplies.

Table 28

Characteristics of Natural Gas Storage Facilities

Type of Storage Facility	Number of Active Fields	Cushion to Working Gas Ratio	Injection Period (Days)	Withdrawal Period (Days)	Injection/ Withdrawal Flexibility
Depleted Reservoir	322	Cushion: 50-80%	200-250	100-150	Low
Aquifer	44	Cushion: 50%	200-250	100-150	Low
Salt Cavern	31	Cushion: 20-30%	20-40	10-20s	High

Source: USDOE, EIA, 2008d; FERC, 2004.

While salt cavern storage provides considerable advantages in today's market, it still represents, at least in number, the smallest share of underground storage types in the U. S. Even today, most gas is stored in depleted oil and gas reservoirs. More detailed information about each type of facility is provided below.

Depleted Reservoir

Depleted reservoirs represent the most common form of underground natural gas storage type (USDOE, EIA, 2004a). Depleted reservoirs are simply geological formations that have stopped economic production of natural gas. These formations make excellent storage facilities since they are typically developed from known formations with a natural gas production history. In addition, quite often, these formations will have surface facilities on site that can be used or converted to gas storage service. According to industry reports, depleted reservoirs tend to be the most economic of the three main storage types both in development and operation (NaturalGas.org, 2007b).

Two of the primary factors determining reservoir suitability for storage purposes are their geographical and geological characteristics. Reservoirs must be in relatively close proximity to natural gas consuming regions and transportation infrastructure, especially trunk pipelines or large diameter lines for natural gas local distribution companies if service is being developed to serve local needs. Depleted reservoirs are more commonly located in producing regions in the U.S. In areas that lack depleted reservoirs, such as New England or certain areas in the Midwest, other storage options must be used including the use of facilities in other regions (NaturalGas.org, 2007b).

In geological terms, high permeability and porosity are required for depleted reservoir formations to be used for storage. A highly porous formation can hold more natural gas. High permeability allows for a higher rate of flow of gas through the formation, which helps determine the rate of injection and withdrawal of working gas (NaturalGas.org, 2007b).

Aquifer Storage

Aquifers are natural water reservoirs that can also be used for natural gas storage. They are porous, permeable rock formations found below the ground. An aquifer can be suitable for gas storage if the formation is overlaid with an impermeable cap rock (USDOE, EIA, 2004a). The geology of aquifers may be similar to depleted reservoirs; however, their use in gas storage may require more base gas and greater monitoring of injection and withdrawals (USDOE, EIA, 2004a). For the most part, aquifers tend to be used mostly in the Midwest and areas where there are no depleted reservoirs.

Aquifer storage can require additional infrastructure that is not commonly used in other types of underground storage facilities. Like other types of storage facilities, wells must be drilled along with inter-facility pipelines, dehydration facilities, and usually some compression to move the gas from the facility into the long-line pipeline system. Aquifers can also require unique dehydration equipment. In addition, “collector” wells are often employed to capture natural gas that escapes from the aquifer (NaturalGas.org, 2007b).

Salt Cavern Storage

The internal integrity and strength of salt formations make formed caverns an ideal type of natural gas storage (Figure 91) (NaturalGas.org, 2007b). Salt caverns have very high withdrawal and injection rates and require lower levels of base gas (in comparison to reservoirs and aquifers). Most salt cavern storage facilities have been developed in salt dome formations in the GOM region (USDOE, EIA, 2004a).

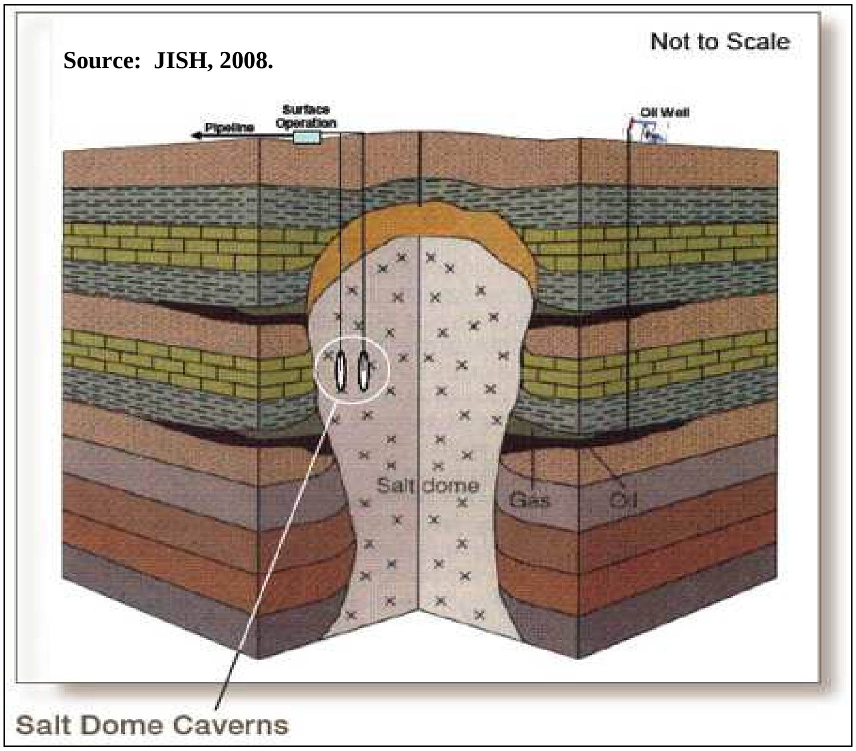


Figure 91. Salt cavern storage.

Developing a salt cavern formation within a salt dome or salt bed involves dissolving and extracting salt from the deposit by pumping water into the formation (Figure 92). The process used for creating salt storage caverns is commonly known as "salt cavern leaching" or "solution mining." Under this type of process, salt is dissolved creating a concentrated brine solution, which in turn, is pumped out through an injection well that is developed in many ways like a typical oil and gas well.

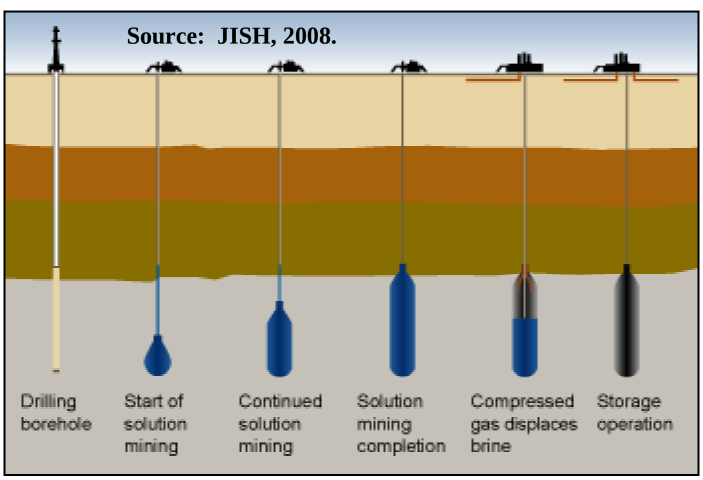


Figure 92. Solution mining process.

While salt cavern leaching can be expensive, it creates a highly valuable underground storage facility that has very high deliverability. An additional advantage is that salt caverns typically require a much lower level of base (or cushion) gas than reservoir or aquifer-based storage.

Salt caverns tend to be smaller than depleted gas reservoirs and aquifers resulting in smaller levels of overall storage capacity. For this reason, salt caverns are commonly not used for baseload storage requirements. Salt caverns do, however, have higher deliverability rates making them very attractive for cycling and/or peaking purposes, particularly during emergency periods or periods of unexpectedly high demand.

The primary disadvantage of the salt cavern is the high capital cost of development. The leaching or mining process involves additional capital investments that include the development of a brine handling system (pipes, pumps, electrical), an injection well that is first fitted out for brine handling (mining) operations, and then converted to facilitate storage service. A number of tests must also be conducted in order to ensure the integrity of both the cavern and the well. Salt cavern construction is more expensive than depleted field conversions when measured on an investment dollars per working gas storage basis. Salt cavern storage can be measured on the basis of dollars per thousand cubic feet of working gas capacity. The ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of each thousand cubic feet of gas injected and withdrawn (USDOE, EIA, 2004a).

11.2.2. Geographic Distribution

As shown in Table 29 and Figure 93, many depleted reservoirs are located near major Northeast and Midwest natural gas consuming regions in order to serve peak winter heating demand. Depleted reservoirs account for approximately 86 percent of working gas capacity in the U.S. Twenty-two percent of the depleted reservoir capacity is found in the Northeast and 27 percent in the Midwest. These regions also account for 23 percent and 33 percent of daily withdrawal capacity, respectively. In the Midwest, depleted reservoirs are supplemented by storage in groundwater aquifers. The Midwest accounts for 70 percent of aquifer storage capacity (USDOE, EIA, 2006c).

The Gulf Coast has a mix of depleted reservoir and salt cavern storage. In fact, the overwhelming majority of all salt cavern storage facilities operating in the U.S. are located along the GOM. Gulf Coast salt caverns account for only 3.5 percent of total U.S. working gas capacity and 16 percent of total U.S. deliverability. Along the GOM, Texas has 14 salt cavern sites with 85 Bcf of working gas capacity. Louisiana has six sites with 42 Bcf of working gas capacity; Mississippi has three sites with 31 Bcf of working gas capacity; and Alabama has one site with 7 Bcf of working gas capacity (USDOE, EIA, 2006c).

Table 29

Underground Natural Gas Storage by Region, 2005

	Depleted-Reservoir Storage			Aquifer Storage			Salt-Cavern Storage			Total		
	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capacity (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capacity (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capacity (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capacity (MMcf)
Central	40	464	4,559	8	91	1,550	1	1	—	49	556	6,109
Midwest	88	916	20,424	31	278	5,855	2	2	85	121	1,196	26,364
Northeast	104	761	14,281	—	—	—	3	6	470	107	767	14,751
Southeast	26	121	2,857	3	7	68	4	38	3,622	33	166	6,547
Southwest	45	895	13,006	1	2	3	20	127	9,199	66	1,024	22,208
Western	17	280	6,823	1	21	850	—	—	—	18	301	7,673
Total	**320**	**3,437**	**61,950**	**44**	**399**	**8,326**	**30**	**174**	**13,376**	**394**	**4,010**	**83,652**

Source: USDOE, EIA, 2006c.

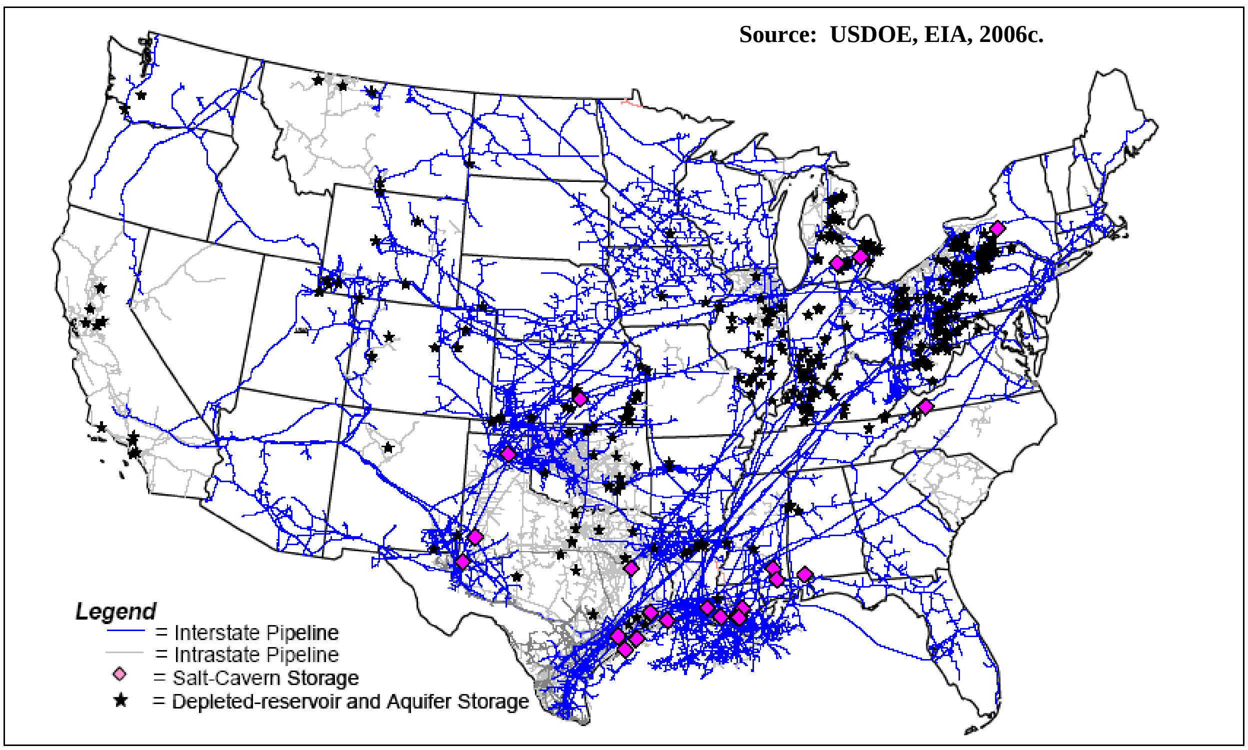


Figure 93. U.S. underground natural gas storage facilities in relation to the national natural gas transportation grid, 2005.

11.2.3. Typical Firms

Natural gas transmission and storage businesses compete with similar facilities that serve the same supply and market areas. The principal elements of competition between these various companies include rates, terms of service, location, and flexibility and reliability of service (SEC, 2007f).

Natural gas that is transported and stored by these natural gas storage companies also competes with other forms of energy available to customers and end-users, including electricity, coal, propane, and fuel oils. Factors that influence natural gas demand include price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather, and other factors.

In general, transportation and storage companies provide services to local distribution companies, electric power generators, natural gas producers, industrial customers, and energy marketers. Many of these typical users can also develop storage as well. For instance, it is not uncommon for an electric or natural gas utility to develop and own storage assets for meeting their regulated service needs. A large amount of traditional natural gas storage service is provided under what is referred to as a firm service agreement where customers reserve capacity and pay smaller incremental fees to move gas in and out of the storage facility. Firm agreements typically require fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipelines or injected or withdrawn from the storage facility (SEC, 2007f).

Most storage companies also provide interruptible services that customers can use if on very short notice, provided the capacity is available and not committed. Payments for these interruptible services are typically volumetric. Interruptible services are typically thought of as value-added services and can include parking and loan (PAL) hub services, and balancing, to name a few (SEC, 2007f).

As shown in Table 30, a significant number of underground natural gas storage sites are operated by independent storage operators. This is a relatively new characteristic of the storage business. Independent storage developers and operators are typically small firms that are able to secure institutional or private financing and are usually not directly associated with LDCs, pipeline companies, or oil and gas firms, hence the name “independent.” Independents account for 74 sites with 521 Bcf of working gas capacity and 14,681 MMcf per day of deliverability. These sites account for 13 percent of working gas capacity and 18 percent of deliverability. One-half of the salt formation sites are operated by independents accounting for 55 percent of working gas capacity and 55 percent of deliverability (USDOE, EIA, 2006c).

Table 30

Underground Natural Gas Storage by Type of Owner, 2005

	Depleted-Reservoir Storage			Aquifer Storage			Salt-Cavern Storage			Total		
	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capacity (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capacity (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capacity (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capacity (MMcf)
Interstate Pipeline												
FERC Jurisdictional	157	2,055	31,821	12	121	2,509	3	21	1,500	172	2,197	35,830
Non-Jurisdictional	—	—	—	—	—	—	—	—	—	—	—	—
Independent												
FERC Jurisdictional	25	270	4,178	—	—	—	9	74	5,957	34	344	10,135
Non-Jurisdictional	33	155	3,183	1	1	3	6	21	1,360	40	177	4,546
LDCs & Intrastates												
FERC Jurisdictional	30	421	8,532	5	72	1,765	4	23	1,315	39	516	11,612
Non-Jurisdictional	75	536	14,216	26	205	4,049	8	35	3,244	109	776	21,509
All Types												
FERC Jurisdictional	212	2,746	44,531	17	193	4,274	16	118	8,772	245	3,057	57,577
Non-Jurisdictional	108	691	17,399	27	206	4,052	14	56	4,604	149	953	26,055
Total	**320**	**3,437**	**61,930**	**44**	**399**	**8,326**	**30**	**174**	**13,376**	**394**	**4,010**	**83,632**

Source: USDOE, EIA, 2006c.

11.2.4. Regulation

Almost all natural gas storage facilities are subject to either state and/or federal regulation (Figures 94 and 95). FERC has jurisdiction over any underground storage project that is owned by an interstate pipeline or integrated into the interstate pipeline network. Independently operated storage projects that offer storage services in interstate commerce are under FERC's jurisdiction (FERC, 2004).

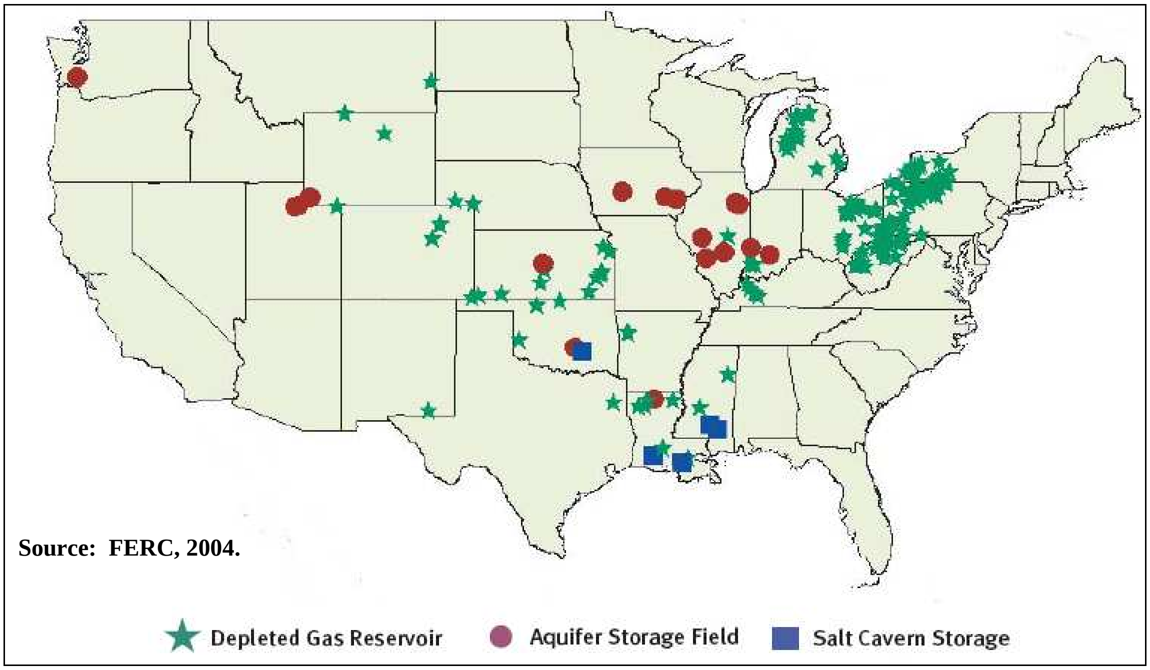


Figure 94. FERC jurisdictional U.S. storage by type and location.

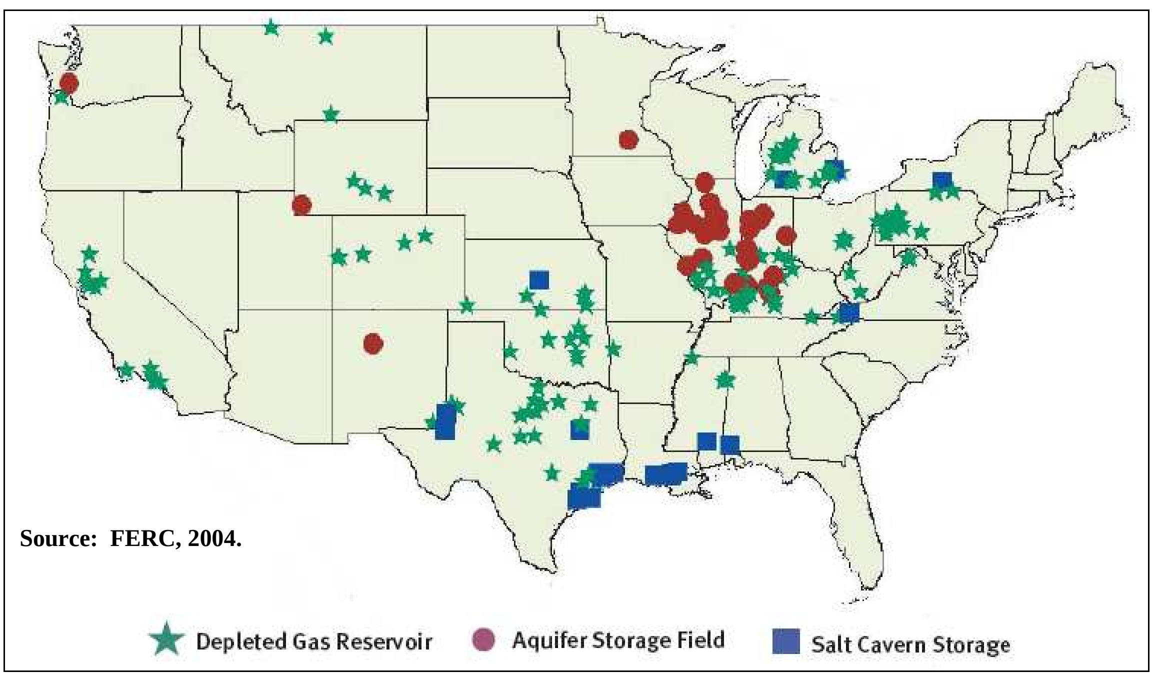


Figure 95. Non-jurisdictional U.S. storage by type and location.

Most underground natural gas storage facilities that are subject to FERC jurisdiction operate on an open-access basis which requires operators to provide available storage capacity to third-parties on a nondiscriminatory basis. Before Order 636, capacity allocation decisions were completely within the purview of the storage owner, which was usually an interstate pipeline company.

As noted in an earlier section of this fact book, FERC issued Order 636 in 1992, completing the transition to a deregulated natural gas commodity market and marking the end of most of the traditional pipeline merchant services. Pipelines' access to storage was one aspect that garners particular attention of the FERC since it believed pipeline ownership of natural gas storage created an unfair competitive advantage by making the transportation component of firm pipeline sales service far superior to the service offered to unaffiliated shippers that may not have access to similar storage resources (Cates, 2001).

Another trend further influencing storage services in the aftermath of Order 636 has been the introduction of competitive storage service pricing at what is referred to as "market-based rates." Under market-based rates, a storage developer can craft rates and terms of service specifically tailored to customer needs.

In June 2006, FERC issued Order 678 modifying prior regulations related to market-based natural gas storage rates. The new regulations are intended to encourage the development of new storage facilities by easing the burden for storage providers to obtain market-based rate treatment (Culotta and Goddard, 2006). FERC Chairman Joseph T. Kelliher observed,

> Since 1988, natural gas demand in the United States has risen 24 percent. Over the same period, gas storage capacity has increased only 1.4 percent. While construction of storage capacity has lagged behind the demand for natural gas we have seen record levels of price volatility. This suggests that current storage capacity is inadequate. Further, this year, what storage capacity exists may be full far earlier than in any previous year. According to some analysts, that raises the prospect that some domestic gas production may be shut-in.... My hope is that reform of market-based pricing for gas storage and flexibility on cost based pricing will help expand gas storage capacity, which in turn will help reduce the price volatility that has characterized gas markets in recent years. There is significant potential for near term expansion of natural gas storage. I hope that potential is realized (FERC, 2006b).

FERC's market-power analysis requirements were also modified by Order 678 and allow storage providers to include non-traditional storage alternatives, such as local production, availability of LNG, and pipeline capacity as competing sources in its market-power analyses (Culotta and Goddard, 2006).

> The Commission finds it is appropriate to adopt a more expansive definition of the relevant product market for storage to explicitly include close substitutes for gas storage services, including pipeline capacity and local production/LNG supplies. As explained below, this modification to our market-power analysis better reflects the competitive alternatives to storage and is supported by changes

> in the natural gas markets that have occurred since the mid 1990s. In today's markets, these non-storage products may well serve as adequate substitutes for gas storage in appropriate circumstances (FERC, 2006c).

Order 678 also implements NGA Section 4(f), which permits FERC to allow market-based rates for new storage facilities, even if the storage provider is unable to show that it lacks market power. The new FERC rules will allow new storage facilities to charge market-based rates provided that doing so is in the public interest and necessary to encourage the construction of needed storage capacity (Culotta and Goddard, 2006). This new provision allowing market-based rates without a market power analysis applies to both greenfield storage facilities and expansions of existing facilities. "The Commission recognizes that significant and substantial enhancements to storage capacity can be achieved at existing fields and finds that it is unnecessary to exclude service from such expansions from consideration for market-based rates by narrowly interpreting the term "facility" in the context of section 4(f) (FERC, 2006c)."

11.3. Industry Trends and Outlook

11.3.1. Trends

According to industry sources, there are 22 underground natural gas storage facilities in the Gulf Economic Impact Areas. These facilities total 372 Bcf of working gas capacity (USDOE, EIA, 2008d).

Access to efficient and dependable underground natural gas storage operations is crucial in today's competitive natural gas transportation marketplace. The approximately 400 underground natural gas storage facilities located strategically throughout the U.S. are key to maintaining reliability, integrity, and capability on the nation's natural gas transmission and distribution network (USDOE, EIA, 2006c).

The ability to store natural gas is essential to the operation of the natural gas market. Storage withdrawals provide additional gas supply during seasonal and short-term gas demand spikes and help keep pipelines and distribution systems in physical balance. Storage also plays an important role in energy commodity trading and management. In general, storage is filled during low utilization periods (April-October) and withdrawn during high utilization periods (winter). This results in a cyclical up and down pattern in the gas that is in storage that corresponds to these periods. Figure 96 below shows these cycles since January 2000. Over the past few years, working gas in storage has exceeded the 5-year average, and in some cases, even the 5-year maximum.

A number of new natural gas storage facilities have been certificated by FERC over the past few years, many of which are being developed to accommodate LNG imports, particularly those along the GOM. Table 31 provides a list of those recently certificated facilities and their capacities. To date, 186 Bcf of storage capacity has been certificated, with almost 70 Bcf in the GOM region. Deliverability for these projects totals 7,440 MMcf per day (4,890 MMcf per day in the GOM region). Like the LNG facilities and their associated pipelines, natural gas storage investments represent additional dollars in local communities, and additions to supporting infrastructure.

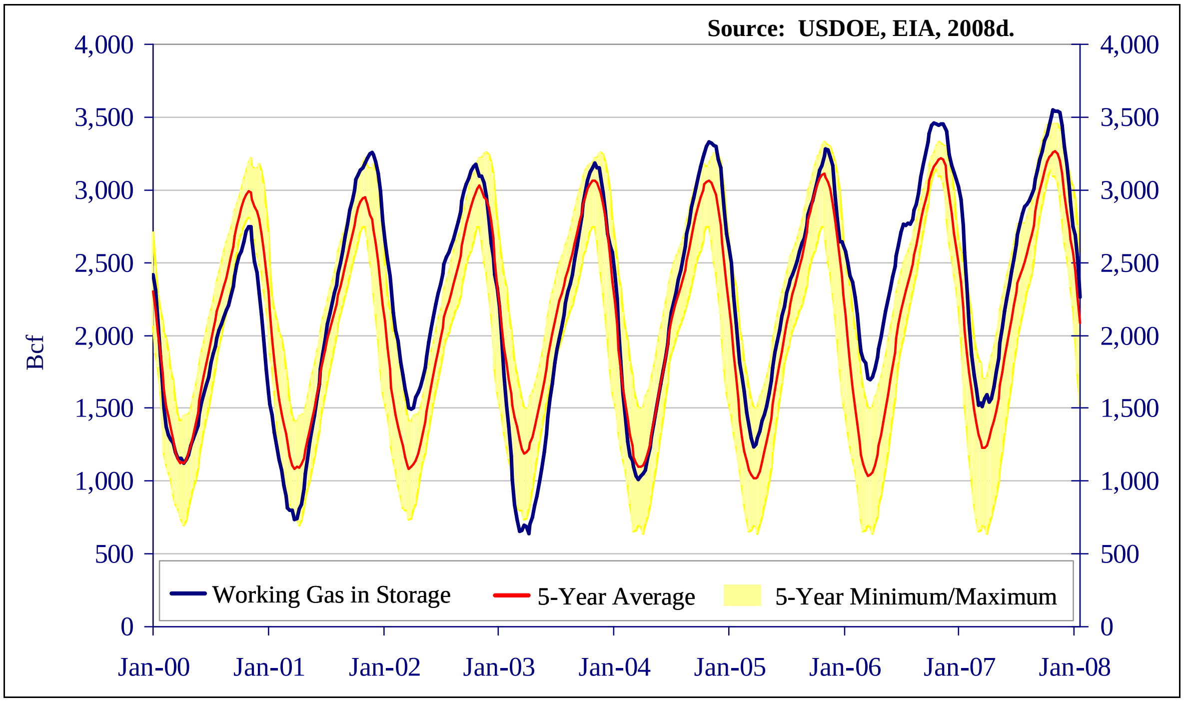


Figure 96. Working gas in underground storage.

Table 31

Recently Certificated Underground Natural Gas Storage Facilities, as of January 2008

Company / Project	State	Capacity (Bcf)	Deliverability (MMcf/d)	Year Certificated	Status
Northeast					
Dominion Transmission, Inc / Northeast Storage Project	NY, PA, WV	9.4	163	2005	In Service
Hardy Gas Storage, LLC / Hardy Storage	WV	12.4	176	2005	In Service
Central NY Oil and Gas Co., LLP / Stagecoach Phase II Expansion	NY, PA	13.0	-	2006	Under Construction
Tennessee Gas/National Fuel / Northeast ConneXion NY-NJ	PA, NJ	-	114	2006	Under Construction
Texas Eastern Transmission, LP / Accident Storage Enhancement	MD	3.0	-	2006	Under Construction
South Central					
CenterPoint Energy Gas Transmission / Chiles Dome Storage Expans	OK	15.0	309	2005	In Service
Natural Gas Pipeline Co. of America / Sayre Storage Field Expansion	OK	10.0	200	2005	Under Construction
Egan Hub Partners, LP / Cavern III	LA	8.0	-	2003	In Service
Liberty Gas Storage LLC / Liberty Gas Storage Project	LA	17.6	1,000	2005	Under Construction
Egan Hub Partners, LP	LA	-	1,000	2006	Approved
Natural Gas Pipeline Co of America / North Lansing Storage Expansion	TX	10.0	140	2006	Under Construction
Northern Natural Gas Company / Cunningham Field Project	KS	-	70	2006	Under Construction
Port Barre Investments, LLC / Bobcat Gas Storage	LA	12.0	1,200	2006	Approved
Southeast					
Caledonia Energy Partners, LLC / Caledonia Energy Complex	MS	11.7	330	2005	Under Construction
Freebird Gas Storage, LLC / Freebird Storage	AL	6.1	160	2005	Under Construction
Gulf South Pipeline Company, LP / Jackson Storage Field Project	MS	2.4	-	2005	Approved
SG Resources Mississippi, LLC / Southern Pines Energy Center	MS	12.0	1,200	2006	Limited Service
Midwest					
Texas Gas Transmission, LLC / Texas Gas Storage Expansion	KY	8.2	82	2005	In Service
Bluewater Gas Storage	MI	29.2	826	2006	Approved
Northern Natural Gas Company / Cunningham Field Project	KS	-	70	2006	Under Construction
Western					
Unocal Windy Hill Gas Storage / Windy Hill	CO	6.0	400	2006	Approved

Source: FERC, 2008a.

11.3.2. Hurricane Impacts

There were no reports of significant damage by the 2005 hurricanes to any underground storage facilities. However, natural gas storage was impacted by the shut-in production throughout the Gulf region. In the months around and following the hurricanes, there were widely reported concerns in the natural gas trade press about whether storage levels would be adequate for the 2005-2006 heating season. For instance, prior to Hurricane Rita's landfall, Petroleum Intelligence Weekly reported, "[a]ny expectations that North American natural gas storage inventories might still be adequate after the passage of Hurricane Katrina had to be demolished by the advent of the storm's even more menacing sister Rita. Timing could not have been worse, especially for the natural gas sector that will officially enter the winter heating season in little more than a month (Petroleum Intelligence Weekly, 2005)." Concerns were widespread that a substantial loss of production could push a nervous market already in record-high price territory into even higher realms (Petroleum Intelligence Weekly, 2005).

Fortunately, the 2005-2006 heating season was "extraordinarily mild weather across the country" and resulted in lower overall natural gas demand and higher-than-expected natural gas inventories (Foster Electric Report, 2006). In addition, demand destruction, from industrial cut-backs and fuel switching, resulting from the summer's high natural gas prices more than offset GOM production curtailments (Platts Oilgram News, 2005). The U.S. storage industry entered the 2005-2006 heating season with a 53 Bcf injection in the second week of November, raising U.S. working inventories to 3.282 Tcf and increasing the surplus over the five-year average to 179 Bcf (Platts Oilgram News, 2005).

By the start of the 2006 injection season, total natural gas in storage was below the previous year's levels, but was 168 Bcf above the 5-year average (Piotrowski, 2006). The record warm January, followed by an unusually warm February, limited the amount of withdrawals during the 2005-2006 heating season. The warm winter weather trend was underscored by the first ever weekly net injection recorded during a heating season, which measured 1 Bcf for the week ending December 29, 2005. Because of the limited withdrawals, storage at the end of the heating season, on March 31, 2006, was 1.7 Tcf, the highest level for this date since 1991 (USDOE, EIA, 2007g).

11.3.3. Outlook

As highlighted by Chairman Kelliher's statement in FERC's issuing of Order 678, natural gas storage development is a top priority. FERC is doing everything it can "to facilitate the development of [natural gas] storage (Magill, 2008)." The development of new LNG import capacity has had the ripple effect of encouraging the construction of nearby storage projects, particularly in the Gulf Coast region (Magill, 2008). Like production, natural gas imports will come year round, while demand is cyclical. Therefore, gas from LNG imports during the injection season when demand is low will need to be injected into storage.

In addition to those recently-certificated natural gas storage projects in Table 31, there are a number of projects that are pending and have filed applications with FERC; or have been announced and are expected to file applications (Tables 32 and 33). GOM announced projects total 112 Bcf or 61 percent of the 182.5 Bcf in pending storage projects. One of these projects includes the Enstor Houston Hub Storage Development. Once completed, the 15 Bcf facility will connect with up to four interstate and intrastate pipelines and provide firm storage services of seven annual cycles. The facility will have a maximum daily deliverability of 1 Bcf, and could also be utilized as a header system to allow customers to capture value between the various pipeline locations (Enstor, 2008).

The largest recently announced natural gas storage project is the Leaf River Energy Center in Mississippi. The Leaf River project will consist of multiple natural gas storage caverns located along a 43-mile header system. Sonat, Gulf South, Transco, Tennessee, and Destin will connect to the system, as will the Kinder Morgan Midcontinent Express pipeline, due to be in service in early 2009 (NGS Energy Fund, 2008).

Black Bayou Gas Storage is another announced project that is being developed to offer high deliverability salt dome storage in Cameron Parish, Louisiana. The initial project development will provide 15 Bcf of working gas capacity and will be directly connected to three major pipeline systems: Kinder Morgan's Louisiana Interstate Pipeline; Sempra Energy's Port Arthur Pipeline; and Transco's Southwest Lateral. In addition, Black Bayou will be located within 25 miles of the Lake Charles LNG as well as five other LNG facilities under development (Cameron LNG; Creole Trail LNG; Sabine Pass LNG; Golden Pass LNG; and Port Arthur LNG) (Black Bayou Storage, 2008).

Table 32

Major Pending Storage Projects

Project	Company	State(s)	Working Gas Capacity (Bcf)
Bobcat Gas Storage	Port Barre Investments, LLC	LA	2.1
Texas Gas Transmission, LLC		KY	8.3
Black Bayou Gas Storage		LA	15.0
Totem Gas Storage Field Project	Colorado Interstate Gas Co.	CO	7.0
Northern Natural Gas Company		IA	8.6
2009 Storage Expansion Project	Natural Gas Pipeline Co. of America	IL	10.0
Houston Hub Storage Project)	Enstor Houston Hub Storage and Trans.	TX	15.0
Junction Natural Gas Storage Project	Chestunut Ridge Storage, LLC	PA, WV	25.0
Petal Gas Expansion	Petal Gas Storage, LLC	MS	10.0
Petrologistics Natural Gas Storage, LLC		LA	6.0
Floridian Natural Gas Storage Co., LLC		FL	8.0
Steckman Ridge, LP		PA	12.0
Leaf River Energy Center, LLC		MS	32.0
Tarpon Whitetail Gas Storage, LLC		MS	8.6
Total			**167.5**

Source: FERC, 2008c and d.

Table 33

Major Storage Projects on the Horizon

Project	Company	State(s)	Working Gas Capacity (Bcf)
Arizona Natural Gas Storage Project	El Paso Natural Gas Co.	AZ	3.5
Hill-Lake Gas Storage Phase III Expansion	Falcon Gas Storage Co.	TX	3.0
Caledonia Energy Partners, LLC		MS	1.7
Dominion Hub Project	Dominion Transmission, Inc.	NY, PA, WV	18.0
Worsham-Steed Gas Storage Project	Falcon Gas Storage Co.	TX	8.0
County Line Storage Project	Duke Energy Gas Transmission	MS	6.0
SemGas LP		NY	5.5
Crawford Expansion Project	Columbia Gas Transmission Corp.	OH	15.0
Enterprise Products Partners		TX	10.0
Pine Prairie Energy Center, LLC		LA	16.0
ANR Pipeline Company		OH	70.0
Waha Storage and Hub Facility	Enstor/PPM Energy	TX	7.2
Four Mile Creek Gas Storage		MS	8.0
Mississippi Hub Gas Storage Project	Energy South Midstream	MS	12.0
Mobay Storage Hub, Inc.		AL	50.0
Bobcat Gas Storage		LA	9.4
Total			**243.3**

Source: FERC, 2008c and d.

11.4. Chapter Resources

Federal Energy Regulatory Commission – Natural Gas Industry
The FERC website provides a list of jurisdictional storage fields. This list can be downloaded by owner, by location, or in a sortable spreadsheet. The website also maintains a list of storage projects that are pending, and on the horizon. In addition, a list of certificated storage projects since 2000 can be downloaded from FERC's Gas Industry site.
http://ferc.gov/industries/gas.asp

Federal Energy Regulatory Commission – eLibrary
On the FERC's eLibrary, documents filed in a particular docket can be downloaded and viewed. This includes both documents that are filed, and issued.
http://ferc.gov/docs-filing/elibrary.asp

Federal Energy Regulatory Commission – Market Oversight
An overview of natural gas markets by region can also be found at FERC.
http://ferc.gov/market-oversight/mkt-gas/overview.asp

Department of Energy, Energy Information Administration
On the EIA's Natural Gas Navigator, storage statistics can be found, such as working gas in underground storage; number of facilities; and capacity. The Weekly Natural Gas Storage Report provides estimates of natural gas in underground storage for the U.S. and three regions of the U.S.
http://tonto.eia.doe.gov/dnav/ng/ng_stor_top.asp

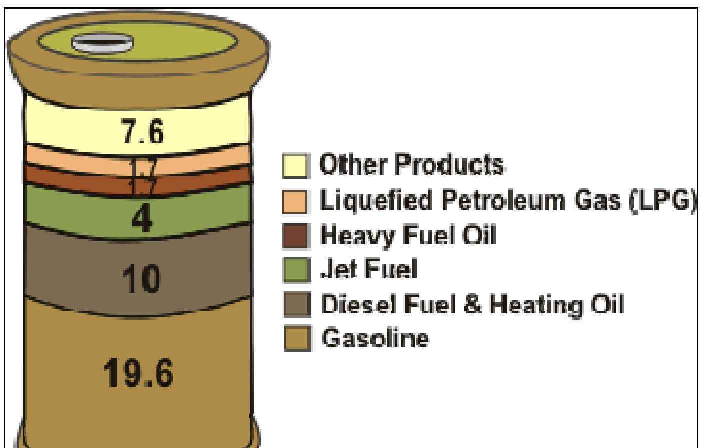
A number of analysis reports can also be found at the EIA.
http://tonto.eia.doe.gov/dnav/ng/ng_pub_analysis_stor.asp

12. REFINERIES

12.1. Description of Industry and Services Provided

Petroleum is a mixture of liquid hydrocarbons extracted from geological formations deep under the earth's surface. The exact composition of these hydrocarbons varies with some being extracted in gaseous form, while others are primarily liquid. Hydrocarbons found in the gaseous state are typically called “natural gas,” whereas that in liquid form is “petroleum.” Crude oil is a mixture of hydrocarbon compounds with other impurities that include oxygen, nitrogen, sulfur, salt, and water. Crude oil varies in color and composition, from a pale yellow, low viscosity liquid to a heavy black 'treacle' consistency. Most crude oil has to be processed in order to be utilized as an energy resource for end-use purposes.

Petroleum refineries have emerged over the past hundred years as a variety of different manufacturing units designed to produce physical and chemical changes to turn crude oil into petroleum products. In the early days of petroleum refineries, the process was quite simple and consisted of heating crude oil at various temperatures to extract what at that time was its most important refined product, kerosene. Today, the process includes various types of heating, distilling, and catalytic conversions. A modern refinery will break down crude into a large number of components. As shown in Figure 97, a 42 U.S. gallon barrel of crude oil provides slightly more than 44 gallons of petroleum products.



Source: USDOE, EIA, 2007d.

Figure 97. Products made from a barrel of crude oil (gallons).

Crude oil is refined into enumerable products and combinations of products, some of the more important being motor gasoline, diesel fuel, jet fuel, and heating fuel. Some of the refined by-products from crude oil also serve as important feedstocks for the development of synthetic fabric for cloths, detergents, dry cleaning solvents, as well as chemical bases for cosmetics and pharmaceutical products and various plastic products from toys to building materials (USDOE, EIA, 1999).

The following are just a few products that are developed from feedstocks produced at refineries:

- Ammonia
- Antiseptics
- Bubble gum
- Crayons
- Denture adhesive
- Eyeglass frames
- Fertilizer
- Floor polish
- Guitar strings
- Heart valves
- Ice chests
- Insect repellant
- Life preservers
- Liquid detergent
- Mascara
- Paint
- Ping-Pong paddles
- Plastic beverage containers
- Roller-skate wheels
- Sneakers
- Synthetic fibers
- Telephones
- Tobacco pouches
- Volleyballs

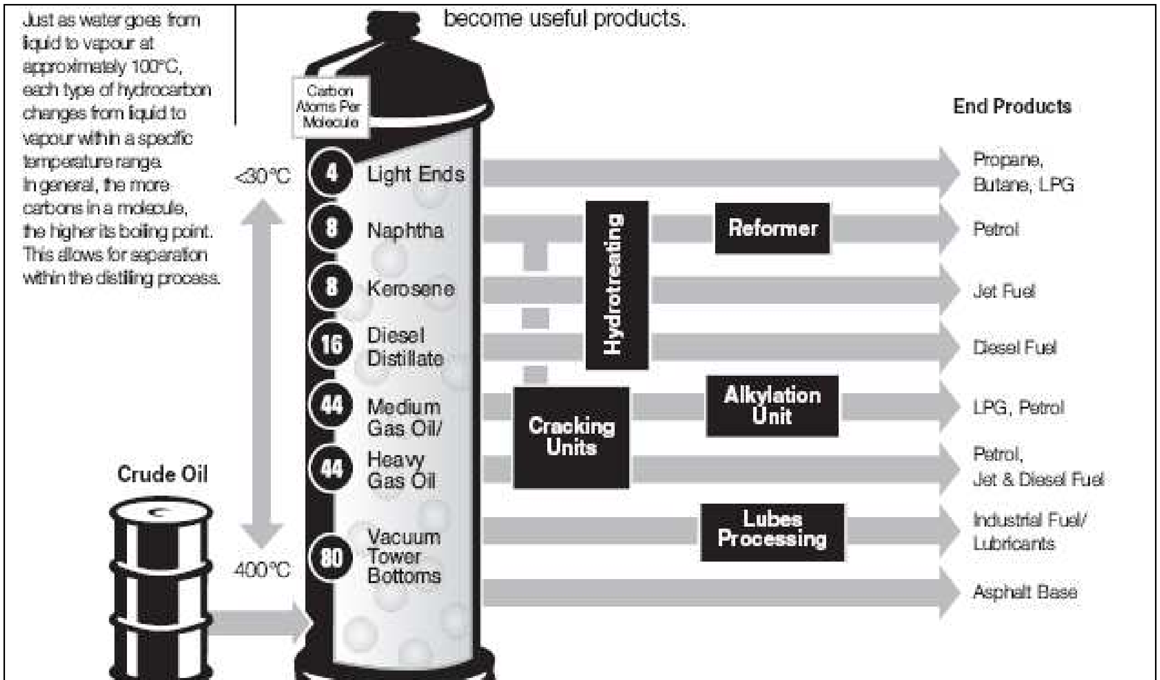
12.2. Industry Characteristics

12.2.1. Typical Facilities

Refineries vary in size, sophistication, and cost depending on their location, the types of crude they refine, and the products they manufacture. Crude oil is not a homogeneous raw material and varies in color, viscosity, sulfur content, and mineral content. These variations give rise to different refineries and different products produced at refineries located along the GOM and other places in the U.S.

The initial phase of the refining process begins with separation of crude oil using distillation towers. Furnaces heat and partially vaporize the feed stream of crude oil which is converted into a part vapor/part liquid medium that is transported into the feed section at the bottom of the distillation tower. The temperature inside these distillation towers can reach as high as 400 degrees Fahrenheit. Vapor rises through the tower, while the liquid part of the mixture remains at the bottom. As the vapor moves up through the tower and the temperature decreases, it condenses into different products (ExxonMobil, 2006a).

The relative percentage of each of the separated components, or product streams, in the distillation process is referred to as the “yield.” This number will vary depending on the makeup of the crude oil being processed. The products from the distillation tower range from gases at the top to very heavy, viscous liquids at the bottom (Figure 98). The viscous liquids at the bottom are considered “unfinished” and require further processing (ExxonMobil, 2006a).



Source: ExxonMobil, 2006a.

Figure 98. Distillation process.

The fractions are further treated to convert them into mixtures of more useful saleable products by various methods such as cracking, reforming, alkylation, polymerization, and isomerisation (ExxonMobil, 2006a). These mixtures of new compounds are then separated using methods such as fractionation and solvent extraction.

Since the quality of crude oil varies, a range of different refining unit configurations are often needed to process a slate of various products. Crude oil availability and the variation of this availability by quality or grade can significantly impact a refinery's ability to produce certain products. Crude oil gravity, for instance, defines its overall density and is an important determinant of crude oil quality. The lower the gravity of the crude, the "heavier" the crude oil is, and vice versa. Heavy oil is viscous, does not flow well, and typically has a high carbon to hydrogen ratio along with a high amount of carbon residues, asphaltenes, sulfur, nitrogen, heavy metals, aromatics, and/or waxes.

Sulfur content is another important crude oil quality determinant and is measured by the percentage of the crude's weight that is comprised by sulfur. Low sulfur or "sweet" crudes typically have less than 0.5 percent sulfur while high sulfur, or "sour" crude, typically has over 0.5 percent sulfur content. These quality characteristics are often identified in crude oil naming conventions such as Heavy Louisiana Sweet, West Texas Intermediate, and Wyoming Sour. Each of these names corresponds to a crude oil quality from a particular producing area or field.

Gravity and sulfur content are two very important qualitative distinctions in the refining process. Heavier crudes require more sophisticated processes to produce lighter, more valuable products; therefore, they are expensive to manufacture. These crudes, however, can also be less expensive from an input price perspective. Because of corrosive qualities, crude oil with higher sulfur content makes it more expensive to handle and process. In general, light crudes are more valuable, i.e., they yield more of the lighter, higher-priced products than heavy crudes. The product slate at a given refinery is determined by a combination of demand, inputs, and process units available, and the fact that some products are the result (co-products) of producing other products.

12.2.2. Geographic Distribution

As of January 1, 2007, there were 149 operable refineries in the U.S. These refineries range in size from small facilities able to process as little as 2,000 barrels of crude oil per day, to those able to process over 550,000 barrels per day (USDOE, EIA, 2008c). In total, the U.S. has an operable refining capacity of 17.44 million barrels per day (USDOE, EIA, 2008c).

One-third of operable U.S. petroleum refineries are located in the Gulf States of Alabama, Louisiana, Mississippi, and Texas (Figure 99). About 30 percent of operable refineries are located in Louisiana and Texas alone. Texas has 25 operable refineries with a total capacity of 4.7 million barrels per day, representing 27 percent of U.S. operable refining capacity. Louisiana has 18 operable refineries with a total capacity of almost 3 million barrels per day, representing 17 percent of U.S. operable refining capacity (USDOE, EIA, 2008c).

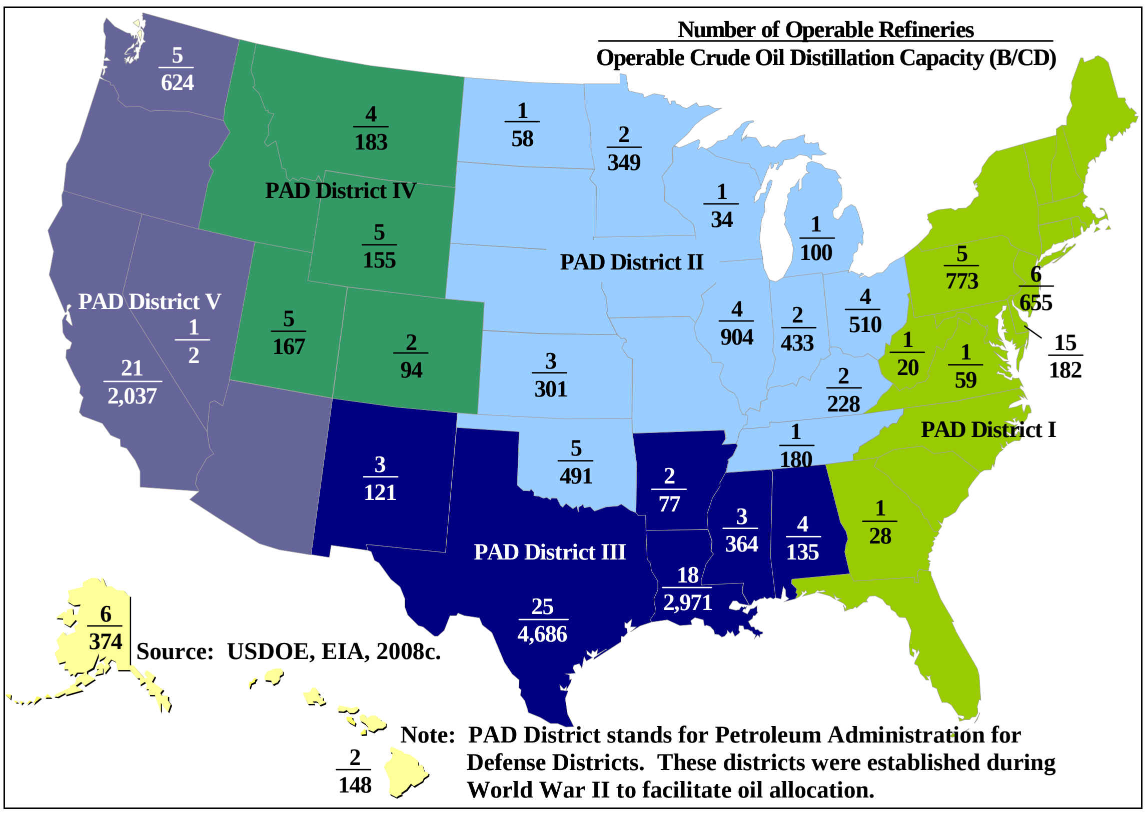


Figure 99. U.S. refineries and capacity by state as of January 1, 2007.

Table 34 shows the top ten refining states in the U.S. as of January 1, 2007. These states – with the highest individual crude distillation capacity – account for 64 percent of the number of operable refineries and 81 percent of total U.S. distillation capacity.

Table 34

Top 10 Petroleum Refining States as of January 1, 2007

State	Number of Operable Refineries	Operable Crude Oil Distillation Capacity (bbl/d)
Texas	25	4,685,526
Louisiana	19	2,971,183
California	21	2,037,188
Illinois	4	903,600
Pennsylvania	5	773,000
New Jersey	6	655,000
Washington	5	623,850
Ohio	4	510,120
Oklahoma	5	490,700
Indiana	2	433,000
Total	**96**	**14,083,167**
U.S. Total	**149**	**17,443,492**

Source: USDOE, EIA, 2008c.

Given the concentration of refineries in the region, the Gulf Coast is not surprisingly the nation's leading supplier in refined products. Refined products are shipped from the Gulf Coast to both the East Coast and the Midwest. Gulf Coast refineries supply the East Coast with more than half of its need for light products such as gasoline, heating oil, diesel, and jet fuel. Over 20 percent of the Midwest's light product consumption also comes from the Gulf Coast despite the fact that there are a considerable number of refineries located within the region in Ohio, Illinois, and Indiana.

As shown in Figure 100, the East Coast imports 62 percent of the finished petroleum products that come to the U.S. (USDOE, EIA, 2008c). The East Coast is the largest or top consuming area in the U.S. since it only has enough refining capacity to meet one-third of its refined product needs. As shown in Figure 101, the East Coast fills the product gap with supplies from other parts of the U.S., particularly the Gulf Coast (USDOE, EIA, 2008c).

The largest importer of crude oil and finished products is the Gulf Coast. These imports, however, are not primarily for finished refined products, but are more concentrated on refinery feedstock and blendstock which are needed to supplement the considerable regional refining and petrochemical capacity. In addition, a significant portion of the Midwest's non-Canadian crude imports move through the Gulf Coast's ports and pipelines. This makes the Gulf Coast the most important crude importing region in the U.S., accounting for over 50 percent of the U.S. total crude and petroleum product imports in 2005 (USDOE, EIA, 2008c).

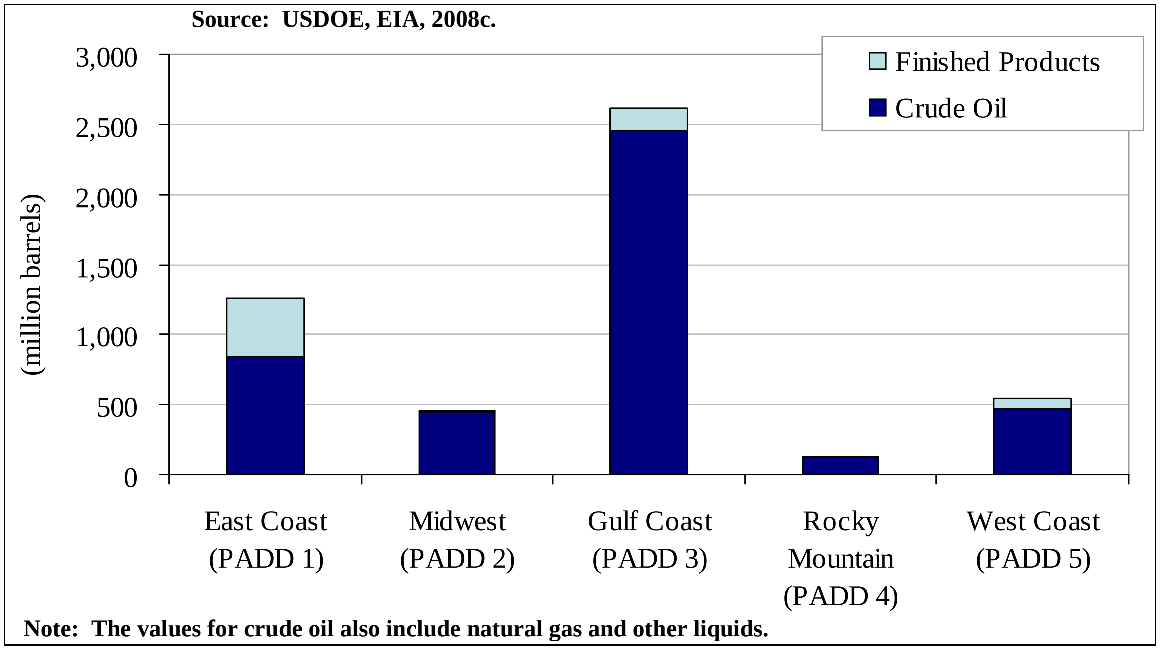


Figure 100. Imports of crude oil and petroleum products by PAD district, 2006.

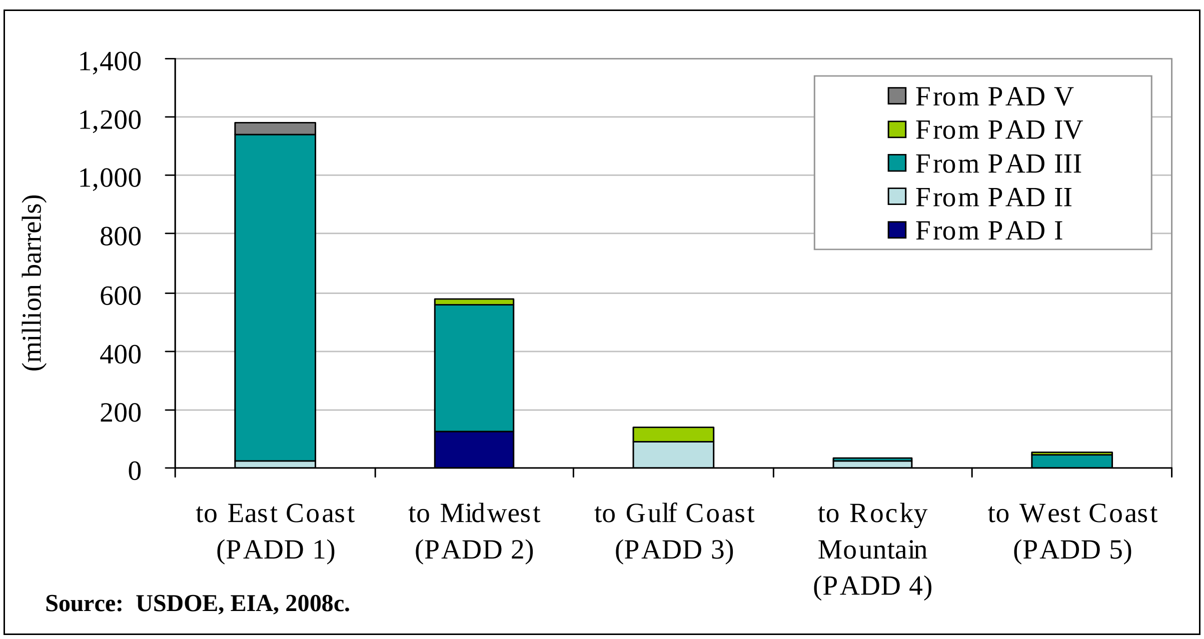


Figure 101. Trade of crude oil and petroleum products between PAD districts, 2006.

As shown in Figure 101, the trade between various domestic regions is focused almost exclusively on the eastern half of the country since the Midwest and East Coast account for 94 percent of the inter-regional flow (e.g., the flow between PAD Districts) (USDOE, EIA, 2008c). The Gulf Coast is the largest regional supplier and accounts for more than 82 percent of the inter-PADD flow (USDOE, EIA, 2008c). By contrast, the Rockies and the West Coast are isolated, in petroleum logistics terms, from the rest of the country. The easy flow of petroleum from the Gulf Coast to other regions including the Midwest and the East Coast, entails that incremental crude oil and product supply is more readily available to those markets in the event of a demand surge or supply drop. In contrast, the West Coast, and the California market in particular, have greater difficulties in securing incremental crude oil supplies.

12.2.3. Typical Firms

Refineries are owned by either large integrated petroleum companies (such as ExxonMobil, Chevron, or ConocoPhillips) or independent refiners such as Valero, Motiva, or Calumet. Many of the large integrated companies are engaged on a national or international basis in many segments of the petroleum products business, including refining, transportation, and marketing.

Refinery profitability is primarily affected by the mark-up, or margin, between refined product prices and the prices for crude oil and other feedstock (SEC, 2007g). The cost of acquiring feedstock, and the price at which refined products are sold, depends upon a number of factors that are beyond a refiner's control, including regional and global supply of, and demand for, crude oil, gasoline, diesel, and other feedstock and refined products. These factors, in turn, depend upon a number of other countervailing influences that include the availability, quantity, and quality of crude oil imports, domestic and international crude oil production, refined product inventories, geopolitics, and governmental regulation. Historically, refining margins have been relatively tight and volatile, and are anticipated to be volatile in the future since these margins tend to closely follow volatile movements in crude oil prices (SEC, 2007g and 2007h).

The following are descriptions of some of the refining companies that operate in the GOM region.

Valero Energy Corporation

The largest refiner in North America is Valero Energy Corporation (Table 35). Valero operates 17 refineries (one in Aruba, one in Canada and 15 in the U.S.) with a throughput capacity of approximately 3.1 MMBbls/d. A significant share of Valero's refining capacity is located on the Gulf Coast, including eight of the company's 17 refineries, representing total refining capacity of 1.45 MMBbls/d or 18 percent of the Gulf Coast region's operable capacity. [The following descriptions are all from Valero's 2007 10-K, (SEC, 2007g)].

Table 35

Valero Refineries

Refinery	Location	Throughput Capacity (barrels per day)
Gulf Coast		
Corpus Christi *	Texas	315,000
Port Arthur	Texas	310,000
St. Charles	Louisiana	250,000
Texas City	Texas	245,000
Houston	Texas	145,000
Three Rivers	Texas	100,000
Krotz Springs	Louisiana	85,000
West Coast		
Benicia	California	170,000
Wilmington	California	135,000
Mid-Continent		
Memphis	Tennessee	195,000
McKee	Texas	170,000
Ardmore	Oklahoma	90,000
Northeast		
Delaware City	Delaware	210,000
Paulsboro	New Jersey	195,000
Outside U.S.		
Aruba	Aruba	275,000
Quebec City	Quebec, Canada	215,000
Total		**3,105,000**

Note: * represents the combined capacities of two refineries - the Corpus Christi East and Corpus Christi West Refineries.
Source: SEC, 2007g.

Valero's Corpus Christi East and West Refineries, which have a combined total capacity of 315 MBbls/d, are located on the Texas Gulf Coast along the Corpus Christi Ship Channel. The West Refinery specializes in processing primarily lower-cost sour crude oil and residual crude into premium products such as RBOB.[29] The East Refinery processes heavy, high-sulfur crude oil into conventional gasoline, diesel, jet fuel, asphalt, aromatics, and other light products. The refineries typically receive and deliver feedstock and products by tanker and barge via deepwater docking facilities along the Corpus Christi Ship Channel. These refineries distribute refined products using the Colonial, Explorer, Valley, and other major refined product pipelines.

[29] RBOB is a base unfinished reformulated gasoline mixture known as "reformulated gasoline blendstock for oxygenate blending" or "RBOB."

The Port Arthur Refinery, a relatively large facility with 275 MBbls/d of capacity, processes primarily heavy sour crude oils and other feedstock into conventional and premium gasoline. Sources of crude oil supplies for this refinery primarily come from Iraq and Saudi Arabia. The Port Arthur refinery processes a variety of products including RBOB, diesel, jet fuel, petrochemicals, petroleum coke, and sulfur. The refinery receives crude oil over marine docks and has access to the Sunoco and oil tanker terminals at Nederland, Texas. Refined products from these refineries are distributed to end-use markets in the eastern U.S. via the Colonial, Explorer, and TEPPCO pipelines. Some refined product is exported via ships or barges. The Port Arthur refinery also has truck-rack access.

The Texas City Refinery is located southeast of Houston on the Texas City Ship Channel off Galveston Bay. The refinery processes primarily heavy sour crude oils into a wide slate of products. Crude oil supplies for this refinery primarily come from foreign markets including Mexico and Iraq. Secondary sources come from Saudi Arabia, Colombia, Kuwait, and Venezuela (USDOE, EIA, 2008c). Few supplies are from GOM-based production (USDOE, EIA, 2008c). The refinery receives and delivers its feedstock and products by tanker and barge via deepwater docking facilities along the Texas City Ship Channel and uses the Colonial, Explorer, and TEPPCO pipelines for distribution of its products.

Valero’s Houston Refinery is a relatively small refinery with 145 MBbls/d of capacity, and is located on the Houston Ship Channel. It processes primarily sour crude oils and low-sulfur residual into conventional gasoline and distillates. The refinery also produces roofing-grade asphalt. The refinery receives its feedstock via tanker at deepwater docking facilities along the Houston Ship Channel and delivers its products through major refined-product pipelines, including the Colonial, Explorer, and TEPPCO pipelines. Most of the crude supplies for this refinery originate in Algeria (USDOE, EIA, 2008c).

The Three Rivers Refinery, a small refinery with 100 MBbls/d of capacity, is located in South Texas between Corpus Christi and San Antonio. It processes primarily heavy sweet and sour crude oils into conventional gasoline and distillates. It has access to crude oil from foreign sources delivered to the Texas Gulf Coast at Corpus Christi as well as crude oil from domestic sources through third-party pipelines. Little of the crude oil processed at this refinery comes from GOM production. Kazakhstan and Nigeria serve as this refinery’s primary sources for feedstock (USDOE, EIA, 2008c). A 70-mile pipeline that can deliver 120,000 barrels per day of crude oil connects the Three Rivers Refinery to Corpus Christi. The refinery distributes its refined products primarily through pipelines owned by NuStar Energy L.P. These pipelines send refined product primarily to the Valero San Antonio terminals (Valero, 2009).

The St. Charles Refinery, a good sized refinery with 250 MBbls/d of capacity, is located approximately 15 miles northwest of New Orleans along the Mississippi River. The St. Charles refinery processes sour crude oils and other feedstock into gasoline, distillates, and other light products. The refinery receives crude oil over five marine docks and has access to the Louisiana Offshore Oil Port (LOOP) where it can receive crude oil through a 24-inch pipeline. Finished products can be shipped over these docks or by pipeline through either the Plantation or Colonial pipeline networks for distribution to the eastern U.S.

The Krotz Springs Refinery, with a relatively small 85 MBbls/d of processing capacity, is located between Baton Rouge and Lafayette, Louisiana on the Atchafalaya River. It processes light sweet crude oils (received by pipeline and barge) into conventional gasoline and distillates. Most of these light sweet crudes come from domestic sources of production, many located in Louisiana (Crouch, 2009). The refinery's location provides access to upriver markets on the Mississippi River, and its docking facilities along the Atchafalaya River are sufficiently deep to allow barge access. The facility also uses the Colonial pipeline to transport refined products to markets in the southeastern and northeastern U.S.

Motiva Enterprises LLC

It is a joint venture owned by Saudi Refining, Inc. and Shell Oil Company and has a concentrated set of assets along the Gulf Coast region of Texas and Louisiana. Motiva owns and operates three refineries with a total combined capacity of about 740,000 barrels per day. Motiva's operations are tied to almost 7,700 Shell-branded gasoline stations and ownership interest in 41 refined product storage terminals with an aggregate storage capacity of approximately 19.8 million barrels (Motiva Enterprises, LLC, 2008).

Originally constructed and operated by Texaco in 1967, Motiva's Convent Refinery is located along the Mississippi River approximately 30 miles southeast of Baton Rouge, Louisiana. A 1979 expansion added a hydrotreater, sulfur complex, three crude oil storage tanks, and an additional dock. In 1984, capacity nearly doubled with another expansion. Crude oil produced in Venezuela and Saudi Arabia serves as the refinery's primary input and is delivered primarily by pipeline, or ships along the Mississippi River (USDOE, EIA, 2008c). The refinery's finished petroleum products are shipped from the facility by pipeline, rail car, tank truck, and waterfront vessels (Motiva Enterprises, LLC, 2008). The Plantation and Bengal pipelines are the primary refined product pipelines servicing the Motiva refinery (Bengal Pipeline Company, LLC, 2009).

Motiva's main refining facility is located approximately 20 miles west of New Orleans, Louisiana, and was originally developed in 1918 by the New Orleans Refining Company or "Norco." The Norco refinery, which currently has some 220 MBbls/d of capacity, became a part of Motiva Enterprises, LLC in 1998. Shell first purchased the refinery in 1929 and continues to operate petrochemical units at the Norco location (Motiva Enterprises, LLC, 2008 and 2009a).

Motiva's Port Arthur, Texas, refinery, originally developed at the turn of the last century in 1903, was a major producer of high-octane aviation fuel in World War II. In 1989, the refinery became part of Star Enterprise, a joint venture between Texaco and Saudi Aramco. Since 1998, it has been operated by Motiva Enterprises, LLC. The refinery currently has some 285 MBbls/d of capacity and most of its refined product, comprised of gasoline and middle distillates, is delivered to market via three major product pipelines: Colonial; Explorer; and Magtex. The refinery has two marine docks: The Port Neches Terminal is primarily a crude oil dock, while the Port Arthur Terminal is a finished product terminal. The two terminals handle approximately 700 vessels per year (Motiva Enterprises, LLC, 2008 and 2009b).

Calumet Specialty Products Partners, L.P.

Calumet owns and operates three smaller specialty refineries in northwest Louisiana as well as a terminal in Burnham, Illinois and facilities in Pennsylvania and Texas. The Princeton refinery in northwest Louisiana was acquired in 1990 and produces specialty lubricating oils, including process oils, base oils, transformer oils, and refrigeration oils that are used in a variety of industrial and automotive applications. The Cotton Valley refinery was acquired in 1995. It produces specialty solvents that are used principally in the manufacture of paints, cleaners, and automotive products. The Shreveport refinery produces specialty lubricating oils and waxes, as well as fuel products such as gasoline, diesel, and jet fuel (SEC, 2007h).

Calumet purchases crude oil from major oil companies as well as from various gatherers and marketers in Texas and north Louisiana. Thus, a good portion of its crude oil inputs are from the GOM region. The Shreveport refinery can also receive crude oil through the ExxonMobil pipeline system originating in St. James, Louisiana, which provides the refinery with access to domestic crude oils and foreign crude oils through the LOOP or other terminal locations. For the year ended December 31, 2007, Calumet purchased approximately 42 percent of its crude oil supply from a subsidiary of Plains under a term contract that would expire in April 2008; 43.4 percent of its crude oil supply through evergreen crude oil supply contracts, which are typically terminable on 30 days' notice by either party; and the remaining 14.6 percent of its crude oil supply on the spot market (SEC, 2007h). Thus, the Calumet facility is significantly different from other major refineries in terms of its feedstock supply arrangements.

12.2.4. Regulation

Although refineries are not regulated economically, they are affected by environmental regulations and legislation. The refining industry is also impacted by regulations placed on the way petroleum is produced, imported, stored, transported, and consumed in the U.S. The following is a description of three major changes in the petroleum industry that have directly impacted refineries.

Petroleum Price and Allocation Decontrol

In the early 1970s a number of controls were put in place that were meant to ensure equitable prices, distribution of products, and to preserve the independent segments of the oil industry (USDOE, EIA, 2002a). These controls constrained domestic petroleum prices keeping them low. In 1978, demand for petroleum increased to record levels as the controlled prices gave petroleum and fuel oil a competitive advantage over natural gas and coal. However, in late 1978, the Iranian Revolution began, resulting in a decrease in the foreign production of crude oil. And, in 1980, the Iran-Iraq War began, further limiting foreign supply. As a result, OPEC crude oil prices increased to unprecedented levels (USDOE, EIA, 2002a).

In early 1981, the U.S. Government responded to the oil crisis by removing price and allocation controls on the oil industry. For the first time since the early 1970s, market forces replaced regulatory programs and domestic crude oil prices were allowed to rise to a market-clearing level. This decontrol also set the stage for the easing of export restrictions on petroleum products and allowed a greater number of refined product imports to enter the country (USDOE, EIA, 2002a).

Price decontrol policies did not impact all refineries equally and many small refineries and older, inefficient plants could no longer compete and were forced to shut down. The contraction in the number (but not necessarily total capacity) of refineries began in earnest during this period and continued for over a decade as smaller less efficient (or less specialized) refineries were shut down in favor of larger, and more efficient refineries and operations. According to the DOE, "the loss of so many small, low-conversion refineries, which served as a significant source of unfinished crude oil and refining stocks sent many larger and more diversified refiners overseas looking for intermediate refinery inputs (USDOE, EIA, 2002a). From 1980, the last full year of price and allocation controls, to 1981, imports of intermediate finished crude and refinery inputs more than doubled, jumping from 55,000 barrels per day to 112,000 barrels per day (USDOE, EIA, 2002a). Unfinished oil imports continued to rise and in 1993 peaked at 491,000 barrels per day. In 2000, the United States imported an average of 274,000 barrels per day of unfinished oils for refinery purposes (USDOE, EIA, 2002a).

Reid Vapor Pressure Regulations of 1989 and 1992

In the spring of 1989, the EPA implemented a two-phased program limiting summertime motor gasoline volatility (the rate at which gasoline evaporates into the air) in some U.S. lower 48 urban areas in order to combat emissions of volatile organic compounds (VOCs) and other ozone precursors. VOCs react photochemically in the atmosphere and are a major component of smog. Thus, lowering gasoline vapor pressures reduces VOCs and the build-up of smog and ozone. Gasoline evaporates more quickly (higher volatility) at warm temperatures and at higher altitudes where VOCs release to the atmosphere more quickly (USDOE, EIA, 2002a). Phase I summer volatility standards went into effect in 1989 and mandated that summer average residual vapor pressure (RVP) from motor gasoline be reduced from 11.5 pounds per square inch (psi) to a maximum of 10.5 psi. Some areas of the country saw restrictions that lowered RVP to 9.0 psi (USDOE, EIA, 2002a). Phase II summer volatility standards were implemented in 1992 and remained in place through the summer of 1994. In 1995, RVP requirements were modified to be consistent with the implementation of the reformulated gasoline program. Phase II set a nationwide maximum summer RVP standard of 9.0 psi but was more restrictive for southern cities that do not meet federal ozone standards which must meet a 7.8 psi RVP standard (USDOE, EIA, 2002a).

The Phase I standards were met by reducing the amount of normal butane blended into motor gasoline. Butane is a lower-cost gasoline blending component that has a high octane value, but also has a relatively high RVP. The more stringent Phase II standards meant further processing of crude oil and unfinished oils that occurs after they are initially run through a crude oil distillation unit. Some refiners made large capital investments to produce high-octane, lower RVP blending components, to meet these standards (USDOE, EIA, 2002a).

Clean Air Act Amendments of 1990

The 1990 Amendments to the Clean Air Act of 1970 (CAAA) imposed strict new controls to reduce mobile sources of air pollution. The CAAA contained six provisions to be implemented by the EPA in stages between November 1, 1992, and January 1, 2000. Four major programs to reduce harmful emissions from highway fuel were slated to go into effect between November 1, 1992, and January 1, 1996. These programs included, as outlined by the U.S. DOE include (USDOE, EIA, 2002a):

- Oxygenated Fuels Program: Effective November 1, 1992, all motor gasoline sold in majority of the 39 carbon monoxide (CO) non-attainment areas must contain a minimum of 2.7 percent oxygen by weight during at least four winter months. Adding oxygenates to motor gasoline lowers the level of carbon monoxide produced by car engines during the combustion process. These increases were limited, however, since concern over nitrogen oxide (NOx) emissions from the higher winter oxygen content resulted in a winter maximum of 2.0 percent oxygen by weight in California's CO non-attainment areas.

- Highway Diesel Fuel Program: Effective October 1, 1993, the sulfur content of highway diesel fuel must be significantly reduced from the current maximum of 0.25 percent to 0.05 percent by weight. In addition, the cetane index, which measures the self-ignition quality of diesel fuel, must be maintained at a minimum of 40. Small refineries received relief from the sulfur limit in the form of tradeable credits until December 31, 1999.

- Reformulated Gasoline Program: Effective January 1, 1995, reformulated gasoline will be required in the nine metropolitan areas with the worst ozone problems. Other areas may "opt in" to the program by applying to the EPA and these provisions may be delayed for up to three years if EPA determines that not enough reformulated gasoline is available. Reformulated gasoline must meet specific composition and emission performance criteria. The core emission requirements for 1995 to 1999 prohibit any increase in NOx emissions, mandate a year-round reduction of toxic air pollutants, and require a summertime reduction of VOCs of 15 percent below 1990 "baseline" gasoline. By 2000, TAP and VOC emissions are to be reduced by a minimum of 20 percent. If technically feasible, a 25-percent cut will be mandated.

- Leaded Gasoline Removal: Sales of leaded motor gasoline are prohibited after 1995.

The CAAA forced many refineries to make considerable investments in oxygenates production facilities. In 1992, 33 refineries increased oxygenates producing facilities and by 1993 production capacity for oxygenates had increased 59 percent (USDOE, EIA, 2002a). Other investments that arose in the aftermath of the CAAA included the construction of desulfurization units, in particular catalytic hydrocracking and hydrotreating units. These investments began to increase after 1980 as heavier, higher-sulfur crude oils became available to U.S. refiners but increased rapidly in reaction to the new clean gasoline standards, particularly diesel standards resulting from the CAAA. New hydrostatic treatment facilities also significantly increased the hydrogen production and use requirements for most refineries (USDOE, EIA, 2002a)."

12.3. Industry Trends and Outlook

12.3.1. Trends

According to the EIA, there are 37 refineries operating in the Gulf Economic Impact Areas with a total capacity of 7.2 MMBBls/d. The U.S. refining industry's ability to meet short-term increases in demand can also be measured by refinery utilization rates which are simply the ratio of gross inputs to crude oil distillation units divided by operable capacity. Utilization rates can fluctuate over time as demand, as well as the addition of new capacity, changes. Figure 102 shows that capacity expansions resulting from the significant gasoline demand increases of the early and mid-1970s started to sow the seeds of lower industry utilization in the latter part of the decade. These capacity additions, coupled by a later, yet significant reduction in refined product demand in the late 1970s and early 1980s pushed utilization rates to some of their lowest levels on record (USDOE, EIA, 2002a).

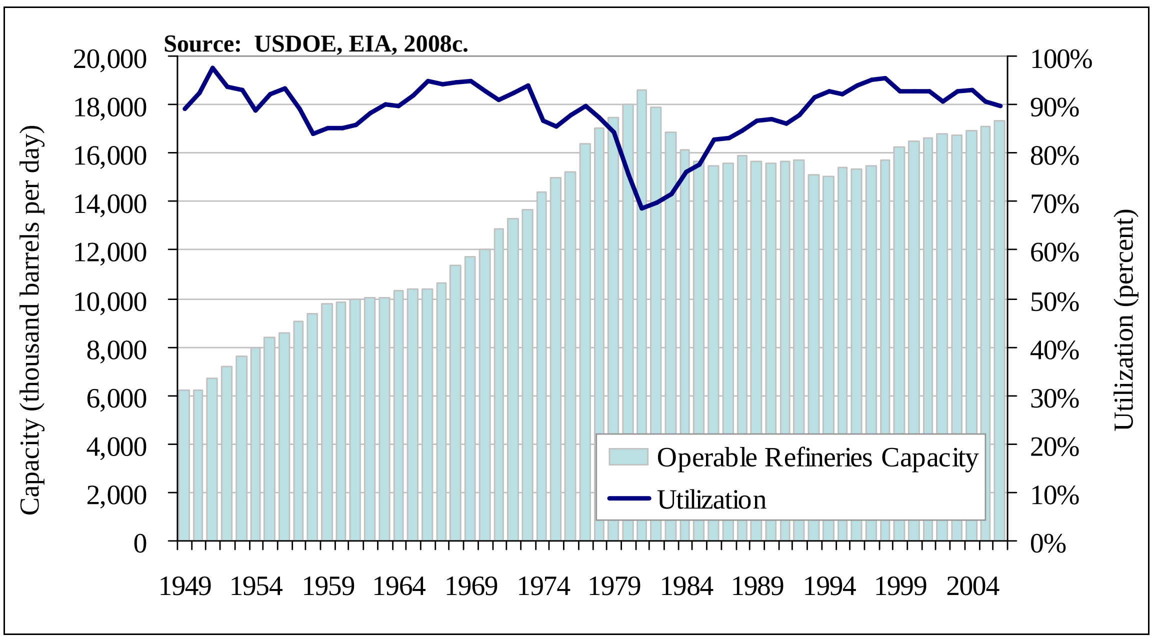


Figure 102. Refinery capacity and utilization, 1949 to 2006.

Markets, however, began the slow and laborious process of correcting themselves in the early 1980s as close to 120 smaller and less efficient refineries, accounting for approximately three MMbbls/d of operable capacity, permanently shut down. This reduction, coupled with the slow and steady increase in refined product demand, resulted in an average annual refinery utilization rate increase from 69 percent in 1981 to almost 93 percent in 2000 (USDOE, EIA, 1999).

The decade of the 1990s was one of the most challenging for most refinery owners and operators and is characterized by very low product margins and profitability given the past capacity over-development. Industry sources at the time reported that refined product capacity "simply outpaced demand growth and industry participants have played a game of chicken in which competitors are waiting for each other to shut down their units… [b]ut nobody wants to be the first (NPN, 1996)." Excess capacity, coupled with considerable new regulatory requirements (and operating investments) needed to comply with the CAAA further increased the cost of a very high-cost sector of the industry.

Low profitability during the 1990s was also the result of a narrowing of the spread between refined product prices at the pump and crude oil input costs. Inflation-adjusted prices for both crude oil and refined product, particularly gasoline, were at their historic lowest levels during this period. The pressures of increased costs and lower product prices forced domestic refiners and marketers to make concerted efforts to realize greater value from their fixed assets and to reduce their operating costs. Refining operations were consolidated, the capacity of existing facilities was expanded (to attain scale economies and efficiencies), and several refineries were closed.

Since 2000, refining capacity has increased by five percent with high utilization (between 90 and 93 percent) despite the fact that no new greenfield refinery has been constructed since the mid 1970s (the Marathon facility at Garyville, La. in 1976). Furthermore, cyclical differences between refined product output and demand are increasingly being met with imports from excess capacity in other parts of the world rather than on developing new domestic capacity. Refined product imports, for instance, have increased by about 25 percent since 2000 (USDOE, EIA, 2008c).

Most refineries are part of major, vertically integrated oil companies that are engaged in both upstream and downstream aspects of the petroleum industry. A wave of mergers that began in the 1990s, however, has whittled down the number of these vertically integrated giant oil companies and resulted in considerable market consolidation. For instance, the top 10 U.S. refiners in 1994 accounted for 57 percent of the market, while today the top 10 U.S. refiners, most of them major integrated oil companies, account for 75 percent of the total domestic refinery operating capacity (USDOE, EIA, 2008c).

The 1990s also saw the emergence of a considerable number of joint ventures (JVs) as large companies pooled their resources and brought in new partners to diversify against ongoing market risk. One of the largest joint ventures affecting U.S. refining and marketing occurred in 1997 between Shell Oil Company and Texaco. This JV, called Equilon Enterprises, combined eight different Midwestern and western refineries and other downstream operations of Shell and Texaco (USDOE, EIA, 2001).

The second significant JV that arose during the industry consolidation efforts of the 1990s was the creation of Motiva Enterprises. This JV included the combination of the eastern and Gulf Coast operations of Shell Oil Company and Star Enterprise, itself a JV formed in 1988 between Texaco and Saudi Aramco (USDOE, EIA, 2001).

The mergers that occurred in the industry during the 1990s were considerable. The major mergers that impacted refining operations during this period include: Exxon and Mobil, Chevron and Texaco, Conoco (which was spun off from Dupont Chemical Company) and Phillips Oil Company, and Marathon and Ashland.

In October 2000, Chevron and Texaco merged. In order to acquire Federal Trade Commission (FTC) approval for the merger, Texaco was required to sell its shares of the Equilon and Motiva Enterprises. The FTC allowed Shell to purchase 100 percent of Equilon, and Shell and Aramco bought out Texaco's share of Motiva (USDOE, EIA, 2000a and 2007f).

Significant mergers have also occurred between independent refiners and marketers. For example, in 1997 Ultramar Diamond Shamrock (itself created by a late 1996 merger) acquired Total Petroleum North America, adding three refineries, more than 2,100 marketing outlets, and hundreds of miles of product pipelines, in addition to a number of other associated assets (USDOE, EIA, 2004b). In 2005, Valero Energy agreed to acquire Premcor Inc. transforming the fourth (Valero) and eighth (Premcor) largest refiners into the second-largest, and largest non-vertically integrated domestic refiner in the U.S. (USDOE, EIA, 2005c).

A summary of the mergers and acquisitions of major U.S. companies, originally complied by the U.S. DOE, can be found in Figure 103. The figure is confined to transactions that represented the merger of entire companies (or at least the entirety of the corporate U.S. oil and gas production or U.S. refining operations). Transactions that involved only some of the corporate assets within the relevant line of business (i.e., U.S. oil and gas production or U.S. refining) are omitted (USDOE, EIA, 2007f).

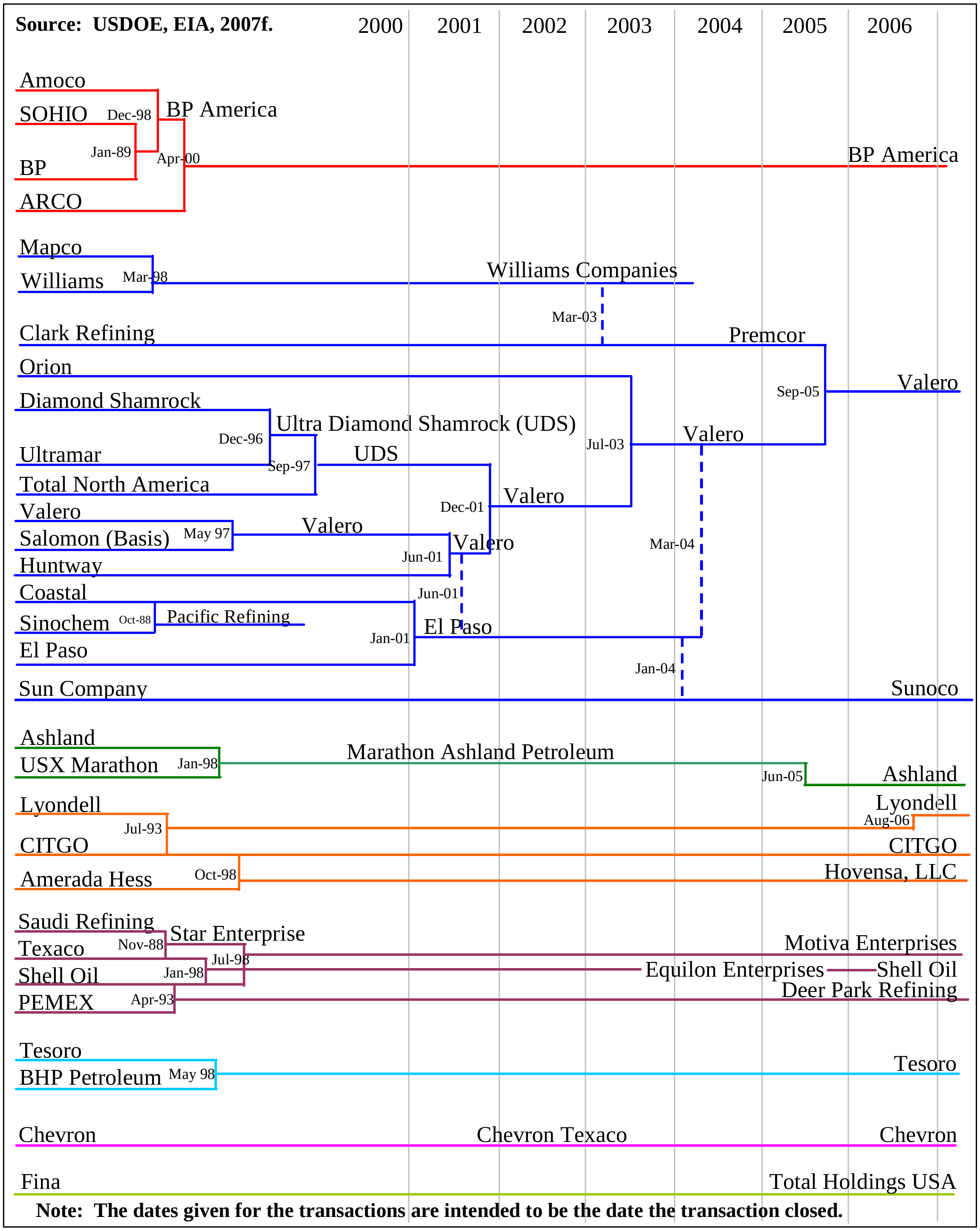


Figure 103. Genealogy of major U.S. refiners.

12.3.2. Hurricane Impacts

Prior to the hurricane season of 2005, the refining sector was under tremendous pressure to keep up with growing refined product demand. Strong domestic and global economic growth was putting pressure on refined product markets in a fashion similar to overall crude oil and natural gas commodity markets. Like energy commodity markets, refined products were being consumed rapidly by developed and developing countries alike, straining existing capacity and driving up prices.

Strong demand during the pre-Katrina period put incredible stress on existing capacity, which, as shown earlier, had not seen significant growth since the mid to late 1970s. The tight refined product markets prior to Hurricane Katrina were facing two important and related challenges. The first challenge, shown in Figure 102, was that refineries in the Gulf region, as well as throughout the country, were running at record capacity levels. During this period, all GOM refineries were operating at levels in excess of 90 percent, placing challenges on meeting refined product demand during this period. Many refineries had to forgo routine maintenance in order to keep up with breakneck levels of refined product demand.

The second important challenge in the pre-Katrina environment was associated with what was then considered record high refined product prices. Figure 104 shows a graph of wholesale gasoline prices in both real (inflation adjusted) and nominal dollars. As seen in the series, prior to Hurricane Katrina, wholesale gasoline prices hit their all-time nominal (non-inflation adjusted) highs of 137.8 cents per gallon. Pre-Katrina prices were not as high as the nominal peak reached in early 1981 in the aftermath of the Iranian Revolution, but they were higher, in real terms, than wholesale gasoline prices experienced during the energy crises of the early 1970s created by the Arab oil embargo. However, unlike the crises of the early 1970s and 1980s, refined product demand during this period did not abate.

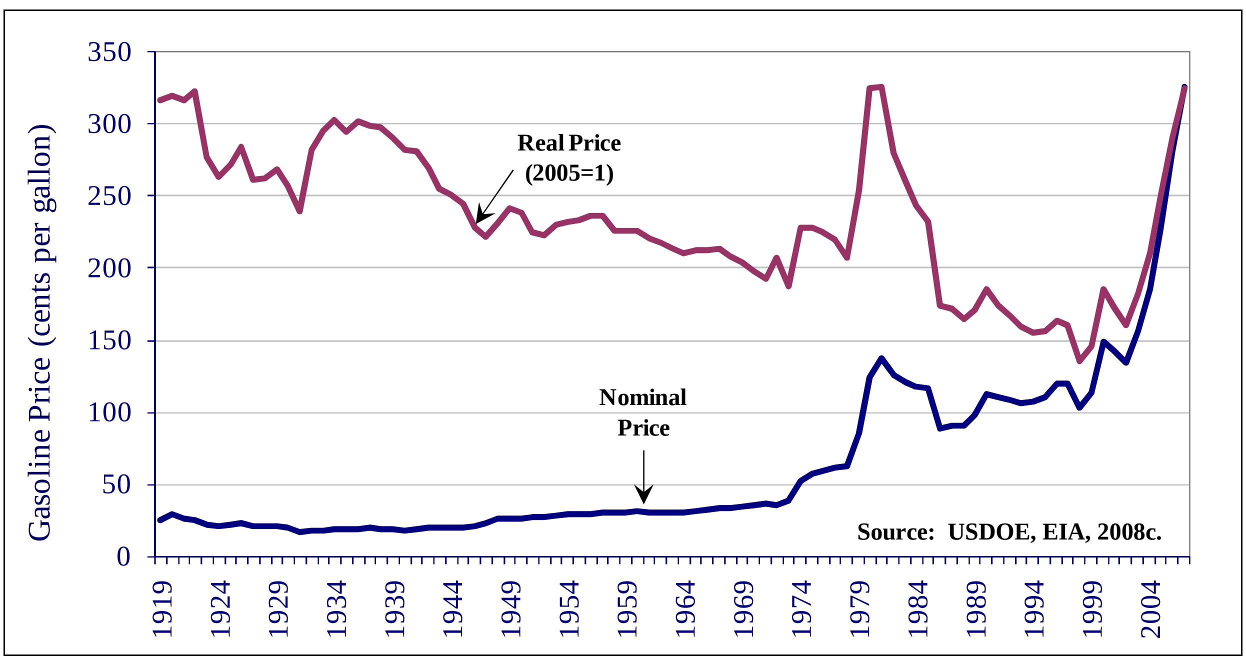


Figure 104. Real gasoline pump price: Annual average 1919-2007.

The impact that Hurricane Katrina had on refined product markets was perhaps one of the most watched consequences associated with the storm. Refined product markets were exceptionally strained in the peak demand summer months leading up to Katrina's landfall. Figure 105 presents a pie chart showing the immediate 'day-one' impacts that Katrina had on the region's and nation's refining capacity.

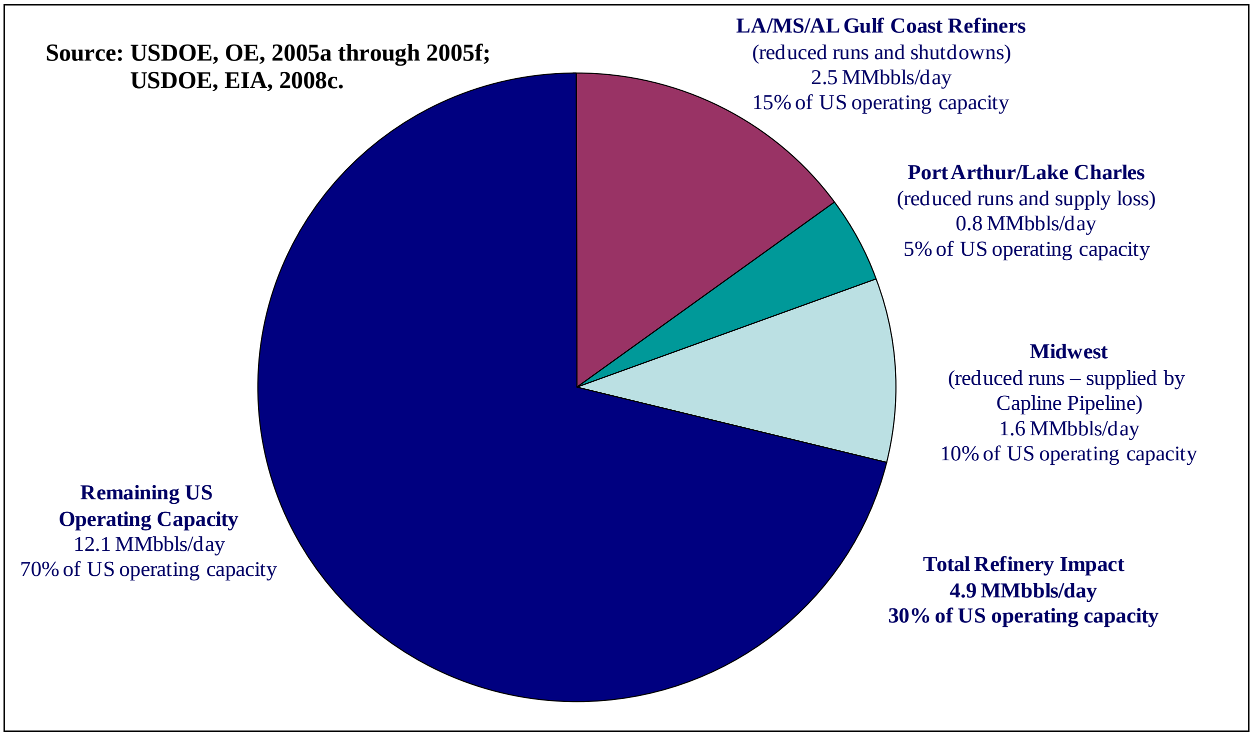
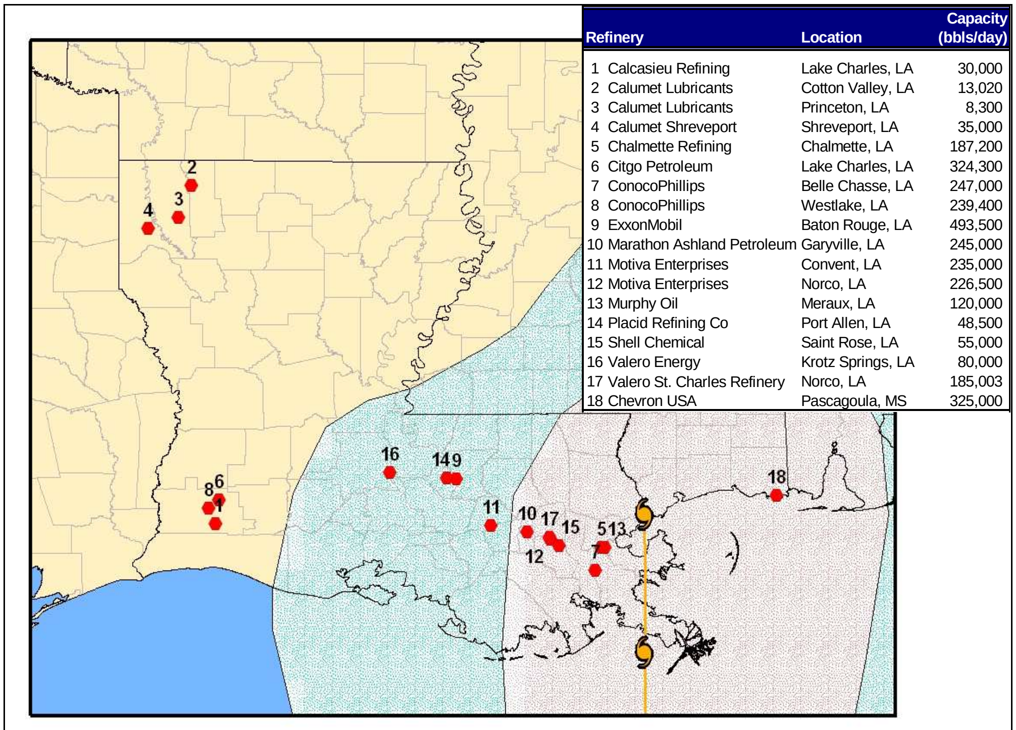


Figure 105. Total immediate refinery impact from Hurricane Katrina.

Thirty-three of the Gulf Coast's 40 operating refineries were impacted in some form or another by the hurricane, and nine sustained damage. Six of the damaged refineries were in Louisiana, two in Texas, and one in Mississippi. These damaged facilities resulted in a total loss of capacity of 2.3 MMBBls/d, or almost half of the 4.9 MMbbls per day of impacted facilities (USDOE, EIA, 2008c; USDOE, OE, 2005c, 2005d, 2005e and 2005f). In addition, many of the facilities that did not sustain direct damage were impacted by supply interruptions. For instance, the refineries in Lake Charles, LA and Port Arthur, were not directly damaged by Hurricane Katrina, but were impacted through transportation interruptions that prevented crude oil tankers from offloading for several days. These refineries were also significantly impacted by widespread power outages during this period as well despite being physically undamaged (or minimally damaged) by Katrina.

Figure 106 shows the location of the impacted Louisiana refineries relative to Katrina's storm path and wind field. In total, some 4.9 MMBBls/d of refining capacity was impacted by Katrina in some way. These impacts were based on three types of interruptions created by the storm: (1) impacts created by being directly in the storm's path; (2) impacts created along the Gulf Coast by supply interruptions to refineries created by the storm; and (3) impacts created in other parts of the country by crude supply interruptions created by pipeline system interruptions.



Refinery	Location	Capacity (bbls/day)
1 Calcasieu Refining	Lake Charles, LA	30,000
2 Calumet Lubricants	Cotton Valley, LA	13,020
3 Calumet Lubricants	Princeton, LA	8,300
4 Calumet Shreveport	Shreveport, LA	35,000
5 Chalmette Refining	Chalmette, LA	187,200
6 Citgo Petroleum	Lake Charles, LA	324,300
7 ConocoPhillips	Belle Chasse, LA	247,000
8 ConocoPhillips	Westlake, LA	239,400
9 ExxonMobil	Baton Rouge, LA	493,500
10 Marathon Ashland Petroleum	Garyville, LA	245,000
11 Motiva Enterprises	Convent, LA	235,000
12 Motiva Enterprises	Norco, LA	226,500
13 Murphy Oil	Meraux, LA	120,000
14 Placid Refining Co	Port Allen, LA	48,500
15 Shell Chemical	Saint Rose, LA	55,000
16 Valero Energy	Krotz Springs, LA	80,000
17 Valero St. Charles Refinery	Norco, LA	185,003
18 Chevron USA	Pascagoula, MS	325,000

Source: USDOE, EIA, 2008c; USDOE, OE, 2005a through 2005f.

Figure 106. Refineries shut down due to Hurricane Katrina.

Table 36 shows the individual refineries on the Gulf Coast that were impacted by Hurricane Katrina and their status as of August 31, 2005, two days after Katrina made landfall.

In addition to the direct impacts of Hurricane Katrina to Gulf area refineries, a number of refineries in the Midwest were impacted by the lack of available supplies, mainly due to the shut-in of Capline Pipeline. This pipeline is an important conduit that moves crude oil from the offloading facilities along the GOM to Midwestern refineries. A summary of the impacts to non-GOM refineries has been presented in Table 37.

Table 36

Refineries Impacted by Hurricane Katrina

Company	Location	Processing Capacity (barrels per day)	Status (as of August 31)
ExxonMobil	Baton Rouge, LA	493,500	reduced runs
ChevronTexaco	Pascagoula, MS	325,500	shutdown
Citgo	Lake Charles, LA	324,300	total supply loss
ConocoPhillips	Belle Chasse, LA	247,000	shutdown
Marathon	Garyville, LA	245,000	shutdown
ConocoPhillips	Lake Charles, LA	239,400	total supply loss
Motiva (Shell)	Convent, LA	235,000	shutdown
Motiva (Shell)	Norco, LA	226,500	shutdown
Total	Port Arthur, TX	211,500	reduced runs
ExxonMobil	Chalmette, LA	187,200	shutdown
Valero	St. Charles	185,000	shutdown
Murphy	Meraux	120,00	shutdown
Valero	Krotz Springs, LA	80,000	reduced runs
Shell Chemical	Saraland, AL	80,000	?
Shell Chemical	St Rose, LA	55,000	shutdown
Placid Oil	Port Allen, LA	48,500	reduced runs

Source: USDOE, OE, 2005a through 2005f and 2006a.

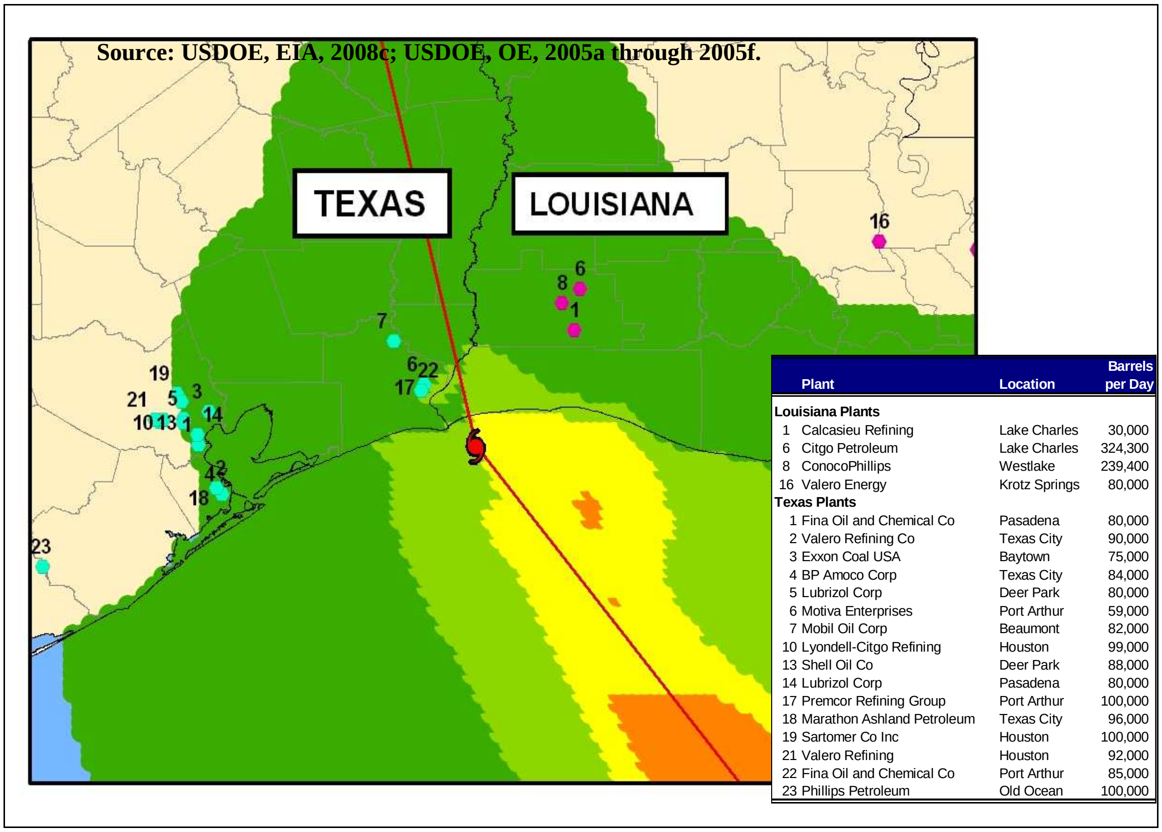
Table 37

Impacts to Refineries Outside the Gulf Coast

Refinery	Location	Capacity (bbl per day)	Status (as of September 1)
BP	Whiting, IN	410,000	reduced runs
BP	Toledo, OH	160,000	reduced runs
ExxonMobil	Joliet, IL	238,000	none
PDV Midwest	Lemont, IL	160,000	none
Marathon	Robinson, IL	192,000	reduced runs
Marathon	Catlettsburg, KY	222,000	reduced runs
Marathon	Detroit, MI	74,000	none
Marathon	Canton, OH	73,000	none
ConocoPhillips	Wood River, IL	306,000	reduced runs
Premcor	Memphis, TN	180,000	reduced runs
Premcor	Lima, OH	158,400	reduced runs
Sun	Toledo, OH	160,000	not available

Source: USDOE, OE, 2005a through 2005f and 2006a.

Figure 107 shows the location of the impacted Louisiana refineries relative to Rita's storm path and wind field.



Plant	Location	Barrels per Day
Louisiana Plants		
1 Calcasieu Refining	Lake Charles	30,000
6 Citgo Petroleum	Lake Charles	324,300
8 ConocoPhillips	Westlake	239,400
16 Valero Energy	Krotz Springs	80,000
Texas Plants		
1 Fina Oil and Chemical Co	Pasadena	80,000
2 Valero Refining Co	Texas City	90,000
3 Exxon Coal USA	Baytown	75,000
4 BP Amoco Corp	Texas City	84,000
5 Lubrizol Corp	Deer Park	80,000
6 Motiva Enterprises	Port Arthur	59,000
7 Mobil Oil Corp	Beaumont	82,000
10 Lyondell-Citgo Refining	Houston	99,000
13 Shell Oil Co	Deer Park	88,000
14 Lubrizol Corp	Pasadena	80,000
17 Premcor Refining Group	Port Arthur	100,000
18 Marathon Ashland Petroleum	Texas City	96,000
19 Sartomer Co Inc	Houston	100,000
21 Valero Refining	Houston	92,000
22 Fina Oil and Chemical Co	Port Arthur	85,000
23 Phillips Petroleum	Old Ocean	100,000

Figure 107. Refineries shut down due to Hurricane Rita.

Table 38 shows the individual refineries on the Gulf Coast that were impacted by Hurricane Rita and their status as of September 26, 2005, two days after Rita made landfall.

Table 38

Gulf Coast Refineries Impacted by Hurricane Rita

Company	Location	Capacity (barrels/day)	Status (as of September 26, 2005)
Port Arthur / Lake Charles			
Citgo	Lake Charles, LA	324,300	shut down; minor damage reported
Conoco Phillips	West Lake, LA	239,400	shut down; wind damage and no power
Calcasieu	Lake Charles, LA	30,000	shut down
ExxonMobil	Beaumont, TX	348,500	shut down; no power
Shell (Motiva)	Port Arthur, TX	285,000	shut down; minor damage reported
Total	Port Arthur, TX	233,500	shut down
Valero (Premcor)	Port Arthur, TX	255,000	shut down; significant damage
Total		**1,715,700**	
Houston / Texas City			
Shell Deer Park	Deer Park, TX	333,700	shut down; minimal damage
Lydonell Citgo	Houston, TX	270,200	restarting
Astra Oil (Crown C	Pasadena, TX	100,000	shut down
Valero	Houston, TX	83,000	shut down
ExxonMobil	Baytown, TX	557,000	shut down; ready for restart
BP	Texas City, TX	437,000	shut down
Valero	Texas City, TX	209,950	shut down; may restart soon
Marathon	Texas City, TX	72,000	shut down; minimal damage
ConocoPhillips	Sweeny, TX	229,000	restarting
Total		**2,291,850**	
Corpus Christi			
Flint Hills Resourc	Corpus Christi, TX	288,126	returning to full rate
Citgo	Corpus Christi, TX	156,000	okay
Valero	Corpus Christi, TX	142,000	returning to full rate
Trigeant	Corpus Christi, TX	30,000	returning to full rate
Valero	Corpus Christi, TX	90,000	returning to full rate
Total		**706,126**	

Source: USDOE, OE, 2005a through 2005f and 2006a.

In addition to the direct impacts of Hurricane Rita to Gulf area refineries, two refineries in the Midwest were impacted by the lack of available supplies. The impacts to these refineries are presented in Table 39.

Table 39

Midwest Refineries Impacted by Hurricane Rita

Company	Location	Capacity (barrels/day)	Status (as of September 26, 2005)
Valero	Lima, OH	158,400	reduced runs
Valero	Memphis, TN	180,000	reduced runs
Total		**338,400**	

Source: USDOE, OE, 2005a through 2005f and 2006a.

12.3.3. Outlook

One of the more important realizations resulting from the 2005 hurricanes was the need for additional refining capacity in order to meet domestic energy needs. The 2005 hurricanes hit at exactly the wrong time in the industry's long cycles of capacity build-up and capacity "burn-off." When Katrina and Rita crossed the GOM, refining capacity was already poised for another period of potential build-up. The restoration activities and the simple fact that industry was simply attempting to keep its head above water briefly stalled what was seen at the time as the inevitable need for new refining capacity.

While many policy makers, industry leaders, and energy policy pundits have called for new greenfield refining capacity in the U.S., such a development is highly unlikely to occur. One proposed provision in the Energy Policy Act of 2005, for instance, went so far as to include incentives offering special considerations for developers interested in constructing and operating new greenfield refineries on former military installations (Loveless, 2005).

Despite the fact that new greenfield refineries are unlikely, several refinery companies have announced considerable expansion projects at their current facilities. In many instances, these expansions will at least double the existing capacity at any given site. Thus, while developers are none too keen on developing new greenfield facilities, they have made numerous commitments to build what is, at least from a capacity expansion perspective, the addition of several new refineries. Some of these upgrades and expansions include the following.

- In September 2007, Motiva Enterprises announced its final decision to proceed with a 325 MBbls/d expansion at its Port Arthur refinery (Shook, 2007). The expansion will increase the refinery's oil throughput capacity to 600 MBbls/d, making it the largest refinery in the U.S. and one of the largest in the world (Shook, 2007). Currently, the largest refinery in the U.S. is Exxon Mobil's plant at Baytown, Texas with a capacity of 575 MBbls/d (Shook, 2007). Originally, the additional production capacity was slated to come online in 2010. However, this date has been revised to the first quarter of 2012. Motiva cited cost concerns and lower refined products demand as the reasons for the slowdown (Platts Oilgram Price Report, 2009).

- In 2007, Marathon Oil Corp began construction of a $3.2 billion addition to its largest refinery in Garyville, LA, which is the site of the last greenfield refinery development in the U.S. The addition will increase the refinery's crude throughput capacity by 180 MBbls/d and is expected to be completed sometime during the fourth quarter of 2009 (Marathon Oil Corporation, 2005; SEC, 2006p). The expansion will create almost 200 full-time jobs and generate $40 to $50 million in sales taxes for St. John the Baptist Parish during construction (St. Martin, 2007). As of late 2009, the project was on schedule and budget.

- In 2007, Placid Refining Co., LLC began a $300 million upgrade to increase crude capacity from 55 MBbls/d to 80 MBbls/d (Placid Refining Company, LLC., 2007). The upgrade was planned in two phases. The first phase, completed in 2008, was a $200 million project that debottlenecked downstream units, installed environmental upgrades, and permitted the use of higher-sulfur crudes (Evans, 2009). The second phase was expected to include the capacity increase and upgrade the reformer, diesel hydrotreater, and FCC (Evans, 2009). However, due to the weak economy, this phase of the project has been delayed from 2010 to 2012 (Evans, 2009).

- In March 2008, Chevron announced plans to develop a pre-commercial plant for the primary purpose of testing the technical and economical feasibility of a breakthrough heavy oil upgrading technology near the site of its existing refinery in Pascagoula, MS. The technology, called Vacuum Resid Slurry Hydrocracking (VRSH), will potentially raise yields of gasoline, diesel, and jet fuel from heavy and ultra-heavy crude oils. The plant is anticipated to begin operations in 2010 (Evans, 2008a). However, Chevron has announced its intention to discontinue the plan to expand its refining capacity by 200 MBbls/d at the same refinery site. The decision was made due to "rising costs and other factors (Evans, 2008b; Moore, 2008)."

- In November 2007, Valero Energy Corp announced a major expansion of its refinery outside of New Orleans. The Norco, LA refinery expansion was anticipated to increase diesel production by 49,000 barrels a day and gasoline production by 11,000 barrels a day. The construction was anticipated to employ 1,500 people over a two-year period, and it is expected to cost $1.4 billion. The capacity expansion announcement anticipated commercial operations from the project to begin in 2010 (Investrend, 2007).

- ExxonMobil announced in 2008 the expansion of its middle distillate refining capabilities in Baton Rouge. The project began development in 2008 and is anticipated to be fully operational in 2010. The project will expand middle distillate production, primarily diesel fuel, by 143 MBbls/d (ExxonMobil, 2009).

- Murphy Oil was recently permitted to expand their refinery in Meraux, Louisiana, which was heavily damaged during Hurricane Katrina. Murphy's development plans include the addition of four large storage tanks as well as the development of an on-site new $5 million laboratory and testing facility (Rioux, 2008).

The EIA estimates that U.S. distillation capacity will grow from a level of 17.3 MMBbls/d in 2006 to 17.6 million barrels per day in 2020 and 18.6 million barrels per day in 2030 (USDOE, EIA, 2007c). Refineries will continue to be utilized intensively, at a range of 89 to 93.5 percent. Net imports of crude oil are expected to increase at an annual growth rate of 0.7 percent per year, from 10.09 million barrels per day in 2006 to 10.15 million barrels per day in 2020 and 11.83 million barrels per day in 2030. Net product imports are expected to increase from 2.36 million barrels per day in 2006 to 2.98 million barrels per day in 2030, an increase of 26 percent (USDOE, EIA, 2007c). The development of new automobile fuel standards, new biofuel and blending requirements, and the continued substitution of traditional fossil fuel automobiles to electric, electric-hybrid, and alternative fuel vehicles (e.g., natural gas/propane) continues to create continued uncertainty for refiners and future capacity additions.

12.4. Chapter Resources

Department of Energy, Energy Information Administration

The EIA's petroleum site provides statistics on petroleum refining and processing. These data include inputs, utilization, production, and capacity.
http://tonto.eia.doe.gov/dnav/pet/pet_pnp_top.asp

In addition, the EIA's Refinery Capacity Report is a data series that includes fuel, electricity, and steam purchased for consumption at the refinery; refinery receipts of crude oil by method of transportation; current and projected capacities for atmospheric crude oil distillation, downstream charge, production, and storage capacities. Respondents are operators of all operating and idle petroleum refineries (including new refineries under construction) and refineries shut down during the previous year, located in the 50 States, the District of Columbia, Puerto Rico, the Virgin Islands, Guam, and other U.S. possessions.
http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html

A number of analysis reports can also be found on the EIA's website.
http://tonto.eia.doe.gov/dnav/pet/pet_pub_analysis_pnp.asp

Oil and Gas Journal

This is a subscription-based publication. It publishes an annual survey that shows plant-by-plant details combined with an analysis of global refining trends. Capacity and production details for more than 650 refineries plants around the world are included.
http://www.ogj.com/index.cfm

U.S. Securities and Exchange Commission

Quarterly and annual reports of operations for publicly traded companies are filed with the Securities and Exchange Commission.
http://www.sec.gov/edgar/searchedgar/companysearch.html

13. PETROCHEMICAL PLANTS

13.1. Description of Industry and Services Provided

The chemical industry converts raw materials (oil, natural gas, air, water, metals, and minerals) into more than 70,000 different products (Figure 108) (USDOE, EIA, 2000b). After natural gas is processed and crude oil is refined, the non-fuel components are typically used as a feedstock, forming the production basis for what is known as "petrochemicals." Petroleum is composed mostly of hydrogen and carbon compounds (called hydrocarbons). It also contains nitrogen and sulfur, and all four of these ingredients are valuable in the manufacturing of chemicals. Because these chemicals are derived from petroleum, they are named *petrochemicals*.

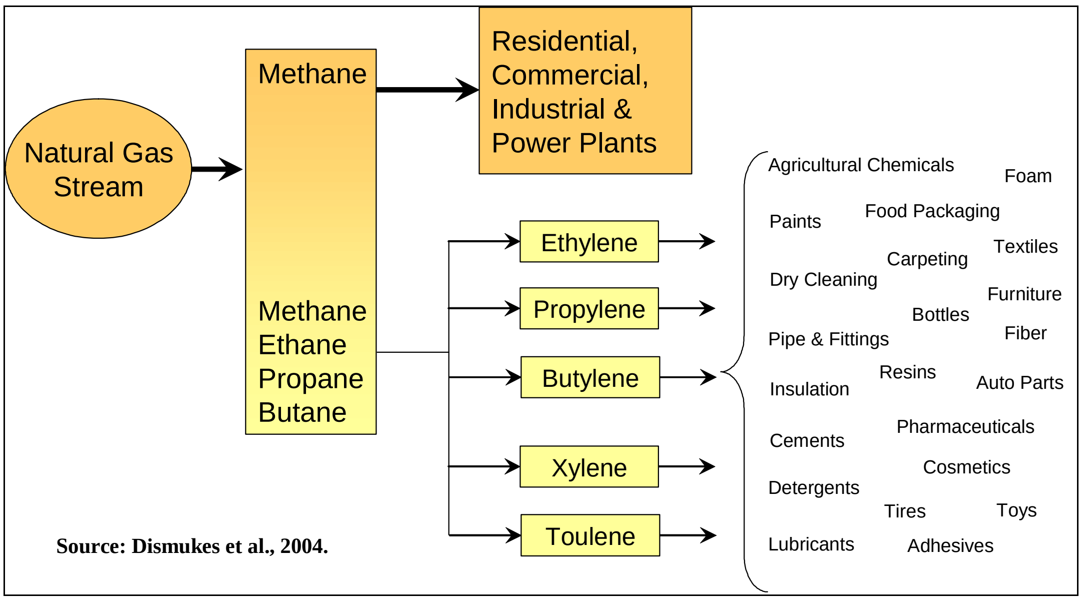


Figure 108. Natural gas components and petrochemical products.

The petrochemical industry is somewhat amorphous and can be difficult to define, particularly around the boundaries. The upstream side of the business is typically defined by the production and primary use of crude oil and natural gas by-products. As one moves downstream, the introduction of industries and facilities that combine petrochemical manufacturing and other organic chemistry-based industries such as plastics, synthetic fibers, agricultural chemicals, paints and resins, and pharmaceuticals are usually included (Tussing and Kramer, 1981). Quite often, companies owning and operating facilities in this industry are petroleum companies who have broadened their interests into chemicals, chemical companies who buy petroleum raw materials, and joint ventures between chemical and petroleum companies. For instance, Shell, ExxonMobil, and Occidental Petroleum have chemical/petrochemical operations. In fact, co-location of chemical and refining operations creates efficiencies and synergies that keep many of these facilities operational in an otherwise mature high-cost environment that defines North American and European operations.

The transformation of raw hydrocarbons into intermediate and final chemical products requires chemical, physical, and biological separation and synthesis processes (Table 40). These processes expend large amounts of energy for heating (heat, steam), cooling, and electrical power. Separations play a critical role and account for 40 to 70 percent of both capital and operating costs. Distillation, which is comprised primarily of subjecting a feedstock to high temperatures, like a boiling process, is the most widely used chemical separation process and accounts for as much as 40 percent of the chemical industry's energy use (USDOE, EIA, 2000b). Chemical synthesis and process heat also play major roles in nearly all chemical operations along the GOM.

Table 40

Industry Specific Technologies

Unit Operation	Purpose	Major Technologies
Separations	Separate products, remove contaminants, dry solids	Distillation, extraction, absorption, crystallization, evaporation, drying, steam stripping or cracking membranes
Chemical Synthesis	Synthesize chemicals, polymers and resins	Catalytic reactions (oxidation, hydrogenation, alkylation) and polymerization, hydration, hydrolysis, electrolysis
Process Heating	Drive chemical reactions and separations; can be direct or indirect	Direct heating: furnaces, kilns, dryers Indirect heating: boilers, heat exchangers Heat transfer fluids: steam, boiling water, organic vapors, water, oils and air

Source: USDOE, EIA, 2000b.

The industrial organic chemical sector includes thousands of chemicals and hundreds of processes that are based upon a set of building blocks (petroleum-based feedstocks) which are combined in a series of reaction steps to produce both intermediate and end-products. Important petrochemical processes include (Waddams, 1969):

1. *Distillation*. A technique of separation that uses the difference in volatility or boiling points of different components in an input stream or a combination of input streams. The use of successive vaporization and condensation processes (into higher and lower temperatures and successive extractions) separates the input streams into progressively lighter or heavier portions.

2. *Solvent Extraction*. Input streams using this process are separated through the use of some liquid component with solvent or solvent-type characteristics. This operation is used for the separation of components by types, for example, the separation of aromatics from paraffins.

3. *Crystallization*. This process runs different input streams or solutions through a filter or centrifuge that, in turn, are subjected to exceptionally cold temperatures, freezing certain components, that can be separated and recovered from those components of less value or interest.

4. *Absorption*. Under this process, a component of a gas or vaporized input mixture is separated by selective absorption, usually in a liquid solvent. The operation is commonly carried out in a packed tower.

5. *Adsorption*. This process utilizes certain highly porous materials (e.g., activated charcoal, silica gel) which can condense various component vapors on their surface for potential extraction and recovery. In some instances, adsorption can be operated selectively and can remove one component from a mixture or input stream.

6. *Cracking*. This process typically breaks down large hydrocarbon molecules into molecules of lower molecular weight through the absence of air by high temperature alone or by a combination of high temperature and catalytic activity.

7. *Reforming*. This refers to processes that use heat and usually a catalyst to transform hydrocarbons into other hydrocarbons or mixtures of hydrocarbons and oxides of carbon, with air or steam taking part in the reaction.

8. *Alkylation*. This is usually the reaction of a hydrocarbon, such as an alkane or aromatic, with an olefin using an acid or other catalyst.

9. *Isomerization*. This process rearranges atoms within a particular molecule and is commonly applied to the conversion of normal paraffin to the isoparaffin.

10. *Polymerization*. A polymer results from a catalyst being employed to form very large molecules from small molecules.

13.2. Industry Characteristics

13.2.1. Typical Facilities

Petrochemical plants are usually located in areas with close proximity to raw materials (petroleum-based inputs) and multiple transportation routes, including rail, road, and water. In many instances, such as development along the GOM, chemical plants arise because of their close proximity to other plants, which can often be their best customers. As noted earlier, it is common for large integrated oil and gas companies that own refineries to have nearby chemical plant affiliates to take advantage of particular waste streams.

Laid out like industrial parks, most petrochemical complexes include plants that manufacture any combination of primary, intermediate, and end-use chemical products. Changes in market conditions and technologies are often reflected over time as input and product slates are changed.

In general, petrochemical plants attempt to run in an "optimized" fashion by attaining the cheapest manufacturing costs and producing the largest level of output while taking advantage of any and all co-locational synergies. Product slates and system designs are carefully coordinated to optimize the use and output of chemical by-products and to use steam, heat, and power as efficiently as possible.

The petrochemical industry is very energy intensive and uses a variety of energy sources, nearly 50 percent of which are used as feedstock. According to the EIA's Manufacturing Energy Consumption Survey, 2002 (the latest available), the chemical industry uses 6,465 trillion Btu per year (fuel and non-fuel), which is 29 percent of the total energy used by the nation's manufacturing sector. In addition, the chemical industry is the single largest consumer of natural gas (over 35 percent of the domestic total) and uses nearly all the liquefied petroleum gas (LPG) and natural gas liquids (NGL) consumed in U.S. manufacturing (see Figures 109 and 110) (USDOE, EIA, 2002b).

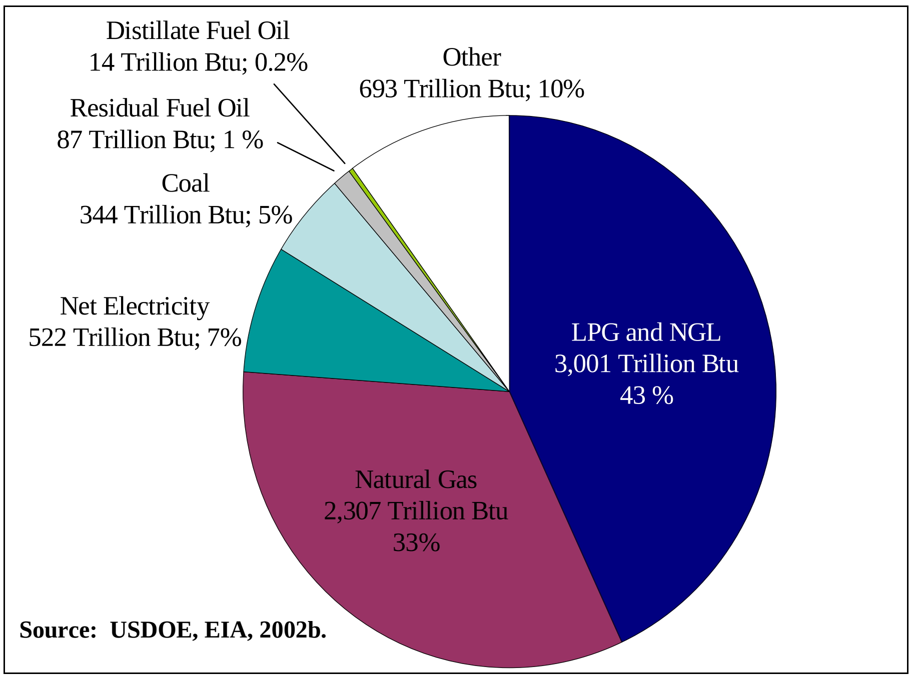


Figure 109. Chemical industry first use of energy for all purposes (fuel and nonfuel), 2002 (trillion Btu).

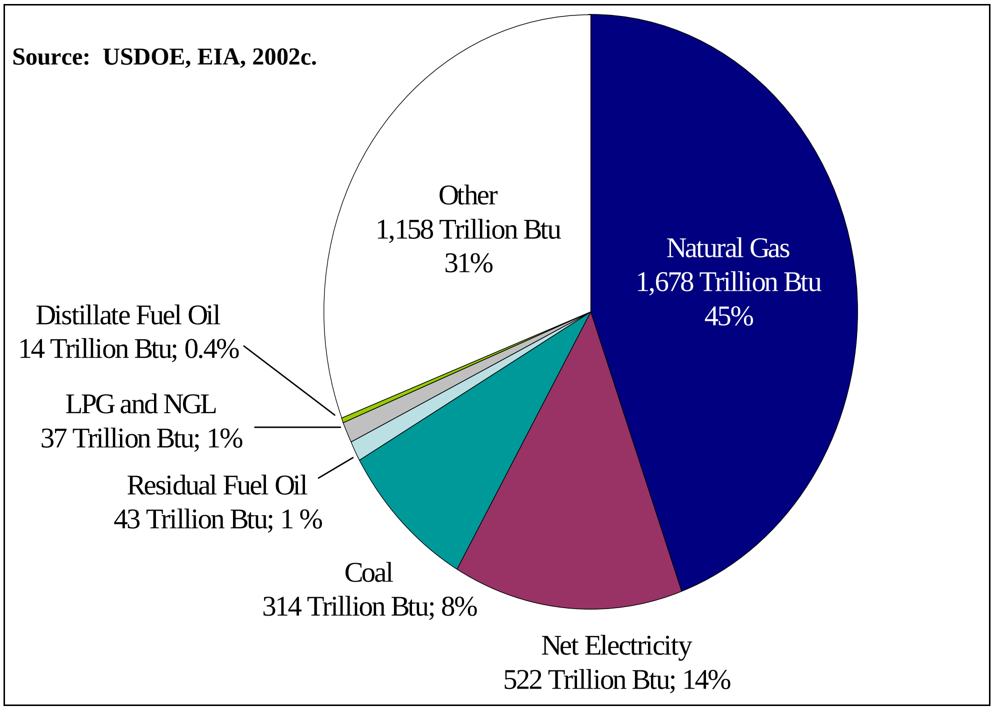


Figure 110. Chemical industry fuel consumption, 2002 (trillion Btu).

Petrochemicals, as defined by the U.S. Census Bureau, (ethylene, propylene, among others) have the third largest energy requirements of all chemical sectors (Figure 111). Inorganic chemicals have the lowest energy requirement since they are made from ores, air, and water, and therefore, require little or no feedstock energy.

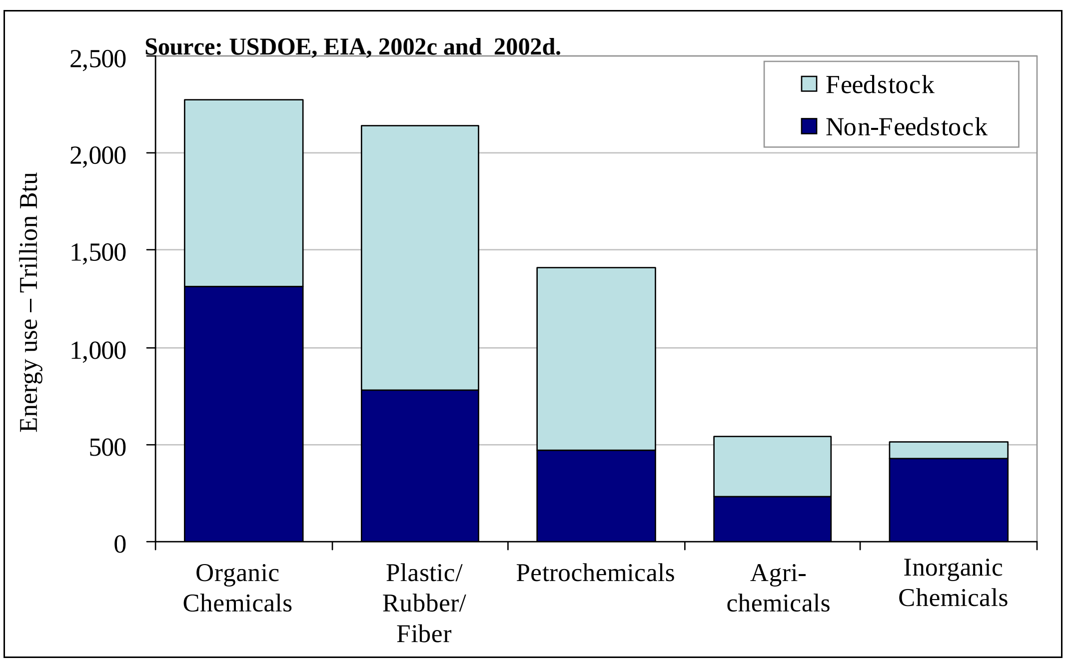


Figure 111. Chemical industry sector energy use (trillion Btu).

Figure 112 illustrates the types of energy used for feedstock, as well as the amount of each type. Liquefied petroleum gases (comprised of a variety of different hydrocarbon gases/liquids that include ethylene, ethane, propane, butane, butylene, propylene, among others) serve as feedstock for the production of polyethylene, polypropylene, and a number of other products. In addition, natural gas is used to produce ammonia, a raw material used in the production of many fertilizers (USDOE, EIA, 2002b).

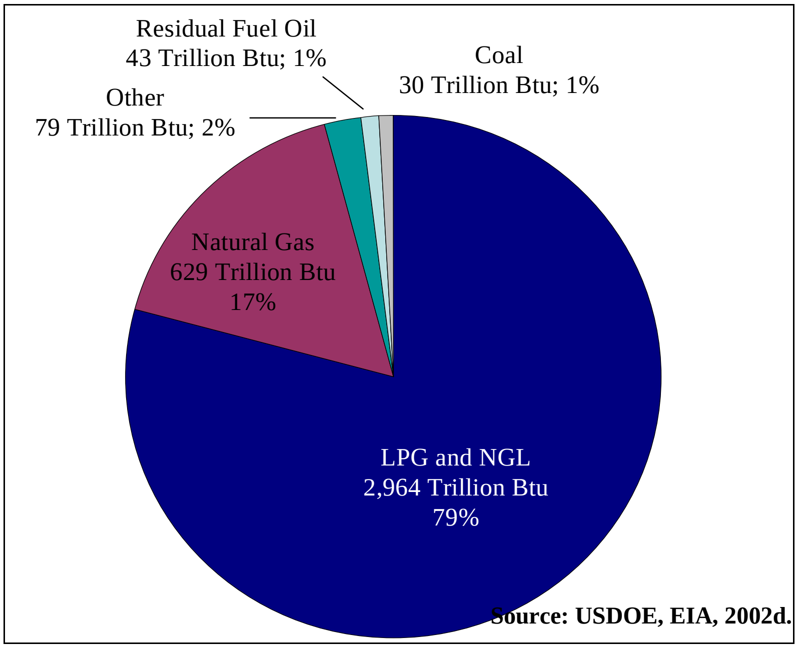


Figure 112. Fuel use for feedstock, 2002 (trillion Btu).

Ethylene Production

There are a variety of petrochemical facilities located in various parts of the country and operated by different companies that use raw materials to produce various end-products. Even along the GOM, there can be many different plant configurations, sizes, and input and output mixes. One commonly recognized building block for modern petrochemicals is ethylene, which serves as a core component in a myriad of consumer products such as detergents, cosmetics, textiles, and antifreeze. Ethylene is also an important input for different types of plastics, including polyethylene plastics, from which items such as trash bags and milk jugs are made. Ethylene is also used within the industry for the production of other derivative products.

Ethylene is mainly produced through the steam cracking of hydrocarbon feedstock. Feedstock used for steam cracking ranges from ethane to naphtha and gas oils. Some ethylene is also produced as a by-product of petroleum refining. Along the GOM, ethylene is commonly stored in large underground (salt) caverns, where it is extracted when needed and transported to facilities or customers through a pipeline system or fully refrigerated ships. The GOM has a very flexible source of supply of ethylene. Large amounts are either produced or imported via ships along the coast or up the Mississippi River.

Olefin plants, which are a broader class of petrochemical plants, have existed along the GOM for well over 50 years. These plants have grown considerably in size over the past few decades as facilities attempt to attain higher efficiencies by operating on a greater scale. The output of olefin plants was formerly recorded in pounds per year but is now measured in tons per year. Today, a so-called "world-scale plant" (the size that achieves whatever is currently considered full economies of scale) can often be larger than many medium-sized refineries (Burdick and Leffler, 1990).

The early olefin plants were designed to use only ethane and propane as feedstock, mostly because of the high output ratio of ethylene that these two fuels could produce. During the energy crisis of the late 1970s, it was believed that natural gas resources were going to be exhausted, and therefore, new plants that used heavier feedstock, such as naphtha and gas oils, were developed. As late as the early 1990s, olefins plants produced approximately half of ethylene yields. With the introduction of the mega-plants and the increased availability of natural gas, as well as a relatively broader world trade in liquid hydrocarbons, the olefins industry is currently moving back toward the use of propane and ethane as feedstock. North American ethylene rated capacity as of December 31, 2006 was approximately 36 million tons per year, with about 77 percent of that capacity located along the Gulf Coast (SEC, 2006t).

13.2.2. Geographic Distribution

Texas, New Jersey, Louisiana, North Carolina, and Illinois are the top domestic chemical producing states. However, most of the basic chemical production is concentrated along the Gulf Coast, where petroleum and natural gas feedstock are available from refineries. Of the top ten ethylene production complexes in the world, five are located in Texas and one in Louisiana. These six production complexes account for 30 percent of the U.S. ethylene production capacity (Nakamara, 2005).

Along the GOM, the petrochemical industry is heavily concentrated in coastal Texas and South Louisiana, and various counties along the Alabama, Mississippi, and Florida coasts. Figure 113 presents a map of all the operational petrochemical plants in the GOM region. In many ways, these petrochemical facilities can be thought of as another form of "hydrocarbon processor." They use natural gas, LPGs, and NGLs to create products much like a refinery takes crude oil and converts it into a variety of products such as gasoline, distillates, kerosene, and other products.

The Houston area is one of the world's largest manufacturing centers for petrochemicals. The Port of Houston is home to a $15 billion petrochemical complex, which is the largest in the nation. The Houston Ship Channel houses 40 percent of the U.S. petrochemical manufacturing plants (Trimble, 2008). It is also home to the several thousand miles of product, LPG, NGL and natural gas pipelines connecting 200 chemical plants, refineries, salt domes, and fractionation plants along the Texas Gulf Coast. The city of Houston also provides easy access to four ports that make the area's petrochemicals accessible to the world (Greater Houston Partnership, 2008).

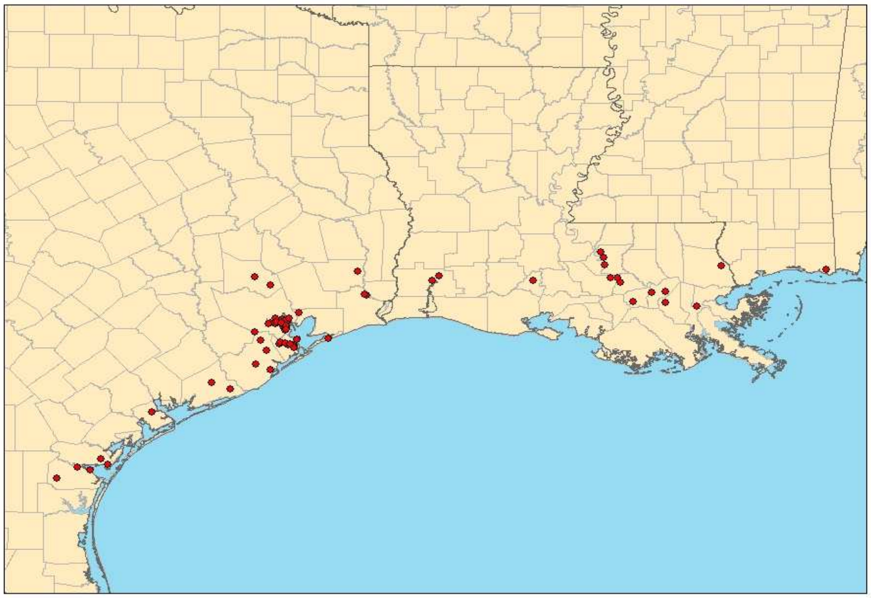


Figure 113. GOM region petrochemical facilities.

As previously mentioned, six of the top ten largest ethylene production complexes in the world are found on the Gulf Coast. The importance of the chemical industry to the economics along the GOM is highlighted in Figure 114. This figure shows the share of chemical industry value added as a percentage of all manufacturing value added for each GOM state. Chemical facilities account for approximately 15 percent of all U.S. value added in total manufacturing (USDOC, BEA, 2008). Compare these statistics to a state like Louisiana that gets over 25 percent of its manufacturing GDP. Texas is also well above the national average, at 27 percent. New Jersey has the highest amount of chemical manufacturing as a percent of total manufacturing 44 percent. Mississippi and Alabama have a chemical industry less than half the size of Texas and Louisiana, and while important along the GOM, is significantly less than the national average.

Figure 115 provides a comparable regional comparison on an employment basis. Chemical industry employment accounts for approximately six percent of total U.S. manufacturing employment. Louisiana, however, is home to a petrochemical sector that accounts for over 14 percent of its total manufacturing employment base. Texas chemical employment is considerably lower than Louisiana on a relative share basis, but is still higher than the national average and is the second highest percentage among GOM states.

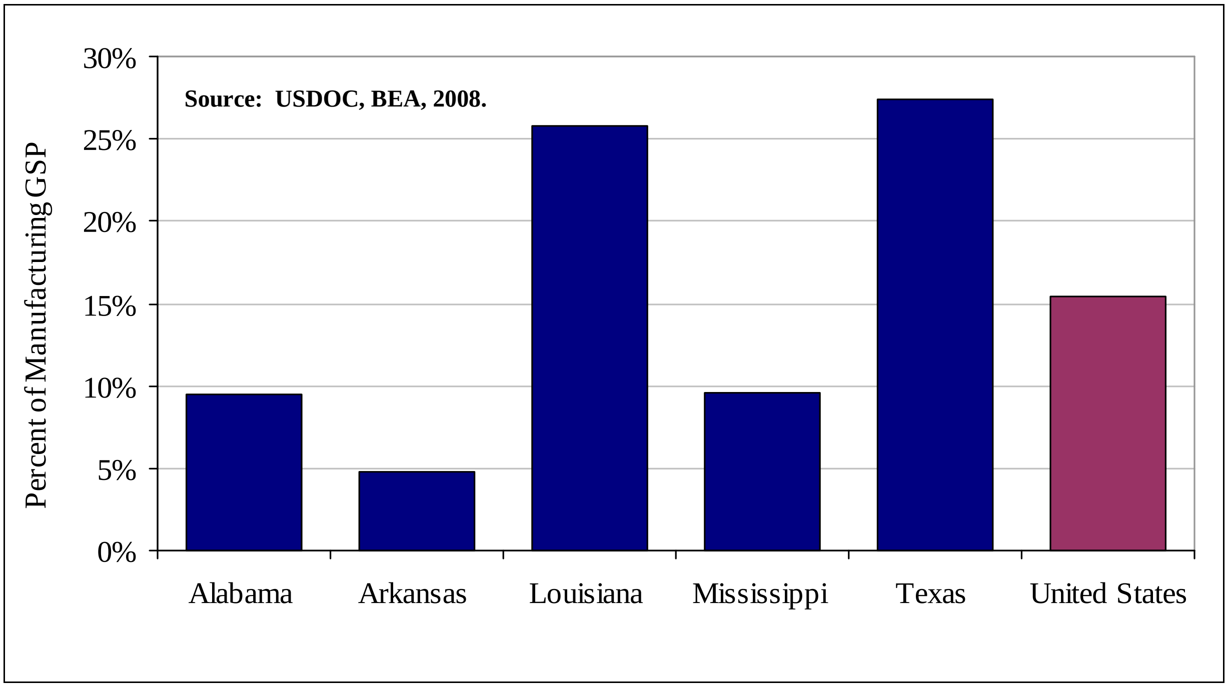


Figure 114. Chemical industry portion of state manufacturing GDP, 2008.

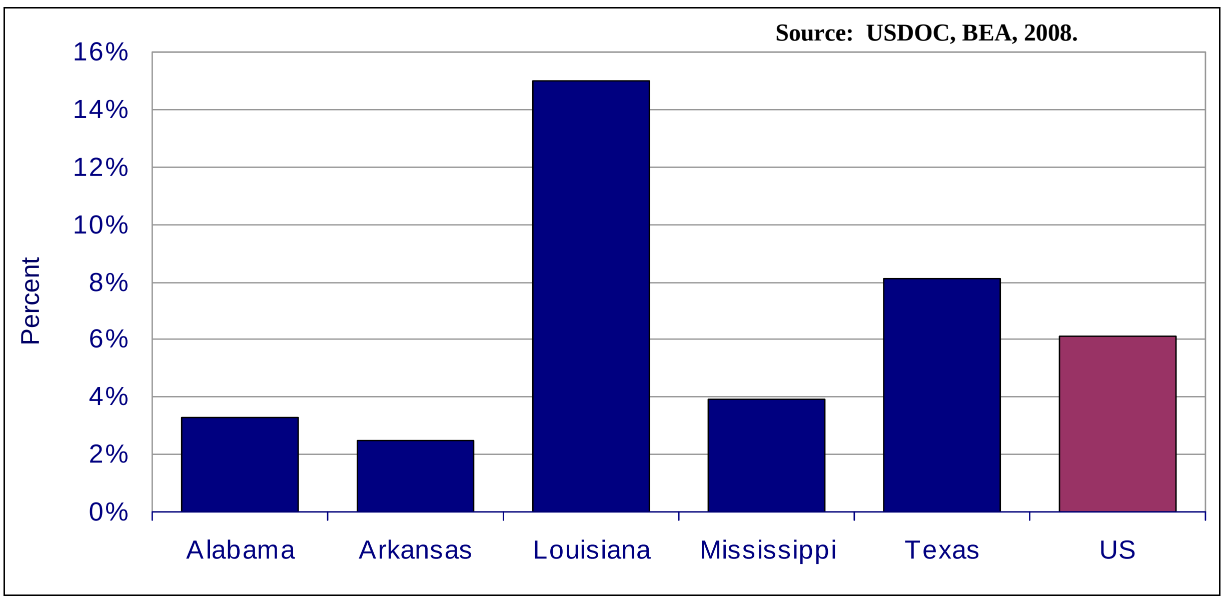


Figure 115. Chemical industry employment as a percent of total manufacturing employment, 2005.

13.2.3. Typical Firms

Companies that have the ability to utilize a large amount and broad range of feedstocks, including heavy liquids, historically have a competitive advantage in the petrochemical industry. Competition is based upon price, product quality, product delivery, reliability of supply, and product performance. Like refining, recent industry consolidation has brought North American petrochemical production capacity under the control of fewer companies (SEC, 2006t). Competition for market share is intense and fought for by both chemical corporations and chemical divisions of major international oil companies. Competition between these entities has historically been quite strong, and it is expected to continue in the future (SEC, 2006u).

Dow Chemical is one of the largest domestic petrochemical companies in the world. They operate 150 manufacturing sites, 55 percent of which are located within the U.S., with the remaining 45 percent located in 36 countries around the world. Dow Chemical uses two major raw material streams: (1) salt, limestone, and natural brine; and (2) hydrocarbons, including LPGs, crude oil, NGLs, natural gas, and condensate. The hydrocarbon raw materials account for 49 percent of the company's production costs and are purchased on both short- and long-term contracts (SEC, 2006u). Research and development comprises a significant portion of Dow's business, employing 5,600 people (out of a 42,413 total) and accounting for $1.2 billion in expenditures. R&D at Dow has led to 34 patents. In 2006, R&D contributed close to $512 million in royalty revenue (SEC, 2006u). Dow Louisiana is the largest petrochemical company in the state, contributing more than $1 billion annually into the Louisiana economy (Dow Chemical, 2008). Dow Louisiana has five sites within the state and manufactures more than 100 basic and specialty chemicals that are shipped worldwide (Dow Chemical, 2008).

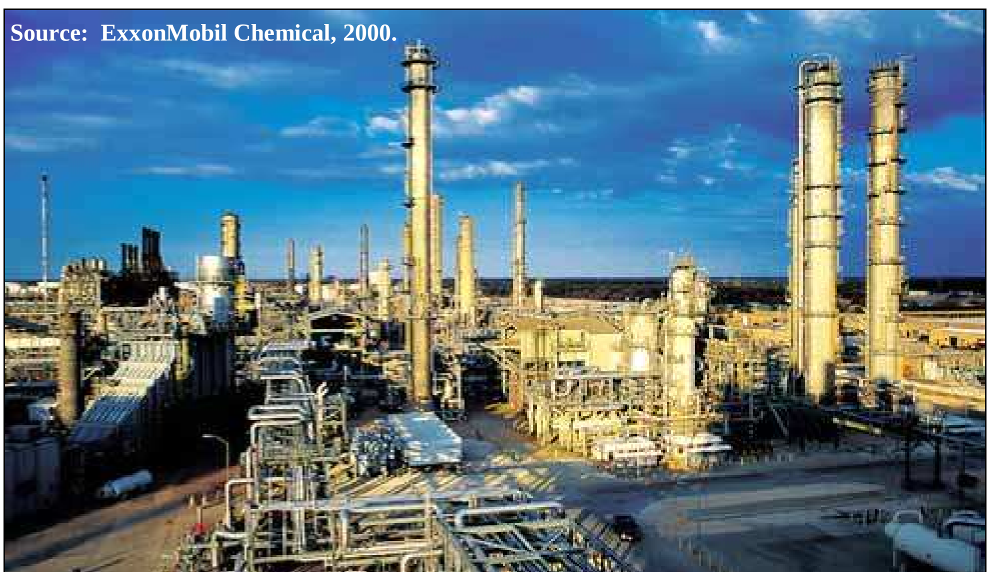
Union Carbide Corporation (UCC) began operations in 1920 when their researchers developed an economical way to make ethylene from natural gas, giving birth to the modern petrochemical industry. In 2006, UCC spent $71 million on research and development. UCC research has contributed in the development of 1,800 U.S. and foreign patents that relate to a wide variety of products and processes. In 2006, UCC reported having 3,800 employees with 15 manufacturing sites in six countries (SEC, 2006v). All of UCCs major production sites are located within the U.S., with three along the Gulf Coast. In 2001, UCC became a subsidiary of The Dow Chemical Corporation (SEC, 2006v).

Equistar Chemicals, a subsidiary of Lyondell Chemical Company, is one of North America's largest chemical manufacturers and maintains its headquarters in Houston, Texas. Equistar produces ethylene, co-products, and derivatives at 15 facilities throughout five states in the U.S. Ethylene sales accounted for about 12.5 percent of total revenues from 2004 to 2006, and polyethylene products represented about 23.5 percent during the same period. Equistar is the second largest producer of ethylene and the third largest of polyethylene in North America. Most of their ethylene is consumed as a raw material in the production of derivatives or is shipped by pipeline to customers. The majority of their ethylene and propylene production at the Channelview, Chocolate Bayou, Corpus Christi, and La Porte facilities is shipped via pipeline to Gulf Coast consumers, usually other petrochemical producers. Equistar, like other petrochemical and midstream companies, uses exchange agreements to share capacity along product and input pipelines in order to reach more consumers (SEC, 2006t).

Enterprise Products Partners (EPP) is primarily an upstream petrochemical company that focuses on providing feedstocks to other, larger integrated petrochemical companies. EPP also provides feedstocks used in the refining/production of motor gasoline. EPP has a total of 1,100 employees in all of their divisions. In 2006, EPP's petrochemical division contributed about 11 percent to overall company consolidated revenues. EPP's petrochemical division includes four propylene fractionation facilities, an isomerization complex, and an octane addition production facility. In addition, EPP owns, operates, or contracts on approximately 679 miles of petrochemical pipeline systems to move products between various sources of supply to demand. EPP's propylene fractionation business is primarily located in Louisiana and Texas, while its isomerization business, the largest complex in the U.S., is located in Mont Belvieu, Texas, a commonly recognized hub for transporting, storing, and trading NGLs and LPGs. In March 2006, EPP announced plans to develop two new propylene fractionators at their Mont Belvieu, Texas facility, as well as the expansion of two refinery-grade propylene pipelines (SEC, 2006q).

The chemical operations of ExxonMobil have origins that date back to the beginning of the petrochemical industry in 1920 with its commercialization of isopropyl alcohol, the first chemical product made from petroleum. ExxonMobil's chemical operations (ExxonMobil Chemical) also invented butyl rubber and the process of steam cracking, which is widely regarded as the engine of most chemical complexes (ExxonMobil Chemical, 2000; ExxonMobil 2007). ExxonMobil has 20 chemical manufacturing sites, located in more than 150 countries around the world (ExxonMobil Chemical, 2008a). ExxonMobil is able to use its vertical integration from upstream refining processes (refining and feedstock production) to downstream chemical operations in order to tap synergies and significant efficiency gains of co-locating refinery and chemical operations. In fact, over 90 percent of ExxonMobil's chemical production capacity is integrated with its refining complexes or natural gas processing plants (which produce feedstock NGLs). ExxonMobil is one of the largest producers of olefin and polyolefins, including polyethylene and polypropylene (Figure 116). Over the past several years, ExxonMobil has made announcements indicating the development of two new chemical facilities in Texas (an expansion from the existing four facilities already located throughout Texas), three new chemical operations in Louisiana, and seven additional expansions throughout other locations scattered about the U.S. (ExxonMobil, 2006b; ExxonMobil Chemical, 2008a and b).

Source: ExxonMobil Chemical, 2000.



The Baytown, Texas, olefins plant is one of the world's largest and also one of the safest.

Figure 116. ExxonMobil's Baytown, Texas olefins plant.

13.2.4. Regulation

Petrochemical plants are affected by nearly all federal environmental statutes. The industry is also subject to numerous laws and health, safety, and environmental regulations from state and local governments. The following is a summary of the major federal environmental regulations that affect the chemical industry (USEPA, 1995b).

Toxic Substances Control Act (TSCA)

TSCA gives the EPA "comprehensive authority to regulate any chemical substance whose manufacture, processing, distribution in commerce, use, or disposal may present an unreasonable risk of injury to health or the environment (USEPA, 1995b)." There are three sections that are most relevant to the organic chemical industry. TSCA §5 requires chemical companies to submit pre-manufacture notices that provide information on health and environmental effects for each new product and tests existing products for these effects. TSCA §4 authorizes the EPA to require testing of certain substances. TSCA §6 gives the EPA authority to prohibit, limit, or ban the manufacture, process, and use of chemicals (USEPA, 1995b).

Clean Air Act (CAA)

The original CAA of 1970 authorized EPA to set limits on chemical plant emissions. The CAAA of 1990 set control targets by industrial sources for 41 pollutants to be met by 1995 and another 148 pollutants to be met by 2003. In April 1994, the EPA proposed regulations to reduce air toxic emissions at chemical plants. The Hazardous Organic National Emissions Standard for Hazardous Air Pollutants, also known as "HON," covers hundreds of chemical plants and thousands of chemical process units (USEPA, 1995b). The HON also includes new provisions such as emissions trading (cap and trade mechanism), which offer industry flexibility in complying with the rule's emissions goals. Subsets of the industry are regulated under other National Emission Standards for Hazardous Air Pollutants (NESHAP). These include vinyl chloride manufacturers, benzene emission from ethyl benzene/styrene manufacturers, benzene equipment leaks, emissions from storage tanks, benzene emissions from benzene transfer operations, and benzene waste operations (USEPA, 1995b).

Other standards that EPA sets through the CAA are the National Ambient Air Quality Standards (NAAQS) (40 CFR part 50), which regulates pollutants considered harmful to public health and the environment (USEPA, 2008a). These standards underwent changes in June 2006 that were expected to create new operational challenges and possibly additional new capital investments for refining and petrochemical operations. At the same time, the EPA issued a final particulate matter standards rule designed to strengthen the 24-hour fine particulate standard (NAPRA, 2007) and set new standards that will impact both refinery and petrochemical production along the GOM.

Clean Water Act

The Clean Water Act (CWA) was first passed in 1972 and subsequently amended in 1977 and 1987. The CWA authorizes the EPA to regulate effluents from sewage treatment works, chemical plants, and other industrial sources into waters. In 1987, the EPA proposed final effluent guidelines for the organic, polymer, and synthetic fiber industry which impacts most all petrochemical plants operating along the GOM. The majority of this rule was upheld by the federal courts and a final proposal for the remaining portions of the rule was issued in August 1993. The implementation of the guidelines is left to the state that issues National Pollutant Discharge Elimination System (NPDES) permits for each facility (USEPA, 1995b).

Superfund

The Comprehensive Environmental Response Compensation and Liability Act of 1980 (CERCLA) and the Superfund Amendments and Reauthorization Act of 1986 (SARA) provide the basic legal framework for the federal "Superfund" program to clean up abandoned hazardous waste sites. In 1986, SARA legislation extended the applicable Superfund taxes and fees for an additional five years in addition to establishing a new broad-based corporate environmental tax (USEPA, 1995b). In 1990, the program authority was extended until 1994 with taxing authorization extended to 1995. The EPA estimated that the chemical industry pays, on average, about $300 million a year in Superfund chemical feedstock taxes (USEPA, 1995b).

Title III of the 1986 SARA amendments (also known as Emergency Planning and Community Right-to-Know Act, EPCRA) requires all manufacturing facilities, including chemical facilities, to report annual information to the public about stored toxic substances as well as release of these substances into the environment (42 U.S.C. 9601). The information submitted by regulated companies is included in a commonly used and cited database referred to as the Toxic Release Inventory (TRI). Between 1988 and 1993, TRI emissions by chemical companies to air, land, and water were reduced by 44 percent. EPCRA also established requirements for federal, state, and local governments regarding emergency planning. In 1994, over 300 more chemicals were added to the list of chemicals for which reporting is required (USEPA, 1995b).

Security

The most recent legislation concerning security for the petrochemical industry was passed in June 2007 and was initiated in response to the terrorist activities of September 11, 2001. The U.S. Department of Homeland Security (DHS) issued an interim final rule that imposes comprehensive federal security regulations for high-risk chemical facilities called Chemical Facility Anti-Terrorism Standards. The rule establishes risk-based performance standards for the security of chemical facilities by requiring covered chemical facilities to (USDHS, 2008):

1. Prepare Security Vulnerability Assessments, which identify facility security vulnerabilities. Some of the facilities may, in specific circumstances, submit an Alternate Security Program instead.

2. Develop and implement Site Security Plans, which include measures that satisfy the identified risk-based performance standards.

13.3. Industry Trends and Outlook

13.3.1. Trends

According to the 2007 U.S. Economic Census, the Chemical industry (NAICS Code 325) consists of 12,937 establishments. This is about four percent less than the 13,476 establishments in 2002. As shown in Table 41, a comparison of the 1997 Economic Census and 2002 Economic Census reveals that the industry is contracting in just about every measure with the exception of the value of payrolls and shipments.[30] The same holds true for Basic Chemical Manufacturing (NAICS Code 3251).[31] For instance, the number of establishments identified as chemical plants decreased from 2,418 to 2,377, and the value of shipments for the domestic basic chemical industry fell from $1.13 trillion to $1.09 trillion. The number of employees also decreased from 200,000 to 180,000. Thus, during this period, the number of establishments dedicated to basic chemical production fell by two percent, the value of shipments for the industry fell by close to four percent, and employment fell by a considerable 11 percent (USDOC, Census, 2002b and 2007).

Despite the decrease in chemical and basic chemical manufacturing, there has been a slight increase in the number of petrochemical establishments (NAICS Code 32511) since 1997. Although the U.S. Census data is not complete for 2007, Table 41 shows that the number of petrochemical establishments has increased by four between 1997 and 2002. However, the number of employees has fallen by over 900 since 1997. Between 1997 and 2002, the petrochemical value of shipments increased about eight percent (USDOC, Census, 2002a and 2007).

Table 41

Chemical Manufacturing Industry

	Companies	Number of Establishments	Number of Employees	Annual Payroll	Value Added	Value of Shipments
				----------------- (billion $) -----------------		
NAICS 325: Chemical Manufacturing						
2007	n.a.	12,937	814,024	$ 49.65	n.a.	n.a.
2002	9,660	13,476	852,297	$ 44.56	$ 253.61	$ 460.42
1997	9,626	13,474	882,645	$ 39.84	$ 224.68	$ 415.62
NAICS 3251: Basic Chemical Manufacturing						
2007	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
2002	1,227	2,377	179,263	$ 10.78	$ 45.51	$ 109.71
1997	1,203	2,418	200,766	$ 10.29	$ 53.74	$ 113.36
NAICS 32511: Petrochemical Manufacturing						
2007	n.a.	56	9,257	$ 0.85	n.a.	n.a.
2002	43	56	9,380	$ 0.66	$ 6.91	$ 21.08
1997	42	52	10,192	$ 0.62	$ 8.36	$ 19.47

Source: USDOC, Census, 1997; 2002a; and 2007.

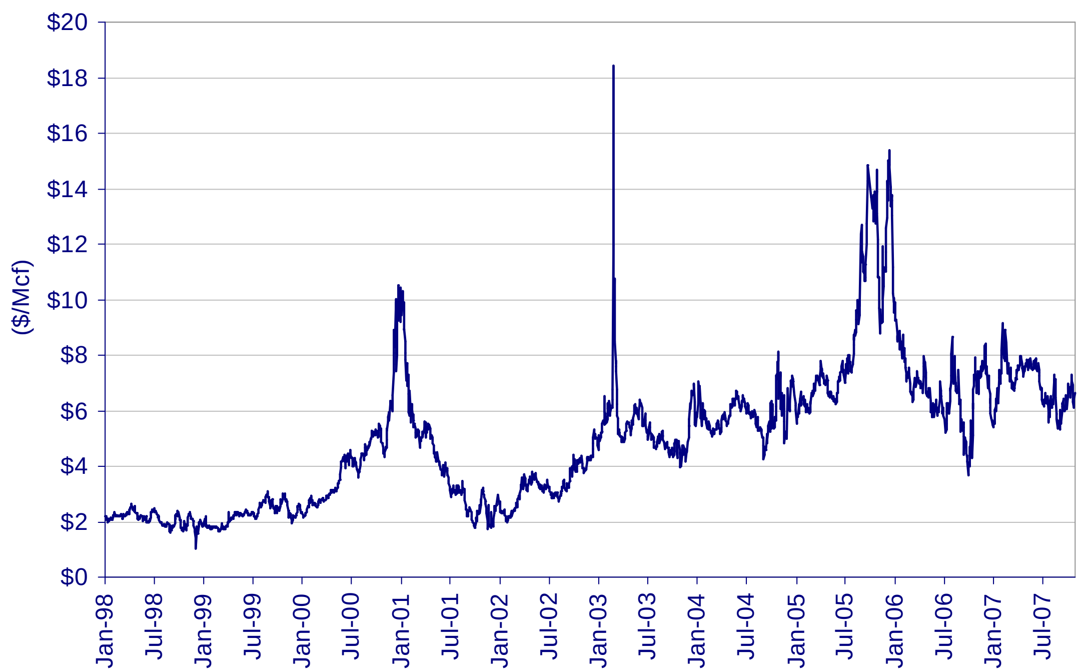
There are approximately 216 chemical facilities in the Gulf Economic Impact Areas.

Price Increase and Volatility

The chemical and petrochemical industry are very sensitive to the change in energy prices since they are both large users of energy for heat, steam, and power purposes, and use a considerable

[30] Complete data is not yet available for the 2007 U.S. Economic Census.
[31] Basic chemical companies are defined as those primarily engaged in manufacturing chemicals using basic processes, such as thermal cracking and distillation.

amount of energy inputs (petroleum and natural gas) as a feedstock. Thus, prices and overall plant profitability can be highly influenced by the price of natural gas and crude oil. Sometimes the changes in natural gas and/or crude oil prices are so quick that it is difficult to pass the increase onto the consumer. In addition, higher North American natural gas prices relative to natural gas cost-advantaged regions, such as the Middle East, have hurt the ability of many domestic chemical producers to compete internationally (SEC, 2006t). Figure 117 shows natural gas price volatility in the U.S. over the past several years.



Source: Intercontinental Exchange, 2008.

Figure 117. Natural gas price volatility.

Figure 118 shows overall employment numbers for the chemical sector, as well as two important sub-sectors highly dependent on natural gas commodities as feedstock: petrochemicals and agricultural chemicals. In his comments before the U.S. Senate Committee on the Environment and Public Works, American Chemistry Council (ACC) President Jack Gerard stated that natural gas costs for the industry alone rose from $7.5 billion in 1999 to over $30 billion in 2005 (Gerard, 2006). These increases have put exceptional strain on chemical industry profitability and performance and, more importantly, employment trends over the past several years.

Figure 118 illustrates the dramatic shift in chemical industry employment since 2000, the year in which natural gas prices began their first surge. The petrochemical industry alone saw a loss of some 1,600 jobs from 2000 to 2001, and another 4,200 jobs lost from 2001 to 2002. Agricultural chemicals, the most dramatically-impacted of all those in the chemical sector, saw 7,500 lost jobs since 2000, a decrease of 21 percent from its 1999 level. While there has been a recent pick up in jobs in 2006, overall industry employment levels are significantly lower than their 1998 levels (USDOL, BLS, 2008).

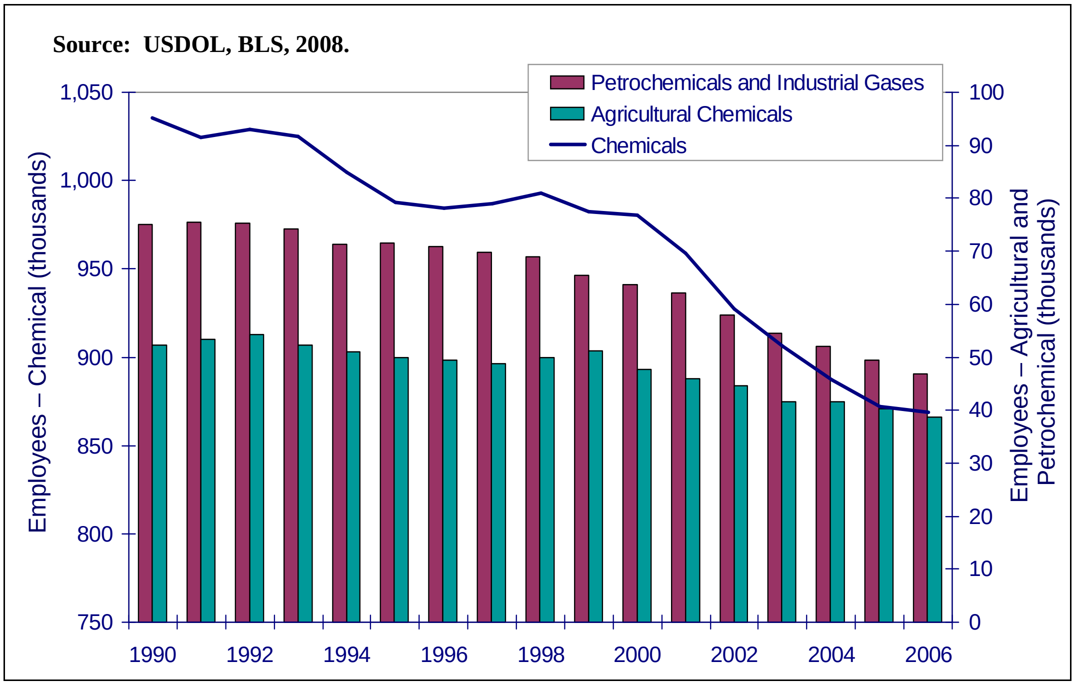


Figure 118. Employment in chemical, fertilizer, and petrochemical industry in the U.S.

Figure 119 illustrates the clear dependency that petrochemical employment has on the natural gas industry and low natural gas prices. The industry, from the end of the Second World War to the early 1970s, was built primarily upon the back of low feedstock costs, which in North America was heavily dependent upon low natural gas prices. Employment levels fluctuated up and down from the early 1970s until recently when natural gas prices started increasing and becoming more volatile. There has been a noticeable decrease in chemical industry employment over the past decade as natural gas prices approached their all time highs.

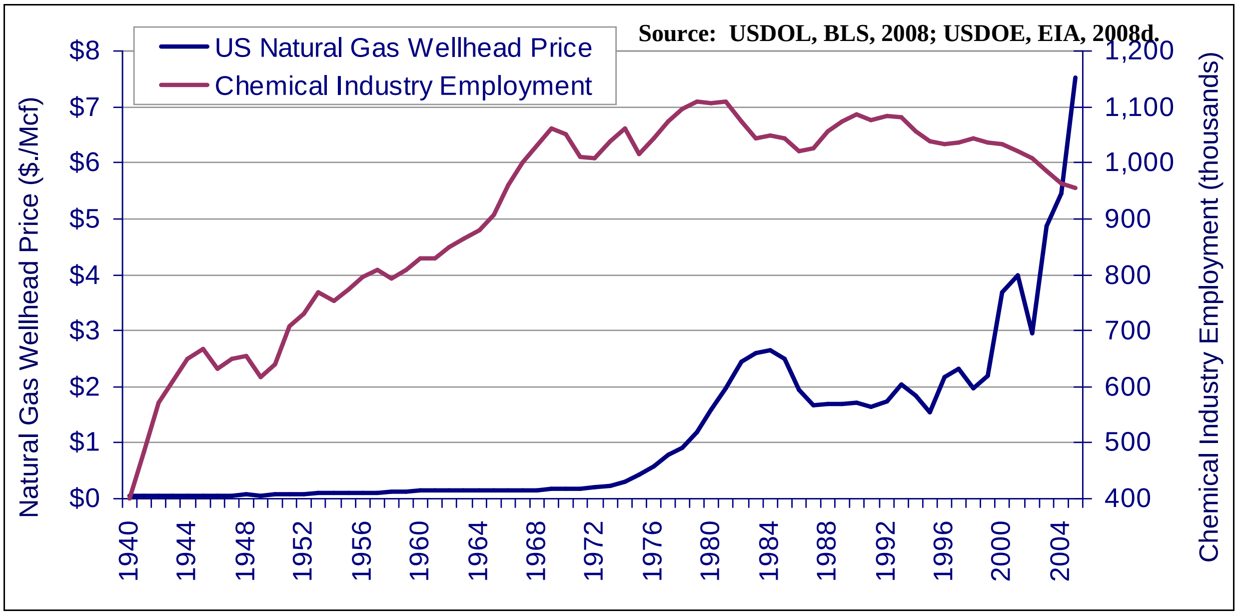


Figure 119. Historic U.S. average wellhead price and chemical industry employment, 1940-2005.

Industry Structure

The National Petrochemical & Refiners Association (NPRA) is a national trade association of over 450 members, including almost all of the U.S. refiners and petrochemical manufacturers. The NPRA 2007 annual report is focused on meeting industry supply challenges. The annual report for 2007 noted increases in refined and chemical product demand and an overall tight market supply/demand balance. There was a report on existing infrastructure challenges in the face of market and investor challenges, hurricane recovery efforts, and progressively more stringent domestic environmental rules (NPRA, 2007).

Another considerable challenge in the industry has been the recent wave of consolidations through various different mergers and acquisitions which have decreased the number of companies and competitors in recent years. These mergers have not led to a major concentration of companies but to anti-trust of other market regulatory concerns. Companies are attempting to achieve economies of scale and other fixed cost savings through strategic combinations. For example, in February 2001 Union Carbide Corp. became a wholly-owned subsidiary of Dow Chemical Co. The acquisition placed Dow as the leading supplier of ethylene in the world.

Greater levels of small-scale specialization have also arisen in a market that has been dominated by major megamergers. Figure 120 highlights many of the global conglomerates of the 1980s splitting into smaller, more customer-focused, specialized companies. Companies in the U.S. are partnering with their counterparts around the world to serve customers more efficiently and profitably (Short, 2007).

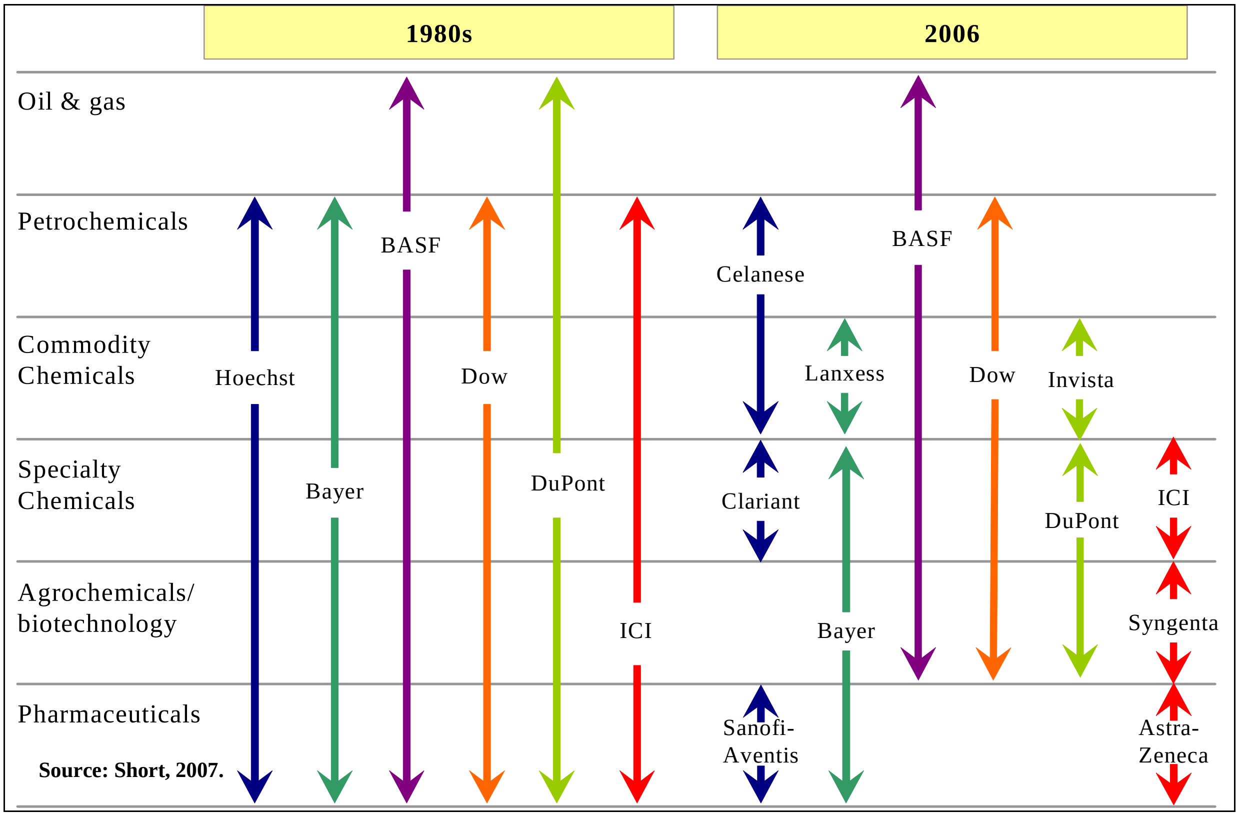


Figure 120. Most of the conglomerates of the 1980s have split into more focused companies.

The other major shift in the foundation of the petrochemical industry has been due to plant closures. According to the ACC, in 2004 alone, 70 plants closed and companies targeted 40 more for shut down in 2005 (USEPA, 2007). Since 1998, Louisiana alone has lost 4,100 chemical industry jobs (Porter et al., 2006). In 2007, Dow announced several plant closures, as did UCC including its polypropylene facility in Lake Charles, Louisiana (Platts Petrochemical Report, 2007). Rising feedstock prices and the quest for greater operating efficiencies has been one of the main culprits for these shut downs. But others have arisen as a result of a capacity oversupply in certain product lines. Some plants that have needed to go off-line for maintenance repairs have simply had their reopening date postponed, or they have reopened with less than 100 percent capacity. The industry has been very quiet about these maneuvers to reduce their operating costs, partly due to the amount of consolidation already taking place (Platts Petrochemical Report, 2006a).

Efficiency and Competition

Due to the reliance upon feedstock prices and energy cost, there has been a growing trend in the petrochemical industry to improve energy efficiency in plants, not only for cost reducing benefits, but also to improve overall emission profiles. Recent analyses suggest that the chemical industry is 60 percent more energy efficient today than it was 30 years ago (NEED, 2007). In fact, the U.S. Department of Energy has targeted the chemical industry as being ripe for energy efficiency R&D through its Industries of the Future program. A division of the DOE is also working with a group of chemical industry executives in a partnership called "Technology Vision 2020" to promote developments in environmentally sound chemical technologies (USDOE, EERE, 2004). Also, the member companies of the ACC have agreed in principle to a greenhouse intensity reduction target of 18 percent from 1990 levels by 2012 (USEPA, 2007). Goals in reducing energy costs are not restricted to efficiency alone, and many companies have been forced to simply shut down operations in the U.S. and move to other areas of the world with lower feedstock and energy costs. Dow, for instance, shut down 23 plants in North America and shifted production overseas to regions with lower energy prices (Reisch, 2005).

The movement of operations to offshore locations is one of the biggest threats to the domestic chemical industry in the U.S. and it is a particularly significant challenge for those facilities located along the GOM. According to CMAI, from 2004 to 2010, 20 million metric tons of new capacity, which is 53 percent of the new capacity anticipated globally during that period, is scheduled to open in the Middle East and Africa. Asia is expected to grow to fulfill 33 percent of the world's new capacity by 2010. If all of this capacity is reached, then North American producers are likely to become competitively disadvantaged and will find their production bound for domestic markets alone. This limits future growth opportunities since the North American chemical product markets are mature and not likely to experience the exceptional growth (and profitability) of serving growth markets in developing countries.

Another serious concern, particularly during cyclical periods of economic downturn, is the potential for lower-cost international overcapacity. This capacity overhang, if lacking in growth markets around the globe, could easily turn their production to North America, driving down further the profitability of more mature facilities along the GOM. There are considerable possibilities, however, that most of the developing regions of the world will not find themselves in a capacity overhang situation.

Environmental regulations, in addition to high energy and feedstock prices, are the second most significant culprit blamed for the premature closure of chemical facilities in North America. Dow Chemical's CEO, for instance, has made a strong public point that U.S. environmental policies are pushing the chemical industry to invest elsewhere. Another complaint by Dow's CEO has been associated with U.S. energy policy, which preferences the use of natural gas for power generation as opposed to other solid fuel resources like coal or nuclear (Reisch, 2005). The use of natural gas for power generation creates a competing use for the chemical industry.

13.3.2. Hurricane Impacts

Hurricanes Katrina and Rita shut down a considerable portion of the U.S. petrochemical production. According to CMAI, Hurricane Katrina forced the shut down of 2.6 million metric tons per year of ethylene cracker capacity (Tullo, 2005) (Figure 121). That capacity equaled 7.5 percent of North America's total chemical production capacity (Tullo, 2005). Hurricane Rita was even more damaging to the industry, resulting in more than 35 percent of North American ethylene capacity being shut down and some 50 percent of all propylene production being temporarily interrupted (Tullo, 2005). Other intermediate and final chemical product production was also interrupted during both hurricanes, including ethylene oxide, acrylonitrile, and benzene. However, despite the interruptions, most petrochemical production was able to resume within three weeks after the storm. Common problems associated with production restoration were associated with restoring power generation and/or transmissions service and feedstock (particularly natural gas) supply. Only nine percent of North American ethylene was still shut-in after Hurricane Rita (Tullo, 2005).

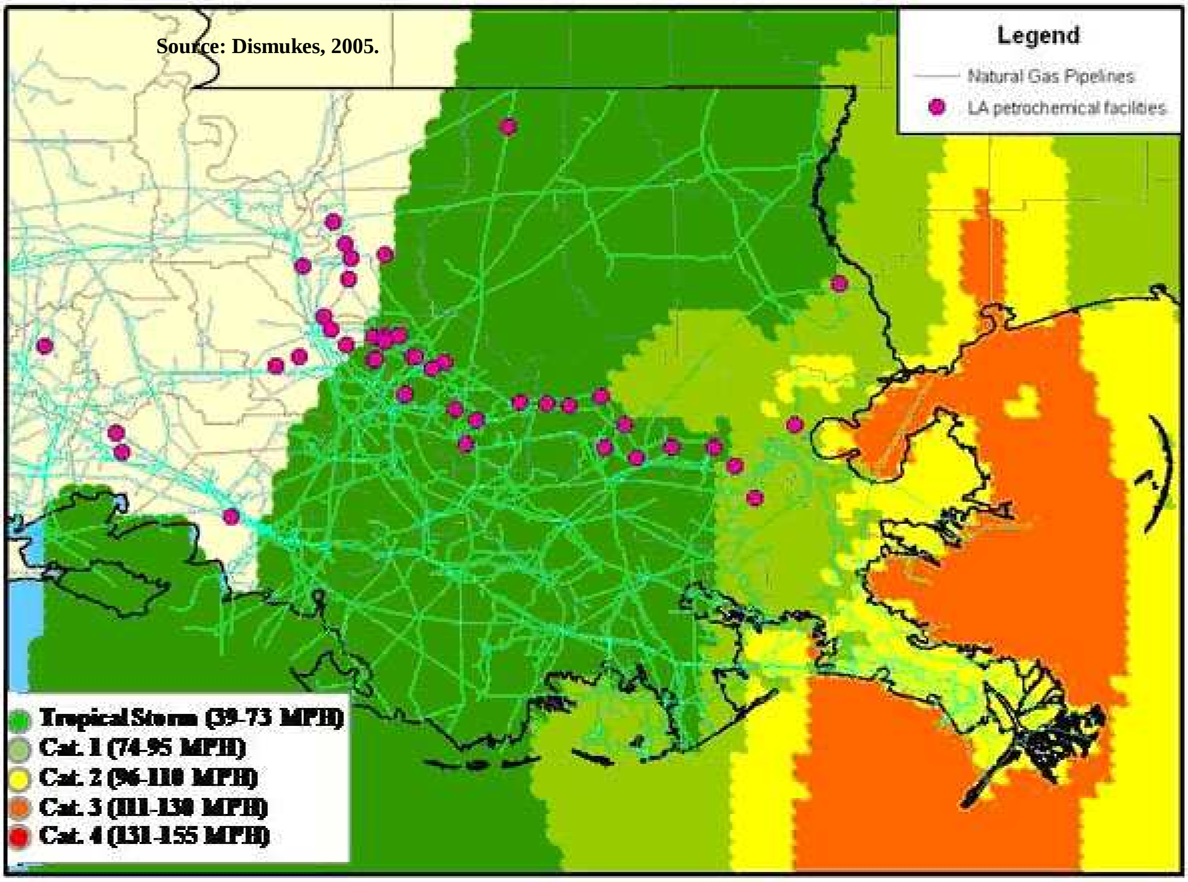


Figure 121. Petrochemical facilities impacted by Hurricane Katrina.

Hurricane Rita severely affected production in Lake Charles, Louisiana and eastern parts of Texas, but spared most major petrochemical plants elsewhere along the GOM (Figure 122). Dow Chemical reported that startup operations at several Texas facilities would take several weeks. Lyondell announced a one month restoration process at its Beaumont plant. Restoration uncertainty was also reported by several other facilities along the Texas Gulf Coast with many indicating that restoration times were indeterminate, even two weeks after the storm (Sim, 2005).

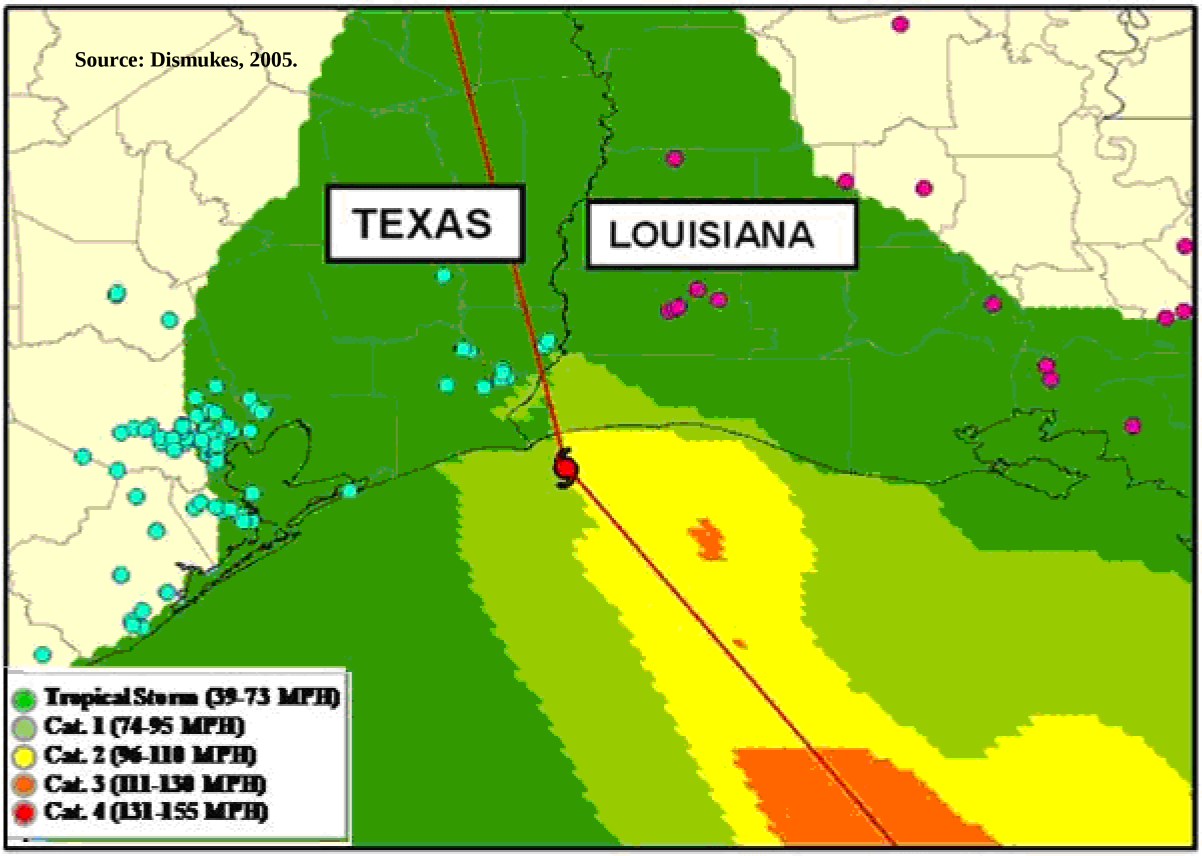


Figure 122. Petrochemical facilities impacted by Hurricane Rita.

Table 42 shows the percentage of chemical production capacity impacted by each 2005 major hurricane along the GOM. Rita's size and landfall uncertainty contributed to the closure of a large number of facilities ranging from the lower Texas Gulf Coast all the way into Louisiana. The storm missed its originally-anticipated destination in the Houston Ship Channel area, but did land within one of the nation's equally important chemical and refining regions between Port Arthur, Texas, and Lake Charles, Louisiana (Federal Reserve Bank of Dallas, 2005). Ten days after Rita hit, 31 percent of all GOM ethylene production capacity, 21 percent of total GOM propylene production, 37 percent of all GOM benzene capacity, and 22 percent of total GOM polyethylene capacity had been shut-in. Most chemical plants returned to service by mid-October. A few plants in the Port Arthur-Lake Charles area were making final repairs or in the process of restarting (Federal Reserve Bank of Dallas, 2005).

Table 42

Chemical Plants Affected by Hurricanes Katrina and Rita

	Katrina	Rita
	------- (percent capacity) -------	
Ethylene	15.8%	58.5%
Propylene	18.5%	30.7%
Benzene	19.6%	68.5%
Polyethylene	3.7%	63.0%
Styrene	29.3%	85.3%
Butadiene	9.1%	95.8%

Source: Federal Reserve Bank of Dallas, 2005.

Several petrochemical facilities along the GOM suffered other impacts from the storms despite receiving only minimal to no physical damage. The lack of labor was a common problem throughout the region and slowed recovery. Some companies had to wait for laborers to finish at a competitor's plant before they could help with their own. Still other employees were unable to return to work immediately given damage to their own homes or their families' homes located in areas experiencing considerable damage. Natural gas and electricity restoration were important constraints for most petrochemical facilities during this process, particularly after Rita. A number of railroad tracks were also shut down in the aftermath of both storms (Platts Petrochemical Report, 2006b).

Equistar Chemicals noted in its 2006 annual report that one of its pressing challenges in the aftermath of the storm was the limited number of suppliers for some of its raw materials and utilities and, in some cases, a limited number of raw materials suppliers in certain geographic regions of its operations. Equistar noted that raw material interruptions can have important "ripple effects" since its facilities and/or distribution channels are part of an integrated system, particularly along the Gulf Coast where the infrastructure of the chemical and refining industries is tightly integrated such that a major disruption of supply of a given commodity can negatively affect numerous participants, including suppliers of other raw materials. If one or more of Equistar's significant suppliers were unable to meet its obligations under present supply arrangements or supplies were otherwise disrupted, Equistar's businesses could suffer reduced supplies or be forced to incur increased costs for their raw materials, which would have a direct negative impact on plant operations. For example, Equistar reported that Hurricanes Katrina and Rita negatively affected crude oil and natural gas supplies, as well as supplies of some of Equistar's other raw materials, contributing to increases in raw material prices during the second half of 2005 and, in some cases, disrupting production. In addition, hurricane-related disruptions of rail and pipeline traffic in the U.S. Gulf Coast area negatively affected shipments of raw materials and product (SEC, 2006t).

Many companies reported physical damages in the millions. Equistar reported damages in the range of $28 million and was forced to suspend operations at all of its Gulf Coast plants in the aftermath of Hurricane Rita (SEC, 2006t). UCC was able to recover $20 million from losses due to Hurricane Katrina and reported insurance receivables of $105 million in December 31, 2005. The company also reported third and fourth quarter 2005 sales volume declines in 2005 (SEC, 2005e).

The storms had a strong impact on energy prices, increasing input costs, and inflicting more damage on a much reduced petrochemical industry. Prices for natural gas on the New York Mercantile Exchange jumped to $11 in September and $14 in October where it had previously averaged about $6 to $8 per MMBtu for most of the year. Higher input costs were passed onto petrochemical customers, with a high for ethylene in November of $0.565 per lb, representing a 36 percent increase from the previous January. Prices for polymer-grade propylene hit a record high of $0.52 per lb in October, an 18 percent increase from the beginning of the year. These rapid price increases ultimately created an anticipated demand response. High price led to U.S. demand decreasing significantly through the end of 2005 with propylene demand falling by as much 4.5 percent by the end of 2005 alone (Tullo, 2005).

13.3.3. Outlook

Over the years, the petrochemical industry has faced many challenges. Extensive environmental, health, and safety laws have been passed throughout the years, and now issues about global warming are inspiring even more attention on the chemical industry. Feedstock and energy costs have been highly variable and supply availabilities are becoming increasingly as important as price. Over the past decade, there has been increased competition for petrochemical sales worldwide. Also, globalization and information technology have significantly affected the organization of petrochemical businesses worldwide (NPRA, 2007).

According to ExxonMobil Chemical's Senior Vice President, the petrochemical industry is growing at about two to three percent above world GDP, which is about five to six percent per year and triple the expected growth rate of energy. The high growth rate reflects the continued infiltration of chemicals and plastics into all aspects of the world economy. This growth is driven primarily by economic activities in Asia and specifically China. Over the next ten years, about 60 percent of the world's petrochemical growth will occur in Asia, with China accounting for around 20 percent of that total growth (Glass, 2007).

The health of the petrochemical industry relies upon the health of the oil and gas industry. Almost all of the feedstock used in the petrochemical industry is based upon either oil or natural gas. Although there are several emerging feedstock substitutes, such as biofuels and bio-feedstocks, oil and natural gas are anticipated to be the primary input sources for petrochemical companies for the foreseeable future.

13.4. Chapter Resources

Department of Energy, Energy Information Administration

The EIA's Manufacturing Energy Consumption Survey (MECS) covers energy consumption by energy source type, industry type, and census region. The tables provide estimates for energy consumed as a fuel, energy consumed as a nonfuel, energy consumed for all purposes, and offsite-produced fuel consumption. Definitions of those and other terms necessary to understand the tables are found by clicking on the section titles. For each industry by region tables, there is

both a physical unit version and a British Thermal Unit (BTU) version. This survey is conducted every four years. The most recent year of data available is 2002.
http://www.eia.doe.gov/emeu/mecs/mecs2002/data02/shelltables.html

U.S. Securities and Exchange Commission

Quarterly and annual reports of operations for publicly traded companies are filed with the Securities and Exchange Commission.
http://www.sec.gov/edgar/searchedgar/companysearch.html

14. POWER GENERATION

14.1. Description of Industry and Services Provided

Electricity is an integral part of modern life in most developed countries. It is used for lighting, running appliances and electronics, and for heating and cooling. It is also indispensable to factories, commercial establishments, and most recreational facilities. As will be discussed later, electricity is also an essential input for the industries located along the GOM.

There are more than 3,273 electric utilities in the United States that are responsible for ensuring a reliable source of electricity to all consumers in their service territories (USDOE, EIA, 2008f). Different types of electric utilities include investor-owned, publicly-owned, cooperatives, and federal utilities. More than 38 percent of the U.S. generating capacity is owned by large, vertically integrated, investor-owned electric utilities. They also serve about 70 percent of the nation's customers (USDOE, EIA, 2008f). There are 210 investor-owned electric utilities, 2,009 publicly owned electric utilities, 883 consumer-owned rural electric cooperatives, and nine federal electric utilities (USDOE, EIA, 2008f). Power marketers are also considered electric utilities. These entities buy and sell electricity, but usually do not own or operate generation, transmission, or distribution facilities.

In addition, over 1,700 nonutility power producers generate electricity in the U.S. These include facilities that qualify under the Public Utility Regulatory Policies Act of 1978 (PURPA), which are typically cogeneration facilities at industrial sites that produce electricity as a by-product for efficiency and reliability purposes. Also included are independent power producers (IPPs) that produce and sell power on the wholesale market at non-regulated rates. The IPPs do not have franchised service territories and most are exempted from the regulatory requirements imposed on traditional utilities by FERC.

Electric utilities have historically been thought of as regulated monopolies and have pre-defined market service territories within which they are the exclusive providers of service. Each state regulates its own electric utilities which continues to be one of the more heavily regulated (economic/price) industries in the various energy industries. Competition in the power generation sector and retail service has been introduced in some states and will be discussed in greater detail below. The introduction of "retail competition," however, is a function of state determinations and policy. There are no federal mandates at this time for retail competition.

Electricity is a relatively homogeneous commodity and is typically only differentiated by customer type and in some instances, on the type of service quality (i.e., firm versus various types of interruptible service). Utility service territories are typically distinguished by restricted geographic locations although this can vary across different states. Classes of service, or sectors, for electricity customers typically include residential, commercial, industrial, and others and are used for setting rates and for long-run capacity planning (i.e., load growth and peak demand) (USDOE, EIA, 2008f).

As shown in Figure 123, electric power consumption in the U.S. has been increasing. Since 1990, residential consumption has increased by almost 50 percent, or at an average annual rate of 2.6 percent. Commercial consumption has increased the most, over 75 percent since 1990.

Industrial consumption has increased as well, but only by seven percent, which equates to less than half of one percent per year.

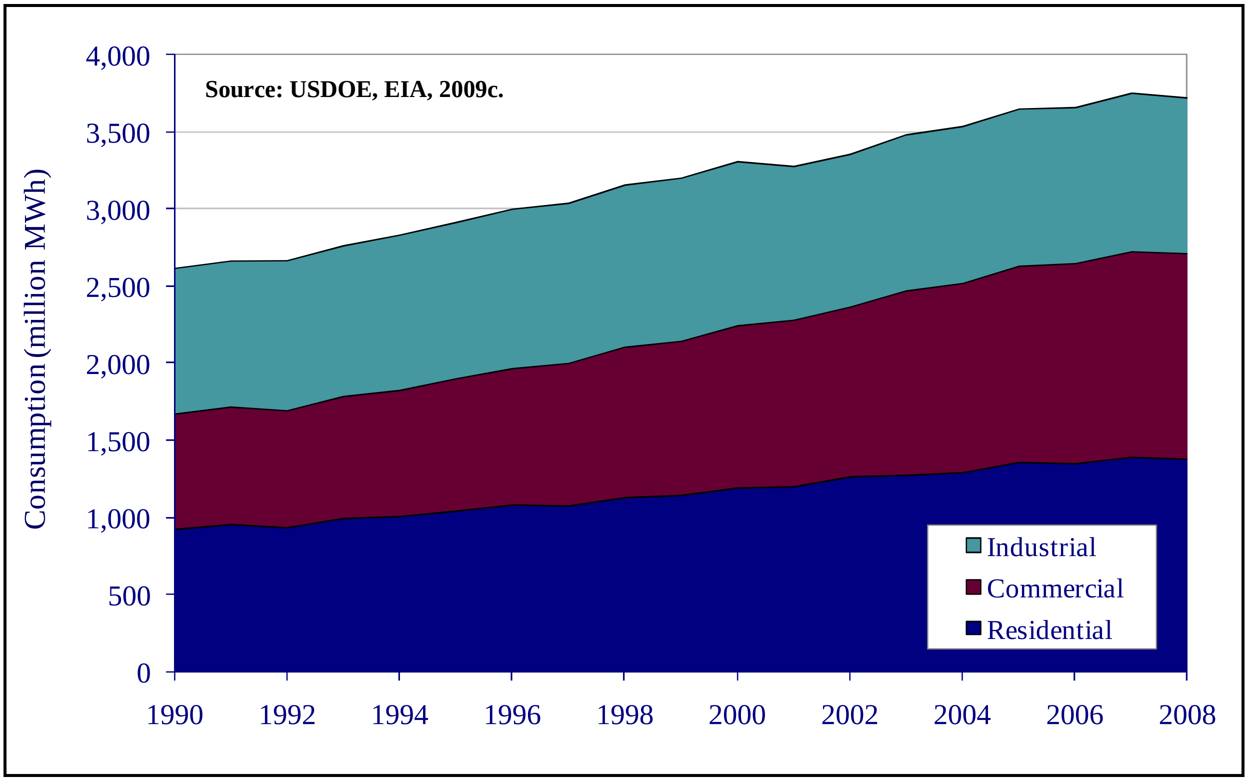


Figure 123. U.S. electric power consumption by year and customer class.

Figure 124 shows the total U.S. shares of sales in 2008 by customer class. The residential and commercial classes are almost equal at 37 percent and 36 percent of total consumption, respectively. Industrial is less, at 27 percent of total U.S. electric consumption.

Figure 125 shows the typical per customer consumption for each of these customer classes from 1990 through 2008. Residential consumption on a per customer basis has increased 16 percent over the last 18 years, which is close to an average annual rate of one percent per year. Commercial consumption has increased by 22 percent, or an average annual rate of just over one percent. And, although industrial consumption accounts for the lowest amount of consumption of the three classes, it has the highest per customer consumption. In 2008, industrial consumption on a per customer basis was 1,300 MWh. Residential and commercial per customer consumption was 11 MWh and 76 MWh, respectively. However, industrial consumption per customer has been decreasing at an average annual rate of 1.5 percent per year, or almost 30 percent since 1990.

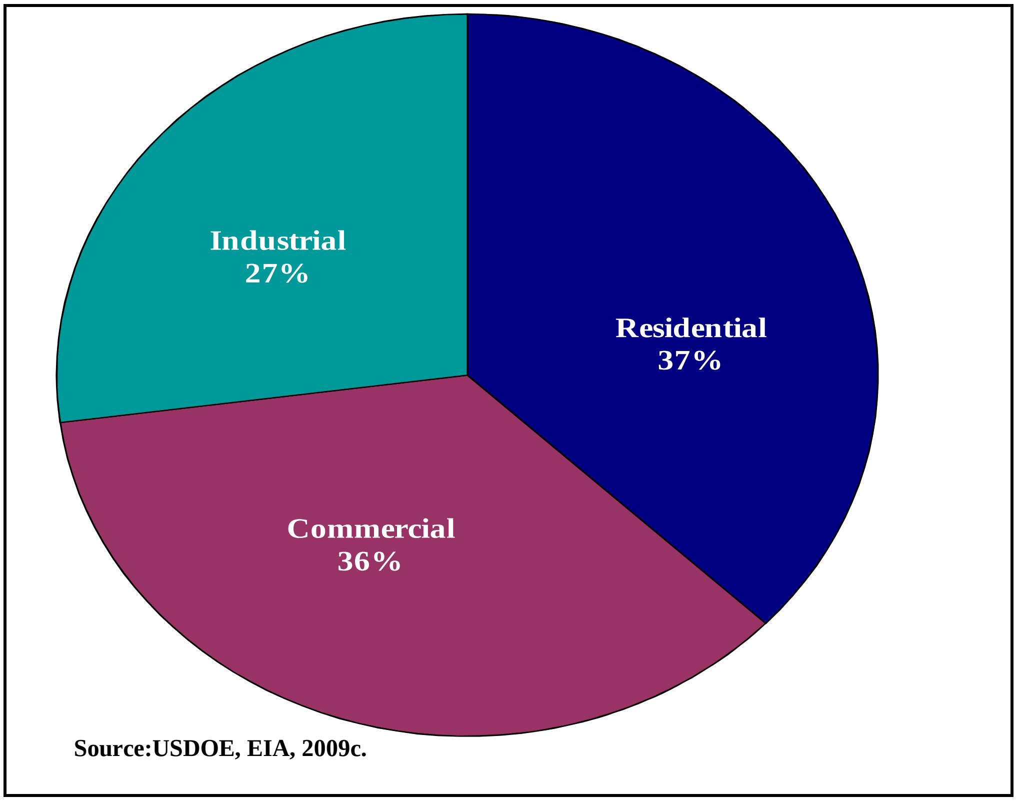


Figure 124. U.S. electric power consumption by customer class.

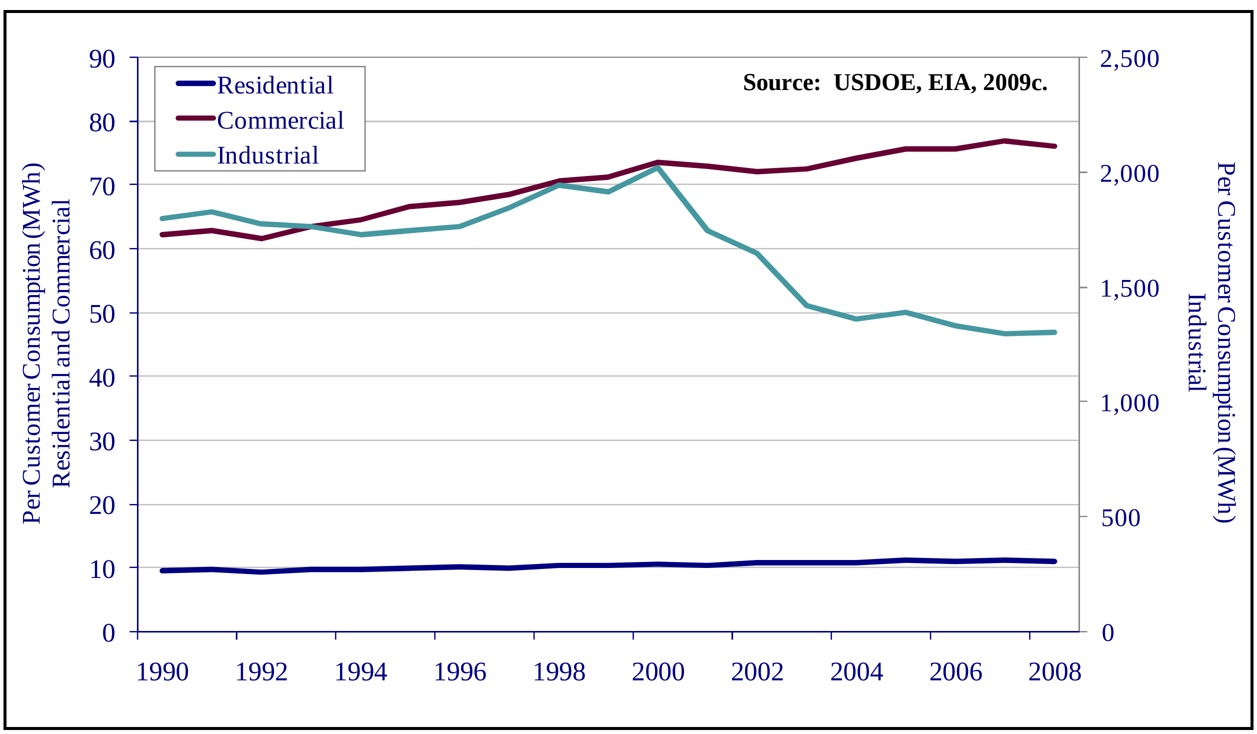


Figure 125. U.S. electric power consumption by year and customer class, line graph.

14.2. Industry Characteristics

14.2.1. Typical Facilities

An electric power system is a group of generation, transmission, distribution, and communication facilities that are physically connected and operated as a single unit under one control (Figure 126). The flow of electricity within the system is maintained and controlled by dispatch centers. It is the responsibility of the dispatch center to match the supply of electricity with the demand for it.

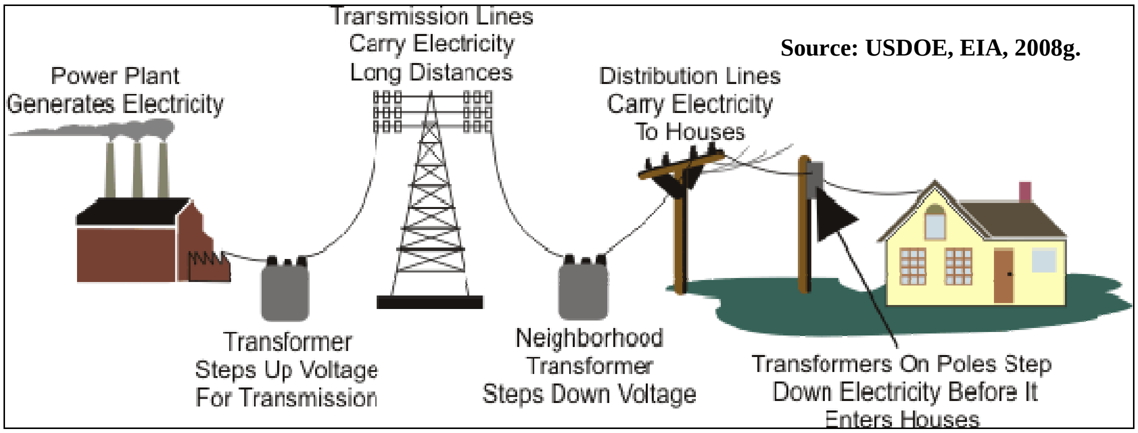


Figure 126. Power generation, transmission, and distribution.

Power plants use a number of different types of fuel to produce electricity, including: fossil fuels (coal, natural gas, or a refined oil product), nuclear energy, and renewable energy sources such as water (hydroelectric power), biomass, waste-to-energy, geothermal, wind, and solar energy, as well as alternative fuels (USDOE, EIA, 2008g). Figure 127 shows the relative share of electricity generation in 2006 by fuel type.

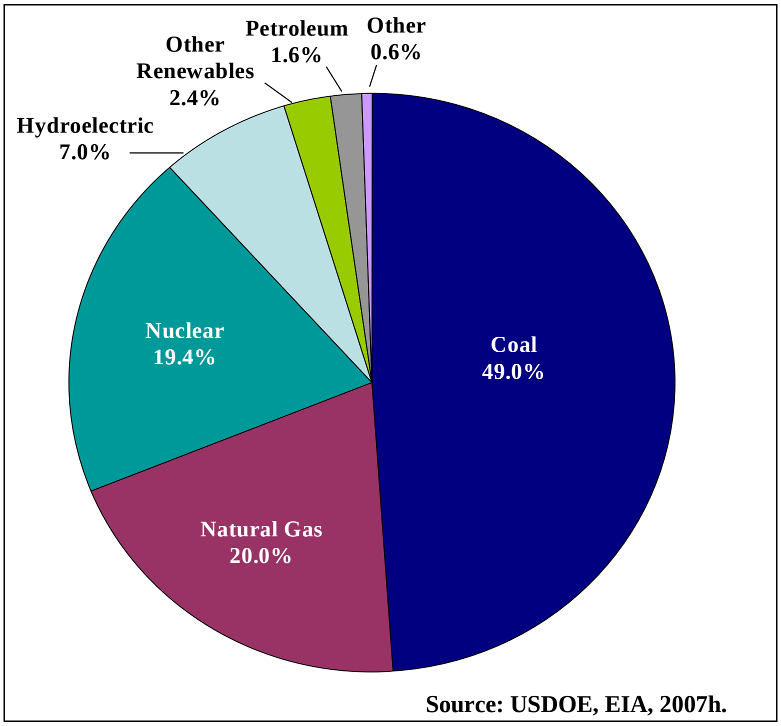


Figure 127. U.S. electric power industry net generation by fuel source, 2006.

In most areas, demand for electricity fluctuates daily. Demand is usually highest in the afternoon and early evening (on-peak). Also, seasonal demand reflects regional weather and climatic conditions, with the highest demand occurring in the summer when air conditioning use is greatest. Power plants tend to operate in two basic modes: base-load and peaking load (USDOE, EIA, 2008g). Base-load power plants are efficient generators that produce electricity around the clock at an even consistent level. These plants generally include nuclear, coal-fired, geothermal and waste-to-energy plants. Peaking plants are turned on or "dispatched" as demand increases above the normal base load or demand. For the most part, these plants are less efficient and expensive to operate. They are often fueled by refined oil products, or natural gas. Plants that use renewable resources such as wind and solar are referred to as intermittent resources. Their production depends on the availability of their energy source (USDOE, EIA, 2008g).

Transmission lines are the large, high-voltage power lines that move electricity from generating plants, sometimes over long distances to substations located near population centers. The voltage from these transmission lines is reduced to move power onto smaller, lower voltage distribution lines.

Local utilities deliver electricity to customers through a network of existing transmission and distribution lines. These are the lines that are seen along streets, supported by wood poles (Figure 128) (USDOE, EIA, 2008g).

Source: CHA, 2008; FreeFoto.com, 2008.

Figure 128. Electric transmission - high voltage transmission and low voltage distribution.

Often, a utility will generate excess electric power that it does not need to serve its customers. This power may be used as "sales for re-sale" and become part of the wholesale electricity market. This wholesale market is open to anyone who can generate power, connect to the transmission grid, and find another party to purchase their production. Sellers in the wholesale market include competitive suppliers and marketers, independent power producers, as well as those utilities with excess generation (EPSA, 2010).

In the past, the electric utility was a regional monopoly, characterized by vertically-integrated companies that provided generation, transmission and distribution service to customers. The utility owned its generation facilities, as well as the transmission and distribution lines through which power travels to customers. These utilities charged customers regulated cost-based rates, comprised of the cost to generate, transport, and distribute power. While most states still use this model, a number of states have restructured their electric power industries. In these states, the generation of electric power is no longer done by the utility, but rather a number of competitive suppliers will compete to supply the electricity. Ownership and/or operation of generation, transmission, and distribution facilities are separated into independent entities. And, in these deregulated markets, prices for electric power are determined by competition in the market. In most cases, the utility that was once the regional monopoly still owns the transmission and distribution service, and rates for such are still regulated and cost-based. While a competitive supplier may be providing the electricity, the regulated utility still delivers that power through its distribution system. As shown in the map below (Figure 129), most states still have integrated-utilities, while others have restructured the market. In addition, some states started the restructuring process and then suspended the effort.

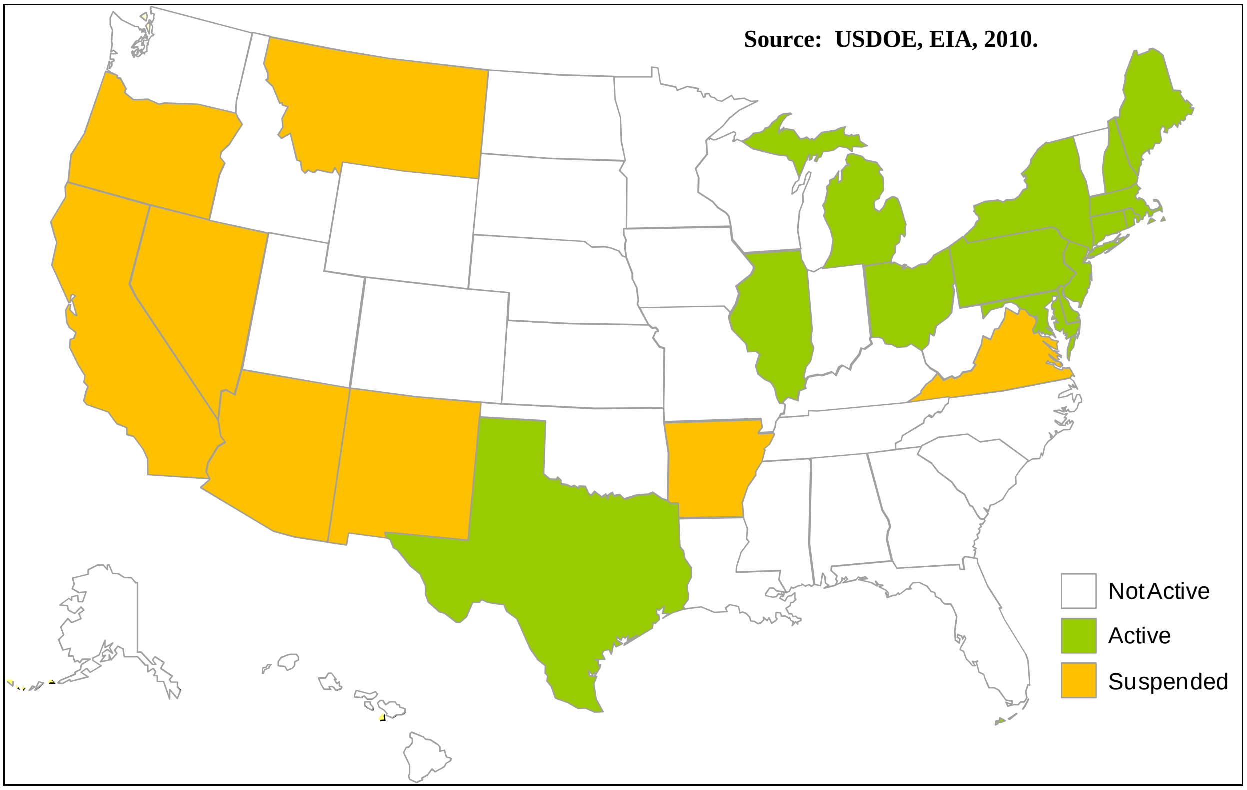


Figure 129. Electricity restructuring by state.

14.2.2. Geographic Distribution

The U.S. transmission system provides the capability to move electric power over long distances and is an integral component of the U.S. electric power industry. To better support competition in the electric power industry, the power transmission system in the U.S. has been reorganized from a 'balkanized' system with many operators to one where a handful of organizations operate the system (USDOE, EIA, 2000c).

When interconnected with each other, transmission lines become high-voltage transmission networks. In the U.S., these networks are referred to as "grids." There are three major grids in the U.S.: The Eastern Interconnect, the Western Interconnect and the Electric Reliability Council of Texas (ERCOT). As shown in Figure 130, these three regions are further separated into eight regional entities:

1. Northeast Power Coordinating Council (NPCC);
2. Reliability First Corporation (RFC);
3. Midwest Reliability Organization (MRO);

4. Southeastern Electric Reliability Council (SERC);

5. Florida Reliability Coordinating Council (FRCC);

6. Southwest Power Pool (SPP);

7. Texas Regional Entity (TRE); and

8. Western Electricity Coordinating Council (WECC).

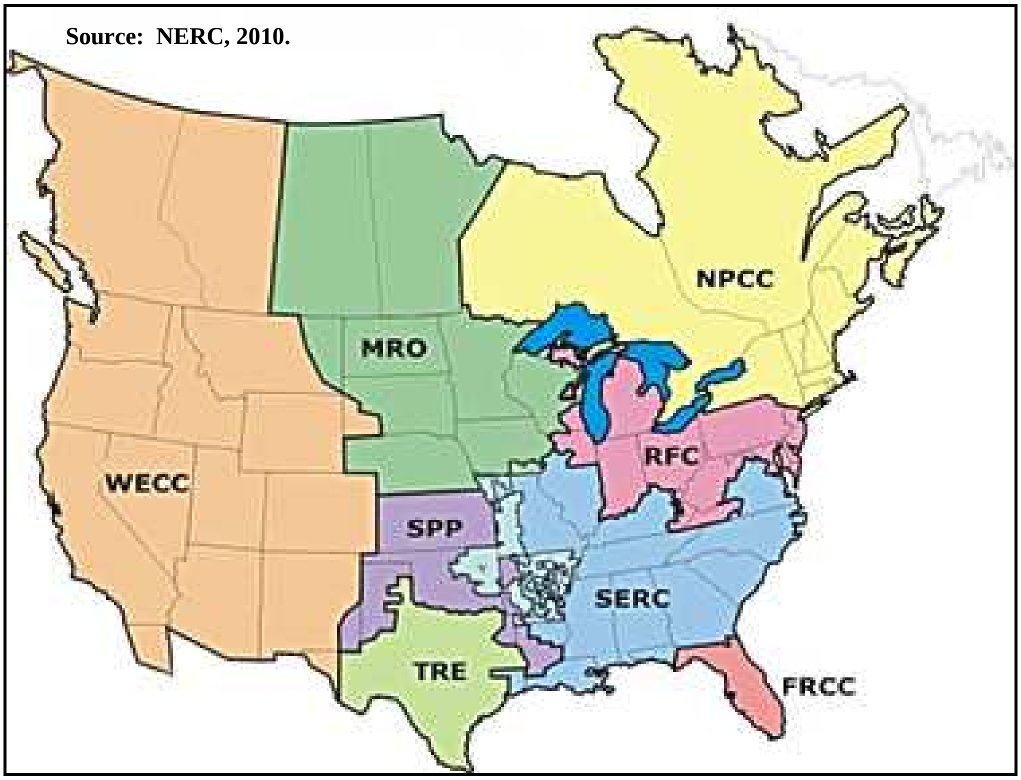


Figure 130. Current NERC regions.

Each of these regions is overseen by the North American Electric Reliability Corporation known as NERC. In 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system and made compliance with those standards mandatory and enforceable (NERC, 2010).

Within each of these regions are Independent System Operators (ISOs), also known as Regional Transmission Organizations (RTOs). FERC created RTOs as a way to coordinate generation and transmission across each geographic region. These regional organizations operate wholesale electricity markets that allow participants to buy and sell electricity on a day-ahead or real-time spot market basis. The RTOs also provide non-discriminatory transmission access; facilitate competition among wholesale suppliers; and forecast demand and schedule generation to ensure that enough power is available at all times. All of these services are provided more efficiently on a regional basis rather than a small-scale utility-by-utility basis. As shown in Figure 131, there are seven RTOs in the U.S:

- ISO NE: operates in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut.

- NY ISO: operates only in New York, but is regulated by FERC because the state's transmission grid is interconnected with the rest of the region.

- PJM: operates in all or parts of Delaware, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and District of Columbia.

- MISO: operates in all or parts of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Pennsylvania, South Dakota, Virginia, Wisconsin, and Manitoba, Canada.

- SPP: Operates in all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas.

- CAISO: operates only in California. This ISO is also regulated by FERC because the state's transmission grid is interconnected with the rest of the Western states.

- ERCOT: operates only in Texas. The ISO is entirely encompassed within the state and has its own intrastate transmission grid and is therefore subject only to state regulatory authority.

Because the trades in the wholesale market occur within these regional, multi-state interconnections, they are interstate sales and regulated by FERC. The one exception to this is ERCOT. The ERCOT region of Texas functions as its own, separate entity and is regulated by the Public Utilities Commission of Texas, as the entire interconnection lies within the state.

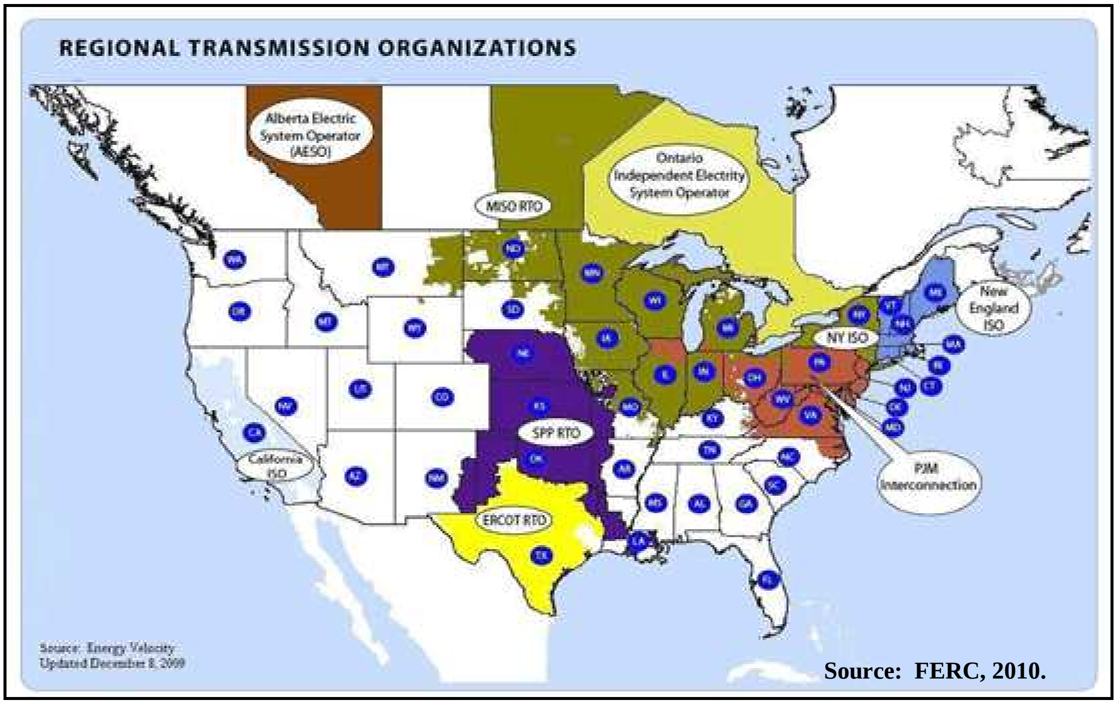


Figure 131. U.S. regional transmission organizations.

14.2.3. Typical Firms

Electric utilities include investor-owned, publicly owned, cooperatives, and federal utilities.

Investor-owned Electric Utilities

Investor-owned electric utilities are privately-owned and operate much like private businesses, providing a service for their customers and a return for their investors. These utilities are assigned certain geographic areas where they must provide service. They are regulated and required to charge reasonable prices and fair service to all consumers. Most provide basic services for the generation, transmission, and distribution of electricity. Nebraska is the only state that does not have investor-owned electric utilities. There, utilities are run by municipal systems and public power districts (USDOE, EIA, 2008f).

In the GOM states, investor-owned utilities provide service to 30 percent of the residential customers and account for 30 percent of residential retail sales. On a total customer basis, investor-owned utilities provide service to 30 percent of customers and about 34 percent of retail sales.

Table 43 shows the investor-owned electric utilities in the GOM area. One large player in this market is Entergy Corporation. Entergy is an integrated energy company with six separate operating companies that produce and distribute electricity in Arkansas, Louisiana, Mississippi, and Texas. Over 40 percent of the customers and retail sales in the GOM states are served by an

Entergy operating company (USDOE EIA, 2009d). The Entergy service territory is provided in Figure 132.

Table 43

Investor-Owned Electric Utilities

Investor Owned Utility	State	Residential			Commercial			Industrial			Total		
		Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers
Cleco Power LLC	LA	408,885	3,595,481	230,063	280,485	2,612,965	39,012	228,393	3,008,436	655	917,763	9,216,882	269,730
Southwestern Electric Power Co	LA	179,007	2,382,526	155,658	148,537	2,383,652	19,069	48,399	910,508	1,984	375,943	5,676,686	176,711
Southwestern Electric Power Co	TX	161,610	2,123,767	142,473	143,421	2,278,419	28,884	152,983	2,956,279	4,466	458,014	7,358,465	175,823
Entergy Operating Companies													
Entergy Gulf States Louisiana	LA	497,782	4,934,277	315,360	474,638	5,098,204	48,833	620,474	9,100,541	4,506	1,592,894	19,133,022	368,699
Entergy Louisiana	LA	853,691	8,645,849	567,107	621,575	6,293,547	77,812	871,852	13,209,208	8,574	2,347,118	28,148,604	653,493
Entergy New Orleans	LA	142,950	1,225,571	110,440	253,904	2,510,269	13,627	46,697	568,445	2,676	443,983	4,307,391	126,766
Entergy Mississippi	MS	500,097	5,474,190	361,308	467,962	5,293,052	67,598	185,119	2,771,322	3,163	1,153,178	13,538,564	432,069
Entergy Texas	TX	532,617	5,280,546	341,132	381,036	4,330,528	43,437	412,279	5,911,022	5,045	1,325,932	15,522,096	389,614
Southern Operating Companies													
Alabama Power Co	AL	1,833,563	18,874,039	1,202,491	1,335,025	14,962,117	216,957	1,238,368	22,805,675	5,795	4,406,956	56,641,831	1,425,243
Mississippi Power Co	MS	230,819	2,134,883	150,601	253,959	2,915,011	33,611	242,436	4,317,656	514	727,214	9,367,550	184,726

Source: USDOE, EIA, 2009d.

Figure 132. Entergy service territory.

As shown in Figure 133, Entergy generates electricity using two primary fuel sources: nuclear and natural gas/oil. In 2008, about 42 percent of electricity generated by the company was fueled by nuclear. Another 35 percent was fueled by natural gas. Coal accounted for the remaining 22 percent. Less than one percent was generated by conventional hydro power.

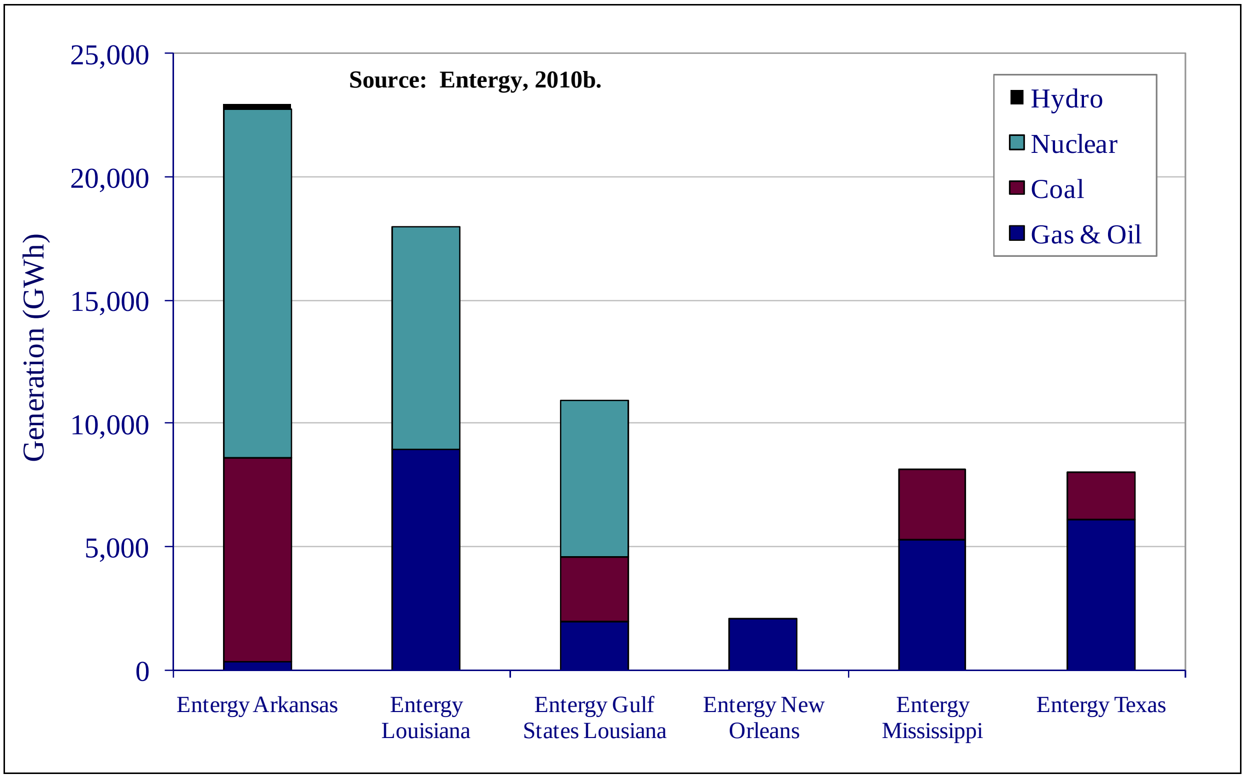
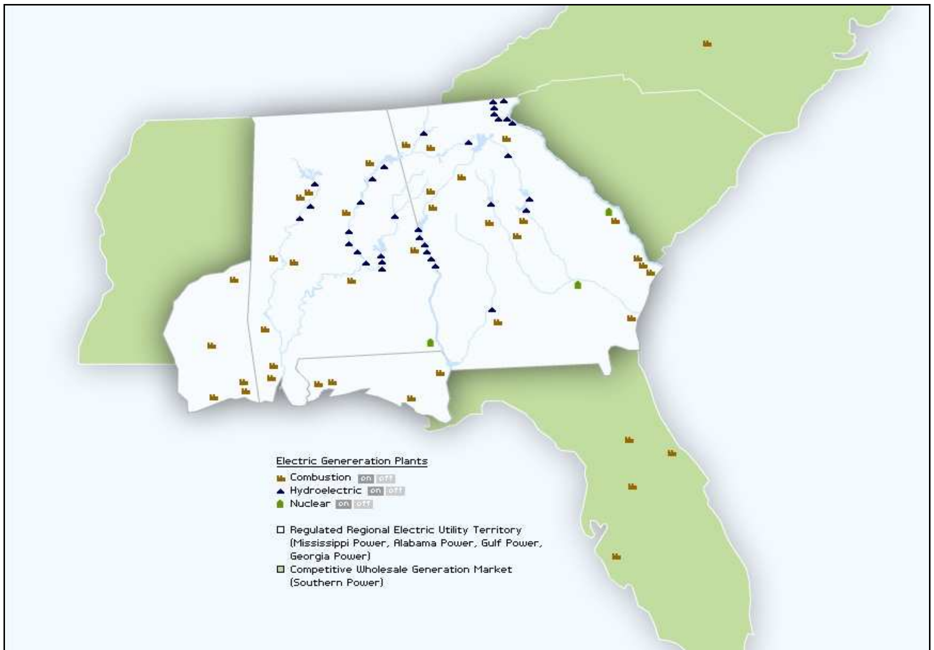


Figure 133. Entergy generation by fuel type, 2008.

Southern Company also has a significant presence in the GOM region. Figure 134 shows Southern Company's service territory. Southern Company provides electric distribution service to 4.4 million customers through its four electric utilities: Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. Alabama Power and Mississippi Power serve the GOM states. Together these two utilities serve over 1.3 million customers, and provide over 35 percent of residential retail power. The company also sells power in the wholesale market and transmits wholesale power for other providers.



Source: Southern Company, 2010a.

Figure 134. Southern Company service territory and generation.

Publicly-Owned Electric Utilities

Nonprofit agencies operated by local governments, publicly-owned electric utilities serve communities in their regions at cost. Excess funds are returned to consumers in contributions to the community, economic growth, efficient operations, and rate reductions. Examples of publicly-owned electric utilities are municipals, public power districts, state authorities, irrigation districts, and other state organizations (USDOE, EIA, 2008f).

Most municipal electric utilities simply distribute power, although some large ones produce and transmit electricity as well. There are 2,009 publicly-owned electric utilities in the United States representing 63 percent of electric utilities and supplying approximately 10 percent of generation and generating capability. They obtain their financing from municipal treasuries and from revenue bonds secured by proceeds from the sale of electricity. Voters in a public utility district elect commissioners or directors to govern the district independent of any municipal government (USDOE, EIA, 2008f).

In the GOM states, municipal electric utilities account for almost 15 percent of retail electric customers, and distribute 14 percent of retail sales. Table 44 shows the totals for each of the GOM states. In Alabama, municipal utilities serve over 500,000 customers, almost 85 percent of which are residential. In fact, the majority of customers served by municipal utilities are residential.

Table 44

Municipal Electric Utilities

State	Residential			Commercial			Industrial			Total		
	Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers
Alabama	541,999	7,029,078	425,229	430,206	5,555,110	82,898	261,715	4,513,615	1,690	1,233,920	17,097,803	509,817
Louisiana	163,751	1,948,070	135,338	192,306	2,384,461	25,829	15,804	202,691	668	371,861	4,535,222	161,835
Mississippi	112,664	1,399,472	100,299	132,180	1,607,226	28,288	70,144	1,170,321	129	314,988	4,177,019	128,716
Texas	1,620,807	18,246,610	1,421,836	1,564,896	20,167,132	195,469	415,710	6,470,476	4,404	3,601,413	44,884,218	1,621,709

Source: USDOE, EIA, 2009d.

Municipal utilities in the GOM states range from having just under 300 customers (Town of Elizabeth, Louisiana) to over 150,000 customers (City of Huntsville, Alabama) (USDOE, EIA, 2009d). One of the larger municipal utilities is the City of Lafayette in Louisiana. The Lafayette Utilities System serves over 60,000 customers, 50,000 of which are residential. The utility owns more than 828 miles of primary distribution line and owns and operates four power generation facilities. These plants total almost 750 MW (Lafayette Utilities System, 2010).

Cooperative Electric Utilities

These utilities are owned by their members and are typically established in rural areas with fewer consumers which are not as attractive to investors. There are 882 cooperatives operating in 47 states; none operate in Connecticut, Massachusetts, Rhode Island, or the District of Columbia. Cooperative electric utilities represent about 27 percent of U.S. electric utilities, 10 percent of sales and revenue, and around 4 percent of generation and generating capability. Cooperatives are incorporated under state laws and are usually directed by an elected board of directors, which in turn selects a manager (USDOE, EIA, 2008f).

There are 10 federal electric utilities in the United States that are part of several agencies in the U.S. government (USDOE, EIA, 2008f):

- the Army Corps of Engineers in the Department of Defense,
- the Bureau of Indian Affairs and the Bureau of Reclamation in the Department of the Interior,
- the International Boundary and Water Commission in the Department of State,
- the Power Marketing Administrations in the Department of Energy (Bonneville, Southeastern, Southwestern, and Western Area), and
- the Tennessee Valley Authority (TVA).

There are also three federal agencies that operate generating facilities (USDOE, EIA, 2008f):

- TVA, the largest federal producer;
- the U.S. Army Corps of Engineers; and
- the U.S. Bureau of Reclamation.

The TVA markets its own power while generation by the U.S. Army Corps of Engineers (except for the North Central Division, for example, Saint Mary's Falls at Sault Ste. Marie, Michigan) and the U.S. Bureau of Reclamation is marketed by the federal power marketing administrations: Bonneville, Southeastern, Southwestern, and Western Area.

The four power marketing administrations also purchase energy for resale from other electric utilities in the United States and Canada. Federal electric utilities represent less than 1 percent of all electric utilities, provide approximately 10 percent of all generating capability and generation, and account for about 1 percent of total sales to ultimate consumers. Federal power is sold not for profit, just to recover the costs of operations (USDOE, EIA, 2008f).

In the GOM states, cooperative electric utilities account for almost 20 percent of retail electric customers, and distribute 14 percent of retail sales. Table 45 shows the totals for each of the GOM states. Like municipal utilities, cooperatives mostly serve residential customers. In Alabama, cooperative utilities serve over 465,000 customers, about 87 percent of which are residential. In Louisiana, cooperative utilities serve over 370,000 customers and 90 percent of these customers are residential.

Table 45

Cooperative Electric Utilities

State	Residential			Commercial			Industrial			Total		
	Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers	Revenue (thousand $)	Generation (MWh)	Customers
Alabama	681,228	6,880,327	465,373	225,394	2,355,316	65,885	148,455	2,411,521	2,321	1,055,077	11,647,164	533,579
Louisiana	460,746	6,146,038	371,691	117,338	1,604,103	36,966	51,121	798,989	2,273	629,205	8,549,130	410,930
Mississippi	889,010	9,502,731	610,270	337,616	3,541,468	92,142	296,724	4,354,180	3,691	1,523,350	17,398,379	706,103
Texas	2,419,937	22,430,577	1,559,391	743,327	7,381,822	229,734	604,483	7,448,809	42,347	3,767,747	37,261,208	1,831,472

Source: USDOE, EIA, 2009d.

14.2.4. Regulation

Electric utilities are regulated by local, state, and federal authorities. As with natural gas pipelines, in general, interstate activities are subject to federal regulation, while intrastate activities are subject to state regulation. Also, approvals for most plant and transmission line construction and retail rate levels are state regulatory functions. Other issues such as wholesale rates (sales and purchases between electric utilities), licensing of hydroelectric facilities, questions of nuclear safety and high-level nuclear waste disposal, and environmental regulation are federal issues.

Not all utilities or electric power suppliers are regulated in the same way. Investor-owned electric utilities are tightly regulated by both the state in which they operate and FERC. However, municipal and cooperative electric utilities are usually not subject to the same regulation.

State Regulation

Traditionally, state governments are charged with regulating investor-owned electric utilities that sell and/or deliver electricity to end-users. In addition, most states regulate the construction and siting of power plants and transmission lines. As previously shown in Figure 129, a number of states have introduced retail competition, where electric power is no longer generated by the utility, but rather by a number of competitive suppliers. In states that have not adopted retail choice, state regulators will examine a utility's entire cost of generating and delivering electric power to customers (cost of service) and then calculate a rate that will reimburse the company for its costs plus a fixed rate of return, or profit. The goal is to keep customers' rates as low as possible, while also allowing the utility to remain financially healthy and able to attract investors.

In the states where electric competition is in place, the electric power portion of customers' rates is often subject to competitive bidding (Southern Company, 2010b). Electricity producers will compete for contracts to serve the retail customers of an electric utility. Although methods vary by state, the overall goal is to keep rates low by encouraging competition among suppliers (Southern Company, 2010b).

Federal Regulation

The primary federal law that regulates the investor-owned segment of the electric power industry is the Federal Power Act (FPA). Enacted in 1935, the FPA regulates interstate wholesale power transactions and the transmission of electric power. The FPA created the Federal Power Commission (FPC) (which later became FERC) to ensure that rates are "reasonable, nondiscriminatory, and just to the consumer (EEI, 2007)."

For many years, national policy has been to foster competition in wholesale power markets. FERC has the authority to regulate the prices, terms, and conditions of wholesale power sales and transmission services. FERC states its core responsibility is to "guard the consumer from exploitation by non-competitive electric power companies (FERC, 2010)." To do this, FERC has attempted to maintain the appropriate balance between regulation and competition. Regulation is the primary approach for wholesale transmission service, while competition is the primary approach for wholesale generation service. Although the commissions' views of this balance have changed over time, the FERC's goal is to find the best mix in order to protect customers from monopoly power (FERC, 2010).

Order 888, issued by FERC in 1996, gave all suppliers of electricity access to investor-owned transmission lines, which created a competitive market for these lines. FERC Orders 888 and 889 suggested the concept of an Independent System Operator as a way to satisfy the requirement of providing non-discriminatory access to transmission. Each ISO would operate the electric grid for a particular region. In Order 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations (See Figure 131) to administer the transmission grid on a regional basis throughout North America (including Canada) (FERC, 2008e).

The Energy Policy Act of 2005 (EPAct 2005)

EPAct 2005 updated a number of federal laws that govern the electric power industry and made important changes to guarantee electric reliability for consumers. The Act strengthened the legal framework for encouraging wholesale competition (FERC, 2010). In addition, it gave FERC authority to review merger and acquisition activity by investor-owned electric utilities. Some of the important changes made by EPAct 2005 are detailed below (EEI, 2007):

- Repeal of the Public Utility Holding Company Act (PUHCA): Enacted in 1935 to regulate the corporate structure and financial operations of utility holding companies. PUHCA was repealed by EPAct which gave FERC more authority to protect consumers. By repealing PUHCA, Congress eliminated federal restrictions on the scope, structure, and ownership of electric companies (Southern Company, 2010b). This has encouraged investment in critical energy infrastructure by allowing new classes of non-utility investors and increasing the availability of capital (Southern Company, 2010b). However, the mandate was accompanied by new provisions allowing FERC and state regulatory authorities access to the books and records of most holding companies and their affiliates. FERC was also given the authority to approve cost allocation issues within holding company systems if requested by a utility or state commission (EEI, 2007).

- Reform of the Public Utility Regulatory Policies Act (PURPA): Signed into law in November 1978 as part of the National Energy Act. In an attempt to expand the use of cogeneration and renewable energy sources, PURPA required utilities to purchase power from a qualifying facility (QF) at their avoided cost regardless of whether they needed the power.[32] PURPA also required electric utilities to sell requested energy and capacity to QFs.

  This resulted in electricity prices that were above-market so EPAct removed some of the requirements. It eliminated the mandatory purchase obligations and revised the criteria for new QFs that wanted to sell power. If an electric utility can prove that QFs in their region have full access to competitive wholesale power markets then they do not have to follow the mandatory purchase obligation.

- Creation of the Electric Reliability Organization (ERO): EPAct also created an independent, self-regulating entity called the ERO. The ERO enforces reliability rules on the nation's transmission system. Unregulated utilities (cooperatives and government-owned utilities) are required to comply with reliability standards as well (Southern Company, 2010b). FERC has oversight authority for the ERO. In July 2006, FERC certified the North American

[32] Avoided cost is the cost the utility would have paid to build or generate power on its own.

Electric Reliability Corporation (NERC) as the ERO, which became operational in January 2007 (EEI, 2007).

Environmental Regulations

There are hundreds of environmental rules and regulations that apply to the electric power industry. Two of the most significant are the Clean Air Act (CAA) and Clean Water Act (CWA). In addition, electric generators are subject to regulations that focus on air emissions from fossil fuel-based plants. The Acid Rain Program, created with a series of amendments made to the CAA in 1990, and subsequent programs to address ozone transport have helped to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOX) from electricity generation. Other noteworthy federal regulations include the Toxic Substances Control Act, which controls chemicals, and the Resource Conservation and Recovery Act, which controls hazardous waste. Electric companies are also subject to state issued environmental regulations (EEI, 2007).

In 2005, the U.S. Environmental Protection Agency (EPA) issued three new major regulations to further reduce SO_2, NOX, and mercury emissions: the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR). Affected states are now focusing on how to implement CAIR and CAMR. While many states will adopt both federal rules, others are considering adopting rules that surpass the EPA requirements (EEI, 2007).

CAIR applies to all fossil fuel-fired units with capacity of 25 MW or greater that provide electricity for sale in 28 eastern states and the District of Columbia. It also includes combined heat and power units larger than 25 MW that sell at least one-third of their potential electrical output and supply more than 219,000 MWh of electricity to the grid. CAVR applies to all states and requires additional controls for SO_2 and NOX to reduce haze that affects national parks and wilderness areas. In addition, many companies participate in voluntary programs to reduce emissions of carbon dioxide (CO_2) and other greenhouse gases (GHGs). “In 2004, leaders from the nation’s power sector pledged to reduce collectively the industry’s GHG emissions intensity—the amount of CO_2 emissions per kilowatt-hour of electricity. In 2005, the latest year for which data are available, the electric power sector undertook programs or projects that reduced, avoided, or sequestered more than 267 million metric tons of carbon-equivalent GHG emissions—accounting for approximately 64 percent of all reductions reported to the federal government in that year (EEI, 2007).”

Each day, billions of gallons of water are used to operate fossil, nuclear, and hydroelectric generating plants. The CWA controls the discharge of pollutants into U.S. waters through the National Pollutant Discharge Elimination System (NPDES) program. Through the CWA, the EPA sets technology standards to control the release of pollutants into waters, which can impact utility cooling water intake structures, thermal discharges, storm water run-off, wetland management, and hydropower licensing. Electric companies are also subject to numerous regulations for waste disposal, hazardous waste handling, recycling, species protection, and land management (EEI, 2007).

14.3. Industry Trends and Outlook

14.3.1. Trends

According to the EIA, there are over 1,000 electric generating units in the Gulf Economic Impact Areas.

Electric generation in the U.S. has increased 21 percent over the past 12 years. As shown in Figure 135, the majority of this generation was from coal, nuclear, and natural gas, which provided between 84.6 and 88.6 percent of total net generation during the period 1995 through 2006. The share of total net generation from petroleum peaked at 3.6 percent in 1998, but has since fallen to 1.6 percent in 2006. Generation from conventional hydroelectric has also declined, from 9.3 percent in 1995 to 7.1 in 2006. Throughout this time period, renewable energy sources other than hydroelectric, have on average accounted for 2.1 percent of net generation (USDOE, EIA, 2007h).

From 1995 to 2006, the average annual growth in natural gas-fired electric power generation was 4.6 percent. For the same time period, coal and nuclear generation experienced a 1.4 percent average annual growth rate. Since 1999, most new electric power plants have been natural gas-fired, which are generally cleaner and more efficient than coal plants. Accordingly, natural gas generation increased the most among traditional energy sources from 2005 to 2006, reaching 813 million MWh (an increase of 7.3 percent). Some of this growth can be attributed to the 2005 hurricane season. The hurricanes contributed to high natural gas prices and low natural gas electric power generation in the Gulf region. But, by 2006 as the Gulf region recovered, natural gas prices returned to a more competitive level (USDOE, EIA, 2007h).

From 2005 to 2006, net generation of electric power increased to 4,065 million MWh (an increase of 0.2 percent). In this time, U.S. real gross domestic product also increased (3.4 percent) and total industrial production increased 3.0 percent. In spite of these indicators of robust economic activity, which usually correspond to increases in demand for electric power, the increase in electric power generation was relatively flat. This is attributed to mild temperatures reducing the demand for electricity for heating and cooling purposes (USDOE, EIA, 2007h).

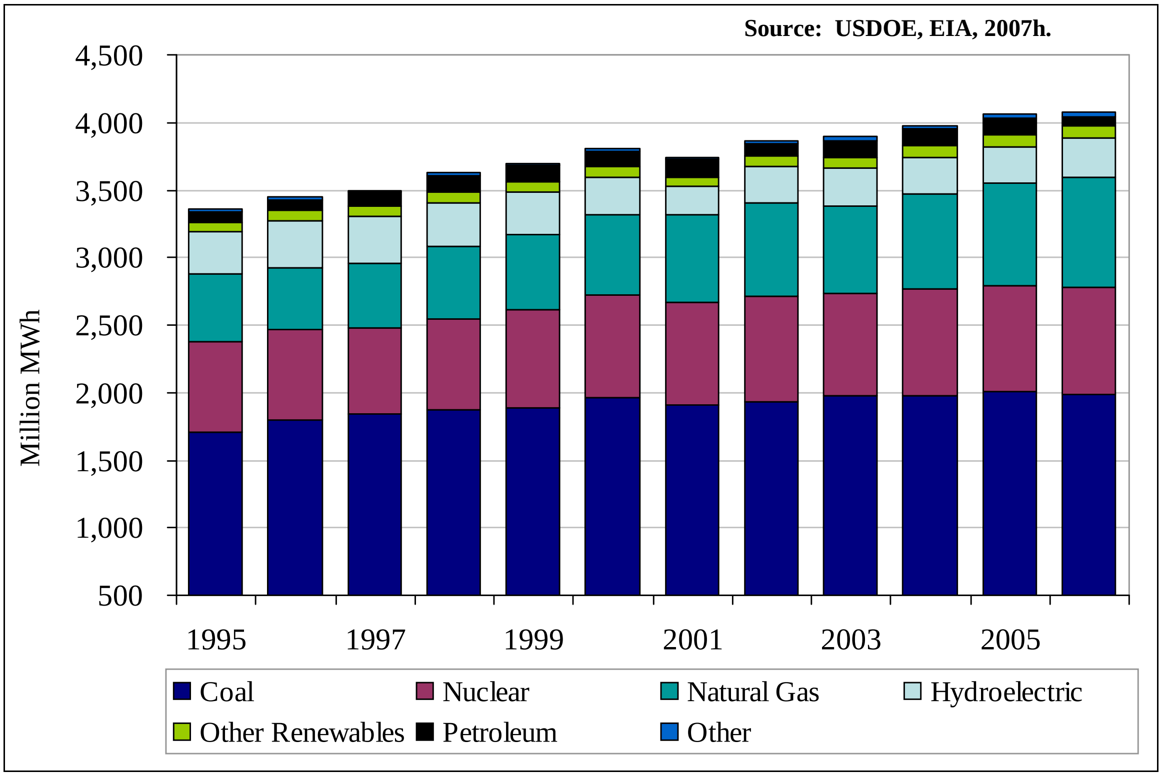


Figure 135. Net generation by energy source.

In 2006, total U.S. net summer generating capacity increased almost 1 percent. New generating capacity totaled 12,129 MW, while retirements totaled 3,458 MW. Natural gas-fired generating units provided 8,563 MW or 70.6 percent of capacity additions. Almost 7,375 MW of these additions were highly efficient combined-cycle units. Since the late 1990s, natural gas has been the fuel of choice for the majority of new generating units, resulting in a 99 percent increase in natural gas-fired capacity since 1999. An increase in the construction of natural gas plants began in 1999. Construction peaked during 2002 and 2003, but has declined significantly since (USDOE, EIA, 2007h).

14.3.2. Hurricane Impacts

In Louisiana, 17 of Entergy's generating units totaling almost 5,000 MW of capacity were shut down during Hurricane Katrina. Almost 1,100 MW of this capacity was operated by Entergy New Orleans. Before the storm hit, Entergy shut down its 1,075 MW Waterford-3 nuclear plant. Although Waterford-3 was not damaged, the company's Michoud and Patterson generating stations were flooded and rendered completely inoperable (Figure 136) (Entergy, 2006; Electric Utility Week, 2005). Table 46 shows the total impact to electric generating stations.

All generation equipment at Plant Watson, Mississippi Power's second-largest electricity generating plant, was damaged by floodwaters, which affected the company's emergency operations center and backup control center located in the plant. Seven other buildings also sustained significant damage, including the corporate headquarters in Gulfport, the building housing the distribution and transmission departments, the substation construction headquarters, the Biloxi service center, and the Pass Christian office. The corporate headquarters was damaged so severely that it did not become fully operational until late 2006 (Ball, 2006).

Figure 136. Entergy's Patterson facility under water.

Table 46

Power Outages, Generating Facilities

Company	Power Plant	Location	Nameplate Capacity (MW)
Entergy Louisiana	Ninemile Point	Westwego, LA	2,142
Entergy Louisiana	Baxter Wilson	Vicksburg, MS	1,328
Entergy New Orleans	Michoud	New Orleans, LA	959
Entergy New Orleans	AB Patterson 3 & 4	New Orleans, LA	133
Mississippi Power	Daniel	Escatawpa	1,064
Mississippi Power	Watson	Gulfport, MS	1,012

Source: USDOE, OE, 2005a; Electric Utility Week, 2005.

In addition to generating facilities, Hurricane Katrina seriously damaged the electric power transmission system and substations (Figure 137). At the height of the storm, Entergy lost a total of 182 transmission lines and 263 substations. Entergy New Orleans lost 95 of 126 line miles of transmission, 500 transformers and 50 substations were also under water (Entergy, 2006; Electric Utility Week, 2005).

About 70 percent of Mississippi Power's 8,000 miles of transmission and distribution system had to be rebuilt or repaired. About 700 miles of lines were down, more than 800 transformers were destroyed, and at least 4,500 poles had to be replaced or repaired (Electric Utility Week, 2005). All but three of the company's 122 transmission lines were out of service and more than 300 transmission towers were damaged (Ball, 2006). In Alabama, Alabama Power had 93 transmission lines with trouble, including broken cross-arms and downed wires (Electric Utility Week, 2005).

Figure 137. Substation flooded by Hurricane Katrina.

As of August 30, 2005, shortly after Hurricane Katrina made landfall, some 2.6 million customers had reported power outages in Louisiana, Mississippi, Alabama, Florida, and Georgia (Table 47). In Alabama approximately 624,427 customers were without power due to Katrina. Of these, 476,606 or 76 percent were in the Alabama Power service area. In addition, 102,821 co-op customers and 45,000 municipal customers had reported outages. Alabama Power Company reported that early indications show that Hurricane Katrina caused extensive damage to the Alabama Power system including the company's transmission system and other infrastructure, and customers should expect extended outages. Katrina was the second-worst storm in Alabama Power history in terms of outages, leaving 636,891 customers without power at its peak. Company officials announced that restoration efforts would take far longer than those following Hurricane Ivan, which left more than 825,000 customers without power in 2004. Ivan restoration took eight days. Company emergency crews worked through the night and damage assessment teams were out at first light (USDOE, OE, 2005a).

Approximately 909,200 customers were without power in Mississippi due to Katrina. Of these, 287,234 were in the Entergy service area, 196,000 in the Mississippi Power service area, and 425,939 in the Mississippi Electric Power Association service area. For Mississippi Power, the 196,000 was the entire customer base. According to the president and CEO of Mississippi

Power the company "has suffered the worst catastrophe in our company's history (USDOE, OE, 2005a)."

According to the Louisiana Public Service Commission, approximately 890,300 customers, or 42 percent of customers in the state, were without power as of August 30, 2005. Entergy (Louisiana and Mississippi) told its customers to expect extended power outages and that the severe damage caused by Hurricane Katrina to Entergy's system would require weeks to rebuild. Flooding, blocked access, or other obstacles would hamper restoration (USDOE, OE, 2005a).

Table 47

Power Outages, Number of Customers

State	Customers without Power	Total Customers	Percent of Total Customers
Alabama	624,427	2,339,004	26.7%
Florida	194,856	9,075,577	2.1%
Georgia	12,500	4,156,052	0.3%
Louisiana	890,294	2,130,925	41.8%
Mississippi	909,173	1,420,571	64.0%
Total	**2,631,250**	**19,122,129**	**13.8%**

Source: USDOE, OE, 2005a.

Entergy's preliminary damage estimates topped $1 billion to repair and replace the electric and gas infrastructure damaged by the hurricane. The Entergy New Orleans portion of this ranged between $325 million and $475 million. In addition, preliminary estimates for the other Entergy subsidiaries are: Entergy Louisiana - $275 million to $400 million; Entergy Mississippi - $75 million to $100 million; and Entergy Gulf States - $25 million to $45 million. Other costs of $50 million to $80 million were expected including business continuity costs (Electric Utility Week, 2005; Powers, 2006).

14.3.3. Outlook

According to the Department of Energy's Energy Information Administration, total electricity sales are projected to increase 41 percent over the next 25 years. The largest increase will be seen in the commercial sector, as service industries continue to drive growth. For the residential sector, electricity demand is projected to grow 39 percent. Growth in population and disposable income is expected to lead to increased demand for products, services, and floor space, with a corresponding increase in demand for electricity for space heating and cooling and to power the appliances and equipment used by buildings and businesses. Population shifts to warmer regions will also increase the need for cooling (USDOE, EIA, 2007c).

The growth in demand for electricity should be somewhat offset by efficiency gains in both the residential and commercial sectors, and higher energy prices are expected to encourage investment in energy-efficient equipment. In both sectors, continuing efficiency gains are expected for electric heat pumps, air conditioners, refrigerators, lighting, cooking appliances, and computer screens. In the industrial sector, increases in electricity sales are offset by rapid growth in on-site generation (USDOE, EIA, 2007c).

Coal-fired power plants (including utilities, independent power producers, and end-use CHP) will continue to supply most of the nation's electricity through 2030. In 2005, coal-fired plants accounted for 50 percent of generation and natural gas-fired plants for 19 percent. Most capacity additions over the next 10 years will most likely be natural gas-fired plants, increasing the natural gas share to 22 percent and lowering the coal share to 49 percent in 2015. As natural gas becomes more expensive, however, more coal-fired plants could be built. Nuclear and renewable generation will increase as well, as new plants will be built, stimulated by federal tax incentives and rising fossil fuel prices (USDOE, EIA, 2007c).

According to the EIA, most areas of the United States currently have excess generation capacity, but all electricity demand regions are expected to need additional, currently unplanned, capacity by 2030. The largest amounts of new capacity are expected in the Southeast and the West. In the Southeast, electricity demand represents a relatively large share of total U.S. electricity sales, and its need for new capacity is greater than in other regions (USDOE, EIA, 2007c).

Throughout the U.S. some new natural gas-fired plants will likely be built to maintain a diverse capacity mix or to serve as reserve capacity. Most will be located in the Midwest and Southeast. The Midwest has a surplus of coal-fired generating capacity and does not need to add many new coal-fired plants. In the Southeast, natural gas-fired plants are needed along with coal-fired plants to maintain diversity in the capacity mix (USDOE, EIA, 2007c).

NERC assesses and reports on the reliability and adequacy of the North American bulk power system as divided into the eight regional areas (shown in Figure 130) (NERC, 2009). In its most recent report, NERC projects the growth rate for electricity demand to be 1.57 percent from 2009 through 2018 for the U.S. In the SERC region, NERC estimates 1.76 percent demand growth rate from 2009 through 2018; and in ERCOT it projects a 2.13 percent demand growth rate (NERC, 2009).

The NERC report also cites the ability to site and build transmission as one of the highest risks facing the electric industry over the next 10 years. As of 2008, the ERCOT region has 28,665 miles of transmission and SERC has 97,256 miles. Together, these two regions account for 35 percent of the transmission miles in the U.S.[33] NERC reports that between 2009 and 2013 there are 4,375 miles of additions planned for the ERCOT region and 1,132 miles of additions planned for the SERC region. This represents 46 percent of total U.S. additions during this time period. By the 2018, it is expected that almost 9,000 miles of transmission will be added to the two regions, for a combined total mileage of 134,839 miles (NERC, 2009).

[33] Total transmission mileage in the U.S. is 365,058.

14.4. Chapter Resources

Department of Energy, Energy Information Administration

The EIA's Electricity page has data on sales, revenue, prices, plants, generation, fuel, cost demand, and emissions. The publications Electric Power Monthly and Electric Power Annual are also available through links on this page.
http://www.eia.doe.gov/fuelelectric.html

A number of databases are also available from the EIA. These include:

- Monthly Cost and Quality of Fuels for Electric Plants (Form EIA-423) - Included are the specific energy source, quantity of fuel delivered, the Btu content, sulfur content, ash content, coal state and county of origin, coal mine type (surface/underground), as well as the supplier of fuel. Fuel cost data collected on this survey will not be made available to the public due to it being classified as confidential.

- Monthly Electric Utility Database (Form EIA-826) - This is an electric utility data file that includes utility level retail sales of electricity and associated revenue by end-use sector, state, and reporting month. The data source is the survey: Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions."

- Annual Electric Generator Report (Form EIA-860) - This is a generator level data file that includes specific information about generators in electric power plants owned and operated by electric utilities and non-utilities (including independent power producers and combined heat and power producers). Data on energy sources, prime mover, nameplate capacity, net summer capacity, net winter capacity, in-service date, NAICS designation, and FERC qualifying facility status are included.

- Annual Electric Power Industry Database (Form EIA-861) - This is an electric utility data file that includes such information as peak load, generation, electric purchases, sales, revenues, and customer counts. The data source is the survey Form EIA-861, "Annual Electric Power Industry Report."

- Power Plant Databases (EIA-906 and EIA-920) - The EIA-906 and EIA-920, and predecessor forms, provide monthly and annual data on generation and fuel consumption at the power plant and prime mover level. Data for utility plants is available from 1970, and for non-utility plants from 1999. Beginning with January 2004 data collection a new form, the EIA-920, has been used to collect data from the combined heat and power plant (cogeneration) segment of the non-utility sector.

http://www.eia.doe.gov/cneaf/electricity/page/data.html

Federal Energy Regulatory Commission
FERC provides an overview of electric power markets on both a national and regional level.
http://ferc.gov/market-oversight/mkt-electric/overview.asp

FERC Form 1 – Annual Report of Major Electric Utility
FERC Form 1 is a comprehensive financial and operating report submitted for electric rate regulation and financial audits. Major is defined as having (1) one million megawatt hours or more; (2) 100 megawatt hours of annual sales for resale; (3) 500 megawatt hours of annual power exchange delivered; or (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).
http://www.ferc.gov/docs-filing/forms/form-1/form1-3Q.pdf

Edison Electric Institute
The Edison Electric Institute (EEI) is the association of U.S. investor-owned electric companies. The EEI website provides current information on topics such as electricity policy, energy infrastructure, environmental issues, and reliability issues. The site also provides an industry overview and industry statistics.
http://www.eei.org/

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