CEP AUGUST 2012 SHALE GAS VOL.108/NO.8

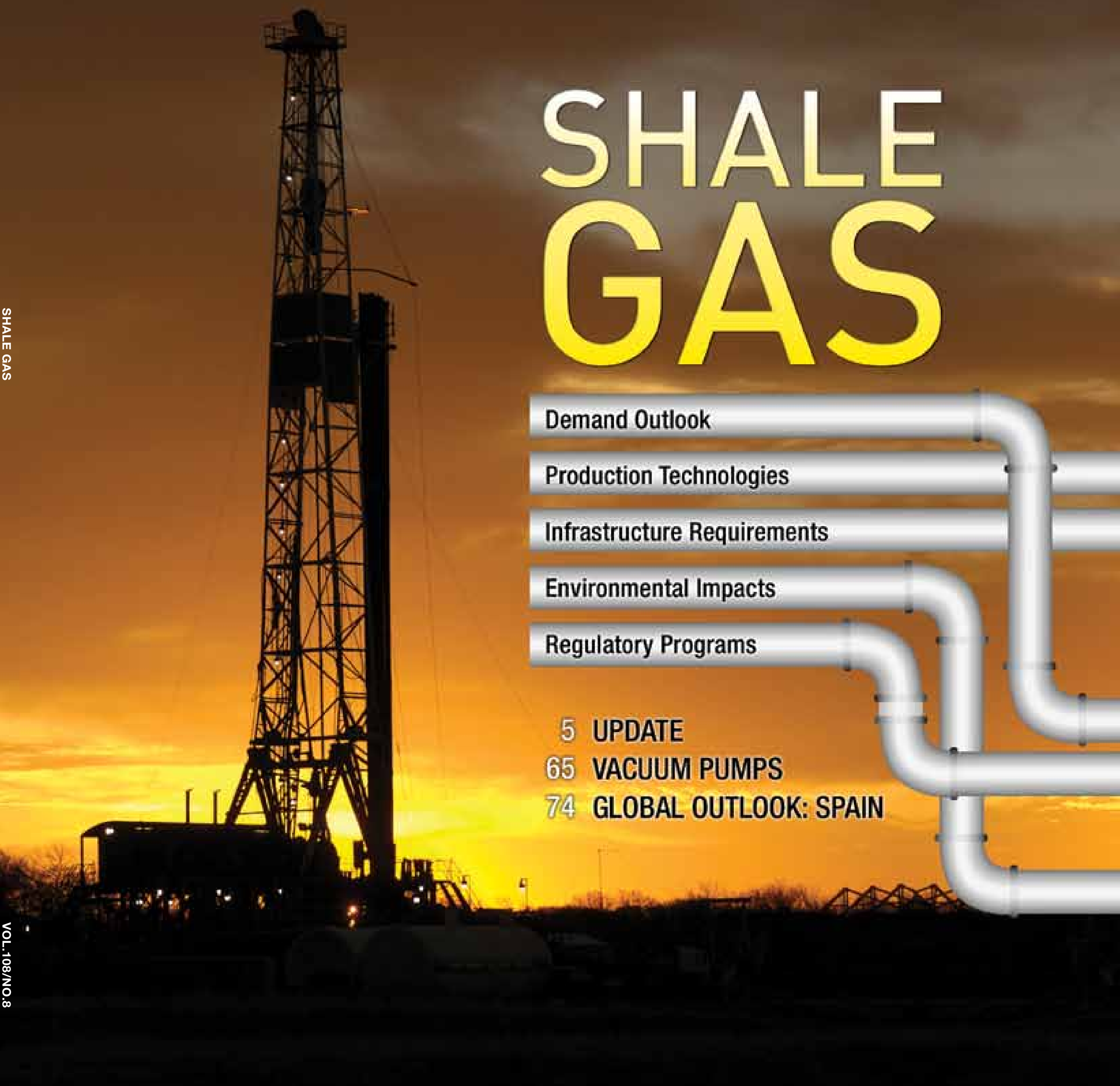
August 2012

CEP

Chemical Engineering Progress

An AIChE Publication

www.aiche.org/cep



SHALE GAS

Demand Outlook

Production Technologies

Infrastructure Requirements

Environmental Impacts

Regulatory Programs

SPECIAL SECTION: ENERGY

SHALE GAS

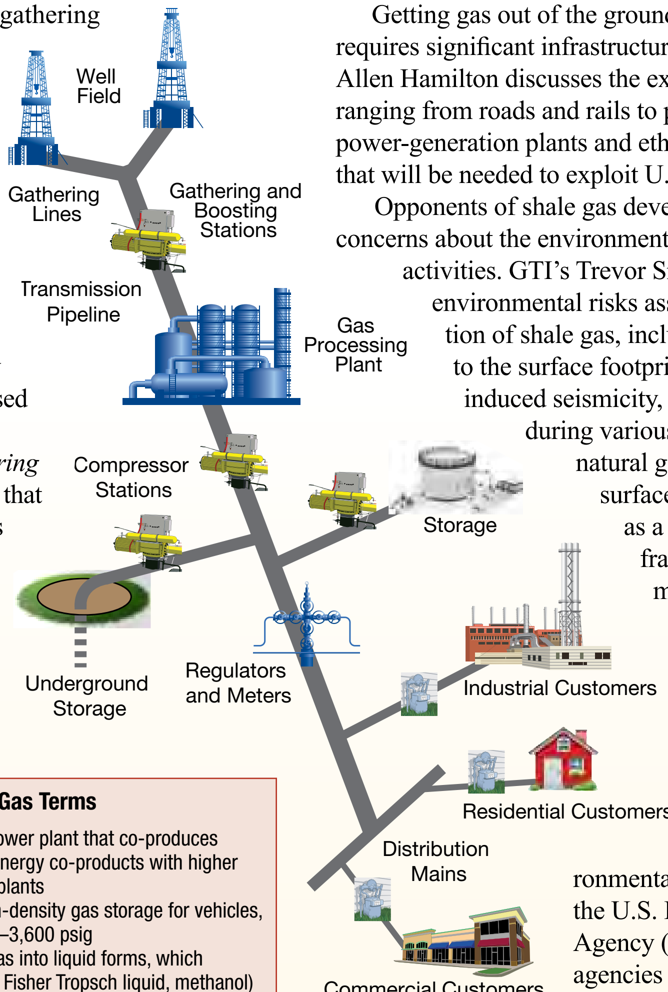
Inset photos courtesy of EQT Corp.

Addressing the Challenges Along the Shale Gas Supply Chain

The production of natural gas from shale formations is one of the fastest-growing segments of the U.S. oil and gas industry today. The U.S. Energy Information Administration's *Annual Energy Outlook 2012* reference-case scenario has shale gas production increasing from 5.0 trillion ft^3/yr (23% of total U.S. dry gas production) in 2010 to 13.6 trillion ft^3/yr (49% of the total) in 2035.

Whether the gas is obtained from a shale formation or another source, the natural gas supply chain is the same. It encompasses wells, gathering and processing facilities, storage, transportation and distribution pipelines, and ultimately an end user, such as an industrial manufacturing plant or a single-family home. This special section on shale gas spans the supply chain.

To set the stage and provide perspective, the first article deals with the end of the supply chain. William Liss of the Gas Technology Institute (GTI) asks the question posed by the title of a recent International Energy Agency report, *Are We Entering a Golden Age of Gas?* Liss believes that based on the confluence of shale gas resources, hydraulic fracturing, and directional drilling techniques, the answer in the U.S. is an emphatic "yes." He supports this assertion with a look at the supply and demand picture in key sectors of the economy that rely on natural gas — industrial, power generation, transportation, residential, and commercial — and the transformative role that shale gas is playing.



In the second article, Stephen A. Holditch, P.E., of Texas A&M Univ. explains the basics of horizontal drilling, hydraulic fracturing, and fracture fluids. He looks at the state of the art and recent developments, as well as some of the remaining challenges and opportunities, and he provides insight into the economics of shale gas production.

Getting gas out of the ground and to the customer requires significant infrastructure. Jesse Goellner of Booz Allen Hamilton discusses the expansion of assets — ranging from roads and rails to pipelines and seaports to power-generation plants and ethane crackers and more — that will be needed to exploit U.S. shale gas resources.

Opponents of shale gas development have raised concerns about the environmental footprint of these activities. GTI's Trevor Smith explores the potential environmental risks associated with the production of shale gas, including impacts on land due to the surface footprint of the operations and to induced seismicity, on air due to emissions during various activities along the natural gas supply chain, and on surface water and groundwater as a result of water use in the fracturing process and the management of the wastewater generated.

The final article, by Mary Ellen Ternes, an attorney with McAfee & Taft, expands Smith's discussion of environmental footprint. She explains the key environmental statutes under which the U.S. Environmental Protection Agency (EPA) and delegated state agencies regulate hydraulic fracturing and other aspects of shale gas development. She also touches on water sourcing issues such as property rights associated with surface waters and groundwater.

Chemical engineers will be needed to innovate all along the supply chain. These articles provide a glimpse into the challenges and opportunities that lie ahead. CEP

Glossary of Natural Gas Terms

- **CHP** *Combined Heat and Power:* A type of power plant that co-produces power and heat (*e.g.,* steam) or other energy co-products with higher efficiency than power-generation-only plants
- **CNG** *Compressed Natural Gas:* Used for high-density gas storage for vehicles, typically at nominal pressures of 3,000–3,600 psig
- **GTL** *Gas to Liquids:* Conversion of natural gas into liquid forms, which includes chemical transformation (*e.g.,* Fisher Tropsch liquid, methanol) or phase change to liquefied natural gas
- **LNG** *Liquefied Natural Gas:* A cryogenic liquid form of natural gas (at –150°C to –160°C) used for high-density stationary storage and vehicle use
- **NGL** *Natural Gas Liquids:* A mixture of light hydrocarbons such as ethane, propane, and butanes that are co-produced and extracted from natural gas
- **NGV** *Natural Gas Vehicles:* Vehicles that operate on natural gas (CNG or LNG)

Compiled by William Liss, GTI

Photos courtesy of EQT Corp.

Demand Outlook: A Golden Age of Natural Gas

William Liss
Gas Technology Institute

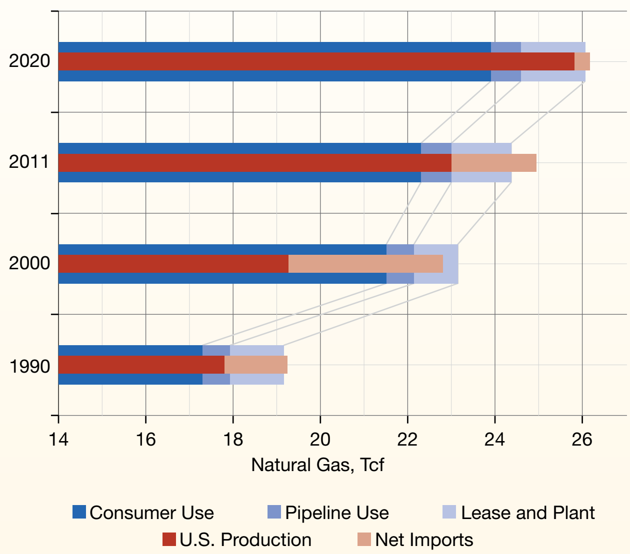
The shale gas boom in the U.S. is transforming the energy marketplace and a wide range of manufacturing industries that rely on natural gas.

The International Energy Agency issued a report last year titled *Are We Entering a Golden Age of Gas? (1)*. In the U.S., the answer is an emphatic "yes" — in large part due to the confluence of shale gas resources, hydraulic fracturing, and directional drilling techniques.

The current situation represents an impressive turnaround in the U.S. gas supply outlook. During the last decade, U.S. reliance on natural gas imports was increasing — along with prices — and liquefied natural gas (LNG) import terminals was a hot topic. Today, the U.S. is on a path toward the elimination of natural gas imports and is now starting to construct LNG export facilities — a remarkable 180-deg. U-turn.

Projected Incremental Growth from 2010 to 2020, billion ft^3

Residential	Commercial	Industrial	Power	Transportation
163	378	893	673	53



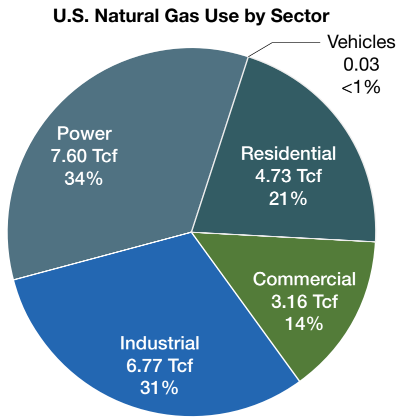
▲ **Figure 1.** Natural gas supply and demand outlook. Domestic production will continue to exceed growing consumer use. Source: *(2, 3)*.

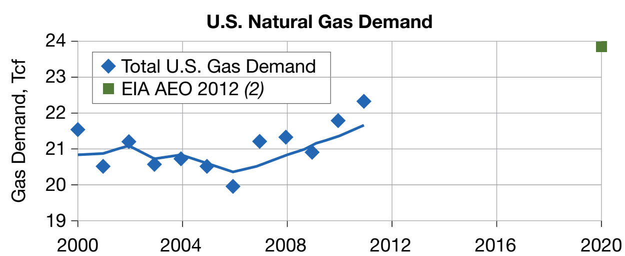
For the chemical and petrochemical industries, the period from 1997 to the recession of 2009 was an era of intense demand destruction, due in part to high natural gas prices and international competition (offshoring). More than 2.3 trillion cubic feet (Tcf) in annual U.S. industrial natural gas demand was eliminated (a 28% decrease).

New shale gas resources have completely transformed the U.S. natural gas supply and demand outlook. Even with a warm winter, 2011 set an all-time record for U.S. natural gas demand, with end users consuming about 22.3 Tcf.

Figure 1 summarizes U.S. natural gas consumption and production trends. The dark blue bars indicate the amount of gas purchased for consumer use in the residential, commercial, industrial, power generation, and transportation sectors. The lighter blue bars represent natural gas used as fuel in well, field, and lease operations, for example to operate drilling equipment, heaters, dehydrators, and field compressors (lease and plant), and in pipeline operations (*e.g.,* to power compressors).

In 1990, domestic production (17.8 Tcf) exceeded consumer use (17.3 Tcf), and imports accounted for only 8% of total natural gas consumption. By 2000, consumer use (21.5 Tcf) outstripped domestic production (19.3 Tcf), and reliance on imports doubled to 16%. Although the consumer use of natural gas surged over the last decade (to 22.3 Tcf in 2011), domestic production ramped up to 23 Tcf — reducing reliance on imports to 9%. The U.S. Dept. of Energy's Energy





▲ **Figure 2a.** U.S. natural gas use trends. The power generation and industrial sectors account for roughly two-thirds of the total U.S. natural gas consumption. Source: *(3).*

Information Administration (DOE-EIA) expects demand to increase to 24 Tcf by 2020 *(2),* although this could prove to be a conservative prediction. Growth is anticipated in all markets, led by the industrial, power generation, and transportation sectors. Import reliance is expected to be negligible in 2020 (less than 1.5% of consumer use).

Figures 2a–2e illustrate natural gas consumption trends by end use sector *(3).* Recent gas demand has been shaped by power generation growth, industrial decline, and, of course, weather. The past two years have seen record demand levels, led by a strong industrial demand rebound and inexorable power generation expansion. Natural gas vehicles (NGVs) are experiencing high growth rates, albeit on a small base, driven by large fuel price differentials compared with diesel and gasoline.

Demand vectors and value creation

It certainly appears to be a golden age for natural gas in the U.S. But a vital question remains: For whom? Many are staking claims and making plans to capitalize on bountiful natural gas supplies. New resources could be channeled along many demand vectors — traditional and nontraditional, large and small. Many options provide a compelling value proposition, with several hinging on multi-billion-dollar capital investments — new industrial manufacturing (*e.g.,* chemical/petrochemical) plants, gas-to-liquids (GTL) (*e.g.,* gasoline or diesel substitutes) plants, power generation facilities, NGV fueling infrastructure, natural gas liquefaction plants, and others.

Natural gas consumers are realizing significant savings (Table 1). Prices for large-volume industrial and power generation users have dropped precipitously. Compared with 2008 prices, current natural gas prices are saving consumers nearly $90 billion per year. For the industrial sector, this frees up working capital for other investments. An added bonus for the U.S. economy is that natural gas imports are down by more than 1.8 Tcf since 2007, which has positively impacted both the balance of trade and employment.

Time will tell how the competitive marketplace will adapt to natural gas supplies and — just as important — how further value creation from natural gas will be realized. This article explores some of the market factors that may influence natural gas use and industrial output, and the role of chemical engineering and chemistry in this transformation.

Industrial demand for natural gas

Natural gas is expected to be a significant game changer in the industrial sector, where it is used extensively by manufacturers for power and steam production, process heating, and as a chemical feedstock. The value proposition associated with expanding industrial natural gas use revolves around growth in manufacturing output, gross domestic product (GDP), and employment. For example, a facility that displaces foreign-made goods has a leveraged positive impact on GDP and job creation. Studies point to the phenomenon known as onshoring, which may increase value-added U.S. manufacturing over the coming decade. The confluence of low-cost natural gas and onshoring may turbocharge U.S. manufacturing over the next 10 to 20 years *(4).*

New U.S. natural gas supplies are playing a key role in this anticipated industrial renaissance, particularly for the chemical and petrochemical segments *(5).* Expansion is projected in the manufacture of products that depend on natural gas or methane, such as ammonia, urea, hydrogen, and

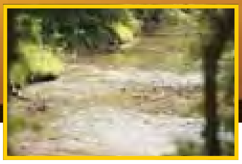
Table 1. The production of shale gas has increased natural gas supplies and driven down prices, resulting in significant savings in all sectors.

Prices, $/MMBtu*	Industrial	Power Generation	Commercial	Residential
2008 Prices	9.65	9.26	12.23	13.89
2011 Prices	5.02	4.87	8.86	10.80
Change	–48.0%	–47.4%	–27.6%	–22.2%
Sector Savings, $ billion	$31.3	$33.4	$10.7	$14.7

* per million Btu

Source: GTI analysis of DOE-EIA data.





methanol, as well as ethylene made from ethane (which is a component of natural gas and natural gas liquids [NGLs]).

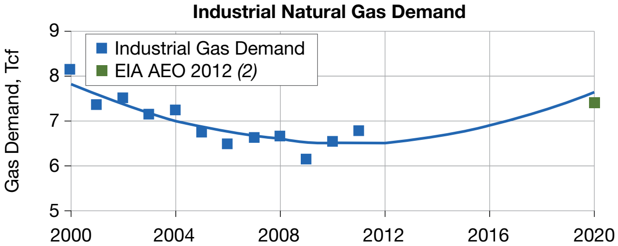
Methane is a chemical precursor not just for the chemical and petrochemical industries. The iron and steel industry can use methane as a reducing agent in iron ore conversion. For example, Nucor Corp. is constructing a major new direct-reduced iron (DRI) plant that will use natural gas for iron ore processing. Integrated steel producers may also look to supplemental natural gas use in blast furnaces to offset coking coal.

Low U.S. natural gas prices help producers compete internationally. In ammonia production, for instance, low gas prices provide U.S. producers with a competitive advantage over foreign producers in a tight commodity market (particularly producers using higher-cost naphtha feedstock). Agriculture is a primary market for ammonia and other nitrogen-based fertilizers. High grain commodity prices (partially tied to ethanol production) and growing international grain demand are acting to increase domestic ammonia demand and prices, making U.S.-based ammonia production from natural gas more profitable. This helps boost GDP and job creation in multiple segments (*e.g.,* agriculture, chemicals, natural gas production) and demonstrates the ripple effect that natural gas supplies and prices can have.

An increasingly robust supply of NGLs being produced as a co-product of natural gas extraction is creating large domestic supplies of ethane. Like methane, ethane is a simple molecule with an outsized impact and value as a chemical precursor. The transformation of ethane to ethylene in ethane steam cracking furnaces has an extensive cascading effect on the production of value-added chemicals and products: low- and high-density polyethylene (trash bags, bottles, food containers, pipe), ethylene oxide (ethylene glycol for antifreeze, and polyester resins and fibers for carpeting and clothing), ethylene chloride (polyvinyl chloride [PVC] for pipe), ethylbenzene (styrene, styrene butadiene rubber), and many other industrial chemicals and products.

These strong NGL and ethane supplies are positioning the U.S. as a top-tier, low-cost ethylene producer — particularly when juxtaposed against countries where ethylene is produced from naphtha. This is inspiring new investments in ethane recovery (*e.g.,* NGL extraction and fractionation plants) and pipeline systems to move ethane from new gas-production regions to existing ethane steam cracking facilities in the South Central U.S. and Ontario, Canada. In addition, several companies are evaluating major investment in new ethane steam cracking plants in Pennsylvania, West Virginia, Ohio, and others states.

The American Chemistry Council (ACC) reports that a 25% increase in U.S. ethane supplies could generate over 400,000 new jobs, nearly $33 billion in new chemical production, and a total GDP impact in excess of $132 billion *(6).*



▲ **Figure 2b.** Industrial demand for natural gas is projected to increase as new domestic sources of shale gas come online. Source: *(3).*

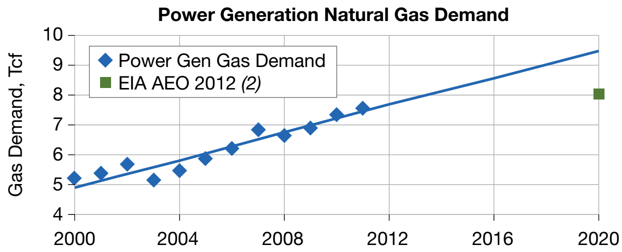
The manufacture of transportation fuels (*e.g.,* diesel, gasoline, and biofuels such as ethanol) is a major part of the chemical process industries. Natural gas works behind the scenes in refineries and ethanol plants to provide the power, steam, heat, and chemistry needed to make transportation fuels. For example, hydrogen from steam reforming of natural gas is used in the hydrodesulfurization of liquid fuels, and natural gas-fueled combined heat and power (CHP) systems provide onsite power and steam at refineries and ethanol plants. Approximately 1.3 Tcf/yr of natural gas is used to produce liquid transportation fuels (including about 0.5 Tcf/yr for ethanol).

From this perspective, natural gas has a larger footprint in the transportation fuels market than is generally recognized. Incremental gas use in the production of transportation fuels could result from refinery capacity expansions and new ethanol plants, although ethanol growth is somewhat contingent on the maturation of cellulosic ethanol production. Bioengineering and chemical engineering could help bring about important breakthroughs in this area.

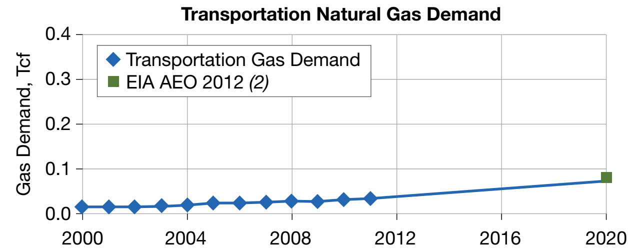
Other vectors by which natural gas could impact the liquid transportation fuels space include gas-to-liquids (GTL) transformation to produce substitute gasoline or diesel fuels (*e.g.,* via the Fischer-Tropsch, Shell Middle Distillates Synthesis [SMDS], ExxonMobil methanol-to-gasoline [MTG], Topsoe Integrated Gasoline Synthesis [TIGAS], and other processes), and methanol production from natural gas. Methanol, which is generally made from methane rather than biomass feedstocks, is considered an alternative or complement to ethanol for vehicles *(7).*

GTL and methanol processes typically have, at their core, synthesis gas production. Synthesis gas (syngas) consists of hydrogen and carbon monoxide, which act as molecular building blocks in the production of methanol and longer hydrocarbons that are compatible with gasoline or diesel. Syngas can be made by various routes, including steam reforming, autothermal reforming, and partial oxidation of natural gas, as well as gasification of solid fuels such as coal or biomass.

Key issues impacting GTL plants are capital cost, access to low-cost gas resources, and conversion efficiency. Conversion (or well-to-wheels) efficiencies in the range of



▲ **Figure 2c.** Consumption of natural gas for power generation will continue to soar. Source: *(3).*



▲ **Figure 2d.** Demand for natural gas in the transportation sector, though growing, is much lower than in other segments of the economy. Source: *(3).*

60–65% have been reported for GTL plants. The chemical engineering challenge is twofold: raise GTL plant conversion efficiency and reduce capital intensity.

Breakeven conditions for GTL plant economics hinge upon high crude oil prices and low natural gas costs. The Pearl complex in Qatar, which produces 140,000 barrels per day (bpd) of liquid fuels and other products using the SMDS process, had a construction cost of over $20 billion, but a reported payback time of less than 3 yr at current oil prices.

Sasol Ltd. recently announced plans to construct an $8–10-billion GTL complex in Louisiana. This facility could consume up to 1 billion cubic feet (Bcf) of natural gas per day and have an output of 96,000 bpd of liquid fuels and other products. Shell is also reportedly considering the construction of a plant of similar scale in the U.S. Gulf Coast area.

Natural gas conversion to liquid fuels includes natural gas liquefaction, a cryogenic refrigeration process that produces LNG at temperatures of –150°C to –160°C. Several companies are considering constructing large-scale, capital-intensive LNG plants and exporting the output to Europe or Asia, which raises concerns about the potential impact of natural gas exports on domestic gas prices. For natural gas producers, the increased demand for natural gas in LNG plants will open a new market option while also boosting NGL output that could be used by chemical and petrochemical producers. There are also potential applications for complementary domestic LNG use in heavy-duty trucks, rail, and marine markets (*e.g.,* ferries, barges).

Natural gas in power generation

Over the past 15 yr, natural gas use for power generation has grown by 85%, with 3.5 Tcf/yr in new demand bringing the total consumption by this sector to 7.6 Tcf/yr. This has occurred even though coal, which has accounted for about 45% of U.S. power production, is less expensive on a per-Btu basis. The value of natural gas in power generation stems from the low capital cost and high efficiency of combined cycle power plants and the efficiency of CHP facilities. Value also arises from operating flexibility — *i.e.,* the ability of gas-fired plants to stop and start and to ramp up and down quickly. Operating flexibility is becoming increasingly important as more intermittent power sources (*e.g.,* solar, wind) populate the electric grid.

In 2011, natural-gas-fired power generation output totaled nearly 988 GWh — a 64% increase since 2000 and nearly 24% of U.S. electricity production. Natural gas CHP systems generated 208 GWh of electricity — much of this tightly integrated with industrial manufacturing operations that benefit from the waste heat and steam co-produced by CHP systems. DOE-EIA's 2012 Annual Energy Outlook *(2)* anticipates natural gas use in power generation growing to 8 Tcf/yr by 2020. If recent market trends (*e.g.,* coal plant retirements) and low natural gas prices continue, natural gas use in power generation may be closer to 9 Tcf/yr by 2020.

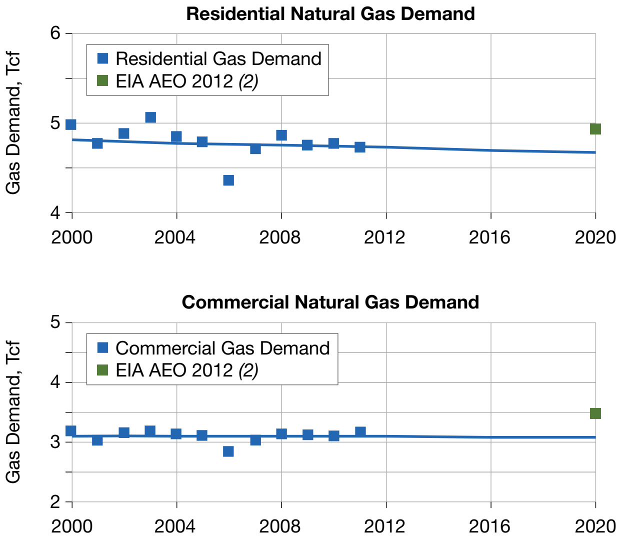
Natural gas demand in the transportation sector

Unlike other sectors, the U.S. transportation market is highly dependent on one energy source — crude oil and its derivative products (*e.g.,* gasoline, diesel). This has impacts on the balance of trade, and creates a long-recognized energy security risk.

As already noted, natural gas plays an indirect role in the production of transportation fuels such as gasoline, diesel, and ethanol. There is significant potential, however, for greater direct use in natural gas vehicles.

The U.S. and the rest of the world now have several decades of experience with compressed natural gas (CNG) and LNG vehicles. Today, an estimated 15 million NGVs are in use worldwide, with about 120,000 of those in the U.S. The NGV industry started in the U.S. around 1990 with the introduction of high-performance, low-emission NGV engines, advanced lightweight composite high-pressure cylinders, and an expanding NGV fueling infrastructure.

NGVs are now poised for a new wave of growth, particularly with high-fuel-use fleet vehicles such as heavy-duty buses and trucks. Significant progress has already been made with transit bus and, more recently, with refuse fleets. Freight trucks, both regional and interstate, represent the next growth segment. These heavy-duty fleet vehicles can use 10,000–20,000 gal/yr of diesel fuel. According to the U.S. DOE January 2012 price survey, diesel prices were $3.86/gal and CNG prices were $2.38 per diesel gallon



▲ **Figure 2e.** Natural gas demand in the residential (top) and commercial (bottom) sectors remains relatively flat. Source: *(3).*

equivalent *(8).* Such price differentials equate to annual fuel-cost savings in the range of \$15,000–\$30,000 per heavy-duty vehicle and provide the opportunity for a 2–4-yr payback on the initial NGV cost premium.

The use of 1 Tcf of natural gas in NGVs — less than 5% of current consumer natural gas demand — could displace nearly 8 billion gal of diesel fuel, saving fleet operators more than \$12 billion/yr in fuel costs while diversifying transportation fuel use and enhancing energy security.

Research on adsorbed natural gas storage as an alternative low-pressure storage option for NGVs is also underway. This includes high-performance carbons and metal organic framework (MOF) materials, both of which might be used in other chemical and petrochemical applications for separation and processing of gases and liquids.

Residential and commercial natural gas demand

Today's residential and commercial (res/com) markets are dominated by natural gas and electricity, which together meet 85–90% of the energy needs of U.S. homes and commercial businesses. In 2011, res/com gas demand totaled 7.9 Tcf (35% of total gas demand). The demand trend in these two sectors is flat, and this trajectory is expected to continue into 2020. Increases in total housing stock and commercial building space are largely offset by improvements in appliance efficiency and tighter building envelopes (*e.g.,* through better insulation and windows). In 2011, U.S. natural gas utilities invested — on behalf of their customers — \$1.2 billion in energy efficiency programs (62% of which was for residential users), and similar investments are expected in coming years.

New value creation opportunities (*e.g.,* consumer energy cost savings) for residences and commercial consumers include displacing inefficient electrical uses (*i.e.,* inefficient on a source-energy basis) and expensive fuel oil.

Source-energy efficiency is an important concept in understanding energy use and losses. It is also referred to as total fuel cycle energy use, and is similar to the chemical engineering practice of drawing a box around a system of process flows. As shown in Figure 3, substantial losses occur in the electricity value chain — significantly more than in the use of natural gas.

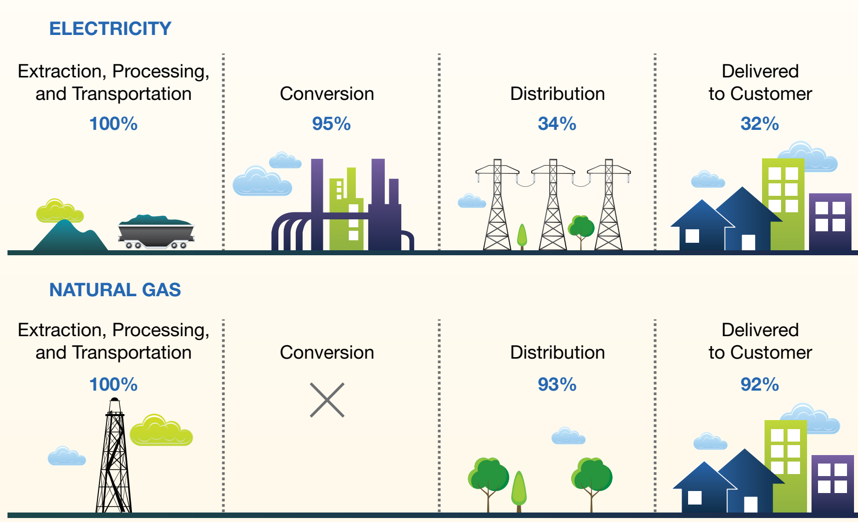
For instance, about 68% of the energy contained in coal is lost before the electricity is delivered to the customer:

- extraction of coal and delivery, typically by railroad, to the power plant — a 5% loss
- conversion to power — a 61% loss, the most significant source of inefficiency
- power transmission and distribution to users — a 2% loss.

In contrast, natural gas losses are about 8%.

DOE-EIA data indicate that res/com sites consume 9.49 quadrillion Btu (quads) of electricity, and an additional 20 quads of energy is lost before the electricity reaches the consumer. Thus, the total res/com electric energy requirement is nearly 29.5 quads. For comparison, the res/com natural gas source energy requirement is about 8.5 quads, which includes markedly lower energy losses of less than 0.7 quads.

Direct use of natural gas for water heating, for example,



▲ **Figure 3.** Source-energy losses are much larger for electricity delivered to the consumer (68%) than for delivered natural gas (8%). Source: *(9).*

is generally twice as efficient as electric water heating on a source-energy basis. Beyond substantial total energy savings, however, consumers can also save money. Efficient natural gas water heating can save consumers $275/yr over electric water heating and $320/yr over heating water with fuel oil. For each 5 million consumers, this adds up to $1.4 billion/yr in energy savings compared with electricity and $1.6 billion/yr compared with fuel oil.

Touchpoints and future needs: Natural gas, chemistry, and chemical engineering

Natural gas has widespread influences in our daily lives. This stems from the myriad ways it is used as an energy source and as a raw material in making a spectrum of products — not only in the chemical and petrochemical industries, but also in the food processing, iron and steel, aluminum, glass, and other manufacturing sectors.

Chemical engineers will play a leading role in transforming the energy marketplace and U.S. manufacturing. Examples of possible chemical engineering contributions include:

- better methane and ethane conversion routes that improve energy efficiency and reduce capital intensity
- more-efficient processes for making ethanol (including cellulosic routes) and methanol for use as chemical feedstocks and transportation fuels
- high-performance materials that reduce building energy losses and ensure efficient use of natural gas in homes and businesses
- advanced working fluids and system solutions for high-efficiency natural gas heat-pump systems used for space heating and cooling
- advanced natural gas fuel processing and electrochemistry solutions for ultra-clean fuel cell power generation and CHP
- methods for cost-effective carbon dioxide capture and use
- high-performance materials (*e.g.,* polymers, epoxy, carbon fibers) for use in NGV fuel storage containers
- advanced materials and adsorbents (*e.g.,* MOF materials) that can be used for gas processing, natural gas storage, and other novel applications
- high-temperature heat-transfer fluids for hybrid solar thermal and natural gas power systems and for heating and cooling applications.

Closing thoughts

Over the past five years, the U.S. shale gas revolution has been a truly remarkable transformation — the full implications of which are still unfolding in the marketplace. This will certainly influence U.S. natural gas demand and have worldwide implications in other regional energy markets. The consequences of shale gas and advanced natural gas production methods are profound.

In the coming decade, we will more fully realize the implication of this sea change in U.S. natural gas end use sectors. There are many ways that natural gas can create value and improve the daily lives of many — from basics such as more efficient and cost-effective water heating, to substantial growth in industrial production and employment, cleaner and more-efficient electricity production, and cost-effective and clean transportation options.

The potential implications in the industrial sector are substantial, particularly for the chemical and petrochemical segments. Continued advancements in science and technology — including chemistry and chemical engineering — can enhance the value-creating potential that is possible with new natural gas supplies. CEP

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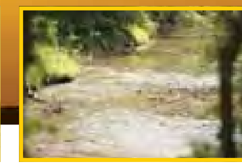

Getting the Gas Out of the Ground

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Technologies developed in the oil and gas industry over the past 60+ years are now being used to produce shale gas.

Until recently, most natural gas came from what are known as conventional reservoirs. This conventional gas is typically trapped in multiple, relatively small, porous zones in rock formations such as sandstones, siltstones, and carbonates. Such gas is relatively easy to recover.

Unconventional gas, on the other hand, is obtained from low-permeability reservoirs in coals, tight sand formations, and shales. These accumulations of gas tend to be diffuse and spread over large geographical areas. As a result, unconventional gas is much more difficult to extract.

An individual well in an unconventional gas reservoir produces less gas over a longer period of time than a well in a conventional reservoir, which has a higher permeability. Thus, many more wells must be drilled in unconventional gas reservoirs to recover a large percentage of the original gas in place (the amount of gas in the formation before any wells have been drilled and produced, OGIP) than are needed for a conventional reservoir.

To optimize production from an unconventional gas reservoir, a team of geoscientists and engineers must optimize the number of wells drilled, as well as the drilling and completion procedures for each well. Often, more data (and more engineering manpower) are required to understand and develop unconventional gas reservoirs than are required for higher-permeability, conventional reservoirs.

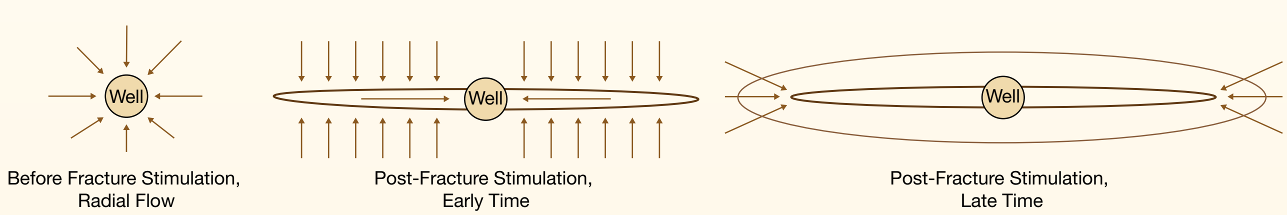
Usually, vertical wells in an unconventional gas reservoir must be stimulated to produce commercial-scale volumes at commercial-scale flowrates. This normally involves a large hydraulic fracture treatment (discussed later). In some unconventional gas reservoirs, horizontal and/or multilateral wells must be drilled, and these wells also need to be fracture-treated.

Improvements in horizontal drilling techniques combined with improved hydraulic fracturing methods have enabled the development of shale gas reservoirs. Neither of these technologies is new. In fact, the combination of horizontal drilling and water fracturing was used extensively in the 1990s in the Austin Chalk formation in Texas.

This article discusses the use of horizontal drilling and hydraulic fracturing in the production of shale gas, some of the key reservoir data needed to determine gas reserves, and the economics of shale gas development.

Changing the reservoir flow pattern

The key to successfully developing any unconventional gas reservoir is to change the flow pattern in the reservoir (Figure 1). In tight gas sands with vertical wells, the flow pattern is altered by pumping large fracture treatments. Simi-



▲ **Figure 1.** Fracture treatment changes the gas flow pattern in a reservoir.

larly, the horizontal wells drilled in shale gas reservoirs need to be fracture-treated to connect the reservoir to the horizontal borehole and to create a network of flow paths.

Figure 1 illustrates how the radial flow pattern characteristic of vertical wells is changed to linear and finally elliptical flow for reservoirs containing either a horizontal wellbore or a long hydraulic fracture.

Horizontal drilling

The horizontal well is the key to changing the flow pattern in the reservoir. It is common to drill horizontally to a distance of 3,000–10,000 ft in length and perform 10 to 30 fracture stages down the length of the wellbore. In many reservoirs, the horizontal wellbore length is about 5,000 ft.

Directional drilling (*i.e.,* the drilling of wells at multiple angles) has been used for over 60 years to develop offshore fields. For a typical onshore well, the drilling rig is located directly above the reservoir target. However, for offshore wells drilled from a fixed platform (and for multiple shale gas wells drilled from a single pad), the wells need to be drilled directionally to reach their reservoir targets.

Beginning in the early 1980s, horizontal wells became a common technology used to develop unconventional resources. The gain in productivity realized by horizontal wells over vertical wells ushered in a new era of development. Increasing exposure to the pay zone (the zone containing gas) and changing the flow pattern in the reservoir allowed many marginal reservoirs to be economically developed. In many cases, the production of oil and gas increased by factors of three to ten compared to vertical wells, while the costs increased by a factor of two or less.

An important breakthrough in directional drilling was the mud motor. Also known as a positive-displacement motor (PDM), the mud motor is a positive-displacement pump that uses the flow of drilling fluid (mud) to turn the drill bit. This rotation at the bit is independent of the rotation of the drill string (the column of pipe that transmits drilling mud and torque to the bit). By pairing the downhole mud motor with a bent sub (an angled section of drill string) above it, the directional driller is able to steer much more effectively.

The PDM has been the standard for drilling directional wells since its introduction, and is still the most commonly used directional drilling tool, both in the U.S. and worldwide. However, a new technology — rotary steerable systems — represents a step-change in downhole directional-drilling technology. Rotary steerable systems eliminate the need to slide the motor to make course corrections and allow the driller to correct the well path while the drill string is being rotated.

Hydraulic fracturing

In hydraulic fracturing, a mixture of hydraulic fluid and propping agents is pumped at high pressure into the well bore. The hydraulic pressure creates artificial fractures in the reservoir and causes the fractures to grow in length, width, and height. Hydraulic fracture treatments are applied to alter the flow pattern in the reservoir.

Figure 2 illustrates schematically how a fracture treatment is conducted. The fracturing fluid is usually water mixed with additives to control viscosity, pH, and other physical characteristics (discussed later). A blender mixes the fluid with a propping agent (usually sand) and various other additives, and supplies the fracture fluid slurry to high-pressure pumps. The main fracturing pumps increase the pressure from a few hundred psi to over 20,000 psi, depending on the depth of the formation and the friction pressure in the wellbore.

Initially, the fracture fluid is pumped into the reservoir without any propping agent (proppant). The high-pressure fluid cracks the rock in the pay zone, pushing the earth apart so a fracture forms and propagates. The cross-hatched area in Figure 2 represents the fracture area. When the fracture is wide enough, the propping agent is blended into the fluid and the slurry is pumped into the well. The area of the fracture containing proppant is referred to as the propped fracture area. Once the fracture fluid pumping is completed, the hydraulic fracture stops growing, and the areas without proppant close.

Gas flows into the wellbore only through the propped fracture area that cleans up (*i.e.*, the area where the long-chain molecules responsible for the fluid's viscosity break into smaller molecules, reducing the viscosity). This allows the fluid to flow from the fracture into the formation or down the fracture to the well-

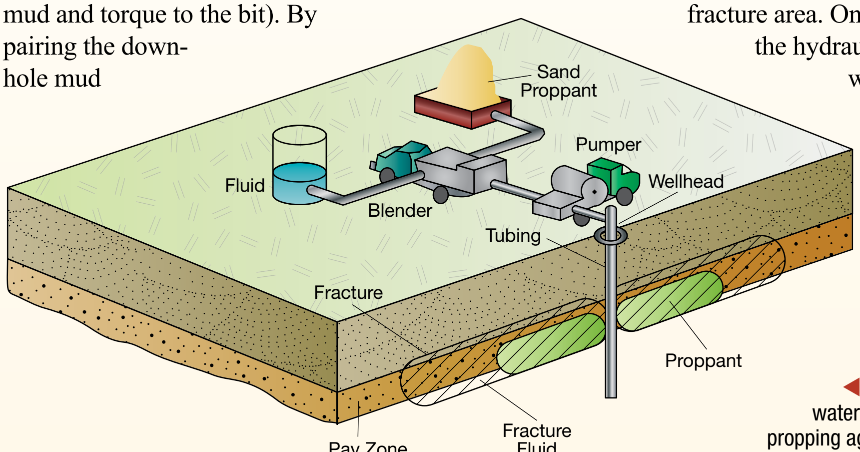


Figure 2. In a typical hydraulic fracturing operation, water containing trace amounts of additives is mixed with a propping agent (usually sand), and the resulting slurry is pumped at high pressure into the well.



bore. If the long-chain molecules do not break (for example, due to increased temperature or a chemical reaction), the fluid will remain in the fracture and natural gas will not be able to enter the fracture and flow to the wellbore. Incomplete fracture-fluid breaking can cause a reduction in gas flowrate and gas recovery.

Fracture treatments in shale gas reservoirs appear to create a network of many fractures that propagate simultaneously, some of which are propped open and others that are not. The fracture network results in the desired stimulation of gas flow in many shale formations. Most engineers believe that the non-propped fractures contribute to the productivity, although it is not clear how much of the gas flow is associated with the non-propped fractures.

Figure 2 is a simple schematic representation. In reality, pumping a large fracture treatment is much more complicated, and involves numerous fracture tanks, blenders, pump trucks, and more, as shown in Figure 3. The capital costs of these fracture treatment spreads are substantial, as are the manpower needed to pump the treatments and the associated labor costs.

Designing a fracture treatment

To predict gas flowrates and ultimate gas recovery and to design the well completion (the steps taken to transform a drilled well into a producing well), the engineer employs a reservoir model, a hydraulic fracture propagation model, and an economic model. The design process involves determining whether to drill a horizontal wellbore, and if so, its location in the reservoir and its length. Fracture-treatment details include the number of stages (*i.e.,* pumping operations conducted in a portion of the horizontal hole), the desired fluid volume per stage, and the injection rate. The engineer must measure or estimate the formation depth, formation permeability, *in situ* formation stresses in the pay zone, *in situ* formation stresses in the surrounding layers, formation modulus, reservoir pressure, formation porosity, formation compressibility, and the thickness of all the reservoir layers.

Vertical profiles of rock properties. To design the well path and the fracture treatment using either a multilayer reservoir model or a pseudo three-dimensional (P3D) hydraulic fracture propagation model, data on the rock properties of all the layers through which the fracture treatment will be pumped are needed. Figure 4 summarizes some of the important input data required by these models for a typical well.

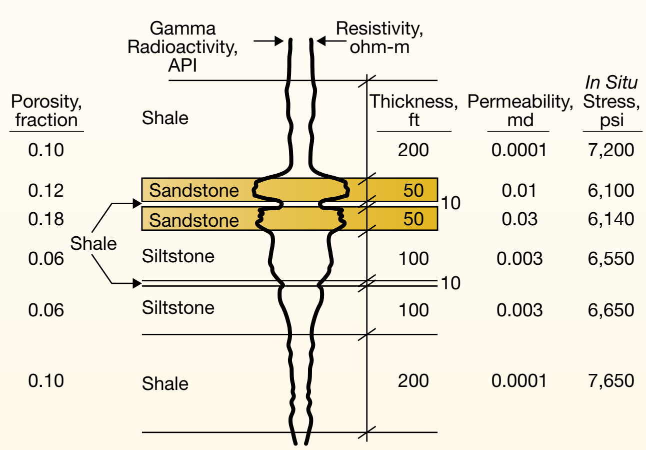
The well depicted in Figure 4 is completed and the fracture treatment is initiated in the sandstone reservoir. A fracture typically grows upward and downward until it reaches a barrier that prevents vertical fracture growth. Thick marine shales, which tend to have higher *in situ* stresses than the sandstones, and highly cleated coal seams, which contain many natural fractures running in different directions that trap the fracture fluid, often serve as barriers to fracture growth.

The data used to design a fracture treatment can be obtained from various sources, such as drilling records, completion records, well files, open hole logs, cores and core analyses, well tests, production data, geologic records, published literature, etc. Table 1 summarizes the most important data and the most likely sources of the information. In addition, well service companies provide data on their fluids, additives, and propping agents.

One of the most difficult and time-consuming responsibilities of a petroleum engineer is to develop an accurate and complete data set for the well to be drilled. Once an accurate data set is available, the actual design of the well and the fracture treatments is fairly straightforward.

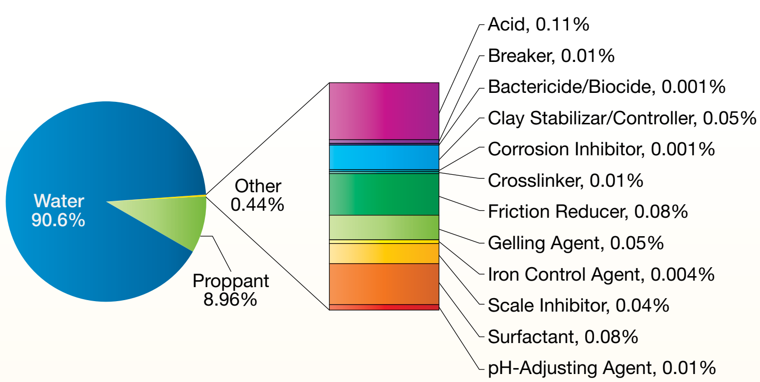
Fracture fluid selection. A critical design decision is the selection of the fracture fluid for the treatment. In shale gas

▲ **Figure 3.** Pumping a fracture treatment involves many tanks, blenders, pump trucks, and other equipment. Photo courtesy of Halliburton.



▲ **Figure 4.** Data such as gamma ray radioactivity, porosity, resistivity, permeability, and *in situ* stress need to be collected for each layer of rock.

Table 1. Data for reservoir and fracture-propagation models come from numerous sources.			
Parameter	**Units**	**Model***	**Sources**
Formation permeability	md	R, F	Cores, well tests, production data
Formation porosity	%	R, F	Cores, logs
Reservoir pressure	psi	R, F	Well tests, well files, regional data
Formation depth	ft	R, F	Logs, drilling records
Formation temperature	°F	R, F	Logs, well tests, correlations
Water saturation	%	R, F	Logs, cores
Net pay thickness	ft	R, F	Logs, cores
Gross pay thickness	ft	R, F	Logs, cores, drilling records
Formation lithology		R, F	Cores, drilling records, logs, geology
Wellbore completion		R, F	Well files, completion prognosis
Reservoir fluids		R	Fluid samples, correlations
Relative permeability		R	Cores, correlations
Formation modulus	psi	F	Cores, logs, correlations
Poisson's ratio		F	Cores, logs, correlations
In situ stress	psi	F	Well tests, logs, correlations
* R = reservoir model, F = fracture-propagation model			



▲ **Figure 5.** Hydraulic fracture fluids typically consist of about 90% water, about 9% propping agent, and less than 1% functional additives.

reservoirs, water that has had guar gum added to increase its viscosity is a common fracture fluid.

The fracture fluid consists of more than 99% water and propping agent, with additives accounting for less than 1% of the fluid by volume. The breakdown of a typical fluid's composition is shown in Figure 5. Many of the additives are common products found in the home (Table 2).

Propping agent selection. During the fracture treatment, high-pressure pumps inject the fracture fluid into a wellbore at a high rate. This increases the pressure in the formation and cracks open the rock; continued pumping allows the cracks to grow in length, width, and height. After pumping ceases, the pressure in the fracture drops as the fluid dissipates through the natural fractures and sometimes into the rock matrix. To effectively stimulate the flow of gas from the well, the fractures need to be propped open to create conductive pathways from the reservoir into the fractures and down the fractures to the wellbore.

The most common propping agent is sand, which is available in many different grades. Premium sand is more rounded and more uniform in size, and has a higher compressive strength, than common sands that have natural fractures or flaws on the individual sand grains.

Sand can be coated with resin to increase the strength of the propping agent and to help minimize the flowback of the sand during gas production. Resin-coated sand is three to four times more expensive than uncoated sand, but in many cases that added cost could easily pay for itself through increased gas flowrates. The shale gas industry also uses synthetic propping agents, which consist of ceramic or bauxite particles that have been processed and sintered.

The selection of the propping agent is based on the maximum effective stress that will be applied to the propping agent during the life of the well. The maximum effective stress depends mostly on the depth of the formation that is being fracture-treated.

In general, if the maximum effective stress is less than 6,000 psi, sand is usually recommended as the propping agent. If the maximum effective stress is between 6,000 and 10,000 psi, either resin-coated sand or ceramic propping agents should be selected. If the maximum effective stress exceeds 12,000 psi, high-strength bauxite should be used. In cases where more liquids are going to be produced, the higher-strength, higher-permeability propping agents usually allow for the highest production rates.

These recommendations are rules of thumb; the engineer should also choose the propping agent on the basis of cost and well performance. It may be necessary to conduct trials in several wells to determine the optimum propping agent for a particular shale formation in a certain area.

Executing the fracture treatment in the field

A successful fracture treatment requires planning, coordination, and cooperation of many parties. Careful supervision of the treatment operation and implementation of quality-control measures can improve the success of the hydraulic fracturing.

Safety is always the primary concern in the field. Safety



begins with a thorough understanding by all parties of their duties in the field. A safety meeting should be held at the beginning of each stage of the fracture treatment to review the treatment procedure, establish a chain of command, ensure that everyone knows his/her job responsibilities for the day, and establish a plan for emergencies. At the safety meeting, the team should also discuss the well completion details and the maximum allowable injection rate and pressures, as well as the maximum pressures to be held as backup in the annulus.

Table 2. Most fracture fluid additives are common substances encountered in daily life.

Type of Additive	Function Performed	Typical Products	Common Use
Biocide	Kills bacteria	Glutaraldehyde	Dental disinfectant
Breaker	Reduces fluid viscosity	Ammonium persulfate	Hair bleach
Buffer	Controls the pH	Sodium bicarbonte	Heartburn-relief medicine
Clay stabilizer	Prevents clay swelling	Potassium chloride	Food additive
Gelling agent	Increases viscosity	Guar	Ice cream
Crosslinker	Increases viscosity	Borate salts	Laundry detergent
Friction reducer	Reduces friction	Polyacrylamide	Water and soil treatment
Iron controller	Keeps iron in solution	Citric acid	Food additive
Surfactant	Lowers surface tension	Isopropanol	Glass cleaner
Scale inhibitor	Prevents scaling	Ethylene glycol	Antifreeze

All casing, tubing, wellheads, valves, and weak links, such as liner tops, should be thoroughly tested prior to beginning the fracture treatment. Mechanical failures during a treatment can be costly and dangerous. Potential mechanical problems should be identified during testing and repaired before starting the fracture treatment.

Prior to pumping the treatment, the engineer in charge should conduct a detailed inventory of all the equipment and materials on location and compare this inventory to the design and the plan for the fracture treatment. After the treatment is concluded, the engineer should conduct another inventory of all the materials left on location. In most cases, the difference in the two inventories can be used to verify what was mixed and pumped into the wellbore and the formation.

Environmental issues. Many operators employ centralized facilities for drilling and fracturing operations. For example, the fracture fluid "pond" in Figure 6 serves as the source of the fracture fluid. The fluid is pumped from the pond to a nearby fracture treatment just before (or even during) the treatment. After treatment pumping is finished, the fluid that flows back from the formation is returned to the pond, treated, and reused. This helps to reduce the operation's environmental footprint and consumption of fresh water. It also cuts down the amount of truck traffic by limiting the number of trips needed to deliver water to the site and haul away wastewater for treatment.

Another way to reduce environmental footprint and minimize truck traffic is to drill multiple wells from a single pad. This approach has been used in parts of Appalachia and in the Rocky Mountains.

Microseismic measurements. Another issue surrounding shale gas production is whether fracture treatments cause earthquakes. The answer is yes and no:

• Yes. During a fracture treatment, the act of the rock breaking causes small microseismic events. The amount of energy released is equivalent to that of a gallon of milk falling off a counter and hitting the floor. These microseismic events cannot be felt at the surface. They can, however, be measured with extremely sensitive geophones, and the data used to map these events to locate where the hydraulic fracture is growing.

In the last few years, the shale gas industry has mapped microseismic data from thousands of wells and tens of thousands of fracture treatments. Warpinski and Fisher have analyzed and sorted the data for each formation by depth to locate the top and bottom of the fractures created during pumping and determine their proximity to the depth of the fresh water aquifers. Figure 7 presents these data for the Marcellus shale formation.

• No. Some very minor earthquakes have been associated with long-term water injection, mainly for water disposal. These earthquakes do not happen often, but when one does, simply stopping the injection prevents further earthquakes. However, these rare and small earthquakes have not been associated with hydraulic fracturing operations.

▲ **Figure 6.** A centralized fracture fluid pond can reduce an operation's environmental footprint.

Article continues on next page

Analyzing reservoir data

The most common methods used by reservoir engineers to determine reserves are volumetric calculations, material balance calculations, analysis of decline curves, and reservoir simulation and modeling.

Volumetric calculations. Volumetric methods work best in high-permeability gas reservoirs for which the drainage area and gas recovery efficiency are known with reasonable certainty. In such reservoirs, the volumetric method can provide relatively accurate estimates of the amount of original gas in place and gas reserves.

In shale gas reservoirs, the volumetric method might provide reasonable estimates of original gas in place. However, its estimates of gas reserves, which is the amount of OGIP that can be produced economically, are not as reliable because it is very difficult to estimate both the drainage area of a particular well and the recovery efficiency. Therefore, the volumetric method of estimating shale gas reserves should be used only prior to drilling the well. Once production data are available, those data should be evaluated to estimate reserves.

Material balance calculations. It is impossible to obtain accurate data to describe the drop in reservoir pressure as gas is produced. Thus, material balance methods should never be used in shale gas reservoirs.

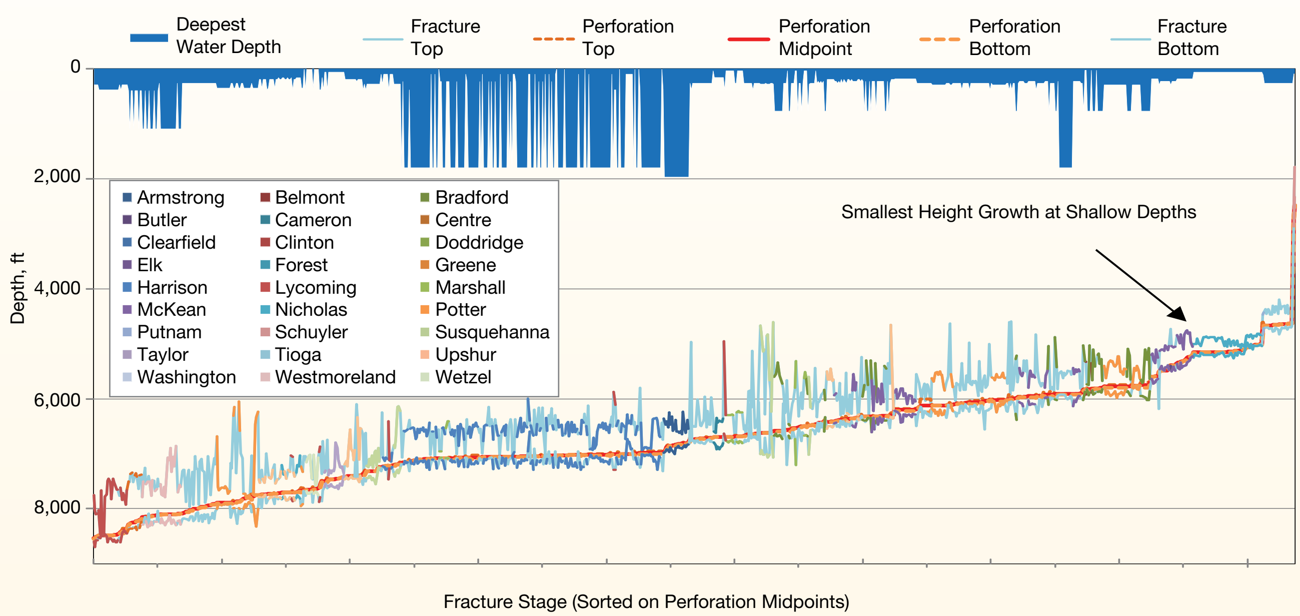
Decline curve analysis. The decline curve analysis method, which looks at the decrease in the gas production rate over time, works well for shale gas reservoirs, especially layered reservoirs that have been stimulated with a large hydraulic fracture or developed with a long horizontal wellbore. However, decline rates are high early in the life of a well (rates of 70% per year and more have been observed in the first year of production for a typical shale gas well containing a long horizontal wellbore). Thus, it is necessary to use a hyperbolic equation to curve-fit the data.

The decline rate becomes smaller over time, and after several years can be approximated by an exponential function. When the decline rate falls below about 6–8%, a constant decline rate of 6% to 8% can be assumed for the remaining life of the well.

Figure 8 is a typical exponential decline curve for a shale gas well. This well initially produces at a rate of 10 million cubic feet per day (MMcf/d), but this declines to 2.5 MMcf/d by the second year. After about three years, the flowrate levels off near 1 MMcf/d.

Figure 9 is a plot of the cumulative gas produced from the same well. Notice that the cumulative recovery after 10–12 yr is about 5,000 MMcf and that half of the ultimate recovery was produced during the first 4 yr. This makes the point that if a shale gas well does not pay out in the first few years, it may not be an economical investment.

Even when using the hyperbolic equation to analyze production from tight gas reservoirs, one must carefully analyze all of the data. For example, many wells begin producing at a high gas flowrate and high flowing tubing pressure (pressure in tubing that is open, for instance with open valves, rather than blocked in). If only the gas flowrate data are considered, the extrapolation into the future is unrealistically optimistic. However, during the first few weeks and months, both the gas flowrate and the flowing tubing



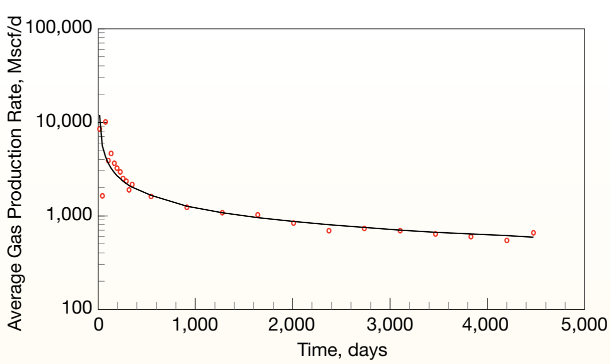
▲ **Figure 7.** Microseismic events resulting from hydraulic fracturing occur well below the water table. Source: *(1).*



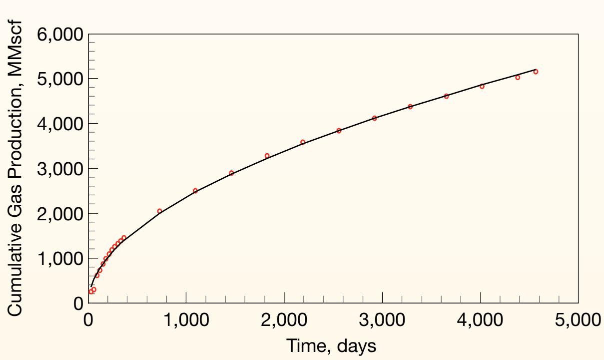
pressure decline. When the flowing tubing pressure reaches the pipeline pressure and stops declining, the gas flowrate decline rate increases. When both the gas flowrate and the flowing tubing pressure are declining, the engineer needs to divide the flowrate by the pressure drop and use the decline-curve model to match both the decline in flowrate and the decline in flowing tubing pressure.

Reservoir modeling method. The most accurate way to estimate gas reserves in tight gas reservoirs is to use a reservoir model, such as a semi-analytical model or a finite difference reservoir model that has been calibrated against historical production data. The model should be capable of simulating layered reservoirs, a finite-conductivity hydraulic fracture, and a variable flowing tubing pressure. In some cases, it might also be necessary to simulate non-Darcy flow, formation compaction, fracture closure, and/or fracture fluid clean-up effects.

The best use of shale gas reservoir simulation is to analyze data from a single well and run various what-if scenarios. Assuming it is possible to devise a reasonable reservoir description, the engineer can compute gas production vs. time for a variety of horizontal well locations, horizontal well lengths, fracture treatment spacings, and fracture treatment sizes. By comparing the results of the what-if analyses with actual field production data, one can start to understand the effects of different drilling and fracture treatment alternatives on gas production and economics.



▲ **Figure 8.** The rate of gas production decreases over time. The rate of decline is high early in the life of a well and eventually levels off.



▲ **Figure 9.** Approximately half of the gas ultimately recovered is produced in the first few years.

Economics of shale gas development

The economics of developing shale gas reservoirs are not unlike those of any other oil or gas reservoir. The decision to drill a well is based on producing enough oil and gas not only to recoup the well's costs in a reasonable time, but also to make a profit that is commensurate with the risk.

Most companies use cash-flow models to compute present-value profit and return on investment. While these precise calculations are required for banking and investment purposes, several rules of thumb can be used to make screening-level decisions:

• *payout* — if a well pays out in less than 5 yr, it will probably be economical to drill; a payout of 1–3 yr is an even stronger indicator of economic viability

• *discounted cash flow vs. costs* — if the discounted cash flow is three or more times the cost to drill the well, it will be economical.

Before discussing the economics of shale gas production, two terms need to be defined:

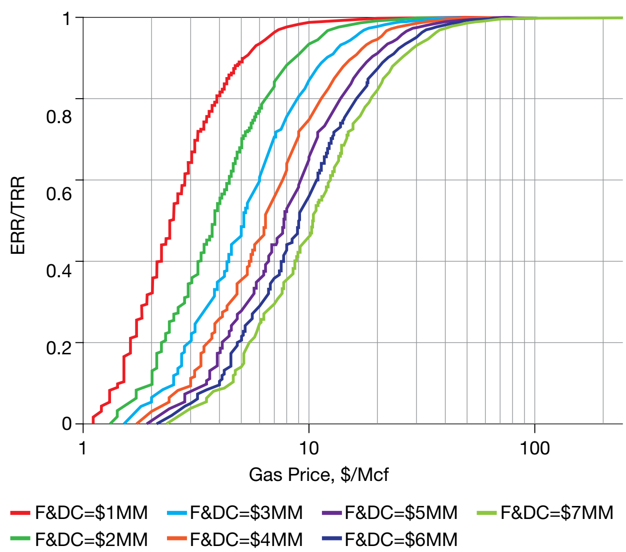
• *technically recoverable resourc*e (TRR) — the fraction of the OGIP that can be produced with available technology at a given point in time, without consideration of economics

• *economically recoverable resource* (ERR) — the gas that can be produced economically for specified values of finding and development costs, operating costs, and gas prices.

At Texas A&M Univ., we have developed a detailed model to calculate values of OGIP, TRR, and ERR for typical shale gas wells. We define an economical well as one that pays out in less than 5 yr and provides a 20% internal rate of return (IRR). To forecast cash flow, we analyzed production data from thousands of wells to determine the distribution of production for a variety of shale gas plays. (The term play refers to a geographical and geological area containing significant accumulations of gas.)

The Barnett Shale play in Texas covers around 3.2 million acres, and its OGIP is estimated to be 348 trillion cubic feet (Tcf). Over 13,000 wells have been drilled in the Barnett, more than 9,000 of which are horizontal. Over 8.9 Tcf of gas has already been produced. The estimated median TRR is approximately 49 Tcf. To fully develop this resource would require 29,000 wells.

Figure 10 is a plot of the ratio of ERR/TRR for the Barnett Shale for a variety of finding and development (F&D) costs ranging from \$1 million to \$7 million per well and gas prices ranging from \$1/Mcf to \$30/Mcf. This graph shows that at a typical F&D cost of \$3 million per well



▲ **Figure 10.** The fraction of the technically recoverable resource that can be produced economically depends on the price of gas and the finding and development costs.

Table 3. The amount of gas that can be economically recovered from a well depends on the finding and development costs and the price of natural gas.

ERR/TRR	Barnett		Eagle Ford	
	F&D Cost, $MM	Gas Price, $/Mcf	F&D Cost, $MM	Gas Price, $/Mcf
25%	1	1.80	6	4.00
	2	2.30	7	4.10
	3	3.00	8	5.00
	4	4.00	9	5.20
	5	4.30	10	6.00
	6	5.20	11	6.30
50%	1	2.30	6	5.50
	2	3.80	7	6.00
	3	5.00	8	7.00
	4	6.10	9	7.20
	5	7.90	10	8.10
	6	9.00	11	9.00
75%	1	3.10	6	8.00
	2	5.10	7	9.00
	3	7.10	8	10.00
	4	9.50	9	10.30
	5	11.00	10	10.60
	6	13.00	11	11.00

and a gas price of $4/Mcf, about 35% of the TRR can be recovered economically.

Table 3 compares various combinations of F&D costs and gas prices required to economically produce 25%, 50%, and 75% of the TRR in the Barnett play and the dry-gas portion of the Eagle Ford play in South Texas.

For instance, the yellow-shaded cells show that if the F&D costs for a well in the Barnett are $3 million and the price of gas is $3/Mcf, 25% of the TRR could be produced economically, whereas it would not be economical to produce 75% of the TRR unless the price of gas hit $7.10/Mcf. Similarly, the orange-colored cells show that with F&D costs of $9 million per well in the dry-gas portion of the Eagle Ford, the price of gas would need to be $5.20/Mcf to economically produce 25% of the TRR, $7.20/Mcf for 50% of the TRR, and $10.30/Mcf for 75% of the TRR.

The green cells illustrate another way to look at the data. If the price of gas is assumed to average $6/Mcf over the long term, half the Eagle Ford's TRR can be produced economically if the F&D costs can be held below $7 million per well, while 75% of the Barnett's TRR can be economically recovered for about $2–3 million in F&D expenditures per well.

Closing thoughts

Shale gas can change the energy future of the U.S. and, eventually, the world. The enabling technologies — horizontal drilling and hydraulic fracturing — are not new. They are safe and proven technologies that have revolutionized the oil and gas industry. The economics of developing shale gas plays depend heavily on the finding and development costs and the price of natural gas. At gas prices of $4–10/Mcf, the industry should be able to economically produce 50% or more of the technically recoverable resource in the U.S. CEP

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Expanding the Shale Gas Infrastructure

JESSE F. GOELLNER
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Development of U.S. shale gas resources will require expansion of infrastructure assets ranging from roads and rails to pipelines and seaports to power-generation plants and ethane crackers, and more.

The Interstate Natural Gas Association of America (INGAA) estimates that over the next 25 years, the U.S. will need to add approximately 43 billion cubic feet per day (cfd) of natural-gas transmission pipeline capacity; 414,000 miles of new gas-gathering lines; 32.5 billion cfd of gas-processing capacity; 14,000 miles of new lateral pipelines to and from power plants, processing facilities, and storage fields; and 12,500 miles of transmission lines with a capacity of 2 million barrels per day (bpd) to transport natural gas liquids (NGLs) *(1)*. These infrastructure needs, however, are only part of the picture.

Virtually all portions of the shale gas value chain need new, expanded, and/or upgraded infrastructure. These needs are related to bringing shale gas resources to production, gathering the natural gas, midstream processing of the gas, and long-distance gas transmission, as well as getting the NGLs that are separated from the gas at the midstream facilities to market. Additional facilities will be needed to absorb the burgeoning supplies of natural gas (*e.g.,* compressed natural gas [CNG] infrastructure, liquefied natural gas [LNG] terminals, and additional gas-fired power-generation plants) and NGLs (*e.g.,* steam crackers).

This article provides an overview of key infrastructure needs and developments associated with the production of shale gas. Gerencser and Vital *(2)* provide a more-detailed assessment of the infrastructure gaps as well as practical suggestions on how to close them.

Enabling drilling and production

To unlock the value of shale gas, wells need to be drilled and brought into operation (completed). Drilling activity increases the local demand for concrete, steel, and site services such as excavation, hauling, and skilled construction (*e.g.,* for well completion and establishment of drilling pads). All of these demands strain the facilities that produce, distribute, and transport these goods and services.

Drilling also requires large quantities of water, sand, and equipment, which need to be transported into areas that are often remote. This, in turn, increases the burden on the region's infrastructure. The road systems in shale plays often require significant upgrading, which the gas industry generally undertakes voluntarily as a necessary cost of doing business. Even so, local highways tend to be insufficient to support the supply of goods and services related to shale gas activity.

Rail systems are similarly stressed. For example, regional railroads in northeastern Pennsylvania that were originally linked to the production of anthracite coal were reinvigorated by the Marcellus Shale boom. However, congestion has become a problem in some terminals and service yards, as has the need for more railcars to meet the increase in demand. This need for railcars has created pressure to turn over the cars faster, so the storage of sand and other materials in railcars is often not practical. This creates additional infrastructure needs for silos and storage to support the distribution network for sand and water.

The procurement and delivery of water to hydraulic fracturing activities is an evolving complex issue involving the management of water and other ecological resources. Additionally, the disposition of produced water (water present in the reservoir that flows to the surface with the gas) and spent water used in the fracturing process further stresses the transportation infrastructure and requires the development of a disposition infrastructure. Although the exact nature of the disposition infrastructure is in flux as regulators and the regulated entities debate the disposition options, the need for more facilities to treat and purify these waters is evident. Facilities to treat waters associated with shale production are more sophisticated and more capital intensive than typical municipal wastewater plants, and require unique designs and additional (independent) investment.

Gathering and processing

After natural gas is produced (brought to the surface), it must be gathered into the natural gas transmission and distribution network. This requires capital outlays for gathering lines (typically 6-in.- to 20-in.-dia. pipelines) to take the raw natural gas to processing facilities, as well as for the gas-processing facilities themselves. The investment can be substantial, and may even create an insurmountable barrier. For example, the capital expenditures associated with separations and gathering lines have made it uneconomical to recover the natural gas associated with oil production in the Bakken play, leading to considerable flaring of natural gas in that region.

Water and condensate (higher-hydrocarbon liquids) are typically removed from the raw natural gas at or near the wellhead. Gathering lines then carry the remaining natural gas to a gas-processing facility that removes other constituents so that the processed gas meets pipeline specifications and so maximum value can be obtained for constituents such as NGLs.

The construction of gathering lines requires complex negotiations of rights of way. An enforcement infrastructure (inspectors) is also needed to enforce local codes, since these are usually intrastate pipelines with limited (or no) federal oversight.

Gathering lines are typically considered the demarcation between upstream production and midstream processing and transmission to market.

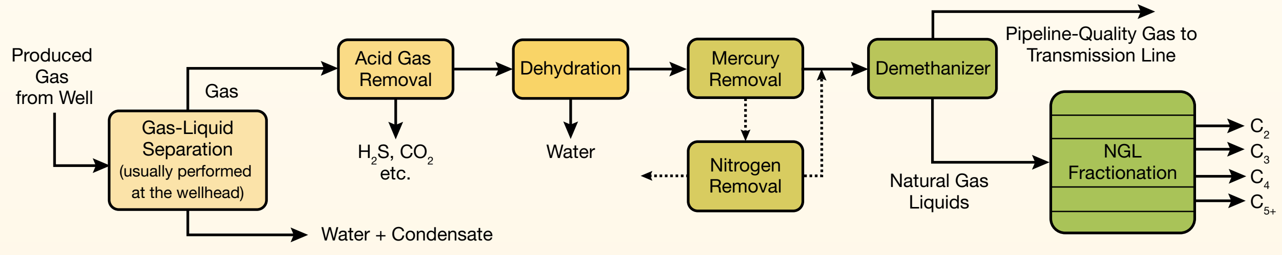
The natural-gas-processing facility (Figure 1) is a dedicated separations train that begins with the removal of acid gases (carbon dioxide, hydrogen sulfide, and organosulfur compounds). Elemental sulfur is often recovered from treatment of the offgas stream from this process. The natural gas stream is then subjected to dehydration and mercury removal, and occasionally nitrogen is removed if warranted. The gas stream is then sent to a demethanizer, which separates NGLs from the pipeline-quality natural gas that is injected into the transmission lines.

If economically feasible, the NGLs may be further separated into high-value ethane, propane, butanes, and a C_{5+} stream. The extent of NGL separation and recovery depends on the quantities of the produced gas, the values of these products, and whether or not they need to be removed from the gas in order to meet pipeline specifications.

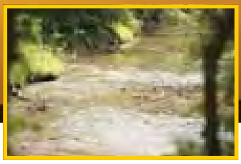
Energy companies have been increasing the capacity of midstream assets in active shale plays. Recent activity in the wet portion of the Marcellus play exemplifies this trend. (The adjectives wet and dry indicate the amount of natural gas liquids and condensate co-produced with the natural gas. Wet regions contain substantial amounts of light hydrocarbons, often to the extent that recovering them is economically justifiable. In dry regions, NGLs are only minor contaminants. The terms are generally used in a relative manner and do not have strict thresholds. The western portion of the Marcellus Shale play has been found to be wet, whereas northeastern Pennsylvania developments have been found to be dry.)

For its Liberty operations in southwestern Pennsylvania and northern West Virginia, Mark West Energy Partners has built 325 million cfd of gathering capacity, 1.15 billion cfd of cryogenic gas processing capacity, 60,000 bpd of C_{3+} fractionation capacity, and 75,000 bpd of de-ethanization capacity. Last year, energy company Dominion augmented its existing assets with the addition of a propane terminal in Charleroi, PA, and the upgrading of its processing facilities in Hastings, Lightburn, and Shultz, WV, and it plans to open 400 million cfd of processing capacity in Natrium, WV, by the end of 2013. Caiman Energy anticipates spending approximately $1.2 billion from 2010 through 2014 on

▼ **Figure 1.** Before it is transported to the end user, natural gas undergoes a series of processing steps at the wellhead and at a processing plant.







its Fort Beeler operations in northern West Virginia, split almost equally between gathering and NGL infrastructure.

The development of these assets in relatively close proximity within the wet region of the Marcellus play demonstrates the rapid response of the market to provide the infrastructure required for the production of shale gas.

After midstream processing, the value chain splits into two components: the processed natural gas value chain, and the NGL value chain.

Getting natural gas to market

Transmission pipelines (typically 20–48 in. diameter) take the processed natural gas from the processing facilities to market centers, where they tie into existing local distribution networks. Although these localized transmission and distribution networks are well established, they will need to adjust to increases in natural gas demand (for heat, power, and transportation) spurred by low natural gas prices.

Activity related to the Marcellus Shale (Figure 2) is typical of the adjustments and augmentation of infrastructure required to support an active shale play.

Spectra Energy announced the construction of a pipeline to move 60 million cfd of natural gas from Oakford, PA, to Station 195 of the Transco pipeline (a distance of about 85 miles, at a cost of $700 million); a pipeline to carry 200 million cfd of natural gas from southwestern Pennsylvania to the eastern half of the state ($200 million); and an expansion of the Texas Eastern Transmission pipeline that extends its reach into the New York City area. These pipeline expansions complement Spectra's natural gas storage assets. Storage assets are required for a more-global natural gas market, as they enable the system to respond to pricing volatility and to arbitrage based on locational and temporal pricing differences.

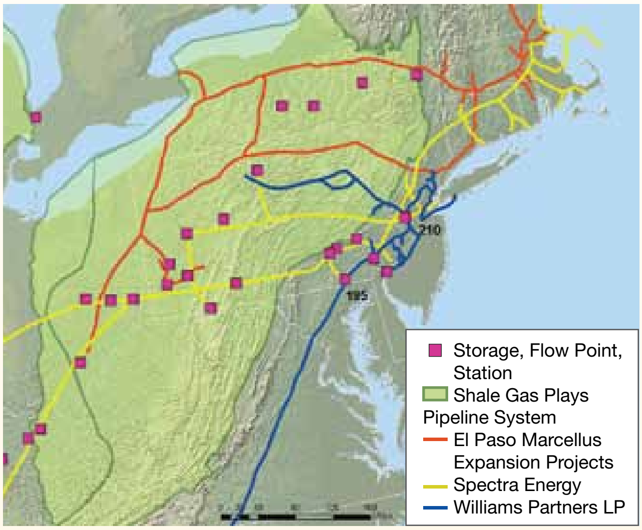
The Tennessee Gas pipeline, similarly, undertook four projects in the eastern U.S. that are coming online between 2011 and 2013 to handle the flow of 14,876,000 dekatherms per day (Dth/day) of natural gas from the Marcellus Shale to northeast markets. (Dekatherm is the unit commonly used for natural gas flowrates and sales. One dekatherm is equal to 10 therms. One dekatherm of natural gas contains one million Btu [1 MMBtu] of energy.)

Growth in demand for pipeline capacity to move gas from Marcellus production sites to market centers has also spurred Oklahoma-based energy company Williams to expand its Transco pipeline system. Projects on its southern section (south of Station 195 in southeastern Pennsylvania), include the 142 MDth/day Mid-Atlantic Connector through Virginia and Maryland (in service in 2012); the 199 MDth/day Cardinal Expansion in North Carolina (in service in 2012); and the 225 MDth/day Mid-South Expansion in Alabama, Georgia, South Carolina, and North Carolina (in service 2012–2013).

Most projects in the northeast U.S. are aimed primarily at either improving the Transco pipeline system's access to northeast markets or adding supply from Marcellus Shale producers to the Transco system. Market access projects include the Northeast Connector in Pennsylvania and New Jersey, as well as the Bayonne Lateral in New Jersey and the Rockaway Delivery Lateral in southeastern New York. The supply of Marcellus Shale gas will be enabled by the Northeast Supply Link and the Atlantic Access pipeline. The Northeast Supply Link, with a capacity of 250 MDth/day, will supply gas from the Leidy hub in north-central Pennsylvania to pipelines in central New Jersey. The 1,100 MDth/day Atlantic Access pipeline, due onstream in 2014, will supply the East Coast with natural gas from the western Marcellus region (including new natural gas processing facilities in Fort Beeler and Natrium, WV).

The industry responded quickly to these opportunities; however, as natural gas prices fall, it is unclear how quickly it will respond to support transmission from dry-gas regions. Dry-gas projects might not provide the return on investment necessary to support their development, whereas wet-gas development can be justified based on the value of both the gas and the NGLs and condensate associated with their development.

Completing the value chain of natural gas is the development of assets that will use the increased supply of natural gas. The conversion of existing coal-fired power plants to natural-gas-fired and the construction of new gas-fired plants will take time, and is complicated by the need to be optimally interfaced with environmental and other permitting requirements, the natural gas supply system, electricity demand, and the nation's bulk electric power system (*i.e.,* the grid). LNG



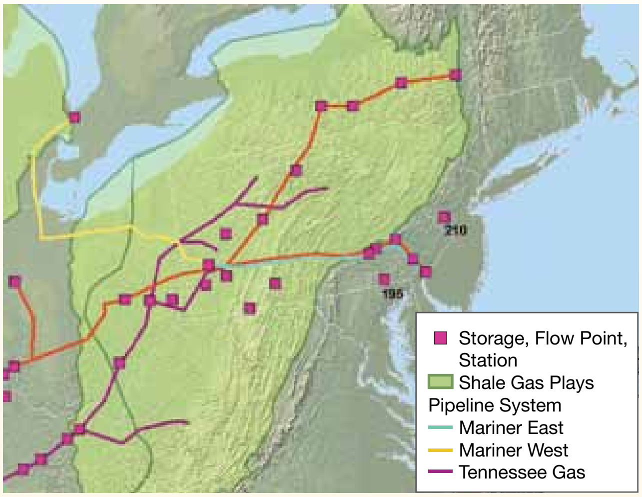
▲ **Figure 2.** Extensive natural gas pipeline infrastructure has been built to enable development of the Marcellus Shale play. Map prepared by Chung Shih.

export terminals need to be built to facilitate trade of U.S.-sourced natural gas on the world market. The development of a compressed natural gas (CNG) vehicle infrastructure, including expanded distribution systems and filling stations as well as the vehicles themselves, will take even longer. (The challenges associated with developing these capital assets are complex and beyond the scope of this article.)

Taking advantage of the liquids

The natural gas liquids that are co-produced with many shale gases have different downstream infrastructure requirements. As mentioned earlier, the co-production of these higher-value, but lower-volume, components requires additional capital investment in natural-gas-processing facilities (beyond that required to upgrade the gas itself). Once separated from the raw natural gas, the NGLs need to be transported to their own markets, and new assets to consume them may need to be built to absorb the increased supply. (The discussion of NGLs in this article focuses on ethane, since it is typically the largest component of NGLs and is the preferred feedstock for producing ethylene, a major petrochemical building block).

A small amount of NGLs can remain in the natural gas (typically less than 10%), but some must be removed from the raw gas in order to meet pipeline specifications. This level of ethane recovery, known as the mandatory portion, is achieved by the gas-processing operation discussed earlier. Ethane removed from the raw gas above and beyond the mandatory level required to meet the pipeline specification is often referred to as discretionary ethane. The quantity of discretionary ethane produced depends on economic conditions, which determine whether it is cost-effective to seek the full value of the ethane as a product (*i.e.,* petrochemical feedstock) or simply capture its heat content. Once removed, the ethane must be delivered to the markets in which it is consumed.



▲ **Figure 3.** Ethane pipeline infrastructure has been developed to transport ethane produced in the Marcellus Shale to established ethane markets. Map prepared by Chung Shih.

The vast majority of ethane is consumed by the chemical industry, mainly in steam cracking units to produce olefins such as ethylene and propylene. In addition to enjoying a price advantage due to the availability of feedstock from shale gas, ethane steam cracking has a much less intense separations train than the cracking of liquid feeds such as naphtha. This translates into lower capital and operating costs (especially with respect to energy consumption). Hence, a strong push has been made to convert existing domestic steam cracking facilities to ethane. Furthermore, capacity increases are being achieved with new ethane cracking facilities (either expansions or entire new plants). These expansions and/or grassroots facilities will take time to come on-stream, and they will require extensive supporting infrastructure, including transportation access, storage, offsites, electricity and other utilities, etc. Olefin-derivative plants (*e.g.,* to manufacture such products as polyethylene and polypropylene) will also be needed for the stable consumption of ethane co-produced with natural gas.

Approximately 95% of domestic steam cracking capacity (including crackers that use liquid feeds) is located in Texas and Louisiana, making transport of ethane to the U.S. Gulf Coast a paramount infrastructure requirement for the disposition of ethane. Ethane can be delivered to the Gulf Coast by pipeline, or by Jones-Act-compliant vessels from a seaport. (The Merchant Marine Act of 1920, better known as the Jones Act, restricts domestic shipping to vessels that are domestically built, staffed, and owned. This puts constraints on the available shipping capacity between domestic ports.)

Shipping through a seaport that is reasonably close to the shale play also opens up access for exporting ethane to foreign markets (*e.g.,* Europe). Sarnia, Ontario's steam cracking capacity of approximately 1.4 million ton/yr makes it a potential market for U.S. ethane.

Five options for disposing of ethane from the wet portion of the Marcellus region have been identified. Four of these involve pipeline transport (Figure 3) of the ethane out of the region:

- The Mariner West pipeline is slated to draw 50,000 bpd (expandable to 65,000 bpd) from Mark West's Liberty processing facility near Houston, PA, for transport to Sarnia, ON.
- The Mariner East pipeline is slated to transport 65,000 bpd to Energy Transfer Partners' storage and shipping terminal assets near Marcus Hook, PA, by the middle of 2013.
- The Marcellus Ethane Pipeline System (MEPS) will connect Mark West's Liberty processing facility and Dominion's Natrium processing facility to the Gulf Coast with a capacity of at least 60,000 bpd (expandable to 100,000 bpd) by November 2014.

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• By January 2014, Enterprise Products Partners will begin moving a minimum of 75,000 bpd (expandable to 175,000 bpd) by pipeline to Baton Rouge, LA, and Mount Belvieu, TX.

These pipelines would transmit ethane to existing markets in Sarnia and along the U.S. Gulf Coast, and enable shipment of ethane to other parts of the world.

• A fifth option for the disposition of ethane from the Marcellus and Utica shale plays is a local ethane cracker. Shell has signaled its intent to build an ethane cracker in the Appalachian region, and has preliminarily selected a site in Monaca, PA (near Pittsburgh).

It appears the market has responded quickly to develop the infrastructure required to capture the full value of the NGL portion of the Marcellus and Utica shale gas. Once the ethane has been transformed into ethylene, the latter is a fungible product easily absorbed by the robust domestic chemical industry.

Closing thoughts

The aggregate capital needed to establish the infrastructure for the Marcellus play alone is staggering — in the billions of dollars. Success will be contingent on highly efficient capital markets and an entrepreneurial culture willing to take the large risks that accompany the potential for large rewards. It is unclear whether the focus necessary for the massive development of infrastructure assets exists and, if so, can be sustained. CEP

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Acknowledgments

The author thanks Chung Shih of Booz Allen Hamilton, who prepared the maps of the natural gas and ethane pipelines (Figures 2 and 3).

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Environmental Considerations of Shale Gas Development

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The impacts of shale gas development on land, air, and water resources can and must be managed through sustainable operating practices.

As shale gas development has moved into more highly populated areas, concerns have been raised about the environmental footprint of these activities. The film *Gasland,* with its images of flaming tap water, has painted a one-sided, negative picture of shale gas development for viewers in the U.S., Europe, and other parts of the world, one in which shale gas developers are unregulated and routinely disregard sustainable operating practices. In addition, numerous reports, such as one that portrayed shale gas extraction as a greater threat to greenhouse gas (GHG) levels than coal mining *(1),* have cast a harsh spotlight on the gas industry's activities.

There is a growing perception that drilling operations pollute the air and consume too much land and water, and that hydraulic fracturing is a significant threat to the world's drinking water. Developers of shale gas have maintained, however, that horizontal drilling and hydraulic fracturing, the technologies used to stimulate and extract these resources, have been used and perfected for decades and have been proven to be safe.

It is true that improper handling and treatment of wastewater at the surface have caused some accidents, and errors related to well casing integrity may have contributed to methane and/or fracture fluid migration into a small number of shallow aquifers. However, it is also true that responsible participants are following region-specific best practices and are working with regulators to carefully monitor environmental conditions before, during, and after well construction and completion *(2).*

This article provides a summary of the potential environmental impacts posed to land, air, and water by shale gas development. Understanding the potential impacts and separating real from perceived risks are important, because unconventional gas constitutes an increasingly vital part of the world's energy supply picture.

Land footprint

One concern related to shale gas development is the amount of land that is required and that is disturbed throughout the process. Shale gas well construction and completion is an industrial and highly visible process. A typical drilling pad sits on a 2–6-acre plot of land and has a holding pond for water effluents, and it relies on hundreds of trucks to haul equipment and water to and from the site for the hydraulic fracturing operations that are conducted there.

Because shale gas typically exists in sedimentary rock deposits that stretch for long distances (for example, the Marcellus Shale occupies 54,000–96,000 mi^2) rather than in discreet pockets, the number of wells required to access the resource is large. These operations are sometimes referred to as gas farming. In regions where population densities are high, such in the northeastern U.S., local concerns about development activities encroaching on areas where people live, work, and play are understandable. In contrast, most oil and gas development over the last 50 years has taken place in less-populated areas in the western U.S. or in areas where residents are more familiar with energy-development activities.

Reducing the surface impact of shale gas development is not only environmentally beneficial but is also in the economic interest of operators, and is a significant focus of technology development. For instance, drilling multiple wells from a single pad allows operators to reach a larger underground area of the resource from the same, much smaller surface area.

The progress that has been made to date is dramatic. In 1970, approximately 502 acres of subsurface area could be drilled from a 20-acre well pad at the surface, whereas today's technology provides access to more than 32,000 acres of subsurface area from a 6-acre well pad at the surface. In addition, natural gas has the second-lowest surface-disturbance impact per unit of electricity generation of all energy sources, behind only nuclear power production *(3)*. As new technologies and best practices move into new production areas, even more footprint reductions will be achievable.

At some point after a well begins to produce natural gas, the drilling company is obligated to restore the site to approximately the condition of its original landscaping and/or previous land use. Generally, a wellhead, two or three brine storage tanks, a metering system, and some production equipment remain on the site.

When a well is no longer capable of production, concrete is pumped down the wellbore to seal it from atmospheric pressure, and production equipment is removed from the site. The entire pad is then revegetated and fully restored.

Induced seismicity

Concerns about the role of hydraulic fracturing and deep-well injection disposal in triggering localized earthquakes (such as were experienced in Texas in 2009, Arkansas in 2011, and Ohio in 2012) have arisen in recent years. Studies conducted to date do not indicate a direct correlation between these earthquakes and drilling or well-completion activities. The primary connection appears to be the improper disposal of wastewater produced from shale gas wells *(4)*.

Seismic activity (seismicity) is generated in two ways. One is through hydraulic fracturing using water, sand, and chemical additives to release natural gas trapped within shale deposits. In fact, the specific intent of hydraulic fracturing is to create permeability in the rock by inducing microseismicity. The second way of generating seismicity is through the subsurface disposal of wastewater and naturally occurring brines that emerge with the desired hydrocarbons after a well is fractured. This type of seismicity is common in many oil and gas fields. All measured seismic activities in the history of shale gas exploration have been small, generally between 2.0 and 4.0 on the Richter Scale, and have not posed a danger to either humans or the environment *(5)*.

In hydraulic fracturing, the magnitude of a seismic event is proportional to the length of the fracture, which is largely a function of the amount of water injected and the injection rate. Provided that care is taken to not pressurize the system too much or too quickly, rupture lengths and seismic magnitudes should be negligible. Current evidence suggests that the risks associated with hydrofracture-induced seismicity are very low. With appropriate management, induced seismicity is not likely to be an impediment to further development of shale gas activities *(5)*.

However, the disposal of waste fluids in Class II deep injection wells is considered a potential cause of minor earthquakes that have been felt at the surface *(4)*. Class II injection wells are used to dispose of fluids associated with the production of oil and natural gas, to inject fluids for enhanced oil recovery, and for the storage of liquid hydrocarbons. As a condition of permitting Class II injection wells in the U.S., disposal wells are located in areas far from identified fault lines, and injection rates are limited to prevent substantial increases in pore pressure at the well depth. Seismic monitoring networks can be installed to detect seismic activity so that actions may be taken to decrease or stop injection if necessary.

The possible causal relationship between deep-well injection and minor earthquakes is not yet fully understood and requires additional investigation.

Air emissions

Natural gas is often lauded for its air quality benefits, as it is the cleanest fossil fuel (primarily because its combustion produces low levels of carbon dioxide emissions). For example, generating electricity with natural gas creates about half the CO_2 emissions of coal-based power generation and 30% less than fuel-oil-based generation. Furthermore, its combustion byproducts are mostly carbon dioxide and water vapor. Consequently, natural gas is considered to be the main fuel in energy industry plans to reduce carbon emissions.

However, shale gas production is not without any air footprint. Exploration in the Marcellus Shale has been shown to impact local air quality and to release some greenhouse gases into the atmosphere *(6)*.

The sources of air emissions depend on the phase of the development process. In the preproduction (drilling and completion) phase, emissions may come from drilling rigs and fracturing engines, which are typically fueled by diesel or gasoline. Air emissions are also created by the many trucks delivering water to the site and hauling wastewater from it. The number of truckloads required varies from site to site, and depends on the amount of water needed, the amount of wastewater generated, the location of the water source, and the distance from the well to the wastewater treatment or disposal facility. In the Marcellus Shale region, for instance, 4 million gal of water are typically required to fracture-treat a single horizontal well, which equates to 800 U.S. truckloads.

After drilling and fracturing operations are finished, the production of natural gas begins. During this phase of operation, compressor engines (and any venting or flaring of gas before gathering lines are in place) can



produce emissions. Fluids (condensate) brought to the surface may include a mixture of natural gas, other gases, water, and hydrocarbon liquids, which can be released into the atmosphere from the condensate tanks *(6)*.

Table 1 lists the main emissions that may be created during drilling, hydrofracturing, and gas extraction.

Air emissions have been measured and analyzed during the extraction of Barnett Shale gas in Texas and in other shale operations in the western U.S. *(6)*. Based on this and other studies, some states have changed their air quality regulations to reduce hydrocarbon emissions during shale gas production.

On April 18, 2012, the U.S. Environmental Protection Agency (EPA) released new air quality rules for hydraulically fractured wells. Beginning in 2015, the regulation requires drillers to use technologies and practices that limit emissions and result in so-called green completions. After a well has been fracture-treated, it is cleaned up, which involves removing the water that was used for fracturing. During this flowback, some natural gas accompanies the water exiting the well. In green well completions, this gas is separated from the water and placed in a pipeline instead of being released to the atmosphere or flared.

Devon Energy's green completion process *(7)*, for example, employs a sand separator to filter out sand, which is sent through a 2-in. pipe into a disposal tank, leaving behind a mixture of natural gas and water. A second separator removes the water from the gas, and the water is recombined with the sand in the disposal tank. The natural gas, meanwhile, is diverted into a separate pipe, and is eventually sent by pipeline to a gas-processing plant.

Because methane is the largest component of natural gas — and methane emissions represent lost product that energy companies would rather produce and sell — most of today's wellheads and pipelines exceed the new EPA benchmark. Many operators have found that the additional revenue that can be generated through green completion offsets a portion of the additional costs associated with extra processing.

Water footprint

Water footprint is perhaps the most contentious environmental issue associated with unconventional gas development. Areas of concern include the management of water for all users in the watershed; the fear of contamination of surface water and/or groundwater during site preparation, drilling, and well completion; and the treatment and safe disposal of the produced water (*i.e.,* water that occurs naturally in the formation and flows to the surface with the gas).

Growth in the development and production of shale gas resources will require greater sourcing of water and management of water, solid waste, and other byproducts. Current practice involves drilling multiple wells from one or two pads in a well field, and constructing hundreds of well fields within each development area. An analysis by the Gas Technology Institute *(8)* found that the quantity and quality of the water that flows back from completed wells over a 45-yr lifecycle of a development area — as well as the output of solid waste, including drilling waste — are highly dynamic and vary from year to year. For example, although water flow from a single well may decrease over time, the salt concentration of that water may increase.

During the construction of well fields, water must be found (sourced), hundreds of thousands of truckloads must transport water to wellheads for hydraulic fracturing of the shale to initiate gas production, tens of millions of barrels of brine (collected as flowback water and produced water) must

Table 1. Air emissions from drilling, hydraulic fracturing, and shale gas extraction activities may contain these compounds.

Compound	Description	Environmental Concern
Methane (CH_4)	The main component of natural gas	A known greenhouse gas
Nitrogen Oxides (NOx)	Formed when fossil fuel is burned to power machinery, compressor engines, and trucks, and during flaring	A precursor to ozone formation
Volatile Organic Compounds (VOCs)	Hydrocarbons, including aromatics (*e.g.,* BTEX) and light alkanes and alkenes. Present in flowback water. May be released during handling and storage in open impoundments	Partial transport of VOCs occurs from water to air
Benzene, Toluene, Ethyl Benzene, and Xylenes (BTEX)	Compounds emitted in low quantities	Toxic to living organisms above certain concentrations
Carbon Monoxide	Occurs during flaring and as a result of incomplete combustion of carbon-based fuels used in engines	Toxic to living organisms above certain concentrations
Sulfur Dioxide (SO_2)	May form when fossil fuels containing small amounts of sulfur are burned	Contributes to acid rain
Hydrogen Sulfide (H_2S)	Exists naturally in some oil and gas formations. May be released when gas leaks, is vented, or burns incompletely during flaring	During natural gas production, operations, and utilization, hydrogen sulfide releases to the atmosphere are very low

be reused or disposed of in an environmentally acceptable manner, and hundreds of thousands of tons of drilling waste and sludge must be carefully managed. Since water and waste management account for a large portion of the annual operating costs of shale gas development, the economical and environmentally acceptable management of these streams is critical to the sustainable development of shale gas plays.

When procuring water for hydraulic fracturing, it is essential to protect water quality and to ensure adequate water resources for other watershed stakeholders, including residential, commercial, and industrial users that depend on water. Water for drilling and fracturing of shale gas wells frequently comes from surface water bodies such as rivers and lakes. It can also come from groundwater, private water sources, and municipal water supplies, and recycled fracturing water can be used as well. While the water volumes needed for drilling and stimulating shale gas wells are significant, they generally represent a small portion — typically less than 1% — of the total water resource in a shale gas basin *(6).*

Many shale gas basins are located in regions that receive moderate to high levels of precipitation. Even in areas of high precipitation, though, the needs of growing populations, other industrial water demands, and seasonal variation in precipitation can make it difficult to meet the water demands of shale gas extraction.

It is also important to consider the connection between water quantity and water quality. For example, taking water for drilling and fracturing from a small stream, rather than from a large river or lake, places a relatively larger burden on plants and wildlife within the immediate ecosystem. Similarly, if fracturing fluid were released into a small stream (regulations and industry recommended practices prohibit this practice), the chemicals might not be diluted sufficiently to prevent damage to fragile ecosystems and aquatic life.

Local water quality may be compromised at several stages of shale gas extraction. Gaining access to the well site involves building access roads for heavy equipment to transport drilling rigs, pipe, and water. Transporting material to the site and site preparation can cause erosion. Drilling through aquifers can contaminate water supplies if proper precautions are not taken to isolate the aquifer from the wellbore.

One of the most important developments in recent years to reduce water footprint is the practice of reusing the flowback water (the fracture fluids that return to the surface after completion of a well) from one well to supplement a portion of the water volume required for the next well's hydraulic fracture treatment. Typically, most of the fracture water that flows back does so during the first few weeks after hydraulic fracturing ends. Reusing this water reduces the potential for environmental impact by reducing air emissions and carbon footprint, water transportation requirements, truck traffic densities, and road wear, and generally results in greater stakeholder acceptance. Even this reuse, however, is transportation-intensive — moving 1 million gal of flowback water from one well to the next requires more than 200 truckloads. Furthermore, the reused water is only about 20–25% of the total 4–5 million gal of water typically needed to fracture the next well.

In addition to reuse, operators may dispose of flowback and produced water by deep-well injection at permitted wells. However, this option is available only in regions where the geology is suitable for deep injection and where such disposal wells have been drilled.

Another option for flowback disposal is the reintroduction of water from hydraulic fracturing to surface water or groundwater. Although this can be an environmentally safe practice if the water is sufficiently treated to remove contaminants, it can be very expensive. Constituents that may need to be removed include fracture fluid additives (*e.g.,* friction reducers), oils and greases, metals, and salts. Salt separation in particular is very energy-intensive and thus expensive. While the industry is working to reduce the cost of such treatment, it will be important for operators to continue treating water for reuse and to protect equipment and the shale formation from damage.

This portfolio of water management options gives operators flexibility and helps to minimize freshwater requirements for shale gas development.

Groundwater contamination

The most hotly contested water footprint issue associated with shale gas development is the potential for drinking water contamination by hydraulic fracturing.

To avoid contamination, multiple layers of steel casing are inserted into the wellbore. The casing reinforces the wellbore and prevents it from collapsing, and isolates it from the surrounding rock formations.

The producible portions of deep shale gas formations exist many thousands of feet below the earth's surface. For example, the productive area of the Marcellus Shale is located at depths ranging from 4,000 ft to 8,500 ft underground, and the typical well there is more than 5,000 ft deep. In contrast, groundwater aquifers in that area are found at depths less than 1,000 ft. Throughout the Marcellus Shale, groundwater aquifers and producing natural gas formations are separated by thousands of feet of protective rock barriers.

The fractures created by hydraulic fracturing propagate upward a few hundred feet at most — significantly short of what would be required to reach the fresh-water aquifers. Fracturing fluid migration from deep shale gas wells into fresh-water aquifers has not been observed *(9).* The fracture fluid remains deep in the earth, and the same low permeability that causes the need for hydraulic fracturing is believed to prevent fluid migration.



However, recent research has raised additional questions about the possibility of methane, a key component of natural gas, flowing from deep underground in the Marcellus through natural pathways in rock to aquifers near the surface *(10)*. To assess the potential impacts of fracturing on groundwater quality, it is useful to consider some of the assertions that have been made about methane migration from hydraulically induced fractures into groundwater.

In one case, a homeowner who suspected that a gas well near Dallas, TX, was affecting the quality of his water well, which draws from the Trinity aquifer, brought a claim against Range Resources in 2010. EPA testing *(11)* confirmed that there were traces of methane in the homeowner's well water. The methane was thermogenic gas (created by high heat and pressure converting organic material to natural gas), which suggested to the EPA that it had originated from a deep source — such as that developed by Range Resources — rather than shallower sources of naturally occurring biogenic gas (which is created from organic material by organisms such as bacteria). The EPA issued a remediation order and an endangerment finding against Range Resources and voiced its concern about natural gas building up in homes and creating the potential for fire or explosion.

The EPA's allegation received a good deal of media attention. However, if that were true, the methane would have had to migrate through 5,000 ft of solid rock or the well's casing would have had to have lost its integrity. Pressure testing found no mechanisms to enable the gas to migrate up from such a deep source and confirmed the integrity of the well. In addition, the reported methane concentrations in the samples were below safety limits for well water. Later testing confirmed that, based on the nitrogen content of the gas, the source of the methane is actually a rock strata laden with natural gas and salt water called the Strawn formation, which sits just below the Trinity aquifer at a depth of 400 ft — not the Barnett shale, which is 5,000 ft deeper *(12)*.

The homeowner's representatives continue to argue that the source could be the Range Resources well, because it is drilled through the Strawn formation and the production casing is not cemented in that section. Recent reports indicate, though, that several water wells in the area contained trace quantities of methane before any gas wells were drilled in the area *(13)*. The case was recently dropped by the EPA, although it was not clear whether the Agency's technical staff had reversed its views on the cause of methane contamination. Nevertheless, it appears likely that fracture propagation was not the cause.

In another case, a Duke Univ. study *(14)* found that surface water near Marcellus Shale drilling sites has higher methane concentrations than nearby surface waters that are not near drilling sites, and that the methane is thermogenic in nature. The Duke samples did not show any evidence of fracturing fluid migration to groundwater, but they did highlight concerns about possible methane migration. Baseline measurements were not taken prior to drilling and isotopic data presented were not compared with the multiple gas formations that exist in the region.

A recent paper *(15)* found that the isotopic signature of the Duke study's thermogenic methane samples are more consistent with those of shallower Upper and Middle Devonian deposits that overlay the Marcellus Shale. These data suggest that the methane samples analyzed in the Duke study could have originated entirely from those shallower sources above the Marcellus and are not related to hydraulic fracturing activities.

This is consistent with a 2010 assessment by the EPA *(16)* in response to well-publicized reports of elevated methane in water in the town of Dimock, PA, the site of the dramatic *Gasland* footage in which a homeowner lit his kitchen tap water on fire. In addition, technical literature and historical publications confirm that methane gas was present in water wells in the region for many decades, and long before shale gas drilling began in 2006 in the area.

The most recent coverage of possible groundwater contamination by fracturing activities resulted from sampling near the town of Pavillion, WY. In December 2011, the EPA issued a draft report *(17)* of a study conducted in response to complaints of objectionable taste and odor problems in well water. The EPA suggests this is the first major study detecting a link between fracturing and groundwater pollution, although the study has not yet been peer reviewed. Analysis of samples taken from deep monitoring wells in the aquifer detected synthetic chemicals consistent with gas production and hydraulic fracturing fluids (glycols and alcohols), benzene concentrations well above Safe Drinking Water Act standards, and high methane levels.

The EPA notes that the draft findings are specific to Pavillion, where the fracturing is taking place in and below the drinking water aquifer — in contrast to fracturing taking place 1–3 km below aquifers in most other locations — and in close proximity to drinking water wells. These production conditions are unlike those in many other areas. Furthermore, other factors may be affecting the Pavillion samples.

One dangerous compound highlighted by EPA was 2-butoxyethyl phosphate. The Petroleum Association of Wyoming has pointed out that this is not an oil and gas chemical, but, rather, is a common fire retardant used in plastics and plastic components in drinking water wells. The testing also detected benzene, which is highly unlikely to have been sourced from the shale gas formation. In addition, the EPA found glycol, which is not injected downhole in this region but is used at the surface. Finally, the contamination detected was in samples from deep monitoring wells, and not the shallower drinking water wells.

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Another explanation for the foul water may be that bacteria have entered the water supply as a result of improper maintenance of aging water wells. More testing will be required to clarify the source of the contamination in this region.

Although it has not been demonstrated that fractures can reach fresh groundwater, the potential exists for contamination due to spills at the surface and to leaks from improperly cemented well casing. Thus, the use of sustainable operating practices that include responsible management of hydraulic fracturing fluids is important.

Fracturing fluid is typically 90.6% water, 9% proppant (often sand) used to keep the fractures open, and 0.4% chemicals added for such purposes as reducing friction and protecting equipment from corrosion. (Many states require public disclosure of the chemical ingredients, but their proportions are considered proprietary information.) These chemicals are used for a wide variety of other applications, including household detergents, food additives, and swimming pool treatments. While the risk of contamination or toxicity should not be ignored, it is important to keep in mind that these are chemicals commonly encountered in daily life.

A movement is currently underway toward the use of greener fluids. This involves reducing or minimizing the amount of chemical additives in the fluids, or finding more environmentally friendly and/or biodegradable options for those chemicals that are essential (*e.g.,* biocides, friction reducers, scale inhibitors),

Another key issue is the salt content of the produced and flowback water, which contains total dissolved solids in a mixture of carbonates, chlorides, sulfates, nitrates, sodium, and other minerals. In some shale formations (*e.g.,* the Marcellus), the solids content of the produced and flowback waters (mostly salts) rises dramatically in the first several days after a fracture application. Flowrates usually fall dramatically over time, so the total amount of salts brought to the surface is limited. Nevertheless, as thousands of wells are completed in an area, the aggregate flows of water with high salt content could prove to be a costly challenge if these waters are to be reintroduced into the natural ecosystem. If handled responsibly, the chance of environmental contamination should be minimized *(8).*

There have been some documented cases of localized releases of fluids at the surface caused by spills and casing ruptures *(18).* (Regulators fined the operators of those wells, and the operators cleaned up the spills and provided alternative sources of fresh water until monitoring could provide the assurance that water quality was restored.) Methane is not an issue with regard to water quality if such a release occurs. Rather, the most significant risk to the environment is the potentially high salt concentrations.

In 60 years of hydraulic fracturing activity, there is yet to be a single proven case of groundwater contamination that has been tied to the practice. This is not to discount the real concerns people have or the potential immediate or long-term environmental impact risks, which should and will continue to be studied. However, it is also important to put any perceived or real risk from hydraulic fracturing in context with other everyday risks *(19).*

Adding such context to what is a spirited conversation about hydraulic fracturing will help society to make more informed decisions and trade-offs between energy sources and the technologies utilized to produce them.

Closing thoughts

Like the development of any energy resource, shale gas development has impacts on land, air, and water resources that can and must be managed. Experience in North America and Europe has shown that failure to adopt sustainable operating practices at the beginning of development activities has led to some operational problems, and lack of adequate explanation of the technology to the public have resulted in media coverage that was not always fact-based. Fortunately, both of these are changing.

Sustainable energy development is increasingly understood as the creation of not only long-term economic value from energy production and utilization, but also long-term environmental and social value for a wide range of stakeholders, including shareholders, employees, consumers, suppliers, communities, and public sector partners. Abundant natural gas will strengthen our economy, energy security, and independence if and only if its production operations are sustainable and completely transparent, and development activities are sensitive of nearby public areas, habitats, and protected resources. CEP

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Regulatory Programs Governing Shale Gas Development

Mary Ellen Ternes
McAfee & Taft

The production of natural gas from shale is subject to environmental regulations, including a combination of requirements already followed by conventional gas developers, plus new ones specific to shale gas.

Environmental issues associated with shale gas development are regulated primarily by the U.S. Environmental Protection Agency (EPA), as well as by state agencies to which the EPA has delegated authority. Shale gas development is a segment of the oil and natural gas industry. The EPA has regulated this industry for many years, primarily under several significant environmental statutes:

• the Resource Conservation and Recovery Act (RCRA), which governs the management of solid and hazardous waste

• the Clean Air Act (CAA), which governs emissions of criteria and hazardous air pollutants, and greenhouse gases

• the Safe Drinking Water Act (SDWA), which applies to activities that could contaminate groundwater sources of drinking water

• the Clean Water Act (CWA), which governs discharges to U.S. surface waters.

These statutes and the EPA's related regulatory programs are discussed in more depth in Ref. 1. This article reviews their applicability to hydraulic fracturing and the EPA's approach to regulating the shale gas industry. Other statutes that might apply, such as the Toxic Substances Control Act (TSCA) and the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), and other agencies' programs are not covered here.

Solid and hazardous wastes (RCRA)

The land footprint of shale gas development often includes surface impoundments that store recovered hydraulic fracturing fluids, which the industry recently began recycling. Prior to recycling, these fluids in surface impoundments are considered "recyclable materials," which the EPA

generally regulates as solid waste until the materials are actually recycled. EPA regulates solid waste (both hazardous and nonhazardous) under RCRA.

The EPA considers solid waste generated during exploration and production (E&P) of oil and gas to be lower in toxicity than other wastes covered by RCRA. Therefore, it exempted these E&P wastes under what it calls the RCRA E&P exemption. This exemption is not well understood by many in the field.

In general, RCRA-exempt E&P wastes are oil and gas drilling muds or fluids, oil production brines (produced water), and other wastes associated with the exploration, development, or production of crude oil or natural gas. The term "other wastes" refers to waste materials intrinsically derived from primary field operations — that is, activities occurring at or near the wellhead and before the custody-transfer point where the oil or gas is transferred for transportation away from the production site; it does not include



wastes generated during transportation or manufacturing.

At the well field, waste from downhole, or waste that was generated by contact with the oil and gas production stream during the removal of produced water or other contaminants from the product, is likely to fall under the E&P exemption *(2)*. When custody of the product changes, the exemption is no longer applicable and the waste is once again subject to the RCRA hazardous-waste-management requirements.

In response to concerns regarding the release of chemicals used in hydraulic fracturing, the EPA is reconsidering the scope of the E&P exemption, particularly with respect to the storage and disposal of fracture fluid chemicals. The Agency is evaluating industry practices and state requirements, as well as the need for technical guidance on the design, operation, maintenance, and closure of chemical storage pits.

Although the EPA's existing RCRA E&P guidance can be interpreted to exempt recovered fracture fluid, new guidance on the application of RCRA to fracture fluid storage pits can be expected in the next few years.

Air emissions (CAA)

Oil and natural gas exploration and production involve many sources of emissions of:

• criteria air pollutants — carbon monoxide, particulate matter, ozone reported as volatile organic compounds (VOCs), nitrogen oxides, sulfur dioxides, and lead

• hazardous air pollutants (HAPs) — *e.g.,* benzene, ethylbenzene, toluene, xylene, *n*-hexane, formaldehyde, and acetaldehyde

• greenhouse gases (GHGs) — carbon dioxide, methane, and nitrous oxide.

Sources of these pollutants include drilling rigs and other equipment powered by engines, flares, compressors, separators, storage tanks, pneumatic pressure and temperature controllers, glycol dehydrators, sweetening units, and amine treatment systems. In addition, produced water and flowback fluids are sources of fugitive emissions. All of these sources of emissions are subject to the Clean Air Act.

Permitting. The CAA imposes preconstruction permit and operating permit requirements, as well as technology standards such as New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs).

CAA permit requirements are triggered by a facility's potential to emit criteria pollutants, HAPs, and GHGs. Prior to construction, operators of hydraulic fracturing systems must calculate their potential emissions to determine whether they will trigger major-source permitting requirements or qualify for a minor-source or general permit. Key to this determination are the definitions of stationary source and facility, which in turn determine whether the source is a major or minor one *(1)*.

A stationary source is any building, structure, facility, or installation that emits or may emit a regulated pollutant. Building, structure, facility, and installation refer to all the pollutant-emitting activities that: belong to the same industrial grouping; are located on one or more contiguous or adjacent properties; and are under the control of the same person. The more individual point sources (*e.g.,* engines, tanks, or wells) that are aggregated into a single stationary source, the higher the potential emissions will be. The higher the potential emissions, the more likely the source will be considered a major source. Major sources are subject to review under the Prevention of Significant Deterioration (PSD) program and may be required to apply the best available control technology (BACT), as well as Title V operating permit requirements.

In aggregating sources, the determination of contiguous and adjacent poses issues unique to the oil and natural gas industry, for instance when wells and tank batteries operated by the same entity are located large distances from each other. To address this, in 2009 the EPA revised its policy and reintroduced the concept of functional interdependence as an additional aggregation consideration, which could require aggregation over much larger areas than the 0.25 miles adopted by some delegated state agencies. Application of this concept has resulted in litigation and created considerable uncertainty for industry *(3)*. A permit issued by a state agency in a manner inconsistent with the EPA's interpretation of the CAA stationary source definition may draw litigation, risking permit challenge or subjecting the permitted entity to a citizen's lawsuit for constructing without a valid permit.

GHG emissions. Petroleum and natural gas producers

Multi-Agency Involvement

To implement the *Blueprint for a Secure Energy Future* issued by the White House in March 2011, the EPA, the Dept. of Energy (DOE), and the Dept. of Interior (DOI) established an interagency research program. The Multi-Agency Collaboration on Unconventional Oil and Gas Research will address the highest-priority challenges associated with safely and prudently developing unconventional shale gas and tight oil resources by focusing on timely science and technologies that support sound policy decisions by state and federal agencies responsible for ensuring the prudent development of energy sources while protecting human health and the environment (www.epa.gov/hydraulicfracture/oil_and_gas_research_mou.pdf).

In addition, the DOI's Bureau of Land Management (BLM) proposed new regulations governing hydraulic fracturing on public and Native American land that require disclosure of chemicals used in the process, increase wellbore integrity rules, and address flowback water issues (www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916).

are required to report GHG emissions to the EPA in accordance with the Mandatory Greenhouse Gas Reporting Rule *(4)*. This rule does not relate to permitting, but rather is a data-gathering exercise. Wells owned and operated by an entity within a single basin, or geologic province as defined by the American Association of Petroleum Geologists, constitute a facility for the purpose of the GHG reporting rule. Owners and operators must use specific emission calculation methods to determine actual emissions of carbon dioxide, methane, and nitrous oxide from pneumatic device and well venting during workovers, completions and testing, flares, storage tanks, compressors, dehydrators, pressure relief valves, pumps, flanges, instruments, etc. Facilities with emissions exceeding 25,000 metric tons of carbon dioxide equivalent (m.t. CO_2e) must report actual GHG emissions to the EPA annually.

New standards. On Apr. 17, 2012, the EPA adopted new and more-rigorous standards for oil and natural gas production facilities, with specific provisions applicable to hydraulic fracturing *(5)*. These include: NSPS for VOC, NSPS for SO_2, NESHAP for oil and natural gas production, and NESHAP for natural gas transmission and storage. The rules also impose for the first time requirements for oil and gas operations not previously subject to federal regulation, such as well completions at new hydraulically fractured natural gas wells and at existing wells that are fractured or refractured.

The new regulations require operators to reduce VOC emissions by capturing natural gas at the wellhead during well completion and separating the gas and liquid hydrocarbons from the flowback water that comes from the well as it is being prepared for production. This practice is called reduced-emission completion, or green completion. Capture must begin by Jan. 1, 2015; flaring is allowed until then. Refractured wells that employ green completions will not be affected by these rules as long as they meet recordkeeping and reporting requirements by the effective date of the rule. Flaring will be required for wells exempt from green completion requirements.

VOC emissions from condensate and crude oil storage tanks with a throughput of at least 1 barrel per day (bpd) of condensate or 20 bpd of crude oil must be reduced by 95%. Natural gas processing plants must implement a leak detection and repair program to control fugitive emissions. VOC emissions must also be reduced from: centrifugal compressors with wet seal systems; reciprocating compressors (which are required to replace rod packing to ensure that VOC does not leak as the packing wears); and high-bleed pneumatic controllers (the use of which is limited to only critical applications such as emergency shutoff valves).

The NESHAPs also establish air toxics emission limits for small glycol dehydrators at major sources; require all crude oil and condensate tanks at major sources to reduce their air toxics by at least 95%; and tighten the definition of a leak for valves at natural gas processing plants.

Power to the People

Most federal environmental statutes provide an opportunity for citizens to sue a regulated entity that fails to meet its permit requirements or other regulatory requirements. These citizen suits, in effect, put a federal district court in the shoes of the EPA or delegated state agency, and require a federal judge to review allegations of noncompliance and assess any penalties. A losing defendant pays penalties to the U.S. Treasury — and typically the prevailing plaintiff's legal fees as well.

Water resource law

The acquisition of water from surface or underground sources for hydraulic fracturing is governed by state law as a property right.

Very generally, in the eastern U.S., water law tends to follow the riparian view, where surface water rights are tied to ownership of the property adjacent to the water source. Western water law tends to follow the principle of prior appropriation, where surface water rights accrue to the first person to use the water for a beneficial purpose.

Groundwater is viewed as property of the landowner owning the surface over the groundwater. The amount of water that can be withdrawn is governed by: the rule of capture, which allows the landowner to capture as much groundwater as he or she can apply to a beneficial use; the riparian right rule, which sets the landowner's right to withdraw water based on the surface area of land owned; or the reasonable use rule, under which the landowner can withdraw an amount that does not damage the aquifer or surrounding wells.

Water property ownership can be divided (or disputed) when a landowner conveys the rights to minerals beneath the surface to another party, severing the mineral rights from the surface rights and creating what is known as a split estate. In the classic split estate, the mineral rights owner has the right to use as much groundwater or surface water as is reasonable for the development of the mineral right. However, this is a broad generalization, as the rights of the surface owner and the mineral rights owner are set by the conveyance document as well as by state law.

Owners and operators of hydraulic fracturing operations typically purchase water or lease water rights from water rights holders, and must comply with state water-use permitting requirements. The volumes of water utilized in hydraulic fracturing have created some conflict in areas impacted by drought, where water resources are perceived as limited.



Drinking water (SDWA)

Because oil and gas development occurs in part beneath the ground, and drinking water sources include groundwater, the EPA regulates some aspects of the oil and gas industry based on its SDWA authority to protect drinking water sources. The SDWA governs the injection of fluids into the ground, which the EPA implements through its underground injection control (UIC) program. The goal of the UIC program is to prevent contamination of underground sources of drinking water (USDW) from subsurface emplacement of fluid by well injection. A USDW is defined as an aquifer or portion of an aquifer that serves as a source of drinking water for human consumption or contains a sufficient quantity of water to supply a public water system, and that contains fewer than 10,000 mg/L of total dissolved solids *(6)*.

The goal of the UIC program is to prevent contamination of drinking water sources due to the migration of injected fluids from subsurface activities, for example, as a result of faulty well construction and leaking casing, faults or fractures in confining strata, nearby wells exerting pressure in the injection zone, injection directly into USDWs, or displacement of injected fluid into USDWs. The degree to which a USDW is threatened by these activities depends on the types and volumes of fluids being injected, the pressure in the injection zone and the overlying USDW, and the amount of injected fluid that could enter the USDW through one of the pathways. To address these concerns, the UIC program requires well operators to obtain permits and perform periodic mechanical integrity testing (among other things).

The UIC program regulates six classes of underground injection wells. Wells used for fluids associated with oil and natural gas production are designated Class II wells. Class II permits allow the following oil and gas-related injection activities *(7)*: injection of fluids brought to the surface in connection with natural gas storage, conventional oil production, or natural gas production; enhanced recovery of oil or natural gas; and storage of liquid hydrocarbons.

Owners/operators of Class II wells must conduct mechanical integrity testing every five years and demonstrate that there are no significant leaks or fluid movement in the wellbore. They must also demonstrate that they have properly constructed or plugged wells penetrating the injection zone. They are also required to submit plans for the eventual plugging and abandonment (P&A) of the wells with permit applications and a P&A report prior to closing any well. Wells must be located so they inject below an unfractured confining bed, and injection pressures need to be monitored and controlled to prevent fractures in the injection zone or confining bed. The fluids must not endanger or have the potential to endanger drinking water supplies, and owners/operators must submit inventories of fluids to be injected prior to injection. Finally, owners/operators must demonstrate that the proximity of injection wells to USDWs is appropriate, and conduct monitoring and testing to track future fluid migration.

EPA's SDWA authority for its UIC program specifically excludes the underground injection of natural gas for purposes of storage, as well as the underground injection of fluids or propping agents (other than diesel fuels) used in hydraulic fracturing for oil, gas, or geothermal production activities. However, the EPA does require UIC permits for the disposal of wastewater from fracturing operations via deep-well injection, as well as for fracture treatment processes that use diesel fluid.

On May 4, 2012, the EPA released draft guidance *(8)* for state permitting of hydraulic fracturing with "diesel fuel," which it defines to include diesel fuel, diesel No. 2, fuel oil No. 2, fuel oil No. 4, kerosene, and crude oil. Under this guidance, companies that perform hydraulic fracturing with fluids containing diesel fuel would have to receive prior authorization via a UIC Class II permit. In addition, the EPA has identified several aspects of fracturing with diesel fuels that will need to be considered in the permitting process, including the intermittent duration of the activity, high pressures, and long lateral fracturing lines.

Water discharges (CWA)

The Clean Water Act regulates the discharge of pollutants by point sources into U.S. surface waters. Facilities must apply for and receive a National Pollutant Discharge Elimination System (NPDES) permit prior to discharge.

The EPA has adopted technology-based requirements, known as best practicable control technology currently available (BPT) *(9)*, for discharges from oil and gas extraction facilities into surface water. BPT prohibits onshore hydraulic fracturing facilities from discharging wastewater pollutants into navigable waters from any source associated with production, field exploration, drilling, well completion, or well treatment (*i.e.,* produced water, drilling muds, drill cuttings, and produced sand). Thus, such facilities must instead utilize underground injection or evaporation pits and ponds.

EPA also regulates discharges to publicly operated treatment works (POTWs), better known as municipal wastewater treatment plants. In the past few years, shale

Additional Legal Liabilities

Compliance with statutory and regulatory federal and state environmental requirements generally does not insulate owners/operators of hydraulic fracturing operations from litigation arising from common law claims of trespass, nuisance, negligence, strict liability, restitution, and waste. These claims allow recovery for property damage, bodily injury, medical expenses, loss of profits, and punitive damage.

gas wastewater has been disposed of at POTWs that were not properly designed to treat these recovered fluids. If a POTW is not designed to treat recovered fracture fluids, it may result in a violation of its own NPDES permit. If so, the entity delivering the fracture fluids that caused the POTW to violate its permit is, in turn, in violation of the CWA pretreatment regulations. To address this issue, the EPA is gathering data and developing a proposed rule (scheduled to be released in 2014) for shale gas wastewater discharges.

The EPA is also updating its water quality criteria for chlorides, for NPDES-delegated states to use in issuing discharge permits. This standard is expected later in 2012 and will likely create additional permitting challenges.

While disposal of wastewater is important virtually everywhere hydraulic fracturing is performed, this issue is especially significant in the Marcellus Shale. On Mar. 17, 2011, the EPA's Office of Wastewater Management provided answers to frequently asked questions about natural gas drilling in the Marcellus Shale under the NPDES program *(10)* and shale gas extraction *(11)*. Although intended primarily to aid EPA regional offices and states in their regulatory and permitting efforts, this guidance can assist regulated entities with wastewater disposal and treatment.

Finally, the EPA regulates stormwater from oil and gas exploration, production, processing, treatment, and transmission operations, but only if the facility previously had a release of a reportable quantity or has contributed to a violation of a water quality standard *(12)*.

Closing thoughts

While oil and natural gas exploration and production, including hydraulic fracturing, have been regulated by the EPA and the states since the first environmental statutes were enacted, hydraulic fracturing has recently received particular scrutiny. Regulation and policy impacting hydraulic fracturing will continue to develop over the next several years, with significantly more public participation and regulatory transparency. To keep informed, visit the EPA's Natural Gas Extraction – Hydraulic Fracturing webpage *(13)* at www.epa.gov/hydraulicfracture and sign up to receive updates. CEP

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