4. Risks to the Environment

In April 2012, President Barack Obama ordered the U.S. DOE, U.S. Department of the Interior (DOI), and the U.S. EPA to cooperate and collaborate on studies related to the potential environmental impacts of unconventional oil and gas (UOG) development. The DOE oil and gas research program had been largely focused in this area already after Energy Secretary Chu ordered risk assessment studies following the 2010 Deepwater Horizon disaster on the Macondo well in the Gulf of Mexico, and several contentious public meetings on the issue of “fracking.” The three agencies developed a joint research plan to identify and address the major issues (http://unconventional.energy.gov/). The Department of Health and Human Services (HHS) was added the following year to provide expertise with human health issues, and the National Science Foundation (NSF) was brought in to help plan research and prevent duplication of effort.

The agencies divided the study into areas where each had the most expertise. DOE focused on the engineering aspects of UOG production to try to determine how drilling fluids and frac chemicals might be escaping from containment and entering the environment. The DOI effort was primarily centered within the USGS, and it focused on resource impacts, establishing baselines, and detecting changes to water and biological resources from UOG operations. This included assessing the possible trends for future UOG development with DOE. The EPA and HHS were focused on the receptors of UOG-related chemicals released into the environment, including potential impacts of drilling, hydraulic fracturing, and production on drinking water resources, ecosystems, and human health. The role of the NSF was to coordinate federal research efforts with studies being funded at various universities.

The focus areas of the interagency UOG investigation included trends of future resource development to assess the locations that might be impacted next, determining impacts on both water availability and water quality, assessing air quality and the life cycle of greenhouse gas emissions, establishing the mechanisms and magnitude of induced seismicity, and trying to quantify both ecosystem and human health effects. The focus by DOE on “engineering risks” has been to understand how the drilling, completion, stimulation, and production activities of shale gas wells might be releasing contaminants into the environment (Soeder et al., 2014b). This is different from “environmental risk,” which assesses the relative impacts of contaminants on receptors in terrestrial or aquatic ecosystems, and which falls into the mission space of the EPA.

Engineering risks of shale gas development include the potential for affecting groundwater during the drilling process as the upper part of the well or “tophole” penetrates the shallow aquifers (Zhang and Soeder, 2015). The construction of the wellbore, cementing technique, and verification of wellbore integrity are other potential engineering risks (Dusseault et al., 2000; Kutchko et al., 2012). Risks during the hydraulic fracturing or stimulation part of the operation include surface spills and leaks from the large volumes of concentrated chemicals stored onsite (Soeder et al., 2014b), or unusual circumstances where the hydraulic fracture itself might go out of zone into shallower formations (Hammack et al., 2014; Myshakin et al., 2015). Finally, during the production phase itself, there is a risk that the well may deteriorate over time and leak gas or oil into aquifers (Dusseault and Jackson, 2014), or that toxins from muds, fluids, and black shale drill cuttings left behind on the surface may slowly leach into the shallow groundwater (Soeder et al., 2014b).

Large amounts of unbiased scientific data from shale gas development done under different circumstances in a variety of locations are needed to obtain an understanding of the true engineering risks of shale gas, but obtaining such data has been difficult. Some researchers have gone into state compliance records and notices of violation to try to construct a statistically valid picture of risk. Tony Ingraffea of Cornell University and his collaborators analyzed 75,505 compliance reports for 41,381 conventional and unconventional oil and gas wells in Pennsylvania (Ingraffea et al., 2014). This was a herculean task, but in the end, they found a six times greater risk of wellbore integrity problems in shale gas wells compared to conventional wells. The issue will be addressed in more detail later, but for the purposes of this discussion, suffice it to say that the number of people willing to undertake this much work to arrive at an answer is statistically small.

An overarching problem with engineering risk assessment has been reluctance on the part of industry to cooperate with such studies, in particular, those involving groundwater (Soeder, 2015). A number of prominent hydrologists have been calling for detailed, field-based groundwater monitoring near shale gas

Soeder, D.J., 2017, Risks to the Environment, *in* Soeder, D.J., Unconventional: The Development of Natural Gas from the Marcellus Shale: Geological Society of America Special Paper 527, p. 65–95, doi:10.1130/2017.2527(04).

wells (Jackson et al., 2013). However, with very few exceptions, operators have not allowed groundwater monitoring wells to be placed near drill sites (Soeder, 2015). Reasons given by industry for refusing access for water studies include concerns that these will lead to new and expensive regulations, or that monitoring groundwater is a waste of time and money because there will be nothing to see. Other operators insist that their practice of collecting baseline water samples from nearby domestic supply wells prior to drilling constitutes all of the "groundwater monitoring" that is necessary.

Some landowners have also refused access because of concerns that long-term groundwater monitoring studies might delay royalty payments. Others have balked at the additional site disturbance required to install monitoring wells. Still others who are already required to remediate existing groundwater contamination on their property have refused access for fear that additional monitoring wells would discover new contaminants (Soeder, 2015).

Nevertheless, collaboration with industry is critical for scientific investigators to obtain access to a sufficient number of well sites and samples for the data to be representative. While a few shale gas exploration and production companies have allowed access for a variety of sampling and monitoring tasks, the number has been statistically insignificant compared to the number of wells drilled. In the few cases where industry itself has funded such studies, the results have been uniformly decried as "tainted" and invalid by hydraulic fracturing opponents.

The risk assessment methodology developed for the underground storage of carbon dioxide in engineered geologic systems by the U.S. DOE National Risk Assessment Partnership (NRAP) has been applied to assessing the engineering risks of shale gas (Soeder et al., 2014b). The approach uses an integrated assessment model, or IAM, which provides probability-based assessments of both site and system risk. The IAM components are identified through a type of analysis called FEP, which stands for features, events, and processes. This method involves cataloging the features in an engineered geologic system that may affect its behavior, along with any events or processes that may impact the risk.

Integrated risk assessment modeling employs site-specific scenario analysis, which takes a set of the most likely FEPs for a site and identifies potential interactions that affect risk. A scenario can be assessed using analogs for comparison, or calculated if the fundamental physical and chemical properties of the geologic system are known. The performance of each of the components is determined using high-fidelity mathematical models. Once described, the results can then be used to determine the potential consequences and risks to health, safety, and the environment. These steps are sometimes referred to as a site performance assessment (Soeder et al., 2014b). The paper by King (2012) provides a detailed description of the factors contributing to hydraulic fracturing risk and performance in unconventional oil and gas wells.

The site-specific risk analyses are incorporated into the IAM to create a system risk assessment. System risk is more complicated than site-specific risk, because of the combined risk contribution from each of the multiple components, and also because the components can interact with one another in ways that increase or decrease risk. For example, an oil refinery and a gas-processing plant both have relatively high site risk, because each contains a great deal of highly flammable material. However, if the oil refinery is located next door to a gas-processing plant, the system risk is much higher, because a fire in either is likely to take out both of them along with a significant amount of the surrounding real estate.

To deal with these complex interactions and reduce the amount of computing power needed for calculations, IAMs use reduced order models, or ROMs, which take the high-fidelity, detailed process models used to describe the FEP site risks and simplify them. This step also serves to help define and reduce the uncertainties within each ROM.

The methodology of the IAM is to divide the system into components, apply validated, high-fidelity models to each, reduce uncertainty, and develop ROMs to reproduce in simpler form the results and detailed model predictions of each component. The ROMs are then linked or integrated through the IAM to predict total system performance, system-scale interactions, and risk. The model is calibrated using field data and databases, and validated by comparison against real-world performance. The goal is to quantify the potential long-term liability of an engineered geologic site, such as a Marcellus Shale well.

The NRAP program was designed to assess the inherent risk from injecting large amounts of carbon dioxide into the ground under pressure. Shale gas wells, on the other hand, are withdrawing large amounts of natural gas from the ground, and reducing pressure. The details of the two systems could not be more different, yet the IAM approach is equally valid on either. Because an IAM reduces the risk assessment into system components, it will work on systems that have different components contributing to risk.

Oil and gas operators typically view risk from a financial standpoint rather than an environmental standpoint, where the disruption of field operations may have serious consequences for their bottom line. As such, operators often make significant investments in specialized risk management with respect to optimizing production practices to reduce the chances of down time in the field. This reduction of risk is good for the environment, along with being good for investors.

SOURCES OF RISK

Risk can come from a number of different sources. The first major source of risk is natural disasters such as wind, lightning, earthquakes, floods, and similar events. These are generally unpredictable, and systems are usually designed to handle worst-case scenarios, but within limits. This reflects a trade-off between cost and what is termed "acceptable risk."

Risk is expressed as a probability, and a standard that applies to all natural disasters is that the bigger ones are less likely to occur than the small ones. Examples include dozens of daily earthquakes that are too small to be felt versus much less common major earthquakes that destroy cities, flooding of a low spot on a road during every rainstorm versus the once-per-century flooding of an entire neighborhood, hundreds of small meteors hitting Earth each day versus rare giant asteroid impacts once every ten millennia, and so on.

Acceptable risk is the cutoff point where the cost of mitigating the risk becomes more expensive than the risk itself. For example, a number of relatively cheap upgrades, such as roof tie-downs and steel shutters, when added to a standard house in Florida will significantly reduce the risk of damage from a low- to moderate-strength hurricane compared to an unprotected house. Based on the previous discussion of natural disasters, low- to moderate-strength hurricanes are expected to be far more common than a super-strong category 5+ hurricane, but if one of these did come along, it could flatten the house, steel shutters and all. A homeowner who was concerned enough to want 100% guaranteed protection against any and all storms, including the most extreme, could in theory build a house to achieve this. Some of these homes actually exist in places like Florida, and they typically consist of thick-walled, massive, rounded, bunker-like structures made of concrete and steel that are quite expensive. Given the low probability of a direct hit from a category 5 hurricane in any one place, is mitigating such a small risk worth the cost? If a homeowner decides it is not, then a category 5 hurricane becomes an acceptable risk.

As described previously in the section on drilling, an ongoing debate between operators and regulators concerns the depth to set surface casing to protect fresh groundwater. Some regulators in Pennsylvania feel that surface casing should be run to a depth of 300 m or 1000 ft to protect the "deepest fresh groundwater," although at this depth, the water is usually brackish and undrinkable. Still, the advocates feel that setting casing to this depth will virtually guarantee that domestic wells will not be contaminated by gas production. On the other hand, many drillers argue that the casing only needs to be set at a depth of ~100 m, or 300 ft, since most domestic water supply wells in the eastern United States are much shallower than this. Setting the casing an additional 200 m deeper is viewed as an unnecessary expense that provides only marginal additional protection from a very unlikely contamination event. Such divergent opinions on the level of acceptable risk for protecting fresh groundwater can have significant financial consequences to either gas well operators or domestic well owners.

The second major source of risk is from engineering design, where a flaw in the architecture of a system introduces a risk. An example is a sewer system like those in many older cities that carry both wastewater and storm water. The wastewater treatment plants attached to such sewers cannot handle the extra water volume introduced by the runoff from even a moderate storm, allowing storm water and raw sewage to overflow into streams. The basic design of the sewer system itself is flawed, and even if it functions perfectly as engineered, the flaws built into the architecture give it a high probability of causing environmental damage. The only way to mitigate the inherent risk of such a design is to re-engineer the system, typically by either adding large storage volumes to hold the water until it can be treated, or by creating separate sanitary and storm drains. Both options are often extremely expensive and disruptive, especially if a large system has to be replaced.

An example of an engineering design flaw in Marcellus Shale wells was an apparent link between stray gas migration into shallow aquifers in northeastern Pennsylvania and the now-discontinued practice of open-hole completions in the gas wells (Baldassare et al., 2014). To save money, operators would set surface casing only, and then continue to drill the tophole down to the kickoff point without setting any additional casing in the vertical well. This practice left bare rock walls exposed in the borehole. Gas from organic-rich shales and other units above the Marcellus could then enter the open vertical borehole, and pressure would build up in the annular space between the production casing and the bare borehole walls. The operators typically did not install a valve at the surface, known as a bradenhead, that could have been used to vent the annulus, so the buildup of gas pressure would result in the migration of gas into shallow aquifers in the upper part of the borehole (Dusseault and Jackson, 2014).

Venting the annulus of an open-hole completed gas well introduces another issue: methane emissions to the atmosphere. This is a concern because methane is a more powerful greenhouse gas than carbon dioxide, although its residence time in the atmosphere is much shorter. The Council of Canadian Academies (2014) produced a report on shale gas environmental impacts in Canada where they attempted to weigh the trade-off between venting the bradenhead to the atmosphere or allowing the methane pressure to build up and possibly migrate into an aquifer as stray gas. Because of the high level of uncertainty with respect to estimating total methane emissions from both conventional and shale gas wells, the report could only conclude that more data are needed. Methane from abandoned wells is also a concern; a group of researchers from Princeton University measured a variety of atmospheric methane emissions from old wells in Pennsylvania that the state is working to properly plug and abandon (Kang et al., 2014).

After 2009, operators began installing intermediate casing in Marcellus wells to isolate the overlying rock column from the borehole and eliminate a direct flow path for gas to enter shallow aquifers. This practice appears to have corrected the engineering design flaw of open-hole completions, and it has significantly reduced the number of reported stray gas incidents.

The third major source of risk is human behavior. Accidents, mishaps, or mistakes can result from inexperience, impatience, overconfidence, lack of knowledge, cost-cutting, distractions, or an uncaring attitude. Most of the environmental incidents, spills, or chemical releases that have occurred on shale gas wells can be traced to a human cause (Glosser, 2013).

Investigations of actual incidents and other available technical and scientific data show that a properly designed shale gas well, drilled, constructed, and completed in a proper manner using best engineering practices, will produce natural gas safely from shale formations with a minimal environmental impact. State records support this (Kell, 2011; Brantley et al., 2014), indicating that the vast majority of gas wells do not have any reportable environmental violations. As explained earlier, the greatest risks occur during the initial drilling of the well through the shallow, drinking water aquifers before the surface casing is set (Zhang and Soeder, 2015), and then during the hydraulic fracturing activity, when large volumes of concentrated chemicals are being transported, stored, and used on the well site (Soeder et al., 2014b).

Many of the environmental problems associated with the Marcellus Shale stem from the rapid development of the play. The big ramp-up for Marcellus gas production was in 2007 and 2008, when drilling companies were descending upon Appalachia in droves and leasing everything in sight. Gas prices at the wellhead in 2008 were near $11 per MCF, which was a record high. The competition to lease the best prospects at the lowest price was intense.

This rush by the drilling industry to get wells in the ground caused significant damage to landscapes and streams. Local workers were being hired off the street to fill vacancies on the drill rigs, and their inexperience resulted in many of the accidents and incidents. Some companies were cutting corners to move forward at breakneck speed. Many drill rigs with highly experienced crews came onto the Marcellus from the Gulf Coast, Texas, and Oklahoma, but their lack of familiarity with Appalachian culture, climate, landscapes, and regulations also contributed to the problems. State, local, and federal government agencies were slow to react, exacerbating the incidents that did occur.

The environmental abuses from this time resulted in much of the current opposition to Marcellus Shale drilling. People became entrenched in their positions, and many remain so today. By 2012, lower gas prices due to overproduction had slowed things down quite a bit, and the rig crews that remained were much more experienced and keenly aware of the risks of environmental damage.

None of this is meant to serve as an excuse for the environmental damage caused during the 2007–2008 period. Indeed, a slower, more careful, and measured approach should have been taken from the very beginning.

ENVIRONMENTAL CONCERNS

There have been numerous articles, editorials, blogs, web pages, documentaries, and countless, heated verbal arguments about the environmental risks that may or may not be posed by shale gas development and hydraulic fracturing. In the end, any reliable assessment of probable risk must be based on facts, and the data supporting those facts must be focused on reducing the uncertainties.

All technologies suffer occasional failures. Nothing works perfectly all the time, and to expect such perfection is an illusion. Cars crash, ships sink, airplanes fall out of the sky, oil refineries and chemical plants blow up, and trains derail and spill their loads. Drilling and hydraulic fracturing have incidents also. However, it is important to separate incidents and accidents from systemic, deeply rooted design flaws in the underlying engineering. An occasional plane crash does not mean that all of aviation is unsafe. Aircraft are designed following solid engineering principles developed over the past two centuries, and they have been tested beginning with the first powered flight by the Wright Brothers in 1903. They are known to be safe. Likewise, the engineering on unconventional oil and gas wells is built on similar strong principles, and when done correctly, hydrocarbons can be produced safely and in an environmentally responsible manner with minimal impacts.

Many nontechnical people such as attorneys, actors, musicians, and movie producers have been warning the populace about the “dangers” of shale gas. Accepting these opinions instead of the judgment of the scientific and engineering communities requires the belief that despite advanced technical degrees and decades of experience with hydraulic fracturing, technical experts in the field have not recognized the serious environmental hazards from shale gas development being pointed out by the film makers, or if they do, they are participating in an airtight conspiracy to cover up and lie about the danger so that the industry can make profits by exploiting this resource without regard for the environment. The truth is that shale gas experts are not a monolithic block of anti-environmentalist, pro-industry shills. Instead, they represent a diverse group of trained scientists in industry, academia, and government who respect facts and data.

The success of movies like *GasLand* (2010) illustrates the depth of distrust that Americans have toward the oil and gas industry. Many people do in fact believe that the oil and gas industry is suppressing data and will cheerfully put the environment at risk whenever there are profits to be made. This is reflected in the results of sociological studies, which report that two out of three American citizens have a negative perception and distrust of the oil and gas industry (Theodori, 2008). Only the tobacco industry was ranked as less trustworthy.

This lack of trust, sometimes with good reason, has been one of the greatest barriers to shale gas development. Problems do happen, and companies do not always provide timely or accurate information to a worried public. Many people conclude that the guilty party is stalling to cover their tracks. Industry is improving on this, but some corporations still respond to nearly all incidents with “we’re the experts—just trust us,” which instantly raises the hackles of concerned citizens.

On the other side of the coin, a single incident by a careless or incompetent company often creates a media frenzy that turns many people against the entire industry. Even though the people who work for environmentally responsible companies will often take pains to point out that the operator who caused the incident was not them, it might not matter: All members of the industry get tarred with the same brush. Condemning an entire industry because of the actions of a few bad apples is unfair and counterproductive, but it happens to government, Wall Street, real estate, used car dealerships, police departments, and many other places, including oil and gas. The vast majority of people working in the oil and gas industry are professionals interested in doing the job correctly without creating an undue liability for their company from environmental or safety violations.

A great deal has been learned over the past few years about the true risks and environmental impacts of unconventional oil and gas development. Sadly for those who crave sensationalism, the news is rather dull. The evidence from the large numbers of published studies suggests that although shale gas development can introduce environmental problems in certain circumstances if not done correctly, fears that the sky is falling are unfounded.

The following list is a small sampling of recent scientific papers and reports that document the problems, risks, and non-issues that come with the development of shale: Andrews et al. (2009), Baldassare et al. (2014), Dusseault and Jackson (2014), Fisher and Warpinski (2012), Hammack et al. (2014), Hayes (2009), Jackson et al. (2013), Kell (2011), Llewellyn et al. (2015), Maloney and Yoxtheimer (2012), Rowan et al. (2011), Small et al. (2014), Soeder and Kappel (2009), Soeder et al. (2014b), Vidic et al. (2013), Warpinski (2013), and Werner et al. (2015). Full citations for all these papers can be found in the References Cited section. A fully comprehensive listing would run to hundreds of titles, with dozens more being published every month.

Current assessments rely heavily on models and empirical evidence, which is often little more than the absence of observable impacts. Many, if not most, of the authors appeal for more access, more data, and additional studies. With few exceptions, the data strongly suggest that environmental impacts from unconventional gas wells differ little from the environmental impacts of conventional gas wells.

However, in environmental and health studies, a lack of data cannot be used to imply a lack of harm, and long-term issues such as cancer may take decades to become apparent (Werner et al., 2015). Those who cite tobacco studies from the 1960s as an example of an industry cover-up are reminded that tobacco is largely a human health issue, and it really did take quite some time to establish air-tight, causative links between smoking and health problems.

Causation is far more difficult to determine than correlation. For example, there might be a statistical correlation between a decrease in traffic fatalities over the past decade and a decline in the number of Dutch marching bands. However, one would be hard-pressed to link these two trends and show that the decrease in Dutch marching bands actually led to a decrease in traffic fatalities. The underlying conundrum of causation is determining exactly how one thing may affect another.

As described previously, a statistical analysis by Ingraffea et al. (2014) of Pennsylvania state compliance reports for 41,381 conventional and unconventional oil and gas wells drilled between the beginning of 2000 and the end of 2012 concluded that shale gas wells experienced casing and cement impairment six times more frequently than conventional wells. Even though there is a statistically valid correlation between well type (conventional vs. unconventional) and probability of cement/casing failure, the correlation does not necessarily imply causality. Ingraffea et al. (2014) are to be commended for their rigorous statistical analysis of Pennsylvania well inspection records. They suggest a number of reasons why well cement and casing failures might occur; however, they do not show how or why shale gas wells might be expected to have a six times greater risk of wellbore integrity problems compared to conventional wells. Is the failure due to the well design, related to the installation process itself, or perhaps tied to the completion technique? Without such a causation link, the statistics are interesting but not conclusive.

Independent of industry, several U.S. government agencies have performed safety and environmental assessments of shale gas development and hydraulic fracturing in recent years. In 2011, a special subcommittee of the Secretary of Energy Advisory Board (SEAB) investigated ways to reduce the environmental impacts of shale gas production, and they came up with a list of 20 recommendations. These included better communication with the public and with state regulators, focusing on protecting air and water, managing short-term and cumulative impacts, and promulgating best management practices throughout the industry, among others. The report is available online (SEAB, 2011).

In 2010, Congress requested the U.S. EPA to investigate possible links between hydraulic fracturing and drinking water contamination. After nearly 5 yr studying contaminated sites, running numerical models, and hosting numerous technical workshops and stakeholder meetings, a draft report was released for public comment in the summer of 2015, with the final report being issued in 2016 (U.S. EPA, 2016). The key findings of this report include identifying the mechanisms by which hydraulic fracturing activities may impact drinking water resources aboveground and belowground. These are related to water withdrawals, spills, subsurface migration of liquids and gases, and inadequate treatment and discharge of wastewater. A conclusion stated in the executive summary of the draft report was that no evidence was found that hydraulic fracturing has led to widespread, systemic impacts on drinking water resources in the United States, although specific instances were found where drinking water resources had been affected.

The EPA Science Advisory Board took issue with a number of statements in the draft report, including specifically the conclusion stated above. They found (U.S. EPA Science Advisory Board, 2016, p. 2) that the "lack of evidence for widespread, systemic impacts of hydraulic fracturing on drinking water resources" is not supported quantitatively; the resources of interest are not clearly described as groundwater or surface water; the local or regional scale of impacts is not assessed; and the use of the terms "systemic" and "widespread" is not properly defined. The statement has been interpreted in many different ways, and the Science Advisory Board recommended that the EPA provide quantitative analysis that supports this conclusion, along with clarification and additional explanations.

The conclusions in the final version of the executive summary (U.S. EPA, 2016, p. 41–42) are more nuanced than the draft, recommending efforts to identify additional vulnerabilities and other factors that could affect the frequency or severity of impacts. The report specifically noted two data gaps that include (1) a lack of groundwater and surface water monitoring in areas with hydraulically fractured oil and gas production wells, and (2) a scarcity of targeted research aimed at better characterizing the environmental fate and transport and human health hazards associated with chemicals in the hydraulic fracturing water cycle.

The combination of hydraulic fracturing activities with local vulnerabilities is more likely to result in environmental impacts. The report identifies some of these as water withdrawals for fracturing at times of low water availability, especially in areas with limited or declining groundwater resources, and the potential for surface leaks or spills that may result in large amounts of chemicals reaching groundwater resources. Performing the hydraulic fracturing process itself in wells with poor mechanical integrity may allow gases or liquids to migrate into groundwater resources, or in the worse-case scenario, result in the inadvertent injection of hydraulic fracturing fluids directly into groundwater resources. Finally, improper handling and disposal of the wastewater can result in contamination of surface water resources through spillage, and contaminate groundwater resources through seepage.

The multiagency assessment by DOE, DOI, EPA, HHS, and NSF (Multiagency, 2014) identified seven areas of concern where additional research is needed. These include:

(1) future resource development,
(2) water availability,
(3) water quality,
(4) air quality,
(5) induced seismicity,
(6) ecosystem impacts, and
(7) human health effects.

These concerns are described in more detail in the sections that follow.

Peer-Review Process

Peer-reviewed scientific literature is the primary method used by the scientific community for grappling with new ideas and findings. Elsevier, a major scientific research publisher, defines peer review as a method to evaluate and validate research (https://www.elsevier.com/reviewers/what-is-peer-review; accessed January 2017). Their web page describes a number of types of peer review, and lays out the typical process. This book, for example, has been peer-reviewed both internally and externally by nearly a dozen different experts, who provided volumes of comments and suggested many changes through eight drafts, which left it greatly improved.

The peer-review process has found little of merit in any of the relatively few published scientific articles trying to make the case that development of Marcellus Shale gas places everyone in imminent danger. Examples include Osborn et al. (2011), Howarth et al. (2011), and Myers (2012). These papers have been promoted in the popular media, who always love a doomsday scenario, but they have received significant criticism within the scientific community for inaccuracy, irrelevance, and improper interpretation of data (Cathles et al., 2012; Saiers and Barth, 2012; Molofsky et al., 2013; Flewelling and Sharma, 2014; Siegel et al., 2015). If a scientific paper cannot withstand a judgment from peer review, the public should be very skeptical of the contents.

Oil and gas drilling on nonfederal and nontribal lands is generally regulated by the states. As such, environmental incidents and safety violations are also reported to and tracked by the states. Two studies analyzed oil-and-gas–related environmental and safety incidents reported to state agencies in Texas and Ohio (Kell, 2011) and in Pennsylvania (Glosser, 2013). Both studies concluded from the evidence that virtually every reportable incident was the result of human failure to follow a prescribed engineering practice or procedure. The practices were not at fault; it was the failure to follow them that led to problems. Recognizing the importance of human factors will hopefully change the focus of the shale gas debate from engineering concerns to the realm of human behavior.

State oil and gas drilling regulations are periodically reviewed. A group known as STRONGER (for State Review of Oil and Natural Gas Environmental Regulations; www.strongerinc.org/) performs invited reviews at state oil and gas agencies. The review teams consist of oil and gas regulatory personnel from other states, industry people, representatives from environmental advocacy organizations, and observers from DOE and EPA. A STRONGER review in Pennsylvania recently developed the following recommendations for Marcellus Shale gas development:

(1) Regulations should require shale gas wells to be constructed according to best engineering practices.
(2) Inspections at intermediate stages should be carried out to ensure that the well construction meets these standards.
(3) Violations of the well construction standards should result in hefty fines and permit revocations, and the size of the fine should be structured to reflect the costs of environmental restoration.
(4) Companies with repeated environmental violations should be banned from drilling in the state.

A report from STRONGER summarizes actions taken by Pennsylvania (2010), Ohio (2011), Oklahoma (2011), Louisiana (2011), Arkansas (2012), and Colorado (2011) in response to the recommendations made by STRONGER in their respective reviews (www.strongerinc.org/stronger-publishes-report-outcomes-hydraulic-fracturing-state-reviews/).

Common Concerns

Questions in public meetings often express three common concerns about the safety of Marcellus Shale gas development: (1) drinking water contamination from the underground injection of fracture fluids, (2) natural gas from shale wells migrating into domestic water wells and causing fires or explosions, and (3) natural gas leaking into the atmosphere from hydraulically fractured shale wells and causing climate change. These are addressed briefly next.

Groundwater Contamination from Fracking

The notion that chemical-laced hydraulic fracturing fluid will move upward to contaminate drinking water aquifers seems logical to many people—pressurized frac fluid is injected underground, and groundwater is underground, so there must be a high risk that the frac fluid will get into the groundwater. In reality, "underground" is a big place, and in areas of shale gas development, the tops of manmade fractures in the shale are usually several kilometers below the shallow, fresh groundwater aquifers (Fisher and Warpinski, 2012). Targeted gas shales typically must be at a minimum depth of at least a kilometer to be under enough overburden stress for the rocks to break vertically when fractured (Hubbert and Willis, 1957). Shallower targets are usually produced with branched horizontal wells and are not hydraulically fractured (Long and Soeder, 2011)

Although hydraulic fracturing fluid is injected under pressure, the volumes are not large enough, nor is the pressure sustained long enough for it to reach shallow aquifers from below. This is supported by significant amounts of empirical evidence (King, 2012).

Methane Gas in Groundwater

Many people have seen video depictions of a kitchen faucet being set ablaze because of gas in the water supply. Admittedly, being able to create a fireball in the kitchen sink by lighting a match near a water faucet makes for some pretty dramatic video. However, it turns out that at least one case of a flaming faucet in Colorado had problems with methane in the groundwater supply long before any gas well drilling occurred in the neighborhood, prompting a response from the Colorado Oil and Gas Conservation Commission (2010). Simple links between natural gas drilling and flammable gas in drinking water ignore the fact that natural gas migration in shallow groundwater can have many causes that are sometimes, but not always, related to the presence of gas wells (Veil, 2012).

From a groundwater hydrology perspective, it is important to keep in mind that stray gas is a complex issue that rarely has easy answers (Baldassare et al., 2014). Dissolved methane gas content and water quality data are now routinely collected on large numbers of water wells prior to gas well drilling to protect gas development companies from liability. The analyses show that methane from both geologic and biologic sources is ubiquitous in the groundwater of northeastern Pennsylvania (Molofsky et al., 2013) and elsewhere in the Appalachian Basin (Mulder, 2012). It is equally common in areas that are and are not being actively drilled for shale gas (Siegel et al., 2015).

Other researchers claim to show that the methane content of groundwater increases closer to gas wells in northeastern Pennsylvania (Osborn et al., 2011), suggesting a link between methane concentrations and gas well drilling. The conflicting evidence and differing interpretations demonstrate the high degree of uncertainty associated with gas migration issues.

Stray gas comes down to two questions: What is the source, and what caused it to migrate? Methane gas occurs naturally in many shallow aquifers from in situ biological sources and also from the slow upward seepage of relatively shallow geologic gas through permeable bedrock or natural fractures. Drilling a gas well nearby may disturb the groundwater and allow preexisting methane to be transported toward nearby domestic water wells (Veil, 2012). Investigations have found that tophole drilling with compressed air may cause groundwater flow surges away from the gas well if pressurized air enters the aquifer (Geng et al., 2013). Modeling results indicate that such groundwater flow surges can mobilize preexisting methane in aquifers and transport that methane to lower-pressure areas like the drawdown cone of a domestic well (Zhang and Soeder, 2015). Because the solubility of methane in water is pressure-dependent, the gas may exsolve from the water in the lower-pressure area near the domestic well and allow the kitchen faucet to be set alight. In extreme cases, such as a recent incident in Geauga County, Ohio, the methane can accumulate in confined areas like basements up to the lower explosive limit (LEL) in air of 5%, and then ignite with devastating results (Veil, 2012). Like groundwater contamination concerns, the number of gas wells that may be affecting methane migration in groundwater is a small percentage of the total. Nevertheless, minor changes in drilling practices, such as using incompressible water instead of compressed air for tophole drilling, would prevent pressure surges in aquifers and mitigate many of the problems.

Greenhouse Gas

The idea that hydraulically fractured shale gas wells may leak copious amounts of natural gas into the air received a lot of attention when it was first published (Howarth et al., 2011). This paper concluded that because natural gas is composed mostly of methane, which is a significantly more powerful greenhouse gas than carbon dioxide, leakage of this gas into the atmosphere from hydraulically fractured rock could cause significant climate change. Methane is indeed a more powerful greenhouse gas than CO_2, and if it did leak into the atmosphere in large quantities, there could definitely be a problem.

As noted earlier, the tops of hydraulic fractures remain deep below the land surface. Assessments of subsurface frac fluid migration using both microseismic monitoring and chemical tracers (Hammack et al., 2014), combined with modeling studies (Zhang et al., 2014), have not shown any indication of upward gas migration after a shale frac. The model does suggest that any migration is likely to be subtle and may require tracer monitoring for a period of years.

A more significant leakage point could be the vertical parts of the wells themselves, and the potential for the deterioration of casing and cement over time is a concern (Dusseault et al., 2000;

Watson and Bachu, 2008; Dusseault and Jackson, 2014). Shale wells are constructed in exactly the same way as any other type of gas well from the surface down to the producing formation, so they should not leak any more gas to the air than a "conventional" well. Nevertheless, as mentioned earlier, a statistical analysis of wellbore integrity in both conventional and unconventional gas wells in northeastern Pennsylvania has found a higher degree of gas leakage from the unconventional Marcellus Shale wells (Ingraffea et al., 2014).

What could be responsible for this? One notable difference between conventional and unconventional gas wells is the use of HVHF in the shale wells. This process sends pressure pulses down from the surface, and it may stress well casings and cement from the high pressures introduced during the operation. If every annulus between every string of casing is filled with cement, as shown in some well construction diagrams from industry, the high pressures could be transmitted through the steel and cement to the rock surrounding the well. While cement is strong under compression, it is weak under tension, and when the hydraulic fracturing pressure is released, the relaxation and rebound of the steel and cement can create a microannulus at the interface of the cement and rock, or cement and steel. A microannulus can persist for long vertical distances in a well, providing a pathway for gas and fluids to migrate upward. Research on how casing and cement respond to repeated frac pressures can help improve the understanding of microannulus formation. New cement formulas may need to be developed and tested, including more flexible resin-based cements, or foamed cement that expands and seals voids to help improve wellbore integrity (Kutchko et al., 2012).

Greenhouse gas (GHG) effects of methane have created additional controversy related to leakage from shale gas wells. Howarth et al. (2011) made the claim that methane leakage from shale gas wells creates significantly greater greenhouse gas impacts in the atmosphere than CO_2 emissions from an equivalent energy in coal. The issue is complicated by the fact that although methane is more efficient at trapping heat in the atmosphere than CO_2, it also has a much shorter residence time. How this may balance out in terms of possible climate impacts is unclear.

Several follow-on studies have contradicted the greenhouse gas claims made by Howarth et al. (2011), including a life-cycle analysis by Skone et al. (2011), which concluded that electricity generated from natural gas emits 42%–53% less greenhouse gas per megawatt hour than electricity generated from coal. Cathles et al. (2012) concluded that mining, transporting, and burning coal has much greater greenhouse impacts than shale gas production and combustion. Howarth and coauthors have in turn rebutted this claim.

Several other assessments have examined the greenhouse gas potential of shale gas production compared to conventional gas wells, and the energy, such as electricity, made from it. These estimates vary widely, from shale gas/greenhouse gas impacts 11% greater (Hultman et al., 2011) to only 1.8%–2.4% greater (Stephenson et al., 2011) than conventional gas wells, down to impacts that are essentially the same (Weber and Clavin, 2012).

Assessing the contribution of natural gas methane to global greenhouse gases is difficult because of the high level of uncertainty concerning leakage rates from the various components of natural gas infrastructure (Skone et al., 2011). Little data exist on emissions from upstream and midstream components such as wells, gas-processing facilities, compressor stations, and transmission pipelines to determine where the greatest losses occur. Significant leakage has been documented in certain downstream systems such as gas storage fields, and aging natural gas distribution infrastructure such as old iron pipelines in cities (McKenna, 2011). Leakage data would provide guidance on priorities for repairing the system to stem the greatest losses first and eventually make all of it gas tight.

Several research projects are monitoring air emissions at Marcellus Shale drill sites and gas pipeline compressor stations in an attempt to quantify fugitive emissions and determine the various mitigation steps that can be employed. Ethane content in air has been found to be a regional indicator for the presence of oil and gas operations (Pekney et al., 2014). Well-site operations like pumping a frac job or running a generator at full power while drilling through a difficult interval create high emissions for short periods of time. These must be addressed statistically against the many hours of much lower emissions when the equipment is slow or idle. Health impacts on people from exposure to pollutants usually depends on whether such exposure is acute or chronic; in this case, exposures to contaminants like carbon monoxide or particulates near a drill site might be acute during the high-emissions periods, and chronic during the low-emissions periods. Another challenge has to do with the location of Marcellus Shale operations in areas that were already marginal in terms of air-quality attainment standards. Separating well site emissions from freeway traffic, factories, and other industrial operations can be difficult.

To be clear, shale gas development is not free of environmental risk. The environmental issues related to shale gas are complex and evolving, and more data are needed in a number of areas. It is important to recognize that not all of the environmental impacts of shale gas production are known or understood. Many of the parameters needed to determine environmental impacts have not been fully measured because neither funding nor time has been available. The cumulative effects from thousands of potential well sites in a region are not known, nor is the "threshold" or number of sites at which these effects become critically important (Soeder et al., 2014b). However, there is no evidence that these impacts will be more severe than those from conventional gas well development, which has been well documented (for example, see Pekney et al., 2014). In fact, given the much greater pad spacing for horizontal shale wells versus old-fashioned vertical wells, the impacts may actually be significantly lower per unit area of land.

Other environmental risks include transporting large amounts of chemicals over rural roads, removing and disposing of recovered fluids, and potential effects on small watersheds and the sensitive headwater areas of streams from the large drill pads and extensive water withdrawals needed for shale gas wells.

More research is needed on the migration of stray gas, the breakdown paths and rates for the natural attenuation of organic compounds used in drilling muds and hydraulic fracturing fluids, the changes in microbial populations in the produced water as it is recycled through subsequent wells, air contamination issues, and the potential for toxic metals, radionuclides, and organic compounds to leach from the black shale drill cuttings and other solid waste.

SHALE GAS IMPACTS

Drilling and production of natural gas, especially shale gas, are industrial activities. Although the construction period for a shale gas well is short compared to the production period, it can be quite disruptive. Large machinery and heavy equipment are required on-site to install the pad, drill down to the appropriate depths, and create and frac the long horizontal boreholes needed for economic gas recovery. The pad and the hydraulic fracturing operations require large volumes of material, including gravel, water, sand, and chemicals, along with many trucks to deliver it all to the well site. Installing the well creates noise, mud, and dust and requires a large crew of workers. The drilling operations typically run 24 h per day and 7 d per week, and they create a nuisance with their work lights, constant racket, steady stream of truck traffic, and endless activity. Having one of these sites near a home, school, or business can be distracting, inconvenient, annoying, and disruptive.

The realities associated with Marcellus Shale drilling are ugly, intrusive, and sometimes dangerous, but separating the actual environmental risks from mere nuisances is complicated by sparse data and high uncertainty.

Polished outreach people from the gas companies speak at public meetings about how a shale gas well is constructed and how a hydraulic fracturing job is done. They typically describe the installation of a shale gas well as a highly engineered and perfectly executed process following best management practices. These presentations are a great opportunity to learn about how it should be done. However, the way it actually is done in the real world is sometimes quite a different story.

In locations like the suburbs of Fort Worth or in the rolling Appalachian hills, a gigantic drill-rig derrick looming over a house is an unusual sight. In other areas, some people cannot enjoy time outdoors on their porches or in their yards for weeks on end because a drill rig is operating across the street. Hundreds of trucks passing by each day may turn quiet paved roads into potholed gravel. Narrow country lanes may be blocked for hours by seismic crews or heavy machinery being transported from place to place. A punctured liner in a poorly constructed storage pit above a stream may release drilling mud waste directly into a creek. Chemicals get into the ground from spills or leaking pits, or seep out of hillsides and banks to contaminate creeks months after the drilling rig has gone. Nearby well water can become unsafe, killing livestock that drink it, or causing a rash after bathing, sometimes requiring people to drive miles to obtain bottled water. All of these incidents have been reported and documented in the Marcellus play.

The public wants transparency and communication, yet citizens often find it difficult to get even the most basic information from the gas production companies. There are many stories where people have called industry information hotlines with specific questions and received a promise that someone would call them back with an answer, only to wait in vain. When industry does come in to repair the damage, supply drinking water, or pay for losses, the landowner is often required to sign a nondisclosure agreement. The widespread use of such agreements has greatly complicated efforts of both government and NGO researchers to determine the exact magnitude of adverse environmental incidents from shale gas development sites.

The initial response of the drilling industry to concerns about the potential risks of shale gas development was to downplay these worries to the public. The industry defines "high-risk" oil and gas operations as those located offshore in deep ocean water, or in hostile, remote places like the High Arctic. From their perspective, gas production from the Marcellus Shale is a lower-risk, domestic, onshore process done at relatively shallow depths using readily available standardized equipment and established technologies.

Industry has not helped their case by being secretive about the methods and chemicals used in shale gas development, while giving the public bland assurances that there is nothing to worry about. The controversy and contentious arguments over "fracking" or HVHF have made them even more cautious. Requests for the most innocuous information are often denied or go unanswered. Companies carefully control the content and delivery of anything they do say. Even though they may actually be hiding very little, it comes across as a cover-up.

Anti-fracking activists have successfully gotten HVHF banned or indefinitely suspended in places like Quebec, New York, New Jersey, and Maryland. The high levels of uncertainty over the actual environmental risks were used to argue against shale gas development. For example, the natural filtration provided by undeveloped watersheds that collect and store drinking water in the upper Delaware River has allowed the New York City drinking water treatment system to qualify for a filtration waiver, saving billions in capital investment and operating costs. This area also overlies the thickest and potentially most gas-productive part of the Marcellus Shale (Hazen and Sawyer, 2009). The possibility of losing that natural filtration because of road, pad, and pipeline construction in these watersheds was used as part of the argument against allowing Marcellus Shale development in New York. Supporters of an HVHF ban claimed that the process is inherently dangerous until proven otherwise, and it would put the drinking water of millions needlessly at risk for industry profits. The arguments resonated, and the measures succeeded because the public does not trust the oil and gas industry to honestly disclose information about actual hazards. Governments decided to err on the side of caution.

These bans have not been without consequences. New York is the fourth largest natural gas-consuming state in the nation, but it produces very little of its own supply (Revkin, 2012). According to some calculations, the statewide ban on HVHF shale gas wells has resulted in the direct economic loss of as much as $1.4 billion in tax revenues and up to 90,000 direct and indirect jobs in the state of New York (Considine et al., 2011).

The exploration and production industry has used the high levels of uncertainty to argue that serious environmental risks have not actually been proven. In their view, HVHF is inherently safe, unless proven otherwise, and all the panic is based merely on hearsay, unrelated incidents, and a few bad operators. These diametrically opposed views between industry supporters and anti-fracking activists have led to some of the most ferocious disagreements in recent history.

Many people believe that gas development in the Marcellus Shale has led to large-scale ecological and property damage, caused serious illness among large populations of people, and significantly threatened water and air quality. There is now a history of Marcellus Shale gas development using HVHF going back to 2007 in West Virginia and Pennsylvania. None of the data collected to date indicate that Marcellus Shale gas wells have transformed these states into wastelands with desolate landscapes and poisoned waters.

Despite the evidence, there is an implied assumption in the news media that if something could happen once, it could happen all the time, everywhere. The modern news media would have called for a ban on ocean liners crossing the Atlantic in the wake of the *Titanic* sinking. In fact, the *Titanic* was doomed by a series of unique problems caused by a number of unusual circumstances, and so far, it is the only major passenger liner in history to have been sunk by ice. In a similar manner, isolated incidents related to shale gas development cannot be applied to all or even most shale gas wells.

This is not meant to be a carte blanche for the industry. There have been incidents, and companies need to improve how these are addressed. The exploration and production industry should follow the approach of other high-risk industries: Learn from accidents, train workers not to make the same mistakes, change procedures to avoid problematic situations in the first place, and foster continuous improvement. Many shale gas operators already invest in risk management to maximize their chance for successful development and minimize down time. Stepping it up a notch to encompass environmental risks should not be a giant leap.

It has been shown that the risks of shale gas development can be managed and mitigated with proper knowledge of the environmental impacts, sensible and effective regulations, rigorous inspections, and strict enforcement (Soeder et al., 2014b). Other industries successfully use this approach, and society coexists with nuclear power plants, oil refineries, steel mills, semiconductor manufacturing plants, plastics factories, chemical plants, and pharmaceutical companies. Commercial quantities of natural gas can certainly be recovered from the Marcellus Shale without destroying the environment in the process.

Risk Assessment

Environmental impacts can have short-term or long-term effects. Short-term impacts are related to well construction, and they include things like water withdrawals, produced water disposal, lights and noise from the drilling operations, effects of water impoundments on wildlife, and air pollution. Most of these disappear once the well is constructed and the equipment moves off-site, but they can be fairly intense during the drilling process.

Long-term impacts are related to the well and drill pad occupying the landscape, and they include concerns like habitat fragmentation; groundwater contamination from leaks, spills, or leachate; the potential introduction of invasive species; and the process of ecological succession as the open drill pad slowly fills back in with vegetation. These factors are somewhat more difficult to quantify, and some, like invasive species, may not show up for some time. Assessment of both of these types of impacts is important for understanding the overall environmental effects of the gas well.

Cumulative impact from the planned development of the resource is perhaps the greatest unknown. Environmental effects from individual wells add up as more wells are constructed within a given area of land. Such accumulating impacts may eventually take environmental conditions across a threshold, causing impacts much greater than the individual wells alone.

A study done a number of years ago on watersheds in Maryland (Barnes et al., 2002) determined that once ~10% of the surface area in a particular watershed becomes impervious (i.e., roads, rooftops, driveways, parking lots, etc.), the biota in streams suffer shifts in population, reductions in diversity, and lower population density. Similar studies suggest that 10% impervious surface area is a threshold at which storm-water runoff events become too intense for normal aquatic ecosystems, and population declines are observed.

A great deal is already known about the envelope of engineering risk associated with development of the Marcellus Shale gas resource. The basic rotary drilling technology dates back to the nineteenth century, and hydraulic fracturing has been used commercially since 1949. Directional drilling and staged hydraulic fracturing are extensions of the proven technology of the earlier techniques. Industry has a good understanding of how these work, and the limits of the technology are well known.

Comprehensive environmental risk assessment of the shale gas development process is still needed. Exploration and production companies need information for better management practices to reduce environmental risks, and the regulatory agencies need information in order to focus their monitoring efforts. Many of the obvious risks to air, water, landscapes, and ecosystems are known, but some are not. Even some of the known risks could create impacts that are not well understood.

It is also important that risk assessments not remain static. Risk evolves over time as new practices are employed, and as drillers and rig crews grow more experienced and become more careful about avoiding environmental problems. For example, a risk analysis of Marcellus Shale drilling using a numerical model to identify pathways of water contamination concluded it was likely that disposal of produced water through publicly owned treatment works (POTW) would release at least 200 m^3 of contaminated fluids from each well as effluent into streams (Rozell and Reaven, 2012). This has been recognized as an area of high risk, and as such, the POTW disposal process is no longer used on most shale plays. It has been replaced by the practice of recycling the produced water and disposing residual waste by injection down deep UIC wells. Thus, the highest risk pathway for environmental contamination identified in this 2012 study was effectively eliminated by the time the results were published.

Historical Data

A compilation of historical data can provide significant information on the nature of risky events, including the frequency, severity, and trends over time (Glosser, 2013). It is challenging to analyze objective data on incidents related to gas shale development. There have been hundreds of incident reports and permit violations since the Marcellus Shale play started in 2007, but just looking at a number is meaningless. For example, a "discharge of industrial waste" violation can range from a spilled liter of motor oil to a leak from a million-liter frac fluid tank. Incident reports compiled in the past on some websites emphasized only the numbers, without further classifying the events for meaningful statistical analysis. Even classification efforts by websites like FracTracker using Pennsylvania DEP inspection data (www.fractracker.org/) only analyze the percentage of violations per company per inspection, providing no details about the circumstances or severity. If someone wanted to dive deeply into the details, and had specific search terms, the Pennsylvania DEP maintains a searchable and downloadable online database of oil and gas well violations at www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/OG_Compliance.

In a report assembled for the Ground Water Protection Council, Kell (2011) investigated state agency responses to groundwater contamination events resulting from oil and gas drilling in Ohio and Texas. The data were compiled from 16 yr of records in Texas and 24 yr of records in Ohio for all oil and gas wells (not just shale gas), and they were broken down by phase of the operation, such as site preparation, drilling, hydraulic fracturing, oil and gas production, plugging, and abandonment. A groundwater contamination incident was rigorously defined as "any reported or detected event associated with upstream development of oil and gas resources and management or disposal of associated wastes that caused contamination of groundwater, or disrupted water supply usage" (Kell, 2011, p. 7). Kell (2011) found that most of the groundwater contamination incidents in Ohio occurred during the drilling and completion phases. Interestingly, the majority of Ohio incidents reported for the years 1983–2007 occurred between 1983 and 1988 (85 of 144 incidents or 60%), with a significant drop-off after this period. These were boom years for Ohio drilling during the high oil price days of the early 1980s, and they pre-date activity on the current Utica Shale play in southeastern Ohio by decades. In contrast, most of the Texas groundwater contamination incidents happened during production operations or in the waste management phases.

According to statements from the Texas Railroad Commission (RRC), which issues drilling permits in that state, regulatory personnel are sent out to "witness" drilling and completion operations on about a third of all permitted wells. RRC personnel are less commonly on-site for the production and waste management operations, which may explain why there are more incidents during these phases. The Texas RRC data from 1993 to 2008 include the development of the Barnett Shale, which began production in 1997.

Texas recorded 211 contamination incidents during the drilling of 187,788 wells, for an occurrence rate of 0.112% (Appendices F and G *in* Kell, 2011). Ohio recorded 144 contamination incidents on 33,304 wells, for an occurrence rate of 0.432% (Appendices C and D *in* Kell, 2011). Both states reported zero groundwater contamination incidents associated with well stimulation (hydraulic fracturing) during the time periods studied.

Another report from the State University of New York at Buffalo (Considine et al., 2012) supports Kell's (2011) study. The Buffalo study, which has been criticized because of perceived ties to industry, reviewed only Marcellus Shale environmental incidents and found reportable incidents in ~0.6% of all Marcellus wells, with a trend in decreasing numbers of incidents over time.

A study by Groat and Grimshaw (2012) in Texas, criticized like the Considine et al. (2012) study because of perceived ties to industry, found that every reported instance of groundwater contamination from hydraulic fracturing of shale gas wells came from surface spills and infiltration. So far, no study by anyone independent of industry has produced unquestionable evidence that Groat and Grimshaw (2012), Considine et al. (2012), or even Kell (2011) were wrong. Anti-fracking activists should stop dismissing every study conducted in cooperation with industry as "tainted" and realize that in order to gain access to sites and data, at least some industry participation is essential (Soeder, 2015).

The incident rate must be reduced further. If one half of one percent of all airliners crashed, for example, there would be more than 10 crashes a day at airports like Chicago O'Hare, which has over 2000 daily flights. Clearly, that is unacceptable. A goal for shale gas could be to move into the realm of airline safety, where risk management is paramount, and incidents are extremely rare.

HYDRAULIC FRACTURING CHEMICALS

High-volume hydraulic fracturing (HVHF) typically requires that large quantities of chemicals, some hazardous, be available on well pads for blending during the course of the frac job.

Because these chemicals are blended during the frac process itself, they are usually delivered to the site and used in concentrated form. This raises the concern that leaks and spills from these chemicals can pose a significant risk to surface streams and groundwater, which has indeed happened on occasion (Brantley et al., 2014). Offsetting this to some degree is the fact that the chemicals are on site for a relatively limited time period (Soeder et al., 2014b).

Other industries use chemicals that are more toxic than any compounds on a drill site, and often in far larger quantities without incident. These industries operate safely, and there is no reason to suspect that gas producers are somehow more reckless, uncaring, or less competent.

The "Halliburton Loophole"

In 2005, at the urging of then–Vice President Dick Cheney, the oilfield service companies that perform hydraulic fracturing were exempted from compliance with the Underground Injection Control (UIC) Program Requirements of the Safe Drinking Water Act. The service companies were concerned that if they were required to meet the UIC standards, they would have to disclose the secret chemical formulas of proprietary frac fluids being injected into the ground, which competitors could then steal. The oilfield service company exemption, often called the "Halliburton loophole" after Cheney's former employer, was only to the UIC requirements of the Safe Drinking Water Act, and not to the entire Clean Water Act, as some people have claimed.

Service companies invest a lot of time and money into developing hydraulic fracturing fluid formulations. The United States has a long history of protecting the trade secrets of companies that develop a proprietary formulation or an industrial process. Like Colonel Sanders' chicken recipe or the formula for Coca-Cola, the service companies claimed the right to keep their mixtures secret. No one thought this would be a problem: The oil and gas industry has a history of being exempted from a number of federal environmental statutes, such as the requirement to obtain a National Pollutant Discharge Elimination System (NPDES) permit for storm-water discharges, for example. Details can be found by searching the EPA website.

This time, the tactic incurred backlash. Environmentalists and the media interpreted the nondisclosure as proof that the industry must be hiding something. The secrecy gave anti-fracking activists and a frightened public free rein to "fill in the blanks" with whatever dreadful chemical soup they could imagine. The EPA eventually compiled a list of over a thousand chemicals that reportedly had been tried in hydraulic fracture treatments after operators were required to fully identify the chemicals they were using. It made quite a soup.

The outcry resulted in the introduction of Senate Bill 1215 by Senator Casey of Pennsylvania in the U.S. Congress in June 2009, known as the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, which would have required the public disclosure of frac chemicals. The proposed bill died in committee without a vote. Although the FRAC Act did not pass, the concerns it raised did result in many oil and gas operators posting well completion reports on the Internet with a list of the chemicals used for hydraulic fracturing. One of the primary websites for this is Frac Focus (http://fracfocus.org/), a joint effort of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. Several states now require the posting of chemicals used in hydraulic fracturing on Frac Focus as part of the well permitting process.

The main components of hydraulic fracture fluid reported on Frac Focus and other websites are typically water, sand as proppant, polyacrylamide to lubricate and reduce friction, guar gum to thicken the fluid for carrying the proppant, hydrochloric acid for cleanup, ethylene glycol for corrosion resistance, and a biocide to prevent sulfate-reducing bacteria from growing downhole and souring the gas. The complex chemical soup that some people thought service companies were injecting into the ground during a hydraulic fracturing job is actually much simpler and cheaper. The basic chemicals listed here are all that are ever generally needed. Companies certainly tried many different kinds of biocides, and many different types of friction reducers, corrosion inhibitors, etc., possibly going through hundreds of chemicals trying to get the formula right for a particular part of a particular play. However, nobody routinely uses hundreds of chemicals on a single job.

Hydraulic Fracturing and Aquifers

There are a number of physical reasons why it is unlikely that hydraulic fracturing of the Marcellus Shale will directly contaminate underground drinking water aquifers from beneath. The length of time the fluid is under pressure while creating the fracture is limited—generally no longer than 2 to 3 h. There is simply not enough time under pressure for it to break the rock all the way up to a shallow aquifer. Along with the limited time, the volumes of fluid used are too small. Although each stage of a hydraulic frac uses millions of liters of fluid, calculations and computer models agree that this is just not enough volume to open up fractures to lengths that can reach shallow aquifers.

Of the tens of thousands of oil and gas wells hydraulically fractured since the process was invented in 1947, a search of the literature has turned up only two claims where the treatment itself has supposedly contaminated a shallow aquifer above the hydraulically fractured zone. Both are questionable.

The more recent event on record occurred in 2008 in the town of Pavillion, Wyoming, where a gas-bearing sandstone immediately beneath a freshwater aquifer was fractured, and chemicals detected in two deep wells were interpreted by the EPA in a draft report (DiGiulio et al., 2011) as having originated from the frac fluid. A review of this assessment in a report by the American Petroleum Institute (2012) found numerous flaws in the methodology. The API report cites water data collected later by the USGS (Wright and McMahon, 2012), which indicate that certain aspects of the EPA study plan were not followed by on-site personnel, leading to potential quality assurance issues with samples. In particular, the casing used in the Pavillion EPA monitoring wells was cited as a potential source of the contamination detected later in water samples from these wells. Despite this, DiGiulio and Jackson (2016) claim that organic compounds and anomalies in major ion concentrations in water samples from the EPA monitoring wells provide evidence of upward frac fluid migration to shallow groundwater. Their interpretation is complicated by legacy disposal practices of diesel-fuel–based drilling mud and production fluids in unlined pits less than 600 m (1900 ft) from domestic wells where diesel range organics and other organic compounds were detected (DiGiulio and Jackson, 2016). As a result of this uncertainty, the results must be considered inconclusive.

An older case in West Virginia was noted in an EPA report (U.S. EPA, 1987) where a hydraulic fracture treatment was performed in a vertical gas well drilled to a total depth of ~1370 m (4500 ft), and located less than 300 m (1000 ft) from a shallow water supply well. Two years later, the water well showed signs of contamination by gel and a fibrous material, identified by the EPA as components of the frac fluid. The EPA report does not contain many details about the incident itself, failing to explain, for example, why it took 2 yr for the frac fluid to migrate to the water well, how fibrous material was able to move through porous rock, and what force drove the fluid upward to the aquifer, in light of the fact that no gas was reported, only the gel and solids. Because the incident occurred over 25 yr ago, and the EPA investigators at the time could not provide a credible migration mechanism, the exact circumstances of what happened will probably never be known. At this point, it must be considered unconfirmed.

Hydraulic fractures rarely extend beyond 300 m (1000 ft) and almost never beyond 600 m (2000 ft). Drinking water aquifers in the Appalachian Basin are usually shallower than 100 m (300 ft), although they can be significantly deeper in the west. For the Marcellus frac fluid to reach a shallow, freshwater aquifer, or travel clear to the surface, would require pumping it kilometers upward against gravity while constantly replacing the volume of water lost. It would literally take a deliberate decision on the part of someone controlling the frac to do this.

Even if the fracture did somehow continue to move upward toward the surface, it would cease to break the rock vertically at shallow depths and become a horizontal feature. Fractures break vertically at depth because of the strong downward stress field imposed by kilometers of overburden. When the maximum compressive stress is downward, the maximum tensile stress or "pull-apart" direction is at right angles to that, in the horizontal plane, resulting in a vertical crack. At shallower depths, the vertical overburden stress becomes less than the lateral rock strength, and the rocks break horizontally along bedding planes (Hubbert and Willis, 1957).

Once the hydraulic fracture pressure is released and gas production starts from the well, flow in the Marcellus Shale and surrounding rocks follows the pressure gradient toward the wellbore, not upward toward the surface. Frac fluid is produced from the gas well as flowback, not from shallow aquifers near the surface. It is doubtful that the frac fluid remaining underground will climb a mile (1.6 km) or more against the force of gravity to contaminate a freshwater aquifer. Even if it could, it would have to find open fractures extending all the way to the surface. Any other route through the rock matrix or pore structure itself would take centuries.

There are concerns about existing fractures that do extend to the surface, such as faults, acting as conduits for the upward movement of hydraulic frac fluids. This is one of the pathways examined in the EPA drinking water assessment (U.S. EPA, 2016). Another potential pathway for transmitting frac fluids might be old, abandoned wells intercepted by the hydraulic frac (Jackson et al., 2013). Such an intercept during the hydraulic fracturing process would result in an immediate drop in pressure at the pumps, and an increase in the volume of flow. This is called a "breakout," and the engineers monitoring the frac job would shut it down until the cause of the fluid loss was discovered. This has happened on very rare occasions (Detrow, 2012), one of which is discussed in the Abandoned Wells section. Hydraulic fracturing is an expensive, specialized procedure, and the people who perform these operations watch the pressure, flow rate, and fracture development very closely. Huge amounts of time, materials, and money could be wasted if they do not.

A contaminant transport study used the MODFLOW groundwater model to assess possible fluid movement though the Marcellus Shale that could bring hydraulic fracturing chemicals to the surface (Myers, 2012). The parameters used in the numerical simulations were estimated, including values used for pressure, volume, permeability, and flow pathways. The paper asserts that advective transport is potentially a major pathway for frac fluids to reach either shallow aquifers or the surface. Publications from the 1980s have noted that the Devonian shales in the Appalachian Basin almost never produce measurable flows of water, and that whatever water is in them is not mobile (Soeder et al., 1986). Well-log data indicate that water saturations of 10%–25% of total pore volume are present in the Marcellus Shale (Engelder, 2012), which is not enough to form a continuous, mobile liquid phase. The mobile phase in the Marcellus Shale is gas.

Flewelling and Sharma (2014) found that hydraulic fracturing affects a very limited portion of the rock overlying the target shale and is unable to create direct hydraulic communication with shallow aquifers. Any upward migration of fluid and brine that does occur is controlled by preexisting permeability and hydraulic gradients, and it is very slow. They concluded that the proposed rapid upward migration of brine and hydraulic fracturing fluids does not appear to be physically plausible and is based on invalid assumptions about the hydrogeology of sedimentary basins.

Warner et al. (2012) reported that brines from the Marcellus Shale can be detected in certain springs and natural seeps in northeast Pennsylvania based on geochemical evidence. Warner and his coauthors estimated groundwater travel times for brines sourced in the Marcellus to be on the order of centuries. The shale is significantly thicker and shallower in this part of the state compared to southwestern Pennsylvania and West Virginia. Seismic survey data collected by shale gas developers in the area suggest that large, through-going faults may be present along the flanks of anticlines in the Nittany Arch. This combination of shallowness and large fracture systems, unique in the Marcellus play to northeastern Pennsylvania, may be responsible for natural upward migration of brine. Additional data are required to clearly determine whether or not these waters originate in the Marcellus Shale as suggested by Warner et al. (2012), or from a formation above or below it.

Geophysical data offer the best evidence for the restricted heights of hydraulic fractures. This is a well-understood, hard science with a long track record. Microseismic monitoring is a geophysical technique used to determine the positions of hydraulic fractures in the ground. DOE and Sandia National Laboratory originally developed this method in the 1980s; it uses a string of sensitive microphones known as "geophones" that are suspended vertically in a borehole near the frac location. The geophones detect the crackling sound emitted by the hydraulic fracture breaking the rock, and the arrival times of the sound waves at the different sensors are carefully measured and matched up. These data are then used to precisely triangulate the location of the frac as it grows through time. The microseismic technique using a vertical geophone string is generally accurate to within centimeters (inches) on the height of the frac. Other techniques using geophone arrays on the surface claim equal or greater accuracy because of the ability to deploy many more geophones across the landscape than down a well, and to "stack" the data.

A company named Pinnacle was formed out of the Sandia work to commercialize this process. Now owned by Halliburton, Pinnacle has amassed a wealth of microseismic geophysical data from Marcellus Shale hydraulic fracture treatments, as well as from many other shale resources, including the Barnett Shale in Texas.

Pinnacle presented their fracture height results in relation to freshwater aquifers in a trade magazine article (Fisher, 2010) and in a peer-reviewed journal (Fisher and Warpinski, 2012). Kevin Fisher of Pinnacle has kindly supplied a graph of the original data for the Marcellus Shale, presented in Figure 33. This graph shows that laterals drilled through the Marcellus Shale range in depth from a bit more than 1.5 km (5000 ft) in the northern part of the play to greater than 2.7 km (9000 ft) along the eastern edge.

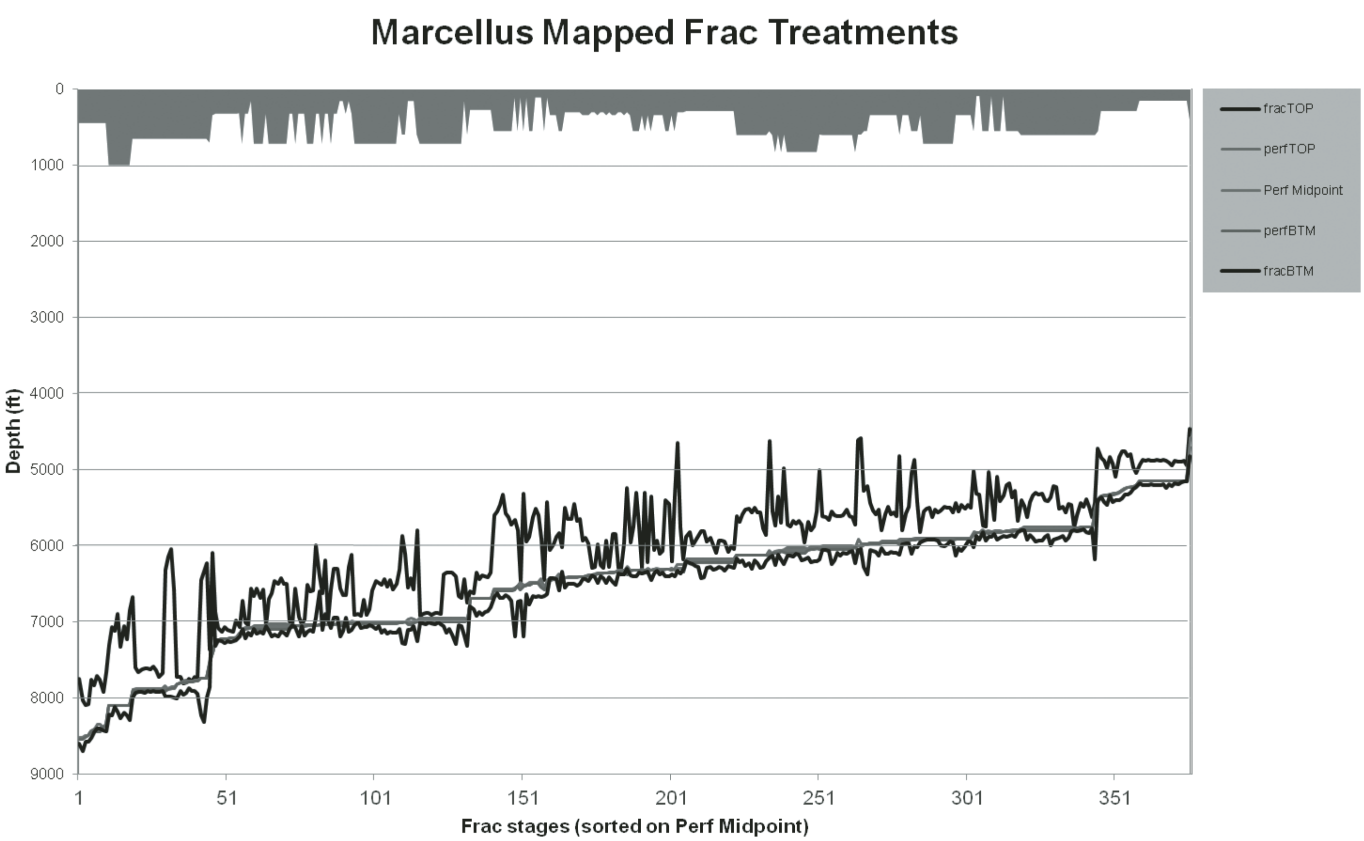

Figure 33. Measured height of hydraulic fractures in nearly 400 Marcellus Shale frac stages in numerous wells, plotted against the depth of the deepest freshwater aquifer in each county, shown as a histogram at the top of the graph. For the figure, the fracs were sorted based on the depth of the perforations in the casing from deepest on the left to shallowest on the right. The jagged lines show the tops (TOP) and bottoms (BTM) of each frac. Data are courtesy of Kevin Fisher from Pinnacle, a Halliburton Company.

The data in Figure 33 are distributed left to right from deepest to shallowest. The laterals are indicated by the more-or-less smooth, horizontal line. The jagged lines above and below it show the vertical extent of the hydraulic fractures. The depths of the deepest freshwater aquifers that are actually produced for drinking water in each county are depicted as a histogram along the top of the graph.

It is clear from the geophysical data in Figure 33 that the tops of the hydraulic fractures do not come anywhere near the depth of the aquifers, and in fact, they are a minimum of 1067 m (3500 vertical ft) below the base of the deepest freshwater aquifers. In many cases, the separation is much greater.

Vertical fractures initiated at greater depths tend to break higher, due to the higher contrast between vertical and horizontal stress gradients under the greater overburden pressures at depth (this is an additional illustration of why shallow fractures break horizontally). It is also interesting to note that the hydraulic fractures tend to break preferentially upward, rather than downward. This is probably due to the rock strength and mechanical properties of the thick Onondaga Limestone below the Marcellus Shale, which acts as a fracture barrier. It also suggests that despite similar chemistry, produced water from the Marcellus is probably not originating in the Oriskany Sandstone below the Onondaga Limestone and being transported upward to the shale via hydraulic fractures. Except for the relatively thin Tully Limestone Member, the bulk of the rocks overlying the Marcellus Shale are series of organic-rich and organic-lean shales (refer back to the cross section in Fig. 3) that possess essentially the same mechanical properties as the target formation.

This is not meant to imply that groundwater contamination does not or cannot occur during hydraulic fracturing operations on the Marcellus or other gas shales. It does happen, but in every case documented so far, the cause has been due to chemical leaks or spills on the land surface. In a manner similar to nearly all other cases of groundwater pollution, the spilled chemicals infiltrate into the ground under the force of gravity and percolate downward into the groundwater. The reader is also reminded that hydraulic fracturing is only one part of the construction operation of a shale gas well, and the groundwater may be at risk during other stages, such as the initial drilling through the shallow aquifer, or during gas production if there is a wellbore integrity problem.

LAND AND WATERSHED IMPACTS

Drill rigs in rural areas are often seen as unattractive, turning forests and farmland into "industrial" landscapes. However, the presence of a drill rig and even the large amount of equipment needed for hydraulic fracturing are temporary. Over the long term, the landscape will be impacted by the drill pad, roads, pipelines, and other surface infrastructure much more than the rig. These more permanent features can affect drainage, runoff, sediment, groundwater infiltration, and recharge, and they can impact both terrestrial and aquatic ecosystems. Interestingly, the EPA drinking water study (U.S. EPA, 2016) did not note land-clearing activities as a potential threat to water supplies.

State permit regulations require full restoration of drill pads after completion, but the schedules for adding extra wells on a pad (known as "infill drilling"), or to re-frac existing wells may require that pad access be maintained for months, or even years. Most drill pads are constructed with an impervious geotextile layer used to protect the groundwater. This may increase runoff and limit infiltration, potentially affecting aquatic ecosystems.

Delaying the restoration of long-term pads is a concern—trees are not able to reestablish themselves, nor are many animal inhabitants. Even if not fully restored, pads could be put into a state of "hydrologic" restoration for intervals of months to years when they are not in active use. Taking up the geotextile liners and installing sediment traps would allow infiltration and runoff to occur naturally. Geotextile liners can be laid back down when the pad is once again needed.

Impoundments containing supplies of freshwater for hydraulic fracturing are generally not much of an environmental concern except from a construction standpoint. Engineers at West Virginia University have found that many operators constructing water supply impoundments are not aware of state dam regulations or engineering requirements.

A greater worry about water impoundments is that they may prove irresistible to water birds, deer, and other local wildlife, such as teenage boys. Land management agencies often refer to these ponds as "attractive nuisances" that may result in accidental drownings. If a company needs to retain the pond for additional drilling or for a re-frac, then fencing it off like a swimming pool or quarry is necessary. Temporarily breaching and draining water impoundments reduces liability for the company, and a small drainage breach in an impoundment can easily be repaired if it needs to be refilled later. Permanently draining, dismantling, and leveling drill pad impoundments after completion of the well will remove the hazard entirely.

A better option is to use tanks instead of earthen impoundments, and a "closed cycle" process for drilling mud and frac fluid to ensure that all liquids are recovered and removed from the well site at the end of the drilling and hydraulic fracturing operations. The tanks themselves are the "ponds," which get taken to the next drilling location, leaving nothing behind but flat, dry ground.

A concern often expressed about Marcellus Shale development is the "cumulative" effects of many well pads on a landscape. A typical manifestation of the cumulative effects of development occurs in areas that have been urbanized, producing what hydrologists call "flashy" streams. Such streams can rise very quickly after a small amount of rain (hence, the term "flash flood") because of changes in the landscape that prevent water storage in the soil and increase runoff. Flashy streams usually have problems with poor water quality because of erosion, and the fast water velocities associated with runoff events negatively impact aquatic habitat and in-stream biota.

As an example, Figure 34 compares stream flow records (called hydrographs) from two similar-size watersheds: the urbanized

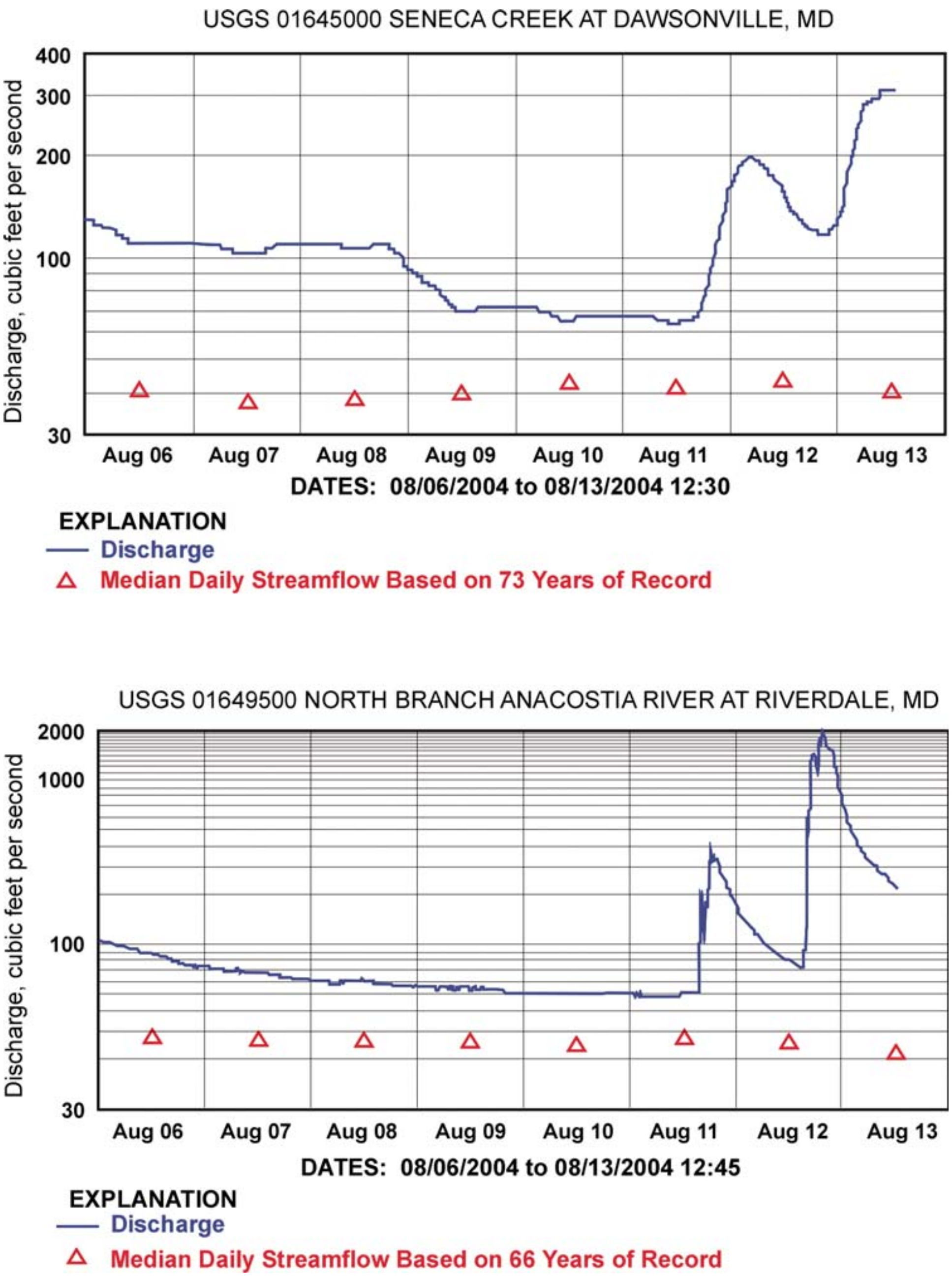

Figure 34. A pair of hydrographs showing runoff from the same August 2004 storm event in similar-sized watersheds: rural Seneca Creek and the highly urbanized Anacostia River near Washington, D.C. The steep rise and higher, sharper peaks on the Anacostia hydrograph are typical of "flashy" stream behavior in an urbanized landscape. Data source: U.S. Geological Survey (2014).

Anacostia River in Washington, D.C., and the more rural Seneca Creek in Maryland. These hydrographs show the same storm event hitting the two different watersheds, and the response of each. Flow in the Anacostia River rises much more quickly and falls more rapidly than Seneca Creek, a sign of a flashy stream. In an urban environment, the usual cause of flashy streams is impervious surfaces, such as rooftops and parking lots. Rain hitting these surfaces does not have an opportunity to be absorbed by leaf cover or infiltrate into soils, as it would in a forest, but immediately becomes runoff, gushing from gutters and storm drains directly into streams. A similar situation could result from shale gas development if a small watershed is forced to cope with excess runoff from packed dirt roads and drill pads, removal of trees, and impervious ground barriers placed on drill sites to protect groundwater.

A modeling study at NETL found that a single drill pad can impact runoff in a small watershed (Fries, 2014). The model assumed that 3.25 ha (8 acres) of impervious surface are added to a watershed from the construction of a 2 ha (5 acre) drill pad and associated roads. Model runs showed that the threshold for significant impacts from a single drill pad was exceeded on forested land in a watershed with a catchment area of 5 km^2

(2 square miles). Because other land-use types are already impaired hydrologically to some degree, larger catchment areas can also be affected by the drill pad. For example, 6.5 km^2 (2.5 square miles) watersheds were impacted on agricultural land, and 13 km^2 (5 square miles) watersheds were impacted on urbanized land (Fries, 2014).

The potential environmental impact of shale gas drill pads scattered across rural areas is not completely understood. The previous use of the land that the pad is replacing is an important consideration. For example, replacing a 5 acre forest with a 5 acre drill pad will probably degrade nearby water resources. However, replacing a 5 acre cornfield with a drill pad may actually be an improvement, because corn is one of the most heavily chemically treated commercial crops, and residual pesticides and fertilizers can contaminate streams and groundwater for years. A drill pad replacing a parking lot in an urbanized area may have no measurable effect at all. To complement the modeling work by Fries (2014), some on-the-ground studies should be done at a wide variety of locations to provide data on the landscape impacts of pads. It is important to note that as drilling technology improves, the pads are being spaced farther apart. This will have the effect of reducing the overall landscape impacts over time, and temporal changes must be considered in any large-scale study.

As mentioned earlier, the New York City water supply comes from protected and managed watersheds in the upper Delaware River and thus requires minimal treatment, saving the city billions of dollars. Impacts of shale gas development within these watersheds would be similar to changing the land use from rural to urban. A few wells, like a few houses, make little difference in a watershed. As well pads and roads continue to be added, however, the small effects from each site would accumulate until hydrologic conditions in the watershed cross a threshold, creating changes that would impact stream flow, water quality, and aquatic biota (Hazen and Sawyer, 2009).

As such, New York State and the Delaware River Basin Commission have never issued any shale gas drilling permits within the New York City water supply area. Indeed, the few leases that were signed in these watersheds during the heyday of the 2008 shale gas boom have been left to expire undrilled.

The large scale of Marcellus Shale field operations leads to a consequently greater impact to the landscape and watersheds compared to conventional wells. Drill sites are commonly located in remote areas accessible only by dirt roads. The operators must often construct several kilometers of road into the site from a state or county highway. Even if there are preexisting roads in the area, they may require modifications such as widening, reinforcing bridges, or straightening curves to allow the supersized Marcellus drilling equipment and supplies to pass (refer back to Figs. 23 and 25).

Steep hills and narrow ravines in West Virginia and Pennsylvania can make road building challenging and expensive. To reduce excavation costs, roads are commonly built alongside streams when possible, and they follow stream valleys up and onto a mountain ridge. Even a well-constructed gravel road alongside a stream can be detrimental to the water body from sediment and rapid runoff. Roads that are poorly constructed or improperly routed can be devastating to the hydrology and aquatic ecosystem.

The states regulate road construction as part of the permitting process. In both Pennsylvania and West Virginia, site plans based on surveys must be extremely detailed and include specifics about roads and pads. In Pennsylvania, wetland surveys are required before the permit process can even start.

The hurried construction of drill pads, roads, and impoundments during the initial boom days of Marcellus Shale development has left significant damage in Wetzel County, West Virginia, in the northwestern part of the state near the Ohio River. This is a land of steep slopes and narrow stream valleys. Well pads excavated into hills have suffered slumping, slippage, and erosion. Instances have been documented in Wetzel County where a bulldozer simply drove a road straight up the bed of a small stream. The flowing stream was reduced to a trickle in a ditch alongside the road or perhaps buried altogether under several feet of fill. Any aquatic habitat that existed before the emplacement of such a road is gone. The hydrology of the stream has been completely altered to an artificial condition, potentially leading to excessive runoff, ponding, flash floods, groundwater contamination, unstable slopes, and poorly drained floodplains. Whatever is left of the original channel will quickly erode and undercut the banks because of increased runoff. Eventually, the road itself will erode completely away, and the stream channel will return to its previous location, but the damage has been done.

Such careless construction techniques also destroy the riparian zone. This zone is the strip along the stream banks that moderates flow, allows groundwater to seep into the stream, and supports a plant community that reduces the amount of nutrients entering the stream. The water quality in headwater streams is critically important to the health of the main stream. Improper road construction on such sensitive landscapes can be extremely destructive to small watersheds. Road and pad construction can and has been done correctly in many places, but sadly, Wetzel County is not among them. Federal regulations apply in cases of damage to small watersheds from Marcellus Shale gas development. The U.S. Attorney in the Northern District of West Virginia, with help from EPA investigators, took action against the Wetzel County violations in 2012 under Section 404 of the Clean Water Act (Ihlenfeld, 2012).

Some states allow operators to dispose of mud and cuttings by simply burying the mud pits with fill dirt once drilling operations are completed. Reports of materials leaking from drill pads into nearby streams (Figure 35) are a concern, along with occasional reports of fluids seeping out of hillsides below abandoned drill pads. Setback distances of drill pads from streams may be an important factor in reducing the risk of watershed impairment, and although this has been heavily debated, there are few studies.

Optimized well spacing is important for producing commercial amounts of gas efficiently with minimal disruption to the landscape. The current practice of horizontal drilling and placing

Figure 35. A black substance identified as drilling mud oozing out of the ground from an eroded stream bank below a drill pad and into the water of Indian Run in Harrison County, West Virginia, in 2010. Photograph is by Doug Mazer, used with permission.

six to eight wells per pad has greatly reduced the impact to the landscape compared to closely spaced, vertical wells. Horizontal wells were typically placed on 0.647 km^2 (160 acre) parcels of land during the early development of the Marcellus play, which had less impact compared to a much tighter spacing 0.162 km^2 (40 acres) for vertical wells. The early development of the Marcellus Shale used lessons learned from the Barnett Shale play, where wells were originally drilled at 0.324 km^2 (80 acres) spacing. This close spacing of well pads in Texas has resulted in significant landscape impacts, as shown in the satellite image in Figure 36.

Improved drilling techniques, longer horizontal laterals, and more efficient hydraulic fracturing practices now dictate a typical spacing for Marcellus Shale wells of 640 acres, equivalent to one well every 2.59 km^2, or 1 square mile. Although this wide spacing between well pads is driven by economics and efficiency, it also positively affects the environment. Many fewer pads, roads, and pipeline rights-of-way are needed to extract the gas from a given volume of rock, making the development process less expensive for the company and more efficient, while greatly reducing the impact on the environment. Such links among favorable environmental practices, efficiency, and favorable economics provide a powerful incentive for industry to protect the environment.

A Marcellus Shale well is a full-blown construction site during the drilling and hydraulic fracturing processes, but it is important to recognize that these impacts are temporary and are really no worse than those at many other construction sites. Once a shale gas well is installed and producing, all that remains is a pipe sticking up out of the ground in a cleared field, with a tank or two alongside it to collect produced water. A natural gas–fueled compressor might be added later when production pressure from the well drops below pipeline pressure. The major disturbance is a worker visiting several times a week to read meters, check levels, and make sure everything is operational. A bigger truck comes by once a month to empty the produced water out of the stock tank.

The final landscape impact on the list comes from the pipelines needed to carry the gas from wellhead to market. In the future, a continuous gas resource like the Marcellus Shale may be able to supply gas as fuel for factories or electrical generation from on-site wells, but at the moment, every gas well needs a pipeline connection. Unlike a road, pipelines produce minimal land disturbance once installed, and vegetation can re-establish itself on the right-of-way. Still, installing the pipelines usually means clearing vegetation and digging. With modern machinery, the trench is often just slightly wider than the pipe itself, and the actual footprint is minimal. It still creates a line of disturbance across a habitat.

Less impact comes from horizontal, directional drilling techniques applied at very shallow depths. Horizontal boreholes allow pipelines to be installed under roads, walkways, and other structures without any surface disturbance. Directional drilling is commonly used to construct pipeline crossings of rivers and streams by going beneath the stream channel. However, occasional blowouts have occurred when drilling under rivers, highlighting the need for experienced field crews and careful design specifications. Running the gas pipeline through a larger-diameter pipe under the stream channel offers the same multilayer protection as casing does in a well.

Many operators are dealing with the lack of pipelines in certain areas by drilling Marcellus Shale wells in preexisting gas fields. Because the Marcellus is a continuous resource, a shale gas well drilled in an already established Bradford or Venango Sandstone gas field will almost certainly produce gas. These conventional gas fields are located in the coarser Upper Devonian formations of the Catskill Delta high above the Marcellus Shale (refer back to the cross section in Fig. 3). Deeper conventional gas fields in the Oriskany and Clinton Sandstones are also being explored for shale gas drilling. The surface infrastructure needed to capture, compress, meter, and deliver the shale gas is already present, improving the economics considerably.

Modern shale gas production techniques greatly reduce landscape disturbance by using long lateral boreholes and drill pads that host multiple wells. With one drill pad every 2.59 km^2 (640 acres), which is currently considered the optimal spacing for

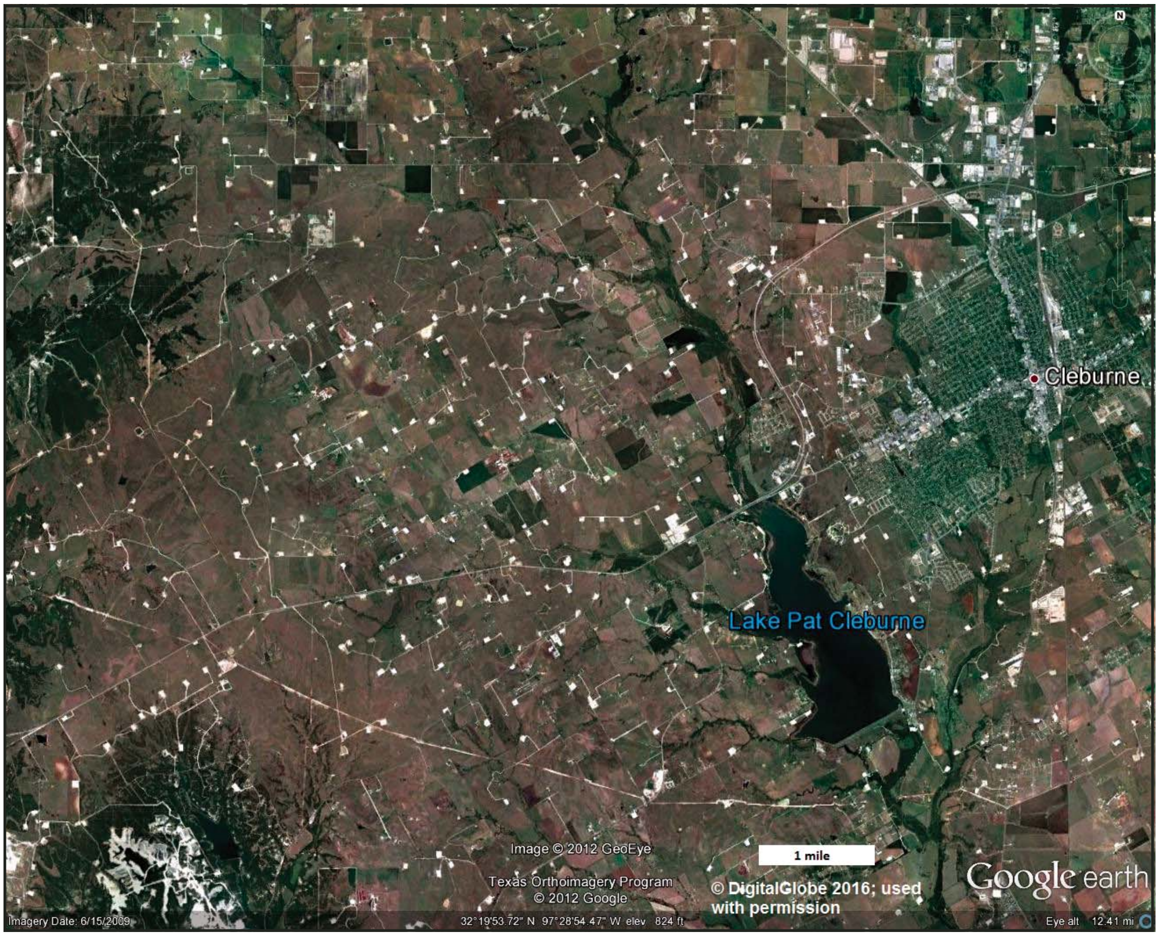

Figure 36. Satellite image of the Cleburne, Texas, area southwest of Fort Worth in 2009. Most of the white "specks" in the image are Barnett Shale drill pads. © DigitalGlobe 2016, used with permission.

Marcellus Shale production, only one pipeline spur is needed to connect that drill pad to a main transmission line. Covering the same area with vertical wells at a spacing of 0.162 km^2 (40 acres) would require 16 pipeline connections to service the wells.

With proper planning, the gas line can be run alongside the well service road, minimizing additional land disturbance, and keeping the pipeline accessible for servicing and repairs if needed. As with many issues related to the production of shale gas, the large scale of the operation can often be used to an advantage.

CONTAMINANT HYDROLOGY

Surveys of people living in the Marcellus Shale development region consistently list the potential impacts to water resources as their single most important concern. The three main issues related to water resources and Marcellus Shale gas production were identified by Soeder and Kappel (2009) as (1) the potential impacts of water use on drinking water supplies, (2) damage to small watersheds and headwater streams from well pad infrastructure, and (3) potential impacts of frac chemicals and produced fluids on water quality.

Changes in water handling procedures since 2011 have alleviated some (but not all) of these concerns. Operators have stopped using municipal drinking water supplies for frac water, and they no longer dispose of flowback in POTWs. Impacts to small watersheds are still significant, however, and several new concerns, such as induced seismicity from UIC disposal wells, and biocide-resistant microbial populations in recycled produced water have been added.

Pennsylvania, West Virginia, Ohio, Maryland, Virginia, and New York are states that were settled early in American history, and they bore the brunt of the industrial revolution. Forests were clear-cut for timber; landscapes and stream valleys were blasted and carved, first for canals and then for roads and railroads; streams were diverted and dammed; coal was mined; oil and gas wells were drilled; factories were built; and waste was dumped, buried, or burned. Evidence of this old infrastructure is everywhere. This history has greatly complicated the process for distinguishing environmental impacts of

Marcellus Shale gas drilling from preexisting or other sources of environmental degradation.

Risks to groundwater from the shale gas drilling, hydraulic fracturing, and production process vary with the particular phase of development (Soeder et al., 2014b). For example, the risks to underground sources of drinking water are highest when the drill is penetrating the shallow aquifers. Once the surface casing is set and the drilling proceeds to great depths, the risk is lower. Risk rises again when hydraulic fracturing chemicals are brought on-site because of the potential for leaks or spills. After the frac, the risk is again reduced, because the chemicals have been removed, but the produced water stored on-site may still pose a threat to groundwater. Finally, during long-term production, the produced water volumes taper off, and the risk comes from materials leaching from solid wastes or loss of wellbore integrity. These risks are summarized in Table 2.

The water produced from completed and stimulated shale gas wells is thought to be composed of (1) recovered fluid introduced downhole for the hydraulic fracture, (2) high-TDS fluid resulting from osmotic diffusion of salts in residual shale pore water into the frac fluid that remains downhole for extended periods, and (3) high-TDS formation water from more porous units above or below the shale that have been intercepted by the frac.

Produced water containing high TDS is a significant source of potential water contamination from shale gas drilling operations (Soeder and Kappel, 2009). In the early days of Marcellus gas development, operators routinely disposed of the flowback fluid and produced water at POTWs, which used processes that did little or nothing to remove inorganic dissolved solids. In early 2011, Pennsylvania DEP Secretary Michael Krancer appealed to the Marcellus Shale drilling industry to stop taking wastewater to POTWs. Operators voluntarily complied, and bromide levels in the Monongahela River decreased soon afterward (Wilson and VanBriesen, 2012). The Pennsylvania DEP recommended that the produced water be run through centralized wastewater treatment (CWT) facilities that use flash distillation or membrane filtration to remove TDS from industrial wastewater, or that it be disposed of by injection down UIC wells. These waste-disposal options increased the cost of water treatment fivefold, resulting in the current practice of filtering and recycling the produced waters (Rodriguez and Soeder, 2015).

Because only a relatively small percentage of injected frac water is returned as flowback, recycling produced water into the next frac serves as a de facto method of disposal for most of it in a very cost-effective manner. Although the recycling is done for economic rather than environmental reasons, the huge reduction in disposal volume has greatly reduced many water-quality problems. Like the increased well pad spacing described previously, this is another example of a strategy that aligns environmental and economic advantages to produce a favorable outcome. Such a strategy can perhaps serve as a model to overcome other environmental impacts of shale gas development, and it may even be useful for addressing unrelated environmental problems.

Typical produced water from the Marcellus Shale contains barium, strontium, chloride, and bromide, and these are the indicator dissolved ions that are often monitored near drill sites (Rowan et al., 2015). The isotopic signature of strontium from the Marcellus Shale is unique enough to positively identify the formation water in recovered fluids (Chapman et al., 2012). No one is totally certain of the source for the high levels of barium and strontium in the shale fluids, which are both more commonly associated with carbonate rocks than with shale. Bromides and chlorides from Marcellus Shale produced water can combine with organic matter in drinking water supplies to form compounds known as disinfection by-products (Hladik et al., 2014). The chlorination process for drinking water disinfection can create brominated trihalomethane and haloacetic acids. These have been linked in laboratory experiments to cancer and other health problems (Coffin et al., 2000).

The source of the high TDS in the Marcellus Shale does not appear to be from solid salt crystals dissolving out of the rock. If this were the case, the ratio of bromine to chlorine in the produced water would be expected to change over time as the different mineral crystals dissolved into the water at different rates. Instead, the ratio of bromine to chlorine remains constant in the produced water as the concentrations increase during production, indicating that the high TDS comes from the evaporation of ancient seawater into concentrated brines (Rowan et al., 2015).

TABLE 2. GROUNDWATER RISK PER PRODUCTION PHASE

Production activity	Potential groundwater risks
Initial spud-in	Risk of air/fluid infiltration into freshwater aquifer
Set surface casing; drill vertical well	Loss of well integrity: risk of annular migration of fluids in open hole
Set intermediate casing; drill lateral	Low risk to groundwater
Set production casing; complete well	Frac chemicals on-site: risk of leakage or surface spills
Hydraulic fracturing	Frac chemicals on-site: risk of leakage/spills; potential to intercept abandoned well
Flowback and produced waters	High-TDS waters on-site: risk of potential surface spills and leakage
Long-term gas production	Potential weathering of cuttings; well integrity and gas migration issues over time

Note: TDS—total dissolved solids.

Geochemical studies have shown that paleo-evaporation can continue to concentrate bromine and other salts even after brines reach the saturation point for sodium chloride (McIntosh, 2012).

Maloney and Yoxtheimer (2012) published water-use estimates based on analysis of 2011 waste management data from the Pennsylvania DEP. They found that nearly 90% of relatively fresh produced water was recycled into additional fracs. Highly saline produced water from later production occurs in lower volumes, but nearly 60% of this high-TDS water is also recycled, despite some problems with accepting the ionic surfactants and friction reducers needed for a frac. As shale gas resources are developed, less opportunity will be available for recycling produced water because there will be fewer new wells, and permanent disposal options of these fluids will be needed.

Common Contaminants

The records of the Pennsylvania DEP indicate that nearly half of the domestic wells in Pennsylvania, which does not have mandated water well construction standards, contain at least one contaminant at levels above EPA drinking water standards (Glosser, 2013). Groundwater and homeowner associations recommend that domestic wells receive annual water quality testing. Few people actually do this, even though most county health departments support the practice and can recommend reputable laboratories where water samples should be sent.

The single most important thing domestic water well owners can do if concerned about the possible effects of nearby shale gas development on groundwater quality is to **have their wells tested** prior to the start of gas well drilling. Armed with the baseline knowledge of what is and is not present in their groundwater, they are in a strong position to monitor potential water-quality changes related to shale gas development. Following the baseline test with periodic, additional analyses will provide a trend line that can be used to determine possible water changes over time. For water wells in the vicinity of gas drilling operations, the National Ground Water Association (NGWA) recommends testing for chloride, sodium, barium, and strontium. Bromide, radium, and high TDS are also indicators of potential contamination from gas wells. Well owners should visit the NGWA well owner information website (www.wellowner.org/water-quality/reasons-to-test-your-water/) for more information and recommendations.

Because Pennsylvania law provides a presumption of liability to the gas well driller if contamination is found in a nearby domestic water supply well after drilling, nearly all operators provide routine, baseline water quality tests on domestic water supply wells within a kilometer or so of the drill pad. Baseline testing is the most effective means for operators to defend themselves against this presumption. The tests are typically performed before any equipment is even moved onto the pad, and certainly before the first gas well is spudded. The results are provided to the well owner, but the company also retains a record of the data in the event of future lawsuits.

Groundwater in the Appalachian Basin has been contaminated in many places from a wide variety of sources, including fuel from leaking underground storage tanks (known as a LUST), nitrates from fertilizers and organometallic pesticides used on farms, chemical waste from industrial operations that may include toxic metals like arsenic or mercury, and components from virtually anything spilled or leaked onto the ground that infiltrated into the soil and percolated down to the water table. Surface streams may be polluted with everything from factory effluent to acid mine drainage (AMD) and may transfer contaminants to groundwater during recharge. Such legacy pollutants make it extremely challenging to separate out groundwater contamination allegedly caused by shale gas development from everything else.

Organic compounds found in groundwater include polycyclic aromatic compounds such as benzene, toluene, ethylbenzene, and xylenes (BTEX, the major water-soluble components of gasoline) and diesel-range organics (DRO), other petroleum liquids such as road tar or motor oil, methyl tertiary butyl ether (MTBE), a compound added to gasoline in the past to improve oxidation and reduce smog (it has since been replaced with ethanol), and synthetic compounds such as plastics and plasticizer chemicals, brominated and phthalate flame retardants used on clothing, polychlorinated biphenyls (PCBs), and organochlorine pesticides such as dichlorodiphenyltrichloroethane (DDT; long banned in the United States but still persistent in the environment). Less common in groundwater but still a concern are pharmaceuticals administered to both humans and farm animals, hormones, and a class of chemicals known as endocrine disruptors that mimic hormones. The list of pollutants is unfortunately both long and detailed.

BTEX has been familiar to groundwater hydrologists for some time as a common contaminant in shallow aquifers throughout the country. A legacy of gasoline escaping from rusted out or corroded LUSTs, BTEX is carried along with the aquifer flow in a tongue or feather-shaped mass known as a plume. Many old gasoline stations in the United States were sources of BTEX. When groundwater travel times are slow, a BTEX plume from a LUST site can take years or even decades to reach a water well downgradient. The original gas station may be long gone, and tracing back the source of the BTEX plume may require some hydrologic detective work.

Small quantities of benzene are sometimes recovered in Marcellus Shale produced waters. The source of this material is not well understood. Petroleum distillates are often used as the "carrier fluid" for the gels and friction reducers, which could be contributing benzene to the produced water. More studies are needed, including predrilling baseline measurements of benzene levels in groundwater. Alternatively, the benzene may have been present in the make-up water from common sources like a LUST-contaminated site before the frac fluid was even injected downhole, and it is just being detected in the flowback. There is also a possibility that the formation might be a source of the benzene.

Much of the organic matter in the Marcellus Shale came from marine algae, known for containing fatty compounds called lipids. This plant material eventually converted to liquid petroleum and natural gas when deeply buried over geologic time. The thermal maturity of the Marcellus Shale is high enough (Rowan, 2006) that virtually all of the hydrocarbons should have been converted into “dry gas,” or nearly pure methane. However, there are natural gas liquids or condensate recovered from the western edge of the Marcellus play, which is less thermally mature. This condensate is primarily ethane, but it could potentially contain polycyclic aromatic compounds like benzene. There are no known reports of benzene in Marcellus Shale gas.

Organic analysis of the rock material from EGSP cores showed that benzene is not common within the Marcellus Shale itself (Zielinski and McIver, 1982). Although considered “oil-prone,” the Marcellus is too thermally mature in most locations to contain significant petroleum liquids (Soeder, 1988), although these have been detected in drill cuttings. Oil could also be coming from other, less thermally mature shales above the Marcellus that are being contacted by the hydraulic fractures. Analysis of organic materials in the shale might help define any association between benzene and shale gas development. In any case, given the common practices for handling, recycling, and eventual off-site disposal of produced water into deep UIC wells, it is highly unlikely that BTEX in domestic water wells has anything to do with the drilling. It is much more probable that such groundwater contamination was decades in the making from a LUST site located somewhere upgradient of the water well.

The small town of Dish, Texas, is north of Dallas in the middle of Barnett Shale country. The former town mayor has claimed that Dish residents received exposure to benzene from the 60 gas wells in and near the town. An investigation by Texas state health officials found that benzene levels in the majority of Dish residents were “similar to those measured in the general U.S. population.” Higher levels of benzene were found in Dish citizens exposed to cigarette smoke, which contains benzene (Bradford et al., 2010). This example illustrates just how difficult it can be to trace the source of chemical compounds. Even an exposure that is “obvious” is not always so obvious.

The Endocrine Disruption Exchange website (www.endocrinedisruption.org/) has been claiming for a number of years that exposures to a group of chemicals known as endocrine disruptors are related to hydraulic fracturing (Colborn et al., 2011). Endocrine disruptors are natural and synthetic hormones or other chemicals, such as household cleaners or fabric treatments, that mimic the effects of hormones. At least some of the chemicals used in hydraulic fracturing may indeed be classified as endocrine disruptors. Everyone pretty much agrees that exposure to these materials is detrimental to human health. However, the transmission routes for chemicals in underground frac fluid to come into contact with humans are still unclear. Although migration of hydraulic fracturing fluid from the Marcellus Shale to the surface is unlikely, these chemicals can enter an aquifer via casing failure or be spilled on the surface and infiltrate into the groundwater. The EPA assessment (U.S. EPA, 2016) identified a number of pathways for frac fluid chemicals to contaminate drinking water, and that document provides a more detailed description of likely and unlikely pathways.

Endocrine disruptors are actually much less of a threat to groundwater than to surface streams, where they can disrupt aquatic life, especially fish. The primary sources of most of these compounds in the environment are pharmaceuticals and household chemicals, which get into surface water via the effluent from POTWs. Typical municipal wastewater treatment is not very effective at removing these pollutants from the wastewater stream.

The USGS found endocrine disruptors in nearly every stream in the United States after a nationwide assessment (Buxton and Kolpin, 2002). USGS biologists have found smallmouth bass in the upper reaches of the Potomac River possessing the sexual characteristics of both genders caused by the effects of endocrine disruptors (Blazer et al., 2007). There is almost no horizontal drilling or HVHF of the Marcellus or any other gas shale in the Potomac watershed. The West Virginia Oil and Gas Well Location website (http://tagis.dep.wv.gov/oog/) shows two Marcellus wells in the eastern West Virginia panhandle, only one of which is in the Potomac watershed. This well was drilled in 2011. Blazer and her colleagues published their smallmouth bass results in 2007.

Several other organic chemicals used in frac fluid are of concern to environmental chemists. One is called 2-butoxyethanol (2-BE), a glycol ether that is used as an antifoaming and anticorrosion agent in slickwater formulations, and that is reported to have potential health effects on the liver. Another worrisome organic compound is a neurotoxin called acrylamide, which is a breakdown product of the friction-reducing chemical polyacrylamide used in frac fluid. Potential contamination of surface water or groundwater by spills or leaks of such chemicals in concentrated form on the drill pad is a concern. The most hazardous chemicals used in hydraulic fracturing are the biocides. As described previously in the Hydraulic Fracturing Chemicals section of Chapter 3, lytic biocides are soluble in water and tend to be easily transported, whereas electrophilic biocides bind to clays and soils as well as bacteria and are less bioavailable (Kahrilas et al., 2015) Many biocides are short-lived and readily degrade, but some breakdown products are even more toxic and persistent. Understanding of the degradation pathways and rates is limited, nor is it known how biocides behave downhole and interact with formation minerals and fluids (Kahrilas et al., 2015).

Glutaraldehyde is a commonly used biocide that can be fatal if ingested. Pictures of dead cattle were circulated on the Internet after a glutaraldehyde tank on a Haynesville Shale well pad in Louisiana leaked and the chemical flowed into a nearby pasture. Other common biocides include tetrakis hydroxymethyl-phosphonium sulfate and quaternary ammonium chloride (source: Frac Focus website: http://fracfocus.org/). Disposing of a biocide such as glutaraldehyde in a POTW is a violation of the Federal Fungicide, Insecticide, and Rodenticide Act. One has to wonder why this practice was allowed to continue for a number of years before being stopped only after industry agreed "voluntarily" to comply.

Naturally occurring radioactive materials (NORM) in the solid waste and produced water from shale gas development are another concern. The organic matter in black shale has an affinity for uranium, which commonly occurs in the Marcellus Shale as tiny grains of uraninite, a solid oxide form (Fortson, 2012). The only significantly water-soluble radionuclide in the Marcellus Shale is radium, which is created as a by-product of uranium and thorium decay. It is, in fact, fairly common in groundwater under certain geochemical conditions, such as low oxygen, low pH, and high TDS (Szabo et al., 2005, 2012).

Radium in produced water has become a concern of many people living near Marcellus Shale wells after a series of newspaper articles in 2011 warned of the dangers of radioactive compounds in produced water being discharged as effluent from POTWs and CWTs. Current water management practices that include recycling and disposal of residual waste down UIC wells should prevent radium from reaching the environment in levels that may become a public health concern. Nevertheless, because of the history of wastewater disposal practices on the shale gas play, the USGS and the Pennsylvania DEP are investigating residual contamination and possible remediation of streambeds that were made radioactive by the discharge of produced water effluent (Skalak et al., 2014).

Marcellus Shale produced water contains radium at levels of parts-per-million, a much lower concentration than most of the other inorganic dissolved solids, which occur at concentrations of parts-per-thousand or even parts-per-hundred. Unless special processing steps are taken for radium samples, the overwhelming amounts of other dissolved solids simply dominate most analytical procedures for TDS. The produced water samples analyzed by the Marcellus Shale Coalition (Hayes, 2009) did not report radium data for this reason.

When compared with historical data on Appalachian salt brines, the radium content in Marcellus Shale water samples overlaps the range for non-Marcellus produced waters (Rowan et al., 2011). The entire data set showed a correlation between higher TDS content and higher radium, but even when corrected for this, produced water from the Marcellus Shale was found to contain statistically more radium than non-Marcellus samples (Rowan et al., 2011). This may be related to the high uranium content of the shale itself (Fortson, 2012), and the production of radium from the uranium decay process.

Direct measurement of radiation levels in water is challenging under the best of circumstances. Alpha (α) radiation is very hard to detect in water, because it is easily blocked by water molecules. Beta (β) radiation is a bit more penetrating, but it can be blocked by the walls of a glass sample container. Gamma (γ) radiation is more easily detected, and in fact wireline gamma well logs are routinely used to identify organic-rich zones in shale. The most gas-prone units of the Marcellus Shale are commonly defined as those with the highest radioactivity, which correlates to high organic content (Boyce and Carr, 2010). Because radiation is ubiquitous in the environment, measurements must be compared to background levels to be meaningful. Refer back to Table 1 for α, β, and γ radiation data on a time series of Marcellus Shale produced water samples.

Other Sources of Contaminants

Although frac chemicals and produced water have been the major concerns as potential threats to water resources in areas of shale gas development, other sources of water contamination also exist. These include the potential seepage of chemicals into the ground from torn pit liners or leaky storage tanks, improperly buried drilling mud and waste, and the possible oxidation and leaching of toxic metals from drill cuttings left on the pad.

Drill cuttings are the small rock chips that the drill bit cuts away (Figure 37), and they are transported to the surface by the circulating drilling mud. Because Marcellus Shale drilling operates at a much larger scale than traditional drilling, it creates significantly more cuttings. For example, a simple volume and density calculation indicates that a 30-cm-diameter (12-in.-diameter) borehole drilled vertically through 30 m (100 ft) of shale will produce a little more than 5 metric tons of drill cuttings. In contrast, the same diameter borehole drilled horizontally through 1525 m (5000 ft) of shale will produce nearly 270 metric tons of cuttings, or more than 50 times as much material. The total volume of cuttings from thousands of Marcellus Shale wells can be enormous.

Drill cuttings from horizontal Marcellus wells are, by definition, primarily black shale. Horizontal boreholes are geo-steered to stay within the most organic-rich, gas-prone, and blackest of the shale layers. Because this rock was deposited in an anoxic environment, it contains reduced minerals such as iron sulfides and others (refer back to Fig. 26). Bottom-water chemistry favorable for the preservation of organic carbon also precipitated these various metals out of the surrounding seawater with the sediment.

When the cuttings reach the surface, they may be exposed to oxygen in the air and freshwater from rain for the first time ever. The sulfides will oxidize into sulfates, which are much more soluble in water. Rainwater percolating through the cuttings could leach the oxidized minerals out of the rock chips, possibly resulting in groundwater contamination from toxic metals and other hazardous materials. Preliminary analyses suggested that this could potentially be a problem (Soeder, 2011). Additional research on the leaching characteristics of these materials under climate and rainfall conditions representative of the Appalachian Basin indicated that the cuttings do meet EPA requirements under the RCRA Subtitle D program for landfill disposal and other uses, but the potential long-term leaching of metals is still a concern (Chermak and Schreiber, 2014; Stuckman et al., 2015).

There have been instances of solid waste from CWT facilities setting off radiation alarms at some Pennsylvania landfills. The Pennsylvania DEP funded an investigation on the fate and

Figure 37. Washed and dried Marcellus Shale drill cuttings displayed in a laboratory dish. Coin shown for scale is 18 mm in diameter. Photograph is by Daniel J. Soeder.

transport pathways of technologically enhanced NORM, or TENORM, in the environment that included the landfill disposal of drill cuttings (Perma-Fix Environmental Services, Inc., 2016). TENORM is natural radioactive material that has been enhanced by human activities, for example, concentrated radium salts from CWT facilities removing TDS from produced waters. Concerns about NORM also resulted in the Pennsylvania DEP rescinding approvals for POTWs to dispose of biosolids by land application if they were accepting oil and gas wastewater, even from conventional wells.

Environmental monitoring of surface water and groundwater near shale gas development sites is needed to fully define the possible engineering risks of shale gas to water quality. This can consist of something as simple as a groundwater monitoring well installed to a depth of a hundred feet or so on the downgradient edge of the pad to help drillers ensure that no contaminants from their operations have entered the groundwater. Such near-field monitoring would allow any spill that did occur to be remediated long before the contaminants reached a domestic water supply well (Soeder et al., 2014b). These wells are commonly installed in the vicinity of chemical storage tanks, underground gasoline tanks, and other potential groundwater pollutant source areas. Commercial water-quality sensors placed in a well to monitor temperature, pH, conductivity, and possibly several other parameters could provide real-time indication of the presence of groundwater contaminants in a well.

Surface-water monitoring at the mouth of the smallest watershed containing the drill pad is another environmental alarm system that can prevent a problem from becoming a disaster. Some drinking water regulations require monitoring for TDS and sediment at the intakes to water treatment plants, and both the Delaware River and Susquehanna River within the Marcellus Shale play have an array of these sensors. However, monitoring temperature, pH, conductivity, and turbidity at the small watershed level would provide more of a time window for mitigation before a spill reached a main-stem river.

Automated electronic monitoring devices for streams are relatively cheap and fairly reliable. They are worth the cost if they save an operator from paying a hefty fine. Research has shown that these instruments can be effective for monitoring drilling fluids, frac chemicals, and produced water from shale gas operations (Harris, 2015). The meters are portable, so once a set of wells is completed on a pad, and the equipment and chemicals are moved off, the stream monitoring instruments can be transferred to another site. It is important to understand how these sensors respond to various chemicals, and periodic assays of volatile organic compounds, major ions, metals, and other dissolved solids can be instrumental in understanding the characteristic contaminants present in both surface-water and groundwater resources.

A probabilistic (Monte Carlo) framework model used by Flewelling et al. (2015) assessed the potential spill volumes and concentrations of hydraulic fracturing fluid and produced water that might reach a drinking water resource from a gas well. The modeling included the likelihood of a spill, and if one occurs, the likelihood that mitigation measures might contain the material and prevent any impacts on drinking water resources in the first place. Concentrations of contaminants from potential spills in surface-water and groundwater resources were evaluated to assess the toxicity of various chemicals that may be present in hydraulic fracturing fluid and produced water to establish risk-based human health benchmarks. The ratio of expected concentrations to the health-based benchmarks was used for a screening analysis to identify the potential human health effects from a spill. Overall, the analysis demonstrated a very low probability that an oil or gas well might have a spill that would contaminate drinking water significantly enough to cause human health effects.

WATER AVAILABILITY

One of the largest hydraulic fracture stimulations ever attempted in a vertical well was performed in the Cotton Valley Limestone in Texas by Mitchell Energy in 1978 (Ahmed et al., 1979). Approximately 3.4 million liters (900,000 gallons) of water and 1.27 million kilograms (2.8 million pounds) of sand were pumped in a single stage into the target formation to create a fracture estimated to extend 823 m (2700 ft) from the wellbore in two directions. In comparison, a 1.5-km-long (5000-ft-long) horizontal shale gas well may use 1.2–1.9 million liters (300,000–500,000 gallons) of water for each stage of a hydraulic fracture, with a total use per well after 10 frac stages of 12–19 million liters or 3–5 million gallons.

Under an intensive drilling scenario, with thousands of wells in a river basin using billions of liters of water, combined withdrawals can add up to a significant impact on regional water resources. This has been a concern for shale gas development in drier areas like Texas or Colorado, where the potential impact of water withdrawals for frac fluid could potentially be a significant issue. Even in the Marcellus play, where surface water and groundwater supplies are abundant, large frac water withdrawals may still have significant impacts on smaller streams (Rodriguez and Soeder, 2015).

The evolution in the trends of water use for hydraulic fracturing over time shows some significant changes with the advent of shale gas development in the twenty-first century. In particular, the change in hydraulic fracturing techniques from the gel or foam formulations used in conventional wells to the slickwater fracs prevalent in shale gas wells has introduced a variety of new chemicals into the environment (Gallegos and Varela, 2015).

The oilfield service companies performing hydraulic fracturing on the Marcellus play were generally new to the Appalachian Basin. Engineers thought initially that very high-quality water was required for hydraulic fracturing, because they were worried that certain water compositions might cause clay minerals in the shale to swell up and block gas flow. This reflected the experience of many operators with smectite and mixed-layer swelling clays on the Gulf Coast. Clays in the Marcellus Shale have been compacted and dewatered, consisting largely of illite and chlorite, which are nonswelling and not very sensitive to water composition (Zielinski and McIver, 1982).

Until operators could obtain their own withdrawal permits, frac water supplies during the boom time of the Marcellus play were purchased from municipal water utilities. Some town water companies received a significant income by selling water to operators, even though this was the same water needed for the town drinking water supply. Such a scenario may not have been sustainable for long, nor was it necessary. It turned out that Marcellus fracs can be done successfully with water of much lower quality, and drinking water is no longer used. Current Marcellus Shale development operations typically use water from nonpotable sources, such as raw stream water or POTW wastewater effluent. Lower-quality water resources are often considerably cheaper than finished drinking water, so there is also an economic incentive for their use. In other shale plays, hydraulic fracturing has been done successfully with undrinkable, brackish water from deep formations and even with seawater.

The use of AMD water as a source for frac fluid is also being considered in Pennsylvania. There is little else that can utilize this contaminated water. Since much of the frac fluid remains downhole, this would also be a disposal technology for AMD. Some geochemists are concerned about how the chemistry of AMD might react with the shale, and studies are under way to investigate this (Chermak and Schreiber, 2014).

Regulating water withdrawals for hydraulic fracturing from small streams can significantly reduce impacts. The two most important factors affecting the ability of a stream to part with large volumes of water for hydraulic fracturing are the streamflow at the time of withdrawal, and the number of companies that are withdrawing water from a particular stream at the same time.

Streamflow varies seasonally, with the highest flows in the early spring, and the lowest flows in late summer. A creek that may easily part with several million gallons of water in the spring flood season may not be capable of providing such supplies during a late summer drought. Thus, timing of the withdrawals is critical. Likewise, given the reluctance of industry to self-police or self-report, it is possible to imagine a scenario where water trucks from two different companies are filling up from the same stream on either bank, with neither acknowledging the presence of the other.

The SRBC regulates frac water withdrawals by issuing allowances to shale gas developers as an industrial use permit. A drill pad, or a group of neighboring drill pads, is treated in the permit process like a factory, although, unlike other commercial uses, water withdrawals for shale gas development are regulated from the first gallon. The DRBC also tightly controls water withdrawals in their basin through a docket system that requires a commission review of every withdrawal application. The SRBC occupies a much more active shale gas development area on the Marcellus than the DRBC, and it supplies much more of the water.

The SRBC estimates that the drilling industry in the basin needs a water allocation of ~114 million liters (30 million gallons) a day (Richenderfer et al., 2016). The SRBC reports that the shale gas industry in fact uses less water than what has been allocated. Because of produced water recycling, the percentage of freshwater required to make up frac fluid has been reduced. Newer frac designs that are more efficient also use less water. Gas operators are required to document and meter water withdrawals, and to pay for them (Richenderfer et al., 2016). Water fees collected by the SRBC from gas operators have increased to $6.2 million, and the commission's budget has doubled since 2007.

Regulation in West Virginia and western Pennsylvania is considerably more relaxed, where watersheds are often managed by a variety of agencies and allocation plans. West Virginia requires operators to file a "water use plan" before a drilling permit is issued, but a water withdrawal permit is not needed.

The consumptive use of water for hydraulic fracturing is a concern of water resource agencies. When water is withdrawn from a river at a municipal or industrial intake, there is an expectation that it will be returned after use to the river as wastewater, runoff, or discharge. Because hydraulic fracturing of the Marcellus Shale recovers less than a quarter of the water emplaced downhole (some estimates are as low as 8%), the water remaining in the shale constitutes a consumptive loss to whatever river basin supplied it.

Although local impacts on small streams and groundwater can be significant, the total or overall amount of water withdrawn from the hydrologic cycle for hydraulic fracturing is actually quite small compared to everyday water use. For example, the New York State Department of Environmental Conservation (2011) estimated that the full-scale development of the Marcellus Shale in New York would increase the annual statewide demand for freshwater by ~0.24% above present withdrawals.

Water availability also plays into something called the energy-water nexus, or more broadly, the food-energy-water (FEW) nexus. This approach attempts to quantify competing demands for water between energy supplies and agriculture (Sieverding and Stone, 2016), primarily in the northern Great Plains of the United States, where global supply chains for both food and energy depend upon the availability of limited water resources. This complex relationship includes water for irrigation of food and biofuel crops, water used for the production of conventional and unconventional energy resources, energy used to fertilize and transport crops to market, and competition between biofuels and fossil fuels for market share. There are concerns that recoverability thresholds could be crossed, and the understanding of critical vulnerabilities is necessary to achieve sustainability. These include landscape segmentation, water availability and usability, habitat destabilization, soil health, rural population declines, and cost and distribution of resources and goods (Sieverding and Stone, 2016). There are similar dependencies within the Marcellus play, but water is more available, and agriculture is less dominant. These interactions can be observed more clearly in the Bakken and Niobrara plays on the upper Great Plains.

OTHER ISSUES

There is such a broad range of issues associated with shale gas development that it would be impossible to cover all of them at length. This section touches briefly on some of the other concerns, and readers are urged to consult the references for more details.

Induced Seismicity

Induced earthquakes are created by the actions of people. Earthquakes below magnitude 2 are rarely felt, and earthquakes large enough to cause damage to structures are generally above magnitude 4. Human activities do not usually cause a significant earthquake directly, but instead tend to trigger one that was building up naturally.

The most common cause of induced or anthropogenic earthquakes is the injection of fluids into the ground. This was discovered after a series of earthquakes hit Denver, Colorado, in the early 1960s, where the trigger mechanism was traced to the injection of liquid waste into deep disposal wells at the nearby Rocky Mountain Arsenal (Healy et al., 1968). The too-rapid injection of fluid increased the pore pressure in the rocks and acted to lubricate a preexisting fault. The fault was already under stress, and the fluid allowed the fault to slip and triggered an earthquake. Simply reducing the injection rate and giving the fluids time to disperse through a formation often solves the problem. Most of the recent cases of induced seismicity associated with shale gas development have been caused by the excessive disposal of residual waste down UIC wells (Rubinstein and Mahani, 2015) Research needed in this area should emphasize both hydrology and geophysics, because the two are closely related.

A series of earthquakes in Arkansas and Oklahoma were linked to the injection of shale gas residual wastewater down UIC wells (Llenos and Michael, 2013). The earthquakes were greater than magnitude 2.2 in Arkansas, and above magnitude 3 in Oklahoma (https://earthquakes.ok.gov/what-we-know/). In both states, earthquakes have continued even after the injection was stopped, suggesting that once these faults are activated, seismicity can continue for some time. A similar series of earthquakes in northeastern Ohio was linked to the disposal of Marcellus Shale produced water down UIC wells near Youngstown.

Series of seismic events in April and May 2011 occurred at Preese Hall near Blackpool in the UK, the largest of which were big enough to be felt. An inquiry by British science and engineering agencies determined that these tremors may have been related to hydraulic fracturing (Royal Society and Royal Academy of Engineering, 2012). The frac in question took place in an organic-rich, shaly limestone, and the limestone component may have given the formation higher rock strength compared to clay-rich shale. A greater degree of stress could have built up across a fault, which was relieved by the hydraulic fracture, causing the earthquake. In North America, possible induced seismicity has been reported from hydraulic fracturing events in Oklahoma and in British Columbia. Microseismic monitoring of a test well site in Greene County, Pennsylvania, detected movement on a previously unidentified fault at a height of more than 0.5 km (2000 ft) above the hydraulic fracture target zone (Hammack et al., 2014). The USGS and DOE are investigating a phenomenon called "tremor" or slow-slip seismicity induced from hydraulic fracturing, where the rocks adjust to stress more slowly and deform in a plastic rather than brittle manner. Tremor has been described as being similar to the creaking of a floorboard versus the snapping of a twig.

Fugitive Emissions

Fugitive emissions differ from the phenomenon of "stray gas" described previously, in that the term is used to describe leakage of natural gas to the atmosphere from the production, transmission, or distribution infrastructure. Stray gas generally refers to the presence of natural gas and other gases in groundwater.

There is a great deal of uncertainty in estimates of the amount of natural gas that may be leaking as fugitive emissions. This is a concern to the industry, which loses money on gas that leaks from their transmission and distribution systems. It is also a concern to climate scientists, because methane, the main component of natural gas, is also a powerful greenhouse gas.

Measurement of fugitive emissions from old distribution lines in San Francisco and Boston (McKenna, 2011) indicated that most of the leakage may be from aging infrastructure on the delivery end, or "downstream" as the industry calls it. (Production wells are "upstream," and transmission pipelines are "midstream.") Gas lines, like water, sewer, and power lines, are an infrastructure problem in the United States suffering from age and years of neglect. This has nothing to do with shale gas specifically, but it is an issue with the entire natural gas distribution system nationwide.

McKenna (2011) reported a total for production-transmission-distribution losses of natural gas of ~1.5% of total throughput, which is in line with earlier fugitive emission estimates by the EPA and GRI. Industry generally believes the loss numbers are lower.

Analysis of air quality in Weld County, Colorado, by NOAA scientists in 2008 found methane and other hydrocarbons in the atmosphere at levels nearly double those claimed by industry (Pétron et al., 2012). The locations sampled were near the giant Wattenberg Field, one of the largest conventional natural gas reservoirs in the United States, which has been producing gas and oil since 1901. Fugitive emissions from deteriorated old wells in this field may be responsible for the high numbers.

Even higher leakage numbers were claimed in a paper by Howarth et al. (2011), which stated that shale gas wells lose 3.6% to 7.9% of their total production to the atmosphere. These very high estimates were generated using data that even the authors admitted were questionable, although they stated that the objective of the article was to call for more and better data to quantify fugitive emissions, which are indeed needed.

A paper by Cathles et al. (2012) challenged the findings of Howarth et al. (2011). Cathles and his coauthors indicate that Howarth and his coauthors significantly overestimated the losses from the system, and that the actual range of fugitive emissions from well drilling to delivery is much lower, i.e., less than 2%, or in closer agreement with EPA, GRI, and McKenna's (2011) published loss numbers. Cathles et al. (2012) also found no discernible difference in methane emissions from shale gas wells and conventional gas wells.

On the upstream side, fugitive emissions from wells, wellbore integrity, and the trade-off between venting a well or shutting it in have been raising many questions, especially on tight oil plays like the Bakken Shale in North Dakota. Although pipelines and gas plant infrastructure are being put into place to handle the gas coproduced with the oil, for a number of years the standard practice was to flare off the gas so the oil could be recovered for transport to refineries by truck or rail. Flaring has been reduced by 85% from 2008 to 2016, according to the tribal oil and gas managers on the Fort Berthold Reservation, because of the implementation of pressure management and gas capture rules. When pipelines are not available, much of the gas is re-injected into the Bakken and Three Forks formations to try to maintain reservoir pressure and keep the oil moving toward production wells.

The flaring of emissions wastes gas and lights up the night sky like a vision out of Dante's Inferno. Not flaring the emissions allows methane gas to escape directly into the atmosphere, where it may pose a flammability hazard and act as a greenhouse gas. Shutting in the well allows the gas pressure to build up in the annulus, where it may escape into shallow aquifers and migrate into a water well or a structure. There are no easy answers for what to do with co-produced gas, except not to drill the well until the gas can be put into a pipeline.

Abandoned Wells

Abandoned wells are not directly related to shale gas development, but they are a concern for both methane gas emissions and hydraulic fracture breakouts. Because of the long history of drilling in the Appalachian Basin in general and Pennsylvania in particular, the Marcellus play has many more of these abandoned and unrecorded, or "orphan" wells compared to other shale gas development areas. The Pennsylvania DEP estimates that there may be as many as 200,000 abandoned wells in the state. Just getting a handle on the scope of the problem has been a challenge.

Many of these old wells are emitting methane gas into the atmosphere, some in significant amounts. Researchers have been making an effort to quantify these gas emissions to include them in national greenhouse gas inventories (Kang et al., 2014). In the meantime, Pennsylvania is pursuing an active program to locate and properly plug abandoned wells, but the numbers are overwhelming, and the budget for this activity is limited. Finding the wells has been especially difficult, even with the use of airborne remote-sensing tools like magnetic surveys. If a well casing is cut flush with the surface and buried under a few inches of soil or overgrown with vegetation, those searching on the ground can be holding a map with an accurate magnetic "bull's-eye" and standing directly on top of the location while seeing nothing.

Gas pressures in the Marcellus Shale tend to be moderately above hydrostatic, or "overpressured" (Wrightstone, 2008). By definition, overpressured gas means that it is not connected to the surface; otherwise, it would be under the pressure imposed by the water column (i.e., hydrostatic pressure). An existing pathway to the surface, either through a fracture system or an abandoned well, is likely to be filled with water, and therefore be under a hydrostatic pressure gradient. If a hydraulic fracture connects the Marcellus Shale to such an existing pathway, there could be enough gas pressure, at least initially, in the shale to displace the overlying water column and move upward.

Although it is highly unlikely that a 300-m-long (1000-ft-long) vertical hydraulic fracture less than a cm wide would intercept a typical 30-cm-diameter (12-in.-diameter) vertical wellbore, the Appalachian Basin contains so many abandoned wells that the probability is not zero. In 2012, a hydraulic fracture from a Marcellus Shale well in Tioga County in northeastern Pennsylvania intercepted an abandoned, 70-yr-old Oriskany Sandstone gas well that no one knew was there. The well was uncased and filled with water. The gas from the shale displaced water from the well, pushing it upward, and creating a rather spectacular, 10-m-high (30-ft-high) fountain at the surface (Detrow, 2012). No pipeline was in place yet, so the operators immediately began flaring gas from the Marcellus Shale to reduce the pressure. After several days, the shale gas pressure dropped below hydrostatic pressure, and the abandoned well stopped flowing. It was then sealed with cement.

Hydraulic fracture breakouts like the Tioga County example are rare, but they do happen. Fortunately, the geometry of abandoned wells in the Appalachian Basin precludes this from happening very often. Most of the old wells were drilled into shallow targets in the Mississippian and Upper Devonian, high above the Marcellus, where the hydraulic fractures do not reach. Even if hydraulic fracturing takes place directly beneath one of these shallow, older wells, it is unlikely to communicate with it (Hammack et al., 2014). Deeper wells into the Oriskany Sandstone or Silurian targets like the Clinton Sandstone that are below the Marcellus are the more significant concern.

Silica Dust

Many human health issues related to hydraulic fracturing operations usually have to do the question of exposure, as in the route, and whether exposure was chronic or acute. The quartz sand used in the frac has been raised as a potential occupational health concern (Esswein et al., 2013). The proppant sand creates respirable crystalline silica dust, and mechanical handling operations may lead to a possible exposure hazard for workers. Personal breathing zone samples collected from 11 drill sites in five states were found to exceed occupational health criteria such as the permissible exposure limit (PEL), the recommended exposure limit, or the threshold limit value (TLV). In some cases, exceedances were more than 10 times the occupational health criteria (Esswein et al., 2013).

Dust-generation points included sand-handling machinery and dust generated from the work site itself. Exposures can be reduced by product substitution when feasible, engineering controls or modifications to sand-handling machinery, administrative controls to keep unnecessary personnel out of dust-generation zones, and the use of personal protective equipment.

The vertical parts of Marcellus Shale wells are often drilled using air instead of mud as the circulating fluid. Air drilling creates dust, but this is usually contained by keeping the air in a closed system, using cyclone separators and filters to clean the air, and employing water sprays to control dust.

The greatest threat from silica dust on Marcellus Shale drill rigs is occupational exposures to the drillers and roughnecks exposed at the well site. Dust levels dispersed onto nearby residents are probably significantly below Occupational Safety and Health Administration respirable dust standards, but this should be measured and documented. Additional concerns about potential medical issues related to shale gas development were raised by Saberi, (2013).

Economics

Financial arguments against shale gas have been made by several authors, primarily Berman (2010), who suggested that shale gas production is unsustainable, and investors in shale gas resources will likely go broke in fairly short order. Berman (2010) based his argument on the drop in gas production from a well over time, called the decline curve. These are of interest to those trying to determine the size of the resource, the volume of reserves, the estimated ultimate recovery (EUR) of gas, and the economic return on investment.

Gas shales consist of a dual-porosity system of high-permeability fractures and low-permeability matrix pores (Soeder, 1988). The volume of the fracture system is much less than the volume of the porous rock matrix. As such, the decline curves for shale gas wells typically show a very steep initial drop as the fractures drain, followed by slow, steady matrix flow that produces a long, flat “tail” on the curve at low production rates that may persist for years to decades (or even more than a century in some documented cases). Production under equilibrium conditions over most of the lifetime of a shale gas well consists of gas flowing slowly out of the tiny matrix pores and feeding into the hydraulic and natural fracture network, which transports it to the wellbore (Clarkson, 2013).

Shale decline curves are very steep at the beginning of production as gas drains from the fracture system, but then they flatten out and decline slowly as gas migrates from the matrix to the fractures. People familiar with conventional reservoirs might interpret the initial drop as the end of production, but it is only production from the fractures. Decline curves for shale gas behave very differently from conventional reservoirs, and production also ends quite differently in a conventional reservoir compared to gas shale.

Gas accumulates in a conventional reservoir in porous rocks above denser liquids, like oil and brine. Because of the high porosity and permeability of the reservoir, gas production declines gradually as the pressure slowly drops throughout most of the production period, until it ends abruptly in a process called “watering-out.” This occurs when the gas pressure drops below a minimum threshold, allowing formation brines below the gas cap to move upward into the reservoir and flood it. Even though there may be significant gas saturation remaining within the rock (sometimes as much as 50%), the incoming brine isolates the gas into disconnected bubbles, creating a nonmobile phase that ceases to flow. Production at the wellhead ends abruptly.

Shale gas reservoirs typically do not contain mobile water, and hence they do not water out. As stated earlier, the partial water saturation in shale pores is a nonmobile phase, and there are virtually no reports of water actually flowing freely into shale gas wells (Soeder et al., 1986). Because there is little to no mobile water, matrix gas production from a shale gas well will just continue to decline until the gas is drained from the rock. Hydraulically fracturing the well again could send fractures into new volumes of rock, tapping into additional reserves of gas and boosting production. This cycle could be repeated several times, and the full depletion of producible gas from horizontal shale wells could take many, many years. Production would be halted at some point, but when exactly this might occur is unclear. Industry generally says “it depends on the price of gas.”

The return on investment depends on the EUR for gas from well and the price of gas (Bruner and Smosna, 2011). At the start of the play, published numbers for EUR in individual, horizontal Marcellus Shale wells were up to 3 BCF (85 million cubic meters). At $4/MCF (or $4 million/BCF), this translates into $12 million worth of recovered gas, compared to about a $4 to $6 million investment to drill and complete the well plus operating costs. Successful drilling company managers pay excruciatingly careful attention to such trends in the cost of capital and the price of gas. There is a trade-off between producing enough gas to pay back investors, but not over-producing and driving down prices.

As drilling and completion methods improve, and recovery efficiencies increase, the vintage of the well must be considered when assessing the EUR. An Associated Press article several years into the Marcellus play (Rubinkam, 2011) reported that Chesapeake Energy was estimating Marcellus Shale EURs in the range of 7 BCF (198 million cubic meters) per well, which is more than double the earlier estimates. These later wells benefited from improved hydraulic fracturing techniques and longer laterals. By 2016, some Utica Shale wells in Ohio reportedly had EURs approaching 30 BCF.

Shale gas economics are steadily improving with the development of ever longer laterals. As described earlier in the section on the Hydraulic Fracturing Process, the Purple Hayes No. 1H well in Guernsey County, Ohio, was drilled in 2016 by Eclipse Resources (Beims, 2016). It has a "superlateral" at a depth of ~9000 ft (2.7 km) that spans a horizontal distance of 18,544 ft (~3.5 miles or 5.6 km), a world record for onshore length at the time. Eclipse drilled the well in only 17.6 d, and completed it with 124 frac stages in 23.5 d, achieving great efficiency and cost savings in terms of rig time and crew. This appears to be a formula for success, with additional laterals planned in the range of 22,000 ft (over 4 mi. or 6.7 km).

Life-cycle analysis is an environmental and economic assessment that considers every product in a process as an eventual waste material that has an environmental impact. "Greener" products can only be selected if the environmental impacts are considered from cradle to grave (Ayres, 1995). These include not only the direct impacts from the production process, and associated indirect wastes and emissions, but also the future fate of a product. Thus, instead of being plugged and abandoned at the end of production, if shale gas wells can be transformed into another useful "product" like CO_2 storage wells (discussed in Chapter 5), the economics and environmental impacts improve. The details of life-cycle analysis are too complex for this discussion, but it is a useful tool with which to determine returns on investment, including costs to the environment.

The consensus among producers is that current reservoir drilling and stimulation methods are recovering ~10% of the GIP in the Marcellus Shale. Leaving 90% of the resource in the ground is not the best return on investment. Future improvements in shale reservoir engineering, perhaps including reservoir pressure management or sweeping methane from the shale with CO_2 might increase recovery efficiency significantly.

The amount of capital that has been invested in Marcellus Shale gas production in Pennsylvania and West Virginia suggests that industry is confident in long-term sustainability. Although dire warnings about the economic perils of shale gas persist, large companies are confident enough to continue risking capital on Marcellus natural gas and liquids.

Social Issues

Oil and gas development in the Appalachian Basin goes back to Colonel Edwin L. Drake's first commercial oil well in Titusville, Pennsylvania, in 1859, and social issues surrounding it have existed from the beginning. Although states like Ohio, Pennsylvania, New York, and West Virginia have a long history of oil and gas production, they have never really been considered a part of the "oil patch," like Texas, Louisiana, and Oklahoma. Until the advent of the Marcellus Shale, Appalachian Basin oil and gas production had always been done on a relatively small scale, with more shallow than deep targets, low production rates, and small recovery volumes. Profitable development was possible with small drill rigs, small crews, and small companies.

This changed after the first successful Range Resources horizontal well kicked off the Marcellus Shale play in 2007. The Marcellus became a full-scale boom, with landmen leasing up everything in sight, and companies eager to get wells in the ground. The large drill rigs, specialized oilfield service equipment, and the numerous trucks needed to haul materials for large-scale horizontal drilling and hydraulic fracturing were generally not available in the Appalachian Basin, and they needed to be brought in from existing big oil operations in the Gulf Coast, Midcontinent, and Rocky Mountains. These often came with crews, but sometimes not.

As the Marcellus boom picked up, drilling companies tried to hire local talent early on, but they found that there were few experienced workers in the local labor pool with the specialized skills needed to work on a drill rig. Inexperienced workers contributed to incorrect pad construction, improperly routed access roads, failures to set casing properly, and poor cement jobs. Many problems were caused by the rush to develop the play, which further exacerbated the shortcomings of an inexperienced work force. As activity on the play matured, work crews gained experience, the pace of development slowed, and environmental violations decreased significantly.

One additional concern is that rigs from the Midcontinent and Gulf Coast may have been carrying hitchhikers that remained behind in Appalachia and now have the potential to become invasive species. Although armadillos are not expected to be seen along Pennsylvania highways anytime soon, plant seeds, insects, and small animals could have dropped from the rigs and associated equipment and made themselves at home. Only time will tell, and compared to the many other environmental concerns associated with the Marcellus Shale, this one is probably pretty minor. There are many different routes invasive species can take to move into new habitat.

The boom years of Marcellus gas production and the lack of experienced local workers also coincided with the national recession that began in 2008. As a result, experienced drill crews from the Gulf Coast and western states migrated to West Virginia and Pennsylvania for jobs. Marcellus boosters had promised that development of the shale gas resource would bring jobs to stressed labor markets in Pennsylvania and West Virginia, but many of those jobs (or at least the better ones) went to out-of-state, migrant workers. In the early days of the play, it was not unusual to see parking lots at local motels full of pickup trucks with Texas and Oklahoma license plates. Local community colleges and workforce training agencies made efforts to teach people in Appalachia the needed skills, but just as these efforts were coming to fruition, gas prices dropped, and development slowed.

Although not as extreme as the Bakken Shale boom in North Dakota, with "man camps," restaurants in trailers, and exotic coffee shops, the influx of oilfield workers did bring an economic boost to local hotels, restaurants, bars, and other service-oriented businesses in Pennsylvania and West Virginia. These workers also drove up rental prices for apartments and houses as demand exceeded supply, making rental housing unaffordable for lower-paid locals. At the same time, some single-family housing prices fell because of the proximity of the properties to shale gas development sites.

Another effect of the shale gas boom has been the increased value of a commercial driver's license (CDL) within the play. Moving all the equipment, water, sand, and other supplies out to a well site in preparation for a hydraulic fracture involves hundreds of trucks, and each requires a trained driver with a CDL. As such, state highway departments had a hard time retaining snow plow drivers, and counties faced difficulties finding school bus drivers as people with CDLs took much-higher-paying jobs at the gas companies.

Hardly anyone on the typical small farms in Pennsylvania or West Virginia is thriving as a farmer. Most people operate the farm for the tax breaks and supplemental income, and they hold down a job in town. Lump-sum payments for signing a gas lease can run as high as $250,000, and once a gas well goes in, royalty payments have been reported to be around $15,000 per month, which translates into an additional income of $180,000 per year. This is very significant money in Appalachia.

The situation in West Virginia is a bit more complicated. Most of the people who own land in the state do not own the rights to the minerals beneath that land. The mineral rights are said to be separated or "severed" from the surface rights. According to historians, this practice goes back to the original Virginia Colony land grants. In the old days, when most people were only interested in trapping, logging, or farming, they could not have cared less about a coal seam or other minerals under their land, and they did not quibble about not having ownership of it. However, most land deeds require the surface owner to allow "reasonable access" to the owner of the mineral rights for the extraction of the resource. So when a Marcellus Shale drill rig shows up and a bulldozer scrapes off a 5 acre (0.02 km^2) pad on someone's pasture with minimal compensation for the land owner, problems can ensue. The West Virginia Surface Owners Rights Organization (www.wvsoro.org/) has been working to educate the state legislature along with landowners about ways to avoid difficulties with drilling companies. Some of their suggestions include proper notifications and negotiated deals for pad locations and roads, greater setbacks of wells from homes and water wells, and restoration of sites after drilling.

Sociologists, educators, city planners, psychologists, architects, and artists are thinking about the potential impacts of large-scale shale gas production on society. Jennie Shanker is an artist and art professor in the Tyler School of Art at Temple University in Philadelphia who focuses on the origin of materials, and how objects are perceived by the population. She has been producing figures and objects using clay from the Marcellus Shale as a sculpting medium. The first work that Jennie made from Marcellus Shale clay was a sculpture of an everyday foam coffee cup, designed to show the replacement of a common but manufactured material (plastic foam), with a natural but artistically rare material (Marcellus Shale clay). The cup motif was used to emphasize the link between the shale and water issues. A photograph of one of Jennie Shanker's Marcellus Shale clay cup sculptures is shown in Figure 38.

Shell Oil Company has developed a set of five operating principles for shale gas development based on what they have heard from concerned citizens and their own scientists. These are:

(1) Implement safe well designs using intermediate casing, steel surface casing, and cement to protect and isolate potable groundwater aquifers, plus provide public disclosure of chemicals used in the hydraulic fracturing

Figure 38. Philadelphia artist Jennie Shanker's sculpture of a foam coffee cup executed in clay from the Marcellus Shale, sitting on a slab of the same material. Cup motif is intended to show a connection between the shale and water. Photograph is by Daniel J. Soeder; sculpture is shown with permission from the artist. Cup is 10 cm (4 in.) high.

process, routine well safety reviews, and emergency response plans.

(2) Ensure water protection by employing safety testing of groundwater supplies before and after operations, and reduce water use by employing nonpotable water for hydraulic fracturing, and by recycling wastewater whenever possible.

(3) Achieve emissions reduction for air quality by focusing on monitoring, employing less-polluting equipment, and making greater use of clean fuels like natural gas in engines.

(4) Mitigate surface impacts by reducing the "footprint" from drilling and completion operations, limiting activities during certain time periods, using pipelines to reduce truck traffic, and restoring the land once operations are concluded.

(5) Engage the community to improve the transparency of operations, share local socioeconomic reports, hire locally, and identify opportunities for local investment and partnerships.

Implementing these sensible operating principles can make a significant difference. If combined with regular inspections, these procedures can go a long way toward preventing a lot of problems.

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