Discovering Shale Gas: An Investor Guide to Hydraulic Fracturing

By Susan Williams
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Key Findings

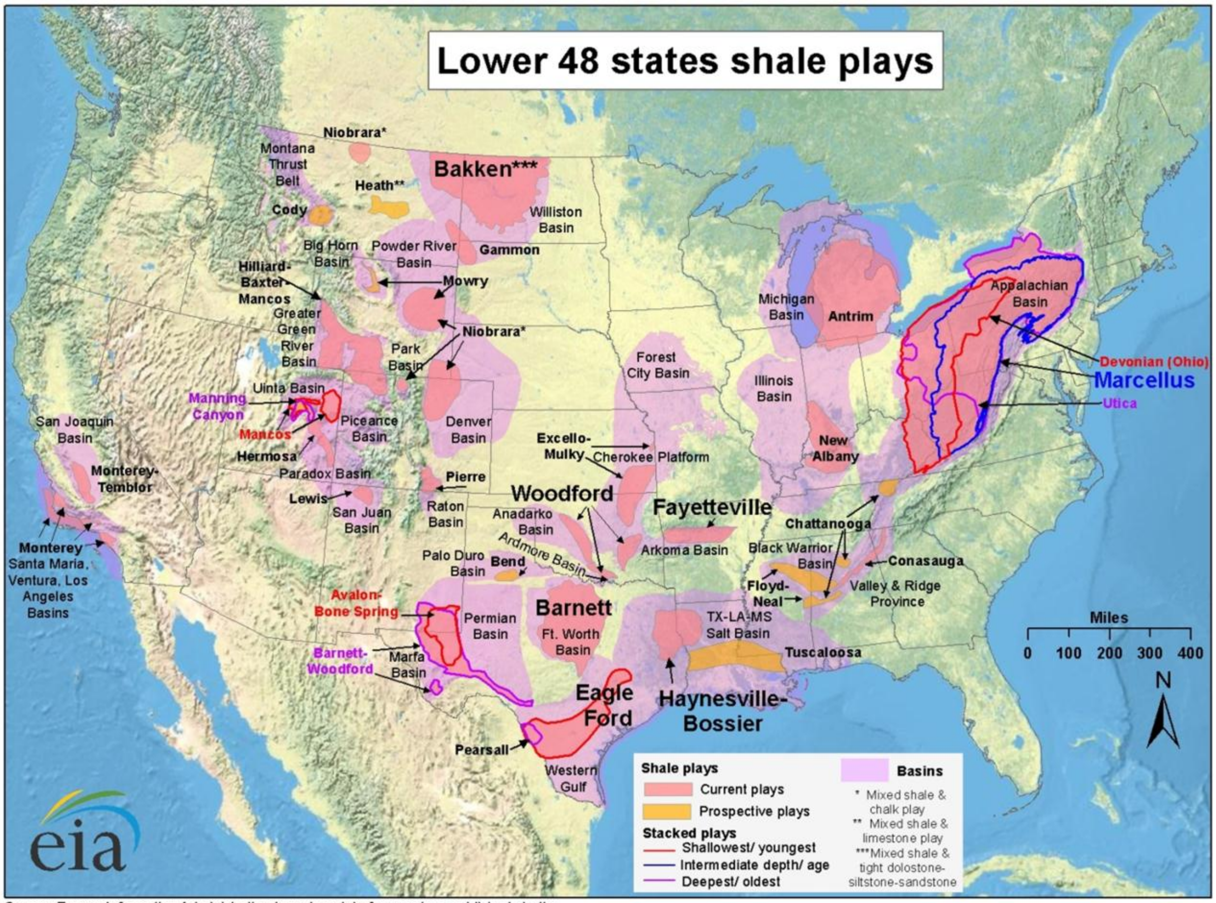
- **The economic benefits of U.S. shale gas development are substantial.** The degree to which companies and their investors can capitalize on this opportunity and profitably tap these vast domestic shale resources depends on reducing environmental and social risks to gain public support. Public apprehension over potential adverse environmental impacts and industrialization of rural and suburban areas have heightened the regulatory, reputational and legal risks associated with shale gas development and, in some instances, led to restrictions on drilling.
- **Shale gas development presents unique management challenges—but not unique technological challenges—to prevent or significantly mitigate potential known adverse impacts on water, air and land.** The basic techniques and methods to prevent pollution are similar to ones that have been employed in conventional onshore natural gas development for many years. Emerging issues, such as a possible link between associated disposal wells and earthquakes, bear watching but are not likely to be show stoppers. Industry is likely to develop alternatives or institute preventive measures in response.
- **Although the U.S. natural gas industry may be technologically capable, it is unclear if the industry has the will or near-term financial incentives to avoid environmental and social impacts that could lead to continued controversy and additional bans, moratoria or restrictions on drilling.** An industry-wide commitment to transparency, best practices and continuous improvement, rather than mere compliance with existing regulations, is essential to reducing environmental and social risks. While such an industry commitment may raise near-term costs, lack of such a commitment could severely limit or curtail domestic shale gas drilling and lead to higher long-term costs.
    - States provide primary government oversight of the oil and gas industry, creating a fragmented and uneven regulatory environment. State regulations vary in their emphasis on and standards to reduce impacts to water, air and land. Most companies do not voluntarily employ methods or processes designed to meet the most stringent state standards throughout their operations. Given the speed of technological development in shale gas development and its rapid spread to states with limited regulatory experience in natural gas development, regulators are likely to continue playing "catch up." Mere compliance with existing regulation may still result in incidents that raise the public's ire.
    - While environmental groups favor natural gas over other fossil fuels, they say industry is not taking sufficient measures to reduce risks to public health and the environment and have been frustrated by the lack of federal government standards and oversight. The recent sharp rise in domestic shale gas production has made improving industry practices and addressing associated externalities even more imperative for environmental activists.
    - Some areas, such as New York City's watershed that provides unfiltered drinking water for more than eight million people, will likely be no-go areas. The risk of any environmental contamination is too great.
- **Three key issues make it challenging for the industry to secure more public support:**
    - **Technical—**Hydraulically fracking a conventional (non-shale) vertical well with a single fracture treatment generally requires 50,000 to 100,000 gallons of fluid. Fracking a horizontal shale well requires from one to eight million gallons of water and thousands more gallons of chemicals than a conventional vertical gas well. These volumes have implications for water

consumption, wastewater management, chemical transport and storage, and possibly truck traffic, depending on how the water and wastewater are transported. Moreover, some companies are drilling multiple wells from a single pad to reduce costs and the footprint on the land. While this approach addresses some environmental impacts, it concentrates others, including air emissions and truck traffic carrying water, chemicals, wastewater and equipment to and from a single site.

- o **Scale—**Some states are anticipating thousands of shale gas wells to be drilled within a few years. If contamination problems occur at only a small percentage of shale gas wells, numerous residents and communities can still be affected by development.
- o **Location—**Because of the location of shale formations, development is spreading to areas not familiar with natural gas development, including the Northeast. Practices and procedures deemed acceptable by regulators and the public in remote areas, or in states and communities that have grown up with and become financially dependent on the oil and gas industry, may not pass muster in new areas that have been free of petrochemical drilling. Communities new to natural gas development are proving to be less tolerant and more scrutinizing of the associated environmental impacts than communities where gas production has occurred historically.

- **Rapid technological innovation to reduce environmental impacts is occurring, and industry can and has shown a willingness to respond quickly to issues of concern.** Examples include the growth in recycling of hydraulic fracturing fluids returned from wells, and the quick response of companies operating in the Marcellus Shale to stop sending wastewater to treatment plants when requested by the state. Commercial and investment opportunities to reduce environmental impacts also are evident, as seen by the growth of recycling technologies and new "green" fracturing fluid products.
- **The social impacts of shale gas development on communities are difficult to mitigate and also more subjective to judge.** Where some see an influx of jobs, economic development and tax and lease payments that can boost sagging rural economies, others perceive infrastructure degradation and industrialization imposed on rural and suburban areas not seeking change. While some of the social impacts can be mitigated, many communities lack the tools to address the broad and cumulative impacts of accelerated shale gas development that can alter a community's identity. Even if environmental concerns can be addressed, some communities may remain opposed to shale gas development because they oppose industrialization of their surroundings.
- **Shale gas development in many ways has been an economic victim of its own success.** Natural gas prices hit a two-year low at the beginning of this year, brought on in large part by estimates of economically viable shale gas development. Natural gas fell to around $2.50 per million British thermal units (BTU), compared to a high of more than $13 per million BTU in 2008. As a result of falling gas prices, companies have been moving from primarily methane-dominated dry shale gas plays to development of "liquids-rich" gas plays, which produce not only dry natural gas but profitable liquids such as propane and butane, and oil shale plays. The reduced emphasis on dry shale gas plays is allowing regulators in those areas with dry shale gas formations more time to develop and implement regulations. Conversely, low natural gas prices make it more challenging for companies to absorb new costs associated with reducing environmental impacts in these plays. Most importantly, despite the economic climate, drilling will continue in dry shale gas plays because producers often have a limited time to begin drilling once they sign a lease with landowners.

Box 1: Key U.S. Shale Gas Plays



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

In early 2012, the U.S. Energy Information Administration (EIA) released its Annual Energy Outlook 2012 Early Release Overview, which estimated 482 trillion cubic feet (tcf) of unproved technically recoverable onshore shale gas resources in the lower 48 states. In a July 2011 analysis (modified by the 2012 outlook), the EIA focused on discovered shale plays totaling 454 tcf. Four of the largest include:

- 114 trillion cubic feet (25 percent) in the **Marcellus Shale**, more than a mile beneath portions of Pennsylvania, New York, Ohio and West Virginia. Range Resources began producing the first gas from the Marcellus shale in 2005.
- 75 tcf (17 percent) in the **Haynesville Shale**, more than two miles below the surface of northwestern Louisiana, southwestern Arkansas and eastern Texas. **Chesapeake Energy** and **Encana** were among the first to begin drilling in this play in the mid-2000s.
- 43 tcf (10 percent) in the **Barnett Shale,** about one and a half miles under north Texas, including the Dallas/Fort Worth area. **Mitchell Energy** (now **Devon Energy**) first paired large-scale horizontal drilling with fracking here in 1995, and the play took off in 2003.
- 32 tcf (7 percent) in the **Fayetteville Shale,** which varies in depth from 1,500 feet to 6,500 feet under north central Arkansas. **Southwestern Energy** pioneered development of this shale in 2003.

"Liquids-rich" shale plays include the Eagle Ford in south Texas and the newly discovered Utica in Pennsylvania and Ohio that hold gas, gas liquids and oil. Oil shale plays include the Bakken in North Dakota and Niobrara in Colorado.

Executive Summary

The U.S. natural gas industry has invested billions of dollars in shale gas properties over the last few years. Technological advancements are making it possible for companies to economically extract natural gas from vast shale formations around the world, including shale plays potentially underlying one-quarter of the United States. American companies have taken the lead in developing these newly accessible resources, prompting government officials, energy analysts and companies to hail domestic shale gas development as a "game-changer," "the most positive event in the U.S. energy outlook in 50 years," and the "Dawn of a New Gas Era." The U.S. Energy Information Administration (EIA) is projecting a 25 percent increase in domestic natural gas production between 2009 and 2035 to 26.3 trillion cubic feet, with shale gas driving this dramatic growth. Shale gas's portion of U.S. natural gas production has climbed from less than 2 percent in 2001 to nearly 30 percent today, and EIA projects it will reach 49 percent by 2035. Altogether, energy analysts now estimate there is enough natural gas to supply the country for at least 100 years at current rates of consumption. The transformation is such that companies now are eyeing liquid natural gas import terminals on the Gulf Coast for conversion into export terminals.

The benefits could be substantial. An influx of domestic natural gas could lead the country toward greater energy independence, enhanced national security and a greener energy future. The U.S. natural gas industry could boost profits, drive economic development and job creation, generate revenues for local, state and federal governments, and provide income for residents who lease their land for drilling. Low-cost natural gas also is spurring several U.S. industries that use gas for fuel or feed stocks to invest in U.S. plants that make chemicals, plastics, fertilizers, steel and other products.

While shale gas reserves are vast and the economic benefits potentially enormous, the key question for investors is how much of this natural gas can be extracted and delivered to the market at a profit while having minimal impact on the environment. A number of challenges have beset the U.S. natural gas industry as it has begun tapping these unconventional resources. The rapid pace of development over the last few years, combined with high-profile incidents of drinking water contamination, have led to public apprehension over the effects on drinking water sources and imposed industrialization of rural and suburban communities. Shale gas production is expected to increase in almost every region in the country. Some of the greatest controversy has been in areas of Pennsylvania and New York, where there has been minimal experience with gas drilling and highly valued watersheds that serve millions of people. Intense media scrutiny has triggered several government investigations, not only into the environmental impacts of natural gas development, but also corporate estimates of natural gas reserves and well productivity. With sides so polarized, and often emotional, misinformation is rife on all sides.

The public outcry has undoubtedly heightened the regulatory, reputational and legal risks associated with shale gas development for companies and investors. Several state governments have imposed *de facto* bans on drilling while they review whether existing regulations adequately protect public health. Even states that have not put restrictions on drilling are revising regulations. The federal government, which has exerted limited oversight over natural gas development, is regulating some activities for the first time and finding additional ways to assert its authority. As a result, regulatory costs are on the rise, particularly for companies that have not adopted internal standards that exceed compliance with existing regulation.

Costs associated with reputational and legal risks have been exemplified by the experiences of **Cabot Oil & Gas** and **Chesapeake Energy**. These two firms have become well-known for contamination incidents and have paid millions of dollars in fines or restitution and face civil litigation. Pennsylvania also has banned Cabot from drilling in part of the state since April 2010. Alleged damages from shale gas development are the subject of more than three dozen lawsuits, including ten class actions, according to Sedgwick LLP, an international litigation and business law firm. Plaintiffs are seeking compensation for past injuries, medical monitoring, diminution of property value, remediation and restoration and punitive damages.

Corporate recognition and management of these risks, or lack thereof, will therefore affect the economics of shale gas development. The industry is facing several new regulations, reports and evaluations released in late 2011 and planned for 2012 and beyond, even as policymakers and regulators race to keep pace with shale gas expansion. Calls for more stringent oversight and increased data collection and transparency have become a consistent theme. Lack of available and publicly reported data is both hindering good decision making by corporations, investors and regulators and contributing to the inability to address public concerns.

Companies have a good story to tell of technological development and adaptation, and many have begun providing more information to investors and the public on their shale gas operations. While many have begun to report on their efforts to reduce environmental impact, such as recycling wastewater, finding alternative sources to freshwater and instituting closed loop systems, few are backing up anecdotal descriptions with hard data. How companies respond to further calls for transparency and adherence to best practices will influence whether the operating environment will improve or whether future rounds of even more stringent regulation or outright bans on drilling will ensue. Given the public scrutiny, a few bad actors may put the entire industry's license to operate at risk.

Environmental and Social Impacts

Similar to other energy sources, including conventional natural gas development, shale gas development has impacts on water, air and land, and also on the people and communities in which development occurs.

Freshwater supply: Shale gas development is conducted in proximity to valuable surface water and ground water and itself requires significant amounts of water. Companies have proven to be innovative in their use, reuse and disposal of water. Still, the potential for drinking water contamination is at the forefront of public concerns. Contamination has occurred primarily through methane migration, poor wastewater management and chemical spills. Yet practices and processes to significantly reduce these risks are widely known and generally practiced in the industry. Poor implementation of these practices and processes generally has been the reason for contamination. Also, public apprehension over chemical additives to fracturing fluids lies at the heart of the contamination issue. Using fracturing fluid that is void of hazardous or toxic chemicals and fully disclosing all chemical additives could address much of this concern. Some companies have been taking steps in this direction, although others maintain current fracking fluid compositions are more efficient, less expensive and do not pose a danger to the environment given concentration levels. Most companies are now voluntarily posting data on some chemicals, although more chemicals could be disclosed. State regulations increasingly are requiring public disclosure of chemicals.

Wastewater disposal: Wastewater also is an important issue, given the large volumes of water required to frack a well and the narrow disposal options. The two main options are deep well disposal and recycling. Deep well disposal is the most common. However, it recently has been linked to small earthquakes. Technologies are available to recycle wastewater—some companies in the Marcellus Shale recycle close to 100 percent of their wastewater already—but it can be more costly than deep well disposal and generally produces a solid waste that then must be disposed. (This presents another reason to reduce the toxicity of fracking fluids.) Few companies are bringing their wastewater to water treatment plants for disposal today. Most Western states ban the disposal of wastewater into surface waters, and Pennsylvania asked companies to halt this practice in 2011. Nonetheless, the EPA announced it would propose new standards in 2014 for natural gas wastewater before it can be brought to treatment plants.

Air: Unlike water, which primarily is a local issue, air emissions not only affect local air quality but also potentially have implications for climate change. Air emissions are among shale gas's most disputed environmental impacts, although developments in the coming year will help to clarify and address some outstanding questions. Air emissions include volatile organic compounds, air toxics and methane. Technological fixes exist to capture most air emissions, and some of these solutions would be required under proposed federal air regulations slated for release in April 2012. In addition, a voluntary industry initiative and federal greenhouse gas reporting requirements will begin to produce data in 2012 that will help fill a current void and inform hotly contested disputes between the U.S. Environmental Protection Agency (EPA) and industry over the amount of methane emissions from shale gas operations and the cost of capturing them.

Land and community: Shale gas development also can significantly alter landscapes and the character of rural and residential areas. The bulk of the surface disturbances related to the well pad can be temporary if appropriate restoration efforts are undertaken. Yet regrowth in forested areas can take many years, and related infrastructure like gas processing plants and compressor stations are relatively permanent. Businesses dependent on tourism and residents specifically choosing their community for its undeveloped character are concerned that scenic areas will be converted into industrial zones, with a growing permanent network of well pads, pipelines, access roads and related infrastructure. Additional concerns are that the network of pipelines and roads, particularly if they require clearing, can fragment land and enable or accelerate additional development in the area. An influx of temporary workers can also have economic and social repercussions for a region. In addition to having concerns about water and air pollution noted above, communities commonly complain about truck traffic, road degradation and noise. Communities also can become polarized as residents take sides on this issue or when all within the community bear the impacts yet only some directly benefit financially.

Report Organization

This report is designed to help investors and others assess the risks and rewards of shale gas development. As part of its value as an evaluative tool, this report includes *key questions* for investors as well as *broader issues* they may want to consider, such as the implications of extending the era in which fossil fuels predominate.

The report examines the following topics:

- the primary *environmental and social impacts* of shale gas development, including associated *risks* and examples of corporate *mitigation measures and innovations.* These include:
    - *land use changes*
    - *community impacts*
    - *freshwater consumption*
    - *water quality, and*
    - *air quality;*
- the U.S. *regulatory framework* under which companies operate;
- recent controversies involving the key accounting issues of *natural gas reserve and production estimates* and *greenhouse gas emissions*; and
- the ongoing *shareholder campaign* seeking increased disclosure on hydraulic fracturing activities.

Three appendices accompany this report. *Appendix 1* includes 2-page profiles of 10 publicly traded shale gas developers, ranging from multinational oil and gas companies to mid-size independent energy companies to a small independent primarily dedicated to shale gas development. The profiles are designed to provide a snapshot of a company's level of involvement in shale gas development, its disclosure of associated risks and mitigation measures, its track record in this area, the level of management oversight and related shareholder activity. The profiled companies include:

Anadarko Petroleum	Chevron	Range Resources
Cabot Oil & Gas	ExxonMobil	Southwestern Energy
Carrizo Oil & Gas	Hess	WPX Energy (formerly Williams Cos.)
Chesapeake Energy		

Appendix 2 identifies key stakeholders in the debate over shale gas development.

Appendix 3 includes available resources for further exploration of shale gas development issues.

Finally, a note on terminology is needed. Hydraulic fracturing and horizontal drilling are the key components of the new technological developments providing access to shale formations. *(See Box 3, p. 13, for a description of these processes.)* In its narrowest sense, hydraulic fracturing represents only a portion of the process, namely when pressurized water creates fissures that allow natural gas to escape from the shale to be produced through the well. But the term “hydraulic fracturing” has become a widely used catchphrase to encompass all of the activities associated with shale gas development—from exploration, construction of a well pad, delivery of water and chemicals, horizontal drilling and production, management of wastes and delivery of gas to end markets. This report addresses impacts from shale gas development broadly defined.

Key Questions for Investors

Disclosure

❖ Are companies disclosing sufficient information about their shale gas operations and their potential impact on shareholder value?

- **Form 10-K and 10-Qs:** What is the quality of disclosure in these annual and quarterly reports related to risks, including potential risks associated with environmental issues and regulatory developments; compliance costs; violations; lawsuits; location of shale gas reserves; and production and reserve estimates?
- **Other stakeholder communications:** Does the company provide adequate information on its prevention and mitigation measures related to the environmental and social impacts of shale gas development? Does the company disclose quantitative data related to its shale gas operations with appropriate specificity? Does the company disclose challenges specific to a shale gas play it is developing, such as availability of freshwater resources?
- **Investor presentations:** Are company reserve and production estimates in investor presentations consistent with those in securities filings? Are companies revising their estimates on a timely basis to reflect new data on productivity, costs and gas prices? Are companies providing realistic assessments given the level of hard data available?

Management Practices

❖ Are companies adequately managing the risks associated with shale gas development?

- Has the company demonstrated that its board of directors and senior management are engaged in risk management, including assessing the environmental and social impacts of shale gas development?
- Is the company taking sufficient action to ensure that its operations are conducted in an environmentally responsible manner?
  - Has the company moved beyond state-by-state regulatory compliance and instituted internal and consistent standards that approach best practice?
  - Has it demonstrated a commitment to continuous improvement processes related to shale gas development?
- Is the company adequately positioned to adapt to a changing regulatory and operating environment?

Investment Strategies

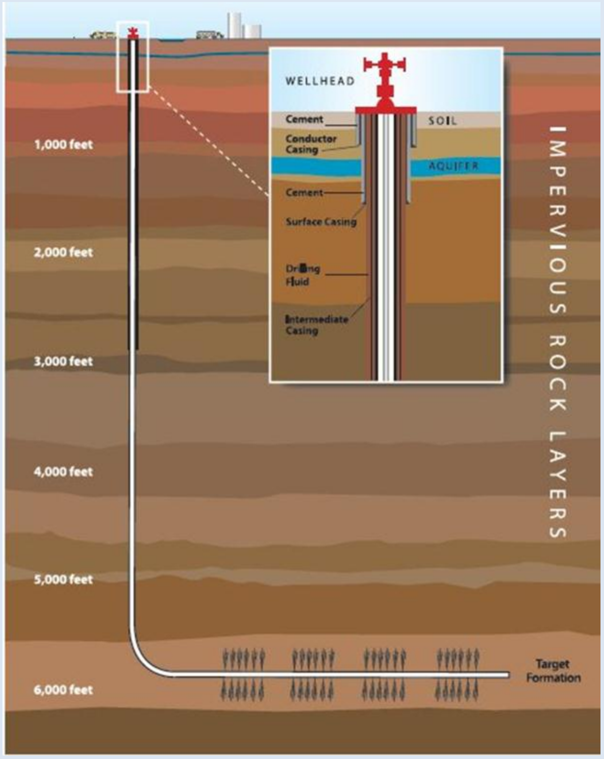
❖ Is the company effectively positioned to capitalize on the new market opportunities associated with natural gas development?

Box 2: Broad Issues for Investors to Consider

In addition to corporate-specific questions that would help investors evaluate companies pursuing shale gas development, investors also may want to consider a number of additional issues critical to the future of shale gas development, but beyond the scope of this report.

- **Global development:** The United States is at the forefront of shale gas development, yet shale gas formations are present throughout the world. What are the economic implications for U.S. investment if and when other countries start tapping their shale gas reserves? What are the opportunities for U.S. companies to extract gas in other countries?
- **U.S. marketplace:** Is the U.S. marketplace prepared to increasingly utilize natural gas? Some U.S. industries are quickly ramping up domestic operations to take advantage of lower energy and feedstock costs resulting from the shale gas boom. Companies are pursuing the conversion of liquid natural gas import terminals on the Gulf Coast into export terminals. What is the likely demand for natural gas in electrical power generation? What is the likely demand for compressed natural gas (CNG) fleet or passenger vehicles and liquefied natural gas (LNG) long-haul truck vehicles?
- **Implications for renewable energy:** Shale gas development is making it possible to extend the fossil fuels era. Given the surge in domestic gas production, will natural gas become a bridge fuel to a clean energy economy or an obstacle? Will low gas prices and plentiful supply deter investments in renewables? Will gas be coupled with intermittent renewable resources to provide reliable power sources or will gas compete with renewables?
- **Climate change implications:** If shale gas development reduces or delays renewable energy development, or if improved data collection and life-cycle analysis bear out increased estimates of methane emissions from shale gas, will natural gas lose critical support from the environmental community? Would the industry lose subsidies from the federal government?
- **Infrastructure planning and cumulative impacts:** What role should investors and individual companies have in addressing the cumulative impacts of shale gas development on communities?

Box 3: Hydraulic Fracturing and Horizontal Drilling of Shale Gas



Example of hydraulic fracturing for shale development, February 2012
Reproduced courtesy of the American Petroleum Institute

The hallmark of modern shale gas development is the extensive use of horizontal drilling and high-volume hydraulic fracturing—two essential features that have made natural gas extraction from unconventional, low-permeability formations, such as shale, economically viable. Extracting natural gas from shale is a multi-step process. First, similar to the extraction of natural gas trapped in a conventional underground reservoir, a well operator drills a vertical section of a well that is "cased" with steel pipe and isolated with cement to prevent migration of produced well fluids or natural gas into freshwater aquifers. Then the operator curves the well as it nears the shale formation, which typically is several thousand feet or more beneath the surface, until the operator can employ horizontal drilling that may extend from 1,000 to 6,000 feet or more through the shale layer. The operator may case all or some remaining portions of the well with steel pipe and cement, depending on local geological/hydrological conditions and applicable state law.

Next comes the multi-stage fracture stimulation process, which can take several days to complete. In the far end of the horizontal well (the "toe"), operators use a perforating device to make small holes that penetrate the casing, the cement that surrounds the casing, and a short distance into the shale formation. Fracking fluid—a mixture primarily of water, but also chemicals and a proppant (usually sand) to prop open fissures—is injected into the well under thousands of pounds of pressure to fracture the shale rock further. The fracking process opens access to millions of tiny fractures and fissures in the body of the shale and allows the natural gas, which is locked in the fractures, to escape and flow into the wellbore for extraction. This process of perforating and fracking is repeated in several sections or "stages" until the entire horizontal section of the well is fracked.

Altogether, each well requires from one to eight million gallons of fracking fluid (about 100,000 to 600,000 gallons per section that is fracked). From 5 to 50 percent of the fluid injected into the well resurfaces; the actual amount is highly dependent on the characteristics of the specific shale.

I. Environmental & Social Impacts

Land Use Changes

Drilling pads: A shale gas drilling complex typically encompasses from three to 10 acres. Clearing land in heavily forested areas, or converting agricultural land or land near residences, can have significant land use impacts. Areas where drilling is a new phenomenon seem to be particularly sensitive.

Developing shale gas requires preparing a pad site for the drilling rig and related equipment. A drilling well pad can be quite large, so as to accommodate multiple wells and support facilities, including space for heavy trucks delivering or removing water, chemicals, wastewater or equipment; surface impoundments or tanks to hold water, wastewater and drillings cuttings; the drilling rig and related equipment; and sometimes housing for workers. (At the same time, by consolidating operations at one location for multiple horizontal wells that access considerable acreage, larger pads can mitigate cumulative land use impacts that would otherwise stem from multiple pads.) Some holding pits serving multiple wells can be as large as a football field. For short periods, drilling rigs from 50 to more than 100 feet tall can dominate the vista during the drilling process. Once natural gas production has begun, the pad site is significantly reduced to host well heads, a smaller amount of equipment, several water or condensate storage tanks and a metering system to measure natural gas production. The number of storage tanks generally increases commensurately with the number of well heads.

Local pipelines and related infrastructure: The infrastructure needed to transport recovered natural gas from the wellhead to market includes a gathering system of low pressure, small diameter pipelines that transport raw natural gas to a processing plant, a larger interstate or intrastate pipeline and then a final distribution network. New pipelines may be installed through traditional open trenching, boring underneath the ground or a combination of the two. When completed and restored, the right of way for a pipeline remains cleared, resembling an open meadow and nearly undetectable when traversing farm or open land but a noticeable swath through forest or developed land. Although some processing

Drilling site in the Marcellus Shale. Source: www.marcellus-shale.us

Gas processing plant in the Marcellus Shale. Source: www.marcellus-shale.org

is done at the wellhead, gas processing plants miles away further remove any liquids from the gas to create pipeline quality gas. Gathering systems may need field compressors to move gas to processing plants, and larger compressor stations generally are sited every 40 to 100 miles to move gas along the pipeline and generally contain some type of liquid separator.

Interstate pipelines: More than half of the interstate natural-gas pipeline projects proposed to federal energy regulators since the beginning of 2010 involve Pennsylvania—at a cost estimated at more than $2 billion, according to the Associated Press. One new interstate project, the MARC I line from northern Pennsylvania's rural Endless Mountains region into New York, has generated controversy and illustrates the difficulty in siting new interstate gas pipelines. The Federal Energy Regulatory Commission (FERC) approved the pipeline in November, but environmental groups and the EPA expressed concerns about its potential environmental impact and whether it is necessary. The EPA contends the line would fragment an undeveloped swath of forest and farm land 39 miles long and potentially stress sensitive streams in an area that supports a robust ecosystem, high quality of life and recreation. The EPA notes the likelihood of secondary and cumulative impacts, pointing out that the MARC I line would "co-exist with, if not induce or accommodate, development of new gas wells" and related infrastructure. Certification by FERC gives a company the right to seek court approval to take property by eminent domain.

Mitigation and innovation—Companies are taking a number of measures to reduce the footprint of drilling and address environmental impacts on the land.

- **Erosion and sediment control** includes controlling stormwater discharges and preventing surface runoff from site construction activities. States oversee related permitting, and the Independent Petroleum Association of America has outlined voluntary stormwater management practices.
- **Multi-well drilling pads** allow multiple horizontal wells to be drilled in multiple directions from a single pad. Concentrating drilling activity results in fewer roads, pipelines and drill sites. **Apache** and **Encana** in Canada's Horn River Basin are using 6.3 acre pads to effectively capture gas from 5,000 acres. Given the large area they access from one pad, operators have a relatively

high degree of flexibility in deciding where to locate these pads which allows companies to take environmental concerns into account more easily in their siting decisions.

Additional land use mitigation measures include:

- **shared** new access roads and/or pipelines;
- **pipelines** (sometimes temporary surface-laid) **rather than roads** to move water from centralized storage facilities to the well pad. (Surface laid pipelines could be used to move wastewater but would require additional monitoring);
- co-locating **dual pipelines** for gas and freshwater in the same trench;
- **temporary** earthen impoundments and portable, above-ground holding ponds (PortaDams) to store water; and
- **restoration** efforts, which involve landscaping and contouring the property as closely as possible to pre-drilling conditions.

Box 4: Access Rights Can Lead to Conflict

Two issues exacerbating the social and environmental impacts of shale gas development are the thorny matters of severed surface and subsurface rights and forced pooling.

Severed surface and subsurface rights: Several states, including Colorado, Pennsylvania, Texas and West Virginia, allow one owner to hold surface rights and another to hold subsurface rights for gas, oil and minerals. Entities holding subsurface rights have rights to reasonable use of the surface in order to access the natural gas—rights that have led to conflicts with homeowners opposed to natural gas development. This issue is particularly acute in areas where there has not been historical drilling activity and homeowners were either unaware of, or did not understand the significance of, this separation of ownership rights.

Despite their opposition, property owners who do not own subsurface rights may have a well drilled on their property, leading to a loss of acreage, decrease in property value and no choice but to deal with the noise and emissions associated with gas development. Opponents to fracking have illustrated this point by circulating pictures of drilling rigs in close proximity to unwilling homeowners concerned about, or experiencing, adverse health effects. Critics also point out that state setback requirements vary widely, and may not have been developed with severed surface and subsurface rights in mind. Property owners typically receive some compensation, but it does not compensate for any loss in property value. In Pennsylvania, where the state retains subsurface rights on just 20 percent of its parkland, debate also is ongoing about whether gas companies should be allowed to exercise their subsurface rights on public land.

Forced pooling: Another controversial subsurface rights issue is "forced pooling," which allows drillers to gain access to natural gas beneath someone's land without their permission—even if they hold subsurface rights. Some 39 states have varied forms of forced pooling laws. Generally, drillers can access gas from a common underground reservoir if they have negotiated leases for a threshold percentage of an entire area. Drillers generally are not allowed to drill surface wells on un-leased land, but they can use horizontal wells to access the gas. One large landowner can trigger forced pooling even if the majority of families in a neighborhood are opposed. Operators must pay a proportionate share of royalty fees to all subsurface rights holders in the pooled unit.

Critics say forced pooling was designed with conventional oil and gas deposits in mind and that it is inappropriate for shale gas. They contrast the uncontrollable nature of a conventional gas deposit, which allows gas to move around relatively freely, to shale gas, which cannot be extracted without deliberate and planned horizontal drilling and fracturing. Supporters of forced pooling say such laws are necessary to support the most efficient subsurface development of the shale gas resource while minimizing the surface impact of the development activities.

Community Impacts

In addition to land use changes, social impacts can dramatically alter a community's way of life. The greatest direct impact associated with gas development occurs over several months as workers clear the area and prepare a well pad, set up the drilling rig, drill, frack, install operational equipment and prepare the well for production. If many wells are drilled from the same pad, this process can extend to a couple of years, according to Range Resources.

Drilling and fracking: To drill and prepare a well takes up to 100 workers, though only one is needed to operate a well in the long term production phase. Drilling, which occurs around the clock, may take four to six weeks and can produce noise, dust, light pollution and diesel emissions. Fracking may take another three or four days, and this operation usually is restricted to daylight hours, although transporting the water needed can be an around-the-clock operation.

Truck traffic and temporary workers: Truck traffic associated with shale gas development is a common complaint of many communities. It takes 200 trucks to transport one million gallons of water, and fracking of shale gas wells requires from one to eight million gallons per well. Wastewater also must be removed. In addition, some 30 to 45 semi-trucks are needed to move and assemble a rig that can drill down 10,000 feet. Additional trucks also carry sand, waste and other equipment (including heavy machinery like bulldozers and graders) along back roads, sometimes in wintry conditions. Local road infrastructure can quickly become degraded and communities often spend more on road maintenance. Depending on the number of wells being drilled in an area, a community may experience these impacts for many years. New workers with good wages moving to the area are a double-edged sword. They can bring economic benefits and activity, but because of the sudden influx, also can drive up local housing prices, making regions less affordable to long-time residents. Temporary workers also sometimes can affect the social fabric of a community. The combination of these factors often drives up costs for police, fire and social welfare broadly. Conflicts also can arise between neighbors if the same party does not own both the surface and mineral rights to a property over a shale formation. *(See Box 4: Access Rights Can Lead to Conflict, p. 16.)*

Local regulation: Land use regulation typically is done at the local government level; there are few regional land use processes in place to coordinate oversight of shale gas development spread over several counties. Local authority varies by state, and some towns have tried to assert their authority by instituting bans on shale gas development. *(See Box 5: Bans and Moratoria, p. 18.)* In addition, more than 100 Pennsylvania towns have enacted ordinances to limit or regulate such drilling. In many instances, pending lawsuits will determine whether such local bans and local regulations are legal. In other instances, municipalities have had to abandon their challenges because they lack the resources for a lengthy legal battle.

Mitigation and innovation—Measures include:

- **community engagement**, such as outreach, education, notification and coordination of local development;
- routing **impact fees** to local authorities;
- voluntary **road monitoring** and maintenance programs;
- **scheduling truck traffic** around school busing and commuting hours or routes;
- **dust** mitigation;
- **sharing** access roads and **coordinating** infrastructure planning with other companies (keeping in mind anti-trust provisions);
- finding **alternatives to truck delivery** and removal, including water pipelines;
- **training** the local work force to fill shale development jobs;

- providing **housing** for temporary workers;
- **noise abatement**, including remote siting, noise cancelling barriers and equipment designs; and
- shifting to **electric or natural gas** as a fuel on the well pad to avoid diesel emissions.

Freshwater Consumption

The drilling, cementing and hydraulic fracturing of shale gas wells requires large volumes of water and results in a net loss of water. From 50 to 95 percent of the hydraulic fracturing fluid pumped down a well does not return to the surface. Water that does return from the well is no longer a freshwater resource as it is becomes a component of fracturing fluid or produced water. This wastewater generally either is recycled or disposed of in deep wells, making it unavailable for other uses.

Fracking a shale gas well uses the lion's share of the water—from one to eight million gallons per well (as many as 1,600 truckloads). Wells also can be fracked more than once to increase productivity. This practice has been used in vertical wells in shale formations, but has been applied to a small number of horizontal wells and is becoming less likely to be used in the future as operators learn how to optimize initial fracture treatments.

Box 5: Bans and Moratoria

- **New York** and **Maryland** have *de facto* temporary hydraulic fracturing bans in place, effectively halting new drilling while they conduct reviews. In June 2011, Maryland Governor Martin O'Malley (D) signed an Executive Order establishing the Marcellus Shale Safe Drilling Initiative, which essentially bans drilling pending the conclusion of a two-year study by the Maryland Department of Environment. Portions of western Maryland lie atop the Marcellus Shale. *(See Box 10 for more on New York, p. 36.)*

- **New Jersey** Governor Chris Christie (R) proposed a one-year moratorium on hydraulic fracturing operations in the state in August 2011, after vetoing a bill passed by the state legislature that would have permanently banned it. Notably, New Jersey is not a natural gas producing state, and does not lie atop the Marcellus Shale. New Jersey does have a vote on the Delaware River Basin Commission (see below).

- **The Delaware River Basin Commission** (DRBC) has had a de facto drilling moratorium in the Delaware River Watershed since May 2010, when the commission halted new permits while it drafted its first-ever rules regulating natural gas drilling. The DRBC is a federal-interstate compact government agency that coordinates withdrawals for drinking water, agriculture, recreation and resource development (such as shale gas). Its five members include the governors of the four basin states—Pennsylvania, New York, New Jersey and Delaware—and a federal representative of the U.S. Army Corps of Engineers. The DRBC repeatedly has postponed meetings to consider draft gas drilling regulations published in December 2010. Most recently, a November 2011 meeting was postponed when the governors of New York and Delaware indicated they would vote against the new rules. No new meeting date has been announced. The draft regulations are more stringent than Pennsylvania's rules, requiring pre-and post- drilling testing of ground and surface waters, $125,000 bond per gas well and disclosure of chemical additives, including the volume used. Numerous companies are affected; for example, the majority of the Marcellus acreage of **Hess** is in the Delaware River Basin.

- **New York City; Buffalo, N.Y.**; and **Pittsburgh and Philadelphia, Pa.**, have either called for bans or banned all fracking activities outright.

- Voters in three **Pennsylvania towns** voted for the first time in November 2011 on initiatives seeking to ban hydraulic fracturing. Results were mixed, although each individual vote was decisive. Referendums in Warren and Peters Township went down to defeat while one in State College passed.

The drilling process, itself, uses far less water. Operators mix water with clay and, sometimes, chemical additives to control the well, cool and lubricate the drill bit and carry rock cuttings to the surface.

Chesapeake Energy reports that drilling a typical deep shale natural gas and oil well requires between 65,000 and 600,000 gallons of water, depending on the depth of the well.

Large water withdrawals increasingly are being regulated, and often are subject to limits. Most states require an analysis of how water withdrawals from watersheds will affect the hydrology and ecosystems as part of the permitting process. Data collected from these studies inform daily withdrawal limits. In some states, a river basin commission or water resources board, such as the Susquehanna River Basin Commission or the Delaware River Basin Commission, control water withdrawals. In other places, water is owned by private individuals who can allocate it at their discretion. In 2011, New York began requiring a special permit to withdraw large volumes of water for industrial and commercial purposes, saying the state's "plentiful water resources are under pressure by heavy demands from increasing commercial, industrial, and public uses as well as the need to maintain river and stream flows for fisheries, wetlands, and other environmental needs." West Virginia is developing a global positioning system website for water withdrawals that will plot withdrawal points and estimated volumes.

Regional and local distinctions largely determine the significance of water consumption. Areas with limited supply, whether it is a constant condition or the result of drought, can affect local operations. While water is abundant in Marcellus Shale states, Texas experienced its worst single-year drought ever in 2011, with some municipalities' traditional sources of water so depleted that they needed to rely on trucked-in water for basic drinking and washing. As a result, **Apache** had to curtail some drilling for lack of water in Texas and Oklahoma. There is a real possibility that access to freshwater could become more difficult, costly and controversial, prompting companies to find alternatives. Apache, for example, has had success using produced brine water for fracturing.

Comparisons to other uses: There is considerable debate about the water intensity of shale gas development in comparison to other fuels and to other uses, such as agriculture or municipal use. The United States Geological Service reports on water use in the United States, but its *Estimated Use of Water in the United States in 2010* report is behind schedule and not expected to be completed until 2014. The last update was 2005, prior to the widespread use of hydraulic fracturing of horizontal wells.

Water: An Emerging Risk Management Issue

Water increasingly is becoming a risk management issue for corporations. The **Carbon Disclosure Project (CDP)**, with backing from 137 institutional investors representing $16 trillion in assets, has identified water as its second strategic issue of interest (after carbon) to investors. In 2010, the CDP sent out its first annual water questionnaire to more than 300 of the world's 500 largest corporations, focusing on sectors including oil and gas that are water intensive or are particularly exposed to water-related risks.

Notably, of 190 companies responding to the CDP's 2011 questionnaire, nearly 60 percent report that responsibility for water-related issues lies at the board level, and 93 percent have developed specific water policies, strategies and plans. In addition to water availability being an operational matter for corporations, it increasingly is becoming a reputational risk as competition for water increases.

In September 2011, **Ceres,** with funding from the IRRC Institute (which also sponsored this report), released a new tool for investors and companies to evaluate risks and opportunities associated with business exposure to global water supply threats. *Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management*, developed with input from 50 investors, companies and public interest groups, allows investors to judge a company's water management strategies against industry peers and detailed definitions of leading practice.

Range Resources compares three to four million gallons of water used to fracture a shale well to water usage at a typical golf course for nine days, adding that ten times as much water is required to produce the equivalent amount of energy from coal and that ethanol production can require as much as a thousand times more water to yield the same amount of energy from natural gas. ExxonMobil says the amount of freshwater required for drilling and fracking a typical horizontal well is usually equivalent to about three to six Olympic-size (50 meters by 25 meters) swimming pools. Chesapeake includes the following chart comparing water usage among various energy sources on its website.

Energy Resource[1]	**Range of Gallons of Water Used per MMBTU of Energy Produced**
Chesapeake deep shale natural gas*	0.84 - 3.32[2]
Conventional natural gas	1 – 3
Coal (no slurry transport)	2 – 8
Coal (with slurry transport)	13 – 32
Nuclear (uranium ready to use in a power plant)	8 – 14
Chesapeake deep shale oil**	7.96 - 19.25
Conventional oil	8 - 20
Synfuel - coal gasification	11 – 26
Oil shale petroleum	22 – 56
Oil sands petroleum	27 – 68
Synfuel - Fisher Tropsch (from coal)	41 – 60
Enhanced oil recovery (EOR)	21 - 2,500
Biofuels (Irrigated Corn Ethanol, Irrigated Soy Biodesiel)	> 2,500

[1]Source: "Deep Shale Natural Gas: Abundant, Affordable, and Still Water Efficient", GWPC 2011
[2]The transport of natural gas can add between zero and two gallons per MMBTU
*Includes processing which can add 0-2 gallons per MMBTU
**Includes refining which consumes major portion (90%) of water needed (7-18 gal per MMBTU)
Solar and wind not included in table (require virtually no water for processing)
Values in table are location independent (domestically produced fuels are more water efficient than imported fuels)

While informative, the usefulness of the analogies and comparative analyses is somewhat limited, since water is a local resource, with water stress varying greatly by location. In other words, the environmental impact of withdrawing an Olympic size swimming pool's worth of water is different in the Hill Country of Texas than in northern Pennsylvania.

Mitigation and innovation—Companies are pursuing a variety of techniques and technologies to reduce freshwater demand. To minimize contamination, companies typically use freshwater for near surface drilling and cementing, but companies are finding alternatives to freshwater in fracturing fluids. They are recycling their own produced water and hydraulic fracturing fluids, using wastewater from other industrial sources and tapping brackish or saline aquifers. They also are creating impoundments to store rainwater or surface water when flows are greatest and avoid withdrawals when water availability is low, or when other industries and agriculture are making greater demand on water sources.

Water Quality

Water that comes back out of the well is referred to in this report as wastewater. It includes residual drilling and fracking fluids and produced water (naturally occurring water originating from the shale formation). Following fracturing of the well, the composition of the wastewater that flows back changes from an initial flow of primarily residual fracturing fluids to water dominated by the salt level of the shale. This "flowback" period generally lasts from a few days to a few months, with the rate of water recovery usually dropping rapidly as gas production starts. Accordingly, operators typically send the large early volumes of returning fluids to storage facilities for the first few days. The wastewater is then treated for reuse or disposed. As gas production continues, processing equipment separates the water and gas. Both the amount and composition of the wastewater vary substantially among shale gas plays. In the Barnett Shale, for example, there can be significant amounts of saline water produced with shale gas.

Fracking operation in the Marcellus Shale. Source: www.marcellus-shale.us

While much public interest has focused on the chemicals in the fracturing fluid *(See Box 6: Fracking Fluid Chemicals, p. 22)*, the produced water originating from the shale formation may include brine, gases, heavy metals, organic compounds and naturally occurring radioactive elements (NORM). The Natural Resource Defense Council (NRDC) petitioned the EPA in 2010 to regulate oil and gas wastes, including drilling fluids and cuttings, produced water and used hydraulic fracturing fluids, under Subtitle C of the Resource Conservation and Recovery Act, which regulates hazardous waste. In its petition, the NRDC contends that it is a common misconception that produced water is relatively clean and says that instead it can contain arsenic, lead, hexavalent chromium, barium, chloride, sodium, sulfates and other minerals, and may be radioactive. Most shales do not report unusual NORM levels in produced fluids, although NORMs are common in some New York and Pennsylvania areas. The Pennsylvania Department of Environmental Protection sampled seven waterways in late 2010 following shale gas wastewater disposal and found NORM to be at or below acceptable background levels.

Potential Avenues of Contamination

The potential for shale gas development to contaminate underground or surface sources of freshwater can take multiple avenues, although most occur on the surface. These include accidental spills, faulty well construction, and poor wastewater management. Techniques and methods to prevent contamination through these avenues are similar to ones that have been employed in conventional onshore natural gas development for many years.

Wellbore integrity

State regulators have identified faulty cementing of well casings as a source of methane migration from conventional gas production and now shale gas production. *(See Box 7 for a description of high-profile*

Box 6: Fracking Fluid Chemicals

Fracking fluid for shale gas formations generally is more than 99 percent water and proppant (usually sand), with the remainder chemical additives. Chemical additives serve a variety of purposes, including preventing scale and bacterial growth and reducing friction. They also vary from one geologic basin or formation to another. Although the additives comprise a relatively small percentage of total fluids, given the millions of gallons of fluids used in each well, they still can amount to tens of thousands of gallons of chemicals per well.

As part of a Draft Supplemental Generic Environmental Impact Statement (SGEIS) related to high volume hydraulic fracturing, the New York State Department of Environmental Conservation (DEC) collected data on many of the additives proposed for use in fracturing shale formations in New York. *(See Box 11 for more on New York's SGEIS, p. 36.)* Six service companies and 15 chemical suppliers provided the DEC with data on 235 products. The DEC determined that it had complete product composition disclosure on only 167 of those products. It also found that the products contained 322 unique chemicals with Chemical Abstracts Service (CAS) Numbers (unique numerical identifiers assigned to every chemical) disclosed and at least 21 additional compounds with undisclosed CAS Numbers due to many mixtures being involved.

Mitigation and innovation—Companies have been working to reduce the amount and toxicity of the chemicals they use. **Chesapeake Energy** reports on its website that it has reduced additives in fracking fluids by 25 percent. In May 2011, **Baker-Hughes** announced the launch of its BJ SmartCare™ family of environmentally preferred fracturing fluids and additives. Also in May 2011, **Halliburton** announced that **El Paso** was the first company to use all three of its proprietary CleanSuite™ production enhancement technologies for both hydraulic fracturing and water treatment. **Frac Tech** reports its "Slickwater Green Customizable Powder Blend" additive has been "designed using principles of green chemistry" that result in no leftover chemicals, and that its powder form can reduce risks of liquid chemical spills. As for proprietary fracking fluid, companies could add a chemical tracer that would enable the source to be identified should contamination occur.

Public concerns about possible water contamination have been exacerbated by the lack of information on specific chemicals in the fracking fluids. While the industry is moving toward more disclosure, a significant debate continues over the level of reporting required by government regulation. Three points of contention concern 1) the determination of hazardous chemicals, 2) trade secret exemptions and 3) ease of public access to data.

Reporting requirements and proprietary exclusions: At present, each company must produce a Material Safety Data Sheet (MSDS) developed for workers and first responders that describes additives used in fracture stimulation at each well location. At issue is that the MSDS only reports chemicals deemed to be hazardous in an occupational setting under standards adopted by the U.S. Occupational Safety and Health Administration (OSHA). MSDS reporting does not include other chemicals that might be hazardous if human exposure occurs through environmental pathways, such as bioaccumulation in the food chain if a chemical is spilled into a waterway. Several states now require companies to provide a listing of all non-proprietary chemicals in fracking fluid, not just those deemed hazardous by OSHA.

As for trade secret exemptions, many companies (generally service providers to gas companies) consider portions of their drilling fluid formulas, including the composition and concentrations, to be proprietary information. They include only a trade name, and not individual chemicals, on the MSDS. OSHA governs standards for what is considered a trade secret, although some states make the final determination while other states allow companies to make that determination themselves. While a company may withhold a specific chemical identity from the MSDS, OSHA standards require the company to disclose the hazardous chemical's properties and effects. OSHA standards also provide for the specific chemical identity to be made available to health professionals, employees and designated representatives under certain circumstances.

Public disclosure: While there are no federal requirements for public disclosure of chemicals in fracking fluids, voluntary and state-mandated disclosure is on the rise. Companies and state regulators are concluding that the high level of public concern warrants easy access to data, although all states allow trade secret exemptions.

FracFocus.org has become the premier source for voluntary information on fracking fluids, and some state and company websites also provide information. **Range Resources, Halliburton, EQT** and **Chief Oil & Gas** were among the first to post information on their fracking fluids beginning in 2010. Not all companies are on board, however. **Carrizo Oil & Gas** noted in its 2010 10-K that proposed "legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers." **Cabot Oil & Gas** included a similar statement in its 2010 10-K.

FracFocus—FracFocus is a U.S. hydraulic fracturing chemical registry website that is jointly operated by the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission. Participating companies, numbering 80 as of November 2011, voluntarily report chemicals in wells hydraulically fractured since January 1, 2011, or the date they registered. Users may run a query by state, county, operator and/or well name for a specific well to generate a report that lists the trade name, supplier, purpose, chemical ingredients, Chemical Abstract Service Number (CAS#), and maximum percentage of ingredients in the mix, when available. The report also includes the fracture date and sometimes the well depth and water volume used. Initially, FracFocus posted only the chemicals that appear on a Material Safety Data Sheet, but in September 2011 the GWPC announced that FracFocus would provide for the reporting of all chemicals added to the fracking fluid, except for proprietary chemicals.

Limitations—While the FracFocus website is a significant step forward in public disclosure for nearby property owners, as currently constructed it is of limited value to investors. The chemical information does not reside in an accessible database that can be queried or in a spreadsheet format, which makes it impractical to aggregate data by company or to identify which companies use a particular chemical. Colorado adopted a public disclosure rule in December 2011 that requires the Colorado Oil and Gas Conservation Commission to build its own searchable database if FracFocus hasn't taken steps to make its data searchable by 2013. Also, FracFocus does not have a singular interpretation of what is considered proprietary, as it follows each state's lead on this issue and state interpretations vary.

State requirements: Eight states—Arkansas, Colorado, Louisiana, Michigan, Montana, Pennsylvania, Texas and Wyoming—require public disclosure of hydraulic fracturing chemicals to varying degrees. Wyoming was the first state to require disclosure; it passed regulations requiring disclosure of chemicals injected underground on a well-by-well basis in 2010. Colorado has the most recent and comprehensive law that calls for drillers to disclose not only all non-proprietary chemicals in hydraulic fracturing but also their concentrations. Drillers must also disclose the chemical family of any proprietary chemical and its concentration. Additional states, including Wyoming, Arkansas and Texas, require disclosure of all non-proprietary chemicals (but not concentrations), while others require disclosure only of chemicals on the MSDS. The table below provides further information on state requirements and methods.

State Chemical Disclosure Requirements and Methods

	AR	CO	LA	MI	MT	PA	TX	WY
Requires disclosure of all non-proprietary chemicals	X	X					X	X
State determines which chemicals are proprietary	X	X						X
Company determines which chemicals are proprietary			X	X	X	X	X	
State requires chemicals to be posted on FracFocus		X	X		X*		X*	
State posts chemicals on own website	X		X	X		**		X

*Montana requires companies to post chemicals on FracFocus or provide it to the Montana Oil and Gas Board.
**Pennsylvania requires companies to disclose non-proprietary chemicals to its Department of Environmental Protection, but does not post the data online. Access to the data requires filing a request under the Right-to-Know process.

drinking water contamination incidents, below.) Typically, the methane is from shallower, usually non-commercial, formations through which the well was drilled and not from the shale formation. Methane is not toxic if ingested, but can be explosive if it accumulates. Well casings near the top of the vertical portion of wells pass through ground water aquifers. To prevent the release of gas and well fluids into aquifers, steel pipe, known as surface casing, is cemented into place as a routine part of well construction. The depth of the casing typically is determined by site-specific conditions and state regulatory requirements.

Mitigation and innovation: The American Petroleum Institute has highlighted industry best practices in its *Well Construction and Integrity Guidelines for Hydraulic Fracturing Operations*. In addition, **Southwestern Energy** has been working with the Environmental Defense Fund (EDF) on a set of model standards for safe drilling. The project partners sent a draft to a number of state regulators in September 2011 and note that the model rules go further than most U.S. state regulations now in place. Specific measures that can be taken to assure the integrity of cement jobs and overall well integrity include pressure testing and cement bond logs, which measure the quality of the cement bond or seal between the casing and the formation. Other measures to address a concerned public include conducting baseline testing of nearby water wells and sharing results with well owners prior to gas development, as well as adding an easily identifiable chemical tracer to hydraulic fracturing fluids.

Box 7: High-Profile Violations

Debate continues over the efficacy of drilling and fracking regulations in part because of well-publicized violations in the shale gas industry.

- In December 2010, **Cabot Oil & Gas** agreed to pay $4.1 million to 19 families in Dimock, Pa., affected by methane contamination attributed to faulty shale gas wells. The company maintains that the methane in Dimock water supplies occurs naturally and is not a result of its gas drilling activities. However, the company also agreed to offer to install whole-house gas mitigation devices and pay the state $500,000. Previously, state regulators had halted Cabot from drilling in the Dimock area in April 2010 and also temporarily suspended review of Cabot's pending permit applications statewide. Although the state resumed review of Cabot's permits outside Dimock and recently granted Cabot's request to stop water delivery to the families in November 2011, no decision has been made on resumed drilling in Dimock. In addition, not all families accepted the 2010 agreement, and litigation is ongoing. The families say they have suffered neurologic, gastrointestinal and dermatologic symptoms from exposure to tainted water.

  In 2009, Pennsylvania ordered Cabot to suspend fracking operations for nine days following three spills of thousands of gallons of fracking fluids by contractors **Baker Tank** and **Halliburton**. The state subsequently fined Cabot $180,000 for spills throughout the state in 2009.

- In May 2011, Pennsylvania officials fined **Chesapeake Energy** $900,000—the single largest state fine ever levied on an oil or gas operator—for contaminating the water supplies of 16 families in Bradford County and $188,000 for a tank fire at a drilling site. The state attributed the contamination to improper casing and cementing of wells.

  A month earlier, thousands of gallons of fracking fluids leaked from a well owned by Chesapeake Energy near Canton in Bradford County, Pa. For two days, the fluids spilled across farm fields and entered a tributary of a creek, and seven nearby families were temporarily relocated. The company voluntarily suspended hydraulic fracturing operations for three weeks.

- In July 2010, state regulators fined **EOG Resources** and its contractor, **C.C. Forbes**, $400,000 and issued a 40-day suspension of their operations in Pennsylvania following a well blow-out at a drilling site in Clearfield County, Pa. The state determined that the companies used untrained personnel, failed to use proper well control procedures and failed to promptly notify officials. Fracking fluid and gas shot 75 feet into the air for 16 hours.

Box 8: Earthquakes

Seismic activity has been tied to shale gas development, although it generally has been linked to underground wells used to dispose of wastewater, rather than the fracking process itself, and is unusual. Regulations for disposal wells have focused on protecting aquifers, not preventing seismic activity. Yet because fluid injection has the potential to change the prevailing stress regime underground, it has the potential to set off minor seismic events. Seismologists at Southern Methodist University in Dallas said a wastewater injection well was a plausible cause of numerous small earthquakes in Texas in 2008 and 2009. In December 2010, the Arkansas Oil and Gas Commission imposed a moratorium on new wastewater disposal wells in an area that had begun experiencing thousands of earthquakes, nearly all too small to be felt. In March 2011, the commission asked **Chesapeake Energy** and **Clarita** to shut down wastewater disposal wells close to a fault after Arkansas experienced its largest earthquake (magnitude 4.7) in 35 years. The Commission also placed a moratorium on new disposal wells in a 1,100 square mile area. In Ohio, where companies dispose of shale gas wastewater from Ohio and neighboring Pennsylvania, officials shut down a disposal well in January 2012 and put another four slated to open on hold after 11 earthquakes, including a 4.0-magnitude earthquake, occurred near Youngstown over eight months.

In the United Kingdom, a November 2011 report by U.K. energy company **Cuadrilla Resources** found "strong evidence" that two minor earthquakes and 48 weaker seismic events resulted from hydraulic fracking operations. The company noted, however, that the events were the result of a "rare combination of geological factors." The company and the government reached an agreement in June 2011 to suspend shale gas test drilling until its consequences were better understood.

Mitigation and innovation: Measures include evaluation of the rock formations below and overlying the well bottom before drilling commences; periodic measurements of earth stresses and microseismic monitoring with public disclosure of results; and limiting pressure and volumes of fluid injected down a well.

Wastewater Management and Disposal

Laws forbid operators from directly discharging wastewater from shale gas extraction to waterways. The two options primarily used today to manage wastewater are underground disposal wells and recycling. Lesser used options include wastewater treatment prior to discharge in public waterways and evaporation in open storage ponds

General preventive measures to help ensure against contamination from wastewater include the use of secondary containments, mats, catchments and ground water monitors, as well as the establishment of buffers around surface waters. Many gas producing states have had manifest systems in place for decades to track waste, including wastewater, if moved offsite from a natural gas drilling operation. SEAB (the Shale Gas Production Subcommittee of the Secretary of Energy Advisory Board) has called for states to manifest all transfers of water among different locations, including measuring and recording data from flowback operations.

Underground disposal wells: In many states, operators inject wastewater into underground geologic formations for permanent disposal. This can be the lowest cost option, but the option is region-specific. In Texas's Barnett Shale, wastewater can be reinjected into permeable rock more than a mile underground. Injection is not feasible in much of the Marcellus Shale region, however, because operators have not identified any formation with sufficient porosity and permeability to accept large quantities of wastewater. Underground disposal also has recently been linked to small earthquakes. Although available data is insufficient to conclusively make a connection, state regulators have asked companies to discontinue use of specific wastewater disposal wells. *(See Box 8: Earthquakes, above.)*

Water impoundments in the Marcellus Shale. Source: www.marcellus-shale.us

Evaporation pits and/or containment pits: Some companies use pits, ponds or holding tanks to store wastewater or drilling mud and cuttings before they are disposed of or reused. (Pits also are used to store freshwater for drilling and fracking.) In some instances, operators dig drilling waste pits and then bury them. In arid regions companies use open pits and tanks to evaporate liquid from the solid pollutants. Full evaporation ultimately leaves precipitated solids that must be disposed in a landfill. These solids are regulated under Resource Conservation and Recovery Act (RCRA) subtitle D and classified as nonhazardous waste, although as noted earlier the NRDC has petitioned the EPA to regulate them as a hazardous waste. The waste typically goes to industrial landfills that test it prior to accepting it. States usually require pits to be built to specifications that include ground compaction, multiple, heavy wall liners, monitoring methods to detect leakage and stormwater control measures. In fall 2011, some wastewater ponds in Pennsylvania overflowed as a result of Tropical Storm Lee. Environmentalists also are concerned that evaporative pits may allow air emissions of volatile organic compounds and other pollutants. In addition, birds and wildlife, and sometimes domesticated animals like cattle, mistake these pits for freshwater sources.

Mitigation and innovation—Companies increasingly are replacing open pits with closed-loop fluid systems that keep fluids within a series of pipes and watertight tanks inside secondary containment. (Operators also are increasingly using closed-loop systems for drilling waste and related fluids.) Some states, such as New York, are proposing to ban open containment. Additional measures include establishing setback requirements for open pits, measuring the composition of wastewater stored in evaporative ponds for appropriate disposal or treatment since contaminants and radioactivity can become more concentrated as water evaporates, and placing a fence around open pits to keep them off limits to animals.

Recycling: The opportunities for recycling wastewater differ substantially among the various shale plays. In the Eagle Ford Shale area in Texas, very little, if any, water is returned from the well after hydraulic fracturing. In contrast, from 20 to 50 percent of the fracturing fluid is produced as flowback water in the Marcellus Shale, where disposal options are limited. As a result, producers in Pennsylvania's

Marcellus Shale reuse on average nearly 60 percent of their recovered water in new fracking jobs, and this percentage is expected to increase, according to the Marcellus Shale Coalition's website. Range Resources reports saving $200,000 at each well by recycling 100 percent of its flowback water in its core operating area in southwestern Pennsylvania. Chesapeake Energy reports annual savings of $12 million from recycling wastewater in the Marcellus Shale. Typically, recycled wastewater is treated and then mixed with freshwater and chemical additives to the achieved desired characteristics for the fracking fluid.

Some companies, including ones in areas of high volume operations such as the Permian Basin of west Texas and southeast New Mexico, may recycle produced water from conventional wells and dispose of frack flowback, given that frack flowback can be more costly to treat for reuse. The availability of disposal wells and produced water will influence the level of frack fluid recycling. Disposal costs (including transport) in Texas are lower than disposal costs in Pennsylvania. Therefore, treatments to recycle fracking fluid make economic sense in Pennsylvania but not in Texas.

In addition to being a more costly option, recycling wastewater typically produces sludge that can contain a variety of chemicals, salts and radioactive materials and other contaminants. Companies must dispose of this material as a solid waste.

Mitigation and innovation—Companies can use a growing suite of onsite wastewater recycling technologies. **General Electric** unveiled a mobile evaporator in September 2010 that can be used on site to recycle wastewater, and **Siemens** offers a FracTreat™ mobile wastewater treatment system. In addition, **Integrated Water Technologies** developed the FracPure™ treatment process in January 2011 designed to treat 100 percent of flowback water to drinking water quality. **Ecosphere Technologies'** oxidation technology offers companies a chemical-free alternative to recycling high volumes of water, and **WaterTectonics** uses an electric coagulation treatment system to avoid the use of chemicals.

In another form of recycling, some operators are selling briny wastewater to communities to spread on roads both for de-icing in the winter and dust suppression in the summer. Environmentalists question whether contaminants are in the wastewater, but states like West Virginia and Pennsylvania and industry sources do not believe these concerns are warranted.

Wastewater treatment: In October 2011, some well operators in Pennsylvania, Colorado and Oklahoma were sending shale gas wastewater off-site for treatment prior to both surface discharge and reuse, according to an EPA press release (elucidated by Si2 communication with the EPA). Treatment of shale gas wastewater became an issue in 2011 in Pennsylvania, which has limited wastewater disposal options. Companies were sending wastewater to municipal wastewater treatment plants, which treated the water and then discharged it into rivers that supply drinking water to Pittsburgh, Harrisburg, Baltimore and Philadelphia. Media reports, most prominently a series of articles in *The New York Times*, raised concerns that these publicly operated plants were neither designed nor capable of removing drilling waste contaminants. In March 2011, the EPA sent a letter to environmental officials in Pennsylvania noting data that indicated "variable and sometimes high concentrations of materials that may present a threat to human health and aquatic environment, including radionuclides, organic chemicals, metals and total dissolved solids" and urged the state to increase monitoring, especially for radionuclides. In April, concerns about elevated levels of bromide, a salt, in state waterways led Pennsylvania regulators to request that companies stop sending wastewater to municipal treatment plants that may not be equipped to treat it. Companies operating in the Marcellus Shale discontinued this practice within two days of the state's request, according to the Marcellus Shale Coalition.

Mitigation and innovation—Currently, a small number of municipal and commercial facilities in Pennsylvania have been approved to treat shale gas wastewater for recycling, according to the Marcellus Shale Coalition. More plants, purpose-built for the task by private industry, are planned. In October

2011, the EPA announced plans to develop national pretreatment standards. Shale gas wastewater would have to meet those standards before going to a treatment facility and being discharged into surface waters. Current thinking is that the standards would be applicable beginning in 2015. *(See the section on Federal Regulation for more, pp. 32-34).*

Chemical and fuel spills

The potential for spills exists when companies transport, store and mix chemicals into the fracking fluid or when they transport, store or use fuel on-site. Chemicals generally are stored in tanks at the drilling site before use.

Mitigation and innovation: The greatest reduction in this risk would result from all chemical additives being nontoxic and nonhazardous. Worker training and contractor training and management also are important factors in reducing spills and detecting leaks. Additional measures include use of dry chemical additives, secondary containment structures for all fracturing additive containers and staging areas and collision-proof totes.

Fissures

Because shale gas formations typically are separated from the freshwater table by several thousand feet of impermeable rock, fissures in the shale formation created in a well-designed fracturing process are highly unlikely sources of contamination of either fracking chemicals or methane. However, such contamination is not impossible, particularly in less typical geologic formations. In December 2011 the EPA released preliminary findings that link chemicals in Pavillion, Wyoming's drinking water to hydraulic fracturing, although the situation differs from most shale gas development underway today. The wells in question are shallow vertical wells drilled only about 1,220 feet into sandstone in close proximity to drinking water wells. Another complicating factor is old wells drilled 40 years ago that may be allowing seepage into the water supply. The stock of **Encana**, which drilled the wells, dropped more than 6 percent in response to the EPA's findings.

Mitigation and innovation: In general, mitigation involves avoiding areas susceptible to such fissure-related contamination. Measures to do so include evaluation of stratigraphic confinement before drilling the well; designing the hydraulic fracturing treatment with sophisticated computer modeling software; and using technologies like periodic microseismic surveys to confirm the accuracy of the hydraulic fracturing design and that hydraulic fracture growth is limited to gas producing formations. Companies also conduct area reviews to identify manmade features, such as abandoned gas or water wells, which could serve as conduits for gas.

Air Quality

Shale gas development can result in numerous air emissions, including volatile organic compounds (VOCs); air toxics, such as benzene, ethyl benzene, and n-hexane; and methane, the primary constituent of natural gas. (Methane is a greenhouse gas more than 20 times more potent than carbon dioxide, according to the EPA.) VOCs contribute to the formation of ozone or smog, which is linked to a wide range of health effects, including aggravated asthma, increased emergency room visits and hospital admissions, and premature death. Air toxics are known, or suspected, to cause cancer and other serious health effects.

The EPA estimates that the oil and natural gas industry is the largest industrial source of VOC emissions and that oil and natural gas production and processing accounts for nearly 40 percent of all U.S. methane emissions, making the industry the nation's single largest methane source. The accuracy of the EPA's estimates is the subject of much debate among federal and state regulators, certain environmental groups and the natural gas industry. *(See the section below on Mitigation and Innovation, p. 30, and the section on Greenhouse Gas Emission Estimates for more on this issue, pp. 39-41.)*

Well completions: Some of the largest air emissions in shale gas development can occur as fractured wells are being prepared for production. During a stage of well completion that generally lasts from three to 10 days, fracturing fluids, water from the shale formation and gas come to the surface at high velocity and volume. This mixture can include a high volume of VOCs and methane, along with air toxics. Because the gas/liquid separator used for normal well flow is not designed for these high liquid flow rates and three-phase (gas, liquid and solid) flow, a common practice has been to separate the gas from the fluids and flare (burn) the gas. Flaring gas eliminates most methane, VOC and hazardous air pollutants, but flaring also releases carbon dioxide and other pollutants to the atmosphere. In some situations, operators simply vent the gas, which results in methane emissions. Methane venting is still done in exploration wells when no pipeline connection is in place, but it is rarely done in development wells. Increasingly, companies are using reduced emissions completions (RECs), also known as "reduced flaring completions" or "green completions." In these cases, companies bring portable equipment on-site to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas and heavier hydrocarbons that then can be treated and sold.

Wet gas, which can come up with oil and contains less methane and more liquid hydrocarbons, can pose a larger air toxics problem than the dry gas being extracted from the shale gas formations that are the focus of this report. The U.S. Energy Information Administration reported that more than one-third of North Dakota's 2011 natural gas production, primarily in the Bakken Shale oil play, was flared or otherwise not brought to market because of insufficient natural gas pipeline capacity and processing facilities.

Additional sources: Other processes and equipment also can emit VOCs, methane and/or air toxics. These include field compressors and compressor stations, which move gas along the pipeline; pneumatic controllers, which are automated instruments used at wells, gas processing plants and compressor stations to maintain conditions such as liquid level, pressure or temperature; storage tanks and pits; natural gas processing plants; and leaks in the pipelines. In addition, drilling is an energy-intensive business; diesel engines and generators provide power to the drilling rigs and other onsite equipment that run around the clock. Diesel also fuels the numerous heavy trucks carrying freshwater, chemicals, wastewater and equipment to and from the site.

Local effects: Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region as well, according to SEAB, a board advising the Secretary of Energy on shale gas production. Emissions are an issue in the Dallas-Fort Worth area of Texas, which sits on the Barnett Shale. In December 2011, the EPA added Wise and Hood Counties to the Dallas-Fort Worth nonattainment area for failing to meet federal ozone standards. The EPA attributed a high growth of emissions in Wise County "in large part to growth in emissions from Barnett Shale gas production development, but also due to growth in population." The EPA also attributed the growth in Hood County's emissions to oil and gas development.

Also in December 2011, the EPA notified Wyoming that it supports the state's 2009 recommendation to designate the Upper Green River Basin in southwest Wyoming as an ozone nonattainment area. In 2009, the Green River Basin's Sublette County, a sparsely populated county with two of the nation's top producing natural gas fields, failed to meet federal standards for air quality. In spring 2011, ozone levels registered higher than any recorded in the prior year in Los Angeles. Air emissions from gas operations contribute to ozone creation, which is brought on by a combination of Sublette County's bright sunshine, snow on the ground and temperature inversions during winter months.

Mitigation and innovation—For the first time, the EPA has proposed air regulations for new wells that are hydraulically fractured as well as for additional oil and gas facilities. *(See the section on Federal Regulation, p. 32.)* If fully implemented, the EPA estimates that its regulations would produce an industry-wide 25 percent reduction in VOCs, a 26 percent reduction in methane, and a nearly 30 percent reduction in air toxics. A key feature of the EPA's proposal is use of reduced emissions completions (RECs) noted above. The EPA estimates that use of RECs reduces VOC emissions from completions of hydraulically fractured wells by 95 percent, and that methane emissions also would be significantly reduced. Some states, such as Wyoming and Colorado, require green completions in certain circumstances. A number of companies, including **Devon Energy** and **WPX Energy**, (formerly **Williams Cos.)**, are voluntarily using this process through the EPA's Natural Gas STAR program.

The EPA further estimates that the industry can recover its costs in about 60 days for RECs, and within about one year for other emission reduction equipment. Industry takes issue with the EPA's estimates, arguing that (among other issues) the agency has overestimated emission rates, underestimated current use of the RECs and underestimated the full cost of RECs, including manpower and equipment costs. The American Petroleum Institute, for instance, estimates that the average cost per ton of VOCs without associated sales from the flowback is $33,748, versus the EPA's estimate of $1,516; the average cost per ton of VOCs with sales is $27,579, versus the EPA's net gain of $99; and the overall cost to the industry for doing RECs in 2015 would be $782.6 million versus the EPA's benefit estimate of $20.2 million. Because companies have not been reporting data on fugitive emissions, it is difficult to assess actual emission rates and how widely RECs are used. Initiatives are underway to fill this void, however. In response to EPA's proposed air regulations, industry is gathering industry-wide air emissions data and plans to release a report in the near future. New greenhouse gas reporting rules also should start producing relevant data in 2012. *(See the section on Federal Regulation, p. 32.)* To date, companies have had little economic incentive to capture methane emissions. California is the only state planning to place a price on greenhouse gas emissions, and no national cap-and-trade program is on the horizon.

Other measures companies can take to reduce air emissions are minimizing truck traffic; installing low-bleed and no-bleed pneumatic devices; stepping up leak detection, including the use of infrared technology; implementing repair programs that aggressively seal condensers, pipelines and wellheads; installing vapor recovery units on storage tanks; and reducing the use of diesel engines for surface power and replacing them with natural gas engines or electricity, where available.

II. Regulatory Oversight

Federal, state and local laws affect each step of the drilling and fracking process. Regulations and related policies are changing as the fracking process comes under increased scrutiny by legislative bodies, federal and state environmental agencies, industry, environmental organizations, the media and the general public. The federal government has exerted limited oversight of oil and gas development, including shale gas development, with most authority to regulate these operations vested in state oil and gas regulatory programs. *The New York Times* notes that parts of at least seven of 15 federal environmental laws that regulate most other heavy industries do not have authority over natural gas drilling. Recently, however, the federal government has announced several proposals to increase its oversight of shale gas-related activities. At the same time, the federal government and individual states are all struggling with budget deficits, making it extremely difficult to fund current oversight and enforcement activities, let alone keep pace with burgeoning gas development. In addition, even when regulators find violations, the resulting financial penalties often are too small to act as an economic deterrent.

Regulation at what level? Ongoing debate exists over whether the states or the federal government should be taking the lead in overseeing shale gas operations. Those in favor of state-led oversight argue that state authorities are better positioned to account for issues concerning unique geological and hydrological characteristics and other local factors that vary significantly throughout the country. State regulators also typically have on-site experience with fracturing sites in their area. In 2009, the Groundwater Protection Council surveyed the regulatory frameworks of 27 states, representing nearly all U.S. oil and natural gas production, and concluded that “state oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements, such as permitting, waste handling, well construction, well plugging, and temporary abandonment requirements.” Supporters of state-led oversight also say that state regulators can respond more quickly to changing developments and point out that there are many examples where a state already has implemented recommendations of SEAB, a board advising the Secretary of Energy on shale gas production.

Others, including environmental groups, would like more natural gas activities to be regulated under federal law. They would like to see more uniformity in government standards and question whether states are up to the task of regulating such a rapidly growing industry. They point out that state regulation is uneven and, in some instances, weak. Moreover, depending on whether the impacts focus on air, water or land, the stringency of regulations can vary within a state. Some also argue that states dependent on the oil and gas industry as an anchor of their economy may be reluctant to impose more stringent rules on the industry.

State Regulations

Despite the debate, it seems likely states will continue to take the regulatory lead over shale gas development given the current political climate. Shale gas development continues to spread, drawing new states into the mix. In October 2011, the Groundwater Protection Council counted 32 gas-producing states. Most states experiencing the shale boom either are reviewing or revising their regulations and permitting requirements. Many also are raising permit fees and considering enacting or raising impact fees or taxes to generate revenue to fund additional oversight positions at environmental agencies.

Several nonprofit organizations are working to strengthen state regulations. The State Review of Oil and Natural Gas Environmental Regulations (STRONGER) assists states in documenting environmental regulations associated with natural gas exploration, development and production. STRONGER posts completed state reviews on its website. It also developed hydraulic fracturing guidelines in February 2010 that outline the key elements of effective state oil and gas environmental regulatory programs and establish environmental goals or objectives for those programs. The guidelines do not establish specific numerical criteria or prescriptive regulatory standards for states, given that the "states vary too much in climate, geology, hydrology, topography, and other factors to be amenable to one-size-fits-all regulation." Additional working groups include the Interstate Oil and Gas Compact Commission (IOGCC) and the Groundwater Protection Council, which in addition to overseeing the FracFocus disclosure website has developed a *Risk Based Data Management System* that helps states collect and publicly share data associated with their oil and gas regulatory programs.

Evaluation of state regulations by investors is no easy task. Some 32 states have distinct regulatory frameworks, and authority for regulating shale-related gas development activities, such as drilling permits, wastewater disposal and air emissions, typically is drawn from several different statutes and regulations within each state. Responsibilities often lie with more than one state agency. Oklahoma is attempting to collate its regulations for hydraulic fracturing activities into one source, but is unique in this endeavor.

Proposed Federal Regulation

Following are proposals and new rules to exert additional federal authority through laws or regulations relating to shale gas development. (*Initiatives by the Obama Administration are describe in Box 10, p. 35.)*

EPA's Proposed Air Regulations

In July 2011, the Environmental Protection Agency (EPA) proposed the first federal air standards for new wells that are hydraulically fractured, existing wells that are fractured or refractured and additional oil and gas facilities, such as compressors, pneumatic controllers and storage vessels. Up to now, the EPA has only promulgated New Source Performance Standards for natural gas processing plants. The EPA says its proposal is based on proven technology and best practices that the oil and gas industry is using in some states today. The proposal, slated for release in a final rule in April 2012, includes four air regulations for the oil and natural gas industry:

1) a new source performance standard for VOCs;
2) a new source performance standard for sulfur dioxide;
3) an air toxics standard for oil and natural gas production; and
4) an air toxics standard for natural gas transmission and storage.

As noted earlier, industry strongly disputes the EPA's emissions estimates and emission reduction costs. Conversely, a coalition of 13 environmental groups says a major limitation is that the proposal does not address many existing sources, such as conventional gas or oil wells, even though existing sources are responsible for the lion's share of emissions. These environmental groups also say the EPA has failed to directly regulate additional pollutants emitted by the industry, including methane, particulate matter, hydrogen sulfides and nitrogen oxides. (The EPA estimates methane will be reduced as a collateral benefit of regulating VOCs.) SEAB also stressed the need for the EPA to directly control methane emissions and for the new rules to encompass existing sources.

GHG reporting rules: In a related development, gas companies will begin reporting additional greenhouse gas (GHG) emissions data to the EPA by September 2012. In November 2010, the EPA finalized reporting requirements for the oil and natural gas industry under its Greenhouse Gas Reporting Program. The 2010 ruling expanded the scope of existing reporting requirements to include fugitive and vented greenhouse gas emissions beginning in January 2011. As a result, for the first time under the

Clean Air Act, thousands of small facilities will have to be counted in the pollution reporting inventory. This final rule requires petroleum and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide (CO_2) equivalent per year to report annual methane (CH_4) and CO_2 emissions from equipment leaks and venting, and emissions of CO_2, CH_4, and nitrous oxide (N_2O) from gas flaring and onshore petroleum and natural gas production combustion emissions, as well as from combustion emissions from stationary equipment involved in natural gas distribution.

Because most producers do not normally track the information the EPA requires for this rule, the EPA is allowing operators to use "Best Available Monitoring Methods (BAMM)" for 2011 data. BAMM include supplier data, monitoring methods currently used by the facility that do not meet the relevant parts of the EPA's rule, engineering calculations, and/or other company records. To continue to use BAMM for 2012 data and beyond, however, operators must submit extension requests to the EPA. Environmental groups see substantial verification problems with BAMM.

Safe Drinking Water Act (SDWA)

This act regulates the process for disposing of wastewater, or flowback, in underground geologic formations known as disposal wells. The SDWA does not have authority to regulate hydraulic fracturing, however, including pumping fracking fluids into a natural gas well, except if they contain diesel. Underground injection of flowback for disposal is regulated either through the EPA's Underground Injection Control (UIC) program or by a state granted primary UIC enforcement authority by the EPA.

Proposed diesel guidance: The EPA has authority to regulate fracturing when diesel is used and for the first time is developing permitting guidance for oil and gas hydraulic fracturing activities that use diesel fuels in fracking fluids. The EPA held a public comment period in fall 2011 and is expected to issue a final guidance in early 2012. The EPA then will have to develop implementation rules in states, such as Pennsylvania and New York, where it implements the UIC program. The 33 states that have primary enforcement authority for the UIC injection program also will have to develop their own rules to implement the EPA guidance. As a result, implementation could easily take until late 2012. A key issue is how broadly the EPA will define diesel. Drillers are concerned it will include the chemical constituents that make up diesel and therefore capture a wide array of petroleum-based solvents used in fracturing.

Some companies have used diesel fuel in hydraulic fracturing fluids as a solvent and dispersant, although the number is in decline. Cost-effective substitutes are available, but diesel is convenient to use in the field because it is already present for use as fuel for generators and compressors. In 2003, major operators involved in coal bed methane development signed a memorandum of agreement with the EPA agreeing to eliminate diesel fuel when conducting hydraulic fracturing operations near underground sources of drinking water.

Proposed FRAC Act: In March 2011, U.S. Sen. Robert Casey (D-Pa.) reintroduced the Fracturing Responsibility and Awareness of Chemicals Act (S. 587/H.R. 1084), or FRAC Act, which would expand the EPA's authority under the Safe Drinking Water Act to regulate the underground injection of fracturing fluids. In addition, the bill would require companies to publicly disclose chemicals in their fracking fluids, including identification of the chemical constituents of mixtures, Chemical Abstracts Service numbers for each chemical and constituent, material safety data sheets when available, and the anticipated volume of each chemical to be used. A Senate subcommittee of the Committee on Environment and Public Works held hearings on the bill in April 2011.

Clean Water Act (CWA)

The Clean Water Act establishes the National Pollutant Discharge Elimination System (NPDES) permit program; it controls water pollution by regulating point sources that discharge pollutants into the nation's waters. In most cases, the NPDES permit program is administered by authorized states. The EPA has jurisdiction over stormwater discharges from construction activities at oil and gas exploration and production operations only if the stormwater runoff is contaminated with oil, grease or hazardous substances.

Proposed standards*:* In October 2011, the EPA announced its intent to solicit comments in 2014 on natural gas wastewater standards it plans to develop for shale gas and coal bed wastewater before it goes to a treatment facility. Noting that it reviewed data that documented "elevated levels of pollutants entering surface waters as a result of inadequate treatment at facilities," the EPA is concerned that "some shale gas wastewater is transported to treatment plants, many of which are not properly equipped to treat this type of wastewater."

Department of Interior

The U.S. Department of the Interior announced in October 2011 that it will issue rules on hydraulic fracturing on public lands, particularly well integrity standards and disclosure requirements for fracking fluids.

Box 9: Upcoming Reports, Legislation and Decisions to Watch

Environmental Protection Agency:

- A two-year EPA study to assess the impacts of hydraulic fracturing on drinking water and ground water. Initial research results will be available in fall 2012 and the full report is planned for release in 2014.
- New air regulations slated for completion in April 2012.
- Proposed hydraulic fracturing wastewater regulations scheduled to be announced in 2014.
- Final permitting guidance for the use of diesel in fracking fluids expected in early 2012.

State/regional developments:

- The public comment period on New York State Department of Environmental Conservation's (DEC) revised draft Supplemental Generic Environmental Impact Statement (SGEIS) ended Jan. 12, 2012. Drilling permits for high volume hydraulically fractured wells have been deferred since December 2010 until the final SGEIS's completion.
- New York State attorney general's office could release of information acquired through subpoenas sent to oil and gas companies in 2011 seeking disclosures on well productivity and risks of hydraulic fracturing.
- The Delaware River Basin Commission's (DRBC) first rules regulating natural gas drilling will be considered at a special meeting, but no date has been set. In November 2011, the DRBC canceled its third attempt to vote on the proposed rules. Approval would mean lifting a de facto drilling moratorium in the Delaware River Watershed that has been in place since May 2010.
- The Maryland Department of Environment will complete a two-year review in 2013. Drilling permits have been deferred until its completion.
- New Jersey's one-year moratorium on fracking operations ends in August 2012.

SEC investigations: The SEC could release information acquired through subpoenas or comment letters sent to natural gas companies in 2011.

FRAC Act: Sen. Robert Casey (D-Pa.) introduced the Fracturing Responsibility and Awareness of Chemicals Act (S. 587/H.R. 1084), known as the FRAC Act, in March 2011. The act would expand EPA's authority to regulate the underground injection of fracturing fluids and require public disclosure of fracking fluid chemicals. The bill is sitting in subcommittees of the Senate Environment and Public Works Committee and the House Energy and Commerce Committee. No further action is scheduled as of February 2012.

Box 10: Obama Administration Actions

The Obama administration has spearheaded three research efforts related to shale gas development:

Shale Gas Production Subcommittee: President Obama's "Blueprint for a Secure Energy Future," issued in March 2011, presented a two-fold charge to U.S. Energy Secretary Steven Chu with respect to fracking. The first was to issue an interim report identifying immediate steps that could be taken to improve the safety and environmental performance of fracking. The second was to develop consensus recommended advice to federal and state agencies on practices for shale extraction to ensure the protection of public health and the environment. Accordingly, a Shale Gas Production Subcommittee of the Secretary of Energy Advisory Board (SEAB) issued an interim report in August 2011 and a final report in November 2011. John Deutch, an institute professor at the Massachusetts Institute of Technology and a former director of the Central Intelligence Agency and deputy defense secretary led the seven-member subcommittee.

Both the interim and final report call for greater regulatory oversight and for the industry to provide more data on overall operations. The interim report included 20 recommendations with the objective of continuous improvement in reducing the environmental impact of shale gas production, while the final report focused on the recommendations' implementation. The final report noted that progress in implementing its recommended measures "is less than the Subcommittee hoped" and cautioned that "whether its approach is followed or not, some concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production and the consequent risk of public opposition to its continuation and expansion."

The reports call for, among other things, the assessment of baseline water quality conditions before drilling starts, disclosure of the composition of drilling wastewater and measurement of air emissions, especially methane, associated with the drilling process. The reports also recommend stronger standards for well construction and wastewater management and call for the creation of a national database of public information on shale gas operations. The reports also urge the natural gas industry to help create a national organization, with external stakeholders, that is dedicated to continuous improvement of best practices for extracting shale gas.

EPA study: In March 2010, the EPA announced that it would undertake a comprehensive two-year study to assess the impacts of hydraulic fracturing on drinking water and ground water at the request of the U.S. House of Representatives Appropriations Conference Committee and the White House. Initial research results will be available in fall 2012 and the full report is planned for release in 2014. The EPA announced its final research plan in November 2011, following a series of public meetings across the nation and review by the Science Advisory Board, an independent panel of scientists. The final study plan looks at the full cycle of water in hydraulic fracturing, from the acquisition of the water, through the mixing of chemicals and actual fracturing, to the post-fracturing stage, including the management of flowback and produced or used water as well as its ultimate treatment and disposal. Earlier in 2011, the EPA announced its selection of locations for five retrospective and two prospective case studies. The five retrospective sites are in the Barnett Shale in Wise County, Tex.; the Marcellus Shale in Bradford and Susquehanna Counties, Pa., as well as Washington County, Pa.; the Bakken Oil Shale in Killdeer and Dunn Counties, N.D.; and the Raton Basin, Colo. The two prospective sites are in the Haynesville Shale in DeSoto Parish, La., and the Marcellus Shale in Washington County, Pa.

At present, the federal Safe Drinking Water Act does not directly oversee underground injection of fracking fluids or propping agents (other than diesel fuels) related to gas production. In 2004, the EPA released a study, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs: National Study Final Report,* that found "'the injection of hydraulic fracturing fluids into CBM [coalbed methane] wells poses minimal threats to USDWs [underground sources of drinking water].'"

Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources was developed by the National Petroleum Council (NPC) at the request of Secretary of Energy Dr. Stephen Chu. The September 2011 report suggests that "natural gas is a good near-term answer for reducing America's carbon footprint." It reviews the North American natural gas supply chain and infrastructure potential, the contribution of natural gas to a low-carbon energy portfolio, strategies to mitigate environmental impacts of increased production and the role of technology in developing reserves.

Box 11: Showcase of Three States

New York, Pennsylvania and West Virginia each have handled the surge in shale gas development differently.

New York: New York is in the midst of a *de facto* ban on high volume hydraulic fracturing for shale gas that began in December 2010. Former Governor David Patterson vetoed a six-month ban on hydraulic fracturing passed by the New York legislature, but instead issued an Executive Order that defers the issuance of any permits for high volume hydraulic fracturing operations until the completion of the New York State Department of Environmental Conservation's (DEC) Supplemental Generic Environmental Impact Statement (SGEIS). The DEC released a draft SGEIS on shale gas development in September 2009 and then a revised draft in September 2011, along with a supplemental analysis of community and socioeconomic impacts. A comment period extended through Jan. 12, 2012.

The DEC is proposing to allow hydrofracking on most private land but not on state land or inside New York City's upstate watershed or a watershed used by Syracuse—the only unfiltered supplies of municipal water in the state—and in primary aquifers. Other draft recommendations would not allow surface impoundments for flowback water and would require an additional string of cemented well casing (intermediate casing) to prevent the migration of natural gas, as well as a new permit process requiring strict stormwater control measures, a special permit to withdraw large volumes of water, tracking of drilling and production waste and full analysis and state and federal approvals before a water treatment facility could accept flowback water. Proposed buffers around New York's waterways are as much as 20 times larger than in neighboring Pennsylvania.

Pennsylvania: Pennsylvania has seen a dramatic rise in the number of shale gas wells drilled in the last few years. Companies have applied for more than 9,500 well permits in the Marcellus Shale since 2005, and more than 4,200 wells have been drilled. In contrast to New York, Pennsylvania never stopped drilling on private land, and a *de facto* ban on state land instituted by then-Governor Edward Rendell (D) in October 2010 was rescinded in February 2011 by newly-elected Governor Tom Corbett (R).

Governor Corbett also immediately began development of a Marcellus Shale Proposal, creating an advisory Commission that issued 96 recommendations in July 2011. In October 2011, Governor Corbett announced a plan to implement many of the recommendations, including changes to enhance environmental standards and a drilling impact fee. Environmentalists widely criticized the plan, saying the proposed impact fee is too low and the regulations fall well short of protecting the commonwealth's water and air resources. Pennsylvania is one of the only major drilling states not to impose an extraction tax on shale gas. Accepted recommendations also include increasing well set-back requirements, increasing well bonding amounts, doubling penalties for violations, and expanding the distance and duration of an unconventional gas operator's "presumed liability" for impairing water quality.

West Virginia: In December 2011, the West Virginia legislature passed a regulatory package to address horizontal drilling in the state's Marcellus Shale. The new law replaces an emergency rule that went into effect in August 2011 that allowed drilling to continue but added additional permitting and operational requirements in response to an executive order by Governor Earl Ray Tomblin (D). The new measures increase permit fees from around $400 to $10,000 for an initial well, and to $5,000 for each additional well at that site. New wells must be kept 250 feet from a water well, 300 feet from a natural trout stream, 625 feet from occupied houses and 1,000 feet from a public water supply intake. The new measure also includes prior notice provisions to both mineral and surface owners, and a new compensation statute for surface owners, in part to address issues that have arisen when surface owners do not own mineral rights beneath their land. *(See Box 4: Access Rights Can Lead to Conflict, p. 16.)* Environmental groups said the setback provisions are insufficient, while industry said the fees are too high.

The law affects well sites that disturb three acres or more or use more than 210,000 gallons of water during any one-month period. The legislation includes provisions for the West Virginia Department of Environmental Protection (WVDEP) to promulgate further rules in the near term regarding air quality and well cementing and casing issues. The measure also codifies water use and wastewater handling regulations in place. In January 2010, the WVDEP had issued a permit addendum requiring operators planning to use more than about 200,000 gallons of water to detail in advance their expected volumes, sources and disposal methods. In March 2010, the WVDEP also began requiring post-use reporting.

III. Key Accounting Issues

Reserve and Production Estimates

Natural gas reserves are central to assessing a gas company's value. The U.S. Securities and Exchange Commission (SEC) requires companies to report on proved reserves—the quantities of oil and natural gas companies estimate they can recover from known reservoirs under existing economic conditions, operating methods and government regulations. Drilling results, production and historical trends determine these amounts. At present, the Modernization of Oil and Gas Reporting rules released in December 2008 by the SEC govern the way companies should report their oil and gas reserves. In October 2009, the SEC's Division of Corporation Finance issued Compliance & Disclosure Interpretations to clarify the new rules. These rules require disclosing oil and gas proved reserves by significant geographic area when such reserves represent more than 15 percent of total proved reserves.

Forecasting reserves is an imperfect science that becomes even more imperfect when tapping a relatively new and unconventional resource that lacks historical data. The ultimate size of technically recoverable shale gas resources is uncertain, and estimates will change as additional information is gained through experience. Because most shale gas wells are only a few years old, their long-term productivity is untested. Production in emerging shale plays has concentrated on areas with the highest known production rates, and many shale plays are so large that most of the play has not been extensively tested. Production rates achieved to date may not be representative of future production rates across the formation. The Energy Information Agency (EIA) reports that experience to date shows production rates from neighboring shale gas wells can vary by as much as a factor of three, and that production rates for different wells in the same formation can vary by as much as a factor of 10. In comparison to conventional natural gas development, where unsuccessful exploration can turn up dry holes, the risk of not finding shale gas decreases, but the risk associated with well productivity goes up. Most gas companies estimate that production will drop sharply after the first few years but then level off, allowing most wells to produce gas for decades.

Natural gas prices also have significant implications for estimating accessible reserves, yet the price of gas has been notoriously unstable, as witnessed by the swing from $13 per million BTU in July 2008 to around $2.50 per million BTU in February 2012. In 2011 the EIA revised its methodology for determining natural gas prices to better reflect a decoupling of oil and natural gas prices, in part because of the increase in U.S. shale gas supply and improvements in natural gas extraction technologies. The regulatory environment, driven by environmental impacts, also can lead to increased costs or limits on productivity that affect future reserve estimates. On the positive side, technological developments and increased understanding of a shale's characteristics are likely to improve future production and bring down costs, as well as decrease uncertainty in estimates.

***The New York Times* reports:** In June 2011, *The New York Times* published several articles not only questioning government and corporate reserve estimates, but also whether corporations were knowingly overbooking their reserves. The paper claimed that interviews with employees and internal emails and documents indicated companies were purposefully slow to incorporate new productivity and cost data into their estimates. The *Times* reported that wells were not performing as well as expected and that data and industry analysts suggested that less than 20 percent of the area heralded by companies as productive in the Barnett, Haynesville and Fayetteville Shales was likely to be profitable under current market conditions. The *Times* said:

> The data show that while there are some very active wells, they are often surrounded by vast zones of less-productive wells that in some cases cost more to drill and operate than the gas they

> produce is worth. Also, the amount of gas produced by many of the successful wells is falling much faster than initially predicted by energy companies, making it more difficult for them to turn a profit over the long run.

Industry groups, such as Energy in Depth, and others, including *Forbes* magazine and investment analysts, refuted *The New York Times* articles. *The New York Times* even included two Op-Eds criticizing the articles by its Public Editor, whose role is to respond to complaints and comments from the public and monitors the paper's journalistic practices. Nonetheless, as discussed below, federal lawmakers called on several agencies, including the SEC, the EIA and the Government Accountability Office, to investigate whether the natural gas industry has provided an accurate picture to investors of the long-term profitability of their wells and the amount of gas these wells can produce. In addition, the New York attorney general also is conducting a broad investigation.

SEC actions: In June 2011, Rep. Maurice Hinchey (D-N.Y.), a senior member of the House Appropriations Committee, sent a letter to the SEC calling for an investigation into whether investors have been "intentionally misled" and questioning whether companies "may be taking advantages of loopholes in SEC regulations to artificially inflate estimates of their gas reserves." The letter further asked the SEC to consider updating its reporting requirements to require companies to reveal the methodologies and technologies they use to develop reserve estimates and to require third-party reserve audits.

Subpoenas—In summer 2011, the SEC issued subpoenas to at least two shale gas producers—**Quicksilver Resources** and **ExCO Resources**—requesting information about proved reserve estimates from shale gas wells and the actual productivity of producing shale wells. Quicksilver's June 2011 10-Q noted that the SEC informed both companies that a number of other shale gas producers had received similar subpoenas and that the SEC's investigation arose out of recent press reports questioning the projected decline curves and economics of shale gas wells.

Comment letters—On another front, the staff of the SEC's Division of Corporation Finance issued comment letters focusing on fracking to companies as part of their reviews of registration statements and other filings. Letters sent in summer 2011 requested additional disclosure on a number of issues. A sampling of requests in the comment letters was provided in an analysis by the law firm Covington & Burling, LLP (emphasis added):

- expanded disclosure of the company's *use* of hydraulic fracturing, including identifying the locations where it is used and acreage or reserves with which hydraulic fracturing is associated;
- disclosure of whether the company has been *cited, found in violation of, or sued* for issues relating to the company's hydraulic fracturing operations (including the circumstances of any such actions, the company's response, and penalties assessed);
- expanded discussion of risks related to possible *changes in applicable laws* related to hydraulic fracturing;
- disclosure of the *costs and funding* associated with hydraulic fracturing operations;
- disclosure regarding the steps the company has taken to *minimize potential environmental impacts* from its hydraulic fracturing operations;
- disclosure of *contractual provisions* that might subject the company to environmental-related damages or that would *indemnify* the company for such amounts, and risks for which the company is insured, related to its hydraulic fracturing operations;
- identifying for the staff *chemicals used* in the company's fracking fluid; and
- providing the staff with information regarding the *amount of water used* in the hydraulic fracturing process.

The SEC also asked some oil and gas companies in summer 2011 to reduce the number of years they predict their shale gas wells will produce, according to *The New York Times*.

New York actions: As part of another investigation into whether energy companies have accurately described to investors the prospects for their shale gas wells, New York attorney general Eric Schneiderman issued subpoenas in the summer of 2011 to three energy companies—**Range Resources, Cabot Oil & Gas** and **Goodrich Petroleum**. The subpoenas requested documents and information regarding the companies' shale and unconventional reservoir reserves calculations. The subpoenas also focused on possible discrepancies between what companies have told investors about natural gas well performance and costs and what is revealed in their federal filings, sources told *The New York Times*. Schneiderman reportedly also asked **Chesapeake Energy** to respond to similar questions.

The attorney general is using a New York law called the Martin Act that gives him broad powers over businesses and allows him to obtain and publicly disclose an unusual amount of information. The law has been used as a tool in other instances to gather information and increase public disclosure. Schneiderman also has used the Martin Act to investigate major Wall Street banks involved in the mortgage-backed securities crisis and other accusations of financial impropriety. In 2002, Former New York attorney general Eliot Spitzer used the law to investigate Wall Street firms, including Merrill Lynch and Salomon Smith Barney, and in 2007 former New York attorney general Andrew Cuomo used the law to subpoena energy companies about potential financial liabilities related to climate change. Cuomo reached settlement agreements with subpoenaed companies that called for additional public disclosure, and in 2010 the SEC issued interpretive guidance clarifying disclosure requirements that apply to climate change.

Earlier, in June 2011, Schneiderman subpoenaed companies—**Talisman, Chesapeake Energy, EOG Resources, Baker Hughes** and **Anadarko—**to obtain documents related to disclosures on the risks of hydrofracking, according to the *Times*.

Greenhouse Gas Emission Estimates

Natural gas when burned emits less than half the level of GHGs as coal, and two-thirds the level of petroleum, per BTU. However, some recent life-cycle analyses (LCA) that look beyond combustion are finding a larger GHG footprint for natural gas than previously estimated. Factors affecting these analyses include an increase in fugitive emissions estimates and higher estimated GHG emissions from shale gas production than from conventional gas production. In addition, methane—the primary component of natural gas—is of growing concern given the projected rise in natural gas production and revised emissions estimates by the U.S. Environmental Protection Agency (EPA). Methane is more than 20 times more potent a greenhouse gas (GHG) than carbon dioxide, the primary emission when coal is burned. At the same time, industry and others strongly dispute the EPA's new estimates of methane emissions and disagree that shale gas prodution has higher methane emissions, saying researchers using such estimates are reaching inaccurate conclusions.

A September 2011 study by the National Center for Atmospheric Research concluded that a greater reliance on natural gas in place of coal would fail to significantly slow down climate change, citing the complex and sometimes conflicting ways in which fossil fuel burning affects the earth's climate.

These competing analyses highlight the need for more publicly available methane emissions data from natural gas production and more detailed analysis of life-cycle emissions. Scientists and policymakers acknowledge that a lack of data hinders conclusive analysis. SEAB, a board advising the Secretary of Energy on shale gas production, recommended in August 2011 that immediate steps be taken to gather better data and conduct a federal analysis of lifecycle greenhouse gas footprint of shale gas operations in comparison to other fuels. As noted in the section on Proposed Federal Regulations, the EPA's GHG reporting rules will help shed light on this issue by producing new data in 2012 on emissions in the natural gas industry. In addition, the EPA's proposed air standards for new natural gas wells should codify some emission reduction practices that many in industry say are already widely used today.

Following is a brief description of recent reports related to shale gas's carbon advantage.

EPA

In April 2011, the U.S. Environmental Protection Agency reported a very substantial increase in its methane emissions estimate from U.S. natural gas systems. The increases largely are from changes in methodology and the addition of unconventional (largely shale) gas well completions and workovers (when major maintenance or remedial treatments of wells occur). The EPA released revised methodologies for estimating fugitive methane emissions from natural gas systems as part of the release of its Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. The agency revised its methodologies for gas well cleanups and condensate storage tanks, and used new data sources for centrifugal compressors with wet seals, unconventional gas well completions and unconventional gas well workovers. The net effect of these changes was an increase in total estimated methane emissions from natural gas systems of between 46.5 and 119.7 percent each year between 1990 and 2008, resulting in an overall annual average increase of 66.4 percent, or 79.3 million metric tons. The EPA estimates U.S. natural gas systems emitted a total of 221.1 million metric tons of carbon dioxide equivalent in 2009. Industry and reports, including one by IHS Cambridge Energy Research Associates, have challenged the EPA's estimates, saying they are overstated and not reflective of current industry practices.

Cornell study

Cornell professor Robert Howarth published a paper in April 2011 in the journal *Climatic Change* concluding that the carbon footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly over 20 years, given that methane has a shorter atmospheric lifetime than CO_2. More importantly, "Compared to coal, the footprint of shale gas is at least 20 percent greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years," stated Howarth. He estimates up to eight percent of the methane from shale gas production escapes to the atmosphere in venting and leaks over the lifetime of a well, an estimate which is at least 30 percent greater, and perhaps more than twice as great, as fugitive emissions from conventional gas. The study's findings have been widely refuted, with critics pointing in large part to underlying low quality data and significant overestimations of fugitive emissions.

NCAR

A study released in September 2011 by Tom Wigley, a senior research associate at the National Center for Atmospheric Research (NCAR), found that greater reliance on natural gas in place of coal would fail to significantly slow down climate change. The report's computer simulations indicate that a worldwide, partial shift from coal to natural gas would slightly accelerate climate change through at least 2050, even if no methane leaked from natural gas operations, and through as late as 2140 if there were substantial leaks. After that, the greater reliance on natural gas would begin to slow down the increase in global average temperature, but only by a few tenths of a degree. Wigley's new study incorporates the cooling effects of sulfur particles associated with coal burning and analyzed the climatic influences of methane, which affects other atmospheric gases such as ozone and water vapor.

DB Climate Change Advisors

DB Climate Change Advisors, part of Deutsche Bank, in collaboration with Worldwatch Institute and ICF International, published a research note in August 2011 that compared life-cycle GHG emissions from natural gas and coal. The authors concluded that "while our LCA finds that the EPA's updated estimates of methane emissions from natural gas systems do not undercut the greenhouse gas advantage of natural gas over coal, methane is nevertheless of concern as a GHG, and requires further attention." The report noted that several recent bottom-up life-cycle studies, including the Carnegie Mellon analysis noted below, had found the production of a unit of shale gas to be more GHG-intensive than that of conventional natural gas. The report added that "if the upstream emissions associated with shale gas production are not mitigated, a growing share of shale gas would increase the average life-cycle greenhouse gas footprint of the total U.S. natural gas supply."

Carnegie Mellon University

An August 2011 Carnegie Mellon University study concluded that GHG emissions from Marcellus Shale gas used to generate electricity would be 20 to 50 percent lower than those for coal (in the absence of any effective carbon capture and storage processes) when estimating the life-cycle greenhouse gas emissions of the two fossil fuels over 100 years. Published in the peer-reviewed journal *Environmental Research Letters*, the study found that shale gas emissions represented an 11 percent increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3 percent increase relative to the life-cycle emissions when combustion is included. The authors noted, however, that there is significant uncertainty in their Marcellus shale GHG emission estimates because of eventual production volumes and variability in flaring, construction and transportation.

IV. Shareholder Campaign on Hydrofracking

The shareholder campaign on hydraulic fracturing will enter its third year in the 2012 proxy season. For 2012, an investor coalition led by the Investor Environmental Health Network (IEHN) (comprised of socially responsible investing firms with an aggregate of more than $30 billion in assets under management) and Green Century Capital Management filed 10 proposals seeking increased disclosure on companies' hydraulic fracturing activities. (See Table 1 for a full listing of 2012 resolutions.) In 2010 and 2011, the investor coalition filed 22 similar proposals. (See Table 2 for a full listing of 2010 and 2011 resolutions.)

The campaign reflects an increasing desire from investors for additional information from companies and has produced both unusually high votes and many agreements between campaigners and companies about more disclosure. The five resolutions that came to a vote in 2011 received the most support of any environmental issue raised in the 2011 proxy season, and the most consistent support for any environmental issue, ever. All but one of the five earned more than 40 percent support of the shares voted for and against the proposals. In 2010, the resolutions received an average of 30 percent support—a strong showing for a first year resolution.

Table 1: 2012 Hydraulic Fracturing Disclosure Resolutions

Company	Primary Proponent	Mtg/Status
Anadarko Petroleum	Trillium Asset Management	May
Chesapeake Energy	Mercy Investment	June
Chevron	Sisters of St. Francis	May
EOG Resources	Green Century Capital Management	withdrawn
ExxonMobil	As You Sow Foundation	May
Noble Energy	Green Century Capital Management	April
Penn Virginia	Miller/Howard Investments	withdrawn
Range Resources	New York State Common Retirement Fund	May
Stone Energy	Miller/Howard Investments	May
Ultra Petroleum	As You Sow Foundation	May

In 2010 and 2011, the proponents withdrew another nine resolutions, generally after companies agreed to fuller disclosure. The proponents note that companies now report in much greater detail in their securities filings than they did when the campaign began two years ago.

Dialogue between companies and investors: In parallel with the shareholder campaign and starting in 2010, Boston Common Asset Management, a socially responsible mutual fund, organized a series of meetings with investors, Apache and other companies about risks, best practices and disclosure for hydraulic fracturing operations. This dialogue resulted in a set of recommendations that the IEHN and the Interfaith Center on Corporate Responsibility (ICCR) issued in December 2011, *Extracting the Facts: An Investor Guide to Disclosing Risks from Hydraulic Fracturing Operations*. *(See Box 12, p. 45, for more on this report.)*

Proponents' Objectives

The coalition of investors led by IEHN and Green Century Funds included the New York State Common Retirement Fund, the As You Sow Foundation, Miller/Howard Investments, Trillium Asset Management, the Park Foundation, Boston Common Asset Management, affiliates of ICCR, First Affirmative Financial Network, the Shareholder Association for Research & Education, Pax World Management and the Sustainability Group.

The 2010 and 2011 proposals were nearly identical in terms of what actions they requested management to take. A sample resolution asked for:

1. Known and potential environmental impacts of the company's fracturing operations; and
2. Policy options for our company to adopt, above and beyond regulatory requirements and our company's existing efforts, to reduce or eliminate hazards to air, water, and soil quality from fracturing operations.

Proponents also asked a handful of companies for management's evaluation of the potential magnitude of material risks, short and long term, that this issue may pose to the company's finances or operations.

The proponents recommend that companies explore efforts such as reducing toxicity of fracturing chemicals, recycling wastewater, monitoring water quality prior to drilling and instituting cement bond logging. They also believe that given contamination incidents and the regulatory morass of weak and uneven controls, companies must take measures above and beyond regulatory requirements to reduce environmental hazards to protect their own long-term financial interests. Compliance with existing regulation has become insufficient, say the proponents.

Table 2: 2010-2011 Hydraulic Fracturing Disclosure Resolutions

Company	Year	Primary Proponent	Status/ Vote (%)
Votes (11)			
Cabot Oil & Gas	2010	New York State Common Retirement Fund	35.9%
Carrizo Oil & Gas	2011	New York State Common Retirement Fund	43.7%
Chesapeake Energy	2010	Green Century Capital Management	25.4%
Chevron	2011	Sisters of St. Francis	40.4%
Energen	2011	Miller/Howard Investments	49.4%
EOG Resources	2010	Green Century Capital Management	30.9%
ExxonMobil	2010	As You Sow Foundation	26.2%
	2011		28.1%
Ultra Petroleum	2010	Green Century Capital Management	21.2%
	2011	As You Sow Foundation	41.7%
Williams Companies	2010	Green Century Capital Management	41.8%
Withdrawn or Omitted (11)			
Anadarko Petroleum	2011	Trillium Asset Management	withdrawn
Cabot Oil & Gas	2011	New York State Common Retirement Fund	withdrawn
El Paso	2010	Miller/Howard Investments	withdrawn
	2011		
Energen	2010	Miller/Howard Investments	withdrawn
EQT	2010	Miller/Howard Investments	omitted
Hess	2010	New York State Common Retirement Fund	withdrawn
Range Resources	2010	New York State Common Retirement Fund	withdrawn
SM Energy	2011	New York State Common Retirement Fund	withdrawn
Southwestern Energy	2011	Domini Social Investments	withdrawn
XTO Energy	2010	New York State Common Retirement Fund	no mtg (merger)

Company Responses

Initially, most of the companies challenged the resolutions at the SEC in 2010, arguing they could be excluded under the "ordinary business" provision of the Shareholder Proposal Rule and for other reasons. Aside from an omission due to insufficient proof of stock ownership, the SEC disagreed in every case. The SEC's 2010 decisions affirmed a new policy announced in fall 2009 that says proposals related to financial implications of environmental risks cannot be excluded automatically on ordinary business grounds. The following year, the SEC continued to favor disclosure, rejecting **ExxonMobil's** challenge—the only challenge on substantive grounds in 2011—that it already had substantially implemented the proposal by including a special section on drilling and fracking in its most recent Corporate Citizenship Report. The commission staff decided that ExxonMobil's "practices and policies do not compare favorably with the guidelines of the proposal." The commission staff had made a similar determination in 2010 with respect to **Chesapeake Energy**, which not only addresses the issue on its website but has created a website devoted to this issue. Chesapeake had also challenged the resolution on "ordinary business" grounds.

As noted above, 11 resolutions went to a vote, while proponents withdrew nine resolutions, including seven in response to corporate commitments, typically to increased disclosure. For those resolutions coming to a vote, most companies stated that drilling and fracking poses no significant risks to the environment, noting that they operate in a highly regulated industry. Some added that management is responsible for evaluating and responding to operational, financial and litigation risks, as well as the environmental impact of the company's operations. Some companies also said that information on hydraulic fracturing already is available, including on their websites. Thus, preparing the requested report would be a significant and burdensome undertaking and waste of corporate resources, they argued. **Carizzo Oil & Gas** also argued that providing additional information about its hydraulic fracturing operations would put it at a competitive disadvantage.

Box 12: Sample Best Practices

Companies are employing best practices in many instances. In addition, industry, government, environmental groups and shareholder proponents are promoting best practices. In December 2011, the Investor Environmental Health Network and the Interfaith Center on Corporate Responsibility published *Extracting the Facts: An Investor Guide to Disclosing Risks from Hydraulic Fracturing Operations*. The guide offers best practice recommendations to energy companies for reporting and reducing risks and impacts related to shale gas operations using hydraulic fracturing. The American Petroleum Institute developed a set of five documents highlighting best practices and providing guidance for risk management associated with hydraulic fracturing. The areas covered include well construction and integrity, water management, mitigation of surface impacts, isolation of potential flow zones during construction and environmental protection of onshore oil and gas production operations. The EPA's Natural gas STAR program encourages natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of methane.

Because of the rapid technological and production advances underpinning shale gas development, however, some best practices will become obsolete. Moreover, the regional diversity of shale gas formations does not lend itself to prescriptive lists of operational best practices. Companies need to make a commitment to the process of continuous improvement—supported and overseen at the highest management levels—to prevent and mitigate environmental and social impacts and their associated risks.

To follow is a sampling of measures companies are taking to minimize the impacts of shale gas development:

- ***Well integrity (cementing and casing)***—**Southwestern Energy** is developing model well integrity standards with the Environmental Defense Fund.
- ***Baseline water testing***—**Hess** had a baseline water testing radius of 5,000 feet for three exploratory wells in the Marcellus Shale. **Anadarko Petroleum** samples water wells within 2,500 feet of drilling locations in Pennsylvania. A third party verifies the results, which are shared with landowners. **Cabot Oil & Gas** has similar practices.
- ***Recycling wastewater***—**Range Resources, Cabot Oil & Gas, Chesapeake Energy** and **WPX Energy** recycle all, or nearly all, of their flowback water in certain Marcellus Shale operations.
- ***Closed-loop drilling fluid systems*—**All of **ExxonMobil's** drilling rigs in the Marcellus region use closed loop drilling fluid systems and have eliminated drilling pits.
- ***"Green" fracturing fluids***—**Baker Hughes, Halliburton** and **Frac Tech** each have produced a line of environmentally-friendly fracking fluids.
- ***"Green completions"***—**Williams Cos**. and **Devon Energy** use special equipment to separate gas and liquid hydrocarbons from flowback as part of the EPA's Natural Gas STAR program.
- ***Leak detections*—Anadarko Petroleum** and **Southwestern Energy** report using specialized infrared cameras to detect fugitive air emissions.
- ***Notices of violations***—**Talisman** posts details about its Notices of Violation in Pennsylvania. While this information is available on the state's website, Talisman provides easy access as well as a chart that describes how Talisman is responding to the violations.
- ***Contractor management*—Cabot Oil & Gas** has a two-page Question and Answer document on its Contractor Management Program on its website.
- ***Reduced truck traffic*—Apache** and **EnCana** reduced truck traffic by roughly 60 to 80 percent in Canada's Horn River Basin. They use brine water from an on-site formation in a closed loop fracturing system and transport sand by rail.
- ***Switching from diesel fuel to natural gas or electric to power drilling rigs*—**In July 2011, **Chesapeake Energy** announced it was converting at least 100 of its drilling rigs and all of its planned hydraulic fracturing equipment to run on LNG.

Appendix I: Company Profiles

Appendix 1 includes a sampling of 10 companies involved in shale gas development in the Marcellus, Haynesville, Barnett and/or Fayetteville Shales. Si2 chose the following firms because they illustrate different levels of involvement in shale gas development—characteristics that have a significant impact on investors' assessments of the risks and opportunities firms present.

- Two of the companies—**ExxonMobil** and **Chevron**—are among the "Big 5" major integrated oil and gas companies. ExxonMobil became the nation's largest U.S. natural gas producer in 2010 when it acquired **XTO Energy**, while Chevron boosted its capacity with the February 2011 purchase of **Atlas Energy**.
- At the other end of the spectrum, **Carrizo Oil & Gas** is the smallest (with revenues of less than $140 million) of the 10 profiled companies, but derived nearly 90 percent of its natural gas production from the Barnett Shale in 2010.
- Similarly, **Southwestern Energy** pioneered development of the Fayetteville Shale and derived nearly 90 percent of its U.S. natural gas production from that play in 2010.
- Both **Chesapeake Energy,** the nation's second largest producer of natural gas, and **Range Resources,** which was the first to apply modern drilling technologies to the Marcellus Shale, also are heavily vested in shale gas development. The four shale gas plays examined in this report represented 60 percent or more of their U.S. natural gas production in 2010.
- In contrast, **Anadarko Petroleum** and **WPX Energy** (the former exploration and production business of Williams Cos.) are active in shale gas development even though their reserves in one or more of these four plays represented 5 percent or less of their total U.S. proved natural gas reserves in 2010.
- **Hess** is an interesting company in that it has been stymied from developing its acreage in the Marcellus Shale because of a drilling moratorium in the Delaware River Basin, but it nonetheless has been proactive in developing mitigation measures and reporting on them to shareholders and the public.
- Finally, **Cabot Oil & Gas** derived nearly 40 percent of its U.S. natural gas production from the Marcellus shale in 2010 and was the best performing energy stock in the S&P 500 in 2011.

Profile sections: Each company profile provides:

- a brief *company description*,
- a snapshot of a company's *level of involvement* in the four shale gas plays named above,
- *disclosure of associated risks and mitigation measures*,
- *board oversight*,
- a company's *track record* in this area, and
- *shareholder activity*.

Descriptions and sources of information for each of the six sections included in the company profiles follow. Si2 provided each company with an opportunity to provide clarifying comments on its profile before publication; Anadarko Petroleum, Cabot Oil & Gas, Chevron and Hess declined.

Notes on Company Profiles

The profiles begin with a **summary** that includes a brief description of a company's operations, identifies its primary U.S. onshore natural gas operations and lists its revenues and number of employees as an indicator of size.

Sources: Form 10-Ks, annual reports, company websites

U.S. Shale Gas Reserves and Natural Gas Production

U.S. shale gas locations (net acres): Identifies acreage in four shale gas plays: **Marcellus, Haynesville, Barnett** and **Fayetteville**. See Box 1: Key U.S. Shale Gas Plays (p. 7) for more information on each of these plays. (In some instances, the Haynesville Shale is referred to as the Haynesville/Bossier Shale; the Bossier Shale lies above the Haynesville Shale.)

U.S. proved natural gas reserves (billions of cubic feet): Represents **all** U.S. proved natural gas reserves (conventional and unconventional). Companies commonly measure natural gas in billions of cubic feet (Bcf) and millions of cubic feet per day (MMcf/d). One billion cubic feet is approximately equal to one trillion British thermal units (BTU).

% shale gas reserves: Indicates the percentage of the company's total proved reserves in the Marcellus, Haynesville, Barnett and/or Fayetteville Shales. U.S. Securities and Exchange Commission rules require companies to disclose oil and gas proved reserves by significant geographic area when such reserves represent more than 15 percent of total proved reserves. For larger companies, this means their securities filings may not contain information identifying their reserves in specific plays, even though they may have substantial holdings there.

U.S. natural gas production (Bcf & million cubic feet/day): Represents **total** 2010 U.S. natural gas production.

% produced from shale gas reserves: Indicates the percentage produced from Marcellus, Haynesville, Barnett and/or Fayetteville Shale reserves in 2010.

Second quarter 2011 (MMcf/d): Total U.S. natural gas production in the second quarter of 2011 compared to production a year earlier; these figures indicate a company's gas production trend.

Sources (for all but Second quarter 2011): Form 10-Ks, websites or company communications. Data is as of Dec. 31, 2010, unless otherwise noted.

Source for Second Quarter 2011: Natural Gas Supply Association's "Top 40 Natural Gas Producers Second Quarter 2011"

Public Disclosure of Risks/Mitigation

This section assesses a company's disclosure of risks and prevention or mitigation measures associated with its shale gas development.

Risk Identification

Form 10-K/10-Qs: Provides a summary description of **risks** identified in annual (10-K) and quarterly (10-Q) securities filings.

Regulatory Risks Identified				
	Water	Chemical Disclosure	Air	Restrictions on Drilling
Federal				
State				

Identification of risks: Yes/No; if yes, the profile notes if the risks identified are regulatory, financial and/or legal. The accompanying table identifies the specific type of regulatory risk the company identifies, if any, and whether it associated the regulatory risk with the state or federal government.

Additional Company Communications

Discussion of mitigation measures: Yes/No; if yes, the profile notes the extent of a company's discussion, which Si2 characterizes as *extensive*, *moderate* or *limited*. The accompanying table identifies specific *preventive or mitigation measures* the company discusses in one or more of the following communications. For the first three (annual report, sustainability/EHS report and website), a summary description of any disclosure appears; for voluntary reporting, each profile indicates where the disclosure can be found.

Company discusses prevention or mitigation measures relating to:			
Water delivery		Fracking fluid toxicity	
Fresh water storage		Solid waste storage	
Wastewater storage		Chemical storage	
Wastewater recycling		Spill prevention	
Wastewater disposal		Air emissions	
Baseline water testing		Surface disturbance	
Well integrity evaluation		Fuel switching	
Contractor oversight		Truck traffic/road wear	
Noise		Community engagement	

- **2010 annual report**
- **Sustainability/Environmental Health and Safety (EHS) report**
- **Website**
- **Voluntary disclosure of chemicals in fracking fluid:** Disclosure falls into three categories:
  1. Company reports *only chemicals determined to be hazardous* by Occupational Safety and Health Administration (OSHA) and includes proprietary exemptions
  2. Company reports *all* chemicals added to fracking fluid and includes proprietary exemptions.
  3. Company reports *all* chemicals added to fracking fluid and does not have any proprietary exemptions.

  States require different levels of disclosure, and companies often comply with disclosure requirements state-by-state. As a result, a company may provide a higher level of disclosure in one state than another. This report does not identify the company as complying with the highest level of disclosure unless it does so throughout its operations. *(See Box 6, p. 22, for more on disclosure of chemicals in fracking fluids.)*
- **Voluntary posting of violations**
- **Voluntary reporting of greenhouse gas emissions**

Board Oversight

This section identifies oversight of risk management and/or environmental responsibilities at the board of directors' level, indicating which board committee is responsible in each case.

Sources: Proxy statements or company websites unless otherwise noted.

Violations/Fines/Litigation

This section provides an indication of a company's track record in shale gas development, although the emphasis is on the Marcellus Shale. While the report covers four shale gas plays, data on violations is most readily available in Pennsylvania. Similarly, media coverage, including that from grassroots sources, of violations and fines is most robust for the Marcellus.

Marcellus Shale wells drilled: The Pennsylvania Department of Environmental Protection's (PaDEP) Office of Oil and Gas Management reports on the number of wells drilled by each operator on an annual basis. The 2011 Wells Drilled By Operator as of 11/30/2011 report, the most recent available, has data through November 2011. The PADEP is revamping its website and the 2010 and 2009 "Wells Drilled by Operator" reports Si2 used for these profiles no longer appear on its website as of January 2012. The reports are slated to be reposted, and in the meantime data can be aggregated through the PaDEP's SPUD Data Report, which shows the "Spud date" (the date drilling began), as reported by the operator to a state oil & gas inspector.

Marcellus Shale violations: The PaDEP also posts inspections, violations and enforcements in the Marcellus Shale. The PADEP issues violations in two categories: 1) administrative and 2) environmental, health and safety (EH&S). The PaDEP designations make a distinction between those violations that represent a failure to comply with a rule with no actual or potential impact to the environment (Administrative) and those violations of a rule that have an actual or greater potential to affect the environment (EH&S). If a company does not address a violation within a designated timeframe, the PaDEP then issues an enforcement action against the company.

Recent Marcellus Shale Wells & Violations

	Wells Drilled	Inspections	Violations			Enforcements
			Total	EH&S	Adm.	
2009						
2010						
2011*						
Total						

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

Si2 used a report that aggregated data by company for these company profiles, but as of January 2012 it is no longer available on the PaDEP's website. Instead, the PaDEP has a new Oil and Gas Compliance Report that shows all inspections that resulted in a violation or enforcement action assigned by the Oil and Gas Program.

Sources: Form 10-Ks, Form 10-Qs, media reports, Pennsylvania Department of Environmental Protection

Shareholder Activity

In 2010 and 2011, an investor coalition led by the Investor Environmental Health Network (IEHN) and Green Century Capital Management filed 22 proposals seeking increased disclosure on companies' hydraulic fracturing activities, and particularly efforts to mitigate environmental impacts. Investors have filed additional proposals for consideration in the 2012 proxy season, as noted in Section IV above (pp. 42-44) on the shareholder campaign. This section identifies shareholder resolutions filed at a profiled company, as well as the outcome or status of the resolution and the primary filer.

Sources: Sustainable Investments Institute (Si2) and the Investor Environmental Health Network

Anadarko Petroleum Corp.

2010 revenues	$10.8 billion*
2010 employees	4,400

*Anadarko noted in its 2010 annual report that a "significant portion of our record sales volumes and reserve growth resulted from accelerated activity in our U.S. onshore shale plays."

Anadarko Petroleum is among the world's largest independent oil and natural gas exploration and production companies. In 2010, natural gas represented 56 percent of Anadarko's product mix. The company operates worldwide, although its U.S. operations accounted for 89 percent of both total sales volumes and total proved reserves in 2010. Anadarko's U.S. assets include positions in onshore resource plays in the Rocky Mountains region, the southern United States and the Appalachian basin. Anadarko is focusing on liquids-rich opportunities, and in 2010 the Marcellus Shale was the only major area where Anadarko continued to drill solely for dry natural gas, citing the "proximity to premium markets that further enhance the already robust economics of the play." In early 2010, Mitsui & Co. agreed to fund up to $1.5 billion of Anadarko's share of capital expenditures in the Marcellus Shale to earn a 32.5 percent interest in its Marcellus shale assets. In June 2011, New York attorney general Eric Schneiderman subpoenaed Anadarko, along with four other companies, to obtain documents related to disclosures on the risks of hydrofracking, according to *The New York Times*.

U.S. Shale Gas Reserves and Natural Gas Production

Shale Gas Locations (net acres)		Proved Natural Gas Reserves (billions of cubic feet)		Natural Gas Production	
		Total	**8,117 Bcf**	**2010 Bcf**	829 Bcf*
		Developed	5,982 Bcf	**2010 million cubic ft/day**	2,272 MMcf/d*
Marcellus	330,000	Undeveloped	2,135 Bcf		
Haynesville	80,000			**% produced from shale gas**	NA#
		% shale gas	<3.5%	**Q2 2011**	2,326 MMcf/d**
				Q2 2010	2,324 MMcf/d**

Data as of Dec. 31, 2010 unless otherwise noted

*Sales of natural gas **Source: NGSA
#Gross production in Marcellus of 330 MMcf/d in Dec. 2010, up from 40 MMcf/d in Jan. 2010.

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Form 10-K/10-Qs: The 2010 10-K has one paragraph addressing risks of a possible amendment to the federal Safe Drinking Water Act. The June 2011 10-Q and Sept. 2011 10-Q have four paragraphs outlining risks, primarily possible environmental regulations, specific to hydraulic fracturing; this discussion also notes that members of Congress have called on the SEC to investigate "any possible misleading of investors or the public regarding the economic feasibility of pursuing natural-gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural-gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates."

Regulatory Risks Identified

	Water	Chemical Disclosure	Air	Restrictions on Drilling
Federal	X	X	X	
State		X		X

Identification of risks—Yes; regulatory risk are discussed in the 2010 10-K and regulatory, financial and legal risks are discussed in the 2011 10-Qs.

Additional Company Communications

Discussion of mitigation measures: Yes; extensive

2010 annual report: Incorporates the 2010 Form 10-K. No additional discussion beyond the risks mentioned above.

Company discusses prevention or mitigation measures relating to:			
Water delivery	X	Fracking fluid toxicity	
Fresh water storage	X	Solid waste storage	X
Wastewater storage	X	Chemical storage	
Wastewater recycling	X	Spill prevention	X
Wastewater disposal		Air emissions	X
Baseline water testing	X	Surface disturbance	X
Well integrity evaluation	X	Fuel switching	
Contractor oversight		Truck traffic/road wear	X
Noise		Community engagement	

2011 EHS brochure: No discussion of risks/mitigation.

Website: Anadarko has four pages on its web site addressing hydraulic fracturing of shale gas. A section on "safeguarding water" discusses pressure testing and cement logging of wells, pipelines and temporary storage systems for freshwater, a closed loop drilling process, wastewater storage in steel tanks and wastewater recycling. The company notes an award for its water management system in Utah that creates temporary staging sites on existing well pads that treat recycled flowback water for reuse and move the filtered water directly to the next operation via temporary pipelines. These pipelines minimize additional surface disturbance, truck traffic and associated emissions. Anadarko also has a four-page question and answer piece on fracking, which discusses the measures above as well as baseline water testing, spill prevention and efforts to reduce air emissions, including infrared cameras to detect fugitive emissions, pipeline construction, equipment consolidation and scheduling arrangements that reduce the need for trucks. Lastly, Anadarko has a two-page fact sheet on the Marcellus Shale that repeats some of these measures.

Voluntary disclosure of chemicals in fracking fluid (by individual well): Yes; FracFocus. Company complies with state requirements; it includes proprietary exemptions and does not always disclose all non-proprietary chemicals.

Voluntary posting of violations: No

Voluntary reporting of greenhouse gas emissions: Yes; website

Board Oversight

Board committee with environmental responsibilities: None specifically disclosed.

Board committee with risk management oversight responsibilities: The Audit Committee reviews and discusses with management significant financial risk exposures, and the steps management has taken to monitor and mitigate such exposures. In addition, to facilitate oversight of potential risk exposures that have not been specifically delegated to any board committee, the board periodically meets with members of an Internal Risk Council to review and assess the company's risk-management process and to discuss significant risk exposures.

Violations/Fines/Litigation

Among Anadarko's violations was a spill of 8,000 to 12,000 gallons of synthetic-based mud in a Pennsylvania state forest in March 2010. In February 2011, a truck serving an Anadarko well crashed and spilled 3,400 gallons of used fracking fluid.

Recent Marcellus Shale Wells & Violations						
	Wells Drilled	Inspections	Violations			Enforcements
			Total	EH&S	Adm.	
2009	20	-	-	-	-	-
2010	92	44	80	34	46	13
2011*	172	27	61	33	28	5
Total	284	71	141	67	74	18

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

Shareholder Activity

In 2011, the As You Sow Foundation withdrew a shareholder resolution asking for a report on hydraulic fracturing after the company shared a draft of planned updates to its website on management of related risks and agreed to continued dialogue. Trillium Asset Management has filed a hydraulic fracturing disclosure resolution for vote at Anadarko's 2012 annual meeting.

Cabot Oil & Gas Corp.

2010 revenues	$884 million
2010 employees	409

Cabot Oil & Gas is an independent natural gas producer, with its entire resource base located in the continental United States. The company's reserves are focused in both conventional and unconventional basins in Appalachia, the Rocky Mountains, the Mid-Continent and the Gulf Coast. Cabot's activity focuses on the Marcellus Shale, where it began drilling in 2006, and on multiple plays including the Haynesville Shale and the liquids-rich Eagle Ford Shale in Texas. In 2011, third parties agreed to fund all of the cost to drill and complete certain Haynesville and Bossier Shale wells in exchange for a 75 percent working interest in related leaseholds. Cabot also has been divesting some of its properties, including some Haynesville and Bossier Shale oil and gas properties in east Texas in May 2011 for $47 million. The company sold oil and gas properties in Colorado, Utah and Wyoming for $285 million in July 2011 and its Woodford shale prospect in Oklahoma for $15.9 million in June 2010. Cabot also sold its gathering infrastructure in Pennsylvania in December 2010. In August 2011, the New York attorney general's office issued Cabot a subpoena requesting documents and information regarding its shale and unconventional reservoir reserves calculations. Cabot is cooperating with the attorney general's office.

U.S. Shale Gas Reserves and Natural Gas Production					
Shale Gas Locations (net acres)		**Proved Natural Gas Reserves (billions of cubic feet)**		**Natural Gas Production**	
		Total	**2,644 Bcf**	**2010 Bcf**	125.5 Bcf
		Developed	1,681 Bcf	**2010 million cubic ft/day**	-
Marcellus	NA	Undeveloped	963 Bcf		
Haynesville	NA	**% shale gas**	**46% +**	**% produced from shale gas**	39% (Marcellus)
		Marcellus	46%	**Q2 2011**	474 MMcf/d*
		Haynesville	NA	**Q2 2010**	318 MMcf/d*

Data as of Dec. 31, 2010 unless otherwise noted *Source: NGSA

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Regulatory Risks Identified				
	Water	**Chemical Disclosure**	**Air**	**Restrictions on Drilling**
Federal	X	X		X
State	X	X		X

Form 10-K/10-Qs: The 2010 10-K has one paragraph on potential federal and state regulations related to hydraulic fracturing. Cabot noted that public disclosure of the chemical makeup of fracturing fluids "could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems." There is no discussion in the June or Sept. 2011 10-Qs.

Identification of risks—Yes; regulatory, financial and legal risks are discussed in the 2010 10-K.

Additional company communications

Discussion of mitigation measures: Yes; extensive

2010 annual report: The report includes several paragraphs on community relations in Susquehanna County, Pa.

Sustainability/EHS report: The company does not publish a sustainability or EHS report.

Website: Cabot has a "Natural Gas Facts" section of its website that includes a hydraulic fracturing "Frequently Asked Questions" document, a Water Protocol document, a Contractor Management document and a rebuttal to the documentary Gasland. Cabot also includes a "Community Outreach and Education" section of its website that includes numerous fact sheets on hydraulic fracturing and discusses its outreach programs.

Voluntary disclosure of chemicals in fracking fluid (by individual well): Yes; FracFocus. The company includes proprietary exemptions and does not always disclose all non-proprietary chemicals.

Voluntary posting of violations: No

Voluntary reporting of greenhouse gas emissions: No

Company discusses prevention or mitigation measures relating to:			
Water delivery		Fracking fluid toxicity	X
Fresh water storage		Solid waste storage	
Wastewater storage	X	Chemical storage	
Wastewater recycling	X	Spill prevention	
Wastewater disposal		Air emissions	X
Baseline water testing	X	Surface disturbance	X
Well integrity evaluation	X	Fuel switching	
Contractor oversight	X	Truck traffic/road wear	X
Noise		Community engagement	X

Board Oversight

Board committee with environmental responsibilities: Safety and Environmental Affairs Committee

Board committee with risk management oversight responsibilities: Audit Committee

Violations/Fines/Litigation

In December 2010, Cabot Oil & Gas agreed to pay $4.1 million to 19 families in Dimock, Pa., affected by methane contamination that Pennsylvania regulators attributed to faulty shale gas wells. The company maintains that the methane in Dimock water supplies occurs naturally and is not a result of its activities. Under the agreement, Cabot also offered to install whole-house gas mitigation devices, remediated two wells and paid the state $500,000. Previously, the company plugged and abandoned three vertical wells and brought a fourth well into compliance. In April 2010, state regulators halted Cabot from drilling in the Dimock area and also temporarily suspended review of Cabot's pending permit applications statewide. No decision has been made on resumed drilling in Dimock, although the state granted Cabot's request to stop water delivery to the families in November 2011. Some families appealed the December 2010 agreement to the Pennsylvania Environmental Hearing Board, which expects to hold a hearing in 2012, and have sued Cabot. At the end of September 2011, Cabot had paid $1.3 million in related fines and penalties to the state, paid $2 million to seven households and accrued a $2.2 million settlement liability.

Between 2005 and Feb. 1, 2011, the Pennsylvania Department of Environmental Protection (PaDEP) fined Cabot four times for a total of $192,000 (not including fines associated with wells described above), according to an analysis by the *Pittsburgh Post-Gazette* based on a Right-to-Know request of PaDEP fines against Marcellus Shale-related companies. Cabot tied for the sixth highest number of fines and had the fourth largest total dollar amount. Altogether, the PaDEP imposed 89 fines for a total of $2.1 million during that period, according to the analysis. The PaDEP also ordered Cabot to suspend fracking operations for nine days in 2009 after contractors had three spills within one week of thousands of gallons of fracking fluids. Cabot's September 2011 10-Q also notes that the PaDEP issued the company a number of Notices of Violations and that resulting fines could result in monetary sanctions in excess of $100,000.

Recent Marcellus Shale Wells & Violations

	Wells Drilled	Inspections	Violations			Enforcements
			Total	EH&S	Adm.	
2009	32	-	-	-	-	-
2010	47	60	113	39	74	17
2011*	54	58	118	53	65	14
Total	133	118	231	92	139	31

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

Shareholder Activity

In 2011, the New York State Common Retirement Fund (NYSCRF) withdrew a shareholder resolution asking for a report on hydraulic fracturing in response to corporate commitments. NYSCRF brought a similar resolution to a vote in 2010 that received support from 35.9 percent of the shares voted.

Carrizo Oil & Gas Corp.

2010 revenues	$139.5 million
2010 employees	132

Carrizo Oil & Gas is an independent energy company engaged in the exploration, development and production of oil and gas in the United States and the United Kingdom's North Sea. The company's operations principally are focused in the Marcellus and Barnett Shales, the liquids-rich Eagle Ford Shale in Texas, the Niobrara Formation in Colorado and the Huntington Field in the North Sea. In 2010, Carrizo announced a growth strategy in crude oil and liquids-rich plays, and in 2011 sold 13,000 leased acres in the Barnett Shale and reached agreements on several Eagle Ford lease purchases. Also in 2011, Carrizo expanded operations to the liquids-rich Utica Shale, holding a 10 percent interest in a joint venture with Avista Capital Partners that acquired 15,000 net acres. Carrizo conducts a substantial portion of its operations through joint ventures. In the Marcellus Shale, Carrizo has a 40 percent working interest in a joint venture with Reliance Industries, the largest multinational company in India, and a 50 percent interest in a joint venture with Vista Capital Holdings. In the Barnett Shale, Carrizo has a strategic alliance with Sumitomo Corp. In 2010, natural gas represented approximately 80 percent of Carrizo's proved reserves.

U.S. Shale Gas Reserves and Natural Gas Production					
Shale Gas Locations (net acres)		**Proved Natural Gas Reserves (billions of cubic feet)**		**Natural Gas Production**	
Marcellus	117,921[1]	**Total**	670 Bcf	**2010 Bcf**	35.7 Bcf
Barnett	44,810[2]			**2010 million cubic ft/day**	98 MMcf/d
Fayetteville	20,000			**% produced from shale gas**	87% (Barnett)
		<u>% shale gas</u>	**<u>93% +</u>**		
		Barnett	93%	**First six months 2011**	98 MMcf/d*

[1] 887 developed, 117,034 undeveloped
[2] 25,595 developed, 19,215 undeveloped
Data as of Dec. 31, 2010 unless otherwise noted

*Source: Carrizo Oil & Gas

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Regulatory Risks Identified				
	Water	**Chemical Disclosure**	**Air**	**Restrictions on Drilling**
Federal	X	X	X	X
State	X	X	X	X

Form 10-K/10-Qs: The 2010 10-K and June 2011 10-Q include a lengthy paragraph on hydraulic fracturing focused primarily on regulatory initiatives, as well as an earlier reference to possible air emissions regulations, pointing to the Barnett Shale area as an example. The paragraph includes a warning that "proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers." The Sept. 2011 10-Q includes a similar paragraph and adds information on regulatory developments in Pennsylvania. The 2010 10-K also discusses risks associated with acquiring adequate supplies of water.

Identification of risks—Yes; primarily regulatory risks and also financial and legal risks are discussed in the 2010 10-K and 2011 10-Qs.

Additional company communications

Discussion of mitigation measures: Yes; limited

2010 annual report: The report incorporates the 2010 Form 10-K. There is no additional discussion beyond the risks mentioned above.

Sustainability/EHS report: The company does not publish a sustainability or EHS report.

Company website: Carrizo Oil & Gas has posted a video on its website describing the horizontal drilling process. Its website also has pages dedicated to "Owner Relations" for property owners in the Marcellus and Barnett Shales that address community relations, leasing tips and royalty checks.

Voluntary disclosure of chemicals in fracking fluid (by individual well): No

Voluntary posting of related violations: No

Voluntary reporting of greenhouse gas emissions: No

Company discusses prevention or mitigation measures relating to:			
Water delivery		Fracking fluid toxicity	
Fresh water storage		Solid waste storage	
Wastewater storage		Chemical storage	
Wastewater recycling		Spill prevention	
Wastewater disposal		Air emissions	
Baseline water testing		Surface disturbance	
Well integrity evaluation		Fuel switching	
Contractor oversight		Truck traffic/road wear	
Noise		Community engagement	X

Board Oversight

Board committee with environmental responsibilities: None specifically disclosed.

Board committee with risk management oversight responsibilities: None specifically disclosed.

Violations/Fines/Litigation

In response to a shareholder resolution, the company reported in its 2011 proxy statement that it was not aware of any hydraulic fracturing-related incidents resulting in environmental contamination at any of its operations.

Recent Marcellus Shale Wells & Violations						
	Wells Drilled	Inspec-tions	Violations			Enforce-ments
			Total	EH&S	Adm.	
2009	1	-	-	-	-	-
2010	4	1	2	1	1	1
2011*	44	20	34	22	12	3
Total	49	21	36	23	13	4

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

Shareholder Activity

A 2011 shareholder resolution asking for a report on hydraulic fracturing received support from 43.7 percent of the shares voted. The New York State Common Retirement Fund was the primary filer.

Chesapeake Energy Corp.

2010 revenues	$9.4 billion
2010 employees	10,000

Chesapeake Energy is the second-largest U.S. producer of natural gas and a Top 15 producer of oil and natural gas liquids. The company discovers and develops unconventional natural gas and oil fields onshore in the United States, and in 2010 natural gas represented 89 percent of its total production. In 2010 Chesapeake announced a strategic shift from focusing exclusively on natural gas to a balanced focus on natural gas and liquids. In 2011, it sold its assets in the Fayetteville Shale to BHP Billiton Petroleum while retaining its interests in the Barnett, Haynesville/Bossier, Marcellus and Pearsall (in Texas) Shales. Since 2008, Chesapeake has entered into various joint ventures to further develop the four shale gas plays and the liquids-rich Eagle Ford Shale, Utica Shale and Niobrara play with Plains Exploration & Production, BP America, Statoil, Total and the Chinese National Offshore Oil Co. The company also has operations in Ohio, Texas, Oklahoma, Wyoming, Colorado and New Mexico and also owns midstream, compression, drilling, trucking, pressure pumping and other oilfield service assets.

U.S. Shale Gas Reserves and Natural Gas Production					
Shale Gas Locations (net acres)		**Proved Natural Gas Reserves (billions of cubic feet)**		**Natural Gas Production**	
		Total	**15,455 Bcf**	**2010 Bcf**	924.9 Bcf
		Developed	8,246 Bcf	**2010 million cubic ft/day**	-
Marcellus	1,671,000	Undeveloped	7,209 Bcf		
Fayetteville[1]	601,000			**% produced from shale gas**	**62% → 69% in Q3 2011**
Haynesville/ Bossier	527,000	**% shale gas**	**63%**	Haynesville	26% → 43%
Barnett	217,000	Haynesville	23%	Barnett	18% → 14%
		Barnett	19%	Fayetteville	12% → 0%
		Fayetteville	16%	Marcellus	6% → 12%
		Marcellus	5%	**Q2 2011**	2,575 MMcf/d*
				Q2 2010	2,497 MMcf/d*

[1] Sold to BHP Billiton Petroleum in 2011

Data as of Dec. 31, 2010 unless otherwise noted

*Source: NGSA

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Form 10-K/10-Qs: The 2010 10-K has a short paragraph noting the possibility of new federal, state or local laws or regulations related to hydraulic fracturing. There was no discussion in the June or Sept. 2011 10-Qs.

Identification of risks—Yes; regulatory and financial risks are discussed in the 2010 10-K.

Regulatory Risks Identified				
	Water	**Chemical Disclosure**	**Air**	**Restrictions on Drilling**
Federal	(specific risk areas not discussed)			
State				

Additional company communications

Discussion of mitigation measures: Yes; extensive discussion of shale gas development; moderate discussion of mitigation measures

2010 annual report: The report notes Chesapeake's efforts to reduce chemical additives in fracking fluids, use multi-well padsites to reduce its footprint, eliminate soil erosion, restore local vegetation, control surface water runoff, recycle wastewater and generally use Best Management Practices to reduce environmental impact.

Sustainability/EHS report: The company does not publish a sustainability or EHS report.

Website: An "Environment" section on the company website discusses mitigation measures noted in the annual report in more detail. Sections on water and air identify specific measures, such as "green completions" that reduce VOCs and methane emissions, and include numerous fact sheets. The company also makes numerous fact sheets, videos and animations available on the Media section of its website. In addition, the company has a separate website, Ask Chesapeake, with similar information on its shale gas development.

Company discusses prevention or mitigation measures relating to:			
Water delivery	X	Fracking fluid toxicity	X
Fresh water storage	X	Solid waste storage	
Wastewater storage	X	Chemical storage	
Wastewater recycling	X	Spill prevention	
Wastewater disposal	X	Air emissions	X
Baseline water testing		Surface disturbance	X
Well integrity evaluation	X	Fuel switching	
Contractor oversight		Truck traffic/road wear	X
Noise	X	Community engagement	X

Voluntary disclosure of chemicals in fracking fluid (by individual well): Yes; FracFocus. The company discloses all information provided by vendors, who do not always disclose all non-proprietary chemicals.

Voluntary posting of violations: No

Voluntary reporting of greenhouse gas emissions: No

Board Oversight

Board committee with environmental responsibilities: None specifically disclosed.

Board committee with risk management oversight responsibilities: Management presents significant risks and possible approaches to mitigate such risks to the full board or one or more of its three committees (Audit, Compensation and Nominating and Corporate Governance).

Violations/Fines/Litigation

In May 2011, the Pennsylvania Department of Environmental Protection (PaDEP) fined Chesapeake Energy $900,000—the single largest fine ever levied on an oil or gas operator in the state. The PaDEP determined that Chesapeake failed to prevent the migration of natural gas into the water supplies of 16 families in Bradford County. Chesapeake disagrees with the determination but also agreed to donate $200,000 to the PaDEP's well-plugging fund. Separately, in May 2011 the company agreed to pay a fine of $188,000 in connection with a February 2011 condensate separator tank fire at a drilling site in Washington County that injured three subcontractors.

Recent Marcellus Shale Wells & Violations						
	Wells Drilled	Inspec-tions	Violations			Enforce-ments
			Total	EH&S	Adm.	
2009	96	-	-	-	-	-
2010	181	72	134	71	63	30
2011*	244	81	133	69	64	12
Total	521	153	267	140	127	42

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

A month earlier, a Chesapeake Energy well blew out in Bradford County and spilled thousands of gallons of diluted fracking fluids into a tributary stream; seven nearby families were temporarily relocated and the company voluntarily suspended fracking operations for three weeks. The PaDEP has rendered findings of no impact. Chesapeake estimates in its September 2011 10-Q that resolution of two unrelated compliance orders alleging violations of the Pennsylvania Clean Streams Law "can reasonably be expected to include monetary sanctions in excess of $100,000." Chesapeake also estimates in its 2010 10-K that resolution of an EPA compliance order related to Clean Water Act permitting requirements in West Virginia will include monetary sanctions exceeding $100,000.

Litigation: Chesapeake is facing five lawsuits alleging water contamination, including a class action, as a result of drilling in the Barnett, Fayetteville and Marcellus Shales. Chesapeake also has been named in a class action suit alleging that disposal wells associated with shale gas development have caused earthquakes in Arkansas.

Shareholder Activity

A 2010 shareholder resolution asking for a report on hydraulic fracturing received support from 25.4 percent of the shares voted. The primary filer was Green Century Capital Management. Mercy investment, which is affiliated with the Interfaith Center on Corporate Responsibility, has filed a hydraulic fracturing disclosure resolution for vote at Chesapeake Energy's 2012 annual meeting.

Chevron Corp.

2010 revenues	$198 billion
2010 employees	58,267

Chevron is the second largest integrated energy company in the country, and among the largest companies in the world. Crude oil and natural gas liquids represented nearly 70 percent of Chevron's production in 2010, including in the United States, which represents about one-quarter of Chevron's oil & gas production. Chevron has been building its gas reserves recently, most notably with the $4.5 billion acquisition in February 2011 of Atlas Energy, which had 486,000 net acres in the Marcellus Shale and 623,000 net acres in the Utica Shale. As part of the deal, Chevron also acquired a 49 percent interest in a venture with Williams Cos. that owns intrastate and natural gas gathering lines in the Marcellus region, and a 60 percent interest in a joint venture with Reliance Industries, a major drilling contractor. Since then, Chevron has acquired additional acreage in the Marcellus Shale, including from Chief Oil and Gas and Tug Hill. In 2010 and 2011, Chevron also acquired shale gas acreages in Canada and licenses in Eastern Europe.

U.S. Shale Gas Reserves and Natural Gas Production					
Shale Gas Locations (net acres)[1]		**Proved Natural Gas Reserves (billions of cubic feet)**		**Natural Gas Production**	
		Total	**2,472 Bcf**	**2010 Bcf**	-
		Developed	2,113 Bcf	**2010 million cubic ft/day**	1,314 MMcf/d
Marcellus	700,000+	Undeveloped	359 Bcf		
Haynesville	70,000+			**% produced from shale gas**	NA
		% shale gas	NA	**Q2 2011**	1,299 MMcf/d*
				Q2 2010	1,317 MMcf/d*

[1] Net acres as of November 2011

Data as of Dec. 31, 2010 unless otherwise noted

*Source: NGSA

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Form 10-K/10-Qs: There is no discussion of risks or mitigation measures related to hydraulic fracturing in the 2010 10-K or in the Sept. or June 2011 10-Qs.

Identification of risks—No

Regulatory Risks Identified				
	Water	**Chemical Disclosure**	**Air**	**Restrictions on Drilling**
Federal	(none)			
State				

Additional company communications

Discussion of mitigation measures: Yes; limited

2010 annual report: There is no discussion of related risks or mitigation measures.

Sustainability/EHS report: The *2010 Corporate Responsibility Report* does not include discussion of related risks or mitigation measures.

Website: A shale gas section on the company website discusses pressure testing wells, lining pits for wastewater, recycling wastewater and delivering fresh water via pipelines.

Voluntary disclosure of chemicals in fracking fluid (by individual well): Yes; FracFocus. The company includes proprietary exemptions. It is unknown if Chevron discloses all non-proprietary chemicals or only non-proprietary chemicals deemed hazardous by OSHA.

Voluntary posting of violations: No

Voluntary reporting of greenhouse gas emissions: Yes; website and *2010 Corporate Responsibility Report*.

Board Oversight

Board committee with environmental responsibilities: Public Policy

Board committee with risk management oversight responsibilities: The full board and its four committees—Audit, Board Nominating and Governance, Management Compensation and Public Policy—provide oversight of Chevron's risk management policies and practices.

Company discusses prevention or mitigation measures relating to:			
Water delivery	X	Fracking fluid toxicity	
Fresh water storage		Solid waste storage	
Wastewater storage	X	Chemical storage	
Wastewater recycling	X	Spill prevention	
Wastewater disposal		Air emissions	
Baseline water testing		Surface disturbance	X
Well integrity evaluation	X	Fuel switching	
Contractor oversight		Truck traffic/road wear	X
Noise		Community engagement	

Violations/Fines/Litigation

Between 2005 and Feb. 1, 2011, the Pennsylvania Department of Environmental Protection (PaDEP) fined Atlas Energy Resources six times for a total of $295,300, according to an analysis by the *Pittsburgh Post-Gazette* based on a Right-to-Know request of PaDEP fines against Marcellus Shale-related companies. Atlas had the fourth highest number of fines and second largest total dollar amount. Altogether, the PaDEP imposed 89 fines for a total of $2.1 million during that period, according to the analysis.

In August 2010, the PaDEP fined Atlas $97,350 for allowing wastewater to overflow a holding pit in Washington County, Pa., in December 2009 and contaminate a tributary of Dunkle Run in the Buffalo Creek watershed. Atlas also failed to report the spill. Atlas Energy says the spill had no negative environmental consequences.

In January 2010, the PaDEP fined Atlas Energy $85,000 for discharging waste and improperly building well facilities at 13 locations from late 2008 through July 2009.

Recent Marcellus Shale Wells & Violations

	Wells Drilled	Inspections	Violations			Enforcements
			Total	EH&S	Adm.	
2009	114	-	-	-	-	-
2010	43	12	16	9	7	15
2011*	70	1	24	15	9	2
Total	227	13	40	24	16	17

Figures include Atlas Resources and Chevron Appalachia
*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

Litigation: In September 2009, landowner George Zimmerman of Washington County, Pa., sued Atlas for polluting his land and water with fracking fluids. He alleges that independent water tests found concentrations of seven carcinogenic chemicals above screening levels established by U.S. Environmental Protection Agency as warranting further investigation at three sites near his home. In March 2010, a fire broke out at an Atlas gas drilling site on Zimmerman's land when gas on the surface of stored wastewater caught fire.

Shareholder Activity

A 2011 shareholder resolution asking for a report on hydraulic fracturing received support from 40.4 percent of the shares voted. The primary filers were the Sisters of St. Francis, who are affiliated with the Interfaith Center on Corporate Responsibility. The Sisters of St. Francis also have filed a hydraulic fracturing disclosure resolution for vote at Chevron's 2012 annual meeting.

Exxon Mobil Corp.

2010 revenues	$370.1 billion
2010 employees	83,600

ExxonMobil is the world's largest publicly traded natural gas producer. Its business covers the whole range of oil- and gas-related activity, including exploration, extraction, refining, transportation and sale of natural gas and petroleum products, plus petrochemicals. ExxonMobil became the nation's largest U.S. natural gas producer in June 2010, following its $41 billion acquisition of XTO Energy, nearly tripling its U.S. gas production and acquiring holdings in several U.S. shale plays. ExxonMobil has continued to acquire unconventional assets in multiple North American shale gas locations, including the Horn River Basin in British Columbia. ExxonMobil's *Outlook for Energy: A View to 2030* forecasts natural gas overtaking coal consumption by 2020 due, in part, to the supplies of shale gas that can be recovered through drilling and fracking. At present, natural gas represents about half of ExxonMobil's total U.S. production.

U.S. Shale Gas Reserves and Natural Gas Production					
Shale Gas Locations (net acres)		**Proved Natural Gas Reserves (billions of cubic feet)**		**Natural Gas Production**	
		Total	**26,111 Bcf**	**2010 Bcf**	-
Marcellus	700,000+	Developed	15,441 Bcf	**2010 million cubic ft/day**	2,596 MMcf/d*
Barnett	277,000	Undeveloped	10,670 Bcf		
Fayetteville	157,000			**% produced from shale gas**	NA
Haynesville	100,000	% shale gas	NA	**Q2 2011**	3,842 MMcf/d**
				Q2 2010	3,909 MMcf/d**

Data as of Dec. 31, 2010 unless otherwise noted *Gas available for sale **Source: NGSA

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Form 10-K/10-Qs: The 2010 10-K has one paragraph on regulatory and litigation risks that lists hydraulic fracturing as an issue where changes in laws or regulations could "increase our cost of compliance or reduce or delay available business opportunities." The June & Sept. 2011 10-Qs have no discussion.

Regulatory Risks Identified				
	Water	**Chemical Disclosure**	**Air**	**Restrictions on Drilling**
Federal	(specific risk areas not discussed)			
State				

Identification of risks—Yes; regulatory and financial risks are discussed in the 2010 10-K.

Additional company communications

Discussion of mitigation measures: Yes; moderate

2010 annual report: There is no discussion of risks or mitigation measures.

Sustainability/EHS report: The *2010 Corporate Citizenship Report* includes two pages on hydraulic fracturing that include discussion of wastewater recycling; pipelines for delivering fresh water, which reduce the need for holding pits and truck traffic; and closed loop drilling systems, which eliminate the need for drilling waste pits and reduce a site's footprint.

Website: ExxonMobil's website contains information similar to the *2010 Corporate Citizenship Report*. It also has a dedicated website on natural gas that focuses on shale gas development and hydraulic fracturing. The "Safety and Responsibility" section of this website notes community engagement, truck schedules, noise abatement and multi-well pads that limit surface impact.

Voluntary disclosure of chemicals in fracking fluid (by individual well): Yes; FracFocus. The company discloses all non-proprietary chemicals.

Voluntary posting of violations: No

Voluntary reporting of greenhouse gas emissions: Yes; website and *2010 Corporate Citizenship Report*.

Board Oversight

Board committee with environmental responsibilities: Public Issues and Contributions Committee

Board committee with risk management oversight responsibilities: The full board has responsibility for risk oversight, and each committee—Audit, Board Affairs, Compensation, Finance and Public Issues and Contributions—focuses on specific key areas of risk.

Company discusses prevention or mitigation measures relating to:			
Water delivery	X	Fracking fluid toxicity	
Fresh water storage	X	Solid waste storage	X
Wastewater storage		Chemical storage	
Wastewater recycling	X	Spill prevention	
Wastewater disposal		Air emissions	
Baseline water testing		Surface disturbance	X
Well integrity evaluation		Fuel switching	
Contractor oversight		Truck traffic/road wear	X
Noise	X	Community engagement	X

Violations/Fines/Litigation

Between 2005 and Feb. 1, 2011, the Pennsylvania Department of Environmental Protection (PaDEP) fined XTO Energy four times for a total of $166,630, according to an analysis by the *Pittsburgh Post-Gazette* based on a Right-to-Know request of PaDEP fines against Marcellus Shale-related companies. XTO tied for the sixth highest number of fines and had the fifth largest total dollar amount. Altogether, the PaDEP imposed 89 fines for a total of $2.1 million during that period, according to the analysis.

Recent Marcellus Shale Wells & Violations						
	Wells Drilled	Inspec-tions	Violations			Enforce-ments
			Total	EH&S	Adm.	
2009	8	-	-	-	-	-
2010	22	25	66	38	28	16
2011*	14	35	71	45	26	7
Total	44	60	137	83	54	23

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

In November 2010, an open valve on a tank holding wastewater at an XTO drilling pad led to wastewater reaching a nearby stream in Penn Township, Lycoming County, Pa. XTO failed to notify the PaDEP of the incident, and ExxonMobil's 2010 10-K estimates that the PaDEP may seek a penalty in excess of $100,000. XTO did not admit to a violation for the alleged release, but agreed to cooperate with the PaDEP in responding to and remediating it.

The Arkansas Public Policy Panel, a nonprofit focused on economic and social justice, conducted an analysis of Arkansas Department of Environmental Quality (ADEQ) inspections in the Fayetteville Shale from July 2006 to August 2010. The ADEQ conducted 45 inspections at XTO Energy sites and 80 percent resulted in a total of 62 violations of water and other environmental laws, according to the panel. Comparatively, the panel identified 538 state inspections in total, with 54 percent finding more than 500 individual violations.

Shareholder Activity

Shareholder resolutions asking for a report on hydraulic fracturing received support from 28.1 percent of the shares voted in 2011 and 26.2 percent support in 2010. The As You Sow Foundation, which was the primary filer of both resolutions, also has filed a hydraulic fracturing disclosure resolution for vote at ExxonMobil's 2012 annual meeting.

Hess Corp.

2010 revenues	$33.9 billion
2010 employees	13,800

Hess is a global integrated energy company engaged in the exploration and production of crude oil and natural gas, as well as the refining and marketing of petroleum products, natural gas and electricity. Natural gas represented around 28 percent of the company's worldwide proved reserves at the end of 2010, when nearly a quarter of the company's total proved oil and gas reserves were in the United States. U.S. operations represented 16 percent of the company's 2010 natural gas production. U.S. operations included offshore properties in the Gulf of Mexico, as well as onshore properties in the Bakken oil shale in North Dakota and in the Permian Basin oil field in West Texas. In the Marcellus Shale, Hess is the operator and holds a 100 percent interest on approximately 53,000 net acres and holds a 50 percent non-operating interest in approximately 38,000 net acres. In 2010, Hess drilled three vertical exploration wells in the Marcellus Shale. The majority of this acreage, however, is in the Delaware River Basin area where a drilling moratorium is in place until the Delaware River Basin Commission establishes new drilling regulations. *(See Box 4, p. 16 for more.)* Also during 2010, Hess acquired approximately 90,000 net acres in the liquids-rich Eagle Ford shale formation in Texas, and in September 2011 it acquired 185,000 net acres in the Utica Shale play in eastern Ohio.

U.S. Shale Gas Reserves and Natural Gas Production

Shale Gas Locations (net acres)		Proved Natural Gas Reserves (billions of cubic feet)		Natural Gas Production	
Marcellus	53,000	**Total**	**280 Bcf**	**2010 Bcf**	-
		Developed	199 Bcf	**2010 million cubic ft/day**	108 MMcf/d
		Undeveloped	81 Bcf	**% produced from shale gas**	0%
		% shale gas	NA	**Q2 2011**	100 MMcf/d*
				Q2 2010	102 MMcf/d*

Data as of Dec. 31, 2010 unless otherwise noted *Source: NGSA

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Regulatory Risks Identified

	Water	Chemical Disclosure	Air	Restrictions on Drilling
Federal				X
State				X

Form 10-K/10-Qs: The 2010 10-K has a short paragraph noting that regulatory bodies responding to concerns about hydraulic fracturing "may impose temporary moratoriums and new regulations on such drilling operations that would likely have the effect of delaying and increasing the cost of such operations." The June & September 2011 10-Qs have no discussion.

Identification of risks—Yes; regulatory and financial risks are discussed in the 2010 10-K.

Additional company communications

Discussion of mitigation measures: Yes; moderate

2010 annual report: The report incorporates the 2010 Form 10-K. There is no additional discussion beyond the risks mentioned above.

Sustainability/EHS report: The 2010 Corporate Sustainability Report notes that "all of our unconventional acquisitions involve several levels of risk management, including identification of baseline environmental conditions and potential oil and gas development constraints." The company reports meeting with four Marcellus Shale vendors to discuss its preference for environmentally friendly additives in fracking fluid and its interest in recycling produced water. Hess also noted consultation with property owners on well pad and ancillary facilities siting in the Marcellus Shale, and the use of risk-based screening to select well pad sites and reduce their potential environmental impact. Hess has performed baseline soil sampling and incorporated soil handling and erosion controls into its construction process. Hess also has commissioned a reverse osmosis plant that will meet the majority of its water requirements in North Dakota by removing dissolved solids from brackish water from an underground aquifer.

Website: There is nothing distinct from the online 2010 Corporate Sustainability Report noted above.

Voluntary disclosure of chemicals in fracking fluid: Yes; FracFocus. The company includes proprietary exemptions. It is unknown if Hess discloses all non-proprietary chemicals or only non-proprietary chemicals deemed hazardous by OSHA.

Voluntary posting of violations: No

Company discusses prevention or mitigation measures relating to:			
Water delivery	X	Fracking fluid toxicity	X
Fresh water storage		Solid waste storage	
Wastewater storage		Chemical storage	
Wastewater recycling	X	Spill prevention	
Wastewater disposal		Air emissions	
Baseline water testing	X	Surface disturbance	X
Well integrity evaluation		Fuel switching	
Contractor oversight		Truck traffic/road wear	
Noise		Community engagement	X

Voluntary reporting of greenhouse gas emissions: Yes; 2010 Corporate Sustainability Report and website.

Board Oversight

Board committee with environmental responsibilities: Audit Committee

Board committee with risk management oversight responsibilities: Audit Committee. In addition, the full board has oversight of the company's risk management policies.

Violations/Fines/Litigation

In August 2011, Hess received a violation for an inadequate, insufficient or improperly installed casing after an inspector saw bubbling outside the casing, and a Hess representative confirmed the bubbling was methane. The company also received a violation for failing to report the defective casing within 24 hours or submit a plan to correct it within 30 days.

Recent Marcellus Shale Wells & Violations						
	Wells Drilled	Inspections	Violations			Enforcements
			Total	EH&S	Adm.	
2009	0	-	-	-	-	-
2010	3	3	6	4	2	1
2011*	0	1	2	1	1	0
Total	3	4	8	5	3	1

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

Shareholder Activity

In 2010, the New York State Common Retirement Fund withdrew a shareholder resolution asking for a report on hydraulic fracturing in response to corporate commitments.

Range Resources Corporation

2010 revenues	$1 billion
2010 employees	713

Range Resources Corporation is among the nation's leading independent natural gas and oil companies. The company operates primarily in the Appalachian and Southwestern regions of the United States. Some 80 percent of its proved reserves are natural gas, and a large portion of its drilling inventory consists of unconventional resource plays targeting shale and coal bed methane natural gas reservoirs. In 2004, Range Resources was the first company to successfully apply modern drilling technologies in the Marcellus Shale. The company has continued to focus on the Marcellus, selling its legacy tight gas sand properties in Ohio for $323 million in 2010 and its Barnett Shale properties, which made up 20 percent of its production, for $889 million in 2011. The New York attorney general's office issued Range Resources a subpoena requesting documents and information regarding its shale and conventional gas operations in 2011. Range Resources says it responded to the request by providing information that is all publicly available.

U.S. Shale Gas Reserves and Natural Gas Production					
Shale Gas Locations (net acres)[1]		Proved Natural Gas Reserves (billions of cubic feet)		Natural Gas Production	
Marcellus	1,100,000	**Total**	**3,566 Bcf**	**2010 Bcf**	142 Bcf
		Developed	1,763 Bcf	**2010 million cubic ft/day**	389 MMcf/d
		Undeveloped	1,803 Bcf	**% produced from shale gas**	60%
		% shale gas	approx. 66%	**Q2 2011**	361 MMcf/d*
				Q2 2010	279 MMcf/d*

[1]Net acres as of November 2011

Data as of Dec. 31, 2010 unless otherwise noted

*Source: NGSA

Public Disclosure of Risks and Mitigation Measures

Risk Identification

Regulatory Risks Identified				
	Water	Chemical Disclosure	Air	Restrictions on Drilling
Federal	X	X	X	
State	X	X	X	X

Form 10-K/10-Qs: The 2010 10-K has one paragraph on possible changes to the Safe Drinking Water Act related to hydraulic fracturing and a lengthy paragraph describing additional regulatory risks stemming from new legislation and regulatory initiatives specific to hydraulic fracturing. There is no discussion in the June or Sept. 2011 10-Qs.

Identification of risks—Yes; regulatory and financial risks are discussed in the 2010 10-K.

Additional company communications

Discussion of mitigation measures: Yes, extensive

2010 annual report: The report discusses the company's community engagement efforts and notes that in 2009 it was the first in the industry to attempt to recycle water used in drilling. The report also notes that in 2010 it became the first company to publicly disclose the hydraulic fracking fluid mixture it used in the Marcellus Shale.

Sustainability/EHS report: The company does not publish a sustainability or EHS report.

Website: Range has a dedicated website on its Marcellus Shale drilling operations and has a question and answer piece on fracking on the company website. The Q&A piece discusses baseline water testing; measures to ensure well integrity; freshwater sources; wastewater recycling, storage and disposal; transportation and mixing of chemicals; and spill prevention.

Voluntary disclosure of chemicals in fracking fluid (by individual well): Yes; website and FracFocus. As noted above, Range Resources was the first company to publicly disclose its hydraulic fracking fluid in the Marcellus Shale. The company discloses chemicals in accordance with state requirements; it discloses only chemicals determined hazardous by OSHA in Pennsylvania and provided broader disclosure in Texas. The company does not include proprietary exemptions.

Voluntary posting of violations: No

Voluntary reporting of greenhouse gas emissions: No

Company discusses prevention or mitigation measures relating to:			
Water delivery	X	Fracking fluid toxicity	X
Fresh water storage		Solid waste storage	
Wastewater storage	X	Chemical storage	X
Wastewater recycling	X	Spill prevention	X
Wastewater disposal	X	Air emissions	
Baseline water testing	X	Surface disturbance	X
Well integrity evaluation		Fuel switching	
Contractor oversight	X	Truck traffic/road wear	X
Noise	X	Community engagement	

Board Oversight

Board committee with environmental responsibilities: Company told Si2 that its full board undertakes a continuous evaluation of environmental matters.

Board committee with risk management oversight responsibilities: The full board regularly evaluates the risk of the company and oversees risk identification and evaluation. Each committee—Audit, Compensation and Governance and Nominating—evaluates specific risks.

Violations/Fines/Litigation

Between 2005 and Feb. 1, 2011, the Pennsylvania Department of Environmental Protection (PaDEP) fined Range Resources seven times for a total of $288,875, according to an analysis by the *Pittsburgh Post-Gazette* based on a Right-to-Know request of PaDEP fines against Marcellus Shale-related companies. Range tied for the second highest number of fines and had the third largest total dollar amount. Altogether, the PaDEP imposed 89 fines for a total of $2.1 million during that period, according to the analysis. Range's fines included $140,000 for a broken pipeline joint that allowed about 10,500 gallons of drill pit wastewater to leak into a nearby stream in 2009. Range says that none of its Marcellus Shale violations have a continuing impact on the environment and that many were self-reported.

Recent Marcellus Shale Wells & Violations						
	Wells Drilled	Inspec-tions	Violations			Enforce-ments
			Total	EH&S	Adm.	
2009	121	-	-	-	-	-
2010	133	23	40	27	13	14
2011*	159	32	60	38	22	14
Total	413	55	100	65	35	28

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

In December 2010, the U.S. Environmental Protection Agency (EPA) issued an administrative order to Range to shut down two gas wells in the Barnett Shale after concluding that they contributed to natural gas in two water wells in southern Parker County, Texas. Range has appealed the order. In March 2011, the Texas Railroad Commission absolved Range of wrongdoing, finding that gas in the water wells likely came from the Strawn geological formation. The EPA responded that it is standing by its belief that gas drilling contributed to the contamination and said it would not comply with a Texas request to rescind its earlier order.

Litigation: Owners of one of the wells in Parker County described above sued Range Resources in the spring of 2011, claiming that natural gas drilling has contaminated their well water with benzene, toluene and ethane, as well as a large amount of methane gas. Range Resources has countersued, charging a testing conspiracy.

In August 2011, a Pennsylvania family settled a lawsuit against drillers and compressor station operators, including Range Resources, alleging air pollution and water contamination from shale gas development harmed their health.

Shareholder Activity

In 2010, the New York State Common Retirement Fund (NYSCRF) withdrew a shareholder resolution asking for a report on hydraulic fracturing in response to corporate commitments. The NYSCRF has filed a hydraulic fracturing disclosure resolution for vote at Range Resource's 2012 annual meeting.

Southwestern Energy Co.

2010 revenues	$2.6 billion
2010 employees	2,088

Southwestern Energy is an independent energy company whose primary business is exploring for and producing natural gas in North America. Southwestern pioneered development of the Fayetteville Shale underlying parts of Arkansas in 2003; its current operations remain focused there. The company began drilling in the Marcellus Shale in Pennsylvania in 2010. It also has a conventional drilling program in the Arkoma Basin in Arkansas and has exploration and production activities in Oklahoma, Texas and New Brunswick, Canada. Southwestern also engages in natural gas gathering activities in Arkansas, Texas and Pennsylvania. Southwestern Energy is collaborating with the Environmental Defense Fund (EDF) on model standards for safe drilling and model standards for air emissions. The company also worked with EDF and other industry partners on public disclosure legislation for hydraulic fracturing fluids in Texas.

U.S. Shale Gas Reserves and Natural Gas Production

Shale Gas Locations (net acres)[1]		Proved Natural Gas Reserves (billions of cubic feet)		Natural Gas Production	
		Total	**4,930 Bcf**	**2010 Bcf**	403.6 Bcf
		Developed	2,687 Bcf	**2010 million cubic ft/day**	1,106 MMcf/d
		Undeveloped	2,243 Bcf		
Fayetteville	915,884			**% produced from shale gas**	**87%**
Marcellus	173,009	**% shale gas**	**89%**	Fayetteville	87%
		Fayetteville	88%	Marcellus	<1%
		Marcellus	1%	**Q2 2011**	1,347 MMcf/d*
				Q2 2010	1,077 MMcf/d*

[1] Net acres as of November 2011

Data as of Dec. 31, 2010 unless otherwise noted

*Source: NGSA

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Regulatory Risks Identified

	Water	Chemical Disclosure	Air	Restrictions on Drilling
Federal	X	X	X	X
State	X			X

Form 10-K/10-Qs: The 2010 10-K has one paragraph describing potential regulations related to hydraulic fracturing, one paragraph noting risks associated with adequate water supplies and cost-effective water disposal and one paragraph discussing greenhouse gas emissions. Southwestern notes that it is focused on unconventional resources and that "the production of hydrocarbons from these sources has an energy intensity that is a number of times higher than that for production from conventional sources. Therefore, we expect that the carbon dioxide, or CO_2, intensity of our production will increase in the long-term." The June & Sept. 2011 10-Qs each briefly note risks associated with "legislation relating to hydraulic fracturing."

Identification of risks—Yes; regulatory and financial risks are discussed in the 2010 10-K and regulatory risks in the 2011 10-Qs.

Additional company communications

Discussion of mitigation measures: Yes; extensive

2010 annual report: The report incorporates the 2010 Form 10-K. There is no additional discussion beyond the risks mentioned above.

Sustainability/EHS report: The company does not publish a sustainability or EHS report.

Website: Southwestern has a section of its website entitled, "Our Responsibility," which identifies its initiatives to reduce its impact, particularly on air and water. Initiatives include "green completions" to prevent emissions of VOCs and methane during well completion, vapor recovery systems on condensate storage tanks, infrared cameras to detect fugitive emissions and a fresh water collection and transfer system using pipelines. It also has a page describing its well integrity standards.

Voluntary disclosure of chemicals in fracking fluid (by individual well): Yes; FracFocus. The company discloses all information provided by vendors, who do not always disclose all non-proprietary chemicals.

Voluntary posting of violations: No

Voluntary reporting of greenhouse gas emissions: Yes (methane emissions reduction); website and EPA's Natural Gas STAR summary report.

Company discusses prevention or mitigation measures relating to:			
Water delivery	X	Fracking fluid toxicity	
Fresh water storage	X	Solid waste storage	
Wastewater storage		Chemical storage	
Wastewater recycling	X	Spill prevention	
Wastewater disposal	X	Air emissions	X
Baseline water testing		Surface disturbance	X
Well integrity evaluation	X	Fuel switching	
Contractor oversight	X	Truck traffic/road wear	X
Noise		Community engagement	X

Board Oversight

Board committee with environmental responsibilities: None specifically disclosed.

Board committee with risk management oversight responsibilities: The Audit Committee has oversight responsibility relating to evaluation of enterprise risk issues, and the entire board engages in a review of the company's "strategic plan and the principal current and future risk exposures of the Company."

Violations/Fines/Litigation

The Arkansas Public Policy Panel, a nonprofit focused on economic and social justice, conducted an analysis of Arkansas Department of Environmental Quality (ADEQ) inspections in the Fayetteville Shale from July 2006 to August 2010. The ADEQ conducted 160 inspections at Southwestern Energy sites and 53 percent resulted in a total of 143 violations of water and other environmental laws, according to the panel. Comparatively, the panel identified 538 state inspections in total, with 54 percent finding more than 500 individual violations.

Recent Marcellus Shale Wells & Violations

	Wells Drilled	Inspections	Violations			Enforcements
			Total	EH&S	Adm.	
2009	0	-	-	-	-	-
2010	20	4	13	7	6	3
2011*	40	9	21	13	8	2
Total	60	13	34	20	14	5

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

In spring 2010, Southwestern Energy Production paid $50,000 to the Susquehanna River Basin Commission for beginning construction activity at a natural gas well pad without having secured a permit from the commission.

Litigation: In September 2010, 13 families in Lenox Township, Susquehanna County, Pa., filed suit against Southwestern Energy for allegedly contaminating their water, making them ill and damaging their property. The families cite spills and discharges of drilling waste, as well as improper casing of a gas well drilled in April 2008. The company notes that water samples taken from nearby water wells both before and during drilling showed that all parameters tested were below maximum contaminant levels. The company adds that the Pennsylvania Department of Environmental Protection has found no direct evidence of contamination from SEPCO's drilling operations.

In May 2011, two related class actions alleging personal injury and property damage claims as a result of Southwestern Energy's drilling in the Fayetteville Shale in Arkansas were filed. One suit filed against Southwestern and Chesapeake Energy claims drilling contaminated well water, and another alleges groundwater, air and soil contamination that has caused diminution in property values.

Shareholder Activity

In 2011, Domini Social Investments withdrew a shareholder resolution asking for a report on hydraulic fracturing, citing the company's candor about the risks and misconceptions surrounding hydraulic fracturing and a commitment to improved website disclosure.

WPX Energy

2010 revenues	$9.6 billion*
2010 employees	5,022 (WPX Energy 1,200)

*Exploration and Production: $4 billion

WPX Energy began trading on the New York Stock Exchange in January 2012 following its spin-off from the Williams Cos. WPX Energy is the former exploration and production business of Williams, which was the tenth largest natural gas producer in the United States in 2010. With nearly 97 percent of its domestic proved reserves in natural gas, WPX has been producing natural gas from unconventional formations since the early 1990s, including tight-sands gas, coal-bed methane and shale. WPX is focused on building a large-scale presence in the Marcellus Shale, having invested more than $1 billion there since 2009. WPX also acquired holdings in North Dakota's Bakken oil play In December 2010. At present, its largest area of concentrated development is in the Piceance basin in northwestern Colorado. WPX also has production areas in the Barnett Shale in Texas, the Powder River basin in Wyoming and the San Juan basin in New Mexico and Colorado. International activities, primarily in Argentina, represent approximately five percent of its total international and domestic proved reserves.

Given that WPX only recently became a stand-alone company, the information in this profile reflects the Williams Cos. and its exploration and production operations before the spin-off.

U.S. Shale Gas Reserves and Natural Gas Production					
Shale Gas Locations (net acres)		**Proved Natural Gas Reserves (billions of cubic feet equiv.[1])**		**Natural Gas Production**	
		Total	**4,272 Bcfe**	**2010 Bcf**	420 Bcf
		Developed	2,498 Bcfe	**2010 million cubic ft/day**	1,185 MMcf/d
Marcellus	99,301	Undeveloped	1,774 Bcfe		
Barnett	29,482	**% shale gas**	**5%**	**% produced from shale gas**	approx. 6%
		Barnett	4.4%	**Q2 2011**	1,203 MMcf/d*
		Marcellus	0.6%	**Q2 2010**	1,099 MMcf/d*

[1]Represents gas & oil reserves, 97% of which are gas.
Data as of Dec. 31, 2010 unless otherwise noted

*Source: NGSA

Public Disclosure of Related Risks and Mitigation Measures

Risk Identification

Form 10-K/10-Qs: The 2010 10-K has a short paragraph noting new state and local rules and moratoria on hydraulic fracturing and the possibility of additional related federal, state or local laws or regulations, including the Department of Interior's plans for public disclosure of fracking chemicals. There is no discussion in the June or Sept. 2011 10-Qs.

Regulatory Risks Identified				
	Water	**Chemical Disclosure**	**Air**	**Restrictions on Drilling**
Federal		X		
State				X

Identification of risks—Yes; regulatory risks are discussed in the 2010 10-K.

Additional company communications

Discussion of mitigation measures: Yes; moderate

2010 annual report: The report incorporates the 2010 Form 10-K. There is no additional discussion beyond the risks mentioned above.

Sustainability/EHS report: The 2010 Corporate Responsibility Report discusses community engagement, wastewater recycling, "green completions" to reduce fugitive air emissions, road wear and reducing the size of drill pads. The 2010 report also references the 2009 Corporate Responsibility Report, which includes five pages on hydraulic fracturing. In addition to the measures noted in the 2010 report, the 2009 report includes discussion of pressure testing, cement logging and reuse of well pads for off-site water and equipment storage.

Website: There is nothing distinct from the online 2010 Corporate Responsibility Report noted above.

Voluntary disclosure of chemicals in fracking fluid (by individual well): Yes; FracFocus. The company discloses only chemicals determined hazardous by OSHA and includes proprietary exemptions. WPX plans to broaden its disclosure in 2012 based on laws pending in certain states.

Voluntary posting of violations: Yes; the online 2010 Corporate Responsibility Report states that in 2010 Williams reported 123 spills associated with its exploration and production operations to either a state or federal regulatory agency.

Voluntary reporting of greenhouse gas emissions: Yes; online 2010 Corporate Responsibility Report.

Company discusses prevention or mitigation measures relating to:			
Water delivery	X	Fracking fluid toxicity	
Fresh water storage	X	Solid waste storage	
Wastewater storage		Chemical storage	
Wastewater recycling	X	Spill prevention	
Wastewater disposal	X	Air emissions	X
Baseline water testing		Surface disturbance	X
Well integrity evaluation	X	Fuel switching	
Contractor oversight		Truck traffic/road wear	X
Noise		Community engagement	X

Board Oversight

Board committee with environmental responsibilities: None specifically disclosed.

Board committee with risk management oversight responsibilities: Committees of the board govern an annual risk assurance process. The Audit Committee annually reviews and provides feedback on a list of the top risks, and the most appropriate board committee further reviews the top risks.

Violations/Fines/Litigation

Recent Marcellus Shale Wells & Violations						
	Wells Drilled	Inspections	Violations			Enforcements
			Total	EH&S	Adm.	
2009	0	-	-	-	-	-
2010	21	6	8	2	6	2
2011*	60	34	55	26	29	13
Total	81	40	63	28	35	15

*Wells through Nov.; inspections, violations and enforcements through Oct.
Source: Pennsylvania Department of Environmental Protection

Shareholder Activity

A 2010 shareholder resolution asking Williams Cos. for a report on hydraulic fracturing received support from 41.8 percent of the shares voted. Green Century Capital Management was the primary filer.

Appendix II: Key Stakeholders

Industry

America's Natural Gas Alliance

http://www.anga.us

Comprised of 30 of North America's largest gas producers, the Alliance has launched a national campaign to highlight the industry's commitment to Safe and Responsible Development.

American Petroleum Institute

http://www.api.org

With more than 400 corporate members, the API is a national trade association that represents all aspects of America's oil and natural gas industry. API developed a set of five documents highlighting best practices and providing guidance for risk management associated with hydraulic fracturing.

Barnett Shale Energy Education Council

http://www.bseec.org

Founded by eight companies operating in the Barnett Shale, the Council provides information to the public about gas drilling and production in the Barnett Shale region in North Texas.

Energy in Depth

http://www.energyindepth.org

Launched by the Independent Petroleum Association of America in 2009, Energy In Depth is a research, education and public outreach campaign "focused on getting the facts out about the promise and potential of responsibly developing America's onshore energy resource base—especially abundant sources of oil and natural gas from shale and other 'tight' reservoirs across the country."

Independent Petroleum Association of America

http://www.ipaa.org

IPAA is a national trade association that represents thousands of independent oil and natural gas producers and service companies across the United States.

Marcellus Shale Coalition

http://marcelluscoalition.org/

The Marcellus Shale Coalition is committed to the responsible development of natural gas from the Marcellus Shale. Its members, including more than 40 board members who are natural gas companies, work to address issues with regulations; local, county, state and federal government officials; and communities.

NaturalGas.org

http://www.naturalgas.org

NaturalGas.org is a website developed and maintained by the Natural Gas Supply Association (NGSA), whose members produce approximately one-third of the U.S. natural gas supply.

Environmental Organizations

Clean Air Task Force

http://www.catf.us/

CATF is a nonprofit organization dedicated to reducing atmospheric pollution through research, advocacy and private sector collaboration. Climate is a key focus of CATF staff, which includes senior engineers, MBAs, scientists, attorneys and communications specialists.

Environmental Defense Fund

www.edf.org

EDF links science, economics, law and innovative private-sector partnerships to address environmental problems. Its staff includes 340 scientists, economists and other professionals. EDF is collaborating with industry on model well integrity standards and model air standards for natural gas development.

Natural Resources Defense Council

http://www.nrdc.org/

The NRDC is an environmental action group staffed with more than 350 lawyers, scientists and other professionals. The NRDC is following hydraulic fracturing on Switchboard, the staff blog of the NRDC.

Sierra Club

http://www.sierraclub.org/

The Sierra Club is the nation's oldest and largest grassroots environmental advocacy group. Natural gas reform is one of the seven goals listed on its website.

Marcellus-Shale.us

http://www.marcellus-shale.us/

Website provides photos, information, opinions, stories, news and public meeting announcements about the Marcellus Shale.

Additional Nonprofit Organizations

FracFocus

http://fracfocus.org/

This hydraulic fracturing chemical registry website is a joint project of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

Groundwater Protection Council

http://www.gwpc.org/home/GWPC_Home.dwt

The GWPC is a national association of state ground water and underground injection control agencies whose mission is "to promote the protection and conservation of ground water resources for all beneficial uses, recognizing ground water as a critical component of the ecosystem." With the **Interstate Oil and Gas Compact Commission**, it created **FracFocus**. The Council also has a project to extend and expand the **Risk Based Data Management System**, which allows states to exchange information about defined parameters of importance to hydraulic fracturing operations.

Interstate Oil and Gas Compact Commission

http://www.iogcc.state.ok.us/

The Interstate Oil and Gas Compact Commission is a multi-state government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety and the environment. With the **Ground Water Protection Council**, it created **FracFocus**.

State Review of Oil and Natural Gas Environmental Regulations

http://www.strongerinc.org/

STRONGER is a non-profit, multi-stakeholder organization whose purpose is to assist states in documenting the environmental regulations associated with exploration, development and production of crude oil and natural gas.

Shareholder Proponents

Investor Environmental Health Network
http://iehn.org/home.php

Green Century Funds
http://www.greencentury.com/

New York State Common Retirement Fund
http://www.osc.state.ny.us/pension/index.htm

As You Sow Foundation
http://www.asyousow.org/

Miller/Howard Investments
http://www.mhinvest.com/

Trillium Asset Management
http://trilliuminvest.com/

Park Foundation
http://www.parkfoundation.org/

Interfaith Center on Corporate Responsibility
http://www.iccr.org/

Appendix III: Additional Resources

Annual Energy Outlook 2012 Early Release Overview

http://www.eia.gov/forecasts/aeo/er/
U.S. Energy Information Administration, April 2011

Annual Energy Outlook 2011

http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf
U.S. Energy Information Administration, April 2011

Blueprint for a Secure Energy Future

http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf
The White House, March 2011

Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management

http://www.ceres.org/aquagauge
Ceres, World Business Council for Sustainable Development, IRRC Institute and Irbaris, September 2011

CDP Water Disclosure Global Report 2011

https://www.cdproject.net/CDPResults/CDP-Water-Disclosure-Global-Report-2011.pdf
Carbon Disclosure Project, November 2011

"Drilling Down" series

http://www.nytimes.com/interactive/us/DRILLING_DOWN_SERIES.html
The New York Times, 2011

Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells

http://gekengineering.com/Downloads/Free_Downloads/Estimating_and_Explaining_Fracture_Risk_and_Improving_Fracture_Performance_in_Unconventional_Gas_and_Oil_Wells.pdf
George King, Apache Corp., January 2012

Extracting the Facts: An Investor Guide to Disclosing Risks from Hydraulic Fracturing Operations

http://iehn.org/publications.reports.frackguidance.php
Investor Environmental Health Network and the Interfaith Center on Corporate Responsibility, December 2011

Modern Shale Gas Development in the United States: A Primer

http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf
Prepared by the Ground Water Protection Council and ALL Consulting for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory, 2009

"Natural Gas Extraction — Hydraulic Fracturing" website

http://www.epa.gov/hydraulicfracture/
U.S. Environmental Protection Agency

Natural Gas STAR Program

http://www.epa.gov/gasstar/
U.S. Environmental Protection Agency

Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resource

http://www.npc.org/Prudent_Development.html
National Petroleum Council at the request of the U.S. Secretary of Energy, September 2011

Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays

http://www.eia.gov/analysis/studies/usshalegas/
U.S. Energy Information Administration, July 2011

Secretary of Energy Advisory Board Natural Gas Subcommittee's Interim and Final Reports

http://www.shalegas.energy.gov/
U.S. Department of Energy, August 2011 and November 2011

Shale Gas: Applying Technology to Solve America's Energy Choices

http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf
National Energy Technology Laboratory brochure, March 2011

Schlumberger Oilfield Glossary

http://www.glossary.oilfield.slb.com/
Schlumberger Limited, 2011