Appendix H

DOE, MODERN SHALE GAS – A PRIMER

U.S. Department of Energy • Office of Fossil Energy
National Energy Technology Laboratory

Modern Shale Gas Development in the United States: A Primer

April 2009

GROUNDWATER PROTECTION COUNCIL
ALL Consulting
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Modern Shale Gas
Development in the United States:
A Primer

Work Performed Under DE-FG26-04NT15455

Prepared for
U.S. Department of Energy
Office of Fossil Energy
and
National Energy Technology Laboratory

Prepared by
Ground Water Protection Council
Oklahoma City, OK 73142
405-516-4972
www.gwpc.org

and

ALL Consulting
Tulsa, OK 74119
918-382-7581
www.all-llc.com

April 2009

ACKNOWLEDGMENTS

This material is based upon work supported by the U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL) under Award Number DE-FG26-04NT15455. Mr. Robert Vagnetti and Ms. Sandra McSurdy, NETL Project Managers, provided oversight and technical guidance. This study was directed by the Ground Water Protection Council (GWPC) with ALL Consulting serving as lead researcher.

GWPC and ALL Consulting wish to extend their appreciation to the following federal, state, industry, and educational institutions which helped with numerous data sources, data collection and technology reviews that were critical to the success of this project. Additionally, the extra time and energy that individuals provided in reviewing and in broadening our understanding of the issues at hand is respectfully acknowledged.

The authors wish to specifically acknowledge the help and support of the following entities: Arkansas Oil and Gas Commission, Louisiana Department of Natural Resources, Michigan Department of Environmental Quality Office of Geological Survey, Montana Board of Oil and Gas Conservation, Montana Department of Natural Resources, New York State Department of Environmental Conservation, Ohio Department of Natural Resources Division of Mineral Resources Management, Oklahoma Corporation Commission, Pennsylvania Department of Environmental Protection, Railroad Commission of Texas, State of Tennessee, State University of New York at Fredonia, West Virginia Department of Environmental Protection, Energy Information Administration, U.S. Environmental Protection Agency, State Review of Oil and Natural Gas Environmental Regulation, Inc. (STRONGER), BP America Production Co., Chesapeake Energy Corp., Devon Energy Corp., East Resources, Inc., Fortuna Energy Inc., Independent Petroleum Association of America, Schlumberger Ltd., Universal Well Services Inc., and Weatherford International Ltd.,

FOREWORD

This Primer on Modern Shale Gas Development in the United States was commissioned through the Ground Water Protection Council (GWPC). It is an effort to provide sound technical information on and additional insight into the relationship between today's fastest growing, and sometimes controversial, natural gas resource development activity, and environmental protection, especially water resource management. The GWPC is the national association of state ground water and underground injection agencies whose mission is to promote the protection and conservation of ground water resources for all beneficial uses. One goal of the GWPC is to provide a forum for stakeholder communication on important current issues to foster development of sound policy and regulation that is based on sound science. This Primer is presented in the spirit of furthering that goal.

Water and energy are two of the most basic needs of society. Our use of each vital resource is reliant on and affects the availability of the other. Water is needed to produce energy and energy is necessary to make water available for use. As our population grows, the demands for both resources will only increase. Smart development of energy resources will identify, consider, and minimize potential impacts to water resources.

Natural gas, particularly shale gas, is an abundant U.S. energy resource that will be vital to meeting future energy demand and to enabling the nation to transition to greater reliance on renewable energy sources.

Shale gas development both requires significant amounts of water and is conducted in proximity to valuable surface and ground water. Hence, it is important to reconcile the concurrent and related demands for local and regional water resources, whether for drinking water, wildlife habitat, recreation, agriculture, industrial or other uses.

Because shale gas development in the United States is occurring in areas that have not previously experienced oil and gas production, the GWPC has recognized a need for credible, factual information on shale gas resources, technologies for developing these resources, the regulatory framework under which development takes place, and the practices used to mitigate potential impacts on the environment and nearby communities. While the GWPC's mission primarily concerns water resources, this Primer also addresses non-water issues that may be of interest to citizens, government officials, water supply and use professionals, and other interested parties.

Each state has laws and regulations to ensure the wise use of its natural resources and to protect the environment. The GWPC has conducted a separate study to summarize state oil and gas program requirements that are designed to protect water resources. These two studies complement one other and together provide a body of information that can serve as a basis for fact-based dialogue on how shale gas development can proceed in an environmentally responsible manner under the auspices of state regulatory programs.

This Shale Gas Primer was intended to be an accurate depiction of current factors and does not represent the view of any individual state. Knowledge about shale gas development will continue to evolve. The GWPC welcomes insights that readers may have about the Primer and the relationship of shale gas development to water resources.

Scott Kell, President,

Ground Water Protection Council

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EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

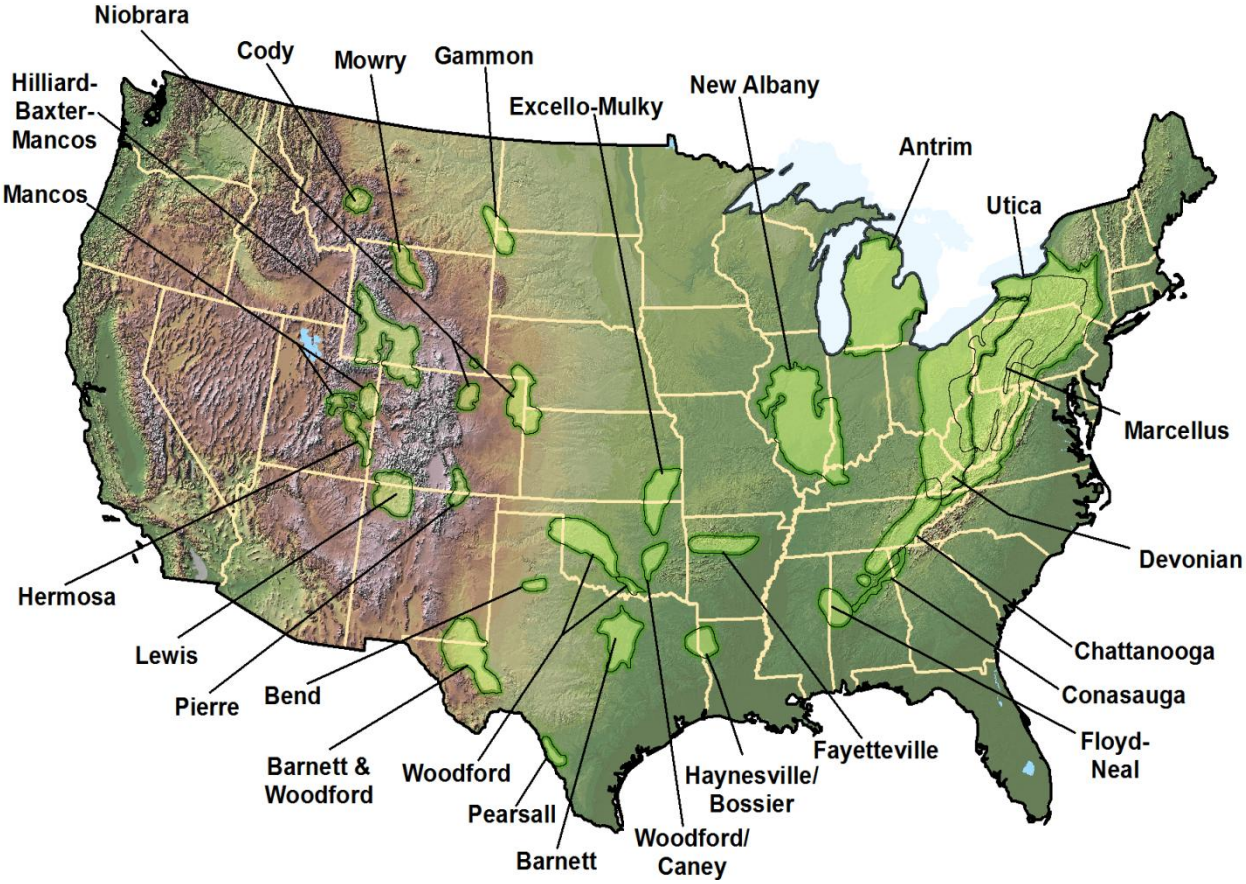
The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. Exhibit ES-1 shows the approximate locations of current producing gas shales and prospective shales. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

EXHIBIT ES-1: UNITED STATES SHALE BASINS



The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and

discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-size-fits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of

well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced

water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include NO_x, volatile organic compounds, particulate matter, SO_2, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

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INTRODUCTION

Natural gas production from hydrocarbon-rich shale formations, known as "shale gas", is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring changes to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

This Primer endeavors to provide much of that information. It describes the importance of shale gas in meeting the future energy needs of the United States (U.S.), including its role in alternative energy strategies and reducing greenhouse gas (GHG) emissions. The Primer provides an overview of modern shale gas development, as well as a summary of federal, state, and local regulations applicable to the natural gas production industry, and describes environmental considerations related to shale gas development.

The Primer is intended to serve as a technical summary document, including geologic information on the shale gas basins in the U.S. and the methods of shale gas development. By providing an overview of the regulatory framework and the environmental considerations associated with shale gas development, it will also help facilitate the minimization and mitigation of adverse environmental impacts. By so doing, the Primer can serve as an instrument to facilitate informed public discussions and to support sound policy-making decisions by government.

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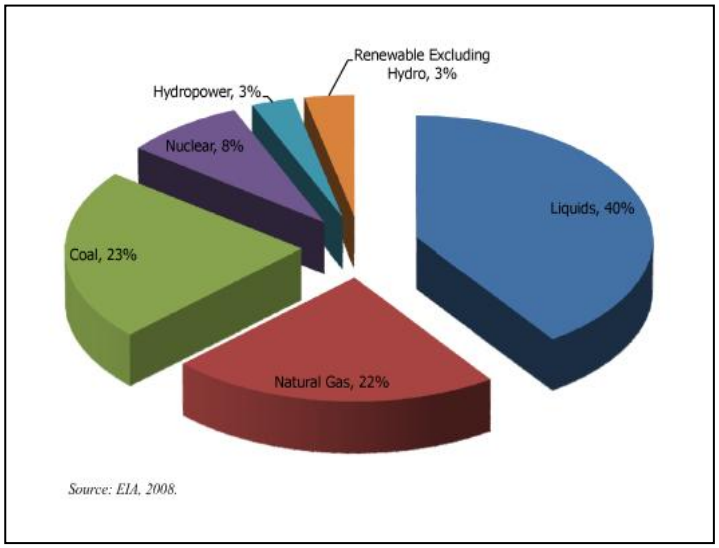
THE IMPORTANCE OF SHALE GAS

The Role of Natural Gas in the United States' Energy Portfolio

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total[1] (Exhibit 1[2]). The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

EXHIBIT 1: UNITED STATES ENERGY CONSUMPTION BY FUEL (2007)



The United States has abundant natural gas resources. The Energy Information Administration (EIA) estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place)[3,4]. Navigant Consulting estimates that technically recoverable unconventional gas (shale gas, tight sands, and coalbed natural gas) accounts for 60% of the onshore recoverable resource[5]. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years[6]. Note that historically, estimates of the size of the total recoverable resource have grown over time as knowledge of the resource has improved and recovery technology has advanced. Unconventional gas resources are a prime example of this trend.

What Is a Tcf?

Natural gas is generally priced and sold in units of a thousand cubic feet (Mcf, using the Roman numeral for one thousand). Units of a trillion cubic feet (tcf) are often used to measure large quantities, as in resources or reserves in the ground, or annual national energy consumption. A tcf is one billion Mcf and is enough natural gas to:

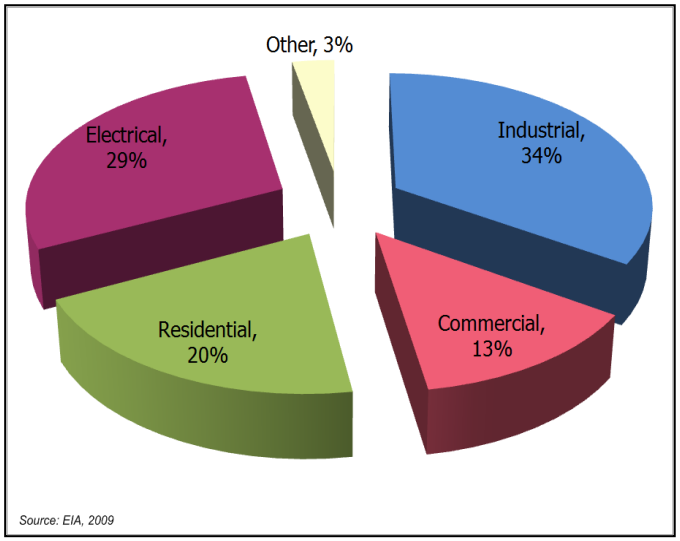
- ***Heat 15 million homes for one year;***
- ***Generate 100 billion kilowatt-hours of electricity;***
- ***Fuel 12 million natural gas-fired vehicles for one year.***

Natural gas use is distributed across several sectors of the economy (Exhibit 2[7]). It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating[8]. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come[9].

Natural gas, due to its clean-burning nature and economical availability, has become a very popular fuel for the generation of electricity[10]. In the 1970s and 80s, the choice for the majority of electric utility generators was primarily coal or nuclear power; but, due to economic, environmental, technological, and

regulatory changes, natural gas has become the fuel of choice for many new power plants. In 2007, natural gas was 39.1%[11] of electric industry productive capacity.

EXHIBIT 2: NATURAL GAS USE BY SECTOR



Natural gas is also the fuel of choice for a wide range of industries. It is a major fuel source for pulp and paper, metals, chemicals, petroleum refining, and food processing. These five industries alone account for almost three quarters of industrial natural gas use[12] and together employ four million people in the U.S.[13] Natural gas is also a feedstock for a variety of products, including plastics, chemicals, and fertilizers. For many products, there is no economically viable substitute for natural gas. Industrial use of natural gas accounted for 6.63 tcf of demand in 2007 and is expected to grow to 6.82 tcf by 2030.

However, natural gas is being consumed by the U.S. economy at a rate that exceeds domestic production and the gap is increasing[14]. Half of the natural gas consumed today is produced from wells drilled within the last 3.5 years[15]. Despite possessing a large resource endowment, the U.S. consumes natural gas at a rate requiring rapid replacement of reserves. It is estimated that the gap between demand and domestic supply will grow to nearly 9 tcf by the year 2025[16]. However, it is believed by many that unconventional natural gas resources such as shale gas can significantly alter that balance.

Half of the natural gas consumed today is produced from wells drilled within the last 3.5 years.

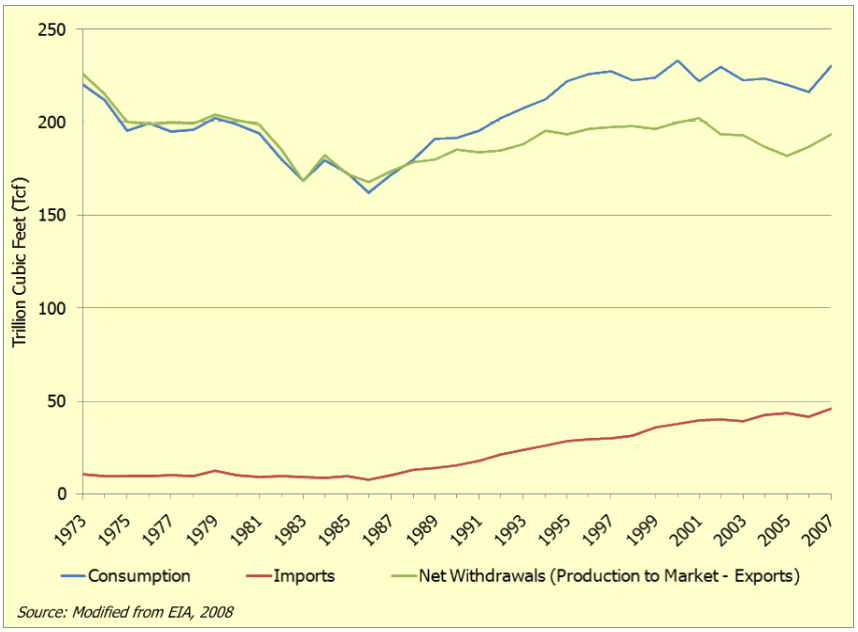
Exhibit 3[17] shows a comparison of production, consumption, and import trends for natural gas in the U.S. with demand increasingly exceeding conventional domestic production. Without domestic shale gas and other unconventional gas production, the gap between demand and domestic production will widen even more, leaving imports to fill the need. Worldwide consumption of natural gas is also increasing; therefore the U.S. can anticipate facing an increasingly competitive market for these imports.

This increased reliance on foreign sources of energy could pose at least two problems for the U.S.: 1) it would serve to decrease our energy security; and 2) it could create a multi-billion dollar outflow to foreign interests, thus making such funds unavailable for domestic investment.

The Advantages of Natural Gas

In the 1800s and early 1900s, natural gas was mainly used to light streetlamps and the occasional house. However, with a vastly improved distribution network and advancements in technology, natural gas is now being used in many ways. One reason for the widespread use of natural gas is its versatility as a fuel. Its high British thermal unit (Btu) content and a well-developed infrastructure make it easy to use in a number of applications.

EXHIBIT 3: COMPARISON OF PRODUCTION, CONSUMPTION AND IMPORT TRENDS FOR NATURAL GAS IN THE UNITED STATES



Source: Modified from EIA, 2008

Another factor that makes natural gas an attractive energy source is its reliability. Eighty-four percent of the natural gas consumed in the U.S. is produced in the U.S., and ninety-seven percent of the gas used in this country is produced in North America[18]. Thus, the supply of natural gas is not dependent on unstable foreign countries and the delivery system is less subject to interruption.

A key advantage of natural gas is that it is efficient and clean burning[19]. In fact, of all the fossil fuels, natural gas is by far the cleanest burning. It emits approximately half the carbon dioxide (CO_2) of coal along with low levels of other air pollutants[20]. The combustion byproducts of natural gas are mostly CO_2 and water vapor, the same compounds people exhale when breathing. Coal and oil are composed of much more complex organic molecules with greater nitrogen and sulfur content. Their combustion byproducts include larger quantities of CO_2, nitrogen oxides (NO_x), sulfur dioxide (SO_2) and particulate ash (Exhibit 4[21]). By comparison, the combustion of natural gas liberates very small amounts of SO_2 and NO_x, virtually no ash, and lower levels of CO_2, carbon monoxide (CO), and other hydrocarbons[22].

EXHIBIT 4: COMBUSTION EMISSIONS
(POUNDS/BILLION BTU OF ENERGY INPUT)

Air Pollutant	Combusted Source		
	Natural Gas	Oil	Coal
Carbon dioxide (CO_2)	117,000	164,000	208,000
Carbon monoxide (CO)	40	33	208
Nitrogen oxides (NO_x)	92	448	457
Sulfur dioxide (SO_2)	0.6	1,122	2,591
Particulates (PM)	7.0	84	2,744
Formaldehyde	0.750	0.220	0.221
Mercury (Hg)	0.000	0.007	0.016

Sources: EIA, 1998

Because natural gas emits only half as much CO_2 as coal and approximately 30% less than fuel oil, it is generally considered to be central to energy plans focused on

the reduction of GHG emissions[23]. According to the EIA in its report "Emissions of Greenhouse Gases in the United States 2006," 82.3% of GHG emissions in the U.S. in 2006 came from CO_2 as a direct result of fossil fuel combustion[24]. Since CO_2 makes up a large fraction of U.S. GHG emissions, increasing the role of natural gas in U.S. energy supply relative to other fossil fuels would result in lower GHG emissions.

Of all the fossil fuels, natural gas is by far the cleanest burning.

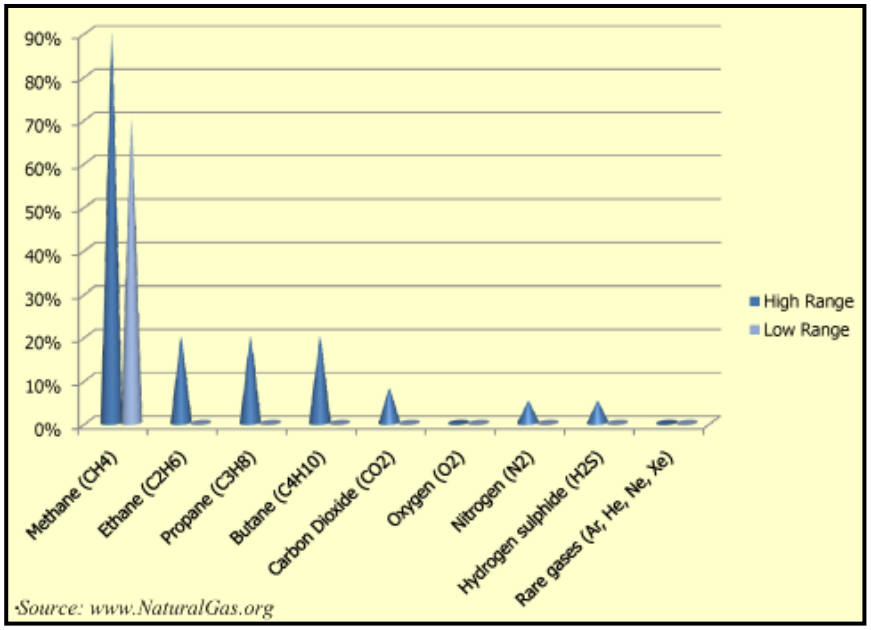
Although there is rapidly increasing momentum to reduce dependence on fossil fuels in the U.S. and elsewhere, the transition to sustainable renewable energy sources will no doubt require considerable time, effort and investment in order for these sources to become economical enough to supply a significant portion of the nation's energy consumption. Indeed, the EIA estimates that fossil fuels (oil, gas, and coal) will supply 82.1% of the nation's energy needs in 2030[25]. Since natural gas is the cleanest burning of the fossil fuels, an environmental benefit could be realized by shifting toward proportionately greater reliance on natural gas until such time as sources of alternative energy are more efficient, economical, and widely available.

Additionally, the march towards sustainable renewable energy sources, such as wind and solar, requires that a supplemental energy source be available when weather conditions and electrical storage capacity prove challenging[26]. Such a backstop energy source must be widely available on near instantaneous demand. The availability of extensive natural gas transmission and distribution pipeline systems makes natural gas uniquely suitable for this role[27]. Thus, natural gas is an integral facet of moving forward with alternative energy options. With the current emphasis on the potential effects of air emissions on global climate change, air quality, and visibility, cleaner fuels like natural gas are an important part of our nation's energy future[28].

Natural Gas Basics

Natural gas is a combination of hydrocarbon gases consisting primarily of methane (CH_4), and lesser percentages of butane, ethane, propane, and other gases[29,30]. It is odorless, colorless, and, when ignited, releases a significant amount of energy[31]. Exhibit 5[32] shows the typical compositional range of natural gas produced in the U.S.

EXHIBIT 5: TYPICAL COMPOSITION OF NATURAL GAS



Natural gas is found in rock formations (reservoirs) beneath the earth's surface; in some cases it may be associated with oil deposits. Exploration and production companies explore for these

deposits by using complex technologies to identify prospective drilling locations. Once extracted, the natural gas is processed to eliminate other gases, water, sand, and other impurities. Some hydrocarbon gases, such as butane and propane, are captured and separately marketed. Once it has been processed, the cleaned natural gas is distributed through a system of pipelines across thousands of miles[33]. It is through these pipelines that natural gas is transported to its endpoint for residential, commercial, and industrial use.

Natural gas is measured in either volumetric or energy units. As a gas, it is measured by the volume it displaces at standard temperatures and pressures, usually expressed in cubic feet. Gas companies generally measure natural gas in thousands of cubic feet (Mcf), millions of cubic feet (MMcf), or billions of cubic feet (bcf), and estimate resources such as original gas-in-place in trillions of cubic feet (tcf).

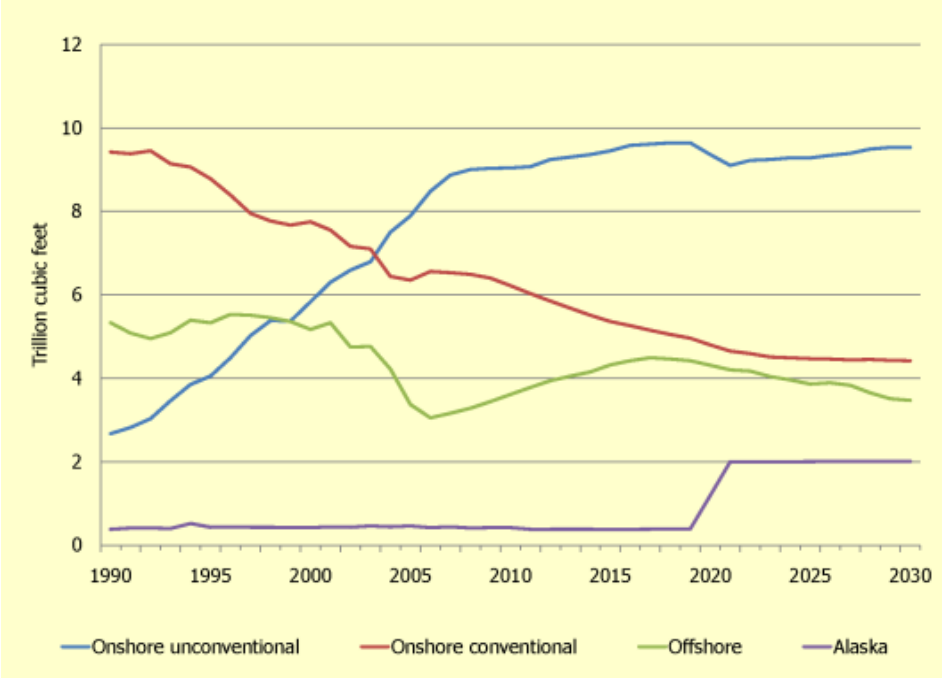
Calculating and tracking natural gas by volume is useful, but it can also be measured as a source of energy. Similar to other forms of energy, natural gas can be computed and presented in British thermal units (Btu). One Btu is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at normal pressure[34]. There are about 1,000 Btus in one cubic foot of natural gas delivered to the consumer[35]. Natural gas distribution companies typically measure the gas delivered to a residence in 'therms' for billing purposes[36]. A therm is equal to 100,000 Btus—approximately 100 cubic feet—of natural gas[37].

Unconventional Gas

The U.S. increased its natural gas reserves by 6% from 1970 to 2006, producing approximately 725 tcf of gas during that period[38]. This increase is primarily a result of advancements in technology, resulting in an increase in economically recoverable reserves (reserves becoming proven) that were previously thought to be uneconomic[39].

In 2007, Texas, Wyoming, and Colorado were the states with the greatest additions to proved gas reserves for the year; these additions were from shale gas, tight sands, and coalbed methane, all of which are unconventional gas plays[40]. Similarly, the states of Texas (30%) and Wyoming (12%) had the greatest volume of proved gas

EXHIBIT 6: NATURAL GAS PRODUCTION BY SOURCE (TCF/YEAR)



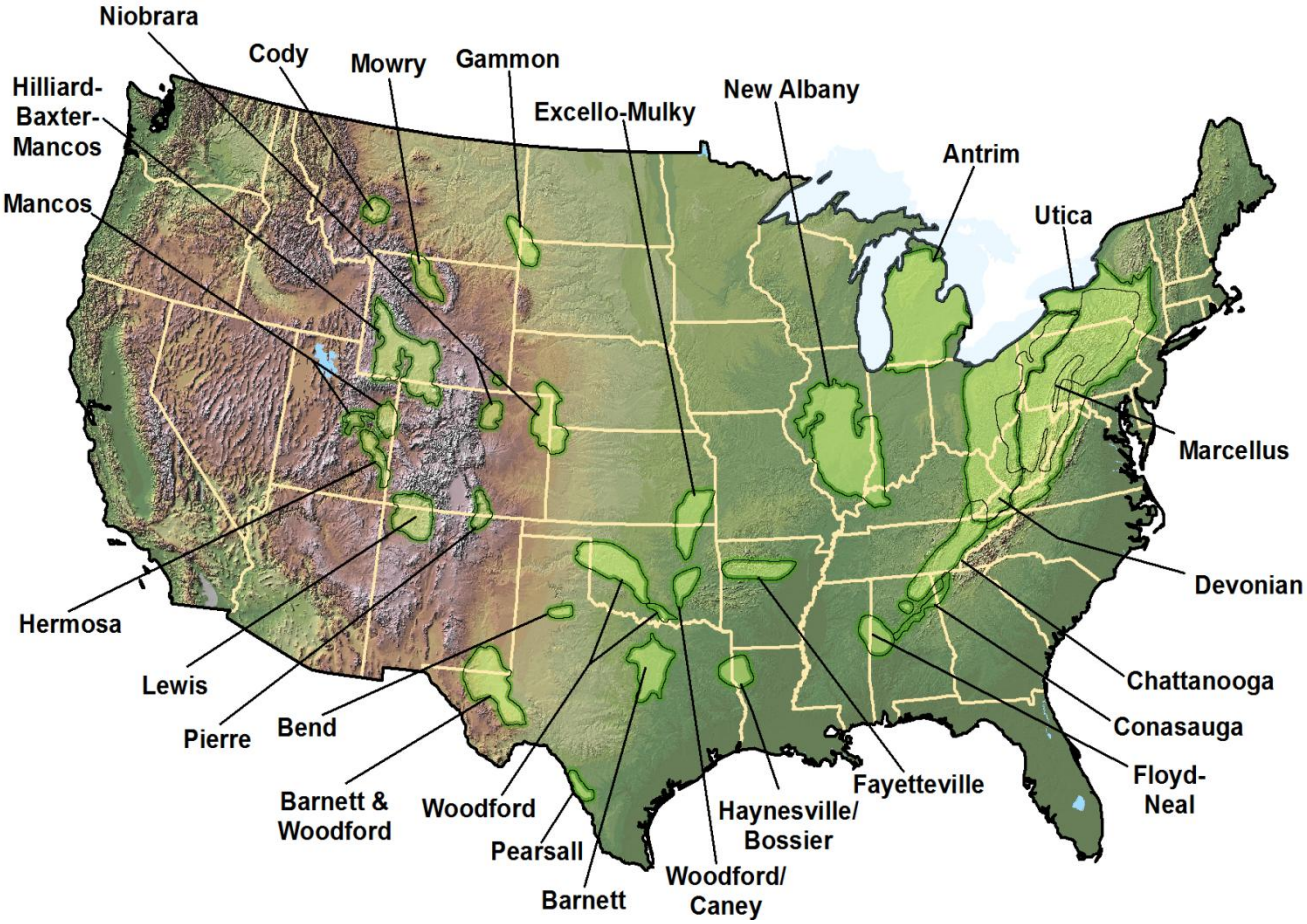
Source: EIA, 2008

reserves in the U.S. in 2007—again, both primarily as a result of developing unconventional natural gas plays[41].

Unconventional production now accounts for 46% of the total U.S. production.

Overall, unconventional natural gas is anticipated to become an ever-increasing portion of the U.S. proved reserves, while conventional gas reserves are declining[42]. Over the last decade, production from unconventional sources has increased almost 65%, from 5.4 trillion cubic feet per year (tcf/yr) in 1998 to 8.9 tcf/yr in 2007 (Exhibit 6). This means unconventional production now accounts for 46% of the total U.S. production[43].

EXHIBIT 7: UNITED STATES SHALE GAS BASINS



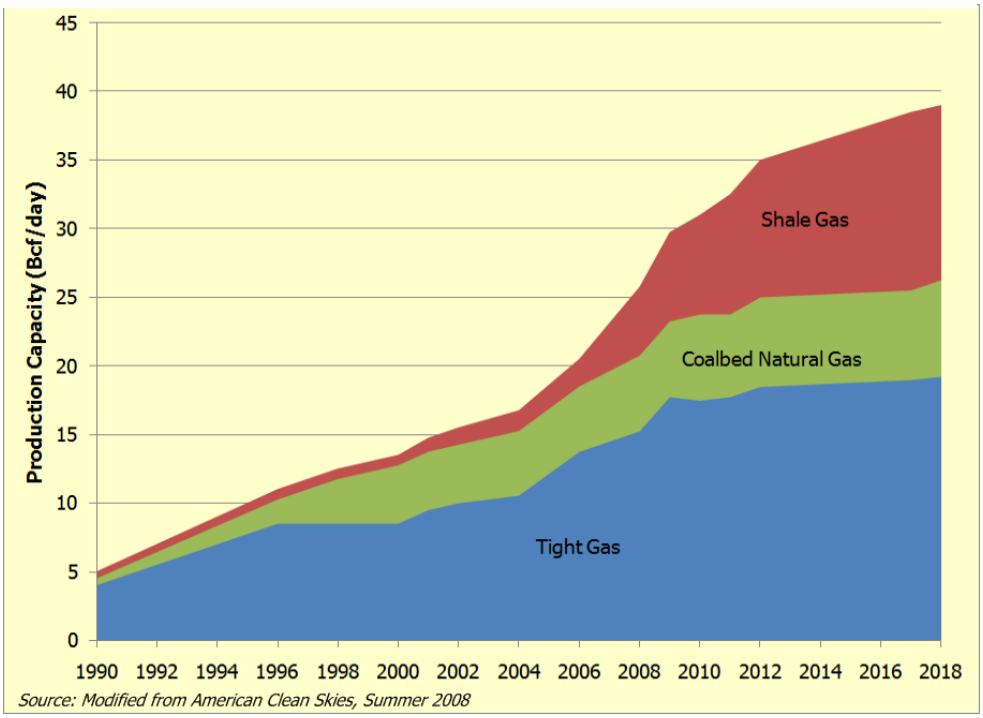
Source: ALL Consulting, Modified from USGS & other sources

The Role of Shale Gas in Unconventional Gas

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas (Exhibit 7[44]). Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 states[45]. Improved drilling and fracturing technologies have contributed considerably to the economic potential of shale gas. This potential for production in

the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook. Exhibit 8[46] shows the projected contribution of shale gas to the overall unconventional gas production in the U.S. in bcf/day.

EXHIBIT 8: UNITED STATES UNCONVENTIONAL GAS OUTLOOK (BCF/DAY)



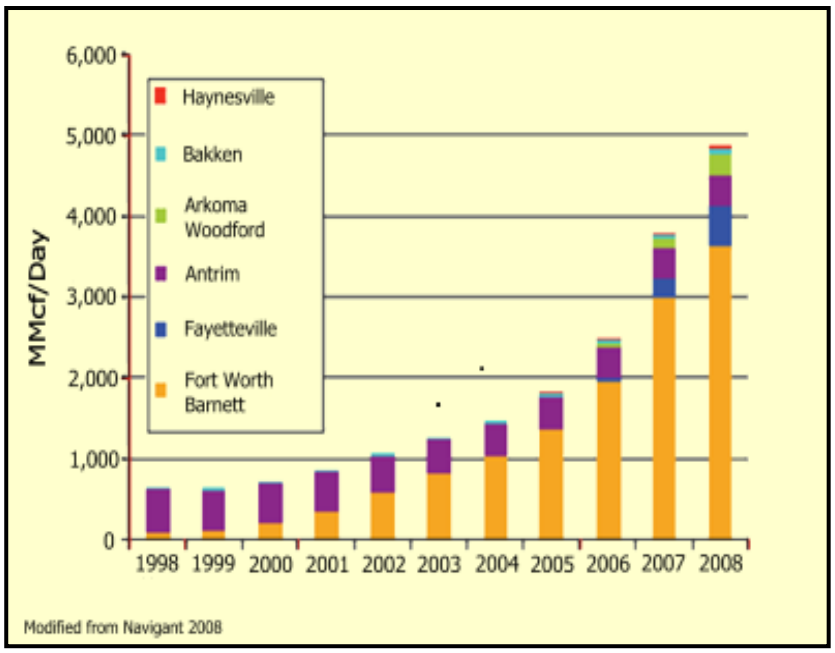
Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Advances in the pre-existing technologies of directional drilling and hydraulic fracturing set the stage for today's horizontal drilling and fracturing techniques, without which many of the unconventional natural gas plays would not be economical. As recently as the late 1990s, only 40 drilling rigs (6% of total active rigs in the U.S.) in the U.S. were capable of onshore horizontal drilling; that number grew to 519 rigs (28% of total active rigs in the U.S.) by May 2008[47].

It has been suggested that the rapid growth of unconventional natural gas plays has not been captured by recent resource estimates compiled by the EIA and that, therefore, their resource estimates do not accurately reflect the contribution of shale gas[48]. Since 1998, annual production has consistently exceeded the EIA's forecasts of unconventional gas production. A great deal of this increase is attributable to shale gas production, particularly from the Barnett Shale in Texas. The potential for most other shale gas plays in the U.S. is just emerging. Taking this into consideration, Navigant, adding their own analysis of shale gas resources to other national resource estimates, has estimated that U.S. total natural gas resources (proved plus unproved technically recoverable) are 1,680 tcf to 2,247 tcf, or 87 to 116 years of production at 2007 U.S. production levels. This compares with EIA's national

Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices.

resource estimate of 1,744 tcf, which is within the Navigant range. Navigant has estimated that shale gas comprises 28% or more of total estimated technically recoverable gas resources in the U.S.[49]. Exhibit 9[50] depicts the daily production (in MMcf/day) from each of the currently active shale gas plays.

EXHIBIT 9: TRENDS IN SHALE GAS PRODUCTION (MMCF/DAY)



As with most resource estimates, especially emerging resources such as unconventional natural gas, these estimates are likely to change over time. In addition, there are a variety of organizations making resource and future production estimates for shale gas. These analyses use different assumptions, data, and methodologies. Therefore, one may come across a wide range of numbers for projected shale gas recovery, both nationally and by basin. These shale gas resource estimates are likely to change as new information, additional experience, and advances in technology become available.

Shale gas resource estimates are likely to change as new information, additional experience, and advances in technology become available.

Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs[51]. The total recoverable gas resources from 4 emerging shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf[52]. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. An additional benefit of shale gas plays is that many exist in areas previously developed for natural gas production and, therefore, much of the necessary pipeline infrastructure is already in place. Many of these areas are also proximal to the nation's population centers thus potentially facilitating transportation to consumers. However, additional pipelines will have to be built to access development in areas that have not seen gas production before[53].

Looking Forward

Considering natural gas's clean-burning nature, the nation's domestic natural gas resources, and the presence of supporting infrastructure, the development of domestic shale gas reserves will be an important component of the U.S.'s energy portfolio for many years. Recent successes in a variety of geologic basins have created the opportunity for shale gas to be a strategic part of the nation's energy and economic growth[54].

Recent successes and improvements in a variety of geologic basins have created the opportunity for shale gas to be a strategic part of the nation's energy and economic growth.

The Environmental Considerations section of this Primer describes how improvements in horizontal drilling and hydraulic fracturing technologies have opened the door to the economic recovery of shale gas. It also discusses additional practices that have allowed development of areas that might previously have been inaccessible due to environmental constraints or restrictions on disturbances in both urban and rural settings. By using horizontal drilling, operators have been able to reduce the extent of surface impact commonly associated with multiple vertical wells drilled from multiple well pads; equivalent well coverage can be achieved through drilling fewer horizontal wells from a single well pad. This can result in a significant reduction in surface disturbances: fewer well pads, fewer roads, reduced traffic, fewer pipelines, and fewer surface facilities. In urban settings, this can mean less impact on nearby populations and businesses. In rural settings, this can mean fewer consequences for wildlife habitats, agricultural resources, and surface water bodies.

Other practices that are now commonly used for drilling, particularly in urban settings, include: the use of sound walls and blankets to reduce noise, the use of directional or shielded lighting to reduce nighttime disturbance to nearby residences and businesses, the use of pipelines to transport water resulting in reduced truck traffic, and the use of solar-powered telemetry devices to monitor gas production resulting in reduced personnel visits to well sites. Such practices are used in specific locations or situations that call for them, and are not appropriate everywhere, but where needed, they provide opportunities for safe, environmentally sound development that may not have been possible without them.

These technologies and practices, along with the increasing gas prices of the last few years, have provided the means by which shale gas can be economically recovered. Improvements in reducing the overall footprint and level of disturbance from drilling and completion activities have provided the industry with the methods for moving forward with development in new areas that were previously inaccessible.

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SHALE GAS DEVELOPMENT IN THE UNITED STATES

Shale formations across the U.S. have been developed to produce natural gas in small but continuous volumes since the earliest years of gas development. The first producing gas well in the U.S. was completed in 1821 in Devonian-aged shale near the town of Fredonia, New York[55]. The natural gas from this first well was used by town residents for lighting[56]. Early supplies of natural gas were derived from shallow gas wells that were not complicated to drill and from natural gas seeps[57]. The shallow wells and seeps were capable of producing small amounts of natural gas that were used for illuminating city streets and households[58]. These early gas wells played a key part in bringing illumination to the cities and towns of the eastern U.S.[59].

The first producing gas well in the U.S. was completed in 1821 in Devonian-aged shale near the town of Fredonia, New York.

Other shale gas wells followed the Fredonia well with the first field-scale development of shale gas from the Ohio Shale in the Big Sandy Field of Kentucky during the 1920s[60]. The Big Sandy Field has recently experienced a renewed growth and currently is a 3,000-square-mile play encompassing five counties[61]. By the 1930s, gas from the Antrim Shale in Michigan had experienced moderate development; however, it was not until the 1980s that development began to expand rapidly to the point that it has now reached nearly 9,000 wells[62]. It was also during the 1980s that one of the nation's most active natural gas plays initially kicked off in the area around Fort Worth, Texas[63]. The play was the Barnett Shale, and its success grabbed the industry's attention. Large-scale hydraulic fracturing, a process first developed in Texas in the 1950s, was first used in the Barnett in 1986; likewise, the first Barnett horizontal well was drilled in 1992[64]. Through continued improvements in the techniques and technology of hydraulic fracturing, development of the Barnett Shale has accelerated[65]. In the ensuing two decades, the science of shale gas extraction has matured into a sophisticated process that utilizes horizontal drilling and sequenced, multi-stage hydraulic fracturing technologies. As the Barnett Shale play has matured, natural gas producers have been looking to extrapolate the lessons learned in the Barnett to the other shale gas formations present across the U.S. and Canada[66].

In addition to the Barnett Play, a second shale play with greater oil production has also been advancing techniques related to horizontal wells and hydraulic fracturing. The Bakken Shale of the Williston Basin of Montana and North Dakota has seen a similar growth rate to the Barnett. The Bakken is another technical play in which the development of this unconventional resource has benefitted from the technological advances in horizontal wells and hydraulic fracturing[67]. In April 2008, the United States Geological Survey (USGS) released an updated assessment of the undiscovered technically recoverable reserves for this shale play estimating there are 3.65 billion barrels (bbls) of oil, 1.85 tcf of associated natural gas, and 148 million bbls of natural gas liquids in the play[68].

The combination of sequenced hydraulic fracture treatments and horizontal well completions has been crucial in facilitating the expansion of shale gas development. Prior to the successful application of these two technologies in the Barnett Shale, shale gas resources in many basins had been overlooked because production was not viewed as economically feasible[69]. The low natural permeability of shale has been the limiting factor to the production of shale gas resources because

it only allows minor volumes of gas to flow naturally to a wellbore[70]. The characteristic of low-matrix permeability represents a key difference between shale and other gas reservoirs. For gas shales to be economically produced, these restrictions must be overcome[71]. The combination of reduced economics and low permeability of gas shale formations historically caused operators to bypass these formations and focus on other resources[72].

Shale Gas – Geology

Shale gas is natural gas produced from shale formations that typically function as both the reservoir and source for the natural gas. In terms of its chemical makeup, shale gas is typically a dry gas primarily composed of methane (90% or more methane), but some formations do produce wet gas. The Antrim and New Albany formations have typically produced water and gas[73]. Gas shales are organic-rich shale formations that were previously regarded only as source rocks and seals for gas accumulating in the stratigraphically-associated sandstone and carbonate reservoirs of traditional onshore gas development[74]. Shale is a sedimentary rock that is predominantly comprised of consolidated clay-sized particles. Shales are deposited as mud in low-energy depositional environments such as tidal flats and deep water basins where the fine-grained clay particles fall out of suspension in these quiet waters. During the deposition of these very fine-grained sediments, there can also be deposition of organic matter in the form of algae-, plant-, and animal-derived organic debris[75]. The naturally tabular clay grains tend to lie flat as the sediments accumulate and subsequently become compacted as a result of additional sediment deposition. This results in mud with thin laminar bedding that lithifies (solidifies) into thinly layered shale rock. The very fine sheet-like clay mineral grains and laminated layers of sediment result in a rock that has limited horizontal permeability and extremely limited vertical permeability. Typical unfractured shales have matrix permeabilities on the order of 0.01 to 0.00001 millidarcies[76]. This low permeability means that gas trapped in shale cannot move easily within the rock except over geologic expanses of time (millions of years).

EXHIBIT 10: MARCELLUS SHALE OUTCROP

Source: ALL Consulting, 2008

The natural layering and fracturing of shales can be seen in outcrop. Exhibit 10 shows a typical shale outcrop which reveals the natural bedding planes, or layers, of the shale and near-vertical natural fractures that can cut across the naturally horizontal bedding planes. Although the vertical fractures shown in this picture are naturally occurring, artificial fractures induced by hydraulic fracture stimulation in the deep subsurface reservoir rock would have a similar appearance.

The low permeability of shale causes it to be classified as an unconventional reservoir for gas (or in some cases, oil) production. These low permeability, often organic-rich units are also thought to be the source beds for much of the hydrocarbons produced in these basins[77]. Gas reservoirs are classified as conventional or unconventional for the following reasons:

1. **Conventional reservoirs** – Wells in conventional gas reservoirs produce from sands and carbonates (limestones and dolomites) that contain the gas in interconnected pore spaces that allow flow to the wellbore. Much like a kitchen sponge, the gas in the pores can move from one pore to another through smaller pore-throats that create permeable flow through the reservoir. In conventional natural gas reservoirs, the gas is often sourced from organic-rich shales proximal to the more porous and permeable sandstone or carbonate.
2. **Unconventional reservoirs** – Wells in unconventional reservoirs produce from low permeability (tight) formations such as tight sands and carbonates, coal, and shale. In unconventional gas reservoirs, the gas is often sourced from the reservoir rock itself (tight gas sandstone and carbonates are an exception). Because of the low permeability of these formations, it is typically necessary to stimulate the reservoir to create additional permeability. Hydraulic fracturing of a reservoir is the preferred stimulation method for gas shales. Differences between the three basic types of unconventional reservoirs include:
    1. **Tight Gas –** Wells produce from regional low-porosity sandstones and carbonate reservoirs. The natural gas is sourced (formed) outside the reservoir and migrates into the reservoir over time (millions of years)[78]. Many of these wells are drilled horizontally and most are hydraulically fractured to enhance production.
    2. **Coal Bed Natural Gas** (CBNG) – Wells produce from the coal seams which act as source and reservoir of the natural gas[79]. Wells frequently produce water as well as natural gas. Natural gas can be sourced by thermogenic alterations of coal or by biogenic action of indigenous microbes on the coal. There are some horizontally drilled CBNG wells and some that receive hydraulic fracturing treatments. However, some CBNG reservoirs are also underground sources of drinking water and as such there are restrictions on hydraulic fracturing. CBNG wells are mostly shallow as the coal matrix does not have the strength to maintain porosity under the pressure of significant overburden thickness.
    3. **Shale Gas** – Wells produce from low permeability shale formations that are also the source for the natural gas. The natural gas volumes can be stored in a local macro-porosity system (fracture porosity) within the shale, or within the micro-pores of the shale[80], or it can be adsorbed onto minerals or organic matter within the shale[81]. Wells may be drilled either vertically or horizontally and most are hydraulically fractured to stimulate production. Shale gas wells can be similar to other conventional and unconventional wells in terms of depth, production rate, and drilling.

Sources of Natural Gas

Shale gas is both created and stored within the shale bed. Natural gas (methane) is generated from the organic matter that is deposited with and present in the shale matrix.

In order for a shale to have economic quantities of gas it must be a capable source rock. The potential of a shale formation to contain economic quantities of gas can be evaluated by identifying specific source rock characteristics such as total organic carbon (TOC), thermal maturity, and kerogen analysis. Together, these factors can be used to predict the likelihood of the prospective shale to produce economically viable volumes of natural gas. A number of wells may need to be analyzed in order to sufficiently characterize the potential of a shale formation, particularly if the geologic basin is large and there are variations in the target shale zone.

Shale Gas in the United States

Shale gas is present across much of the lower 48 States. Exhibit 7 shows the approximate locations of current producing gas shales and prospective shales. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. The following discussion provides a summary of basic information regarding these shale gas plays.

Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique challenges. For example, the Antrim and New Albany Shales are shallower shales that produce significant volumes of formation water unlike most of the other gas shales. Development of the Fayetteville Shale is occurring in rural areas of north central Arkansas, while development of the Barnett Shale is focused in the area of Forth Worth, Texas, in an urban and suburban environment.

Key Gas Resource Terms

***Proved Reserves**: That portion of recoverable resources that is demonstrated by actual production or conclusive formation tests to be technically, economically, and legally producible under existing economic and operating conditions.*

***Technically Recoverable Resources**: The total amount of resource, discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.*

***Original Gas-In-Place**: The entire volume of gas contained in the reservoir, regardless of the ability to produce it.*

As new technologies are developed and refined, shale gas plays once believed to have limited economic viability are now being re-evaluated. Exhibit 11 summarizes the key characteristics of the most active shale gas plays across the U.S. This exhibit supplies data related to the character of the shale and also provides a means to compare some of the key characteristics that are used to evaluate the different gas shale basins. Note that estimates of the shale gas resource, especially the portion that is technically recoverable, are likely to increase over time as new data become available from additional drilling, as experience is gained in producing shale gas, as understanding of the resource characteristics increases, and as recovery technologies improve.

EXHIBIT 11: COMPARISON OF DATA FOR THE GAS SHALES IN THE UNITED STATES

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
Estimated Basin Area, square miles	5,000	9,000	9,000	95,000	11,000	12,000	43,500
Depth, ft	6, 500 - 8,500[82]	1,000 - 7,000[83]	10,500 - 13,500[84]	4,000 - 8,500[85]	6,000 - 11,000[86]	600 - 2,200[87]	500 - 2,000[88]
Net Thickness, ft	100 - 600[89]	20 - 200[90]	200[91] - 300[92]	50 - 200[93]	120 - 220[94]	70 - 120[95]	50 - 100[96]
Depth to Base of Treatable Water[#], ft	~1200	~500[97]	~400	~850	~400	~300	~400
Rock Column Thickness between Top of Pay and Bottom of Treatable Water, ft	5,300 - 7,300	500 - 6,500	10,100 - 13,100	2,125 - 7650	5,600 - 10,600	300 - 1,900	100 - 1,600
Total Organic Carbon, %	4.5[98]	4.0 - 9.8[99]	0.5 - 4.0[100]	3 - 12[101]	1 - 14[102]	1 - 20[103]	1 - 25[104]
Total Porosity, %	4 - 5[105]	2 - 8[106]	8 - 9[107]	10[108]	3 - 9[109]	9[110]	10 - 14[111]
Gas Content, scf/ton	300 - 350[112]	60 - 220[113]	100 - 330[114]	60 - 100[115]	200 - 300[116]	40 - 100[117]	40 - 80[118]
Water Production, Barrels water/day	N/A	N/A	N/A	N/A	N/A	5 - 500[119]	5 - 500[120]
Well spacing, acres	60 - 160[121]	80 - 160	40 - 560[122]	40 - 160[123]	640[124]	40 - 160[125]	80[126]
Original Gas-In-Place, tcf[127]	327	52	717	1,500	23	76	160
Technically Recoverable Resources, tcf[128]	44	41.6	251	262	11.4	20	19.2

NOTE: Information presented in this table, such as Original Gas-in-Place and Technically Recoverable Resources, is presented for general comparative purposes only. The numbers provided are based on the sources shown and this research did not include a resource evaluation. Rather, publically available data was obtained from a variety of sources and is presented for general characterization and comparison. Resource estimates for any basin may vary greatly depending on individual company experience, data available at the time the estimate was performed, and other factors. Furthermore, these estimates are likely to change as production methods and technologies improve.

Mcf = thousands of cubic feet of gas
scf = standard cubic feet of gas
tcf = trillions of cubic feet of gas
# = For the Depth to base of treatable water data, the data was based on depth data from state oil and gas agencies and state geological survey data.
N/A = Data not available

The Barnett Shale

The Barnett Shale is located in the Fort Worth Basin of north-central Texas. It is a Mississippian-age shale occurring at a depth of 6,500 feet to 8,500 feet (Exhibit 11 and Exhibit 13[131]) and is bounded by limestone formations above (Marble Falls Limestone) and below (Chappel Limestone) (Exhibit 12).

With over 10,000 wells drilled to date, the Barnett Shale is the most prominent shale gas play in the U.S.[132]. It has been a showcase for modern tight-reservoir development typical of gas shales in the U.S.[133]. The development of the Barnett Shale has been a proving ground for combining the technologies of horizontal drilling and large-volume hydraulic fracture treatments. Drilling operations continue expanding the play boundaries outward; at the same time, operations have turned towards infill drilling to increase the amount of gas recovered[134]. Horizontal well completions in the Barnett are occurring at well spacing ranging from 60 to 160 acres per well (Exhibit 11).

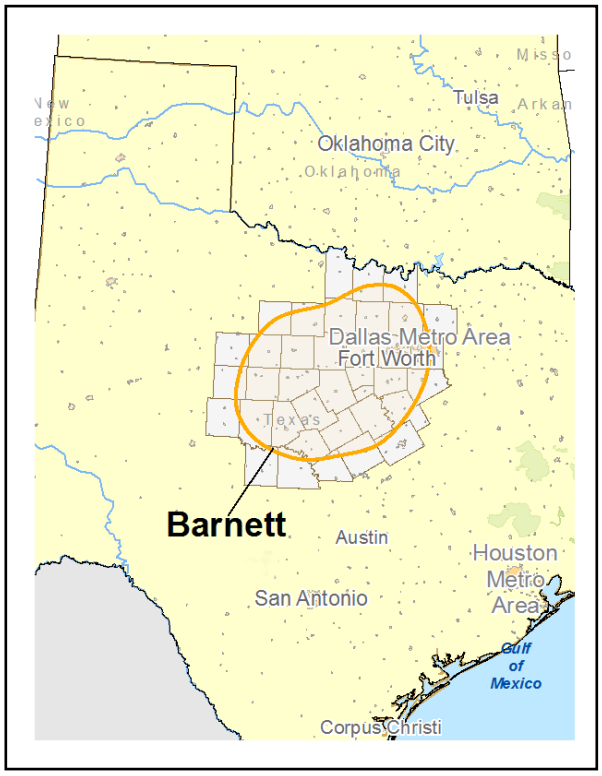
The Barnett Shale covers an area of about 5,000 square miles with an approximate thickness ranging from 100 feet (ft) to more than 600 ft (Exhibit 11). The original gas-in-place estimate for the Barnett Shale is 327 tcf with estimated technically recoverable resources of 44 tcf (Exhibit 11). The gas content is the highest among the major shale plays, ranging from 300 standard cubic feet per ton (scf/ton) to 350 scf/ton of rock (Exhibit 11).

EXHIBIT 12: STRATIGRAPHY OF THE BARNETT SHALE

Period			Group/Unit
Permian		Leonardian	Clear Fork Grp
			Wichita Grp
		Wolfcampian	Cisco Grp
Pennsylvanian		Virgilian	
		Missourian	Canyon Grp
		Desmoinesian	Strawn Grp
		Atokan	Bend Grp
		Morrowan	Marble Falls Limestone
Mississippian		Chesterian - Meramecian	Barnett Shale
		Osagean	Chappel Limestone
Ordovician			Viola Limestone
		Canadian	Simpson Grp Ellenburger Grp

Source: Hayden and Pursell, 2005[129]
AAPG, 1987 [130]

EXHIBIT 13: BARNETT SHALE IN THE FORT WORTH BASIN



Source: ALL Consulting, 2009

The Fayetteville Shale

The Fayetteville Shale is situated in the Arkoma Basin of northern Arkansas and eastern Oklahoma over a depth range of 1,000 ft to 7,000 ft (Exhibit 15[135] and Exhibit 11). The Fayetteville Shale is a Mississippian-age shale bounded by limestone (Pitkin Limestone) above and sandstone (Batesville Sandstone) below (Exhibit 14).

Development of the Fayetteville began in the early 2000s as gas companies that had experienced success in the Barnett Shale of the Fort Worth Basin identified parallels between it and the Mississippian-aged Fayetteville Shale in terms of age and geologic character[136]. Lessons learned from the horizontal drilling and hydraulic fracturing techniques employed in the Barnett, when adapted to development of the Fayetteville Shale, made this play economical[137]. Between 2004 and 2007 the number of gas wells drilled annually in the Fayetteville shale jumped from 13 to more than 600, and gas production for the shale increased from just over 100 MMcf/yr to approximately 88.85 bcf/yr[138]. With over 1,000 wells in production to date, the Fayetteville Shale is currently on its way to becoming one of the most active plays in the U.S.[139].

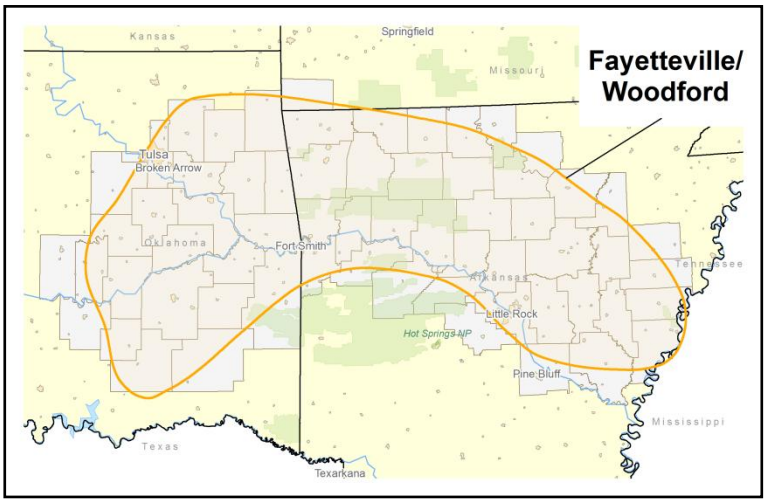
The area of the Fayetteville Shale play is nearly double that of the Barnett Shale at 9,000 square miles, with well spacing ranging from 80 to 160 acres per well, and pay zone thickness averaging between 20 ft and 200 ft (Exhibit 11). The gas content for the Fayetteville Shale has been measured at 60 to 220 scf/ton, which is less than the 300 to 350 scf/ton gas content of the Barnett. The lower gas content of the Fayetteville, as compared to the Barnett, results in lower estimates of the original gas-in-place and technically recoverable resources: 52 tcf and 41.6 tcf respectively (Exhibit 11).

EXHIBIT 14: STRATIGRAPHY OF THE FAYETTEVILLE SHALE

Period		Group/Unit	
CARBONIFEROUS	Pennsylvanian	Atoka	
		Bloyd	
		Hale	Prairie Grove
			Cane Hill
	Mississippian	(IMO)	
		Pitkin	
		Fayetteville	
		Batesville	
		Moorefield	
		Boone	

Source: Hillwood, 2007[140]

EXHIBIT 15: FAYETTEVILLE SHALE IN THE ARKOMA BASIN



Source: ALL Consulting, 2009

The Haynesville Shale

The Haynesville Shale (also known as the Haynesville/Bossier) is situated in the North Louisiana Salt Basin in northern Louisiana and eastern Texas with depths ranging from 10,500 ft to 13,500 ft (Exhibit 17[141] and Exhibit 11). The Haynesville is an Upper Jurassic-age shale bounded by sandstone (Cotton Valley Group) above and limestone (Smackover Formation) below (Exhibit 16).

In 2007, after several years of drilling and testing, the Haynesville Shale made headlines as a potentially significant gas reserve, although the full extent of the play will only be known after several more years of development are completed[142].

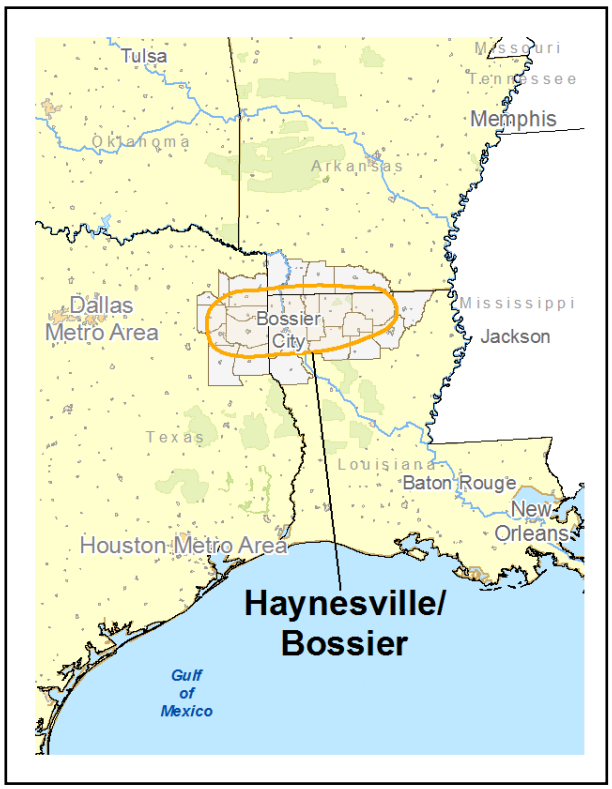
The Haynesville Shale covers an area of approximately 9,000 square miles with an average thickness of 200 ft to 300 ft (Exhibit 11). The thickness and areal extent of the Haynesville has allowed operators to evaluate a wider variety of spacing intervals ranging from 40 to 560 acres per well (Exhibit 11). Gas content estimates for the play are 100 scf/ton to 330 scf/ton. The Haynesville formation has the potential to become a significant shale gas resource for the U.S. with original gas-in-place estimates of 717 tcf and technically recoverable resources estimated at 251 tcf (Exhibit 11).

EXHIBIT 16: STRATIGRAPHY OF THE HAYNESVILLE SHALE

Period		Group/Unit
Cretaceous		Navarro
		Taylor
		Austin
		Eagle Ford
		Tuscaloosa
		Washita
		Fredericksburg
		Trinity Group
		Nuevo Leon
Jurassic	Upper	Cotton Valley Group
		Haynesville
		Smackover
		Norphlet
	Middle	Louann
	Lower	Werner
Triassic	Upper	Eagle Mills

Source: Johnson et al, 2000[143]

EXHIBIT 17: HAYNESVILLE SHALE IN THE TEXAS & LOUISIANA BASIN



Source: ALL Consulting, 2009

The Marcellus Shale

The Marcellus Shale is the most expansive shale gas play, spanning six states in the northeastern U.S. (Exhibit 19[144]). The estimated depth of production for the Marcellus is between 4,000 ft and 8,500 ft (Exhibit 11). The Marcellus Shale is a Middle Devonian-age shale bounded by shale (Hamilton Group) above and limestone (Tristates Group) below (Exhibit 18).

Following an increase in gas prices, triggered by the Natural Gas Policy Act (NGPA) of 1978, Devonian shale gas development rose in the early- to mid-1980s in the northeast, but decreasing gas prices resulted in uneconomical wells and declining production through the 1990s[145]. In 2003, Range Resources Corporation drilled the first economically producing wells into the Marcellus formation in Pennsylvania using horizontal drilling and hydraulic fracturing techniques similar to those used in the Barnett Shale formation of Texas[146]. Range Resources began producing this formation in 2005. As of September 2008, there were a total of 518 wells permitted in Pennsylvania in the Marcellus shale and 277 of the approved wells had been drilled[147].

The Marcellus Shale covers an area of 95,000 square miles at an average thickness of 50 ft to 200 ft (Exhibit 11). While the Marcellus is lower in relative gas content at 60 scf/ton to 100 scf/ton, the much larger area of this play compared to the other shale gas plays results in a higher original gas-in-place estimate of up to 1,500 tcf (Exhibit 11).

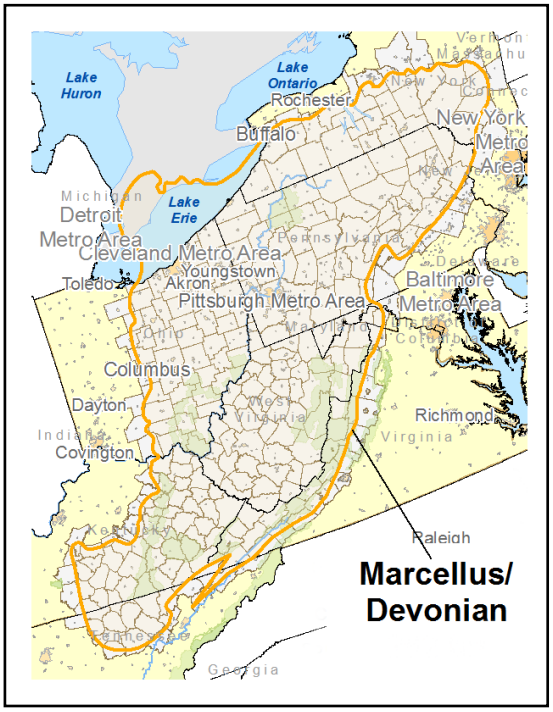
At an average well spacing in the Marcellus is 40 to 160 acres per well (Exhibit 11). The data in Exhibit 11 show technically recoverable resources for the formation to be 262 tcf, although much like the Haynesville, the play's potential estimates are frequently being revised upward due to its early stage of development.

EXHIBIT 18: STRATIGRAPHY OF THE MARCELLUS SHALE

Period		Group/Unit	
Penn		Pottsville	
Miss		Pocono	
Devonian	Upper	Conewango	
		Conneaut	
		Canadaway	
		West Falls	
		Sonyea	
		Genesee	
	Middle	Tully	
		Hamilton Group	Moscow
			Ludlowville
			Skaneateles
			Marcellus
		Onandaga	
	Lower	Tristates	
		Helderberg	

Source: Arthur et al, 2008[148]

EXHIBIT 19: MARCELLUS SHALE IN THE APPALACHIAN BASIN



Source: ALL Consulting, 2009

The Woodford Shale

Located in south-central Oklahoma, the Woodford Shale ranges in depth from 6,000 ft to 11,000 ft (Exhibit 21[149] and Exhibit 11). This formation is a Devonian-age shale bounded by limestone (Osage Lime) above and undifferentiated strata below (Exhibit 20).

Recent natural gas production in the Woodford Shale began in 2003 and 2004 with vertical well completions only[150]. However, horizontal drilling has been adopted in the Woodford, as in other shale gas plays, due to its success in the Barnett Shale[151].

The Woodford Shale play encompasses an area of nearly 11,000 square miles (Exhibit 11). The Woodford play is in an early stage of development and is occurring at a spacing interval of 640 acres per well (Exhibit 11). The average thickness of the Woodford Shale varies from 120 ft to 220 ft across the play (Exhibit 11).

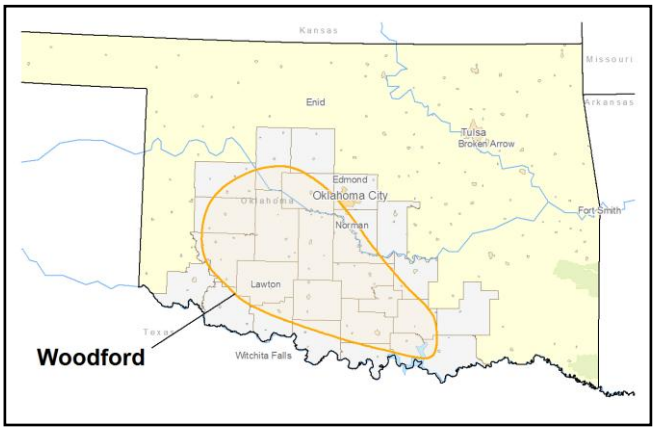
Gas content in the Woodford Shale is higher on average than some of the other shale gas plays at 200 scf/ton to 300 scf/ton (Exhibit 11). The original gas-in-place estimate for the Woodford Shale is similar to the Fayetteville Shale at 23 tcf while the technically recoverable resources are 11.4 tcf (Exhibit 11).

EXHIBIT 20: STRATIGRAPHY OF THE WOODFORD SHALE

Period		Group/Unit	
Permian	Ochoan	Cloyd Chief Fm	
	Guadalupian		
		White Horse Grp	
		El Reno Grp	
	Leonardian	Enid Grp	
	Wolfcampian	Chase Grp	
		Council Grove Grp	
		Admire Grp	
Penn.	Atokan	Atoka Grp	
	Morrowan	Morrow Grp	
Mississippian	Chesterian	Chester Grp	
	Meramecian	Miss Lime	Meramec Lime
	Osagean		Osage Lime
	Kinderhookian		
Devonian		Woodford Shale	
	Upper	Undifferentiated	
	Middle		
	Lower	Hunton Grp	Haragan Fm Henryhouse Fm

Source: Cardott, 2007[152]
AAPG, 1983[153]

EXHIBIT 21: WOODFORD SHALE IN THE ANADARKO BASIN



Source: ALL Consulting, 2009

The Antrim Shale

The Antrim Shale is located in the upper portion of the lower peninsula of Michigan within the Michigan Basin (Exhibit 23[154]). This Late Devonian-age shale is bounded by shale (Bedford Shale) above and by limestone (Squaw Bay Limestone) below and occurs at depths of 600 ft to 2,200 ft which is more typical of CBNG formations than most gas shales (Exhibit 22 and Exhibit 11).

Aside from the Barnett, the Antrim Shale has been one of the most actively developed shale gas plays with its major expansion taking place in the late 1980s[155].

The Antrim Shale encompasses an area of approximately 12,000 square miles and is characterized by distinct differences from other gas shales: shallow depth, small stratigraphic thickness with average net pay of 70 ft to 120 ft, and greater volumes of produced water in the range of 5 to 500 bbls/day/well[156] (Exhibit 11).

The gas content of the Antrim Shale ranges between 40 scf/ton and 100 scf/ton (Exhibit 11). The original gas-in-place for the Antrim is estimated at 76 tcf with technically recoverable resources estimated at 20 tcf (Exhibit 11). Well spacing ranges from 40 acres to 160 acres per well.

EXHIBIT 22: STRATIGRAPHY OF THE ANTRIM SHALE

Period		Formation	
Quaternary	Pleistocene	Glacial Drift	
Jurassic	Middle	Ionia Formation	
Pennsylvanian	Late	Grand River Formation	
	Early	Saginaw Formation	
		Parma Formation	
Mississippian	Late	Bayport Limestone	
		Michigan Formation	
	Early	Marshall Sandstone	
		Coldwater Shale	
		Sunbury Shale	
Devonian	Late	Ellsworth Shale	Berea Sandstone
			Bedford Shale
		Antrim Shale	Upper Member
			Lachine Member
			Paxton Member
			Norwood Member
		Squaw Bay Limestone	

Source: Catacosinos et al, 2000 [157]

EXHIBIT 23: ANTRIM SHALE IN THE MICHIGAN BASIN

Source: ALL Consulting, 2009

EXHIBIT 24: STRATIGRAPHY OF THE NEW ALBANY SHALE

Period		Formation	
Pennsylvanian	Missouri n	Mattoon	
		Bond	
		Patoka	
	Desmoinesi an	Shelburn	
		Dugger	
		Petersburg	
		Linton	
		Staunton	
	Atokan	Brazil	
	Morrowan	Mansfield	
Mississippian	Chesterian	Tobinsport	
		Branchville	
		Tar Springs	
		Glen Dean Limestone	
		Hardinsburg	
		Haney Limestone	
		Big Clifty	
		Beech Creek Limestone	
		Cypress	Elwren
		Reelsville Limestone	
		Sample	
		Beaver Bend Limestone	
		Bethel	
		Paoli Limestone	
		Ste. Genevieve Ls.	
	Valmeyeran	St. Louis Limestone	
		Salem Limestone	
		Harrodsburg Limestone	
		Muldraugh	Ramp Creek
		Edwardsville	
		Spickert Knob	
		New Providence Sh.	
	Kinderhookian	Rockford Ls	Coldwater Sh.
		New Albany Shale	Sunbury Sh.
			Ellsworth Sh.
Devonian	Senecan Chautauquan		Antrim Sh.
	Erian	North Vernon Ls.	Transverse
		Jeffersonville Ls.	Detroit River

Source: Indiana Geological Survey, 1986[158]

The New Albany Shale

The New Albany Shale is located in the Illinois Basin in portions of southeastern Illinois, southwestern Indiana, and northwestern Kentucky[159] (Exhibit 25[160]). Similar to the Antrim Shale, the New Albany occurs at depths between 500 ft and 2,000 ft (Exhibit 11) and is a shallower, water-filled shale with a more CBNG-like character than the other gas shales discussed in this section. The New Albany formation is a Devonian- to Mississippian-age shale bounded by limestone above (Rockford Limestone) and below (North Vernon Limestone) (Exhibit 24).

The New Albany Shale is one of the largest shale gas plays, encompassing an area of approximately 43,500 square miles with approximately 80-acre spacing between wells (Exhibit 11). Similar to the Antrim Shale, the New Albany play has a thinner average net pay thickness of 50 ft to 100 ft and has wells which average 5 to 500 bbls of water per day[161] (Exhibit 11). The measured gas content of the New Albany Shale ranges from 40 scf/ton to 80 scf/ton. The original gas-in-place for the New Albany formation is estimated at 160 tcf with technically recoverable resources estimated at less than 20 tcf (Exhibit 11).

EXHIBIT 25: NEW ALBANY SHALE IN THE ILLINOIS BASIN

Source: ALL Consulting, 2009

REGULATORY FRAMEWORK

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency (EPA) administers most of the federal laws, although development on federally owned land is managed primarily by the Bureau of Land Management (BLM), which is part of the Department of the Interior, and the U.S. Forest Service, which is part of the Department of Agriculture. In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies. Those laws and their delegation are discussed below.

Federal Environmental Laws Governing Shale Gas Development

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act (CWA) regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act (SDWA) regulates the underground injection of fluids from shale gas activities. The Clean Air Act (CAA) limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts.

However, federal agencies do not have the resources to administer all of these environmental programs for all the oil and gas sites around the country. Also, as explained below, one set of nation-wide regulations may not always be the most effective way of assuring the desired level of environmental protection. Therefore, most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight). By statute, states may adopt their own standards; however, these must be at least as protective as the federal standards they replace, and may even be more protective in order to address local conditions. Once these state programs are approved by the relevant federal agency (usually the EPA), the state then has primacy jurisdiction.

By statute, states may adopt their own standards; however, these must be at least as protective as the federal standards they replace, and may even be more protective in order to address local conditions.

State Regulation

State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-size-fits-all regulation at the federal level[162]. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. The state agencies that

permit these practices and monitor and enforce their laws and regulations may be located in the state Department of Natural Resources (such as in Ohio) or in the Department of Environmental Protection (such as in Pennsylvania). The Texas Railroad Commission regulates oil and gas activity in the nation's largest oil and gas producing state, home to the Barnett Shale. The names and organizational structures vary, but the functions are very similar. Often, multiple agencies are involved, having jurisdiction over different activities and aspects of development.

These state agencies do not only implement and enforce federal laws; they also have their own sets of state laws to administer. These state laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

The states have broad powers to regulate, permit, and enforce all activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well.

States have many tools at their disposal to assure that shale gas operations do not adversely impact the environment. The regulation of shale gas drilling and production is a cradle-to-grave approach. The states have broad powers to regulate, permit, and enforce all activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. Different states take different approaches to this regulation and enforcement, but state laws generally give the state oil and gas director or agency the discretion to require whatever is necessary to protect human health and the environment[a]. In addition to the general protection regulations, most states have a general prohibition against pollution from oil and gas drilling and production[b]. Most of the state requirements are written into rules or regulations, while some are added to permits on a case-by-case basis as a result of environmental review, on-the-ground inspections, public comments, or commission hearings.

All states require a permit before an operator can drill and operate a gas well. The application for this permit includes all the information about a well's location, construction, operation and reclamation. Agency staff reviews the application for compliance with regulations and to assure adequate environmental safeguards. If necessary, a site inspection will be made before permit approval. Also, most states require operators to post a bond or other financial security when getting a drilling permit to ensure compliance with state regulations and to make sure that there are funds to properly plug the well once production ceases. Another safeguard is that producers

[a] An example of this type of provision is the following from Pennsylvania's statute: "[T]he department shall have the authority to issue such orders as are necessary to aid in the enforcement of the provisions of [the oil and gas] act." (58 P.S. section 601.503.).

[b] An example of such language can be found in New York's rules, which state: "The drilling, casing and completion program adopted for any well shall be such as to prevent pollution. Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited." (6 NYCRR Part 554). Another example is the requirement in the rules of the Texas Railroad Commission: "No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state." (TAC 16.1.3.8).

generally must notify the state agencies of any significant new activity through a "sundry notice" or a new permit application so that the agency is aware of that activity and can review it[c].

States have implemented voluntary review processes to help ensure that the state programs are as effective as possible. The Ground Water Protection Council (GWPC) has a program to review state implementation of the Underground Injection Control (UIC) program. In addition to the GWPC UIC review, state oil and gas environmental programs other than UIC programs can also be periodically reviewed against a set of guidelines developed by an independent body of state, industry, and environmental stakeholders, known as STRONGER (State Review of Oil and Natural Gas Environmental Regulation, Inc.)[163]. Periodic evaluations of state exploration and production waste management programs have proven useful in improving the effectiveness of those programs and increasing cooperation between federal and state regulatory agencies. To date, 18 states have been reviewed under the state review guidelines, and several have been reviewed more than once. The STRONGER program has documented the effectiveness of and improvements in these state oil and gas environmental programs[164,165]. The Interstate Oil and Gas Compact Commission (IOGCC) also completed state reviews using earlier versions of the guidelines prior to the formation of STRONGER.

The organization of regulatory agencies within the various oil and gas producing states varies considerably. Some states have several agencies that may oversee some facet of oil and gas operations, especially environmental requirements. These agencies may be in various departments or divisions within the states' organizations. These various approaches have developed over time within each state, and each state tries to create a structure that best serves its citizenry and all of the industries that it must oversee. The one constant is that each oil and gas producing state has one agency with primary responsibility for permitting wells and overseeing general operations. While this agency may work with other agencies in the regulatory process, they can serve as a good source of information about the various agencies that may have jurisdiction over oil and gas activities. Exhibit 26 provides a list of the agencies with primary responsibility for oil and gas regulation in each of the states that have or are likely to have shale gas production.

Local Regulation

In addition to state and federal requirements, additional requirements regarding oil and gas operations may be imposed by other levels of government in specific locations. Entities such as cities, counties, tribes, and regional water authorities may each set operational requirements that affect the location and operation of wells or require permits and approvals in addition to those at the federal or state level.

[c] See, for example, Louisiana Statewide Order 29-B, section 105, or Texas Administrative Code 16.1.3.5.

EXHIBIT 26: OIL AND GAS REGULATORY AGENCIES IN SHALE GAS STATES

State	Agency	Web Address
Alabama	Geological Survey of Alabama, State Oil and Gas Board	http://www.ogb.state.al.us/ogb/ogb.html
Arkansas	Arkansas Oil and Gas Commission	http://www.aogc.state.ar.us/
Colorado	Colorado Department of Natural Resources, Oil and Gas Conservation Commission	http://cogcc.state.co.us/
Illinois	Illinois Department of Natural Resources, Division of Oil and Gas	http://dnr.state.il.us/mines/dog/index.htm
Indiana	Indiana Department of Natural Resources, Division of Oil and Gas	http://www.in.gov/dnr/dnroil/
Kentucky	Kentucky Department for Energy Development and Independence, Division of Oil and Gas Conservation	http://www.dogc.ky.gov/
Louisiana	Louisiana Department of Natural Resources, Office of Conservation	http://dnr.louisiana.gov/cons/conserv.ssi
Michigan	Michigan Department of Environmental Quality, Office of Geological Survey	http://www.michigan.gov/deq/0,1607,7-135-3306_28607---,00.html
Mississippi	Mississippi State Oil and Gas Board	http://www.ogb.state.ms.us/
Montana	Montana Department of Natural Resources and Conservation, Board of Oil and Gas	http://bogc.dnrc.mt.gov/default.asp
New Mexico	New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division	http://www.emnrd.state.nm.us/OCD/
New York	New York Department of Environmental Conservation, Division of Mineral Resources	http://www.dec.ny.gov/energy/205.html
North Dakota	North Dakota Industrial Commission, Department of Mineral Resources Oil and Gas Division	https://www.dmr.nd.gov/oilgas/
Ohio	Ohio Department of Natural Resources, Division of Mineral Resources Management	http://www.ohiodnr.com/mineral/default/tabid/10352/Default.aspx
Oklahoma	Oklahoma Corporation Commission, Oil and Gas Conservation Division	http://www.occ.state.ok.us/Divisions/OG/newweb/og.htm
Pennsylvania	Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management	http://www.dep.state.pa.us/dep/DEPUTATE/MINRES/OILGAS/oilgas.htm
Tennessee	Tennessee Department of Environment and Conservation, State Oil and Gas Board	http://www.tennessee.gov/environment/boards/oilandgas.shtml
Texas	The Railroad Commission of Texas	http://www.rrc.state.tx.us/index.html
West Virginia	West Virginia Department of Environmental Protection, Office of Oil and Gas	http://www.wvdep.org/item.cfm?ssid=23

When operations occur in or near populated areas, local governments may establish ordinances to protect the environment and the general welfare of its citizens. These local ordinances frequently require additional permits for issues such as well placement in flood zones, noise level, set backs from residences or other protected sites, site house-keeping, and traffic. For example, ordinances may set limits on noise levels that may be generated during both daytime and nighttime operations[166,167,168,169].

In some cases, regional water-permitting authorities that have jurisdiction in multiple states have also been established. These federally established authorities have been created to protect the water quality of the entire river basin and to govern uses of the water[170]. Additional approvals and permits may be required for operations in these river basins. For example, the Delaware River Basin Commission (DRBC) covers parts of New York, Pennsylvania, New Jersey and Delaware[171]. Natural gas operators wishing to withdraw water for consumptive use in this basin must first receive a permit from the DRBC, which has the legal authority to fine violators of their rules and regulations.

The variety of laws governing shale gas exploration and production, and the multitude of federal and state agencies that implement them, can sometimes be confusing. Therefore, the following discussion has been organized according to the various environmental media that are affected by these activities, i.e., water, air, and land. The major laws and programs affecting each of these are discussed below. Additional considerations on federal land and unique state requirements are also covered, along with some of the programs that cut across these environmental media.

Regulation of Impacts on Water Quality

Potential impacts to water quality are primarily regulated under several federal statutes and the accompanying state programs. The primary federal statutes governing water quality issues related to shale gas development are the Clean Water Act, the Safe Drinking Water Act, and the Oil Pollution Act. These statutes and their relationships to shale gas development are discussed below.

Clean Water Act

The Clean Water Act (CWA) is the primary federal law in the U.S. governing pollution of surface water. It was established to protect water quality, and includes regulation of pollutant limits on the discharge of oil- and gas-related produced water. This is conducted through the National Pollutant Discharge Elimination System (NPDES) permitting process. Although EPA sets national standards at the federal level, states and tribal governments can acquire primacy for the NPDES program by meeting EPA's primacy requirements.

The CWA establishes the basic structure for regulating discharges of pollutants into the waters of the U.S. and quality standards for surface waters. The basis of the CWA was enacted in 1948 and was called the Federal Water Pollution Control Act; the Act was significantly reorganized and expanded in 1972. "Clean Water Act" became its common name, with additional amendments made in 1977 and later.

Under the CWA, EPA has implemented pollution control programs such as setting wastewater standards for industry. They have also set water quality standards for a variety of contaminants in surface waters.

The CWA made it unlawful to discharge any pollutant from a point source into the navigable waters of the U.S., unless done in accordance with a specific approved permit. The NPDES permit program controls discharges from point sources that are discrete conveyances, such as pipes or man-made ditches. Industrial, municipal, and other facilities such as shale gas production sites or commercial facilities that handle the disposal or treatment of shale gas produced water must obtain permits if they intend to discharge directly into surface waters[172,173]. Large facilities usually have individual NPDES permits. Discharges from some smaller facilities may be eligible for inclusion under general permits that authorize a category of discharges under the CWA within a geographical area. A general permit is not specifically tailored for an individual discharger. Most oil and gas production facilities with related discharges are authorized under general permits because there are typically numerous sites with common discharges in a geographic area.

A state that meets the federal primacy requirements is allowed to set more stringent state-specific standards for this program. Since individual states can acquire primacy over their respective programs, it is not uncommon to have varying requirements from state to state. This variation can affect how the oil and gas industry manages produced water within a drainage basin located within two or more states, such as the Marcellus shale in the Appalachian Basin. Effluent limitations serve as the primary mechanism under NPDES permits for controlling discharges of pollutants to receiving waters. When developing effluent limitations for an NPDES permit, a permit writer must consider limits based on both the technology available to control the pollutants (i.e., technology-based effluent standards) and the regulations that protect the water quality standards of the receiving water (i.e., water quality-based effluent standards).

The intent of technology-based effluent limits in NPDES permits is to require treatment of effluent concentrations to less than a maximum allowable standard for point source discharges to the specific surface water body. This is based on available treatment technologies, while allowing the discharger to use any available control technique to meet the limits. For industrial (and other non-municipal) facilities, technology-based effluent limits are derived by: 1) using national effluent limitations guidelines and standards established by EPA, or 2) using best professional judgment (BPJ) on a case-by-case basis in the absence of national guidelines and standards.

Prior to the granting of a permit, the authorizing agency must consider the potential impact of every proposed surface water discharge on the quality of the receiving water, not just individual discharges. If the authorizing agency determines that technology-based effluent limits are not sufficient to ensure that water quality standards will be attained in the receiving water, the CWA [Section 303(b)(1)(c)] and NPDES regulations [40 Code of Federal Regulations (CFR) 122.44(d)] require that more stringent limits are imposed as part of the permit[174].

EPA establishes effluent limitation guidelines (ELGs) and standards for different non-municipal (i.e., industrial) categories. These guidelines are developed based on the degree of pollutant reduction attainable by an industrial category through the application of pollution control technologies.

The CWA requires EPA to develop specific effluent guidelines that represent the following:

1. Best conventional technology (BCT) for control of conventional pollutants and applicable to existing dischargers.
2. Best practicable technology (BPT) currently available for control of conventional, toxic and nonconventional pollutants and applicable to existing dischargers.
3. Best available technology (BAT) economically achievable for control of toxic and nonconventional pollutants and applicable to existing dischargers.
4. New source performance standards (NSPS) for conventional pollutants and applicable to new sources.

To date, EPA has established guidelines and standards for more than 50 different industrial categories[175].

The ELGs for Oil and Gas Extraction, which were published in 1979, can be found at 40 CFR Part 435. The onshore subcategory, Subpart C, is applicable to discharges associated with shale gas development and production[176].

The CWA also includes a program to control storm water discharges. The 1987 Water Quality Act (WQA) added Section 402(p) to the CWA requiring EPA to develop and implement a storm water permitting program. EPA developed this program in two phases (Phase I: 1990; Phase II: 1999). Those regulations establish NPDES permit requirements for municipal, industrial, and construction site storm water runoff. The WQA also added Section 402(l)(2) to the CWA specifying that the EPA and states shall not require NPDES permits for uncontaminated storm water discharges from oil and gas exploration, production, processing or treatment operations, or transmission facilities. This exemption applies where the runoff is not contaminated by contact with raw materials or wastes. EPA had previously interpreted the 402(l)(2) exemption as not applying to construction activities of oil and gas development, such as building roads and pads (i.e., an NPDES permit was required)[177].

The Energy Policy Act of 2005 modified the CWA Section 402(l)(2) exemption by defining the excluded oil and gas sector operations to include all oil and gas field activities and operations, including those necessary to prepare a site for drilling and for the movement and placement of drilling equipment. EPA promulgated a rule that implemented this exemption. However, on May 23, 2008, the U.S. Court of Appeals for the Ninth Circuit released a decision vacating the permitting exemption for discharges of sediment from oil and gas construction activities that contribute to violations of the CWA[178]. The court based its decision on the fact that the new rule exempted runoff contaminated with sediment, while the CWA does not exempt such runoff. As a result of the court's decision, storm water discharges contaminated with sediment resulting in a water quality violation require permit coverage under the NPDES storm water permitting program.

While the EPA storm water permitting rule contains a broad exclusion for oil and gas sector construction activities, it is important to note that individual states and Indian tribes may still regulate storm water associated with these activities. EPA has clarified its position that states and tribes may not regulate such storm water discharges under their CWA authority, but are free to regulate under their own independent authorities. EPA states that "[t]his final rule is not intended

to interfere with the ability of states, tribes, or local governments to regulate any discharges through a non-NPDES permit program"[179]. In addition to state and tribal regulation, the industry has a voluntary program of Reasonable and Prudent Practices for Stabilization (RAPPS) of oil and gas construction sites[180]. Producers use RAPPS in order to control erosion and sedimentation associated with storm water runoff from areas disturbed by clearing, grading, and excavating activities related to site preparation.

Safe Drinking Water Act

Congress originally passed the Safe Drinking Water Act (SDWA) in 1974 to protect public health by regulating the nation's public drinking water supply. The law was amended in 1986 and 1996 and requires many actions to protect drinking water and its sources, including rivers, lakes, reservoirs, springs, and ground water wells. SDWA authorizes the U.S. EPA to set national health-based standards for drinking water to protect against both naturally occurring and man-made contaminants that may be found in drinking water. EPA, states, and municipal water system agencies then work together to make sure that these standards are met[181].

As one aspect of the protection of drinking water supplies, the SDWA establishes a framework for the Underground Injection Control (UIC) program to prevent the injection of liquid wastes into underground sources of drinking water (USDWs). The EPA and states implement the UIC program, which sets standards for safe waste injection practices and bans certain types of injection altogether. The UIC Program provides these safeguards so that injection wells do not endanger USDWs. The first federal UIC regulations were issued in 1980.

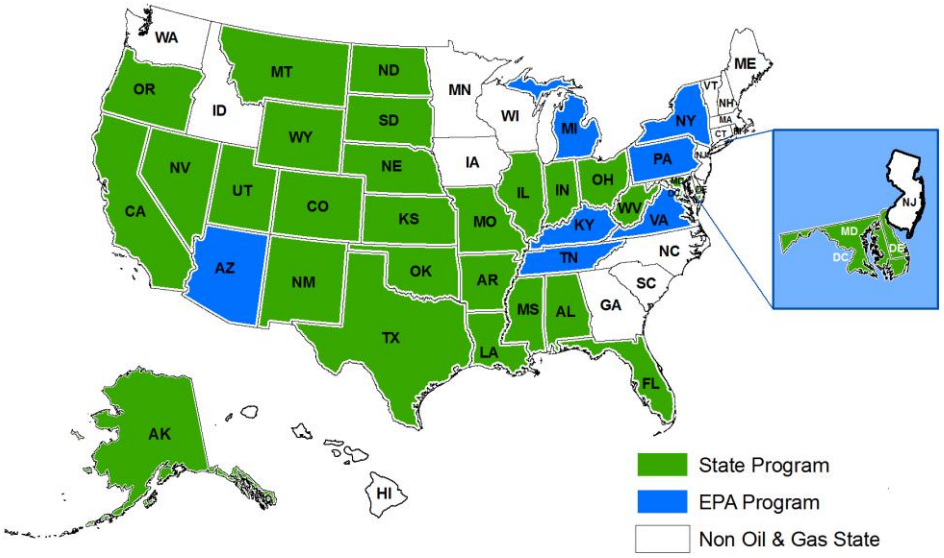
EPA currently groups underground injection wells into five classes for regulatory control purposes, and has a sixth class under consideration. Each class includes wells with similar functions, construction and operating features so that technical requirements can be applied consistently to the class.

1. **Class I** wells may inject hazardous and nonhazardous fluids (industrial and municipal wastes) into isolated formations beneath the lowermost USDW. Because they may inject hazardous waste, Class I wells are the most strictly regulated and are further regulated under the Resource Conservation and Recovery Act (RCRA).
2. **Class II** wells may inject brines and other fluids associated with oil and gas production.
3. **Class III** wells may inject fluids associated with solution mining of minerals.
4. **Class IV** wells may inject hazardous or radioactive wastes into or above a USDW and are banned unless specifically authorized under other statutes for ground water remediation.
5. **Class V** includes all underground injection not included in Classes I-IV. Generally, most Class V wells inject nonhazardous fluids into or above a USDW and are on-site disposal systems, such as floor and sink drains which discharge to dry wells, septic systems, leach fields, and drainage wells. Injection practices or wells that are not covered by the UIC Program include single family septic systems and cesspools as well as non-residential septic systems and cesspools serving fewer than 20 persons that inject ONLY sanitary waste water.
6. **Class VI** has been proposed specifically for the injection of CO_2 for the purpose of sequestration, but has not yet been established.

Most injection wells associated with oil and gas production are Class II wells. These wells may be used to inject water and other fluids (e.g., liquid CO_2) into oil- and gas-bearing zones to enhance recovery, or they may be used to dispose of produced water. The regulation specifically prevents the disposal of waste fluids into USDWs by limiting injection only to formations that are not "underground sources of drinking water." EPA's UIC Program is designed to prevent contamination of water supplies by setting minimum requirements for state UIC Programs. The basic premise of the UIC Program is to prevent contamination of USDWs by keeping injected fluids within the intended injection zone. The injected fluids must not endanger, or have the potential to endanger, a current or future public water supply. The UIC requirements that affect the siting, construction, operation, maintenance, monitoring, testing, and, finally, closure of injection wells have been established to address these concepts. All injection wells require authorization under general rules or specific permits.

The law was written with the understanding that states are best suited to have primary enforcement authority (primacy) for the UIC Program. In the SDWA, Congress cautioned EPA against a "one-size-fits-all" regulatory scheme, and mandated consideration of local conditions and practices. Section 1421(b)(3)(A) requires that UIC regulations permit or provide consideration of varying geological, hydrological, or historical conditions in different states and in different areas within a state. Section 1425 allows a state to obtain primacy from EPA for oil- and gas-related injection wells, without being required to adopt the complete set of applicable federal UIC regulations. The state must be able to demonstrate that its existing regulatory program is protecting USDWs as effectively as the federal requirements[182].

EXHIBIT 27: UIC CLASS II PRIMACY MAP



Source: EPA,, 2008

To date, 40 states have obtained primacy for oil and gas injection wells (Class II), although, as shown in Exhibit 27 not all of these states have oil and gas production. The U.S. EPA administers UIC programs for ten states, seven of which are oil and gas states, and all other federal jurisdictions and Indian Lands[183] (Exhibit 27[184]).

Oil Pollution Act of 1990 – Spill Prevention Control and Countermeasure

The CWA and the Oil Pollution Act (OPA) include both regulatory and liability provisions that are designed to reduce damage to natural resources from oil spills. Congress added Section 311 to the

CWA, which in part authorized the President to issue regulations establishing procedures, methods, equipment, and other requirements to prevent discharges of oil from vessels and facilities [Section 311(j)(1)(c)]. In response to the Exxon Valdez oil spill in Alaska, Congress enacted the OPA in 1990[185]. The OPA amended CWA Section 311 and contains provisions applicable to onshore facilities and operations.

Section 311, as amended by the OPA, provides for spill prevention requirements, spill reporting obligations, and spill response planning. It regulates the prevention of and response to accidental releases of oil and hazardous substances into navigable waters, on adjoining shorelines, or affecting natural resources belonging to or managed by the U.S. This authority is primarily carried out through the creation and implementation of facility and response plans. These plans are intended to establish measures that will prevent discharge of oil into navigable waters of the U.S. or adjoining shore-lines as opposed to response and cleanup after a spill occurs.

A cornerstone of the strategy to prevent oil spills from reaching the nation's waters is the oil Spill Prevention, Control and Countermeasure (SPCC) plan. EPA promulgated regulations to implement this part of the OPA of 1990. These regulations specify that:

1. SPCC Plans must be prepared, certified (by a professional engineer) and implemented by facilities that store, process, transfer, distribute, use, drill for, produce, or refine oil;
2. Facilities must establish procedures and methods and install proper equipment to prevent an oil release;
3. Facilities must train personnel to properly respond to an oil spill by conducting drills and training sessions; and,
4. Facilities must also have a plan that outlines steps to contain, clean up and mitigate any effects that an oil spill may have on waterways[186].

Before a facility is subject to the SPCC rule, it must meet three criteria:

1. It must be non-transportation-related;
2. It must have an aggregate aboveground storage capacity greater than 1,320 gallons (31.4 bbls) or a completely buried storage capacity greater than 42,000 gallons (1,000 bbls); and
3. There must be a reasonable expectation of a discharge into or upon navigable waters of the U.S. or adjoining shorelines.

An SPCC Plan is a site-specific document that describes the measures the facility owner has taken to prevent oil spills, and what measures are in place, if needed, to contain and clean spills. It includes information about the facility, the oil storage containment, inspections, and a site diagram with locations of tanks (above and below ground) and drainage, and other pertinent details. Prevention measures include secondary containment around tanks and certain oil-containing equipment.

The SPCC program is not as applicable to shale gas operations as it is to oil production sites. Shale gas operators may have to prepare plans if they store large amounts of fuel (exceeding the volumes stated above) on site, or if oil-filled equipment is present, and there is a risk of that oil impacting waters of the U.S.

In October 2007, EPA proposed amendments to the SPCC rule intended to increase clarity and tailor certain requirements to ensure increased compliance. Among other things, these amendments would streamline some requirements by allowing the use of a plan template for smaller facilities, extending some deadlines for plan preparation, and exempting some vessels and flow lines from secondary containment requirements. They would also add spill prevention requirements for some oil and gas facilities. These proposed rules have not yet been made final[187].

State Regulations and Regional Cooperation

In addition to implementing federal statutes for the NPDES, UIC, and storm water programs, states and tribes may impose their own requirements to protect their water resources, both surface and underground. For example, they establish water quality standards for some or all of their surface water. These standards are approved by EPA and become the baseline for CWA permits[188].

In addition, some areas have established regional water authorities that regulate water withdrawals and discharges within a river basin. For example, the Susquehanna River Basin Commission (SRBC)[189] and the DRBC[190] in New York and Pennsylvania require that entities seeking to withdraw water from their river systems first obtain permits. These commissions have authority separate from the states. They have recently directed their attention to the water requirements for drilling and hydraulically fracturing Marcellus Shale gas wells and are updating their requirements for both water withdrawals and discharge of the water after use. Other river basin commissions are more advisory in nature, providing water flow and quality information and coordinating river conservation efforts by state agencies and others.

State agencies are the principal organizations for enforcing water quality regulations. They have inspectors, usually located at regional offices throughout the state, who visit oil and gas well sites to ensure compliance with regulations. When a violation occurs, state enforcement and legal personnel develop the case and order compliance, in many cases also imposing penalties against the violator. Penalties can range from fines to revocation of permits, and even to criminal sanctions in severe cases. Such penalties are usually imposed only after hearings before a board of commissioners or other state body. In addition to fines and penalties, companies that pollute surface or ground water must clean up or remediate the contamination they caused.

Regulation of Impacts on Air Quality

Air quality impacts are regulated under the Clean Air Act (CAA). As described below, the Act sets national standards for emissions of certain pollutants and requires permits for some industrial operations. Greenhouse Gases are not regulated as such, and are not, therefore, discussed in this section.

Clean Air Act

The CAA is the primary means by which EPA regulates potential emissions that could affect air quality. The U.S. Congress passed the CAA in 1963, and they have amended it on several occasions since, most recently in 1990[191]. The CAA requires EPA to set national standards to limit levels of certain pollutants. EPA regulates those pollutants by developing human health-based and/or environmentally and scientifically based criteria for setting permissible levels. Air regulations do not normally include exceptions for a company's size, the age of a field, or the type of operation. Typically, the air rules are silent on issues such as conventional versus unconventional plays, old

versus new fields, and the depth of a well. For the most part, the air emissions, applicable regulations, and associated emissions controls for a shale play are no different than those for any other natural gas operation. There may be differences due to location (some areas of the country have better air quality than others), equipment needs (some shale plays may produce a wetter gas than others), and sulfur content level of the gas.

Geographic areas that do not meet EPA's standards for a given pollutant are designated as "nonattainment areas"[192]. This is the case for the Barnett Shale play, much of which is located in or near the Dallas-Fort Worth ozone nonattainment area. As a result, Barnett Shale production activities must often comply with much more stringent regulations than similar operations proposed outside of a nonattainment area. As a result of the implementation of the CAA, air quality has improved dramatically across the U.S. during the last few decades and existing regulations should continue to reduce air pollution emissions during the next twenty years or longer[193].

Air Quality Regulations

Like any other U.S. industry, shale gas producers must comply with existing and new air regulations including those resulting from the 1990 CAA Amendments. These rules pose an ongoing challenge to company resources as producers strive to understand and comply with enforcement, fines, public reaction, and possibly even project cancellations in light of new standards.

EPA has established National Emission Standards for Hazardous Air Pollutants (NESHAPs), which are nationally uniform standards to control specific air emissions. In 2007, EPA implemented a new standard referred to as the Maximum Achievable Control Technology (MACT) standard for hazardous air pollutants (HAP) that targeted small area sources such as shale gas operations located in areas near larger populations. These standards limit HAP emissions (primarily benzene) from process vents on glycol dehydration units, storage vessels with flash emissions, and equipment leaks.

Another example of new or amended federal regulations that will have a direct impact on controlling emissions from shale gas operations is the Stationary Spark Ignition Internal Combustion Engine new source performance standard[194] and Reciprocating Internal Combustion Engine NESHAP[195] rules, which regulate new and refurbished engines. These rules, passed in 2007, target all internal combustion engines regardless of horsepower rating, location, or fuel (electric engines are not included) and include extensive maintenance, testing, monitoring, recordkeeping, and reporting requirements[196].

EPA is not large enough to regulate every air emissions source nationwide, let alone consider the local and regional differences. Therefore, they typically delegate that role to local, state, and tribal agencies. This delegation of authority can include rule implementation, permitting, reporting, and compliance. Any state given such delegation of authority can pass more restrictive rules, but they are prohibited from passing a rule that is less stringent than its federal counterpart.

Air Permits

Air permits are legal documents that facility owners and operators must abide by. The permit specifies what construction is allowed, what emission limits must be met, how the emissions source(s) must be operated, and what conditions—specifying monitoring, record keeping, and

reporting requirements—must be maintained to assure ongoing compliance. Shale gas producers may need air quality permits for a number of emissions sources, including gas compressor engines, glycol dehydrators, and flares.

A company's permitting responsibility does not end with the issuance of their initial air permit. They must be constantly vigilant that a new regulation, modification, replacement, or process change does not impact their existing permit and require a permit amendment or a more stringent permit. Although these permits may differ across the country, they all contain specific conditions designed to ensure state and federal standards are met and to prevent any significant degradation in air quality as a result of a proposed activity.

Regulation of Impacts to Land

Impacts to land from shale gas operations include solid waste disposal and surface disturbances that may impact the visual landscape or may affect wildlife habitat. Operations on federal lands are a special case with unique requirements that are discussed below.

Resource Conservation and Recovery Act (RCRA)

RCRA was passed in 1976 to address the growing problems of the increasing volume of municipal and industrial waste. RCRA established goals for protecting human health and the environment, conserving resources, and reducing the amount of waste. RCRA Subtitle C established a federal program to manage hazardous wastes from cradle to grave to ensure that hazardous waste is handled in a manner that protects human health and the environment. Subtitle D of the RCRA addresses non-hazardous solid wastes, including certain hazardous wastes which are exempted from the Subtitle C regulations[197].

In 1978, EPA proposed hazardous waste management standards that included reduced requirements for some industries, including oil and gas, with large volumes of wastes. EPA determined that these large volume "special wastes" were lower in toxicity than other wastes being regulated as hazardous waste under the RCRA[198].

In 1980, the Solid Waste Disposal Act (SWDA) amended RCRA to exempt drilling fluids, produced waters, and other wastes associated with exploration, development, and production of crude oil, natural gas and geothermal energy[199]. The SWDA Amendments also required EPA to provide a report to Congress on these wastes and to make a regulatory determination as to whether regulation of these wastes under RCRA Subtitle C was warranted[200].

In 1988, EPA issued a final regulatory determination stating that control of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted.

In 1987, EPA issued a Report to Congress that outlined the results of a study on the management, volume, and toxicity of wastes generated by the oil, natural gas and geothermal industries. In 1988, EPA issued a final regulatory determination stating that control of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted. EPA made this determination because it found that other state and federal programs could protect human health and the

environment more effectively. In lieu of regulation under Subtitle C, EPA implemented a three-pronged strategy to ensure that the environmental and programmatic issues were addressed:

1. Improve other federal programs under existing authorities;
2. Work with states to improve some programs; and
3. Work with Congress to develop any additional statutory authorities that may be required[201].

These wastes have remained exempt from Subtitle C regulations, but this does not preclude these wastes from control under state regulations or other federal regulations[202]. The exemption applies only to the federal requirements of RCRA Subtitle C. A waste that is exempt from Subtitle C regulation might be subject to more stringent or broader state hazardous and non-hazardous waste regulations and other state and federal program regulations. For example, oil and gas exploration and production wastes may be subject to regulation under RCRA Subtitle D, the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, and/or the Oil Pollution Act of 1990[203,204].

In 1989, EPA worked with the Interstate Oil and Gas Compact Commission (IOGCC), state regulatory officials, industry representatives, and nationally recognized environmental groups to establish a Council on Regulatory Needs. The purpose of the council was to review existing state oil and gas exploration and production waste management programs and to develop guidelines to describe the elements necessary for an effective state program. This effort was begun by EPA as part of the second prong of the agency's approach. These groups then worked together with state regulatory agencies to review the state programs, on a voluntary basis, against these guidelines and to make recommendations for improvement. This state review program continues today under the guidance of a non-profit organization called STRONGER. The state programs reviewed to date represent over 90% of the onshore domestic production[205].

Working with the IOGCC, STRONGER has continued to update the guidelines consistent with developing environmental and oilfield technologies and practices. Under the state review process, state programs have continued to improve, and follow-up reviews have shown significant improvement where states have successfully implemented the recommendations of the review committees.

Endangered Species Act

The Endangered Species Act (ESA) of 1973 (Pub. L. 93-205) protects plants and animals that are listed by the federal government as "endangered" or "threatened"[206]. Sections 7 and 9 are central to regulating oil and gas activities. Section 9 makes it unlawful for anyone to "take" a listed animal, and this includes significantly modifying its habitat[207]. This applies to private parties and private land; a landowner is not allowed to harm an endangered animal or its habitat on his or her property.

Section 7 applies not to private parties, but to federal agencies. This section covers not only federal activities but also the issuance of federal permits for private activities, such as Section 404 permits issued by the Corps of Engineers, to people who want to do construction work in waters or wetlands[208]. Section 7 imposes an affirmative duty on federal agencies to ensure that their actions (including permitting) are not likely to jeopardize the continued existence of a listed species (plant

or animal) or result in the destruction or modification of critical habitat. Both Sections 7 and 9 allow "incidental takes" of threatened or endangered species, but only with a permit.

To "take" is to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect a plant or animal of any threatened or endangered species. Harm includes significant habitat modification when it kills or injures a member of a listed species through impairment of essential behavior (e.g., nesting or reproduction).

For any non-federal industrial activity, the burden is on the owner and/or operator to determine if an incidental take permit is needed. This is typically accomplished by contacting the U.S. Fish and Wildlife Service (FWS) to determine whether any listed species are present or will potentially inhabit the project site. A biological survey may be required to determine whether protected species are present on the site and whether a Section 9 permit may be required[209,210]. The FWS as well as many state fish and game agencies offer services to help operators determine whether a given project is likely to result in a take and whether a permit is required. FWS can also provide technical assistance to help design a project so as to avoid impacts. For example, the project could be designed to minimize disturbances during nesting or mating seasons[211].

A Section 9 permit must include a habitat conservation plan (HCP) consisting of: an assessment of impacts; measures that will be undertaken to monitor, minimize and mitigate any impacts; alternative actions considered and an explanation of why they were not taken; and any additional measures that the FWS may require[212]. Mitigation measures, which are actions that reduce or address potential adverse effects of a proposed activity upon species, must be designed to address the specific needs of the species involved and be manageable and enforceable. Mitigation measures may take many forms, such as preservation (via acquisition or conservation easement) of existing habitat; enhancement or restoration of degraded or former habitat; creation of new habitats; establishment of buffer areas around existing habitats; modifications of land use practices; and restrictions on access[213].

State Endangered Species Protections

All fifty states have fish and game/wildlife agencies that work in cooperation with the U. S. FWS district offices with regard to the incidental take permitting process. Many states also have their own endangered and threatened species lists that may include species not on the federal lists, and have their own requirements for protecting endangered species[214].

Oil and Gas Operations on Public Lands

Federal Lands

The U.S. Department of Interior's Bureau of Land Management (BLM) is responsible for permitting and managing most onshore oil and gas activities on federal lands. The BLM carries out its responsibility to protect the environment throughout the process of oil and gas resource exploration and development on public lands. Resource protection is considered throughout the land use planning process—when Resource Management Plans (RMPs) are prepared and when an Application for Permit to Drill (APD) is processed[215]. The BLM's inspection and enforcement and monitoring program is designed to ensure that operators comply with relevant laws and regulations as well as specific stipulations set forth during the permitting process.

Since most shale gas activity in the near future is expected to occur in the eastern U.S. basins, it is not likely that much of this development will occur on federal lands. While there are some federal lands, such as National Parks, National Forests, and military installations, these are much less extensive in the east than in the west. Where shale gas operations do occur on federal lands, BLM has a well established program for managing these activities to protect human health and the environment.

State Lands

The amount of state-owned land varies considerably from state to state and each state manages these lands differently. In most states, leasing of state-owned minerals occurs through lease auctions. Since states are already set up to manage oil and gas operations within their borders, no special permitting or enforcement systems are required. Some states do have Environmental Policy Acts that require a review of environmental impacts that may result from leasing or operations on state lands or of any state action that may affect the environment.

Other Federal Laws and Requirements that Protect the Environment

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund, was enacted by Congress on December 11, 1980. This law created a tax on the chemical and petroleum industries and provided broad federal authority to respond directly to releases or threatened releases of hazardous substances that may endanger public health or the environment. CERCLA established prohibitions and requirements concerning closed and abandoned hazardous waste sites, provided for liability of persons responsible for releases of hazardous waste at these sites, and established a trust fund to provide for cleanup when no responsible party could be identified. Over five years, $1.6 billion was collected and placed in a trust fund for cleaning up abandoned or uncontrolled hazardous waste sites.

CERCLA was amended by the Superfund Amendments and Reauthorization Act (SARA) in 1986. SARA made several changes to the Superfund program that augmented its effectiveness, provided new enforcement authorities, boosted state and citizen involvement, and increased the size of the trust fund.

In addition to the provisions for cleaning up hazardous waste sites, CERCLA requires the person in charge of a vessel or facility to immediately notify the National Response Center when there is a release of a hazardous substance in an amount equal to or greater than the reportable quantity (RQ) for that substance [CERCLA Section 103(a)]. The reportable quantity depends on the substance released.

CERCLA Section 101(14) excludes certain substances from the definition of hazardous substance, thus exempting them from CERCLA regulation. These substances include petroleum, meaning crude oil or any fraction thereof that is not specifically listed as a hazardous substance, natural gas, natural gas liquids, liquefied natural gas, and synthetic gas usable for fuel. If a release of one of these substances occurs, CERCLA notification is not required. Thus, CERCLA reporting will only apply to shale gas production and processing sites if hazardous substances other than crude oil or natural gas are spilled in reportable quantities; such are not usually present at these sites.

However, this particular exclusion applies only to CERCLA Section 103(a) reporting requirements; it does not exempt a facility from the Emergency Planning and Community Right-to-Know Act (EPCRA) Section 304 reporting requirements. A release of a petroleum product containing certain substances is potentially reportable under EPCRA Section 304 if more than an RQ of that substance is released[216].

Many states have separate requirements regarding hazardous substances. Reporting of releases of the materials exempted under CERCLA may be required under state law.

Emergency Planning and Community Right-to-Know Act

Congress enacted EPCRA in 1986 to establish requirements for federal, state and local governments, tribes, and industry regarding emergency planning and "community right-to-know" reporting on hazardous and toxic chemicals. The community right-to-know provisions of EPCRA are the most relevant part of the law for shale gas producers. They help increase the public's knowledge and access to information on chemicals at individual facilities, along with their uses and potential releases into the environment.

Under Sections 311 and 312 of EPCRA, facilities manufacturing, processing, or storing designated hazardous chemicals must make Material Safety Data Sheets (MSDSs), describing the properties and health effects of these chemicals, available to state and local officials and local fire departments. Facilities must also provide state and local officials and local fire departments with inventories of all on-site chemicals for which MSDSs exist. Information about chemical inventories at facilities and MSDSs must be available to the public. Facilities that store over 10,000 pounds of hazardous chemicals are subject to this requirement. Any hazardous chemicals above the threshold stored at shale gas production and processing sites must be reported in this manner.

Section 313 of EPCRA authorizes EPA's Toxics Release Inventory (TRI), which is a publicly available database that contains information on toxic chemical releases and waste management activities reported annually by certain industries as well as federal facilities. EPA issues a list of industries that must report releases for the database. To date, EPA has not included oil and gas extraction as an industry that must report under TRI. This is not an exemption in the law. Rather it is a decision by EPA that this industry is not a high priority for reporting under TRI. Part of the rationale for this decision is based on the fact that most of the information required under TRI is already reported by producers to state agencies that make it publicly available. Also, TRI reporting from the hundreds of thousands of oil and gas sites would overwhelm the existing EPA reporting system and make it difficult to extract meaningful data from the massive amount of information submitted[217, 218].

EPCRA section 304 requires reporting of releases to the environment of certain materials that are subject to this law. As noted in the section above, this requirement would apply to any releases of petroleum products that exceed reporting thresholds, even if those products are exempt from CERCLA reporting. While shale gas production facilities do not normally store the materials subject to EPCRA reporting, known as EPCRA "Extremely Hazardous Substances" and CERCLA hazardous substances, a limited number of chemicals used in the hydraulic fracturing process, such as hydrochloric acid, are classified as hazardous under CERCLA. These chemicals may be brought on site for a few days, at most, during fracturing or work-over operations. Businesses must report non-permitted releases—into the atmosphere, surface water, or groundwater—of any listed

chemical above threshold amounts, known as the "reportable quantity", to federal, state, and local authorities. Therefore, while every precaution is taken to prevent chemical spills, in the event of an accidental release above the reportable quantity, a report would be made to these authorities by the operator.

Occupational Safety and Health Act

Under the Occupational Safety and Health Act of 1970, employers are responsible for providing a safe and healthy workplace for their employees. The Occupational Safety and Health Administration (OSHA) promotes the safety and health of America's working men and women by setting and enforcing standards; providing training, outreach and education; establishing partnerships; and encouraging continual process improvement in workplace safety and health[219].

OSHA has developed specific standards to reduce potential safety and health hazards in the oil and gas drilling, servicing and storage industry[220]. States also have requirements that provide further worker and public safety protections.

Summary

The U.S. has a long history of actively regulating the oil and gas industry including the shale gas industry. A comprehensive set of federal and state laws and programs regulate all aspects of shale gas exploration and production activities. Under these programs, federal, state and local agencies enforce an array of requirements designed to protect human health and the environment during drilling, production, and abandonment operations. Together, these requirements have reduced environmental risk and adverse impacts to our water, air, and land nationwide.

A comprehensive set of federal and state laws and programs regulate all aspects of shale gas exploration and production activities.

ENVIRONMENTAL CONSIDERATIONS

As described in the previous sections, natural gas is an important part of the nation's energy supply. As a clean-burning, affordable and reliable source of energy, natural gas will continue to play a significant role in the energy supply picture for years to come. Unconventional sources of natural gas have become a major component of that future supply and shale gas is rapidly emerging as a critical part of that resource.

There exists an extensive framework of federal, state, and local requirements designed to manage virtually every aspect of the natural gas development process. These regulatory efforts are primarily led by state agencies and include such things as ensuring conservation of gas resources, prevention of waste, and protection of the rights of both surface and mineral owners while protecting the environment[221]. As part of their environmental protection mission, state agencies are responsible for safeguarding public and private water supplies, preserving air quality, addressing safety, and ensuring that wastes from drilling and production are properly contained and disposed of[222].

In order to make sound decisions about future shale gas development, it is important to understand the process of drilling and producing shale gas wells (Exhibit 28) and the attendant environmental considerations. A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective BMPs, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Many of the human and environmental considerations associated with shale gas production are common to all oil and gas development. However, the horizontal drilling and hydraulic fracturing that have become the standard for modern shale gas development bring with them new considerations as well as new ways to reduce impacts. As shale gas development has spread into more densely populated areas, new challenges have been encountered and new technologies and practices have been developed to meet these challenges. In addition, collaborations between industry, regulators and the public have created innovative environmental solutions to problems that at first seemed insurmountable.

Collaborations between industry, regulators and the public have created innovative environmental solutions to problems that at first seemed insurmountable.

One consideration associated with traditional gas development has been the surface disturbance required for access roads and well pads. As described in greater detail below, horizontal drilling provides a means to significantly reduce surface disturbance and a host of related concerns.

EXHIBIT 28: PROCESS OF SHALE GAS DEVELOPMENT (DURATION)

Mineral Leasing

Companies negotiate a private contract or lease that allows mineral development and compensates the mineral owners. Lease terms vary and can contain stipulations or mitigation measures pertinent to protect various resources. (Several weeks to years)

Permits

The operator must obtain a permit authorizing the drilling of a new well. Surveys, drilling plans, and other technical information are frequently required for a permit application. The approved permit may require site specific environmental protection measures. Other permits such as water withdrawal or injection permits may also be required. (Several weeks to months)

Road and Pad Construction

Once permits are received, roads are constructed to access the wellsite. Well pads are constructed to safely locate the drilling rig and associated equipment during the drilling process. Pits may be excavated to contain drilling fluids. (Several days to weeks)

Drilling and Completion

A drilling rig drills the well and multiple layers of steel pipe (called casing) are put into the hole and cemented in place to protect fresh water formations. (Weeks or months)

Hydraulic Fracturing

A specially designed fracturing fluid is pumped under high pressure into the shale formation. The fluid consists primarily of water along with a proppant (usually sand) and about 2% or less of chemical additives. This process creates fractures in rock deep underground that are "propped" open by the sand, which allows the natural gas to flow into the well. (Days)

Production

Once the well is placed on production, parts of the wellpad that are no longer needed for future operations are reclaimed. The gas is brought up the well, treated to a useable condition, and sent to market. (Interim Reclamation: days; Production: years)

Workovers

Gas production usually declines over the years. Operators may perform a workover which is an operation to clean, repair and maintain the well for the purposes of increasing or restoring production. Multiple workovers may be performed over the life of a well. (Several days to weeks)

Plugging and Abandonment/Reclamation

Once a well reaches its economic limit, it is plugged and abandoned according to State standards. The disturbed areas, including well pads and access roads, are reclaimed back to the native vegetation and contours or to conditions requested by the surface owner. (Reclamation Activity: Days; Full Restoration: Years)

Another set of considerations associated with traditional oil and gas development are the conflicts that arise from split estates. In some instances mineral rights and surface rights are not owned by the same party. This is referred to as "split estate" or "severed minerals". The condition of split estate is more prevalent in western states where the federal government owns much of the mineral rights[223]. In the mid-west and eastern states, where shale gas development resources are more prevalent, only 4% of the lands are associated with a federal split estate[224]. However, these same areas frequently have private-private split estate scenarios where the surface owner differs from the mineral estate owner. In these cases the mineral owner may be another individual or a business enterprise such as a coal company.

It is important to understand that surface owners who do not own minerals rights are still afforded certain protections.

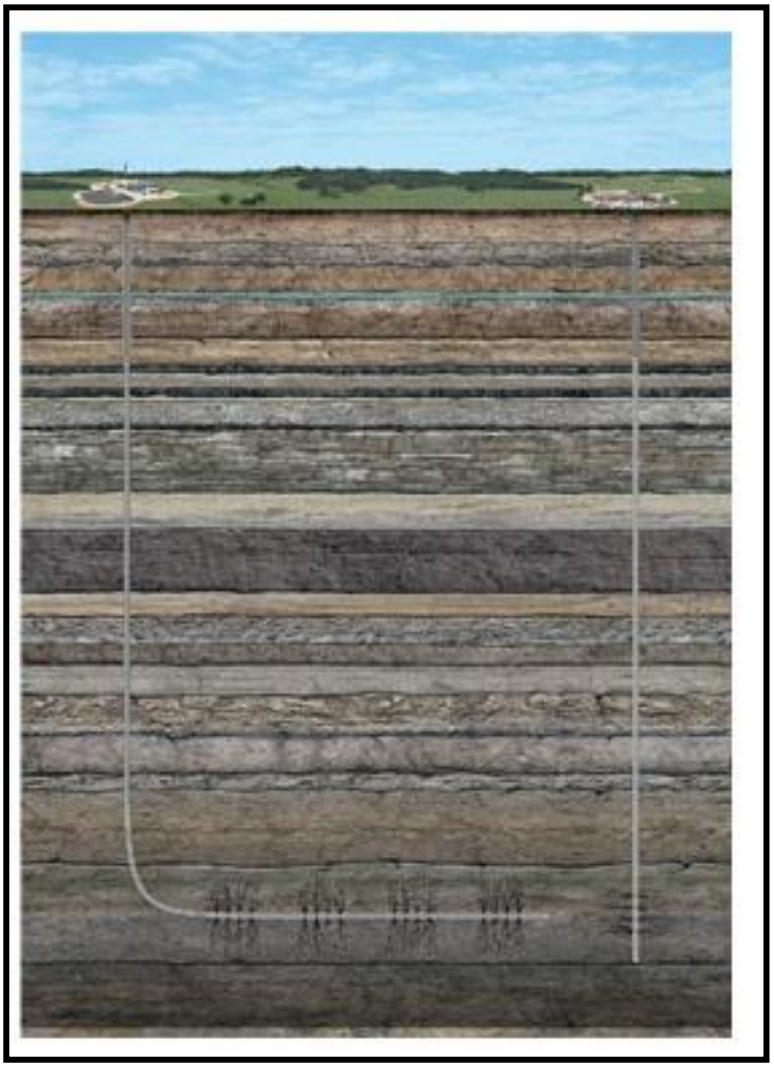
A split-estate situation, regardless of its nature, can result in conflicts—especially in areas where active mineral resource development is not commonplace. Land-owners can be surprised to find that the mineral lease holder is entitled to reasonable use of the land surface even though they do not own the surface. However, it is important to understand that surface owners who do not own minerals rights are still afforded certain protections. If the mineral owner does not own the surface where drilling will occur, a separate agreement may be negotiated (in some states it is required) with the land owner to ensure that he or she is compensated for the use of the land and to set requirements for reclaiming the land when operations are complete[225].

Shale gas development within or near existing communities has created challenges for production companies. New technologies have generally allowed these challenges to be met successfully. In some cases, a combination of modern shale gas technologies and the innovative use of BMPs has been required to allow development to continue without compromising highly valued community resources.

In one instance, Chesapeake Energy Corporation constructed a well pad near a popular Fort Worth community area, known as the Trinity Trail System, to develop natural gas from the Barnett Shale. The Trinity Trail System is located on private land and consists of a 35-mile network of paved and natural surface pathways. The drilling pad was constructed approximately 200 feet from one portion of the trail. During the initial planning stages, proposed use of this land for development of natural gas was met with significant opposition by the public. Maintaining healthy populations of upland hardwood forest habitat was important to the community because such woodlots are rare in urban settings. To address the concerns of the community, the company sponsored public meetings and opinion surveys; provided landscape plans; planted trees and shrubs; and enhanced the general area by improving irrigation and lowering maintenance requirements. The well pad was specifically designed to be as small as possible in order to reduce the well's footprint. Preventative construction practices were used that helped to preserve many of the existing trees. The construction zone was isolated from view using a 16-ft barrier fence with sound baffling. This approach benefitted both parties: the company was able to produce the shale gas, important community resources were protected, and at no point in the process was any portion of the trail closed[226].

The following discussions describe the general process of development with emphasis on the horizontal drilling and hydraulic fracturing technologies that are the hallmarks of modern shale gas production. The section also describes the environmental considerations that accompany shale gas development and the technologies and practices that are in place to prevent or minimize impacts.

EXHIBIT 29: HORIZONTAL AND VERTICAL WELL COMPLETIONS



Source: John Perez, Copyright ©, 2008

Horizontal Wells

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells (Exhibit 29). The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature[227,228,229]. The technologies utilized by operators to drill shale gas wells are similar to the drilling techniques that have been industry standards for drilling of conventional gas wells. Both horizontal drilling and hydraulic fracturing are established technologies with significant track records; horizontal drilling dates back to the 1930s and hydraulic fracturing has a history dating back to the 1950s[230]. The key difference between a shale gas well and a conventional gas well is the reservoir stimulation (large-scale hydraulic fracturing) approach performed on shale gas wells[231].

The evolution of the Barnett Shale play toward favoring horizontal wells resulted from improvements in the technology combined with the economic benefits of the greater reservoir exposure that a horizontal well provides over a vertical well. While both well types may be used to recover the resource, shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well

Both horizontal drilling and hydraulic fracturing are established technologies with significant track records; horizontal drilling dates back to the 1930s and hydraulic fracturing has a history dating back to the 1950s.

economics[232]. Exhibit 29 illustrates how horizontal drilling provides more exposure to a formation than does a vertical well. For example, in the Marcellus Shale in Pennsylvania, a vertical well may be exposed to as little as 50 ft of formation while a horizontal well may have a lateral wellbore extending in length from 2,000 to 6,000 ft within the 50- to 300-ft thick formation[233]. This increase in reservoir exposure creates a number of advantages over vertical wells drilling.

There are a wide range of factors that influence the choice between a vertical or horizontal well. While vertical wells may require less capital investment on a per well basis, production is often less economical. A vertical well may cost as much as $800,000 (excluding pad and infrastructure) to drill compared to a horizontal well that can cost $2.5 million or more (excluding pad and infrastructure)[234].

Source: ALL Consulting, 2008

Active Drilling Rig in the Barnett Shale Play

Reducing Surface Disturbance

Complete development of a 1-square mile section could require 16 vertical wells each located on a separate well pad. Alternatively, six to eight horizontal wells (potentially more), drilled from only one well pad, could access the same reservoir volume, or even more[235]. The low natural permeability of shale requires vertical wells to be developed at closer spacing intervals than conventional gas reservoirs in order to effectively manage the resource. This can result in initial development of vertical wells at spacing intervals of 40 acres per well, or less, to efficiently drain the gas resources from the tight shale reservoirs. In addition, horizontal drilling can significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat fragmentation, impacts to the public, and the overall environmental footprint. Devon Energy Corporation reports that the use of horizontal wells in the Barnett Shale has allowed the company to replace 3 or 4 vertical wells with a single horizontal well. While it is too early to determine the final well spacing that will most efficiently recover the gas resource in all basins, experience to date indicates that the use of horizontal well technology will significantly decrease the total environmental disturbance.

Exhibit 11 includes data on well spacing for some of the developing shale gas basins. Using this data it is possible to compare the development of a typical 640-acre (1 square mile) area with vertical versus horizontal wells. The spacing interval for vertical wells in the gas shale plays averages 40 acres per well for initial development. The spacing

interval for horizontal wells is likely to be approximately 160 acres per well. Therefore, a 640-acre section of land could be developed with a total of 16 vertical wells, each on its own individual well pad, or by as few as 4 horizontal wells all drilled from a single multi-well drilling pad. Analysis performed in 2008 for the U.S. Department of the Interior estimated that a shallow vertical gas well completed in the Fayetteville Shale in Arkansas would have a 2.0-acre well pad, 0.10 miles of road and 0.55 miles of utility corridor, resulting in a total of 4.8 acres of disturbance per well[236]. The same source identified a horizontal well pad in Arkansas as occupying approximately 3.5 acres plus roads and utilities, resulting in a total of 6.9 acres. If multiple horizontal wells are completed from a single well pad it may require the pad to be enlarged slightly. Estimating that this enlargement will result in a 0.5-acre increase, the 4-well horizontal pad with roads and utilities would disturb an estimated total of 7.4 acres, while the 16 vertical wells would disturb approximately 77 acres. In this example, 16 vertical wells would disturb more than 10 times the area of 4 horizontal wells to produce the same resource volume. This difference in development footprint when considered in terms of both rural and urban development scenarios highlights the desire for operators to move toward horizontal development of gas shale plays.

Reducing Wildlife Impacts

Research has documented that activities associated with gas development can affect wildlife and its habitat during the exploration, development, operations, and abandonment phases[237]. The development of shale gas utilizing horizontal wells and multi-well pads not only reduces surface area disturbances by reducing the total number of wells drilled and well pad sites constructed, but also results in fewer roadways and utility corridors. This overall reduction in a project's footprint results in significantly less habitat disturbance while allowing for more operational flexibility. Furthermore, by drilling underneath sensitive areas such as wetlands, areas near streams and rivers and wilderness habitats, gas can be produced without disturbing some of these resources. This ability to reduce surface disturbance is especially important in certain critical habitats. For example, certain portions of New York (e.g., Catskill Park, the Shawangunk Ridge, the Hudson Highlands and the Poconos) are dominated by hardwood forests, which are important wildlife habitats that are susceptible to fragmentation[238].

Source: WVSORO

Drilling Rig in Rural Upshur County, West Virginia

In addition, state regulations and, in some cases, local ordinances include stipulations dictating operational restrictions to provide added protection for wildlife or sensitive resources. In the city of Flower Mound, Texas, ordinances have been adopted to protect the surface resources and allow for future growth of the community without detracting from the land value or sense of community. These ordinances

prevent construction in or near streams or rivers, floodplains and sensitive upland forest to protect wildlife species and their associated habitats.

At the state level, special plans or waivers are required when surface use actions may affect threatened or endangered species. Such waivers must demonstrate that contemplated disturbances will not adversely impact the species in question. In Pennsylvania, wildlife are further protected on state lands (by the Pennsylvania Game Commission) by using lease agreements that require, whenever feasible, the use of existing timber and maintenance roads to access wells and avoidance of areas such as wetlands and unique and critical habitats for threatened or endangered species[239].

When disturbances to wildlife habitat are unavoidable, energy companies mitigate land disturbances by implementing land reclamation practices to restore disturbed land to original conditions. In general, reclamation practices (or mitigation measures) designed to protect and maintain wildlife will depend on project features, regional characteristics, and the potentially affected species. However, because technologies associated with modern shale gas development can reduce impacts in the first place, the need for additional protective restoration measures may also be reduced. Regardless of the situation, the timely reclamation of disturbed lands (e.g., re-seeding, land contouring, and re-vegetating) can minimize short and long-term disturbances to natural habitats[240].

Reducing Community Impacts

States, local governments, and industry can work together in the initial planning phase of development to minimize long term effects and to address citizen concerns such as traffic congestion, damage to roads, dust, and noise [241].The process of shale gas development, especially drilling and hydraulic fracturing, can create short-term increases in traffic volume, dust and noise. These nuisance impacts are usually limited to the initial 20- to 30-day drilling and completion period[242]. Along with increases in traffic volume, damage to road surfaces can occur if design parameters for traffic volume and weight loads are exceeded. Where these effects are an issue, developers have worked with authorities to adjust work schedules to help alleviate congestion; water unpaved roads to reduce dust; and adjust timing of some operations and install special sound barriers to reduce noise for nearby residents. When feasible, developers can also use avoidance practices to help minimize traffic congestion on heavily traveled roads. In the Barnett Shale play around the Dallas-Fort Worth International Airport, operators have constructed permanent pipelines to transfer produced water from well sites to disposal facilities, thereby

Source: Parker County Commissioner's Office

Tanker Trucks in Parker County, Texas

reducing traffic and potential damage to roads[243]. When these practices are coupled with the benefits of multiple directional wells from fewer pads, the number of access roads and associated traffic can be further reduced.

In many cases, developers have negotiated to compensate local municipalities for road damage that does occur as a result of their activities. Alternatively, they may negotiate road maintenance and repair agreements to ensure that damage to roadways are repaired and that the cost is absorbed by the drilling enterprises[244]. The Perryman Group, in their 2007 study of the Barnett Shale play, noted that although traffic volume is a legitimate concern in the area, developers were effectively addressing the issue through maintenance agreements so that road repairs do not adversely affect local taxpayers[245].

From a traffic perspective, members of the public or local municipalities often have the ability to limit traffic volume in residential areas by developing restrictions in neighborhood lease agreements or by developing ordinances that prevent road construction in certain areas, respectively. In urban areas these agreements can be used to coordinate local traffic patterns to minimize congestion, control speed limits to address safety concerns, and specify weight zones to reduce road damage.

With continued advances in technologies, modern developers are afforded a higher level of drilling flexibility than in the past. This provides producers with the ability to adjust their operational plans allowing them to access drilling locations that would otherwise be inaccessible. Although drilling circumstances vary by geologic region and well location, in many cases, shale gas plays are being developed with both vertically and horizontally drilled wells (Exhibit 29). Based on the current development activities of active gas shale basins, horizontal drilling has become the preferred method of drilling in most shale gas plays. Horizontal wells have also been used in many areas of the country to remotely access natural gas resources beneath existing infrastructure, buildings, environmentally sensitive areas, or other features that would prevent the use of vertical wells. The development of the Barnett Shale near Dallas-Fort Worth International Airport is a prime example of how development of urban areas is possible with horizontal wellbores[246].

Source: ALL Consulting, 2008

Shale Gas Activity at Dallas-Fort Worth International Airport

The purpose of ordinances and best management practices is to facilitate the development of the natural gas resource while protecting quality of life and environmental values in the surrounding areas.

Changes in practices during the drilling and completion of shale gas wells have evolved from the Barnett Shale play near Dallas-Fort Worth International Airport and other urban areas surrounding the airport. Development practices there have been altered to suit local ordinances implemented to lessen community impacts and protect environmental resources. These ordinances include detailed setbacks from residences, roadways, churches, and schools, and means to control visual and noise impacts including the required use of directional lighting[247]. This results in the use of BMPs for sound barriers and lighting. Typically, drilling operations in rural gas development areas continue around the clock until the well is completed. When these same operations moved into the urban areas around the cities of Arlington, Burleson, Cleburne, Fort Worth, Joshua and North Richland Hills, specific ordinances were developed requiring additional permitting, well set backs from properties, day-time and night-time noise limits, and directional lighting[248]. Directional lighting provides illumination of well sites for worker safety, directing the light downward and shielding the surrounding area to prevent illuminating neighboring residences, roads or other buildings[249].

Source : Chesapeake Energy Corporation, 2008

Insulation Blankets Used to Deaden Noise from Drilling Operations

In a similar concept, these drilling rigs are also being outfitted with blanket-like enclosures that act as an acoustic barrier to reduce engine noise. Sound deadening technology is a BMP that is also being applied to reduce noises from compressor facilities in both rural and urban settings[250]. These sound barriers include developing alternative building materials with integral sound absorbing properties.

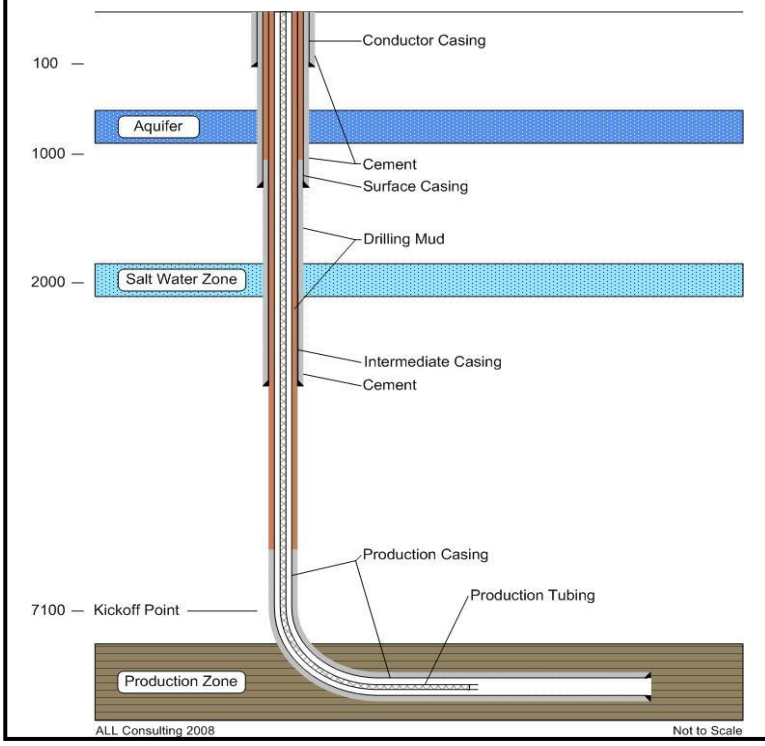
These "BMPs" are not appropriate for all operations and must be applied on a case-by-case basis. In some cases, a given BMP may actually be counter-productive. In other cases, a particular BMP may create other environmental, safety, or operational problems that must be weighed against each other. While BMPs have certain benefits in certain situations, they cannot be universally applied or required.

Protecting Groundwater: Casing and Cementing Programs

State oil and gas regulatory programs place great emphasis on protecting groundwater. Current well construction requirements consist of installing multiple layers of protective steel casing and

cement that are specifically designed and installed to protect fresh water aquifers and to ensure that the producing zone is isolated from overlying formations. During the drilling process, a conductor and surface casing string are set in the borehole and cemented in place. In some instances, additional casing strings may be installed; these are known as intermediate casings (Exhibit 30[251]). After each string of casing is set, and prior to drilling any deeper in the borehole, the casing is cemented to ensure a seal is provided between the casing and formation or between two strings of casing[252]. Exhibit 30 illustrates the casing and cement that may be installed in shale gas wells and highlights how the casing can be set to isolate different water-bearing zones from each other. The exhibit shows the multiple strings of casing, layers of cement and the production tubing, which are all important parts of the well completion in preventing contamination of fresh water zones and assuring that the gas resource does not flow into other, lower pressure zones around the outside of the casing rather than flowing up the well to be produced and sold.[253].

EXHIBIT 30: CASING ZONES AND CEMENT PROGRAMS



The conductor casing serves as a foundation for the well construction and prevents caving of surface soils. The surface casing is installed to seal off potential freshwater-bearing zones, this isolation is necessary in order to protect aquifers from drilling mud and produced fluids. As a further protection of the fresh water zones, air-rotary drilling is often used when drilling through this portion of the wellbore interval to ensure that no drilling mud comes in contact with the fresh water zone. Intermediate casings, when installed, are used to isolate non-freshwater-bearing zones from the producing wellbore. Intermediate casing may be necessary because of a naturally over-pressured zone or because of a saltwater zone located at depth. The borehole area below an intermediate casing may be uncemented until just above the kickoff point for the horizontal leg. This area of wellbore is typically filled with drilling muds.

Each string of casing serves as a layer of protection separating the fluids inside and outside of the casing and preventing each from contacting the other. Operators perform a variety of checks to ensure that the desired isolation of each zone is occurring including ensuring that the casing used has sufficient strength, and that the cement has properly bonded to the casing[254]. These checks may include acoustic cement bond logs and pressure testing to ensure the mechanical integrity of casings. Additionally, state oil and gas regulatory agencies often specify the required depth of protective casings and regulate the time that is required for cement to set prior to additional drilling. These requirements are typically based on regional conditions and are established for all

wildcat wells and may be modified when field rules are designated. These requirements are instituted by the state oil and gas agency to provide protection of groundwater resources[255]. Once the casing strings are run and cemented there could be five or more layers or barriers between the inside of the production tubing and a water-bearing formation (fresh or salt).

Analysis of the redundant protections provided by casings and cements was presented in a series of reports and papers prepared for the American Petroleum Institute (API)[256] in the 1980s. These investigations evaluated the level of corrosion that occurred in Class II injection wells. Class II injection wells are used for the routine injection of water associated with oil and gas production. The research resulted in the development of a method of calculating the probability (or risk) that fluids injected into Class II injection wells could result in an impact to a USDW. This research started by evaluating data for oil and gas producing basins to determine if there were natural formation waters present that were reported to cause corrosion of well casings. The United States was divided into 50 basins, and each basin was ranked by its potential to have a casing leak resulting from such corrosion.

Detailed analysis was performed for those basins in which there was a possibility of casing corrosion[257]. Risk probability analysis provided an upper bound for the probability of the fracturing fluids reaching an underground source of drinking water. Based on the values calculated, a modern horizontal well completion in which 100% of the USDWs are protected by properly installed surface casings (and for geologic basins with a reasonable likelihood of corrosion), the probability that fluids injected at depth could impact a USDW would be between 2×10^{-5} (one well in 200,000) and 2×10^{-8} (one well in 200,000,000) if these wells were operated as injection wells. Other studies in the Williston basin found that the upper bound probability of injection water escaping the wellbore and reaching an underground source of drinking water is seven changes in one million well-years where surface casings cover the drinking water aquifers[258].

These values do not account for the differences between the operation of a shale gas well and the operation of an injection well. An injection well is constantly injecting fluid under pressure and thus raises the pressure of the receiving aquifer, increasing the chance of a leak or well failure. A production well is reducing the pressure in the producing zone by giving the gas and associated fluid a way out, making it less likely that they will try to find an alternative path that could contaminate a fresh water zone. Furthermore, a producing gas well would be less likely to experience a casing leak because it is operated at a reduced pressure compared to an injection well. It would be exposed to lesser volumes of potentially corrosive water flowing through the production tubing, and it would only be exposed to the pumping of fluids into the well during fracture stimulations.

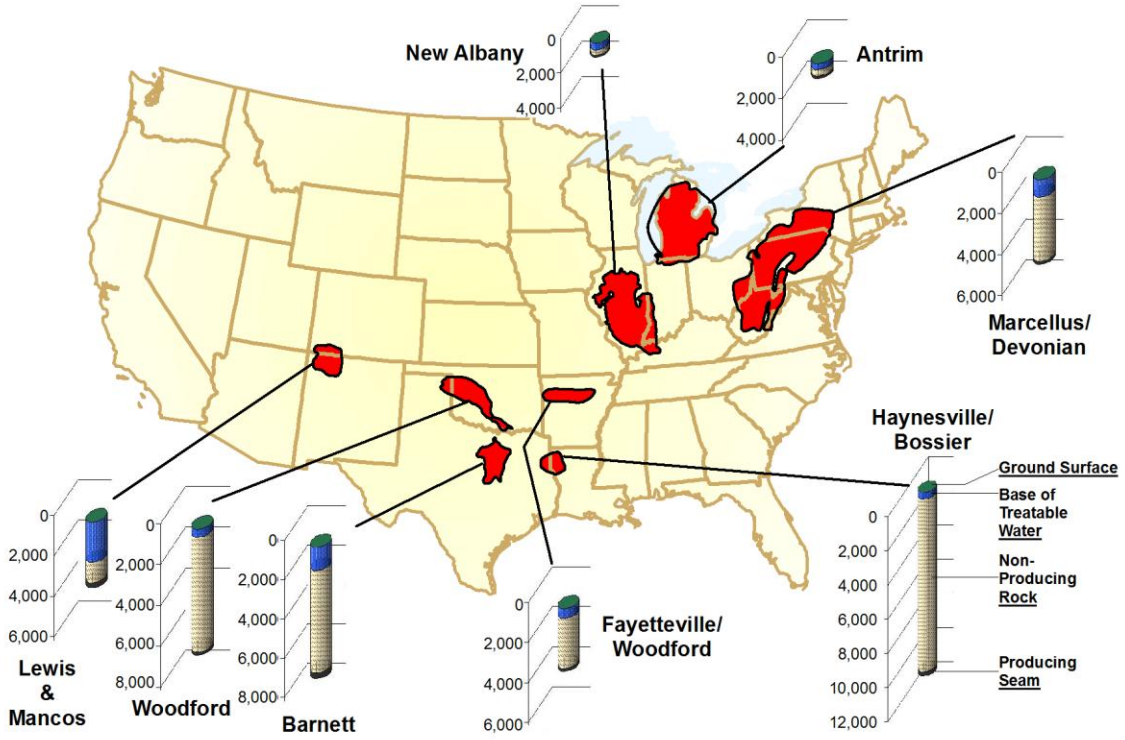
The API study included an analysis of wells that had been in operation for many years when the study was performed in the late 1980s, and does not account for advances that have occurred in equipment and applied technologies and changes to the regulations. As such, a calculation of the probability of any fluids, including hydraulic fracture fluids, reaching a USDW from a gas well would indicate an even lower probability; perhaps by as much as two to three orders of magnitude. The API report came to another important conclusion relative to the probability of the contamination of a USDW when it stated that:

> …for injected water to reach a USDW in the 19 identified basins of concern, a number of independent events must occur at the same time and go *undetected* [emphasis added]. These events include simultaneous leaks in the [production] tubing, production casing, [intermediate casing,] and the surface casing coupled with the unlikely occurrence of water moving long distances up the borehole past salt water aquifers to reach a USDW[259].

As indicated by the analysis conducted by API and others, the potential for groundwater to be impacted by injection is low. It is expected that the probability for treatable groundwater to be impacted by the pumping of fluids during hydraulic fracture treatments of newly installed, deep shale gas wells when a high level of monitoring is being performed would be even less than the 2×10^{-8} estimated by API.

In addition to the protections provided by multiple casings and cements, there are natural barriers in the rock strata that act as seals holding the gas in the target formation. Without such seals, gas and oil would naturally migrate to the earth's surface. A fundamental precept of oil and gas geology is that without an effective seal, gas and oil would not accumulate in a reservoir in the first place and so could never be tapped and produced in usable quantities. These sealing strata also act as barriers to vertical migration of fluids upward toward useable groundwater zones. Most shale gas wells (outside of those completed in the New Albany and the Antrim) are expected to be drilled at depths greater than 3,000 feet below the land surface (based on the data presented in Exhibit 11). Exhibit 31 compares estimated shallowest producible depth of the target ("pay") shale zone and the maximum base of treatable water. For any fluid present in the producing zone to reach treatable groundwater the fluid must migrate through these overlying zones.

EXHIBIT 31: COMPARISON OF TARGET SHALE DEPTH AND BASE OF TREATABLE GROUNDWATER



Source: Compiled from Various Data Sources

A fundamental precept of oil and gas geology is that without an effective seal, gas and oil would not accumulate in a reservoir in the first place and so it could never be tapped and produced in usable quantities. These sealing strata also act as barriers to vertical migration of fluids upward toward groundwater zones.

Drilling Fluids and Retention Pits

Drilling fluids are a necessary component of the drilling process; they circulate cuttings (rock chips created as the drill bit advances through rock, much like sawdust) to the surface to clear the borehole, they lubricate and cool the drilling bit, they stabilize the wellbore (preventing cave in), and control downhole fluid pressure[260]. In order to maintain sufficient volumes of fluids onsite during drilling, operators typically use pits to store make-up water used as part of the drilling fluids. Storage pits are not used in every development situation. In the case of shale gas development, drilling operations have been occurring in both urban and rural locations, requiring that drilling practices be adapted to facilitate development in both settings. Drilling with compressed air is becoming an increasingly popular alternative to drilling with fluids due to the increased cost savings from both reduction in mud costs and the shortened drilling times as a result of air based drilling[261]. The air, like drilling mud, functions to lubricate, cool the bit, and remove cuttings. Air drilling is generally limited to low pressure formations, such as the Marcellus shale in New York[262].

Source: ALL Consulting, 2008

Lined Fresh Water Supply Pit from the Marcellus Shale Development in Pennsylvania

In rural areas, storage pits may be used to hold fresh water for drilling and hydraulic fracturing. In an urban setting, due to space limitations, steel storage tanks may be used. Tanks can also be used in a closed-loop drilling system. Closed-loop drilling allows for the re-use of drilling fluids and the use of lesser amounts of drilling fluids[263]. Closed-loop drilling systems have also been used with water-based fluids in environmentally sensitive environments in combination with air-rotary drilling techniques[264]. While closed-loop drilling has been used to address specific situations, the practice is not necessary for every well drilled. As discussed in the previous section, drilling is a regulated practice managed at the state level, and while state oil and gas agencies have the ability to require operators to vary standard practices, the agencies typically do so only when it is necessary to protect the gas resources and the environment.

In rural environments, storage pits may be used to hold water. They are typically excavated containment ponds that, based on the local conditions and regulatory requirements, may be lined. Pits can also be used to store additional make-up water for drilling fluids or to store water used in the hydraulic fracturing of wells.

Water storage pits used to hold water for hydraulic fracturing purposes are typically lined to minimize the loss of water from infiltration (notice the black synthetic liner in the accompanying photograph). Water storage pits are becoming an important tool in the shale gas industry because the drilling and hydraulic fracturing of these wells often requires significant volumes of water as the base fluid for both purposes[265].

Hydraulic Fracturing

The other technological key to the economic recovery of shale gas is hydraulic fracturing. Hydraulic fracturing is a formation stimulation practice used to create additional permeability in a producing formation, thus allowing gas to flow more readily toward the wellbore[266,267]. Hydraulic fracturing can be used to overcome natural barriers to the flow of fluids (gas or water) to the wellbore. Such barriers may include naturally low permeability common in shale formations or reduced permeability resulting from near wellbore damage during drilling activities[268].

Stimulations are optimized to ensure that fracture development is confined to the target formation.

Hydraulic fracturing involves the pumping of a fracturing fluid into a formation at a calculated, predetermined rate and pressure to generate fractures or cracks in the target formation. For shale gas development, fracture fluids are primarily water-based fluids mixed with additives which help the water to carry sand proppant into the fractures. The sand proppant is needed to "prop" open the fractures once the pumping of fluids has stopped. Once the fracture has initiated, additional fluids are pumped into the wellbore to continue the development of the fracture and to carry the proppant deeper into the formation. The additional fluids are needed to maintain the downhole pressure necessary to accommodate the increasing length of opened fracture in the formation. Each rock formation has inherent natural variability resulting in different fracture pressures for different formations. The process of designing hydraulic fracture treatments involves identifying properties of the target formation including fracture pressure, and the desired length of fractures. The following discussion addresses some of the processes involved in the design of a hydraulic fracture stimulation of a shale gas formation.

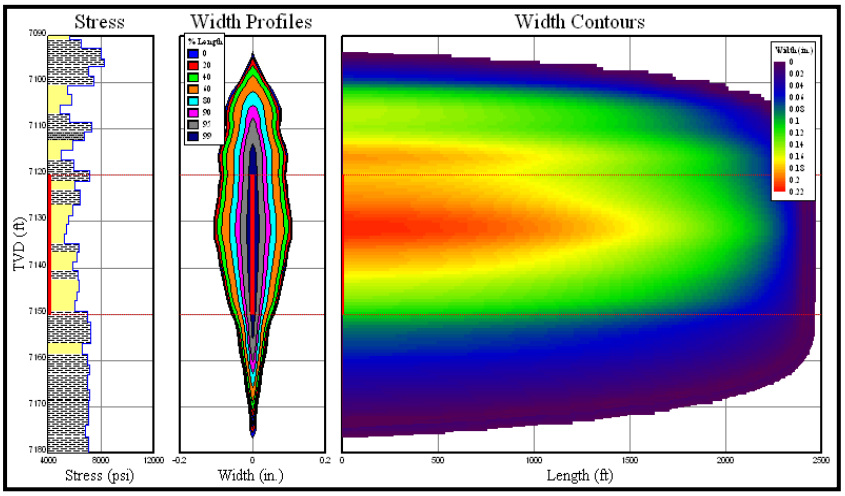
Source: ALL Consulting, 2008

A Fracture Stimulation Is Closely Monitored by Many Specialists (Fayetteville Shale - Arkansas)

Fracture Design

Modern formation stimulation practices are sophisticated, engineered processes designed to emplace fracture networks in specific rock strata[269]. A hydraulic fracture treatment is a controlled process designed to the specific conditions of the target formation (thickness of shale, rock fracturing characteristics, etc.). Understanding the *in-situ* reservoir conditions present and their dynamics is critical to successful stimulations. Hydraulic fracturing designs are continually refined to optimize fracture networking and maximize

EXHIBIT 32: EXAMPLE OUTPUT OF A HYDRAULIC FRACTURE STIMULATION MODEL



Source: Chesapeake, 2008

gas production. While the concepts and general practices are similar, the details of a specific fracture operation can vary substantially from basin to basin and from well to well.

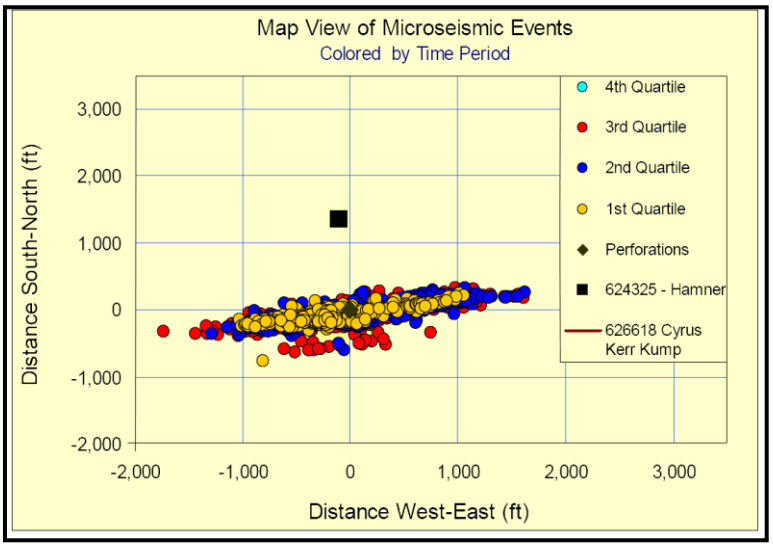
Fracture design can incorporate many sophisticated and state-of-the-art techniques to accomplish an effective, economic and highly successful fracture stimulation. Some of these techniques include modeling, microseismic fracture mapping, and tilt-meter analysis.

A computer model can be used to simulate hydraulic fracturing designs[270]. This approach helps maximize effectiveness and economically design a treatment event. The modeling programs allow geologists and engineers to modify the design of a hydraulic fracture treatment and evaluate the height, length, and orientation of potential fracture development (Exhibit 32)[271]. These simulators also allow the designers to use the data gathered during a fracture stimulation to evaluate the success of the fracture job performed. From these data and analyses, engineers can optimize the design of future fracture stimulations.

Additional advances in hydraulic fracturing design target analysis of hydraulic fracture treatments through technologies such as microseismic fracture mapping (Exhibit 33[272]) and tilt measurements[273]. These technologies can be used to define the success and orientation of the fractures created, thus providing the engineers with the ability to manage the resource through the strategic placement of additional wells, taking advantage of the natural reservoir conditions and expected fracture results in new wells.

As more formation-specific data are gathered, service companies and operators can optimize fracture patterns. Operators have strong economic incentives to ensure that fractures do not propagate beyond

EXHIBIT 33: MAPPING OF MICROSEISMIC EVENTS



Source: Oilfield Service Company, 2008

Operators have strong economic incentives to ensure that fractures do not propagate beyond the target formation and into adjacent rock strata.

the target formation and into adjacent rock strata[274]. Allowing the fractures to extend beyond the target formation would be a waste of materials, time, and money. In some cases, fracturing outside o f the target formation could potentially result in the loss of the well and the associated gas resource. Fracture growth outside of the target formation can result in excess water production from bounding strata. Having to pump and handle excess water increases production costs, negatively impacting well economics. This is a particular concern in the Barnett Shale of Texas where the underlying Ellenberger Group limestones are capable of yielding significant formation water.

Fracturing Process

Hydraulic fracturing of horizontal shale gas wells is performed in stages. Lateral lengths in horizontal wells for shale gas development may range from 1,000 feet to more than 5,000 feet. Because of the length of exposed wellbore, it is usually not possible to maintain a downhole pressure sufficient to stimulate the entire length of a lateral in a single stimulation event[275]. Because of the lengths of the laterals, hydraulic fracture treatments of horizontal shale gas wells are usually performed by isolating smaller portions of the lateral. The fracturing of each portion of the lateral wellbore is called a stage. Stages are fractured sequentially beginning with the section at the farthest end of the wellbore, moving uphole as each stage of the treatment is completed until the entire lateral well has been stimulated[276]. Horizontal wells in the various gas shale basins may be treated using two or more stages to fracture the entire perforated interval of the well. Each stage of a horizontal well fracture treatment is similar to a fracture treatment for a vertical shale gas well.

For each stage of a fracture treatment, a series of different volumes of fracture fluids, called sub-stages, with specific additives and proppant concentrations, is injected sequentially. Exhibit 34[277] presents an example of the sub-stages of a single-stage hydraulic fracture treatment for a well completed in the Marcellus Shale[278]. This is a single-stage treatment typical of what might be performed on a vertical shale well or for each stage of a multi-stage horizontal well treatment. The total volume of the sub-stages in Exhibit 34 is 578,000 gallons. If this were one stage of a four-stage horizontal well, the entire fracture operation would require approximately four times this amount, or 2.3 million gallons of water.

Before operators or service companies perform a hydraulic fracture treatment of a well (vertical or horizontal), a series of tests is performed. These tests are designed to ensure that the well, well equipment and hydraulic fracturing equipment are in proper working order and will safely withstand the application of the fracture treatment pressures and pump flow rates. The tests start with the testing of well casings and cements during the drilling and well construction process. Testing continues with pressure testing of hydraulic fracturing equipment prior to the fracture treatment process[279]. It should be noted that construction requirements for wells are mandated by state oil and gas regulatory agencies to ensure that a well is protective of water resources and is safe for operation.

EXHIBIT 34: EXAMPLE OF A SINGLE STAGE OF A SEQUENCED HYDRAULIC FRACTURE TREATMENT

Hydraulic Fracture Treatment Sub-Stage	Volume (gallons)	Rate (gal/min)
Diluted Acid (15%)	5,000	500
Pad	100,000	3,000
Prop 1	50,000	3,000
Prop 2	50,000	3,000
Prop 3	40,000	3,000
Prop 4	40,000	3,000
Prop 5	40,000	3,000
Prop 6	30,000	3,000
Prop 7	30,000	3,000
Prop 8	20,000	3,000
Prop 9	20,000	3,000
Prop 10	20,000	3,000
Prop 11	20,000	3,000
Prop 12	20,000	3,000
Prop 13	20,000	3,000
Prop 14	10,000	3,000
Prop 15	10,000	3,000
Flush	13,000	3,000

Notes:

Volumes are presented in gallons (42 gals = one barrel, 5,000 gals = ~120 bbls).

Rates are expressed in gals/minute, 42 gals/minute = 1 bbl/min, 500 gal/min = ~12 bbls/min.

Flush volumes are based on the total volume of open borehole, therefore as each stage is completed the volume of flush decreases as the volume of borehole is decreased.

Total amount of proppant used is approximately 450,000 pounds

Source: Arthur et al., 2008

After the testing of equipment has been completed, the hydraulic fracture treatment process begins. The sub-stage sequence is usually initiated with the pumping of an acid treatment. This acid treatment helps to clean the near-wellbore area which can be "damaged" (pores and pore throats become plugged with drilling mud or casing cement) as a result of the drilling and well installation process. The next sequence after the acid treatment is a slickwater pad, which is a water-based fracturing fluid mixed with a friction reducing agent. The pad is a volume of fracturing fluid large enough to effectively fill the wellbore and the open formation area. The slickwater pad helps to facilitate the flow and placement of the proppant further into the fracture network.

Source: Chesapeake Energy Corporation, 2008

Hydraulic Fracturing of a Marcellus Shale Well, West Virginia

After the pad is pumped, the first proppant sub-stage, combining a large volume of water with fine mesh sand is pumped. The next several sub-stagesin the stage increase the volume of fine-grained proppant while the volume of fluids pumped are decreased incrementally from 50,000 gallons (gals) to 30,000 gals. This fine-grained proppant is used because the finer particle size is capable of being carried deeper into the developed fractures[280]. In this example, the fine proppant sub-stages are followed by eight sub-stages of a coarser proppant with volumes from 20,000 gals to 10,000 gals. After the completion of the final sub-stage of coarse proppant, the well and equipment are flushed with a volume of freshwater sufficient to remove excess proppants from the equipment and the wellbore.

Hydraulic fracturing stimulations are overseen continuously by operators and service companies to evaluate and document the events of the treatment process. Every aspect of the fracture stimulation process is carefully monitored, from the wellhead and downhole pressures to pumping rates and density of the fracturing fluid slurry. The monitors

Every aspect of the fracture stimulation process is carefully monitored.

also track the volumes of each additive and the water used, and ensure that equipment is functioning properly. For a 12,000-bbl (504,000-gallon) fracture treatment of a vertical shale gas well there may be between 30 and 35 people on site monitoring the entire stimulation process.

The staging of multiple fracture treatments along the length of the lateral leg of the horizontal well allows the fracturing process to be performed in a very controlled manner. By fracturing discrete intervals of the lateral wellbore, the operator is able to make changes to each portion of the completion zone to accommodate site-specific changes in the formation. These site-specific variations may include variations in shale thickness, presence or absence of natural fractures, proximity to another wellbore fracture system, and boreholes that are not centered in the formation.

Fracturing Fluids and Additives

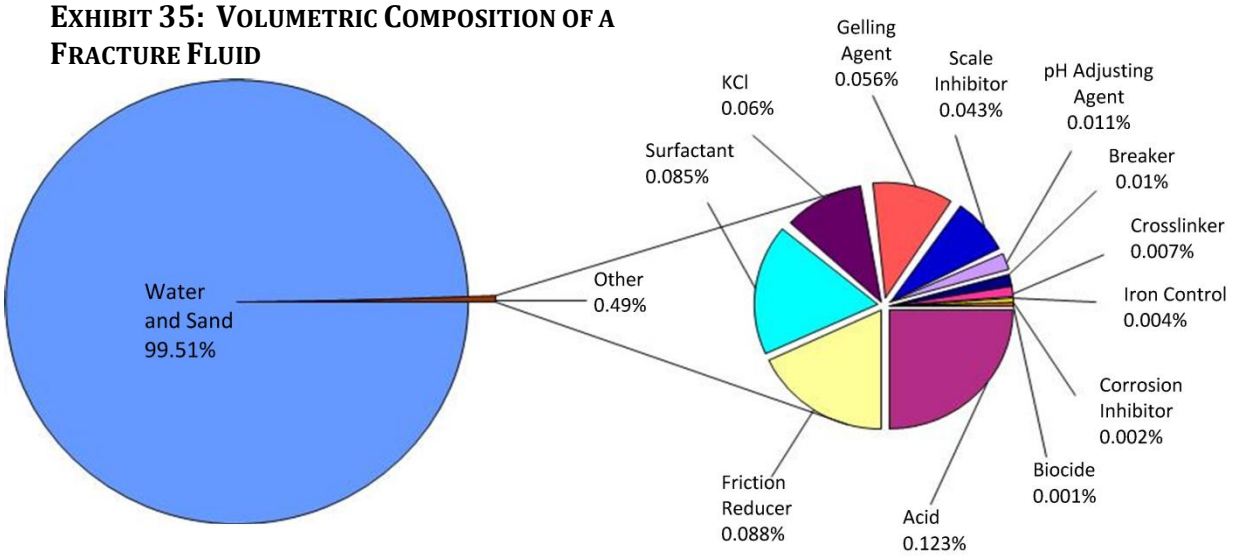
As described above, the current practice for hydraulic fracture treatments of shale gas reservoirs is to apply a sequenced pumping event in which millions of gallons of water-based fracturing fluids mixed with proppant materials are pumped in a controlled and monitored manner into the target shale formation above fracture pressure[281].

The fracturing fluids used for gas shale stimulations consist primarily of water but also include a variety of additives. The number of chemical additives used in a typical fracture treatment varies depending on the conditions of the specific well being fractured. A typical fracture treatment will use very low concentrations of between 3 and 12 additive chemicals depending on the characteristics of the water and the shale formation being fractured. Each component serves a specific, engineered purpose[282]. The predominant fluids currently being used for fracture treatments in the gas shale plays are water-based fracturing fluids mixed with friction-reducing additives (called slickwater)[283].

The addition of friction reducers allows fracturing fluids and proppant to be pumped to the target zone at a higher rate and reduced pressure than if water alone were used. In addition to friction reducers, other additives include: biocides to prevent microorganism growth and to reduce bio-fouling of the fractures; oxygen scavengers and other stabilizers to prevent corrosion of metal pipes; and acids that are used to remove drilling mud damage within the near-wellbore area[284]. These fluids are used not only to create the fractures in the formation but also to carry a propping agent (typically silica sand) which is deposited in the induced fractures.

Exhibit 35[285] demonstrates the volumetric percentages of additives that were used for a nine-stage hydraulic fracturing treatment of a Fayetteville Shale horizontal well. The make-up of fracturing fluid varies from one geologic basin or formation to another. Evaluating the relative volumes of the components of a fracturing fluid reveals the relatively small volume of additives that are present. The additives depicted on the right side of the pie chart represent less than 0.5% of the total fluid volume. Overall the concentration of additives in most slickwater fracturing fluids is a relatively consistent 0.5% to 2% with water making up 98% to 99.5%.

EXHIBIT 35: VOLUMETRIC COMPOSITION OF A FRACTURE FLUID



Source: ALL Consulting based on data from a fracture operation in the Fayetteville Shale, 2008

Because the make-up of each fracturing fluid varies to meet the specific needs of each area, there is no one-size-fits-all formula for the volumes for each additive. In classifying fracturing fluids and their additives it is important to realize that service companies that provide these additives have developed a number of compounds with similar functional properties to be used for the same purpose in different well environments. The difference between additive formulations may be as small as a change in concentration of a specific compound. Although the hydraulic fracturing industry may have a number of compounds that can be used in a hydraulic fracturing fluid, any single fracturing job would only use a few of the available additives. For example, in Exhibit 35 there are 12 additives used, covering the range of possible functions that could be built into a fracturing fluid. It is not uncommon for some fracturing recipes to omit some compound categories if their properties are not required for the specific application.

Most industrial processes use chemicals and almost any chemical can be hazardous in large enough quantities or if not handled properly. Even chemicals that go into our food or drinking water can be hazardous. For example, drinking water treatment plants use large quantities of chlorine. When used and handled properly, it is safe for workers and near-by residents and provides clean, safe drinking water for the community. Although the risk is low, the potential exists for unplanned releases that could have serious effects on human health and the environment. By the same token, hydraulic fracturing uses a number of chemical additives that could be hazardous, but are safe when properly handled according to requirements and long-standing industry practices. In addition, many of these additives are common chemicals which people regularly encounter in everyday life.

EXHIBIT 36: FRACTURING FLUID ADDITIVES, MAIN COMPOUNDS, AND COMMON USES.

Additive Type	Main Compound(s)	Purpose	Common Use of Main Compound
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction Reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
	Mineral oil		Make-up remover, laxatives, and candy
Gel	Guar gum or hydroxyethyl cellulose	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron Control	Citric acid	Prevents precipitation of metal oxides	Food additive, flavoring in food and beverages; Lemon Juice ~7% Citric Acid
KCl	Potassium chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, and de-icing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant, and hair color

Note: The specific compounds used in a given fracturing operation will vary depending on company preference, source water quality and site-specific characteristics of the target formation. The compounds shown above are representative of the major compounds used in hydraulic fracturing of gas shales.

Exhibit 36[286] provides a summary of the additives, their main compounds, the reason the additive is used in a hydraulic fracturing fluid, and some of the other common uses for these compounds. Hydrochloric acid (HCl) is the single largest liquid component used in a fracturing fluid aside from water; while the concentration of the acid may vary, a 15% HCl mix is a typical concentration. A 15% HCl mix is composed of 85% water and 15% acid, therefore, the volume of acid is diluted by 85% with water in its stock solution before it is pumped into the formation during a fracturing treatment. Once the entire stage of fracturing fluid has been injected, the total volume of acid in an example fracturing fluid from the Fayetteville shale was 0.123%, which indicates the fluid had been diluted by a factor of 122 times before it is pumped into the formation. The concentration of this acid will only continue to be diluted as it is further dispersed in additional volumes of water that may be present in the subsurface. Furthermore, if this acid comes into contact with carbonate minerals in the subsurface, it would be neutralized by chemical reaction with the carbonate minerals producing water and carbon dioxide as a byproduct of the reaction.

Water Availability

The drilling and hydraulic fracturing of a horizontal shale gas well may typically require 2to 4 million gallons of water[287], with about 3 million gallons being most common. It should be noted that the volume of water needed may vary substantially between wells. In addition the volume of water needed per foot of wellbore appears to be decreasing as technologies and methods improve over time. Exhibit 37[288] presents a table of estimated per-well water needs for four shale gas plays currently being developed.

EXHIBIT 37: ESTIMATED WATER NEEDS FOR DRILLING AND FRACTURING WELLS IN SELECT SHALE GAS PLAYS

Shale Gas Play	Volume of Drilling Water per well (gal)	Volume of Fracturing Water per well (gal)	Total Volumes of Water per well (gal)
Barnett Shale	400,000	2,300,000	2,700,000
Fayetteville Shale	60,000*	2,900,000	3,060,000
Haynesville Shale	1,000,000	2,700,000	3,700,000
Marcellus Shale	80,000*	3,800,000	3,880,000

* Drilling performed with an air "mist" and/or water-based or oil-based muds for deep horizontal well completions.
Note: These volumes are approximate and may vary substantially between wells.

Source: ALL Consulting from discussions with various operators, 2008

Water for drilling and hydraulic fracturing of these wells frequently comes from surface water bodies such as rivers and lakes, but can also come from ground water, private water sources, municipal water, and re-used produced water. Most of the producing shale gas basins occur in areas with moderate to high levels of annual precipitation as shown in Exhibit 38[289]. However, even in areas of high precipitation, due to growing populations, other industrial water demands, and seasonal variation in precipitation, it can be difficult to meet the needs of shale gas development and still satisfy regional needs for water.

Source: ALL Consulting, 2008

Little Red River, Arkansas

While the water volumes needed to drill and stimulate shale gas wells are large, they generally represent a small percentage of the total water resource use in the shale gas basins. Calculations indicate that water use will range from less than 0.1% to 0.8% by basin[290]. This volume is small in terms of the overall surface water budget for an area; however, operators need this water when drilling activity is occurring, requiring that the water be procured over a relatively short period of time. Water withdrawals during periods of low stream flow could affect fish and other aquatic life, fishing and other recreational activities, municipal water supplies, and other industries such as power plants. To put shale gas water use in perspective, the consumptive use of fresh water for electrical generation in the Susquehanna River Basin alone is nearly 150 million gallons per day, while the projected total demand for peak Marcellus Shale activity in the same area is 8.4 million gallons per day[291].

One alternative that states and operators are pursuing is to make use of seasonal changes in river flow to capture water when surface water flows are greatest. Utilizing seasonal flow differences allows planning of withdrawals to avoid potential impacts to municipal drinking water supplies or to aquatic or riparian communities. In the Fayetteville Shale play of Arkansas, one operator is constructing a 500-acre-ft impoundment to store water withdrawals from the Little Red River obtained during periods of high flow (storm events or hydroelectric power generation releases from Greer's Ferry Dam upstream of the intake) when excess water is available[292] (one acre-foot is equivalent to the volume of water required to cover one acre with one foot of water). The project is limited to 1,550 acre-ft of water annually. As additional mitigation, the company has constructed extra pipelines and hydrants to provide portions of this rural area with water for fire protection. Also included is monitoring of in-stream water quality as well as game and non-game fish species in the reach of river surrounding the intake. This design provides a water recovery system similar in concept to what

This project was developed with input from a local chapter of Trout Unlimited, an active conservation organization in the area, and represents an innovative environmental solution that serves both the community and the gas developer.

some municipal water facilities use. It will minimize the impact on local water supplies because surface water withdrawals will be limited to times of excess flow in the Little Red River. This project was developed with input from a local chapter of Trout Unlimited, an active conservation organization in the area, and represents an innovative environmental solution that serves both the community and the gas developer.

Because the development of shale gas is new in some areas, these water needs may challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies can help operators and communities to coexist and effectively manage local water resources. Understanding local water needs can help operators develop a water storage or management plan that will meet with acceptance in neighboring communities. Although the water needed for drilling an individual well may represent a small volume over a large area, the withdrawals may have a cumulative impact to watersheds over the short term. This potential impact can be avoided by working with local water resource managers to develop a plan outlining when and where withdrawals will occur (i.e., avoiding headwaters, tributaries, small surface water bodies, or other sensitive sources).

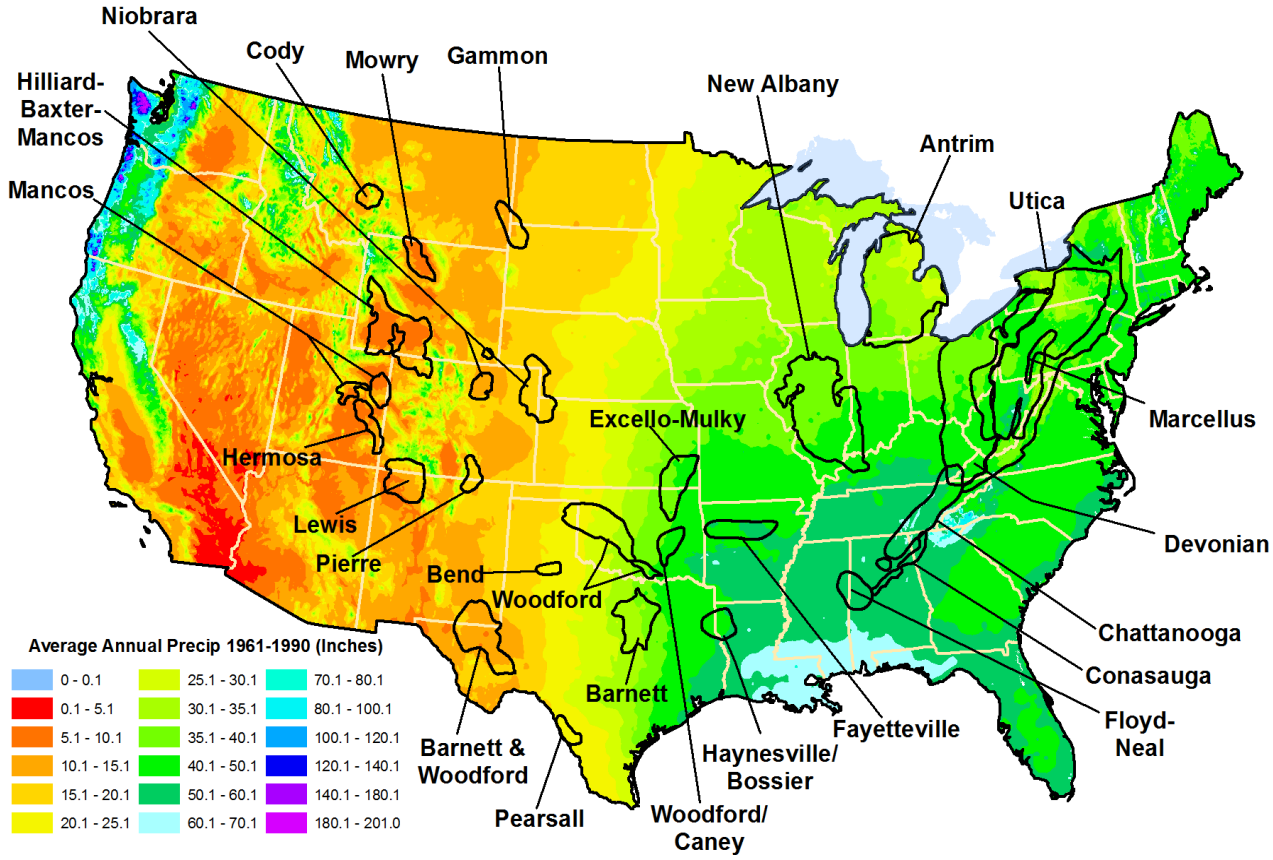
One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs.

In some basins, one key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region and even within a region such that developers will also need to understand local water laws[293] .

Water Management

After a hydraulic fracture treatment, when the pumping pressure has been relieved from the well, the water-based fracturing fluid, mixed with any natural formation water present, begins to flow back through the well casing to the wellhead. This produced water may also contain dissolved constituents from the formation itself. The dissolved constituents are naturally occurring compounds and may vary from one shale play to the next or even by area within a shale play. Initial produced water can vary from fresh (<5,000 ppm Total Dissolved Solids (TDS)) to varying degrees of saline (5,000 ppm to 100,000 ppm TDS[294] or higher). The majority of fracturing fluid is recovered in a matter of several hours to a couple of weeks. In various basins and shale gas plays, the volume of produced water may account for less than 30% to more than 70% of the original fracture fluid volume[295]. In some cases, flow back of fracturing fluid in produced water can continue for several months after gas production has begun[296].

EXHIBIT 38: ANNUAL RAINFALL MAP OF THE UNITED STATES



Source: NRCS

A suite of circumstances explains the disposition of fracturing fluids that are not recovered through production. However, it is important to understand that unrecovered fluids, if any, will remain contained within the target formations. Some of these fluids will occupy macro-porosity (typically natural fracture porosity) in the shale formation and some will occupy the micro-pore space vacated by the gas that is produced. Also, some of the fracturing fluids remain stranded in fractures within the reservoir rock that heal after fracturing, thus preventing the fluids from flowing back to the well. Some of these stranded fluids may flow back to the well in very small volumes over an extended time span. The longer contact time these fluids have with the formation further alters the chemistry of these fluids through increased dissolution of formation minerals, making them similar to the natural formation water. For these reasons it is not possible to unequivocally state that 100% of the fracturing fluids have been recovered or to differentiate flow back water from natural formation water.

Natural formation water has been in contact with the reservoir formation for millions of years and thus contains minerals native to the reservoir rock. The salinity, TDS, and overall quality of formation water vary by geologic basin and specific rock strata. After initial production, produced water can vary from brackish (5,000 ppm to 35,000 ppm TDS), to saline (35,000 ppm to 50,000 ppm TDS), to supersaturated brine (50,000 ppm to >200,000 ppm TDS)[297], and some operators

report TDS values greater than 400,000 ppm[298]. The variation in composition changes primarily with changes in the natural formation water chemistry.

States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. Exhibit 39 summarizes current produced water management practices for the various shale gas basins, and is compiled from data collected from producers and regulatory agencies in these basins.

Underground injection has traditionally been the primary disposal option for oil and gas produced water. In most settings, this may be the best option for shale gas produced water. This process uses salt water disposal wells to place the water thousands of feet underground in porous rock formations that are separated from treatable groundwater by multiple layers of impermeable rock thousands of feet thick. Underground injection of the produced water is not possible in every play as suitable injection zones may not be available. Similar to a producing reservoir, there must be a porous and permeable formation capable of receiving injected fluids nearby. If such is not locally available, it may be possible to transport the produced water to a more distant injection site. In well developed urban plays such as the Barnett Shale around the City of Fort Worth, pipelines have been constructed to transport produced water to injection well disposal sites. This minimizes trucking the water and the resultant traffic, exhaust emissions, and wear on local roads[299]. Injection disposal wells are permitted under the federal Safe Drinking Water Act (SDWA), Underground Injection Control (UIC) program (or in the case of state primacy, under equivalent state programs), a stringently permitted and monitored process with many environmental safeguards in place.

Treatment of produced water may be feasible through either self-contained systems at well sites or fields or municipal waste water treatment plants or commercial treatment facilities. The availability of municipal or commercial treatment plants may be limited to larger urban areas where treatment facilities with sufficient available capacity already exist. As in underground injection, transportation to treatment facilities may or may not be practical[300].

Re-use of fracturing fluids is being evaluated by service companies and operators to determine the degree of treatment and make-up water necessary for re-use[301]. The practical use of on-site, self-contained treatment facilities and the treatment methods employed will be dictated by flow rate and total water volumes to be treated, constituents and their concentrations requiring removal, treatment objectives and water reuse or discharge requirements. In some cases it would be more practical to treat the water to a quality that could be reused for a subsequent hydraulic fracturing job, or other industrial use, rather than treating to discharge to a surface water body or for use as drinking water. At the time this Primer was developed there were plans to construct commercial waste water treatment facilities specifically designed for the treatment of produced water associated with shale gas development in some locations around the country[302]. The completion and success of such plants no doubt will be closely tied to the successful expansion of production in the various shale gas plays.

EXHIBIT 39: CURRENT PRODUCED WATER MANAGEMENT BY SHALE GAS BASIN.

Shale Gas Basin	Water Management Technology	Availability	Comments
Barnett Shale	Class II injection wells[303]	Commercial and non-commercial	Disposal into the Barnett and underlying Ellenberger Group[304]
	Recycling[305]	On-site treatment and recycling	For reuse in subsequent fracturing jobs [306]
Fayetteville Shale	Class II injection wells[307]	Non-commercial	Water is transported to two injection wells owned and operated by a single producing company [308]
	Recycling	On-site recycling	For reuse in subsequent fracturing jobs[309]
Haynesville Shale	Class II injection wells	Commercial and non-commercial	
Marcellus Shale	Class II injection wells	Commercial and non-commercial	Limited use of Class II injection wells[310,311]
	Treatment and discharge	Municipal waste water treatment facilities, commercial facilities reportedly contemplated[312]	Primarily in Pennsylvania
	Recycling	On-site recycling	For reuse in subsequent fracturing jobs[313]
Woodford Shale	Class II injection wells	Commercial	Disposal into multiple confining formations[314]
	Land Application		Permit required through the Oklahoma Corporation Commission[315]
	Recycling	Non-commercial	Water recycling and storage facilities at a central location[316]
Antrim Shale	Class II injection wells	Commercial and non-commercial	
New Albany Shale	Class II injection wells	Commercial and non-commercial	

New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water. The treated water can be reused as fracturing make-up water, irrigation water, and in some cases even drinking water. Recycling or re-use of produced water can decrease water demands and provide additional water resources for drought-stricken or arid areas. This allows natural gas-associated produced water to be viewed as a potential resource in its own right[317,318]. In one case, Devon Energy Corporation (Devon) is currently using water distillation units at centralized locations within the Barnett Shale play to treat produced water from hydraulic fracture stimulations[319]. As of early 2008, Devon had hydraulically fractured 50 wells using recycled water. Devon reports that the program is still in its testing and development stages. With further development, such specialized treatment systems may prove beneficial, particularly in more mature plays such as the Barnett; however, their practicality may be limited in emerging shale gas plays. Current levels of interest in recycling and reuse are high, but new approaches and more efficient technologies are needed to make treatment and re-use a wide-spread reality.

While challenges still exist, progress is being made. New technologies and new variations on old technologies are being introduced on a regular basis, and some industry researchers are pursuing ways to reduce the amount of treatment needed. In early 2009, studies were underway to determine the minimum quality of water that could successfully be used in hydraulic fracturing. If hydraulic fracturing procedures or fluid additives can be developed that will allow use of water with a high TDS content, then more treatment options become viable and more water can be re-used. Treatment and re-use of produced water could reduce water withdrawal needs as well as the need for additional disposal options. This approach could also help to resolve many of the concerns associated with these withdrawals.

Naturally Occurring Radioactive Material (NORM)

Some soils and geologic formations contain low levels of radioactive material. This naturally occurring radioactive material (NORM) emits low levels of radiation, to which everyone is exposed on a daily basis. Radiation from natural sources is also called background radiation. Other sources of background radiation include radiation from space and sources that occur naturally in the human body. This background radiation accounts for about 50% of the total exposure for Americans. Most of this background exposure is from radon gas encountered in homes (35% of the total exposure). The average person in the U.S. is exposed to about 360 millirem (mrem) of radiation from natural sources each year (a mrem, or one one-thousandth of a rem, is a measure of radiation exposure)[320]. The other 50% of exposures for Americans comes primarily from medical sources. Consumer products, industrial, and occupational sources contribute less than 3% of the total exposure[321].

In addition to the background radiation at the earth's surface, NORM can also be brought to the surface in the natural gas production process. When NORM is associated with oil and natural gas production, it begins as small amounts of uranium and thorium within the rock. These elements, along with some of their decay elements, notably radium$_{226}$ and radium$_{228}$[322], can be brought to the surface in drill cuttings and produced water. Radon$_{222}$, a gaseous decay element of radium, can come to the surface along with the shale gas.

When NORM is brought to the surface, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges[323]. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks[324].

The principal concern for NORM in the oil and gas industry is that, over time, it can become concentrated in field production equipment[325] and as sludge or sediment inside tanks and process vessels that have an extended history of contact with formation water[326]. Because the general public does not come into contact with oilfield equipment for extended periods, there is little exposure risk from oilfield NORM. Studies have shown that exposure risks for workers and the public are low for conventional oil and gas operations[327,328].

If measured NORM levels exceed state regulatory levels or OSHA exposure dose risks (29 CFR 1910.1096), the material is taken to licensed facilities for proper disposal. In all cases, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment for workers when radiation doses could exceed 5 mrem in one hour or 100 mrem in any five consecutive days. In addition to these federal worker protections, states have regulations that require operators to protect the safety and health of both workers and the public.

Currently there are no existing federal regulations that specifically address the handling and disposal of NORM wastes[d]. Instead, states producing oil and gas are responsible for promulgating and administering regulations to control the re-use and disposal of NORM-contaminated equipment, produced water, and oil-field wastes. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard oilfield waste. Conversely, if NORM concentrations are above regulatory limits, then the material must be disposed of at a licensed facility.

These regulations, standards, and practices ensure that oil and gas operations present negligible risk to the general public with respect to potential NORM exposure. They also present negligible risk to workers when proper controls are implemented[329].

Air Quality

Many of today's air quality rules were primarily designed to regulate emissions from single sources with large volumes of emissions output such as refineries, chemical plants, iron and steel manufacturing facilities, and electrical power generating sites. However, smaller sources such as individual shale gas well sites are also subject to state and federal regulations. Shale gas exploration and production operations are similar to most other conventional and unconventional natural gas exploration and production operations in terms of their air emissions. However, varying gas composition and the fact that there is little or no associated oil production affects the nature of potential emissions.

[d] EPA does have drinking water standards for NORM.

Sources of Air Emissions

The exploration and production of shale gas may include a variety of potential air emission sources that change depending on the phase of operation. In the early phases of operation, emissions may come from such sources as drilling rigs whose engines may be fueled by either diesel or natural gas and from fracturing operations where multiple diesel-powered pumps are often used to achieve the necessary pressure. Other sources may include the well completion process, which may involve the venting or flaring of some natural gas, and vehicular traffic with engine exhaust and dust from unpaved roads.

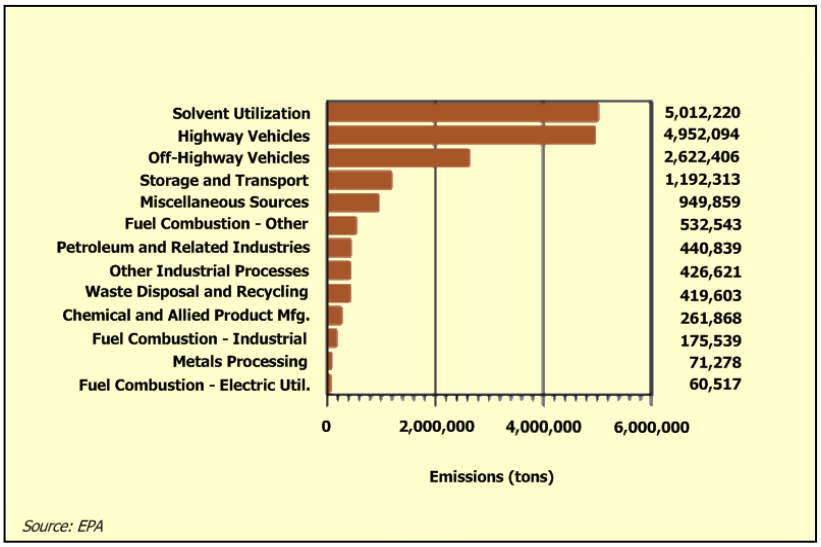
Once production has begun, emission sources may include compressors or pumps that may be needed to bring the produced gas up to the surface or up to pipeline pressure. Fugitive emissions such as leaks from pipe connections and associated equipment may also occur. Piping and pumping equipment may include pneumatic instrument systems, which, as part of their normal operations, release or bleed small amounts of natural gas into the atmosphere. Other sources of emissions in this phase of operations include flaring or blow down of gas in non-routine situations, dehydration units to remove water from the produced gas, and sulfur removal systems that may include flares and/or amine units.

Composition of Air Emissions

EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities[330]. These emissions and their sources are discussed below.

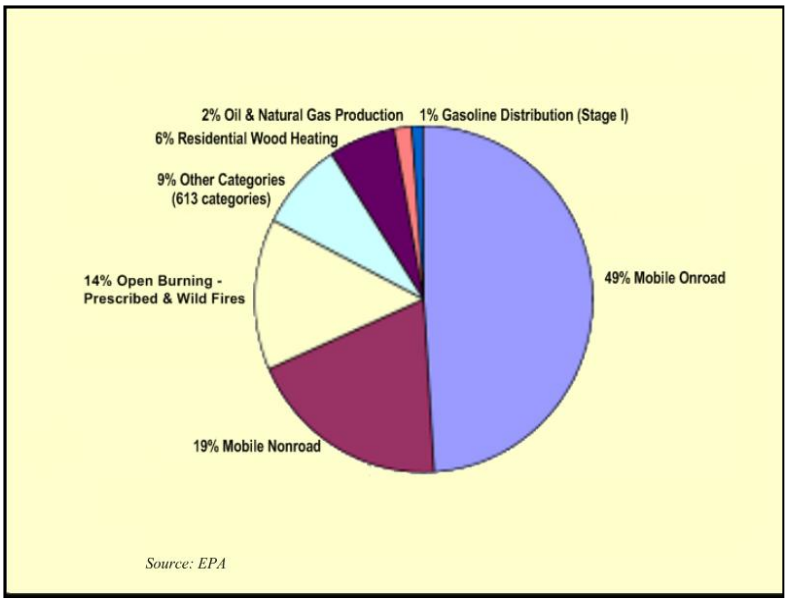
As in any construction or industrial activity, NO_x are formed when fossil fuel is burned to provide power to machinery such as compressor engines and during flaring operations. In addition, VOCs may be emitted during the dehydration of natural gas. VOC emissions are typically lower in natural gas activities than those associated with oil production because gas production is essentially a closed process from well to pipeline with fewer opportunities for emissions. In addition, emissions of benzene, toluene, ethylbenzene, and xylenes are low simply because these compounds do not exist in significant quantities in the natural gas stream. The oil and gas industry in general is a lesser contributor to air emissions than numerous other common sources (see Exhibit 40[331]). Further, oil and natural gas production contributes only 2% of the total benzene emissions in the U.S.[332], and shale gas

EXHIBIT 40: VOC EMISSIONS BY SOURCE CATEGORY



represents a very small subset of this 2%.

EXHIBIT 41: BENZENE EMISSIONS BY SOURCE - 1999

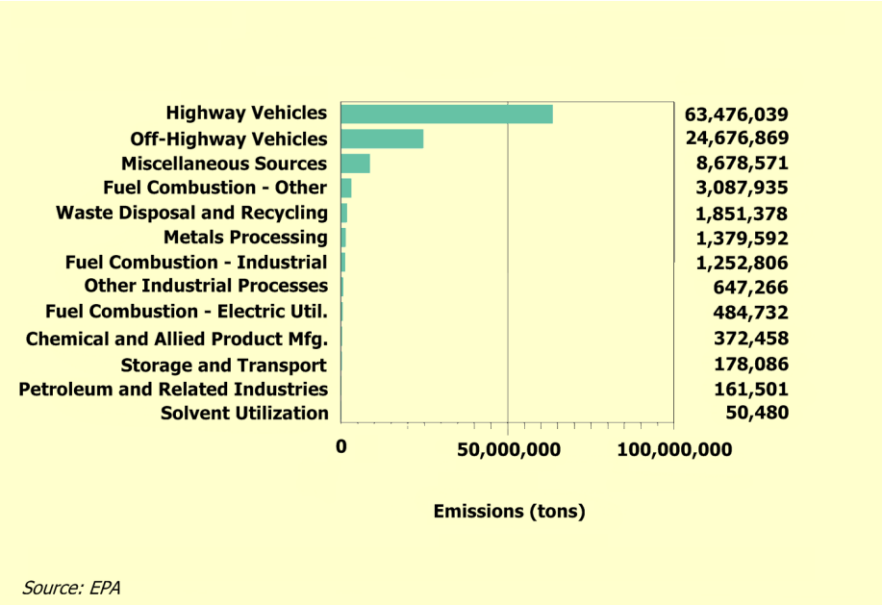


Particulate Matter (PM) may occur from dust or soil entering the air during pad construction, traffic on access roads, and diesel exhaust from vehicles and engines. In addition, CO may be emitted during flaring and from the incomplete combustion of carbon-based fuels used in engines. Flaring is seldom necessary with natural gas operations except during short periods of well testing, completions or workovers and non-routine situations such as a temporary pipeline closure. Exhibit 42[333] shows that CO emissions from the natural gas industry represent a very small part of the total[334].

SO_2 may form when fossil fuels containing sulfur are burned. Thus, SO_2 may be emitted from gasoline or diesel powered equipment used at a shale gas production site. However, emissions of SO_2 are typically very small for shale gas operations compared to coal or oil[335].

Ozone (O_3) itself is not released directly during natural gas development, but two of its main precursors, volatile organic compounds (VOCs) and NO_x, may combine with sunlight to form ground-level O_3 which can then be associated with exploration and production operations.

EXHIBIT 42: CO EMISSIONS BY SOURCE CATEGORY



Hydrogen sulfide (H_2S) emissions are not a concern in shale gas production as, based on discussions with operators from each of the major basins, the shale gas plays developed to date have not produced "sour" gas. If H_2S is encountered as production continues, both states and operators are well equipped to

implement appropriate safety measures. States have well-established public safety and worker protection requirements in place and operators have access to proven procedures for working with natural gas contaminated with H_2S.

The American Petroleum Institute (API) has a Recommended Practice (RP 49) for Drilling and Well Servicing Operations Involving H_2S[336]. Producers voluntarily follow this practice to minimize the release of and exposure to H_2S. In areas where concentrations of H_2S may exceed 10 parts per million (ppm), producers implement an H_2S contingency plan. The plan includes appropriate instruction in the use of hydrogen sulfide safety equipment to all personnel present at all hydrogen sulfide hazard areas, gas detection where hydrogen sulfide may exist, and appropriate respiratory protection for normal and emergency use.

Methane (CH_4) is the principal component of natural gas and a known GHG. Although the processing of natural gas is essentially confined from the well to sales, CH_4 may be released as a fugitive emission from gas processing equipment, especially equipment in high pressure service such as pneumatic controls. Producers have strong economic incentives to limit fugitive methane emissions to the greatest degree possible in order to maximize delivery of methane to market. Therefore, they rely on multiple BMPs (e.g., low-bleed gauges and valves, inspection and maintenance programs, infra-red (IR) cameras, etc.[337]) to reduce any potential energy loss.

Another potential source of emissions in natural gas fields are compressor engines. Many gas compressor engines are fueled by natural gas from the lease. Engine manufacturers are constantly improving their technology to reduce the amount of NO_x emissions from their engines. One key has been the use of catalytic technologies to chemically convert NO_x into inert compounds. The addition of catalytic emissions controls has successfully lowered engine emissions from 20 grams per horsepower hour down to 2 grams of NO_x per horsepower hour or less. Also, the addition of air-fuel ratio controllers can be used to ensure the continuous low emissions performance of these engines. Recent EPA regulations require new engines to meet more stringent low NO_x emissions standards regardless of engine size or fuel.

Technological Controls and Practices

The best way to reduce air pollution is to prevent it from occurring in the first place. Pollution prevention can take many forms—upgrading equipment, improving operational practices, reducing waste through byproduct synergies, improving management practices, and installing emissions controls. Several government programs have been established that encompass avoidance, minimization, and mitigation strategies applicable to exploration and production activities. Some are mandatory regulations, as described in the Regulatory Framework section, while others are voluntary.

An example of the latter is the Natural Gas STAR program, a voluntary partnership between the EPA and the natural gas industry formed in 1995 to find cost-effective ways to ensure the natural gas industry is doing everything possible to prevent energy losses and to minimize GHG emissions[338]. The primary goals of the program are to promote technology transfer and implement cost-effective BMPs while reducing CH_4 emissions. The program provides information on many practices that not only reduce CH_4 emissions, but also works to retain greater volumes of natural gas for producers to sell.

Some of the most effective and economic technologies promoted by this program include:

1. Identification of high-bleed pneumatic devices (transducers, valves, controllers, etc.) and replacement with low-bleed ones to reduce fugitive product losses. Traditional pneumatic devices control processes by measuring changes in pressure, releasing small quantities of natural gas in the process. Newer devices are now available that perform the same functions while releasing much smaller amounts of gas.
2. Use of IR cameras in the field to visually identify any fugitive hydrocarbon leaks so that they may be rapidly repaired to reduce potential energy losses. These cameras are tuned to the wavelengths that are reflected by hydrocarbon gases, so that those normally-invisible gases actually become visible as "smoke" in the camera image, thus allowing companies to quickly detect and repair leaks.
3. Installation of flash tank separators in situations that require the use of dehydrators. This can recover 90 to 99% of the methane that would otherwise be flared or vented into the atmosphere[339].
4. Performance of green well completions and workovers. These shale gas operations typically use portable equipment to process and direct the produced natural gas into tanks or directly into the pipeline rather than the traditional practice of venting or flaring the gas. On average, green completions recover 53% of the natural gas that would otherwise have been flared or vented. That captured gas is now retained and sold to market[340].

Many other pollution reduction technologies and practices are described on EPA's GasSTAR web site. In 2004, the Methane to Markets Partnership was formed as a voluntary international program aimed at advancing the recovery and use of methane as a valuable clean energy source[341]. The program includes the oil and gas sector as a focus area along with coal mines, landfills, and the agricultural business. There are approximately 400 program members across the globe representing the oil and gas sector[342]. The collective results of these voluntary programs have been substantial. Total U.S. methane emissions in 2005 were over 11% lower than emissions in 1990, in spite of economic growth over that same time period[343]. EPA expects that these emissions will continue to fall in the future due to expanded industry participation and the ongoing commitment of the participating companies to identify and implement cost-effective technologies and practices.

Additional technologies and practices have been identified that may be used in some settings to reduce air emissions in shale gas fields. One such practice is the use of natural gas instead of diesel to fuel drilling rigs. Another emission-reducing practice applicable to some settings is the use of centralized processing facilities; this reduces vehicle trips, and therefore engine exhaust and dust emissions. Operators have also found that reducing glycol pump rates on dehydration units from their maximum setting to an optimized pump rate will minimize benzene, toluene, ethylbenzene, and total xylenes (BTEX) emissions. These units are often operated at a rate (based on at or near maximum throughput) that accommodates the initial, high rate of gas production from a field. However, as production rates decline, the dehydration units can be adjusted to conform to the lower gas throughput and reduce emissions. Other emission-reducing technologies include the installation of plunger lift systems into shale gas well heads to optimize gas production and reduce methane emissions associated with blowdown operations as well as the optimization of

compressor and pump sizes to reduce the necessary horsepower and thus the subsequent exhaust emissions.

As with all operational practices, these BMPs must be applied on a case-by case basis. In some cases a given BMP may actually be counter-productive. In other cases, a particular BMP may create other environmental or operational problems that must be weighed against each other. While each BMP has certain benefits in certain situations, it cannot be universally applied or required.

State and federal requirements along with the technologies and practices developed by industry serve to limit air emissions from shale gas operations. As described earlier, state and federal requirements ensure that local conditions and other emission sources in the area are considered in issuing permits. In addition, advanced technologies and current practices serve to limit air emissions from modern shale gas development.

Summary

The primary differences between modern shale gas development and conventional natural gas development are the extensive use of horizontal drilling and multi-stage hydraulic fracturing. Horizontal drilling allows an area to be developed with substantially fewer wells than would be needed if vertical wells were used. The overall process of horizontal drilling varies little from conventional drilling, with casing and cementing being used to protect fresh and treatable groundwater. The use of horizontal drilling has not introduced new environmental concerns. On the contrary, the reduced number of horizontal wells needed, coupled with multiple wells drilled from a single pad, has significantly reduced surface disturbances and the associated impacts to wildlife and impacts from dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to help reduce community impacts, impacts to sensitive environmental resources, and interference with existing businesses.

Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proven to be a safe and effective stimulation technique. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. The multi-stage hydraulic fracture operations used in horizontal wells may require 3 to 4 million gallons of water. Since it is a relatively new use in these areas, withdrawals for hydraulic fracturing must be balanced with existing water demands. Once the fracture treatment is completed, most of the fracture water comes back to the surface and must be managed in a way that conserves and protects water resources. While challenges continue to exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users can be met and that surface and ground water quality is protected.

An additional consideration in shale gas development is the potential for low levels of naturally occurring radioactive material (NORM) to be brought to the surface. While NORM may be encountered in shale gas operations, there is negligible exposure risk for the general public and there are well established regulatory programs that ensure public and worker safety

Although the use of natural gas offers a number of environmental benefits over other fossil energy sources, some air emissions commonly occur during exploration and production activities. EPA sets standards, monitors the ambient air quality across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

Taken together, state and federal requirements, along with the technologies and practices developed by industry, serve to protect human health and to help reduce environmental impacts from shale gas operations.

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ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
bbls	barrels, petroleum (42 gallons)
bcf	billion cubic feet
BLM	Bureau of Land Management
BMP	Best Management Practices
Btu	British thermal units
CAA	Clean Air Act
CBNG	Coal Bed Natural Gas
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CWA	Clean Water Act
DRBC	Delaware River Basin Commission
EIA	Energy Information Administration
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
FR	Federal Register
ft	foot/feet
FWS	Fish and Wildlife Service
gal	gallon
GHG	Greenhouse Gases
GWPC	Ground Water Protection Council
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCl	Hydrochloric acid
IOGCC	Interstate Oil and Gas Compact Commission
IR	infra-red
Mcf	thousand cubic feet
MMcf	million cubic feet
mrem	millirem
mrem/yr	millirem per year
MSDSs	Material Safety Data Sheets
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory

NORM	Naturally Occurring Radioactive Material
NO_x	Nitrogen Oxides
NPDES	National Pollution Discharge Elimination System
NYDEC	New York State Department of Environmental Conservation
O_3	Ozone
OPA	Oil Pollution Act
OSHA	Occupational Safety and Health Administration
PM	Particulate Matter
ppm	parts per million
RAPPS	Reasonable and Prudent Practices for Stabilization
RCRA	Resource Conservation and Recovery Act
RP	Recommended Practice
RQ	Reportable Quantity
SARA	Superfund Amendments and Reauthorization Act
SCF	standard cubic feet
SDWA	Safe Drinking Water Act
SO_2	Sulfur Dioxide
SPCC	Spill Prevention, Control and Countermeasures
SRBC	Susquehanna River Basin Commission
STRONGER	State Review of Oil and Natural Gas Environmental Regulation, Inc.
SWDA	Solid Waste Disposal Act
tcf	trillion cubic feet
TDS	Total Dissolved Solids
tpy	tons per year
TRI	Toxics Release Inventory
UIC	Underground Injection Control
U.S.	United States
U.S.C.	United States Code
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
VOC	Volatile Organic Compound
WQA	Water Quality Act
yr	year

DEFINITIONS

AIR QUALITY. A measure of the amount of pollutants emitted into the atmosphere and the dispersion potential of an area to dilute those pollutants.

AQUIFER. A body of rock that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

BASIN. A closed geologic structure in which the beds dip toward a central location; the youngest rocks are at the center of a basin and are partly or completely ringed by progressively older rocks.

BIOGENIC GAS. Natural gas produced by living organisms or biological processes.

CASING. Steel piping positioned in a wellbore and cemented in place to prevent the soil or rock from caving in. It also serves to isolate fluids, such as water, gas, and oil, from the surrounding geologic formations.

COAL BED METHANE/NATURAL GAS (CBM/CBNG). A clean-burning natural gas found deep inside and around coal seams. The gas has an affinity to coal and is held in place by pressure from groundwater. CBNG is produced by drilling a wellbore into the coal seam(s), pumping out large volumes of groundwater to reduce the hydrostatic pressure, allowing the gas to dissociate from the coal and flow to the surface.

COMPLETION. The activities and methods to prepare a well for production and following drilling. Includes installation of equipment for production from a gas well.

CORRIDOR. A strip of land through which one or more existing or potential utilities may be co-located.

DISPOSAL WELL. A well which injects produced water into an underground formation for disposal.

DIRECTIONAL DRILLING. The technique of drilling at an angle from a surface location to reach a target formation not located directly underneath the well pad.

DRILL RIG. The mast, draw works, and attendant surface equipment of a drilling or workover unit.

EMISSION. Air pollution discharge into the atmosphere, usually specified by mass per unit time.

ENDANGERED SPECIES. Those species of plants or animals classified by the Secretary of the Interior or the Secretary of Commerce as endangered pursuant to Section 4 of the Endangered Species Act of 1973, as amended. See also **Threatened and Endangered Species**.

EXPLORATION. The process of identifying a potential subsurface geologic target formation and the active drilling of a borehole designed to assess the natural gas or oil.

FLOW LINE. A small diameter pipeline that generally connects a well to the initial processing facility.

FORMATION (GEOLOGIC). A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

FRACTURING FLUIDS. A mixture of water and additives used to hydraulically induce cracks in the target formation.

GROUND WATER. Subsurface water that is in the zone of saturation; source of water for wells, seepage, and springs. The top surface of the groundwater is the "water table."

HABITAT. The area in which a particular species lives. In wildlife management, the major elements of a habitat are considered to be food, water, cover, breeding space, and living space.

HORIZONTAL DRILLING. A drilling procedure in which the wellbore is drilled vertically to a kick-off depth above the target formation and then angled through a wide 90 degree arc such that the producing portion of the well extends horizontally through the target formation.

HYDRAULIC FRACTURING. Injecting fracturing fluids into the target formation at a force exceeding the parting pressure of the rock thus inducing a network of fractures through which oil or natural gas can flow to the wellbore.

HYDROSTATIC PRESSURE. The pressure exerted by a fluid at rest due to its inherent physical properties and the amount of pressure being exerted on it from outside forces.

INJECTION WELL. A well used to inject fluids into an underground formation either for enhanced recovery or disposal.

LEASE. A legal document that conveys to an operator the right to drill for oil and gas. Also, the tract of land, on which a lease has been obtained, where producing wells and production equipment are located.

NORM (Naturally Occurring Radioactive Material). Low-level, radioactive material that naturally exists in native materials.

ORIGINAL GAS- IN- PLACE The entire volume of gas contained in the reservoir, regardless of the ability to produce it.

PARTICULATE MATTER (PM). A small particle of solid or liquid matter (e.g., soot, dust, and mist). PM_{10} refers to particulate matter having a size diameter of less than 10 millionths of a meter (micro-meter) and $PM_{2.5}$ being less than 2.5 micro-meters in diameter.

PERMEABILITY. A rock's capacity to transmit a fluid; dependent upon the size and shape of pores and interconnecting pore throats. A rock may have significant porosity (many microscopic pores) but have low permeability if the pores are not interconnected. Permeability may also exist or be enhanced through fractures that connect the pores.

PRIMACY. A right that can be granted to state by the federal government that allows state agencies to implement programs with federal oversight. Usually, the states develop their own set of regulations. By statute, states may adopt their own standards, however, these must be at least as protective as the federal standards they replace, and may be even more protective in order to

address local conditions. Once these state programs are approved by the relevant federal agency (usually the EPA), the state then has primacy jurisdiction.

PRODUCED WATER. Water produced from oil and gas wells.

PROPPING AGENTS/PROPPANT. Silica sand or other particles pumped into a formation during a hydraulic fracturing operation to keep fractures open and maintain permeability.

PROVED RESERVES That portion of recoverable resources that is demonstrated by actual production or conclusive formation tests to be technically, economically, and legally producible under existing economic and operating conditions.

RECLAMATION. Rehabilitation of a disturbed area to make it acceptable for designated uses. This normally involves regrading, replacement of topsoil, re-vegetation, and other work necessary to restore it.

SET-BACK. The distance that must be maintained between a well or other specified equipment and any protected structure or feature.

SHALE GAS. Natural gas produced from low permeability shale formations.

SLICKWATER. A water based fluid mixed with friction reducing agents, commonly potassium chloride.

SOLID WASTE. Any solid, semi-solid, liquid, or contained gaseous material that is intended for disposal.

SPLIT ESTATE. Condition that exists when the surface rights and mineral rights of a given area are owned by different persons or entities; also referred to as "severed estate".

STIMULATION. Any of several processes used to enhance near wellbore permeability and reservoir permeability.

STIPULATION. A condition or requirement attached to a lease or contract, usually dealing with protection of the environment, or recovery of a mineral.

SULFUR DIOXIDE (SO_2). A colorless gas formed when sulfur oxidizes, often as a result of burning trace amounts of sulfur in fossil fuels.

TECHNICALLY RECOVERABLE RESOURCES The total amount of resource, discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.

THERMOGENIC GAS. Natural gas that is formed by the combined forces of high pressure and temperature (both from deep burial within the earth's crust), resulting in the natural cracking of the organic matter in the source rock matrix.

THREATENED AND ENDANGERED SPECIES. Plant or animal species that have been designated as being in danger of extinction. See also **Endangered Species.**

TIGHT GAS. Natural gas trapped in a hardrock, sandstone or limestone formation that is relatively impermeable.

TOTAL DISSOLVED SOLIDS (TDS). The dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in parts per million.

UNDERGROUND INJECTION CONTROL PROGRAM (UIC). A program administered by the Environmental Protection Agency, primacy state, or Indian tribe under the Safe Drinking Water Act to ensure that subsurface emplacement of fluids does not endanger underground sources of drinking water.

UNDERGROUND SOURCE OF DRINKING WATER (USDW). 40 CFR Section 144.3 An aquifer or its portion:

(a) (1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer.

WATER QUALITY. The chemical, physical, and biological characteristics of water with respect to its suitability for a particular use.

WATERSHED. All lands which are enclosed by a continuous hydrologic drainage divide and lay upslope from a specified point on a stream.

WELL COMPLETION. See **Completion**.

WORKOVER. To perform one or more remedial operations on a producing or injection well to increase production. Deepening, plugging back, pulling, and resetting the liner are examples of workover operations.

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Ground Water Protection Council
Oklahoma City, OK 73142
405-516-4972
www.gwpc.org

ALL Consulting
Tulsa, OK 74119
918-382-7581
www.all-llc.com

National Energy Technology Laboratory
Strategic Center for Natural Gas and Oil
Morgantown, WV 26507
1-800-533-7681
www.netl.doe.gov

U.S. Department of Energy
Office of Fossil Energy
Washington, DC 20585
202-586-5600
www.fossil.energy.gov

April 2009

Printed on recycled paper