

Briefing Paper 1

Addressing the Environmental Risks from Shale Gas Development



**Mark Zoback
Saya Kitasei
Brad Copithorne**

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Mark Zoback^a, Saya Kitasei^b, Bradford Copithorne^c

I. Executive Summary

The rapid development of shale gas resources in the past few years has already dramatically affected U.S. energy markets—lowering energy prices and carbon dioxide emissions—and could offer an affordable source of low-carbon energy to reduce dependence on coal and oil.¹ However, the development of shale gas has been linked to a range of local environmental problems, generating a public backlash that threatens to bring production to a halt in some regions. While hydraulic fracturing in particular has been the focus of much controversy, our analysis indicates that the most significant environmental risks associated with the development of shale gas are similar to those associated with conventional onshore gas, including gas migration and groundwater contamination due to faulty well construction, blowouts, and above-ground leaks and spill of waste water and chemicals used during drilling and hydraulic fracturing.

Many technologies and best practices that can minimize the risks associated with shale gas development are already being used by some companies, and more are being developed. The natural gas industry should work with government agencies, environmental organizations, and local communities to develop innovative technologies and practices that can reduce the environmental risks and impacts associated with shale gas development.

Stronger, fully-enforced government regulations are needed in many states to provide sufficient protection to the environment as shale gas development increases. In addition, continued study and improved communication of the environmental risks associated with both individual wells and large scale shale gas development are essential for society to make well-informed decisions about its energy future.

This briefing paper, part of an on-going series on the role of natural gas in the future energy economy, provides an overview of how horizontal drilling and hydraulic fracturing are used to extract shale gas, examines the environmental risks, associated with shale gas development, and provides an overview of the industry best practices and government regulations that are needed if shale gas is to contribute its full potential to help build a low-carbon economy in the years ahead.

Cover photo: A drilling rig near Shreveport, Louisiana, by danielfoster437.

^a Benjamin M. Page Professor of Geophysics, Stanford University

^b MAP Sustainable Energy Fellow, Worldwatch Institute

^c Finance Specialist, Environmental Defense Fund

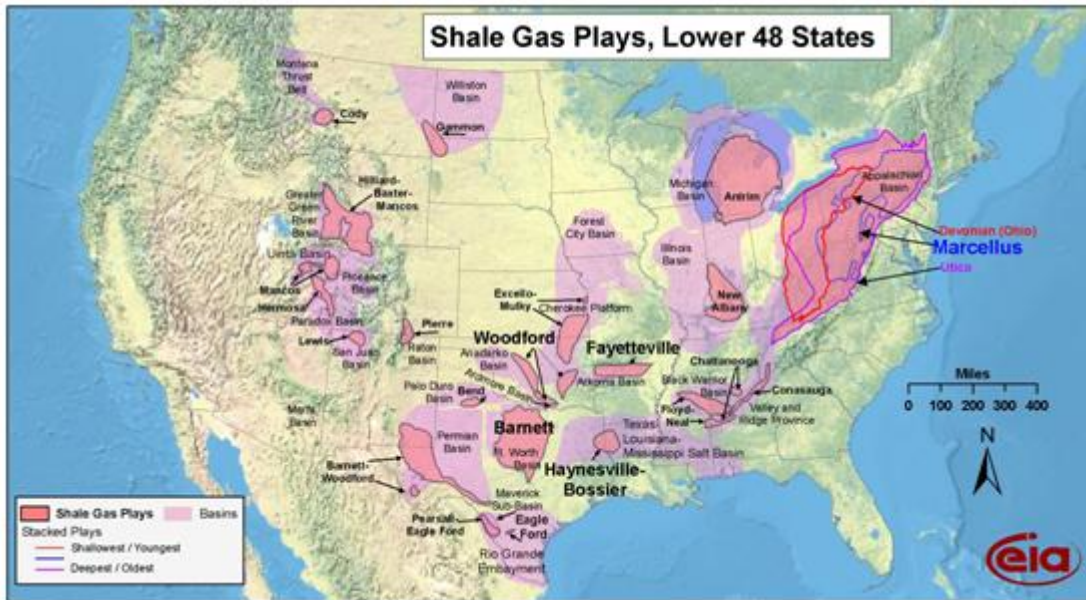
II. Extracting Natural Gas from Shale

Geologists have long been aware that large amounts of natural gas lie trapped in some formations of shale, a sedimentary rock formed from deposits of mud, silt, clay, and organic matter. Over time, that organic matter breaks down, creating molecules of methane, also known as natural gas. While some of this natural gas migrates into other formations over millions of years, much of it remains trapped in its shale source rock.

Although the first producing U.S. natural gas well was drilled into a shale formation in New York (in 1821), most commercial drilling during the 19th and 20th centuries targeted gas that has migrated out of its source rock and accumulated in permeable reservoirs such as sandstone formations.² Unlike these “conventional” reservoirs, whose relatively high permeability enables producers to extract gas using vertical wells, shale is a much “tighter,” less permeable rock. As a result, methane molecules cannot flow easily through shale and a vertical well is only able to drain gas only from a very small volume of the rock surrounding it, which generally prevents vertical wells from producing sufficient gas to be economical.

Over the past decade, however, the application of two techniques, horizontal drilling and hydraulic fracturing, has enabled operators to extract gas economically from shale formations thousands of feet deep. Although both technologies originally were developed to increase production from conventional wells, their use in the Barnett Shale, near Fort Worth, Texas, revealed that they could be the key to unlocking the trillions of cubic feet of natural gas estimated to exist in shale gas plays throughout the United States.³ (See Figure 1.) At year-end 2009, the five most productive U.S. shale gas fields – the Barnett, Haynesville, Fayetteville, Woodford, and Marcellus shales – were producing some 8.3 billion cubic feet a day, the equivalent of nearly 1.6 million barrels of oil a day, or 30 percent of total U.S. crude oil production during 2009.⁴

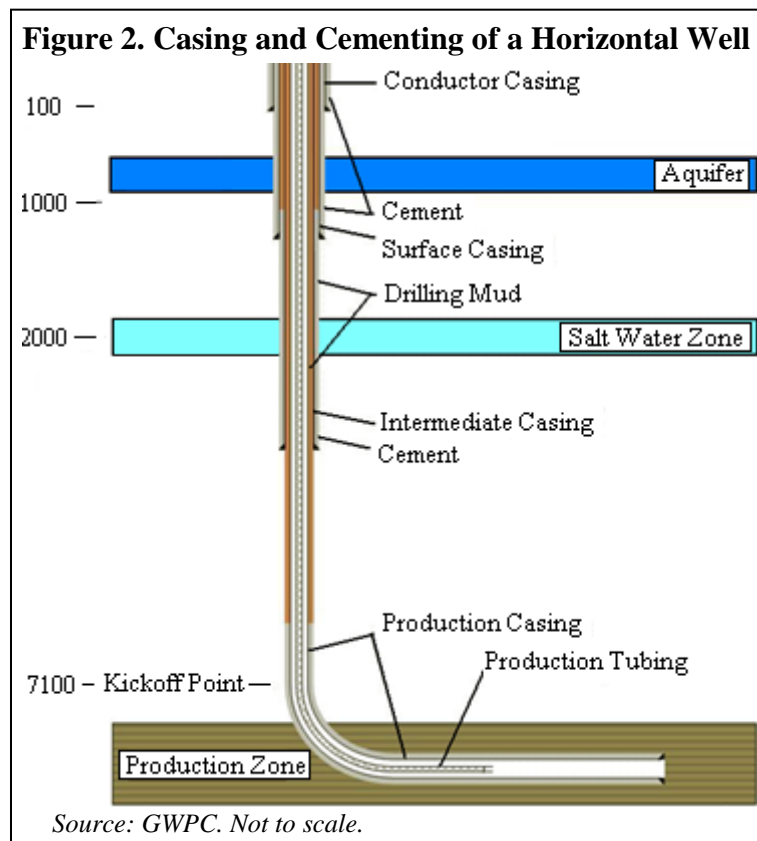
Figure 1. Map of Shale Gas Plays, Lower 48 States



Source: EIA

Oil and gas drilling generally begins in the same way in both vertical and horizontal wells. Operators insert an initial length of steel pipe, called “conductor casing,” into a vertical wellbore soon after drilling begins in order to stabilize the well as it passes through the shallow, often unconsolidated sediments and soils near the Earth’s surface.⁵ (See Figure 2.) Then, operators continue drilling vertically and insert surface casing, which most states require to extend from the ground’s surface past the depth of all underground sources of drinking water (USDW’s).⁶

Operators then pump cement into the casing, followed by water, to push the cement out through the bottom of the casing and back up into the space between the surface casing and the wellbore (called the “annulus”) until it is entirely filled. Almost all states require the surface casing to be fully-cemented before drilling is allowed to continue.⁷ After the surface casing has been cemented into place, regulators may require operators to install blowout prevention equipment (BOPE) at the surface to prevent any pressurized fluids encountered during drilling from moving up the well through the space between the drill pipe and the surface casing.⁸



After allowing the cement behind the casing to set, operators continue drilling for a short distance, typically 10 to 20 feet, and test the integrity of the cement by pressurizing the well. They then continue drilling vertically until state regulations may require the insertion of intermediate casing, which can be used to help stabilize deep wells. In addition, between the base of the surface casing and the target gas-bearing shale formations, wellbores pass through thousands of feet of rock formations. These formations may contain hydrocarbons, including natural gas, or briny water containing highly concentrated salts and other contaminants. Intermediate casing is designed to isolate such formations from each other and the wellbore, preventing contamination

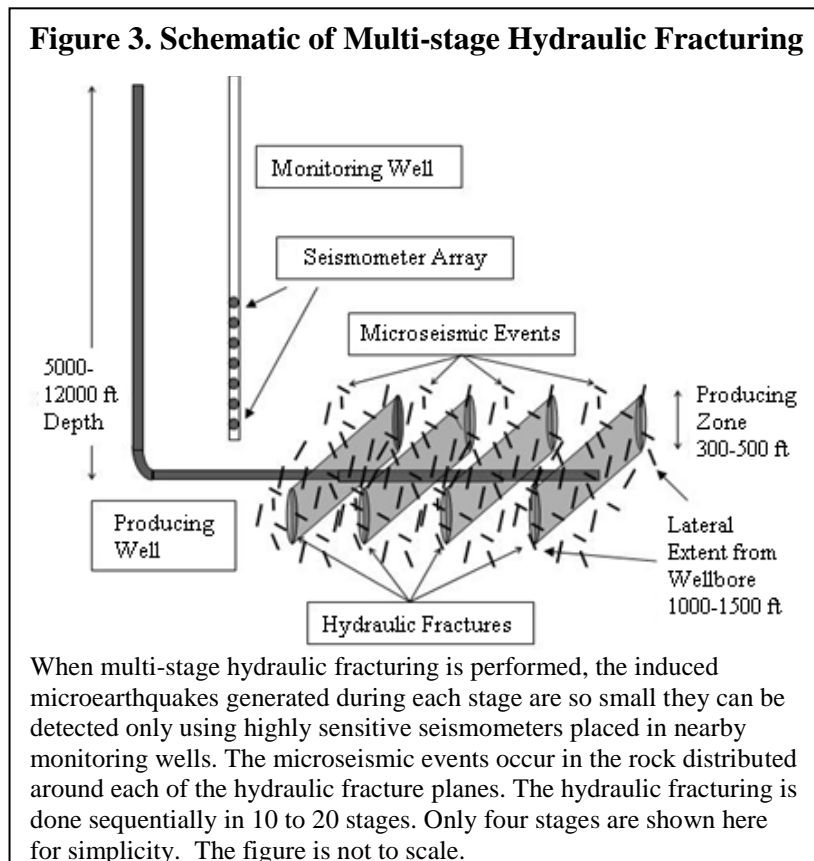
of the gas that will be produced and of freshwater aquifers near the Earth’s surface.

When drilling a horizontal well, operators begin turning or “kicking off” the drill when they near the top of the target formation or “production zone,” until the wellbore runs through the formation horizontally. Horizontal drilling, which can extend up to 10,000 feet, vastly increases the wellbore’s contact with the gas-bearing formation relative to vertical drilling, which would be limited to the thickness of the formation—less than 300 feet in most major U.S. shale plays.⁹

After drilling the horizontal section of the well, operators run a string of “production casing” into the well and cement it in place. They then “perforate” the production casing using small explosive charges at intervals along the horizontal wellbore where they intend to hydraulically fracture the shale.

Hydraulic fracturing was first used in the late 1940s, and has since become a common technique to enhance the production of low permeability formations, especially unconventional reservoirs such as tight sands, coal beds, and deep shales.¹⁰ Hydraulic fracturing is a technically complex process. Because most horizontal wells are quite long, operators conduct fracturing in stages, starting at the tip or “toe” and proceeding toward the end closest to the vertical portion or “heel” of the foot-shaped wellbore. A wellbore that extends 5,000 feet horizontally within a shale layer, for example, might be hydraulically fractured 10 to 15 times at intervals several hundred feet apart. Each perforation interval is isolated in sequence so that only a single section of the well is hydraulically fractured at a given time.

During a hydraulic fracturing operation, operators pump fracturing fluid at high pressure through the perforations in a section of the casing. The chemical composition of the fracturing fluid, as well as the rate and pressure at which it is pumped into the shale, are tailored to the specific properties of each shale formation and, to some extent, each well. When the pressure increases to a sufficient level, it causes a hydraulic fracture or “hydrofracture” to open in the rock, propagating along a plane more or less perpendicular to the path of the wellbore.¹¹ (See Figure 3.)



A typical hydrofracture is designed to propagate horizontally about 500 to 800 feet away from the well in each direction and vertically for the thickness of the shale. Operators monitor and control the fracture pressure to prevent vertical propagation beyond the thickness of the gas-producing shale layer.¹²

One of the most novel discoveries in the Barnett Shale was the possibility of using “slickwater” as a fracturing fluid in deep shale formations. Unlike the highly viscous gels used previously to fracture conventional formations, slickwater is a more dilute, low-viscosity water-based fluid designed to carry a small amount of sand into fractures to

prop them open after the pumping stops, allowing gas to escape. Chemical additives are designed

to inhibit scale and bacterial growth in the wellbore, reduce friction, and generally improve the effectiveness of the fracture job. Slickwater works well in shale gas reservoirs because its low viscosity allows the fracturing fluid to leak out of hydraulic fractures into many small, naturally occurring fractures in the shale.

Slickwater increases water pressure in these microfractures, inducing shear-slip, or micro-seismic events that generally have magnitudes of less than -1.5 on the Richter scale—about as much energy as is released by a gallon of milk dropped from chest height to the floor. Because of the small magnitudes of these events, which represent micro-earthquakes about one-millionth the size of tremors that might be detected by inhabitants of a populated area, operators must deploy ultrasensitive seismometers in nearby monitoring wells in order to detect them.¹³ (See Figure 4.)

Figure 4 shows microseismic data from a well drilled in the Barnett Shale and hydraulically fractured with slickwater in 11 stages. The locations of the microseismic events generated during slickwater hydraulic fracturing provides a picture of where the hydrofractures propagated. This information is important to operators because the microseismic events define the portion of the reservoir stimulated during hydraulic fracturing, increasing the shale's permeability and allowing gas molecules to flow more easily into the production casing.

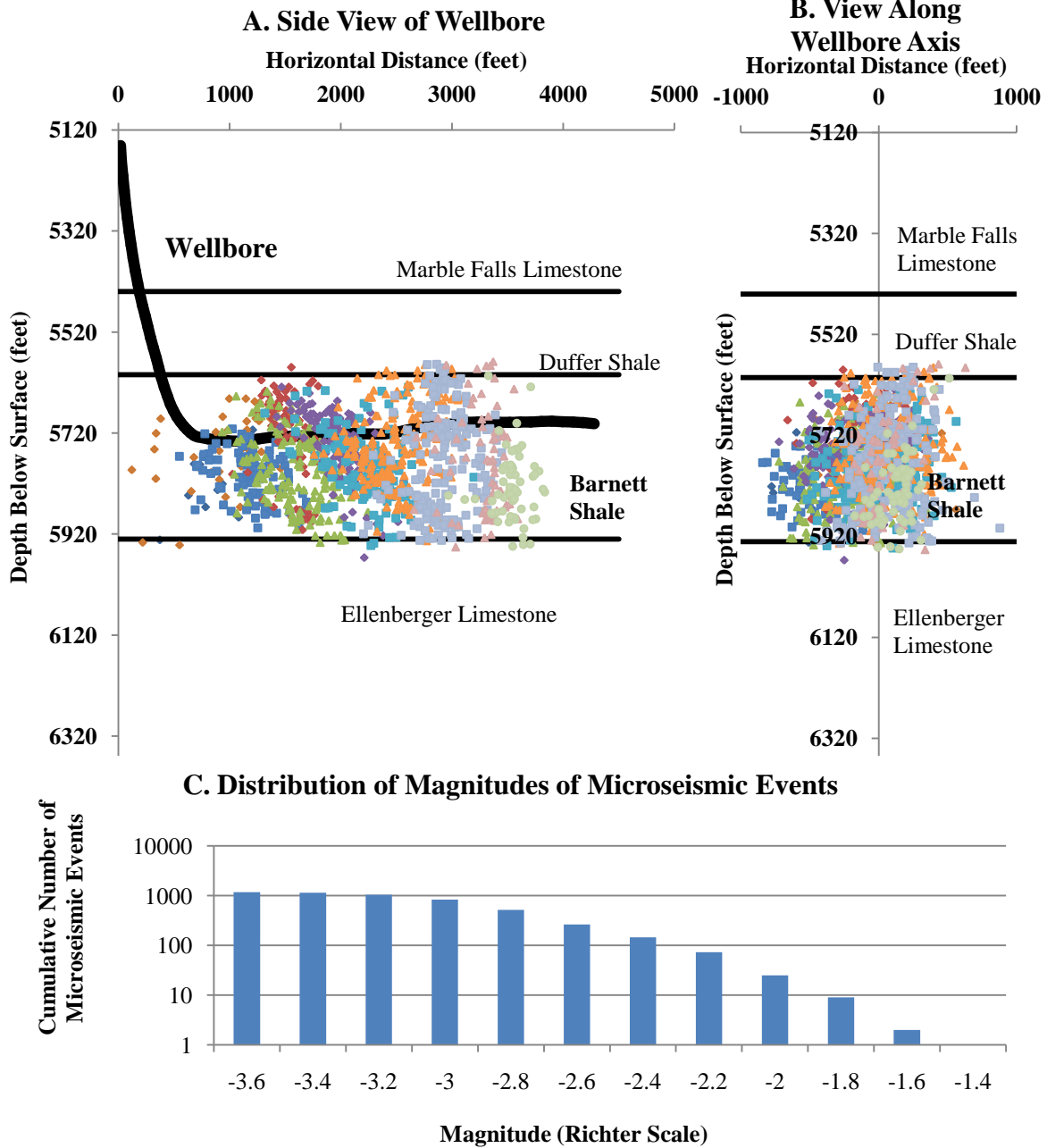
The above-mentioned well targeted a portion of the Barnett Shale about 330 feet thick and at depths between about 5,600 and 5,930 feet below the surface. The horizontal wellbore is roughly 3,800 feet long. Monitoring detected microseismic activity over the entire thickness of the shale, about 150 feet above and 200 feet below the wellbore (Figure 4A), and about 500 to 700 feet to its sides (Figure 4B). Monitoring did not detect microseismic activity any significant distances above or below the shale formation, suggesting that the design of this fracture job successfully confined stimulation to the target formation. In this case, the propagation of fractures into the underlying Ellenberger Limestone, which contains highly saline brine, would have allowed brine to contaminate the gas in the Barnett Shale, decreasing the efficiency and increasing the cost of its extraction. No microseismic events with magnitudes greater than -1.6 were detected.

Drilling and fracturing a typical horizontal well in the Marcellus shale takes about three weeks to complete and costs about \$3.5 to \$4.5 million.¹⁴ After hydraulic fracturing is complete, gas begins to flow out of the well to the surface, where it is processed, compressed, and transported to markets through pipelines. During this period, maintenance may be performed on the well, but much of the equipment used for drilling and fracturing the well is used to drill another horizontal well from the same well pad and wellbore or removed for use at other sites. Each unconventional well's production rate declines rapidly after the first few months of production. While the great majority of gas is produced during the first few years of production, a well could continue to produce for five to ten years before becoming uneconomical.¹⁵ In some cases, a well may be fractured again to restimulate production, but while research is underway to improve the performance of refracturing, it is not currently used in most shale gas wells.¹⁶

When a well becomes uneconomical, state regulations require operators to permanently plug it with cement or another material. The majority of gas-producing states require plugs to be placed through producing zones and from the surface to the base of ground water. Plugs are intended to prevent fluid, which might include hydrocarbons, formation water, and fracturing fluid absorbed

by the target formation, from migrating along the wellbore to other layers of rock and potentially contaminating ground water after the well has been abandoned.¹⁷

Figure 4. Microseismic Diagrams of Typical Hydraulic Fracturing Job in the Barnett Shale



Each dot in Figure 4A and B represents a microseismic event induced during hydraulic fracturing of an actual well in the Barnett Shale, with each color representing a distinct fracturing stage. Figure 4C displays the distribution of these microseismic events by magnitude. Figures are not to scale.

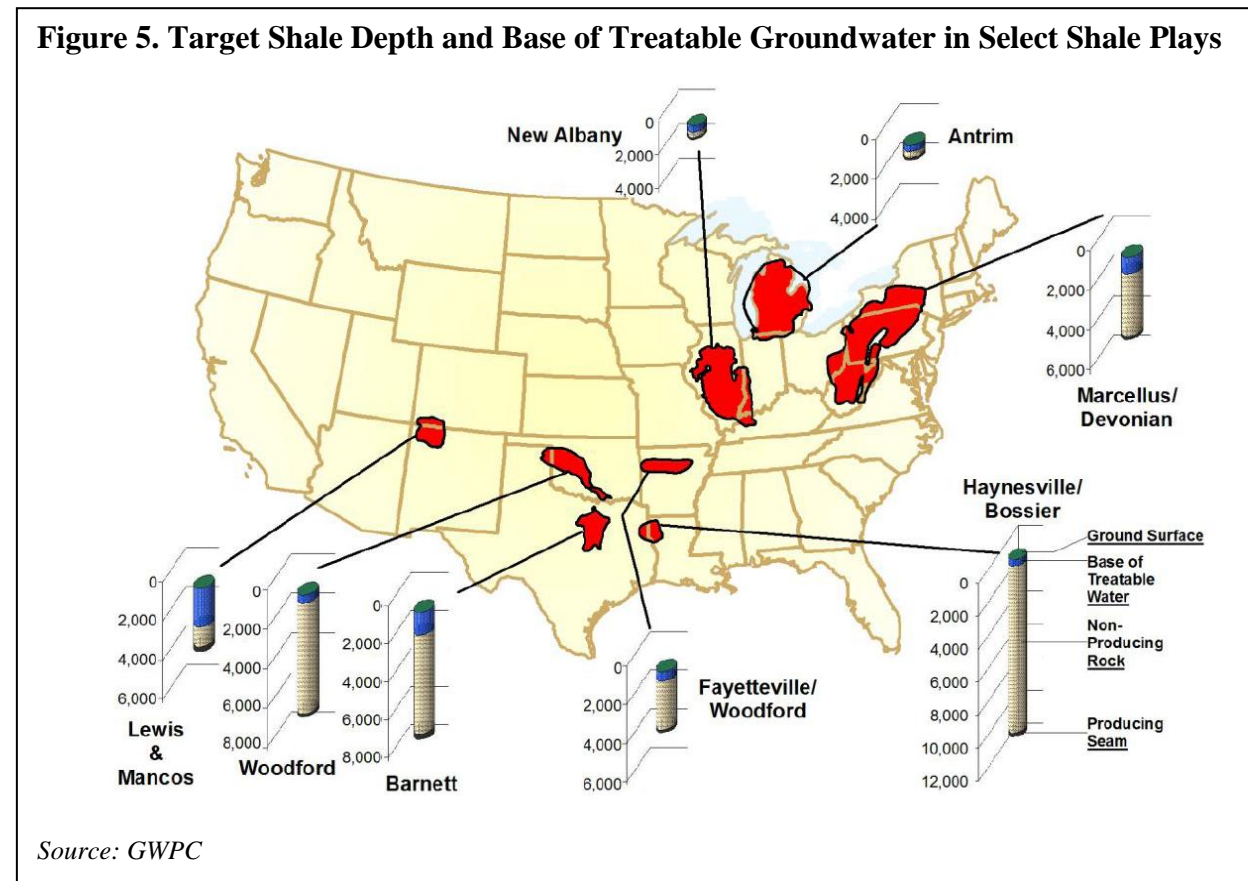
Source: Data courtesy of the Stanford Department of Geophysics

III. Environmental Risks and Best Practices

Shale gas has received a good deal of attention recently for the potential negative impacts that its development may have on the environments and communities in which it occurs. Instances of water contamination, air pollution, and earthquakes have been blamed on gas extraction activities. A thorough understanding of the techniques used to extract gas from shale formations and the safeguards that exist to prevent environmental damage is critical to assessing the sources and magnitudes of risk involved in shale gas development.

Subsurface Contamination of Ground Water

A frequently expressed concern about shale gas development is that subsurface hydraulic fracturing operations in deep shale formations might create fractures that extend well beyond the target formation to water aquifers, allowing methane, contaminants naturally occurring in formation water, and fracturing fluids to migrate from the target formation into drinking water supplies. With the notable exceptions of the shallow Antrim and New Albany Shales, many thousands of feet of rock separate most major gas-bearing shale formations in the United States from the base of aquifers that contain drinkable water.¹⁸ (See Figure 5.)



Because the direct contamination of underground sources of drinking water from fractures created by hydraulic fracturing would require hydrofractures to propagate several thousand feet

beyond the upward boundary of the target formation through many layers of rock, such contamination is highly unlikely to occur in deep shale formations during well-designed fracture jobs. For example, the top of the Marcellus Shale, which runs from upstate New York through Pennsylvania, West Virginia, and parts of Ohio, lies from 4,000 to 8,500 feet below the surface.¹⁹ The deepest underground sources of drinking water in this region lie about 850 feet below the surface.²⁰ Geologists estimate that there is at least a half mile of rock between the natural gas deposits and the groundwater, including nine layers of impermeable shale, each of which acts as a barrier to vertical propagation of both natural and artificial fractures.²¹

As mentioned earlier, seismic monitoring is an essential tool for assuring that hydraulic fracturing is inducing microseismic activity only within the shale gas reservoir. Yet only about three percent of the ~75,000 hydraulic fracturing stages conducted in the United States in 2009 were seismically monitored.²² Public confidence in the safety of hydraulic fracturing would be greatly improved by more frequent microseismic monitoring and public dissemination of the results.

Failure of the cement or casing surrounding the wellbore poses a far greater risk to water supplies. If the annulus is improperly sealed, natural gas, fracturing fluids, and formation water containing high concentrations of dissolved solids may be communicated directly along the outside of the wellbore among the target formation, drinking water aquifers, and layers of rock in between. For example, in 2007, a well that had been drilled almost 4,000 feet into a tight sand formation in Bainbridge, Ohio was not properly sealed with cement, allowing gas from a shale layer above the target tight sand formation to travel through the annulus into an underground source of drinking water. The methane eventually built up until an explosion in a resident's basement alerted state officials to the problem.²³

A variety of tools exist to help producers and regulators minimize the risk of cement and casing failures. The American Petroleum Institute (API) develops and updates standards and "recommended practices" for oil and gas exploration and production activities.²⁴ Many state regulations require steel casing and cement used in oil and gas well construction to meet standards set by API or other organizations.²⁵ Frequent monitoring and testing also allow producers and regulators to check the integrity of casing and cement jobs. Many states require operators to perform a test such as a cement bond log, which measures the quality of the cement-casing and cement-formation bonds.²⁶ Ensuring that these tests are conducted and heeded in accordance with regulations, and requiring them in states where they are currently voluntary, are essential to preventing accidents such as occurred in Bainbridge.

Blowouts

Recent gas well blowouts in Pennsylvania and West Virginia during drilling operations in the Marcellus Shale, set against the backdrop of the recent offshore blowout and oil spill in the Gulf of Mexico, underscore the environmental and public risks associated with drilling into highly pressurized zones of hydrocarbons and introducing pressurized fluids during hydraulic fracturing.²⁷ At the time of writing this article, the causes of all three blowouts were still under investigation. Operators in Pennsylvania reported that that blowout occurred because the blowout preventer proved inadequate to deal with higher-than-anticipated pressures.²⁸ In West Virginia,

drillers reportedly encountered an unexpected pocket of methane in an abandoned coal mine only about 1,000 feet below the surface, and a blowout preventer had not yet been installed.²⁹

Such disasters stress the need for gathering accurate information about the subsurface and ensuring that personnel on drill sites are trained to deal with unusual and unexpected situations, including blowouts. Even if drilling and well construction are carried out in full compliance with local, state, and federal regulations, and industry best practices are followed, many decisions during drilling and fracturing operations must be made by individuals, and training and experience, together with full enforcement of strong regulations and adoption of industry best practices, are critical to the protection of the public and the environment.

Seismic Risks

Another subsurface risk that has received attention recently is the possibility that drilling and hydraulically fracturing shale gas wells might cause low-magnitude earthquakes. In 2008 and 2009, the town of Cleburne, Texas, experienced several clusters of weak earthquakes all registering 3.3 or less on the Richter scale.³⁰ Since the town had never registered an earthquake in its 142-year history, some residents wondered if the recent increase in local drilling activity associated with the Barnett Shale might be responsible. A study by seismologists with the University of Texas and Southern Methodist University found no conclusive link between hydraulic fracturing and these earthquakes but indicated that the injection of waste water from gas operations into numerous saltwater disposal wells that were being operated in the vicinity could have caused the seismic activity.³¹ Over 200 such wells exist in the Barnett Shale, and are the preferred means of waste water disposal for operators in the area.³²

While the hydraulic fracturing process does create a large number of microseismic events, or micro-earthquakes, the magnitudes of these are generally too small to be detected at the surface. Figure 4C shows the cumulative frequency distribution of microseismic events of different size in a Barnett Shale well. Altogether, a downhole seismometer array deployed in a nearby well detected about 1,000 micro-earthquakes. The biggest micro-earthquakes have a magnitude of about -1.6. An earthquake of this size represents slip of less than a hundredth of an inch, about the thickness of a human hair, on a pre-existing fault only a couple of feet across. The number of extremely small earthquakes (less than a magnitude of about -2.8) tapers off because they are so small that they cannot be detected.

Underground fluid injection is an integral part not only of hydraulic fracturing, but of waste water disposal in injection wells, some geothermal energy projects, and carbon dioxide sequestration. The seismic monitoring of hydraulic fracture jobs discussed earlier is critical to improving understanding of how underground injection might spark unexpectedly high-magnitude seismic activity.

Surface Water and Soil Contamination

Because of the quantities of chemicals that must be stored at drilling sites and the volumes of liquid and solid waste that are produced, significant care must be taken that these materials do not contaminate surface water and soil during their transport, storage, and disposal.

Fluids used for slickwater hydraulic fracturing are typically more than 98 percent fresh water and sand by volume, with the remainder made up of chemicals that improve the treatment's effectiveness, such as thickeners and friction reducers, and protect the production casing, such as corrosion inhibitors and biocides.³³ These fluids are designed by service companies that tailor fracturing treatments to suit the needs of a particular job. In a 2009 survey of six service companies and 12 chemical providers, the New York State Department of Environmental Conservation received a list of some 200 chemical additives that companies might use in fracturing fluids.³⁴

Because the fluids in each fracturing treatment would contain a different subset of these chemicals, and because these chemicals could be hazardous in sufficient concentrations, public disclosure of the chemicals used in hydraulic fracturing on a site-by-site basis is necessary to enable regulatory agencies, health professionals, and citizens to conduct baseline water testing and respond appropriately should contamination or exposure occur. A number of companies are investigating use of more environmentally benign fracturing fluids.³⁵ These would also help limit the environmental and health risks posed by fracturing fluids in the case of contamination.

Chemicals to be used in fracturing fluids are generally stored at drilling sites in tanks before they are mixed with water in preparation for a fracturing job. Under the Emergency Planning and Community Right to Know Act of 1986 (EPCRA), companies must post Material Safety Data Sheets (MSDSs) that list the properties and any health effects of chemicals stored in quantities of more than 10,000 pounds.³⁶ Disclosure of chemicals stored in smaller quantities is not currently required by law, and access to MSDSs can often be limited. Several ongoing efforts would require greater disclosure of fracturing fluids, including a provision in draft climate legislation introduced by Senators John Kerry (D-MA) and Joe Lieberman (I-CT) in May 2010 that would amend EPCRA to mandate the disclosure of all chemicals used on public websites.³⁷

After each fracturing stage, the fracturing fluid, along with any water originally present in the shale formation, is "flowed back" through the wellbore to the surface. Flowback and water produced during a well's lifetime can contain naturally occurring formation water that is millions of years old and therefore can display high concentrations of salts, naturally occurring radioactive material (NORM), and other contaminants including arsenic, benzene, and mercury.³⁸ As a result, the water produced during hydraulic fracturing must be disposed of properly. The "flowback" period typically lasts for periods of hours to weeks, although some injected water can continue to be produced along with gas several months after production has started.³⁹ In the Marcellus Shale, approximately 25 percent of the water injected during hydraulic fracturing operations may be produced during flowback.⁴⁰

Flowback water is dealt with differently in different states. In the Barnett, Fayetteville, Haynesville, Woodford, Antrim, and New Albany Shales, the primary disposal method has been injection into underground saline aquifers, such as the Ellenberger Limestone that underlies the Barnett formation.⁴¹ While injection is regulated at the federal level under the Safe Drinking Water Act (SDWA), the availability of adequate disposal wells is a major issue that needs to be addressed for shale gas development to take place. There are tens of thousands of licensed

injection wells in Texas, but because of political and geological constraints, many fewer exist in the Marcellus Shale. The state of Pennsylvania currently only has about 10 Class II wells.⁴²

As a result, one option for dealing with flowback water from wells in the Marcellus Shale is disposal at municipal waste water treatment facilities, which generally discharge treated water into surface water bodies such as rivers and streams.⁴³ Current waste water treatment facilities in the Marcellus are insufficient to handle the volumes of fluids that would be produced were shale gas development to increase significantly. In addition, they may not be designed to handle the highly saline water produced by gas drilling.

In late 2008 and 2009, there were significant spikes in the level of total dissolved solids (TDS) in Pennsylvania's Monongahela River, which supplies drinking water to approximately 350,000 people. Since flowback contains large amounts of total dissolved solids (TDS), and drilling fluids constituted up to 20 percent of the waste water being treated by some facilities, the Pennsylvania Department of Environmental Protection (PADEP) ordered these facilities to restrict their intake of drilling waste water.⁴⁴ PADEP reported that TDS levels, which also can be influenced by abandoned mine drainage, stormwater runoff, and discharges from industrial or sewage treatment plants, exceeded standards at least twice more in 2009.⁴⁵

Given the constraints on both underground injection and treatment and discharge in the Marcellus Shale, serious investment will be needed in advancing treatment technologies that enable companies to reuse fluids for subsequent fracturing jobs. As flowback comprises only 25 percent of the water injected into a given well in the Marcellus, treated flowback water could be diluted with fresh water and re-injected. Recycling water minimizes both the overall amount of water used for fracturing and the amount that must be disposed of. Many water treatment processes are currently being investigated that could be potentially be used at large scale and have a significant impact on this problem.⁴⁶

Finally, one of the problematic aspects of handling flowback water is the temporary storage and transport of such fluids prior to treatment or disposal. In many cases, fluids may be stored in lined or even unlined open evaporation pits.⁴⁷ Even if the produced water does not seep directly into the soil, a heavy rain can cause a pit to overflow and create contaminated runoff.⁴⁸ Storing produced water in enclosed steel tanks, a practice already used in some wells, would reduce the risk of contamination while improving water retention for subsequent reuse.⁴⁹

In addition, equipment used to move fluids between storage tanks or pits and the wellhead must be monitored and tested regularly to prevent spills, and precautions must be taken while transporting produced water to injection or treatment sites, whether via pipeline or truck. In May 2009, PADEP discovered that two leaky joints in a pipeline carrying waste water from gas wells to a disposal site had resulted in the release of about 4,200 gallons of waste water into Cross Creek, causing the deaths of some fish and invertebrates.⁵⁰ Range Resources, the owner of the wells, was fined for this violation of Pennsylvania's environmental statutes, as well as for another spill that occurred in October 2009.⁵¹

Other Surface Impacts

Drilling operations require significant above-ground development. In addition to the well pad itself, roads may need to be built and gathering infrastructure installed to bring the natural gas from the wellhead to a pipeline that, for a typical well in the Marcellus Shale, may require the development of several acres of land. Total land use can be reduced by drilling multiple wells from a single well pad, as is done in areas of steep topography or environmental sensitivity. Nonetheless, because so many wells have to be drilled and appreciable infrastructure developed, it is important to do as much as possible to minimize the overall impact on local communities. Land use decisions affect a wide range of stakeholders including the landowners, neighbors and surrounding communities. Permitting procedures will need to evaluate the needs of each of the stakeholders and include clear and enforceable remediation strategies to ensure minimal impact and maximum restoration of the land associated with natural gas production.

The trucks used to transport equipment, fracturing fluid ingredients, and water to the wellpad, drilling rigs, compressors, and pumps all emit air pollutants, including carbon dioxide, nitrogen and sulfur oxides (NO_x and SO_x), and particulate matter. Volatile organic compounds (VOCs) and other pollutants associated with natural gas and fracturing fluids can enter the air from wells and evaporation pits. In addition, natural gas, whose main component is methane, is itself a greenhouse gas more potent than carbon dioxide and could represent a significant source of emissions during the gas production process.⁵²

Many technologies and practices to reduce venting and leakage during gas production and transport have been compiled by the U.S. EPA's Natural Gas STAR program.⁵³ Emissions of gases that contribute to local air pollution, public health risks and climate change can be reduced by available control technologies, improved monitoring, and more efficient production operations. (The impacts of natural gas development with air quality will be the focus of a future briefing paper by the Natural Gas and Sustainable Energy Initiative.)

Even compared with drilling, which might use up to a million gallons of water per well, hydraulic fracturing is a water-intensive procedure, requiring between 2 and 8 million gallons per well fractured.⁵⁴ In the Barnett Shale, for example, an average of almost 3 million gallons of water is used per well, the great majority of which is used for hydraulic fracturing.⁵⁵ Since development of this resource will require tens of thousands of shale gas wells to be drilled, the required volumes of water are dramatic.

Any set of water use regulations must take into account local hydrology and competing uses for the water in a given area. Operators and regulators must work together to explore opportunities to reduce water use and increase recycling of produced water. Greater reuse of fracturing fluids would reduce demands on community water supplies. Steps can also be taken to utilize excess water during peak seasonal run-off and to try to use less water during slickwater fracturing operations. (The water requirements for natural gas development will be the focus of a future briefing paper by the Natural Gas and Sustainable Energy Initiative.)

While a well is being drilled and completed, operators are generally working around the clock for several weeks. Drilling sites generate significant amounts of noise pollution, although noise

can be reduced through the construction of sound barriers.⁵⁶ Gas development can also affect communities in less tangible ways. While it may stimulate the local economy and provide jobs, gas development may also lead to increased traffic and greater strains on public resources. Operators must work with local stakeholders to minimize the impact of gas development activities on a community's resources and quality of life.

BOX: Current Regulatory Framework Governing Shale Gas Development

Most regulation of oil and gas development is currently left to the states, where regulatory bodies are in charge of enforcing state environmental laws as well as rules and regulations specific to oil and gas production. Rules and regulations developed by state agencies such as the Colorado Oil and Gas Conservation Commission, the Texas Railroad Commission, or the Pennsylvania Department of Environmental Protection govern the specifics of gas production, requiring producers to obtain permits before drilling, and requiring certain standards and practices to be used during well construction, hydraulic fracturing, waste handling, and well plugging. State regulations also deal with tanks and pits as well as any chemical or waste water spills.

Currently, there is significant variation in the particulars of these rules and regulations from state to state. For example, in a 2009 survey of the 27 largest gas-producing states, the Ground Water Protection Council (GWPC) found that 25 states required surface casing to be set below the deepest groundwater, 21 require a cement set-up period or test such as a cement bond log, 10 require companies to list chemicals or pressures used during hydraulic fracturing, and none requires companies to list an estimate of how much of this fracturing fluid flows back to the surface after a well has been fractured. The non-profit STRONGER (State Review of Oil and Natural Gas Environmental Regulations) has been updating guidelines for reviews of state programs since 1999. A list of states that have completed initial and follow-up reviews is available on STRONGER's website (www.strongerinc.org).

In addition to these state rules and regulations, some federal environmental regulations also apply to shale gas development. For example, the Clean Water Act regulates contaminated storm water runoff and surface discharges of water from drilling sites, and the 1986 Emergency Planning and Community Right-to-Know Act (EPCRA) requires companies to post material safety data sheets describing the properties and health effects of any chemicals stored in quantities that exceed 10,000 pounds. In some cases, states may obtain authority to enforce a federal law. The Safe Drinking Water Act (SDWA), which regulates the underground injection of waste water from gas wells, though not hydraulic fracturing, is one example of a federal law which allows state regulatory agencies to obtain primacy over enforcement if they demonstrate that they can do so to the minimum standards laid forth by the Environmental Protection Agency.

Source: See Endnotes 2 and 5 for this section.

IV. Conclusion

New supplies of gas from shale could provide many U.S. states with an attractive, lower-carbon transition fuel on the path to a fully renewable energy supply, while providing jobs and generating appreciable revenue. However, these opportunities cannot be realized unless the environmental risks posed by shale gas development are managed effectively. Our analysis suggests that while shale gas development poses significant risks to the environment, including faulty well construction, blowouts, and above-ground contamination due to leaks and spills of fracturing fluids and waste water, technologies and best practices exist that can help manage these risks.

Best practices are currently being applied by some producers in some locations, but not by all producers in all locations. Enforcing strong regulations is necessary to ensure broader adoption of these practices and to minimize risk to the environment. In addition, if increased shale gas development is to be undertaken responsibly, the cumulative risks of developing thousands of wells must be considered. Ongoing studies by the Environmental Protection Agency and others examining the environmental impacts of hydraulic fracturing will arm state and federal decision makers with critical information upon which to base future regulations.

By developing and adopting innovative best practices, industry can take a proactive role in addressing the environmental risks associated with shale gas development. The Houston Advanced Research Center and Texas A&M University are working with companies, environmental organizations, universities, government laboratories, state and federal agencies, and others to reduce the environmental impacts of drilling and production. The Environmentally Friendly Drilling Systems Program focuses on solutions to reduce the footprint of drilling activities, ensure the safe transport and disposal of drilling fluids and cuttings, lower air and noise pollution, and minimize other risks to the environment.⁵⁷

Robust regulatory oversight is an important ingredient to assure environmental and public protection. Under current U.S. laws, some aspects of shale gas development are regulated by the Clean Water Act, the Clean Air Act, and the Safe Drinking Water Act, but regulation of drilling and hydraulic fracturing is left largely to the state level where regulatory capacity and enforcement, as well as the regulations themselves, vary widely.

The state of Colorado recently revised its oil and gas rules to strengthen protections for the local environment.⁵⁸ The new rules, which went into effect on April 1, 2009, were devised after a boom in gas production from coal bed methane and tight sands was linked to both environmental and public health problems as well as permitting bottlenecks. Colorado Governor Bill Ritter has argued that the public assurance that these rules created was as an important prerequisite for adoption of Colorado's 2010 Clean Air-Clean Jobs Act. That Act requires Colorado's rate regulated utilities to retire or re-power some 900 megawatts of coal-fired power plants, displacing them primarily with natural gas.⁵⁹ However, many independent producers feel that they were excluded from what was touted as a multi-stakeholder process and argue that the Colorado Oil and Gas Conservation Commission did not fully account for the increased costs the new rules would impose, while some environmentalists feel that the revisions did not go far enough.⁶⁰

Colorado's example provides valuable lessons to other states pursuing their own reform of oil and gas regulations. The Wyoming Oil and Gas Conservation Commission passed a package of new oil and gas drilling rules on June 8, 2010. These rules make Wyoming the first state to require operators to disclose the composition and concentration of chemicals used in hydraulic fracturing.⁶¹ Other shale-producing states may soon follow suit.⁶²

New York, a relative newcomer to the modern oil and gas industry, has been the site of a contentious debate over future development of the state's gas resources in the Marcellus Shale. The New York Department of Environmental Conservation (NYSDEC) has been charged with updating rules regulating horizontal drilling and high-volume hydraulic fracturing and is currently evaluating public comments on a draft Supplemental Generic Environmental Impact Statement that it released in September 2009.⁶³ In the meantime, 10 bills relating to shale gas development, including one that would place a moratorium on drilling until 120 days after the EPA's study of hydraulic fracturing is completed, are making their way through the state legislature.⁶⁴ In neighboring Pennsylvania, where over 564 wells were drilled in the Marcellus Shale during the first half of 2010, Governor Ed Rendell has said that he would sign a bill calling for a three-year moratorium on new leasing of state forest land for gas exploration while potential environmental impacts are studied.⁶⁵

The experiences of Colorado, Wyoming, Pennsylvania, and New York have demonstrated that strong public pressure exists for stricter oversight of the oil and gas industry and that state regulators can and will move forward in strengthening their own regulations. If they are produced responsibly, shale gas resources in the United States could play a central role in building a low-carbon energy economy. Greater outreach and public education about shale gas development are clearly necessary to enable the many stakeholders engaged in shale gas development to work together to find the most effective technological and regulatory solutions for developing shale gas resources while protecting the environment and public interest.

Endnotes

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- ⁵ Figure 2 from GWPC, *State Oil and Natural Gas Regulations Designed to Protect Water Resources*, prepared for NETL (Oklahoma City, OK: May 2009), p. 20.
- ⁶ State regulations requiring surface casing to be set below the deepest ground water exist in 25 of the 27 oil and gas-producing states surveyed by the GWPC in 2008. Twenty-four states required surface casing to be cemented along its entire length. GWPC and NETL, *State Oil and Gas Regulations Designed to Protect Water Resources* (Oklahoma City: May 2009), p. 19.
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- ¹⁰ GWPC, *op. cit.* note 5, p. 21.
- ¹¹ Figure 3 created by Mark Zoback, Stanford University.
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