Unconventional: The Development of Natural Gas from the Marcellus Shale

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Dedicated to Dr. Philip L. Randolph (1931–2010). In the role of scientist, boss, mentor, and friend, the most important lesson he taught is that scientific research can move forward only when one has the freedom to make mistakes.

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1. ABSTRACT

New technology in the twenty-first century has opened up vast new reserves of natural gas and oil from formerly non-economic resources, such as organic-rich shale. Production techniques including horizontal drilling and high-volume hydraulic fracturing have led to the recovery of large amounts of natural gas and oil from formations like the Barnett Shale in Texas, the Fayetteville Shale in Arkansas, the Bakken Shale in North Dakota, and the Marcellus Shale in Pennsylvania and West Virginia. These resources have created a surplus of natural gas, abundant supplies of oil, and have made the United States essentially energy-independent for the first time in decades.

Although terms like "fracking" and "Marcellus Shale" have become commonplace, few people realize the development of the technology that enabled the economic production of these resources had its origins in the oil embargos and energy crises of the 1970s. The U.S. Department of Energy (DOE) funded the Eastern Gas Shales Project in the late 70s and through the 1980s to characterize the resource potential of the extensive, organic-rich, Devonian shales in eastern geologic basins, including the Marcellus, and to develop the engineering technology needed to extract natural gas from these rocks economically. Mitchell Energy pursued this into the 1990s, and their persistence eventually achieved the breakthrough needed to produce commercial amounts of gas from low permeability resources like shale. The application of greatly improved directional drilling technology developed for deepwater offshore platforms, combined with slickwater hydraulic fracturing allowed Mitchell to use horizontal boreholes with multiple stages of hydraulic fracturing to engineer high-permeability fracture flowpaths into a sufficient volume of reservoir rock to produce significant amounts of gas from the Barnett Shale.

Other companies followed suit on other formations, with Range Resources achieving the first commercial horizontal Marcellus Shale well in southwestern Pennsylvania in 2007. Range used data and assessments from the DOE Eastern Gas Shales Project to select target intervals in this well, and their competitors also combed through the DOE archives for relevant reports and data. The development of the Marcellus Shale has been largely in two play areas; southwestern PA and northern WV, where the shale is a bit thinner but pipelines are present to receive the gas, and northeastern PA, where the shale is thicker but access to pipelines is not as easy. Estimates of recoverable gas from the Marcellus and other gas shales run to many hundreds of trillions of

cubic feet, which should supply the United States with natural gas for decades. Shale gas has completely changed thinking about world fossil energy supplies.

The development of natural gas from the Marcellus and other shales has not been without controversy. Anti-fracking activists have made claims that shale gas development in general, and hydraulic fracturing in particular contributes to climate change, and threatens groundwater resources, terrestrial and aquatic ecosystems, and human health. Based on these claims, the states of New York and Maryland have banned high volume hydraulic fracturing on the Marcellus Shale, although it is permitted in Pennsylvania and West Virginia. The actual environmental impacts are neither as extensive nor as persistent as some activists believe, but there certainly are issues. Shale gas development can affect air quality, water resources, landscapes, and ecosystems.

Most of environmental problems stem from the boom-and-bust nature of the oil and gas business. In their hurry to capitalize on this new resource, exploration and production companies often hired many inexperienced people to install a large number of wells as quickly as possible, resulting in significant impacts. The boom led to an oversupply of gas, causing a drop in gas prices and a slowing of drilling activities. When the bust came, only the most experienced drilling crews were retained, but the damage done during the earlier boom cycle left large numbers of people permanently opposed to "fracking."

Research is attempting to reduce the uncertainties related to environmental impacts of shale gas development. Federal interagency studies are investigating air pollution and greenhouse gas emissions, impacts to water availability and water quality, subsurface migration of gas and liquids, wellbore integrity, geochemistry of produced fluids, impacts to ecosystems, and exposure routes and possible impacts to human health. Many university and research foundation studies are working along similar lines, and efforts are being made to coordinate, collaborate, and reduce duplication of efforts. Research is also being focused on finding new uses for the abundant natural gas being produced from shale. Two suggested utilization technologies are generating electricity and use as a transportation fuel.

The successful development of the Marcellus Shale achieves the long-sought goal of greater energy independence for the United States. It also contributes to an "all-of-the above" energy strategy that utilizes existing resources while continuing to develop new ones.

2. PREFACE

In recent years, the Marcellus Shale has become a household term throughout much of New York, Pennsylvania, Maryland, West Virginia, and Ohio. Many people are aware that the Marcellus Shale is a geological formation containing significant amounts of natural gas, but few realize just how much is there. Official government estimates for the amount of gas that may be recovered from this formation are as high as 3.2 trillion cubic meters or 114 trillion cubic feet (TCF), which represents nearly five years of natural gas supply for the entire United States at current usage rates (Coleman et al., 2011). Unofficial, more optimistic estimates (Engelder, 2009) have placed the recoverable resource at four to five times greater. Whatever the actual amount, the Marcellus is just one of approximately two dozen shale formations in the United States that may contain similar resources.

So why had no one ever heard of this large natural gas resource under the states of New York, Pennsylvania, and West Virginia until recently? How did it remain undiscovered (or at least unrecovered) until the 21st Century? The answer is that although the existence of the resource has been known for some time, the technology to produce the gas in an economical manner was not available until much more recently. New engineering technologies led to the current shale gas boom.

As with most new technologies, there are a number of associated concerns, some realistic and some exaggerated. Issues are often raised over the potential environmental impacts of hydraulic fracturing, one of the technologies required to extract gas from the shale. Worries include the possibility of hydraulic fracturing fluids moving upward from below to contaminate groundwater (DiGiulio et al., 2011), or that cracking open the rock with hydraulic fractures may allow the natural gas to migrate into water wells (Osborn et al., 2011), or escape into the atmosphere (Howarth et al., 2011). A number of careful scientific studies have been unable to find evidence to support the validity of such claims (i.e. Kell, 2011; Glosser, 2013; Molofsky et al., 2013; Hammack et al., 2014; Siegel et al., 2015).

There are indeed some real environmental issues related to shale gas development that include impacts to air, water, human health, and ecosystems (Multiagency, 2014). The actual problems are more subtle, complex, and challenging to explain to the public than the dramatic incidents portrayed in the news media and often linked in these stories to oil and gas industry activities. There is no question that setting a kitchen faucet ablaze from stray methane gas in the groundwater creates dramatic video, even though the flammable gas may have been created by microbes living in the aquifer and is not actually related to any nearby drilling activity. However, facts like these are rarely allowed to spoil a good story, and the constant reposting of these videos on social media stokes public concern.

The gas industry itself often exacerbates environmental concerns by offering bland assurances to the public that everything is under control, while rarely releasing details about the spills, leaks, and accidents that do occur. Such data could help document the actual risks of the shale gas development process. However, exploration and production companies seldom allow access to drill sites for independent researchers to monitor air, water, or other environmental indicators, and this lack of data has resulted in high levels of uncertainty about the real environmental risks of shale gas development (Soeder et al., 2014b).

Except on federal lands, oil and gas production in the United States is generally regulated by state governments. Uncertainty over environmental risks has led to wide differences in the ways different states have approached shale gas development and hydraulic fracturing issues. Some, like New York and Maryland, have instituted moratoria or permanent bans on shale gas development. Others, such as Ohio, West Virginia, and Pennsylvania have permitted the gas to be produced. These different perceptions of risk have resulted in a vigorous and often contentious debate between shale gas supporters and opponents.

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This book is an attempt to assemble the details of shale gas development from at least one geologic formation, the Marcellus Shale, using my experience as the basis for a narrative. My first job out of grad school in 1979 was as a contractor to the U.S. Department of Energy (DOE) in Morgantown, West Virginia, on a research program known as the Eastern Gas Shales Project (EGSP). The goal of this project was to assess the resources and develop the engineering technology needed for the production of natural gas from organic-rich, Devonian-age shales in the Appalachian, Michigan, and Illinois basins (Schrider and Wise, 1980). The research successfully produced reams of engineering, geologic and resource data on many of the prominent eastern gas shales, including the Marcellus.

Investigations on shale and other unconventional fossil energy resources continued into the 1980s at various national labs, universities, government contractors, and research institutes. I was part of a group at the Institute of Gas Technology in Chicago (now known as the Gas Technology Institute or GTI) that made the first high-precision porosity and gas permeability measurements on the Marcellus Shale as part of a DOE-funded tight gas research project. The results were published in a series of DOE reports, and in a technical journal (Soeder, 1988). Our findings contradicted the relatively modest, official resource estimates that had been published a few years earlier for shale gas, suggesting instead that the amount of natural gas present in the Marcellus Shale might be truly significant. The paper had little impact at the time, when large-scale production methods for recovering economical amounts of shale gas did not yet exist.

Fossil energy research funding fell with low oil prices in the late 1980s, and the shale gas studies ended. I became a hydrologist with the U.S. Geological Survey (USGS), where my focus turned to water resource issues. The Marcellus Shale reports and core analysis data sat on the shelf unnoticed for almost two decades.

Oilfield technology moved ahead, economics improved, and eventually it became possible to produce profitable amounts of natural gas from shale. Mitchell Energy initiated the shale gas boom on the Barnett Shale in Texas in the late 1990s, and Range Resources began producing commercial amounts of gas from the Marcellus Shale by the mid-2000s. I started receiving telephone calls at the USGS from gas industry people inquiring about my previous work on the Marcellus Shale in Pennsylvania and West Virginia. (I actually thought the first person who called me about it was playing a practical joke.) Once I realized that they were serious, I was as surprised as anyone back in 2007 to learn about the sudden new economic interest in producing shale gas.

The possible effects that high volume hydraulic fracturing (HVHF) methods might have on water availability and water quality were of immediate interest to me as a USGS hydrologist in Maryland. Along with my colleague Bill Kappel at the USGS Water Science Center in New York, we looked into the issues and put together a fact sheet describing the potential water impacts (Soeder and Kappel, 2009).

When an opportunity came along in 2009 to transfer to the DOE National Energy Technology Laboratory, I switched agencies and found myself back in Morgantown, where I had started my career almost exactly thirty years earlier, once again working on issues related to shale gas. Life can turn in a big circle sometimes, but I suppose the lesson here is to always do your best at everything, because you never know what might turn out to be important someday.

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This book was written for contaminant hydrologists and environmental geologists who are interested in learning about the production technology, history, and potential environmental impacts of shale gas development, especially in the Appalachian Basin. Others who might find it useful include petroleum geologists and engineers interested in the air, water, and ecosystem concerns associated with shale gas, scientists in other fields, educators, students, and members of the general public.

Because of the expected wide audience, some of the technical descriptions may seem a bit basic to the more expert readers. I ask everyone to please be patient and recognize that some people may require greater levels of detail to understand the issues.

Although a lot of technical information is included, but it was not my intention to produce a dry, scientific textbook. I wanted to incorporate the human dimensions of the story, and to produce a shale gas memoir of sorts. I was one of the younger people who worked on the Eastern Gas Shales Project, and hardly anyone is left at DOE or the other research agencies and contractors from the EGSP days. Most of those folks have retired, and sadly, many have passed away. Nevertheless, the U.S. Department of Energy and the old-timers who are still around deserve an enormous amount of credit for the development of shale gas, even though the initial research took decades to bear fruit. For their sakes, I wanted to get the story told.

The development of the Marcellus Shale was a complex endeavor and encompassed much more than can be compiled in a single document, even one of book length. It is important to keep in mind that one can only write from experience. There are often many side stories and nuances to any series of events that make up a story, some of which may not have been known to me. Although it was impossible to have been there for every key event, I did experience a certain level of overall exposure. I also was present on a number of occasions when important things happened. Hopefully, these experiences will provide a fairly accurate representation of the scope and substance of the story reflected in this narrative.

Finally, this book attempts to provide some factual information to address the sometimes intense disagreements that have become a distressing part of the current shale gas and hydraulic fracturing debates. People on both sides of the issues are getting into heated arguments based on misunderstandings, inaccurate statements, and incorrect interpretations of events. Many of the assertions that I have seen posted, blogged, and tweeted are simply wrong.

It is important for everyone interested in these issues to employ a little critical thinking to review and consider the common-sense aspect of statements being made, and to require data to support the claims. It is my hope that people on both sides of the debate will try to better understand the facts. Readers are urged to obtain copies of the documents listed in the references section for additional information and further reading. Many of these can be downloaded for free, and Web addresses were included when available.

Although there are still some uncertainties, the technology in use for shale gas development is well-understood, and improvements are constantly under development. Nevertheless, a better assessment of the engineering risks to the environment from the production of shale gas can drive new technologies to help further reduce such risks, while continuing the economic development of this important resource.

The production of shale gas resources has proven beneficial to the energy infrastructure of the United States. Shale gas and liquids have significantly reduced our dependence on imported oil, while at the same time providing a breathing space for the development of new energy technology. These were two of the original goals of the DOE Eastern Gas Shales Project back in the 1970s. Although it took nearly 40 years to achieve, the current success of shale gas is a tribute to the vision of those researchers who planned the EGSP back during the dark days of the energy crisis.

- DJS

3. INTRODUCTION AND BACKGROUND

The development of gas resources from the Marcellus Shale has been a success story for the government and people of the United States. It is also the success of a Federal research program that was put into place during a crisis to solve specific problems with energy supplies. Scientific and engineering data collected under this research program ultimately proved to be extremely valuable decades later, when technological advances finally allowed for the economic production of the resource. The large quantities of gas now being produced from shale are simply astounding, even to those who have a history with this resource.

3.1 BASIC GEOLOGY

The best place to start this story is with the rock itself. Shale is the name of a class of sedimentary rocks made of tiny grains of quartz, flakes of clay, and carbonate minerals such as calcite; the mineral components of mud. In fact, the generic term for this rock is “mudstone.” Mudstones are subdivided into (1) predominantly silt or (2) predominantly clay. Silt-rich rocks are called siltstone.

The mud was deposited as clastic sediment in quiet water, and then buried under younger sediments. The weight of these younger sediments compressed and heated the mud, driving out most of the water, cementing the minerals together, and turning the material into a rock through the process of lithification.

Clay is both a size term for very small sediment particles, and a type of mineral called a phyllosilicate, related to mica, that forms tiny sheets or flakes. As the sediment is deposited, the flakes of clay tend to stack together flat, one on top of another like a deck of cards, and as a result, lithified, clay-rich mudstone often has a finely-layered structure that allows it to split into paper-thin sheets. This property is called fissility. Under the strict sense of the term, a fine-grained, clastic rock must exhibit fissility to be called shale. Many parts of the Marcellus Shale are non-fissile calcareous or silty mudstone, but the formation name “Marcellus Shale” is applied to the entire unit.

The proportion of the three primary mineral components of mudrocks (clay, quartz, and carbonate) varies in any particular shale, but most are composed of some combination of these end members. Shales also typically contain secondary minerals, such as pyrite and siderite that precipitated out of the water trapped within the sediment, and diagenetic minerals, such as dolomite, that precipitated from fluids passing through natural fracture systems over geologic time. The sediment making up the bulk of shale is clastic in nature. As such, similar fine-grained but non-clastic carbonate rocks like chalk are classified as limestones. Intermediate rocks composed of both clastic and carbonate minerals are known as shaly limestones or calcareous shales, depending on the proportion of the constituents.

Rocks composed of something as simple as mud may not seem very exotic, but taking a closer look often reveals some interesting features. Shale contains complex and often rather strange-looking grain and pore structures (Schieber, 2010; Goral et al., 2015), and laboratory experiments using flumes have shown that the depositional environments of fine-grained clastic sediment are often complicated.

From an oil and gas production perspective, shale comes in two varieties—dark and light—depending on how much organic material is included with the mineral matter. Organic-rich shales are commonly known as black shale, and organic carbon contents of only a few percent are needed to turn the rock "black" (Hosterman and Whitlow, 1980). Organic-lean shales are lighter gray, green, or sometimes red in color, but referred to generically as "gray" shale. Black shales were deposited under anoxic conditions, which preserved the organic material from decay. Most of it had originated as dead plant fragments that accumulated with the sediment. The organic remains were subjected to heat and pressure in the absence of oxygen over geologic time periods during lithification, and this converted the organic material into hydrocarbons, such as petroleum, natural gas, and coal.

The Marcellus Shale was deposited in the Appalachian Basin between about 400 and 385 million years ago during the Middle Devonian Period. (A million years is commonly abbreviated as a mega-annum, or Ma. Age dates and boundary picks are from the Geological Society of America Geologic Time Scale compiled by Walker and Geissman, 2009.)

The Marcellus Shale is named for the type section that occurs in an outcrop on State Route 175 near Slate Hill Road less than 1.6 km (one mile) south of the small village of Marcellus, in Onondaga County, New York (fig. 1). The exposure here along the eastern valley wall of Ninemile Creek was described by Cooper (1930), and the formation was named after the town.

1. Photograph of fissile and fractured Marcellus Shale at the type section near Marcellus, New York. Photo by Dan Soeder

The lower boundary of the Marcellus is sharp, resting on the Onondaga Limestone. In contrast, the upper boundary is gradational, changing over a distance of several meters into the Mahantango Shale, an organic-lean gray shale named by Willard (1935) for exposures in the valley of Mahantango Creek in Snyder County, Pennsylvania. The Marcellus and Mahantango shales are combined into a larger geologic formation called the Hamilton Group, which may or may not (depending on the author) also include the Tully Limestone above the Mahantango (Stamm, 2015).

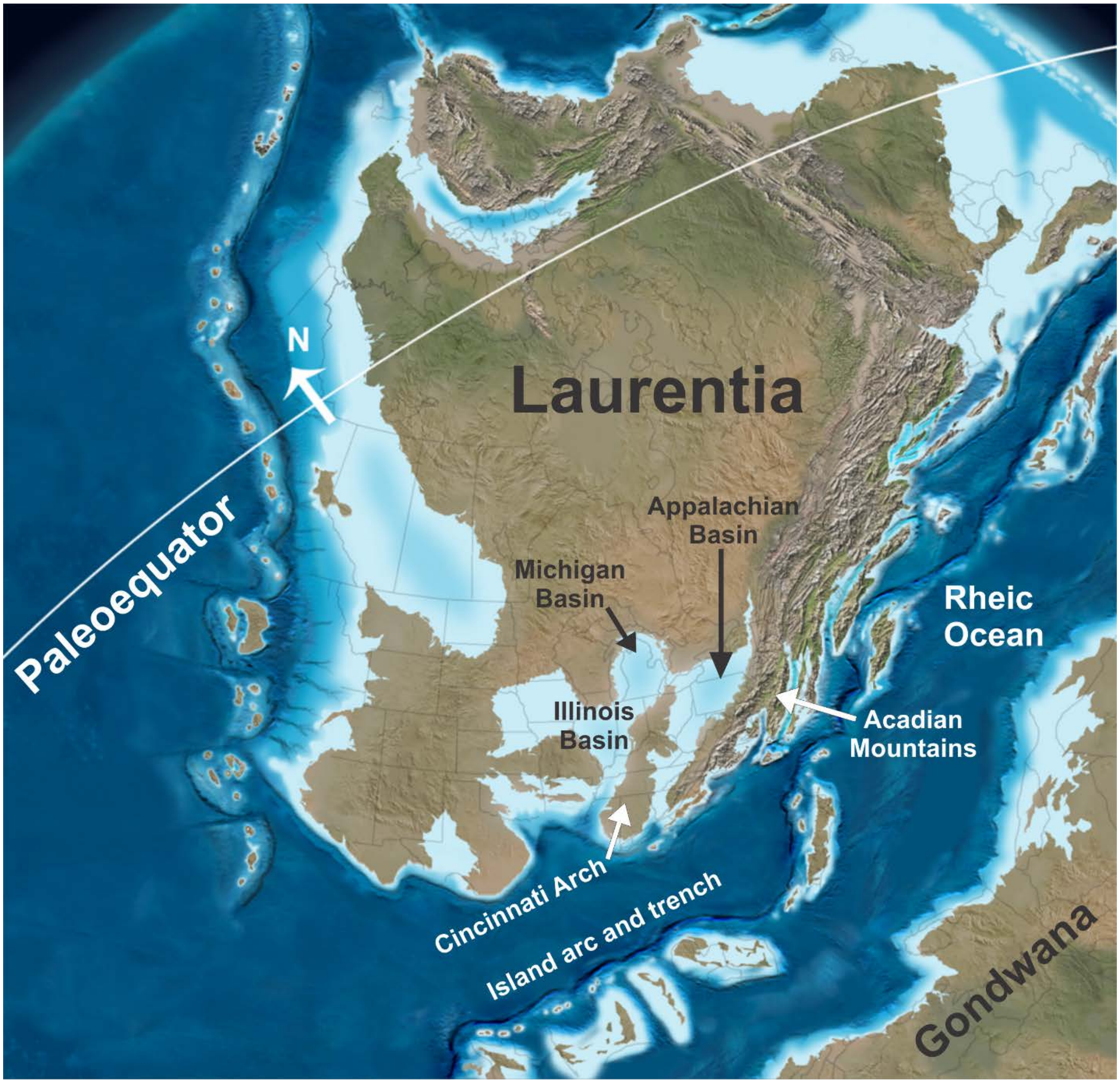
The village name of Marcellus honors a famous Roman general and consul, Marcus Claudius Marcellus (268–208 BC). A number of other New York towns in the area also bear classical Greek or Roman names (i.e., Ithaca, Utica, Rome, Syracuse, etc.). General Marcellus was known as “The Sword of Rome,” and most famously led Roman troops against Hannibal of

Carthage. He is credited with preventing the army of Carthage from approaching close to the City of Rome itself by keeping them occupied out in the Italian countryside. Marcellus was eventually ambushed on a scouting mission by Hannibal's cavalry and died a soldier's death on the battlefield at age 60, impaled on a spear. The Roman historian Plutarch recorded his exploits. (http://classics.mit.edu/Plutarch/marcellu.html).

3.1.1 Geologic framework

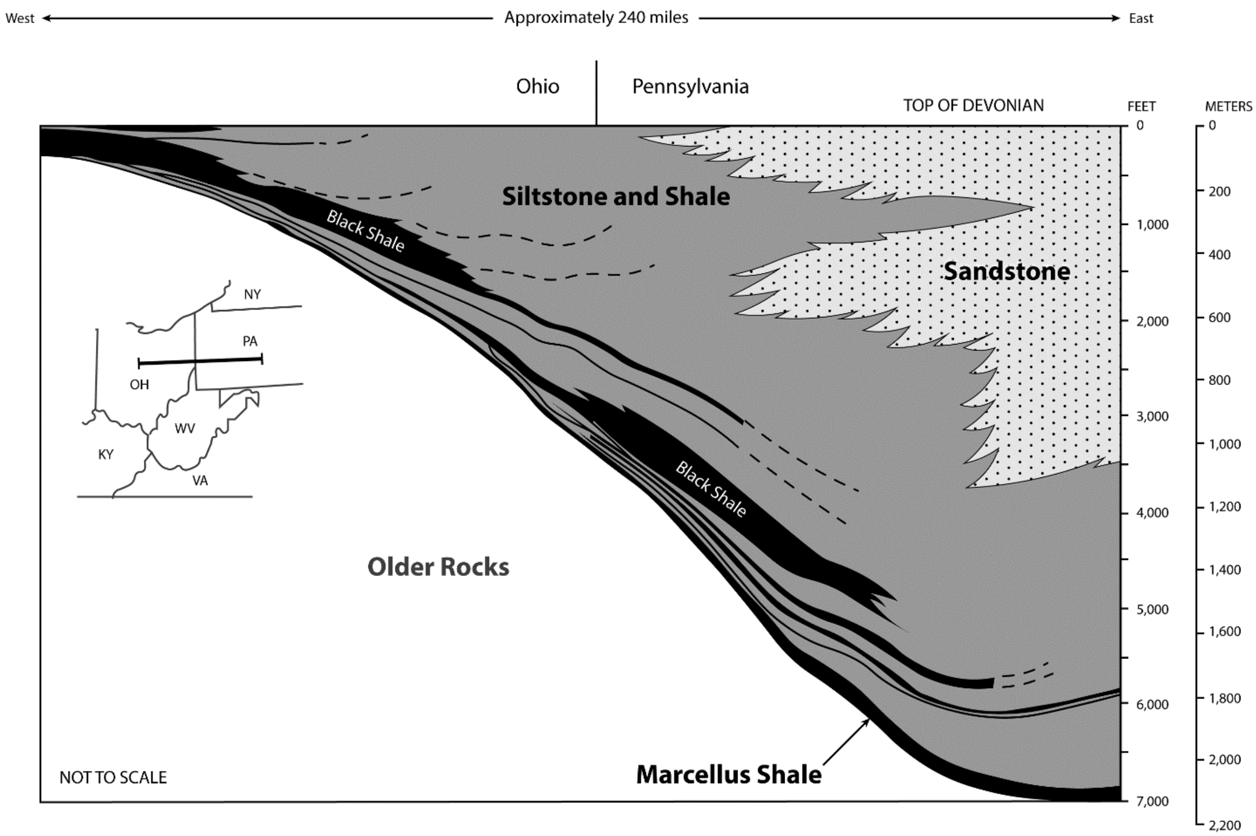
The Appalachian Basin is a large depression in the Earth's crust on the eastern margin of North America, filled with sedimentary rocks. It is deeper in the east and shallower to the west, forming and filling from about 520 Ma to approximately 250 Ma, and experiencing several episodes of mountain building along its eastern edge. Because of continental drift, the ancestral North American continent known as Laurentia, which contained the Appalachian Basin, was located largely south of the equator during the Devonian (416–359 Ma), Mississippian (359–318 Ma), and Pennsylvanian (318–299 Ma) geological periods.

An inland sea flooded the Appalachian Basin from New York to Georgia (fig. 2). Such inland water bodies on continental platforms are known as epeiric or epicontinental seas. Modern analogs include the Baltic Sea and Hudson Bay, although the Appalachian Sea was much warmer than either. The Marcellus Shale was deposited in this inland sea on top of some Early to Middle Devonian limestones and sandstones. A great river delta was built out into the sea on top of the Marcellus Shale during the Upper Devonian Period (374–359 Ma). The Catskill Mountains of New York are the remains of this delta (Schwietering, 1979). The delta system was actually quite complex, with as many as five major river systems contributing sediment to the basin along some 160 km (100 miles) of coastal plain shoreline (Boswell and Donaldson, 1988). Eventually, as much as 4 km (12,000 vertical feet) of sediment in the Catskill Delta accumulated on top of the Marcellus Shale (Milici and Swezey, 2006). The deep burial of the Marcellus Shale exposed it to fairly high pressures and temperatures (Rowan, 2006), which broke down nearly all of the complex hydrocarbons in this rock to methane (CH_4), the simplest and most common form of natural gas.



2. Reconstruction of ocean and land geography on the ancient continent of Laurentia (containing ancestral North America) during Marcellus Shale deposition 385 million years ago (after Blakey, 2011).

Additional black shales were deposited into the Appalachian Basin throughout the Upper Devonian (374–360 Ma) and Lower Mississippian Periods (360–352 Ma), including the Geneseo, Middlesex, Rhinestreet, Dunkirk, Huron, Cleveland, and Sunbury. All are organic rich, and many contain gas. Gray, organic-lean shales and siltstones were deposited between the black shale units, as basin anoxia decreased or sediment influx became greater. A representative cross-section of these rocks is shown in fig. 3.



3. Vertical cross-section modified from Potter, Maynard, and Prior (1980) of the Appalachian Basin from Ohio into Pennsylvania showing the layered sequence of Devonian-age black and gray shales.

A thin, older, Lower Devonian formation called the Mandata Shale occurs beneath the Marcellus Shale (Baez, 2004), but it is separated from the main Devonian shale sequence by the Onondaga Limestone, the Oriskany Sandstone and Helderberg Group limestone units. The Marcellus Shale is generally considered to be the basal unit of the main Devonian shale sequence, overlain by more than two kilometers of continuous sediment deposition into the Appalachian Basin from Middle Devonian to Lower Mississippian time.

The basin became increasingly shallow in the Upper Devonian and Mississippian Periods (359–318 Ma). A number of sedimentary deposits were exposed to the air, resulting in the oxidation of iron minerals that typically color the rocks red. The “red beds” of the Upper

Devonian Catskill Formation and the underlying Lock Haven Formation are prominently exposed in Pennsylvania along Route 322 west of State College. Likewise, the red shale and sandstone beds of the Missippian Mauch Chunk Formation are recognizable at a number of locations in eastern West Virginia, including an outcrop on Route 72 along the Cheat River north of Parsons. The Pennsylvanian-age sediments (318–299 Ma) on top of the Mississippian rocks were deposited in a very shallow basin—many of the Pennsylvanian coals were formed from woody plants growing in fluvial and paludal wetlands.

3.1.2 Geologic structure

Pulses of clastic sediment deposition into a basin are often influenced by episodes of mountain building along the basin margin followed by erosion. Plate tectonics theory describes the crust of the Earth as being divided into a number of large plates that float on the semi-liquid mantle. Plates can do one of three things at their boundaries: 1) pull apart, allowing magma to upwell and create new land on mid-ocean ridges such as Iceland; 2) slide past one another causing earthquakes like the San Andreas Fault in California; or 3) collide and force one plate to descend beneath another in what is known as a subduction zone, forming deep ocean trenches like the Japan Trench. As the descending plate melts, the resulting magma will often rise and create an arc of volcanic islands behind the subduction zone, such as the islands of Japan.

On the edges of continents, a mountain building episode known as an orogeny can occur when plate tectonic movements cause land masses to uplift or collide. As a slab of ocean crust descends into a subduction zone, the lighter continental crust on top is rafted along like an empty canoe and may eventually collide with another floating continent. This is not exactly a car wreck—the continents "crash" into each other at the rate of a few centimeters per year, or about the speed at which human fingernails grow. Nevertheless, such a collision is powerful and inexorable, crumpling and folding the continental rocks. The force will thrust the rocks downward into the Earth and upward into the sky, forming mountains. The Himalayas are the highest and one of the newest mountain ranges on the planet, currently being thrust upward by a continental collision between India and southern Asia.

The eastern edge of the Appalachian Basin has recorded three distinct orogenic events as this part of ancient Laurentia faced the closing Iapetus Ocean and then the closing Rheic Ocean during Paleozoic time (Nance and Linnemann, 2008). The oldest mountain range in the

Appalachian Basin dates from the Taconic Orogeny, which occurred in the Late Ordovician to Early Silurian Periods (458–439 Ma). This mountain range formed when Laurentia collided with an oceanic island-arc system (Colton, 1970). The collision had closed off the ancient Iapetus Ocean by the Late Silurian Period, and another, more southern ocean called the Rheic (fig. 2) was formed as the ancient continents moved about (Nance and Linnemann, 2008).

The seam where continents join is known as a suture zone, and the Blue Ridge Mountains that extend from Georgia to Pennsylvania marks the suture zone of the Taconic Orogeny (Clark, 2008; Nance and Linnemann, 2008). One of the dominant rock units forming the Blue Ridge is a greenish metamorphic rock called metabasalt. These rocks were originally erupted from a mid-ocean ridge as lava and comprised the seafloor of the ancient ocean. The Catoctin Metabasalt, visible in road cuts through the Blue Ridge along Interstate 70, west of Frederick, Maryland, and on Interstate 66 east of Front Royal, Virginia is all that remains of the Iapetus Ocean.

The next mountain range resulted from the Acadian Orogeny during the Middle Devonian to Lower Mississippian Periods (387–352 Ma), caused by collisions between Laurentia and a series of minor continental bodies called terranes, with the exotic names of Avalonia, Baltica, and Armorica (Hatcher, 1989; Bruner and Smosna, 2011). Terranes are fragments of continental crust broken off from a tectonic plate and accreted onto another tectonic plate. Terranes retain their original geology, which usually differs from their neighbors. The Acadian Orogeny created a mountain range in what is now New England, which was the principal source area for sediments that formed the Marcellus Shale, and the rocks of the Catskill Delta above it.

Late in the Pennsylvanian Period (320–286 Ma) and continuing into the Permian (286–245 Ma), the ancient continents of Laurentia and Gondwana collided head-on to fully close the Rheic Ocean and assemble the supercontinent of Pangaea (see Hatcher, 1989). The episode of mountain building that resulted from this collision was the Allegheny Orogeny that formed the Appalachian Mountain range (Clark, 2008). The suture zone from the closure of the Rheic Ocean is deep beneath the Atlantic Coastal Plain, and not visible at the surface (Nance and Linnemann, 2008).

During a continental collision, rock layers arch upward into anticlines, or warp downward into synclines, similar to the crumpling hood of a car hitting a brick wall. Cross sections of some of these folds in the Appalachians show steep angles of the rocks on the flanks of parallel ridges, and a reconstruction of where they would have met overhead suggests that the original peaks easily rose 5 km (16,000 feet) or higher above sea level (Hatcher, 1989). While not as lofty as the Himalayas, because the collision was slower and spread out across a wider contact area, these were still very substantial mountains when first formed.

The intrusive igneous rocks and high-grade metamorphic bedrock in the present-day Piedmont area east of the Blue Ridge are part of the deep continental basement crust called the craton. In the Piedmont, these basement rocks were uplifted by the Allegheny Orogeny and exposed at the surface by subsequent erosion. The high degree of metamorphism suggests that they were once covered by a great deal of overlying rock. The weathered granite, gneiss, and schist remain as evidence that the ancient core of the mountains once stood here.

No one crossing the Appalachians today would mistake them for serious mountains like the Rockies or Alps. Even the highest existing peaks, such as Clingmans Dome in Tennessee (2,025 meters or 6,643 feet), or Mount Mitchell in North Carolina (2,037 meters or 6,684 feet), would be considered little more than foothills in places like Colorado. The difference is age. The steep slopes of the ancestral Appalachians subjected the highest peaks to the most intense erosion, and after hundreds of millions of years of ice, snow, sleet, rain, and wind, only the nubs remain. Much of the sediment making up the Atlantic Coastal Plain, Eastern Continental Shelf, Mississippi Embayment, and the Gulf Coast washed down from the ancestral Appalachian Mountains. The present-day Appalachians consist mostly of low ridges of erosion-resistant sedimentary rock strata that will also disappear someday.

The supercontinent of Pangaea began to split apart in the Triassic Period (245–200 Ma), creating a number of small rift basins up and down the present day East Coast of the United States (many of these rift basins contain organic-rich black shales, some of which are being assessed for gas – see Milici et al., 2012). As the Earth's crust began to pull apart, volcanic activity resumed, sending magma into fractures that cooled into linear dikes that occur from New Jersey to Georgia. The newly separated continents became modern North America on the western landmass, and modern Europe and Africa on the east. The ocean that formed between them is the Atlantic, which continues to slowly widen. Every year, the distance of a flight from New York to London increases by a few centimeters (see Withjack et al., 1998).

The Allegheny Orogeny created tight folds and high peaks on the eastern margin of the basin in an area known as the Valley and Ridge Province. These folds have, in fact, brought the Marcellus Shale to the surface, where it outcrops in many places. To the west of these tightly folded rocks, the forces building the Appalachian Mountains thrust up a series of broader, flatter folds along a linear feature called the Allegheny Structural Front (Price, 1931).

The mountains along the Allegheny Front were less steep and are therefore eroded more slowly than the original, lofty Valley and Ridge peaks, and the even higher mountains of the Blue Ridge and Piedmont. The Allegheny Front now has some of the highest mountains remaining in the Appalachians. These include: Spruce Knob, the highest point in West Virginia; Backbone Mountain, the highest point in Maryland; and Mount Davis, the highest point in Pennsylvania.

The gentle folds of Laurel Mountain and Chestnut Ridge mark the western edge of the Allegheny Mountains. Westward from the base of these ridges, into northwest Pennsylvania, central Ohio, West Virginia, and eastern Kentucky, the flat-lying rocks of the Appalachian Basin have been vertically uplifted to form the Appalachian Plateau. This plateau is analogous to the Tibetan Plateau formed at the distant edge of the folds and thrusts making up the Himalaya Mountains, although it is much lower. The bulk of the Marcellus Shale and other sedimentary rocks in this central and western part of the Appalachian Basin were relatively undisturbed by the Appalachian Mountain building to the east.

3.1.3 <u>Formation of black shale</u>

A common interpretation of the origin of black shales is that organic-rich muds were deposited in anoxic, deep water below a permanent pycnocline (Boyce, 2010). Although anoxia is important to preserve organic matter in the sediment, deep water is not the only way to create low oxygen bottom conditions.

An assessment of modern depositional environments for black muds suggests that the two factors are critical for the preservation of organic matter: 1) high productivity of algae in the water column (Wrightstone, 2011), which is mainly controlled by nutrient input, and 2) deposition of organic material in a water body that has a low rate of sediment input, thereby preventing the “dilution” of organic carbon with inorganic mineral sediment (Smith and Leone, 2010). These processes together create organic-rich muds. Animals and aerobic microbes feeding on the high organic-content mud quickly deplete the limited dissolved oxygen in the bottom water, creating anoxic conditions that prohibit further consumption of organics, thus preserving the mud to later form a black shale.

In what has become the classical view, often referred to as the "Black Sea" model, black shales are thought to have formed in a deep, restricted, foreland basin somewhat like the modern-day Black Sea (Ettensohn, 2008). The alternating sequence of black shale units and intervening coarser clastic wedges in the northern Appalachian Basin (fig. 3), has been interpreted by Ettensohn (2012) as evidence of the cyclic nature of Acadian mountain building, which sent pulses of sediment into the basin that can be used to approximate water depths during black-shale deposition.

The deposition of each black shale unit was interpreted by Ettensohn (2012) as being the result of an episode of rapid subsidence in a foreland basin below the pycnocline, followed by the infilling of the basin with shales and coarser clastics. Ettensohn (2012) measured the thickness of the clastic wedges above each black shale to estimate, within an order-of-magnitude, the absolute basin depth. His assumption that sea level is represented by the top of the clastic wedge is affected by the one-time nature of each subsidence event, the possible under-filling of the basin, and the varying effects of compaction. Nevertheless, water depths in the northern Appalachian Basin estimated by this approach ranged from 80 meters to 310 meters (250 to 1000 feet) during deposition of Early Devonian-through-Early Mississippian black, organic-rich muds. The estimates also show a general deepening with time, which may reflect the cumulative effects of tectonic loading, plus rising Devonian sea levels.

The water depths proposed for such a model are unusually deep compared to modern epeiric seas, which tend to have depths of less than 100 meters, leading other researchers to suggest that a different model is needed (see Arthur and Sageman, 2005). A number of papers postulate that Appalachian black shales were deposited in quiet, shallow water with little sediment influx on distal margin of the basin (i.e. Schieber, 1994; Mosher, 2010; Smith and Leone, 2010). Evidence from petrographic studies of both the Utica and Marcellus shales by Smith and Leone (2010) includes fossil skeletal material found in black shales, described as "calci-silt." The fossil material is composed of fragments from echinoderms, bryozoans, brachiopods, and other animals that typically lived on the sea bottom, not floating in the water column. This suggests that the upper layers of sediment were not permanently anoxic, but possibly just seasonally disoxyic.

These ideas align with a shallow seasonal model for anoxia proposed by Tyson and Pearson (1991). They postulated an early/midspring algal bloom in the water column fed by nutrients released during winter storms. By late spring, the algae had created organic matter that descended to the seafloor as "marine snow." The "snow" consisted of organic matter surrounded by minerals, such as clay, suspended in the water. Such "organomineralic" aggregates helped to protect the organic matter from being eaten as it descended to the seafloor. Shallow water also reduced the descent time, further improving the chances of organics not being consumed on the way down. The water column stratified over the summer, and a redox boundary formed at the sediment-water interface as decay bacteria consumed oxygen. The anoxic conditions halted decay and preserved the organic matter in the sediment. Late fall and winter storms then re-mixed the water column and brought nutrients back to the surface water.

Smith and Leone (2010) noted that many black shale units in the Appalachian Basin and elsewhere rest on erosional unconformities at the top of the underlying limestones. In addition to the Marcellus Shale, the Rhinestreet Shale, Barnett Shale, Haynesville Shale, Woodford Shale, Pierre Shale, and Bakken Shale all onlap unconformities, suggesting that many black shales are a distal basin margin transgression onto a surface that may have been eroded during a previous sea level lowstand.

As the Appalachian Basin filled with sediment and the lithospheric load to the east decreased with erosion of the Acadian highlands, the geographic depositional center for the Upper Devonian black shales moved progressively westward. The Huron and Cleveland Shales were deposited on the flank of the Cincinnati Arch, a structural feature located roughly along the Ohio-Indiana state line, which approximates the western boundary of the Appalachian Basin (Ryder et al., 2012). The Cincinnati Arch was probably not a deep water environment. The black Antrim Shale in the Michigan Basin has been shown by fossil content (Matthews, 1983) to be the same age as the Huron Shale and identical in character, suggesting that this black shale may have been draped across the Cincinnati Arch during the Upper Devonian (374–360 Ma) Period.

The change in sedimentary facies across a basin has been understood in geology for quite some time. Details of such facies were described by Caster (1934) across the Appalachian Basin in northern Pennsylvania. Using fossils as biomarkers, he was able to trace various key beds in the Upper Devonian that changed character significantly from east to west. The sediments grade laterally from nearshore coarse sandy material to offshore finer siltstones and gray shales, and eventually to distal marine black shales and limestones as one moves from the Catskill source area out into the basin. This is illustrated schematically in the fig. 3 cross section.

Facies can also change vertically with changes in water depth over time, probably driven by sea-level variations. Walker-Milani (2011) identified six different lithofacies in the Marcellus Shale in West Virginia that are related to water energy, depth, oxygen levels, and other factors. The presence of these complex lithofacies would not be expected in the uniform bottom waters of a deep ocean.

The Upper Devonian-age Brallier Formation overlies the Hamilton Group in the central part of the Appalachian Basin and is stratigraphically equivalent to shales to the west. It is composed of quiet water shales interbedded with turbidity current deposits, known as "turbidites" (Hasson and Dennison, 1978). These are unstable silty and sandy sediments deposited on a slope close to shore that collapsed into an underwater avalanche or landslide. The moving sediments formed a dense, bottom-hugging suspension called a turbidity current, which continued to flow downhill and carried coarse material very long distances (Bouma, 1962). Some of the other coarse Upper Devonian sediments in the eastern part of the basin, such as the Greenland Gap or Hampshire formations, are shallow water shelf or storm deposits.

3.1.4 Marcellus boundaries

The Onondaga Limestone is present beneath most of the Marcellus Shale. It is named for exposures along Onondaga Lake and other locations in Onondaga County, New York (Hall, 1839). The contact of the Marcellus Shale against the Onondaga Limestone is sharp, indicating an abrupt change in depositional environment between the two units across an unconformity. The Onondaga Limestone extends southward from New York at least to northern West Virginia. It was recognized below the Marcellus Shale at a depth of 2286 m (7,500 ft.) in the EGSP WV-6 core drilled at Morgantown in 1978, and at a depth of 2019 m (6,625 ft.) in the EGSP WV-7 core, also drilled in 1978 near New Martinsville, close to the Ohio River (Bolyard, 1981). Toward the eastern margin of the basin, the Onondaga Limestone grades into the time-equivalent Needmore Shale (Willard, 1939) which is named for exposures near the town of Needmore in Fulton County, Pennsylvania.

A number of volcaniclastic units known as the Tioga ash beds (see Roen and Hosterman, 1982) occur near the top of the Onondaga Limestone and Needmore Shale and into the base of the Marcellus Shale. Because a volcanic eruption is virtually "instantaneous" as far as geologic time is concerned, the ash beds provide excellent markers for the location of the seafloor at a given time. Plate tectonics theory suggests that the volcanic eruptions were probably caused by the melting of a descending tectonic plate under the Laurentian continent as Gondwana slowly approached across the closing Rheic Ocean (see fig. 2).

The volcanic eruptions left behind at least eight distinct layers of Tioga ash that have been identified by Dennison (1961). Dennison and Textoris (1970) indicated that granodiorite plutons having the "correct general age … and composition" for the Tioga source magma may be found in Fluvanna County, Virginia, and that the actual volcanic center was likely east of Fluvanna County. A few years later, armed with improved sedimentary thickness and paleowind direction data, Dennison and Textoris (1987) moved the location of the possible source volcano farther northeast, near the present-day city of Fredericksburg, Virginia.

The third type of rock unit, along with the Needmore Shale and Onondaga Limestone that underlies the Marcellus Shale is the Huntersville Chert, named after the small hamlet of Huntersville along the Greenbrier River in Pocahontas County, West Virginia (Woodward, 1943). The Huntersville Chert is a chemostratigraphic unit formed by the silicification of the Needmore Shale and Marcellus Shale by a post-depositional hydrothermal or diagenetic alteration. Some researchers have suggested that the Tioga ash bed might be the source of the silica, because both it and the Huntersville Chert become thicker to the southeast (Woodward, 1943). Although this is the general direction of the assumed Tioga source volcano in what is now the Virginia Piedmont, the idea is hotly debated. Another interpretation is that the silica was provided by wind-blown dust (Cecil, 2004).

Rowan (2006) created thermal history profiles using wells in the Appalachian Plateau that indicated the existing rocks were once buried as much as 3.8 km (12,500 ft) deeper than their present position. Despite the fact that a great deal of the original surface has been eroded away, the Appalachian Plateau still stands more than 300 meters (1,000 feet) on average above sea level and is an impressive topographic feature. From central Ohio westward, the sedimentary rocks of the Appalachian Basin thin and pinch out against the Cincinnati Arch.

The gas-producing part of the Marcellus Shale lies primarily beneath the Appalachian Plateau (Zagorski, et al., 2012). The rocks here are flat-lying and relatively undisturbed. The shale is still buried quite deeply throughout most of the basin—generally 2 to 3 km (6,000 to

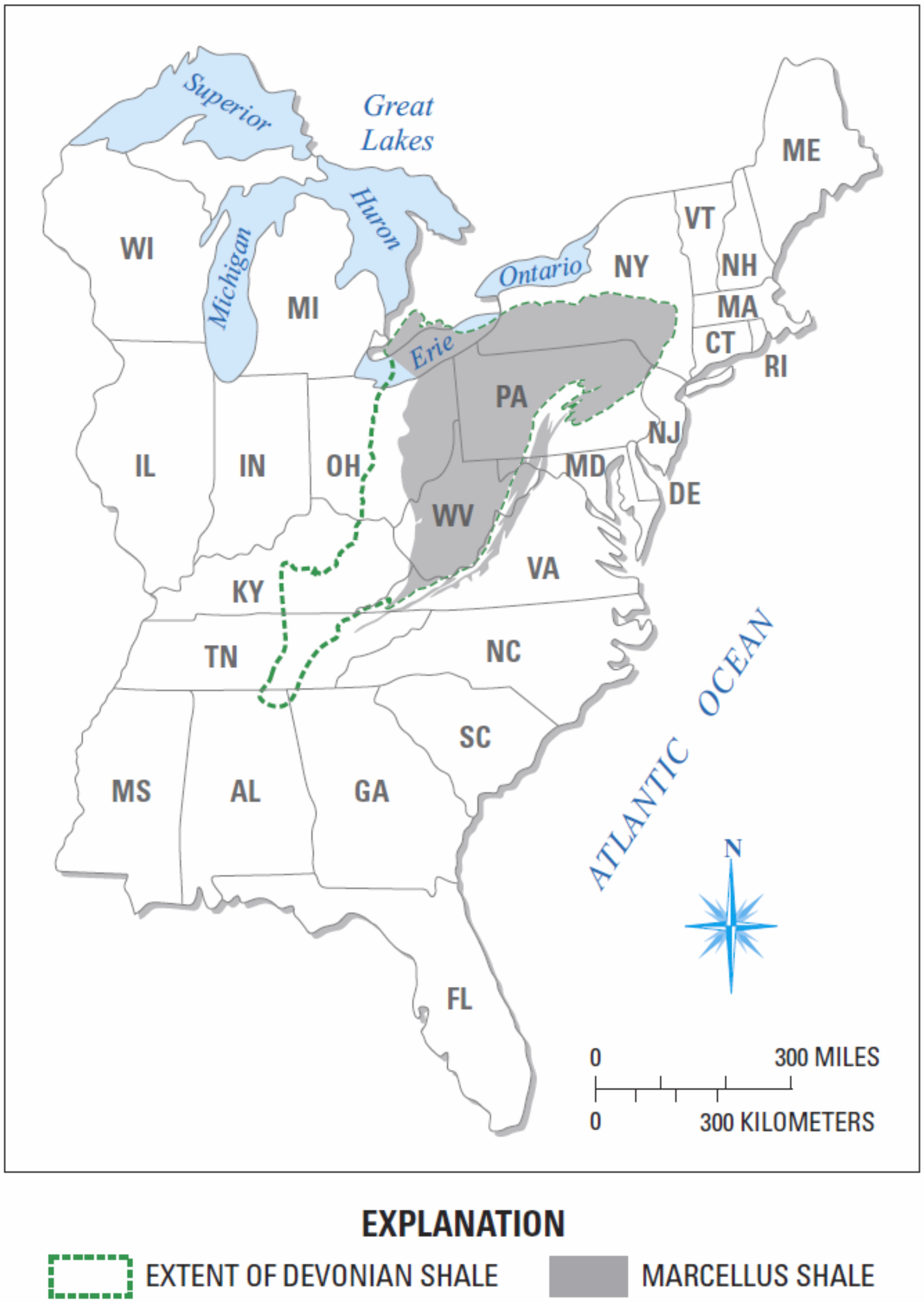
8,000 feet) or more below the land surface. The Marcellus becomes thinner toward the west, eventually disappearing as a feather edge deep underground in Ontario, central Ohio, western West Virginia, and eastern Kentucky (map, fig. 4). To the south, the Devonian shale section is compressed, and the Marcellus becomes a component of another black shale known as the Millboro Shale, which extends into southwestern Virginia (Butts, 1940).

The only places to view exposed outcrops of the Marcellus Shale at the surface are along the northern and eastern edges of the Appalachian Basin. The northern edge of the Marcellus Shale is exposed in New York State near the Finger Lakes. The rocks here are horizontal and well preserved. The Marcellus Shale sits on top of the Onondaga Limestone, which in turn lies above the Oriskany Sandstone (fig. 5). The Onondaga Limestone and the Helderberg Limestone beneath it are quarried at a number of locations in New York. Quarry operators often allow geological sampling of the Marcellus Shale.

In central Pennsylvania and eastern West Virginia, the Marcellus Shale has been brought to the surface by folding during the Allegheny Orogeny and exposed by erosion (Soeder et al., 2014a). The folds have tilted the originally horizontal shale beds to very steep dips, sometimes nearly vertical (fig. 6). It is occasionally overturned as well. The Oriskany Sandstone is one of the erosion-resistant rocks that form ridges in the Appalachian Valley and Ridge province. Because many shales look alike, one of the best ways to locate the Marcellus Shale in the Appalachian Mountains is to find an Oriskany Sandstone ridge, and then proceed up-section to the Marcellus.

Shale is a soft rock, and it was often deformed in these folds as it was squeezed and smeared between harder rocks above and below. This disruption makes folded shale a challenge to map and sample. There may be internal small folds within the shale or faults that cause the section to repeat itself several times in an outcrop (Walker-Milani, 2011). Some Marcellus-Millboro Shale locations in Virginia near fold axes contain flatter-lying outcrops that are less deformed (Soeder et al., 2014a).

Outcrop samples have limited value for geological and geochemical analysis due to long-term exposure to weathering, which affects the mineral and organic composition of the rock, as well as the microscopic structure. Also, by definition, these rocks are from the perimeter of the basin, not the central parts where gas is being produced, and it is unclear how closely outcrop samples may correspond to the lithology of the shale being drilled. Many operators have been happy to provide drill cuttings of the shale, but these consist of sand-size particles of limited usefulness. It is difficult and expensive to obtain fresh drill core samples of the Marcellus Shale from deep within the basin, but it is necessary to determine certain rock and reservoir properties.



4. Map showing the lateral extent of the Marcellus Shale in the Appalachian Basin (after Soeder and Kappel, 2009).

5. **Photograph of Hanson Quarry at Oriskany Falls, New York. Photo by Dan Soeder**.

6. Photograph of steeply dipping beds of Marcellus Shale in a road cut across the Warm Springs Anticline near Berkeley Springs, West Virginia. Photo by Dan Soeder

The Marcellus Shale is composed of three primary subunits or members (fig. 7). The basal subunit is the Union Springs Member, named for a town in New York on the eastern shore of Cayuga Lake (Cooper, 1930). It consists of organic-rich, black silty mudstone, siltstone, and limestone. The Union Springs is the most organic and gas productive part of the Marcellus Shale. It does not contain very much clay, so it lacks significant fissility, typically splitting along bedding planes into slabs or flagstones that are a centimeter to a few centimeters thick (a half inch to a few inches). The high silica content gives these a tendency to shatter like crockery when struck with a hammer. The brittleness of the rock causes it to break easily during hydraulic fracturing.

7. Photograph of Marcellus Shale exposed in the Hanson Aggregates quarry in Oriskany Falls, New York. Photo by Dan Soeder

The sediment-water interface in a stagnant environment with restricted circulation is said to be “euxinic,” which is another term often used by geologists to describe black shales. Euxinic is sometimes used erroneously to mean anoxic. Euxinic waters are commonly anoxic, but not always. Likewise, not all anoxic water has the restricted circulation that defines euxinic water. When euxinic waters are sulfur-rich, reduced sulfur minerals like pyrite (iron sulfide) are commonly deposited in the sediment. The Union Springs Member contains abundant pyrite in laminations and small clustered balls called framboids, named for their raspberry-like appearance.

Above the Union Springs is a dark, organic-rich carbonate member called the Cherry Valley Limestone, named by Cooper (1930) for a location in east-central New York. It is notable for having many open voids or vugs that contain clear calcite and beige-colored dolomite crystals. The Cherry Valley Limestone is not continuous throughout the entire extent of the Marcellus Shale. It was once thought to disappear to the south in central Pennsylvania, although de Witt et al. (1993) established that it extends into northwestern West Virginia based on drill core data.

Another limestone called the Purcell (Cate, 1963) occurs within the Marcellus in southern Pennsylvania and West Virginia. Geologists disagree about whether the Purcell Limestone is present at the exact same place in the stratigraphy that the Cherry Valley Limestone occupies up north, and is thus a southern equivalent, or if it is a totally separate unit that was deposited at a different time than the Cherry Valley (Lash and Engelder, 2011; Repetski et al., 2012; Chen et al., 2015). The “type section” of the Purcell Limestone occurs deep in a well on the Purcell gas field in Pennsylvania, and when it was first described by Cate (1963), he suggested that the name be used informally.

The upper subunit of the Marcellus Shale is called the Oatka Creek Member, named for exposures in the bed of the creek that runs through the town of LeRoy, NY (Cooper, 1930). It makes up the bulk of the outcrop at the Marcellus type section (refer back to fig. 1), and is less organic and more clay-rich than the Union Springs. In the quarry wall photograph shown in fig. 7, most of the Oatka Creek Member is missing due to erosion, and the upper part of the wall consists of much younger Pleistocene glacial gravels and till from the last Ice Age.

The Oatka Creek is fissile on many outcrops, including the Marcellus type section, because it is rich in clay. Parts of it also contain abundant ball or lens-shaped concretions, which range in diameter from a few centimeters to a meter or more, and are usually composed of siderite, an iron carbonate mineral. The Oatka Creek Member grades upward into the overlying Mahantango Shale, gradually becoming less organic-rich and lighter in color.

The upper formation boundary of the Marcellus Shale is hard to locate in drill cores or on outcrops. Most people select it from wireline well log data. It is formally defined using paleontology by the change in conodonts and other fossils from the Marcellus to the Mahantango (Harris, et al., 1994), although this is not something most people can easily recognize in core or on an outcrop. Many operators consider the lower Mahantango Shale to be part of the same gas-productive zone as the Marcellus Shale, and count on it for gas from an interval extending several tens of meters above the Onondaga Limestone and across the formation boundary between the two shales.

The micro-stratigraphy of the Marcellus Shale is much more complex than explained here, because a number of minor members occur in the thicker parts of the formation in NE Pennsylvania and southern New York (Nyahay et al., 2007, Harper, 2008). See the references cited in this section for more details.

3.2 Petroleum and natural gas formation

A brief explanation of some petroleum geology concepts is presented to help readers understand how gas was emplaced in the Marcellus Shale. For many, many years, the bulk of commercial oil and gas was produced from “conventional” resources. The hydrocarbons in a conventional oil and gas reservoir were usually created elsewhere, and migrated into the porous, permeable reservoir rock, typically sandstone or limestone, where they were trapped. Conventional reservoirs can typically be produced at economic rates with standard vertical well drilling technologies.

The Marcellus Shale, gas-bearing coal seams, tight gas sandstones, and methane hydrates are known as “unconventional” resources. These hydrocarbons were typically created in-place from organic material deposited with the sediment. The reservoirs often consist of low to very low permeability materials, and require special engineering techniques, such as horizontal drilling and high-volume hydraulic fracturing (HVHF) to produce economic quantities of oil and gas. These resources tend to be less concentrated, but total quantities are often very large, sometimes extending throughout almost the entire volume of the formation.

3.2.1 Conventional resources

Hydrocarbon resources in conventional reservoirs tend to be high-grade and concentrated. Classical petroleum geology describes a complex process for filling a conventional reservoir with oil and natural gas (Selley, 2014). A number of conditions and events must occur in a specific order and with proper timing. If anything goes wrong, the end result is no hydrocarbons. This is the reason why exploration for conventional oil and gas requires a deep knowledge of geology, lots of data, and no small amount of luck. Each step in the process is described in more detail below.

A. Source rock: Petroleum and natural gas are formed from decayed plant matter trapped in sediment. Initially, there must be an input and preservation of this organic matter when the sediments are deposited. Two common sources of organic material are algae or other water plants, and woody land plants. Some animals may have contributed as well, but most fossil fuel is derived from preserved plant material, not dead dinosaurs. Oxygen is required by the small animals and aerobic bacteria that carry out the decay process, so if the dead plants settle to the bottom in water that contains low levels of dissolved oxygen, the organic matter is often preserved from decay and buried under more sediment. As such, source rocks consist of fine-grained sediments deposited in quiet water, such as black shale.

Once lithified, the organic plant material becomes kerogen, classified into three major types. Type 1 kerogen is waxy and was derived from freshwater algae; Type 2 is oily and comes from marine algae that contained oily or fatty organic compounds known as lipids; and Type 3 is coaly and was sourced from woody land plants with high cellulose contents. Kerogen derived from algae tends to form petroleum, while woody land plant kerogen forms coal. All three types of kerogen produce methane, the main component of natural gas.

B. Thermal maturity: In addition to containing a few percent of preserved organic matter, the source rock sediment had to be buried deeply, and subjected to heat and pressure within the Earth over geologic time periods in the absence of oxygen. This process is called thermal maturation, and it breaks down the organic carbohydrates into fossil fuel hydrocarbons. Low levels of thermal maturity produce brown “lignite” coal, “wet” gas, and heavy crude oil.

High levels of thermal maturity produce high grade anthracite coal and dry gas, with no surviving liquid petroleum.

Temperatures within the Earth increase with depth along geothermal gradients. These vary somewhat with location, but in most places, the temperature increases by about 25 degrees Celsius with every kilometer of depth (Blackwell and Richards, 2004), or about twenty degrees Fahrenheit per thousand feet. Deeper burial of a rock means exposure to higher temperatures.

Rocks often retain evidence of their temperature history. One indicator is a black, glassy, organic material called vitrinite that is a component of type 3 kerogen. The material becomes more reflective to light with higher and longer exposure to elevated temperatures. Assessment of vitrinite reflectance, often abbreviated R_o, is a common tool for determining thermal maturity of source rocks.

In rocks where vitrinite is not present, such as those pre-dating the appearance of land plants, or from sediment deposited in an open marine environment far from land, other thermal indicators can be applied. One is a small, tooth-like fossil called a conodont element. These record the temperature history of the rock by a color change on a scale known as the conodont alteration index, or CAI (Repetski et al., 2008), wherein the fossil becomes a darker brown color in response to temperature. Another indicator uses a type of tarry organic material called bitumen to assess thermal maturity by reflectance, followed by an empirical conversion to a R_o value. It is less precise than a direct R_o measurement or a CAI determination, but sometimes it is the only indicator available. Bitumen is commonly used on the Utica Shale, which was deposited during the Ordovician Period before there were any land plants in existence.

The burial history of the Marcellus Shale has defined the thermal maturity. In a burial-history analysis for Devonian formations in western New York, Lash (2008) determined that the Marcellus Shale was initially buried quite rapidly during the Upper Devonian and Mississippian Periods beneath the Catskill Delta, which may have been as thick as 4 km (12,000 feet). During the Pennsylvanian Period and into the Permian, the Marcellus was uplifted by the mountain building of the Allegheny Orogeny, and some of the delta sediments above it were eroded. Once the higher mountains to the east started eroding more rapidly, the shale was quickly buried again in the Late Permian and Triassic Periods beneath more sediment. This was followed by steady uplift and erosion to the present time.

An assessment of Appalachian Basin erosion by Rowan (2006) concluded that 2–3 km (7,000–10,000 feet) of sedimentary rocks have been removed from above the present-day land surface. When added to the current burial depth of the Marcellus Shale, which is still some 1,500–2,500 meters (5,000–8,000 feet) deep throughout much of the basin, significant parts of the formation must have been buried as deeply as 3,500 to 5,500 meters (11,000 to 18,000 feet). The deeper rocks would have been exposed to temperatures above 175 degrees Celsius (350 degrees Fahrenheit) for millions of years.

Most measurements of thermal maturity on the Marcellus Shale place it quite high, well beyond the liquid petroleum range. In fact, nearly the only hydrocarbon present in this shale is dry methane gas, with a small percentage of ethane in the shallower, western parts of the formation.

C. Reservoir rock: Rocks that produce conventional oil and gas usually consist of coarse-grained sandstones or limestones with high porosity and permeability. The coarse grain size results in larger pore sizes (imagine comparing the void spaces between a stack of BBs and a stack of bowling balls). Larger pores typically have wide pore openings or apertures, known as pore “throats.” Wide pore throats allow hydrocarbons trapped within the pores to flow freely into a well.

There is a catch, of course. In clastic sediments, the larger grains that make up these rocks were deposited by the high water energy needed to entrain and transport coarse material. High water energy is not favorable for the deposition of fine-grained sediment and particles of organic matter; these materials were carried off to be deposited elsewhere in a low energy, quiet water environment. Even if any organics were by chance trapped with the coarser material, it was likely that they were consumed by microbes and scavengers combing through the aerobic sediment. Good reservoir rocks usually make poor source rocks, and vice versa.

Carbonate rock or limestone reservoirs often increase in porosity after the dissolution of component grains or matrix. This commonly occurs over geologic time when solutions of hydrothermal groundwater pass through the rock and either dissolve out components or cause the carbonate minerals to recrystallize. Both of these processes typically increase porosity.

D. Trap and seal: To contain the gas and oil in a conventional reservoir, there must be some kind of a trap, such as a fold or a fault, to displace the rock layers and create an underground structure that acts as a container to hold the hydrocarbons in the reservoir rock. To be effective, the trap must also include a seal made from an impermeable caprock, such as shale, gypsum, or salt beds. A body of reservoir rock without a trap and seal will not retain any hydrocarbons.

E. Migration pathway: Because the source rocks and reservoir rocks are usually completely different formations, once the oil and gas have formed in the source rock, a migration path is needed for these to get from the source rock to a reservoir rock. This can be a through-going fracture, such as a fault that allows movement through the intervening rocks, or just tilted beds that will let hydrocarbons slowly seep updip.

Timing is everything: if the migration pathway is in place before a reservoir rock is available, the oil and gas will be lost. Likewise, if the reservoir rock is present, but no migration path ever develops, the reservoir stays empty.

In summary, an operator will end up with a non-productive well in a conventional oil or gas reservoir if any one of the five items described above is missing, or occurs out of sequence. It is a tribute to the talents of the petroleum geologists and petroleum engineers that virtually all of the oil and gas produced throughout history, until the first decade of the 21st Century, has been found in conventional reservoirs.

3.2.2 Unconventional resources

The Marcellus Shale and other gas shales are in a class of hydrocarbon reserves known as unconventional resources. Although "unconventional" is on the way to becoming "conventional" in the minds of some people, the term does have a specific definition. It means that the target formation must be engineered with some type of reservoir stimulation (such as hydraulic fracturing) to produce economical amounts of hydrocarbons.

Gas in the Marcellus Shale was generated in-place from thermally-mature organic material that had been deposited with the shale. The Marcellus is a classic source rock, and in fact it has contributed significant amounts of gas to overlying conventional reservoirs. However, much gas has also remained within this black shale, and can be produced directly from it. Gas shales like the Marcellus represent a new concept in petroleum geology: the source rock is also the reservoir rock.

The USGS refers to gas shales as "continuous resources," to distinguish them from hydrocarbons in traditional traps and seals (Charpentier and Cook, 2011). One can drill and stimulate a well almost anywhere in a continuous resource with the proper production technology and expect to recover economical amounts of hydrocarbons. The amount of recoverable gas in U.S. shale formations vastly exceeds the remaining amount of recoverable gas in conventional reservoirs.

For many years, limits on engineering technology restricted commercial shale gas to places like the Big Sandy field in Kentucky near the West Virginia border, which has been producing gas since the 1920s from vertical wells in the Ohio Shale thanks to a unique set of natural fractures (Hunter and Young, 1953). Expanding this production to other locations and other shales like the Marcellus required the development of new technology, which worked better than anyone had anticipated and made shale gas wells profitable. This has changed the thinking about potential gas resources in the United States.

4. THE HISTORY OF U.S. SHALE GAS STUDIES

The first commercial American gas well was hand-dug into Devonian-age shale in 1821 by a gunsmith named William Hart along the bank of Canadaway Creek in Fredonia, New York (Curtis, 2002). Hart sold gas from his 27 ft. (8 m) deep well to a grist mill, tavern, and the village to provide fuel for gas lamps and street lighting. Local legends say that he inverted his wife's washtub over the hole to contain the gas and act as a primitive wellhead. There is a history of similar small-scale gas production from Devonian shales along the south shore of Lake Erie throughout the 19th and early 20th Centuries. The notion that organic-rich shales contain natural gas has been understood for a long time.

Serious shale gas studies did not begin in the United States until the mid-1970s, however, after an event known as the "energy crisis." This was actually two separate incidents: one in 1973–74 and a second in 1979. Although the U.S. had experienced a number of localized and short-lived energy shortages after the Second World War, the shortages experienced during these crises in the 1970s were a huge concern and led to major changes in U.S. domestic and foreign policy.

A Middle East war known variously among historians as the Yom Kippur War, the Ramadan War, the 1973 Arab-Israeli War, or the Fourth Arab-Israeli War was fought between October 6 and October 25, 1973. It started with the Egyptian and Syrian armies invading Israel, followed by an Israeli counterattack, and ended in less than three weeks with a United Nations-brokered ceasefire (Rabinovich, 2004). Armies from Iraq and Jordan were also involved. Because this conflict occurred during the height of the Cold War, both the United States and Soviet Union enlisted the two sides as proxies, with the Soviets resupplying and supporting Egypt, and the Americans airlifting material and providing intelligence support to Israel.

American support for Israel led some Arab members of the Organization of Petroleum Exporting Countries, an oil cartel better known by its acronym OPEC, to call for an embargo on oil exported to the United States. At a meeting of oil ministers in Kuwait on October 20, 1973, several members of OPEC, led by Libya, declared a total embargo on oil deliveries to the United States (Yergin, 1991).

The oil embargo on the U.S. lasted from the autumn of 1973 until the spring of 1974. Although this was at a time when significantly less than half of the oil used in the United States was imported, and not all the member countries of OPEC had even joined the embargo, the action resulted in severe U.S. fuel shortages, long lines at gasoline stations when there was fuel available, and consumer panic. The price of oil quadrupled almost overnight. American drivers, who had not worried about gasoline supplies since the days of fuel rationing during World War II, were shocked and stunned (Soeder, 2012a). Oil exports from the U.S. were banned beginning in 1975, which remained in effect until Congress lifted the ban in 2015 (*The Economist*, December 18, 2015)

It is hard to overstate how traumatic the 1973-74 oil embargo was for the American public. After World War II, many people had moved out of cities and into suburban housing, located in formerly rural areas that were often long distances from city centers, and connected to cities by freeways. The result was that many people in the suburbs were dependent on the automobile for almost all transportation needs. Travel to work, shopping, church, school, and almost everywhere else required the use of a vehicle. Drive-in movie theatres, drive-in restaurants, drive-up bank tellers, and other establishments catering to the automobile became commonplace. Suburban families, especially those with driving-age children, often owned multiple vehicles.

The energy crisis challenged this suburban lifestyle. For the first time, citizens faced the prospect of being left stranded in the sticks with an empty gas tank in a useless car, unable to carry out even the simplest tasks. It created huge amounts of worry and concern throughout the population and the government. The U.S. government even printed batches of official gasoline ration coupons in response to the 1973-74 energy crisis, but the coupons were never issued (they are now prized collector's items). In the rhetoric of the times, people demanded that something be done to prevent America from being held "hostage" to imported oil. The last Apollo moon landing had been made the previous year, and many people expressed a belief that if the United States could send men to the moon, we certainly ought to be able to gas-up our cars.

The second energy crisis occurred in 1979, among the protests and disarray associated with the Iranian revolution that disrupted oil production for several months. Although the United States received only a relatively small amount of imported oil from Iran, the disruption to global supplies was enough to prompt a second oil shortage with the same long gas station lines and panic as seen in 1973-74. The 1979 crisis was much shorter-lived, however, because Saudi

Arabia and other exporting nations were able to make up for the Iranian oil shortages and return American imports to nearly steady levels.

The in-depth story on both of these crises is far more complicated than any simple explanation can capture. Yergin (1991) provided a detailed assessment of the complex relationships between oil and politics. His very long book is recommended for further reading.

The U.S. Department of Energy (DOE) was created from a number of smaller energy agencies as a cabinet-level entity of the U.S. Federal government under President Jimmy Carter on August 4, 1977. The following day, James R. Schlesinger was appointed as the first Secretary of Energy. Along with inherited responsibilities like running the national labs and maintaining the nation's nuclear weapons stockpile, the primary mission of the new DOE was to find technological solutions to the energy crisis by improving energy efficiency and increasing the domestic energy supply.

One responsibility of DOE was to help the U.S. oil and gas industry locate and develop new domestic resources of fossil fuel, including natural gas. Some of the potential new gas resources investigated by the government in the late 1970s, and now thought of as "unconventional" included coalbed methane, tight gas sands, and shale gas (Schrider and Wise, 1980). Although it was known that the production of these gas resources would be technically challenging, energy from them could help displace imported oil. In 1975, the Energy Research and Development Administration, a predecessor agency to the U.S. Department of Energy, set out to investigate some of these resources with a number of scientific and engineering studies, one of which was known as the Eastern Gas Shales Project (Soeder, 2012a).

4.1 THE EASTERN GAS SHALES PROJECT

The premise behind the Eastern Gas Shales Project (EGSP) was that the sequence of Devonian-age black shales in the Appalachian Basin (refer back to the cross section in fig. 3), as well as similar-age black shales in the Michigan and Illinois basins could potentially produce large amounts of natural gas under the right conditions. One of these conditions was that gas would flow out of a fine-grained rock like shale in economical quantities only if the formation contained abundant natural fractures to act as high-permeability flowpaths. Natural fractures supplemented by engineered induced fractures form a gathering system to collect up all the small gas flows throughout a large volume of shale and transport the combined flow to a well at economical rates of gas production. This turned out to be accurate, although the scales required to achieve commercial success were much larger than those being considered in the 1970s.

The focus of the EGSP was to investigate black shales that contained abundant natural fractures. As designed in 1975, the EGSP had three major components: 1) resource inventory and characterization, 2) development of production technology, and 3) the transfer of that technology to industry. It was largely an engineering project, focused on developing reservoir stimulation technology that used hydraulic fracturing to intercept and connect with natural fractures, thereby creating a network of high permeability flowpaths.

The project was operated out of the DOE Morgantown Energy Technology Center, or METC, which was a precursor to the present-day National Energy Technology Laboratory (NETL). Over a period of about 6 years, from 1976 to 1982, the EGSP used cooperative agreements with commercial drilling companies to collect oriented drill core from a variety of shale units in the Appalachian, Michigan, and Illinois basins. Because the EGSP was a research project, dozens of meters (hundreds of feet) of drill core were cut from the Devonian shale section in each well to ensure that enough samples were available for a multitude of tests. Wells were located at many sites throughout the three basins under study to provide access to a variety of stratigraphic units, organic contents, fracture patterns, and thermal maturity for characterization. All of the core was oriented, because one of the critical pieces of data being gathered was the directional trend of the natural fractures.

4.1.1 Field processing of shale core

Standard drillstem coring techniques were employed to obtain the shale samples. For readers unfamiliar with these, the core was cut using a hollow bit, somewhat resembling a donut with sugar sprinkles. In this case, the donut was hardened tool steel, and the sprinkles were industrial-grade diamonds. The downhole core barrel that received the core had inner and outer components. The system was designed such that the cutting bit, outer core barrel, and the drill pipe could remain downhole, and the inner core barrel, with about 10 meters or 30 feet of core inside, could be retrieved by attaching a wireline to it and pulling it to the surface through the center of the drill pipe. This avoided having to remove the entire drill string from the hole every ten meters just to get the core.

Directional orientation was achieved by scribing three grooves into the sides of the 9 cm (3.5 inch) diameter core cylinder as the rock was cut. These scribe lines were made with a set of knives mounted on the inside of the inner core barrel, which did not rotate with the rest of the drill string. Two scribes were spaced close together with the third scribe farther apart. The azimuthal orientation of the third groove was determined by using a downhole camera to photograph it against a compass needle about every half meter (every 2 feet). The compass worked because the drill collar it was mounted in was made from Monel, a non-magnetic alloy. The cut core went into a PVC plastic sleeve that lined the inner core barrel. The sleeves were used to help keep the shale together and reduce breakage. They generally worked pretty well, except in a few cases where the core split and jammed the sleeve into the barrel, or the temperatures at depth got hot enough to soften and stretch the plastic.

A subsidiary of the Cleveland-Cliffs Iron Company, chartered in West Virginia as Cliffs Minerals, Inc. was responsible under a DOE contract for processing the core from drill sites in the Appalachian and Michigan basins. The Illinois Geological Survey processed shale core in the Illinois Basin. Most of the EGSP cores came from the Appalachian Basin, and many of these were from sites in the shallower, western side near the Ohio River. This bias toward the Ohio River was partly based on an attempt to follow the trend of the Big Sandy field along the axis of the Appalachian Basin, and also because the shale sequence in the eastern part of the basin is deeper and more expensive to drill. Only about 25% of the Appalachian Basin EGSP wells were drilled to the Marcellus Shale.

As soon as the core came out of the ground inside the PVC sleeve, Cliffs Minerals field personnel were responsible for handling it. The 10 meter (30 foot) sleeves were cut into approximately 2 meter (6 foot) lengths using a pipe cutter, and the core unloaded. It was washed to remove drilling mud, assembled, aligned, measured for length, and had depths marked on it at each foot (30 cm). Downhole arrows were also drawn on as many segments as possible.

The field crew set to work collecting and preserving samples and creating a field description of the lithology, noting in particular any gas shows, natural fractures, or other features (fig. 8). The quickest way to do this in the field was by dictating into a portable tape recorder, and transcribing the descriptions onto paper later. The most time-sensitive of the field samples were short segments of core designated for gas chemistry that still had gas bubbling out of the rock. As quickly as possible, but absolutely within two hours of the core reaching the surface, these offgassing samples had to be preserved in airtight steel cans. The EGSP field team used a hand-cranked, commercial can-sealing machine out in the field. The hermetically-sealed cans went to the Mound Facility in Ohio, where the composition of the gas was analyzed (Zielinski and McIver, 1982).

The final field task was to pack the core back up into the PVC liners and cap the ends with silver duct tape for transport back to the lab in Morgantown. The cores were solid cylinders of rock that weighed about 15 kilograms per meter (10 pounds per foot). After the core got back to the lab, it was placed on long wooden tables into boards with shallow v-cuts in their top surfaces to keep the round drill cores from rolling off (fig. 8).

8. Photograph of Cliffs Minerals personnel processing freshly recovered core in the field (L); view inside the Cliffs Minerals warehouse, showing EGSP cores laid out on core tables (R). Photos by Dan Soeder.

4.1.2 <u>Laboratory processing</u>

Once the EGSP cores were laid out on tables, they were carefully pieced together with the main orientation groove facing upward, cleaned again and measured. The cleaning fluid was a bucket of tap water with potassium chloride (KCl) salt dissolved in it. It was thought that the KCl would help keep clay minerals from swelling up in fresh water and disintegrating the core. This was probably not necessary, since these shales contain very little swelling clay, and plain tap water would likely have worked fine.

The depth marks that had been put on the cores in the field were re-traced as needed. Using the core orientation data and a circular plastic protractor, north lines were drawn on the rock cylinders referenced to the location of main groove. Marking the north direction allowed for the later measurement of the orientation of any features or natural fractures encountered in the core. Fig. 9 shows an oriented segment of EGSP core.

9. Photograph of contact between the black Cleveland Shale and the underlying gray Chagrin Shale in an EGSP core from Ohio. Photo by Dan Soeder.

Cleaned and oriented cores were processed for data collection. The lithology and color of the core were described unit by unit, with bedding thicknesses and any unusual features noted.

Fractures were identified as natural or coring-induced. The strike and dip of natural fractures were measured, and the frequency of induced fractures was counted. The cores were photographed, and natural gamma radiation levels were measured before various samples were removed. Details of these processes are described below.

There were a number of potential sources of error when processing the core. Geologic descriptions were done from the base of the core upward, because that is the order in which the sediments were deposited. Drillers' logs, on the other hand, ran from the top of the core downward, because that is the direction in which it was drilled. The names for rock units used by geologists differ from the names used by the drillers, and it was important for the geologists to understand the vocabulary. For example, within the Ohio Shale, the black Cleveland Shale member is called "Little Cinnamon" by the drillers, the gray Chagrin Shale beneath it is the "Gordon," and the black Huron Shale at the base is the "Big Cinnamon." The driller's term for the Marcellus Shale is "Lower Olentangy." Geologic columns published by state geological surveys in the region typically have both the geologic names and the drillers' names listed side-by-side.

Most places in the world do not have different geologist and driller names for the rocks. However, the history of oil and gas drilling in the Appalachian Basin pre-dates the development of the formal geologic nomenclature. The first oil well was drilled at Titusville, Pennsylvania in 1859, and oil and gas drilling boomed in the region after the Civil War. Geologists didn't describe and name the Cleveland and Huron shales until 1870; the Chagrin Shale in 1903; and the Marcellus Shale in 1930 (Stamm, 2015). The drillers were out there years or even decades ahead of the geologists and were forced to make up their own names. Those terms have persisted.

Core depths were usually measured from the raised drill rig floor at the level of the turntable known as the Kelly Bushing. The Kelly Bushing was a round, rotating platform a couple of meters (several feet) across with a square hole in the center, through which a length of square drill pipe (called the Kelly) was fitted. The Kelly was turned by the Kelly Bushing, and it rotated the entire drill string, turning the bit at the end and cutting the rock. The Kelly Bushing was normally about 3 meters or 10 feet above the ground on the rig platform.

The drill rig was usually long gone when the well logging truck arrived, and the logger would use the ground level as a reference point for measuring depths. Thus, a comparison of log features to core features by depth would commonly be offset by the height of the Kelly Bushing, or about 3 meters. This discrepancy in depth measurement reference points had to be reconciled for the side-by-side charts of well logs and lithology provided in the drill core reports.

Color was noted by comparing wet core surfaces to a Munsell color chart of paint chips, which classifies colors according to a standard hue, chroma, and intensity scale. A hue is the actual color (for example, blue) and the chroma is the lightness or darkness of the color (i.e. sky blue versus navy blue). Intensity describes the strength of the color; for example, bright sky blue versus pale sky blue. Wetting the core gave a more uniform color to the rock, without changing the hue or intensity. It just altered the chroma, making it darker.

The color chart was used because a direct and simple correlation was sought between the color of the shale and the organic carbon content, and hence gas potential. This turned out not to work very well—once the organic carbon content reaches about 4 percent, the shale is black and it doesn't get any "blacker" with the addition of more carbon (Hosterman and Whitlow, 1980). As an interesting aside, many of the Appalachian Devonian black shales are not truly black; most are a yellowish black color similar in tint to ripe olives. Only the Marcellus was found to be an actual charcoal black.

Fractures were identified as natural or coring-induced, based on a number of criteria in shale defined by Kulander et al. (1977). Natural fractures were further classified as joints or faults. Joints are fractures where the two sides have simply pulled apart. Faults are fractures where the two sides have slid past one another; often leaving behind a polished, grooved surface in shale called a slickenside. An example is shown in fig. 10. These are fairly obvious in shale core, making it easy to distinguish faults from joints.

The orientation of the natural fractures was measured using the north directional line on the core as a reference. The primary set of natural fractures in the Appalachian Basin trend to the east-northeast, with a secondary set trending to the northwest (Engelder and Lash, 2008). The coring-induced fractures were described, and the frequency counted, but little else could be done with them. It was hoped that they could at least provide an indication of the brittleness of the rock and its possible response to hydraulic fracturing.

10. Photograph of a slickenside on a segment of red shale core. Photo by Dan Soeder.

The cores were comprehensively photographed with a specially made rig that could trundle a camera down the length of a core table. These photos were taken using color film, which was processed locally. The finished photos were hand-pasted into albums and kept as a reference. Sadly, many of these photos were damaged by water during decades of storage. Some of the EGSP cores have been re-photographed more recently with a digital camera (fig. 11) as samples were collected for X-ray data and other analysis. Unfortunately, due to drying and desiccation, oxidation of minerals, relaxation of the rock, and multiple episodes of handling and sampling, the cores have deteriorated in quality over the past 35 years.

11. A recent photograph of the contact between the Marcellus Shale and Onondaga Limestone in the EGSP WV-6 drill core (from Bruner and Smosna, 2011).

Radiation readings were collected on the EGSP cores using a scintillometer, a detector for gamma radiation. The scintillometer readings were taken every foot to compare with gamma ray logs collected downhole on a wireline tool by a service company. While some geologic contacts between black and gray shales are easy to spot visually in a core (such as the Cleveland/Chagrin contact shown back in fig. 9), others are more subtle. Gamma readings are often a good method for determining the precise formation contact in the shale sequence. Like the core photographs, the scintillometer measurements are another data set that unfortunately has been lost over the decades.

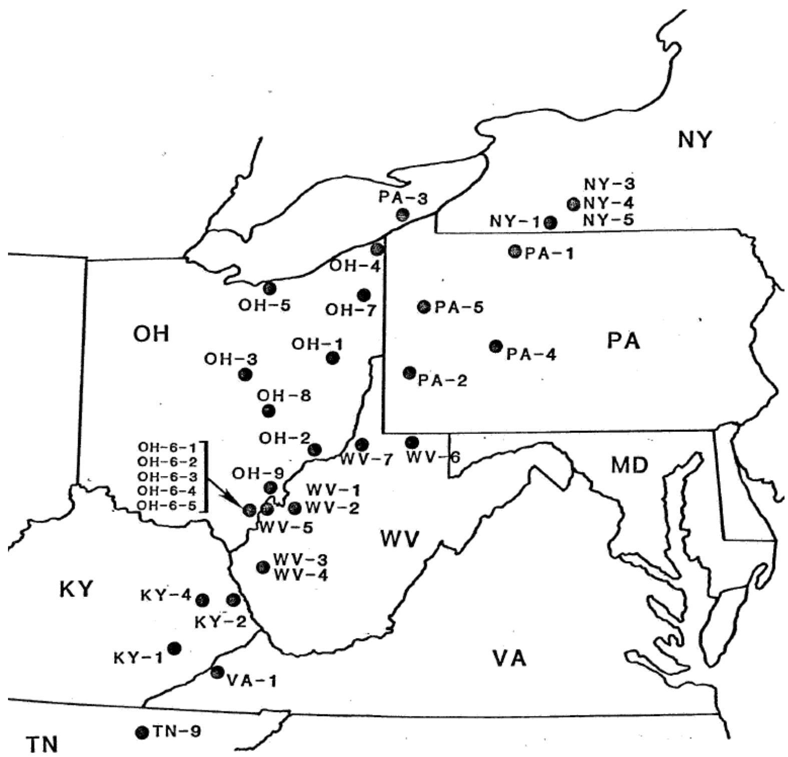
Rock samples were collected from the cores for the various labs, government agencies, and universities that had asked for them, and small wooden blocks with information identifying the top and bottom depths of the missing piece and who had possession of it were inserted into the core from where the samples were taken. This tradition has been continued on these cores over the years, although sometimes the wooden blocks have been replaced with much less durable pieces of Styrofoam, cardboard, or even yellow sticky notes.

The orientation scribe lines cut in the core would have affected the direction in which the rock broke during mechanical testing, so "undercores" were cut from the centers of the whole EGSP cores using a diamond bit on a drill press to obtain samples well away from the scribe lines. The undercores consisted of vertical cylinders 5 cm (2 inches) in diameter, ranging in length from 10 to 20 cm (4 to 8 inches). Each cylinder was sliced into numerous test disks approximately one centimeter (0.5 inch) in thickness. Shale disks were prepared for measurements of point load, directional tensile strength, and other tests by Michigan Technological University (Michigan Tech) designed to determine rock strength and directional anisotropy.

Prior to cutting, the north orientation of the core was transferred in yellow wax pencil to the undercore, and then onto each individual disk as they were sliced with a rock saw, preserving the directional orientation. The fragile nature of the shale meant that a significant percentage of the samples split, cracked or disintegrated before they could be shipped to Michigan Tech for testing, requiring frequent sample replacement.

4.1.3 EGSP cores

Cores were collected from 34 different EGSP wells in the Appalachian Basin (Bolyard, 1981), in shales ranging from the Cleveland to the Marcellus. Three wells were also cored in the Antrim Shale of the Michigan Basin (Cliffs Minerals, 1982), and seven wells were drilled in the New Albany Shale in the Illinois Basin (Cobb and Wilhelm, 1982) for a total of 44. The locations of the EGSP wells in the Appalachian Basin are shown in fig. 12 (Bolyard, 1981).



12. Map locations of the DOE Eastern Gas Shales Project (EGSP) drill cores collected in the Appalachian Basin between 1975 and 1981, modified from Bolyard, 1982.

The most exotic EGSP core was TN-9 from Grainger County in Tennessee, where the black Chattanooga Shale is located in a structurally complex setting against the Saltville thrust fault. It was thought the faulting would produce abundant fractures in the shale (Cobb and Wilhelm, 1982). This idea was more or less correct—the core was essentially a fault breccia. It contained dozens of fractures per foot (30 cm), most of which had been cemented back together by a black, bituminous substance presumably derived from the black shale. The sealed fractures were not especially gas productive.

A more representative core came from the WV-6 well in Morgantown, drilled on the property of the National Energy Technology Laboratory. At the time, the lab was known as the Morgantown Energy Research Center or MERC. The WV-6 well was drilled at MERC in 1978 and was designated on the state permit as MERC#1. It reached a depth of 2,286 meters (7,500 feet), penetrating through the Marcellus Shale into the top of the Onondaga Limestone (this contact is shown in fig. 11). One of the engineers tending the WV-6 well during the drilling process reported that the measured reservoir pressure in the shale was 24,132 kPa (3,500 psi).

The casing that had been placed in this well was relatively thin-walled with a minimal pressure rating. Due to this weak casing and higher-than-expected regional stress gradients, the casing split vertically during the hydraulic fracturing process. The high pore pressure in the shale caused it to erupt through the split and into the well. This released more gas from the formation, which rushed into the well through the split in the casing. The gas flow was great enough to blow bits of shale up the wellbore all the way to the surface. The collapsed part of the borehole had to be backfilled with cement to stabilize the well, and production in this well came from the Upper Devonian sandstones. The Marcellus Shale was probably the source rock for the gas in these sandstones. The WV-6 well produced gas continuously from 1978 until it was plugged and abandoned in the summer of 2016.

EGSP WV-6 is important to this story because the reservoir pressures and gas flows were the highest reported from a Devonian shale at the time, suggesting that some of these shales might contain significant amounts of gas. Laboratory studies on the core performed a nearly a decade after the well was drilled helped to better quantify the resource based on core analysis measurements and pressure data on this well (Soeder et al., 1986).

Funding for the EGSP formally ended in 1992, but the budget had been at relatively low levels since 1982. Despite a decade of low funding levels, a number of cutting-edge engineering experiments were still conducted on gas shale. An air-drilled, horizontal test well was completed in the Huron Shale in December 1986 (Duda et al., 1991), which was constructed with the intent of intercepting existing fractures and improving the efficiency of natural gas recovery. Innovative logging techniques, directional drilling techniques, assessments of reservoir anisotropy, liquid carbon dioxide fracturing, and other new technologies were tried out on gas shales near the end of the program. These studies greatly assisted the commercial development of shale gas a decade or so later.

The commercial Marcellus Shale gas drilling activity began in 2005. By 2007, many of the old EGSP reports, publications, and data tables were of immense interest to industry as more and more companies became Marcellus gas producers. Several popular publications were in short supply. In 2007, the NETL library assembled just about every relevant document from the DOE unconventional gas program, some of which were literally down to the last existing copy. With support from the NETL Strategic Center for Natural Gas and Oil, the documents were scanned, indexed, and transferred into an electronic database called the 2007 Natural Gas Program Archive. It is available through the NETL library (http://www.netl.doe.gov/library).

4.2 INSTITUTE OF GAS TECHNOLOGY TIGHT GAS RESEARCH

The Institute of Gas Technology (IGT), now known as the Gas Technology Institute or GTI, had a very active research program on unconventional natural gas supplies in the 1980s, when IGT was located on the south side of Chicago on the campus of the Illinois Institute of Technology (IIT) at South 35th and State Streets. IGT had been founded in 1949 as a non-profit research institute for the gas utility companies. At the time, gas utilities were moving away from the use of manufactured or "town" gas, and replacing it with natural gas that was being produced from oil wells. Interstate transmission companies were building long pipelines from production areas on the Gulf Coast to market areas in the Northeast and Midwest. In order to recoup some of the investments in the pipelines and new distribution systems, the gas utility and transmission companies were interested in encouraging the use of more natural gas. IGT was initially founded to conduct gas utilization research, such as developing new consumer appliances and finding additional commercial and industrial applications for natural gas.

Town gas had been in use for many decades as a fuel for cooking and lighting gas lamps before the invention of the electric bulb. It was made by heating coal and water in the absence of air. The reaction produced a gaseous mix of carbon monoxide and hydrogen, which was combustible, and also extremely dangerous. A gas leak inside a home could kill the unwary occupants very quickly from carbon monoxide poisoning. It is hard to imagine these days that people actually had this gas piped into their houses, given what is now known about the dangers of carbon monoxide poisoning from combustion in poorly-vented appliances. Natural gas, on the other hand, is composed mostly of methane, which is not toxic. Natural gas can still kill by asphyxiation if enough is released to drive oxygen from a room, but the greatest danger comes from the explosion hazard at concentrations between 5% and 15% in air.

IGT added a gas supply research program after the first energy crisis in 1973-74. The research included several projects studying gas storage, deep source gas, and gas flow and water movement in low permeability sandstones and coal. The gas supply group was interested in expanding the research program to perform similar investigations on shale and other unconventional fossil energy resources.

In the early 1980s, IGT was working under a subcontract with Sandia National Laboratory to perform porosity and relative permeability analysis on tight sandstone core from the DOE Multiwell Experiment (MWX). This project consisted of a series of wells drilled relatively close together into the Mesaverde Group in the Piceance Basin of western Colorado. The Mesaverde is named from exposures on and near Mesa Verde, in southwestern Colorado, and consists of a thick sequence of Late Cretaceous, littoral to non-marine sandstones, shales and coals. It is primarily located in western Colorado and eastern Utah, although it has also been mapped in Wyoming and New Mexico (Law and Johnson, 1989).

The sandstones in the Mesaverde tend to be “tight” in that they contain about 10% porosity with gas in the pores, and the permeability of the rock is almost as low as that of shale. The DOE study plan was to hydraulically fracture one of the wells, and look for the effects in one or more of the other wells a short distance away. A technique called microseismic monitoring that is widely used these days to map the heights and extent of hydraulic fractures in gas shale was developed by Sandia scientists and engineers as part of the MWX project to try to monitor the growth of the fractures (Warpinski, 2013).

IGT engineers developed a number of unique laboratory devices to accurately determine the properties of these tight rocks that controlled gas production. The measurement of rock properties such as porosity, permeability, pore volume compressibility, capillary entry pressure, pore size distribution, and flowpath aperture is collectively known as core analysis, and is part of the wider field of petrophysics.

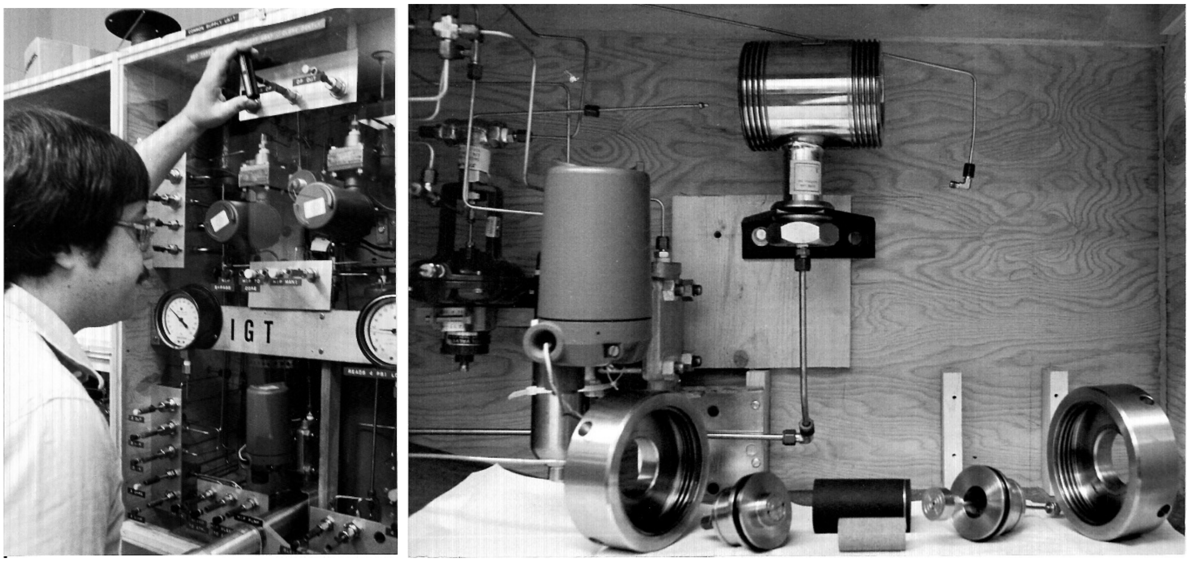
The director of IGT unconventional gas supply research at the time, Dr. Philip L. Randolph, had given a lot of thought to how the measurements might be made under more representative pressure conditions and flows that the rocks might experience at depth, and used the MWX research to develop the new methodology. The key was to maintain stable temperatures inside the apparatus, so gas pressures would not fluctuate due to thermal instability. Under steady temperatures, volume and flow measurements using gas were very accurate. Phil Randolph and several others came up with the designs, and many people spent countless hours in the lab constructing, testing and calibrating the devices.

The slightest leak in a tube fitting or a valve packing could thwart measurements at extremely low flows, and there was a steep learning curve to find the types of valves and fittings that would prove the most leak-tight and work the best. Eventually, the device was perfected to the point where the reference pressure was stable to about one part in a half million, and steady-state gas flows as low as one millionth of a standard cubic centimeter per second could be measured accurately.

A "standard" cubic centimeter of gas is the volume at "standard temperature and pressure" (STP), nominally room temperature and sea-level atmospheric pressure. A sugar cube represents a volume of roughly one cubic centimeter. The apparatus could measure this amount of gas at STP coming out of a rock over a time period of a million seconds, which is more than 11 ½ days.

Some people have questioned whether IGT could actually make steady-state gas flow measurements through shale with this degree of precision, and the answer is yes. The flow measurements were not a misinterpretation of gas moving through the rubber sleeve, or leaking through a valve. These were real gas flows through the rock, which behaved differently at different pressures and liquid saturations.

Gas flow was measured with electronic sensors, and the equipment was controlled by a 1980's version of a desktop computer, which used cassette tapes to transfer programs and record data. The device was named the CORAL, or Computer-Operated Rock Analysis Lab. This is a bit of a misnomer, because it also had strip chart recorders and manual readouts. The capabilities of the apparatus were described in a Society of Petroleum Engineers paper by Randolph (1983). A photograph of the CORAL in operation is shown in fig. 13, along with a disassembled view of a coreholder.



13. Photograph of the Computer Operated Rock Analysis Lab operations at IGT in 1983; view of the components of a coreholder. Photos by Phil Randolph.

4.2.1 Contributions of Phil Randolph

This book is dedicated to Dr. Philip L. Randolph (1931–2010) of IGT, because he is responsible for a significant amount of the content. Originally from Wyoming, Phil had received a PhD in nuclear physics from the University of Washington in 1958, and started work at Lawrence Livermore National Laboratory on various nuclear projects, including a program called Project Plowshare, which was attempting to develop peaceful uses for nuclear explosives. One of the experiments to assess the ability of nuclear devices to excavate soil and rock left an impressive crater at the Nevada Test Site called “Sedan,” approximately 120 meters (400 feet) deep and 400 meters (a quarter-mile) across. The curious can find Sedan Crater on satellite images at 37°10'36.68"N latitude and 116° 2'46.44"W longitude.

Another technology investigated under Plowshare was the potential for nuclear explosives to stimulate or fracture tight gas sandstones. Based on the results of underground nuclear weapons tests in the alluvium and volcanic rocks at the Nevada Test Site, the cavities created by the detonations were thought to be useful as “chimneys” for natural gas production from low permeability formations. Phil Randolph made the leap from nuclear physics to fossil fuels when he was hired by El Paso Natural Gas in Texas, who wanted to get involved with this technology.

The nuclear stimulation of tight gas sands actually worked quite well from a technical standpoint. Mobilization of radioactive gases such as tritium and krypton were a concern (Chew and Randolph, 1974), but Phil Randolph always maintained that there were no insurmountable technical problems with the process. All of the solid radionuclides remained downhole, and gaseous isotopes, such as radon and tritium have relatively short half-lives of a few days. Curious readers seeking more details are directed to the reference above, or to related information in the Project Plowshare bibliography (West and Kelly, 1971).

Project Plowshare and El Paso Natural Gas performed a nuclear stimulation in a tight gas sand in New Mexico in 1967 (Project Gasbuggy), followed by two in Colorado (Projects Rulison in 1969 and Project Rio Blanco in 1973). The fourth detonation was to be Project Wagon Wheel, planned for the Pinedale Field of Wyoming in 1973 or 1974.

By this time, however, the program was coming under strong criticism from local populations and environmentalists concerned about radiation, and there was considerable resistance to the Wagon Wheel design, which called for five stacked nuclear detonations in the Wyoming well (Lederer, 1998). Among the other worries, if the Wagon Wheel test proved to be successful, El Paso intended to stimulate dozens of additional wells in the Pinedale Field using the same technique.

A group of local residents formed the "Wagon Wheel Information Committee," which was strongly opposed to the planned test. They held several citizen information meetings that were contentious affairs with hundreds of people in attendance, some for, some against, and many loud arguments. El Paso spokespeople insisted that all of this was safe, and the public had nothing to worry about. Citizens groups rallied people against the destruction of roads and bridges that would surely result from the nuclear blasts. Local newspapers blamed "out-of-state environmentalists" and "emotional conservationists" for much of the trouble. To anyone involved in the current hydraulic fracturing/shale gas debate, this will sound familiar.

When the Wagon Wheel Environmental Impact Statement (EIS) came out in 1972, it proved to be inadequate. El Paso Natural Gas was required to repeat or expand many of the studies and assessments, which raised questions about their ability to guarantee the safety of a nuclear stimulation (Lederer, 1998). A few weeks later, Congressman Teno Roncalio, who had run in Wyoming on an anti-Wagon Wheel platform, announced that the budget for the Atomic Energy Commission (a precursor agency of DOE) "did not include funds for any Plowshare program test events in fiscal 1974." Wagon Wheel was the only such test event scheduled for 1974 and that was the end of it (Lederer, 1998).

El Paso Natural Gas was now stuck with a deep hole drilled into the tight gas sand formations in the Pinedale field of Wyoming. Because the borehole had been designed to contain a nuclear device, the diameter was quite large, and vast amounts of water could be pumped down it quickly. El Paso decided that in lieu of a nuclear stimulation, they would try a "massive" hydraulic fracturing procedure instead.

In a vertical well, hydraulic fracturing creates a pair of long, vertical fractures into the rock, called "wings." The wings break symmetrically on either side of the wellbore in the direction of maximum principal stress. The vertical fracture wings can extend up to 300 meters (1,000 feet) laterally on either side of the well. Sand is pumped in with the water to act as a proppant, which keeps the fractures open after the pressure is released. El Paso engaged nearly every Halliburton pump truck west of the Mississippi River for the Wagon Wheel massive hydraulic fracture job, which was the largest one ever attempted at the time (fig. 14).

14. Photograph of the massive hydraulic fracture operation on the El Paso Natural Gas Wagon Wheel well near Pinedale, Wyoming in 1974; photo courtesy of Phil Randolph.

Phil Randolph continued to follow developments in tight gas and shale technology after he retired, and was pleased by the success achieved on the Marcellus and other shales that brought fossil energy production up to current levels. Until his death in 2010, he occasionally still supplied ideas for shale gas research and fossil energy investigations to DOE.

4.2.2 IGT core analysis of shale

After the subcontract with Sandia National Lab expired, IGT received funding in 1983 directly from the DOE Morgantown Energy Technology Center to perform additional MWX core analysis. The project was also funded to do more experimental work with the CORAL, including trying to measure two-phase flow of gas and water through tight sandstone cores.

During negotiations over the statement of work, IGT suggested that the CORAL be used to try to run some porosity and permeability measurements on Devonian shale core. The DOE project manager agreed, and supplied a list of "zones of interest" in many of the original EGSP cores. These were selected on the basis of gas production (or gas shows), correlation with gas-productive intervals in nearby wells, successful stimulation results, or indications of high organic content.

The Cliffs Minerals EGSP core processing lab had been shut down in 1982, and the shale cores were boxed up and shipped for storage and safekeeping to the state geological surveys in the state from where they had been drilled. IGT personnel visited a number of state geological survey core libraries and selected samples for the study. Twenty-eight zones of interest were sampled from 13 wells in five states: Ohio, Kentucky, New York, Pennsylvania, and West Virginia. These zones represented ten different stratigraphic horizons within the Middle and Upper Devonian eastern gas shales sequence (Soeder et al., 1986). Although this was far more rock than could ever be analyzed under the time and funding constraints of the contract, too much was better than not enough.

In the end, IGT was only able to run two full loads of shale core in the CORAL. The device had four core holders, so this was a total of eight samples. Six of the samples were the black Huron Member of the Ohio Shale, which was known to be a gas-productive zone in the Big Sandy field of eastern Kentucky and of high interest to DOE. One of the Huron Shale cores in the first batch had cracked inside the coreholder, so core seven was a repeat run of another sample from this same well. Core number eight was a piece of the Marcellus Shale from the

EGSP WV-6 well, which was selected mostly because it was different from the Huron. It was also known to be gas productive based on well reports from the WV-6 frac, including the episode of shale chips being blown clear to the surface.

The CORAL had been upgraded in anticipation of the shale analyses. The upgrades included changing the flow directions of the air circulation system so temperatures of critical components were more stable and returned to equilibrium more quickly. A better data logger was installed to improve the digitizing resolution. The temperature control software was re-programmed to predict when temperatures were nearing a setpoint and reduce power to the heating coils beforehand, instead of overshooting and then having to correct. These changes led to an overall improvement in the performance of the apparatus on all samples. The benefits to core analysis technology that came from the attempts to make meaningful measurements on shale were described in the final IGT report on the project (Randolph and Soeder, 1986).

Rock cylinders were cut horizontally from the EGSP core samples with a water-cooled diamond bit for CORAL analysis. Several attempts were often required to obtain a single, usable plug. Because of the fine, layered structure of the shale, it was thought that trying to flow gas across bedding planes in a vertical direction would be much more difficult that flowing gas parallel to bedding planes in a horizontal direction. The horizontal direction was also thought to be more representative of *in situ* conditions, as gas from pores in the shale matrix flows horizontally into vertical natural fractures. Directional permeabilities were planned to be measured at some point in the future, but the project ended before those could be carried out.

The core plugs cut for testing were 4 cm (1.5 inches) in diameter and 4 cm (1.5 inches) long. Normally, a length to diameter ratio of 2:1 is sought to minimize end effects, and typical core plug sizes for the CORAL were 2.5 cm (1 inch) in diameter by 5 cm (2 inches) long. The larger diameter shale plugs were intended to provide a greater cross-sectional area for the gas to move through more easily. Because the drill core itself was only 9 cm (3.5 inches) in diameter and a cylinder, it was not possible to cut a 4 cm diameter horizontal plug, trim the ends flat, and end up with a usable length of 8 cm. A significant length of the sample plug was trimmed from each end to try to get away from drilling fluids that may have penetrated the rind of the core, and microcracks that may have been created on the core surface by the orientation scribing knives. As such, a 1:1 length to diameter ratio for the CORAL plug was considered acceptable in light of all the other factors that could influence gas permeability.

The samples were dried in a controlled relative humidity oven until they reached a stable weight, at which point equilibrium conditions had been achieved. Harsh drying under high temperatures and/or in a vacuum oven was found to cause clay minerals to dry out and collapse, opening up pores and creating abnormal permeability. Drying the samples at 60 degrees Celsius under 45 percent relative humidity removed all the free pore water, but left a layer of bound water on the clays, helping to preserve them (Soeder, 1986).

Four samples of Huron Shale core went into the first CORAL load in July 1984. The confining pressure was set at 13,445 kPa (1,950 psi), and nitrogen gas inside the rocks was set at a nominal pressure of 1,379 kPa (200 psi), placing the cores under a net confining pressure of 12,066 kPa (1,750 psi). This was thought to be representative of initial reservoir conditions (Soeder et al., 1986).

The net confining pressure is intended to reproduce stress states in the ground for gas flow through the rock. Deep underground, gas pressure in the rock pores helps to offset some of the overburden or weight from the hundreds of meters of rock above the formation pressing down on the pores. As gas is produced from a well, pore pressure drops, but the overburden pressure remains the same. Thus, drawdown of the well increases the “net” overburden pressure or net stress on the rock. Low-permeability formations, which usually have very small, narrow pores and flowpaths, tend to be more strongly affected than conventional reservoirs by this increase in net stress during gas production and reservoir drawdown.

A representative value for initial net stress had been carefully determined. The default estimate used a lithostatic pressure gradient of approximately 22.1 kPa per meter of depth (1 psi per foot) for the overburden pressure, and a hydrostatic pressure gradient of approximately 11.3 kPa per meter (0.5 psi per foot) for the pore pressure. Any data on actual measured reservoir pressures or pressure gradients was used when available.

Gas permeability of the shales was measured at an initial net stress that assumed full hydrostatic pressure in the pores. Net confining pressure was then increased to a value that represented 50 percent drawdown of the reservoir, or the net stress at half the initial pore pressure. Permeability measurements were repeated at the higher net stress value to determine the sensitivity of a rock like shale to drawdown. The excursion to higher net stress was only done once, because of a concern that flowpaths would be crushed and irreversibly changed. The presence of such permeability hysteresis after a stress increase was a well-known property of tight rocks.

A differential pressure gradient of about 35 to 70 kPa (5 to 10 psid - the "d" at the end stands for "differential") across the core had been sufficient to flow measureable amounts of gas through most tight sandstone samples. The shale were assumed to be tighter than tight sand, so the initial differential pressure gradient across the first batch of was set at 140 kPa (20 psid). It seemed to be an appropriate place to start, and the differential pressure could be rapidly adjusted up or down as needed to properly record the flow.

Once pressures and temperatures stabilized inside the CORAL, valves were opened to allow upstream gas at a pressure 1,448 kPa (210 psi) to flow into the rock pores, which were pressurized at 1,310 kPa (190 psi). When the gas flowed out the other end, the pressure increase in the small volume of the downstream line would be measured by the sensitive differential pressure transducer. The rate of pressure build up in the downstream line volume was used to calculate flow and permeability.

Thus, the first steady-state gas permeability measurements on the Huron Shale began, and the result was…nothing! Zip. Nada. No measureable gas at all flowed through the rocks.

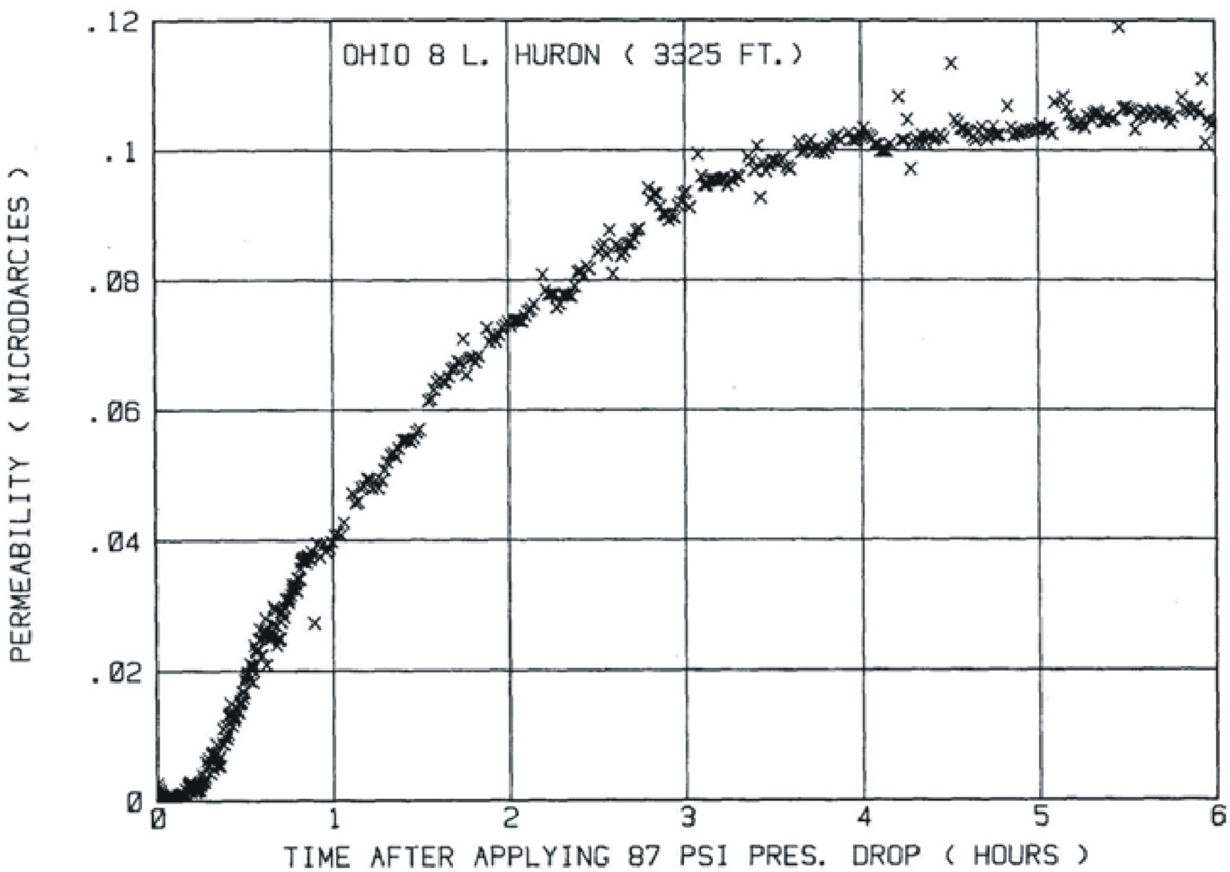
This lack of results was at first incredibly disappointing. The CORAL *should* have been able to measure gas flow through the samples. These were porous rocks in the machine, not steel plugs. They had been dried to stable weights, and the weight loss during drying showed that there was at least some porosity, because the water had evaporated from somewhere. The equipment was operating perfectly: temperatures were uniform, reference pressures were holding steady, nothing was leaking, and all the electronics were working. If any gas had been coming out of the cores, the transducers would have measured it. Therefore, nothing was getting through.

Like the cub reporter who returned from a society wedding with no story because the groom hadn't shown up, something significant was being overlooked. The lack of results turned out to be critically important. The question of *why* the gas wasn't getting through the cores was the key.

With no measurable flow at a differential pressure of 140 kPa (20 psid), the pressure gradient across the cores was increased to 345 kPa (50 psid), with still no flow. It was raised to

483 kPa (70 psid), and then to 600 kPa (87 psid), when the flow transducers on the downstream lines finally began to detect some gas.

The differential pressure across the plugs was held at 600 kPa (87 psid) for an entire day. Gas began to flow, slowly at first and then faster over time until the flow rate leveled out (fig. 15). Previous gas-water flow measurements at IGT on tight sands suggested that the Huron Shale core was behaving as if there was a liquid in the pores. The data appeared to show that a liquid phase was being driven out of the pore system by the gas pressure, and gas permeability was gradually increasing as the flowpaths were drained of liquid.



15. Gas permeability of the EGSP OH-8 Huron Shale core over time after applying a gas pressure drop of 87 psi across it (Soeder et al., 1986).

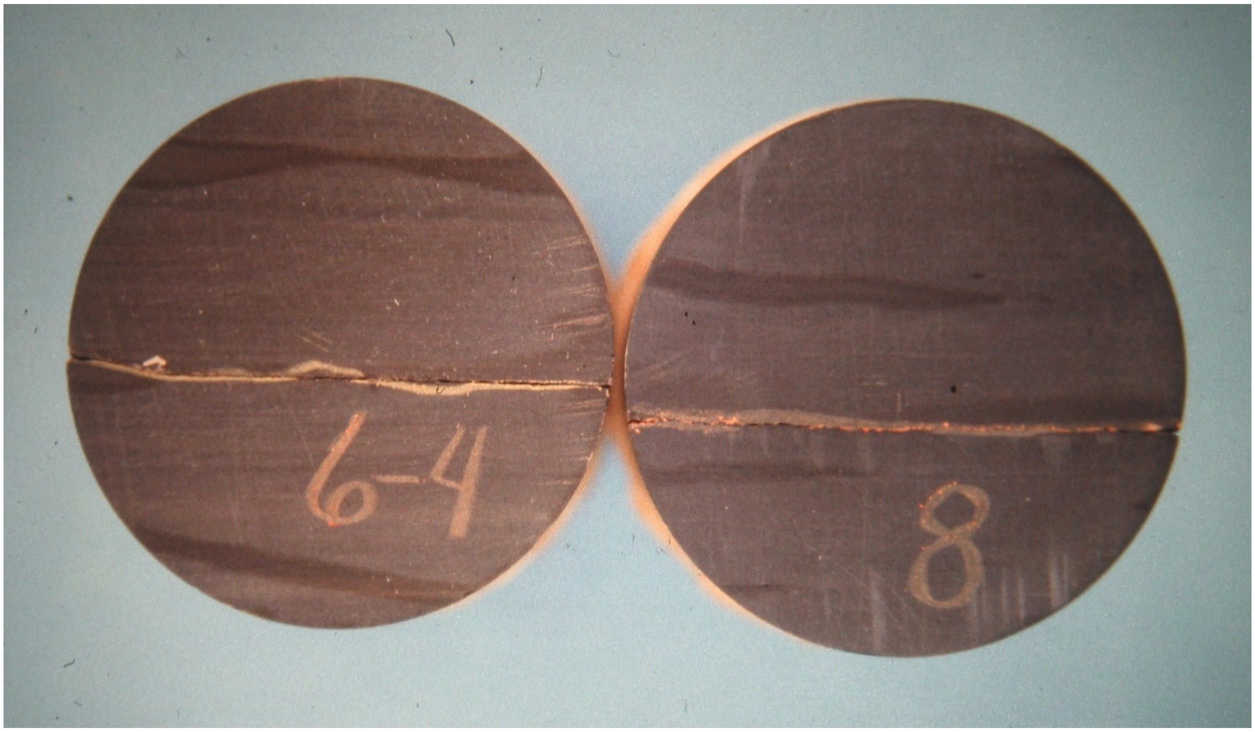
A liquid phase trapped in the Huron Shale pores by capillary pressure could explain the data. Capillary pressures can be very high in tiny shale pores—possibly hundreds to thousands of kPa (tens to hundreds of psi). At low differential pressures, the pore throats remained completely blocked, allowing no gas to flow. When the differential pressure across the core plug finally overcame the capillary entry pressure, gas was able to move into the pores, displace liquid, and flow.

What was the mystery liquid? Dozens of tight sandstone samples had been dried to a stable weight under the same temperature and relative humidity conditions as the shale cores. None of the sandstones ever showed any pore throat blockage or other evidence that liquid water remained in the pores. Yet the Huron Shale cores definitely behaved as if there was a liquid phase in the pores. If the liquid wasn't water, what was it?

It turned out to be oil. When the samples were unloaded at the end of the permeability run, the downstream faces of several plugs displayed streaky, wet layers that smelled like diesel fuel (fig. 16). The IGT analytical chemistry lab was brought in to help. They pulverized a sample of the Huron Shale core, placed the powder in a tagged solvent to dissolve any oil, and then ran the liquid through a gas chromatograph. The chemistry data on this and several other Huron samples revealed that the shale contained a liquid identified as light paraffinic petroleum, typical of Appalachian Basin oils. It is important to note that a similar analysis on the Marcellus Shale sample revealed that there was no oil present in this rock (details of these analyses are presented in Soeder, et al., 1986).

Perhaps the discovery of oil draining from the pores of a gas shale core should not have been a surprise, or even a very big deal. But no one had ever before analyzed gas flow through the shale at this level of detail, and certainly no one expected to see gas-liquid relative permeability curves on shale samples that had been dried in an oven.

A few years earlier, DOE had produced an assessment of the various reservoir stimulation techniques that had been tried on Devonian shale wells during the EGSP (Horton, 1981). Many different types of stimulations had been used, including hydraulic fracturing, explosives, and fracturing with cryogenic liquids, gas, and foam, among others. Some stimulation methods performed well on certain formations in certain locations, and poorly elsewhere, with no apparent pattern. The DOE report concluded that stimulation alone was insufficient to achieve commercial shale gas production (Horton, 1981), and that other factors were involved. With the finding by IGT that oil was present in the pores of at least some shales, the stimulation failures became more understandable.



16. Photograph of dark oily stains on the downstream faces of two Huron Shale plugs from the first CORAL run. Photo by Dan Soeder.

The inability of gas to flow through oil-bearing shale has another important implication for shale gas resources. It has been known for some time that organic-lean gray shales like the Chagrin in the Appalachian Basin can produce significant amounts of gas (Hoover, 1960). The sources of the natural gas and the mechanisms that might trap it in gray shale are not well understood. However, if a gray shale is overlain by a sharp contact with oil-bearing black shale, such as the one shown on the core photo back in fig. 9, the impermeable black shale might act as a caprock to seal gas in the underlying gray shale. As shown in the fig. 3 cross section, the gray shales form upward-dipping wedges into the black shales, which might create a classic stratigraphic trap to contain the gas. A few companies have reportedly drilled and tested the gray shales a few times without success, but perhaps better definition of the stratigraphic trap might be needed to achieve commercial production.

The single Marcellus Shale sample from WV-6 was included in the second CORAL run of shale in August 1984. The 3 Huron Shale samples in this run were confined under the same net pressures as the previous batch, but the Marcellus was from a much greater depth and required higher net confining stress.

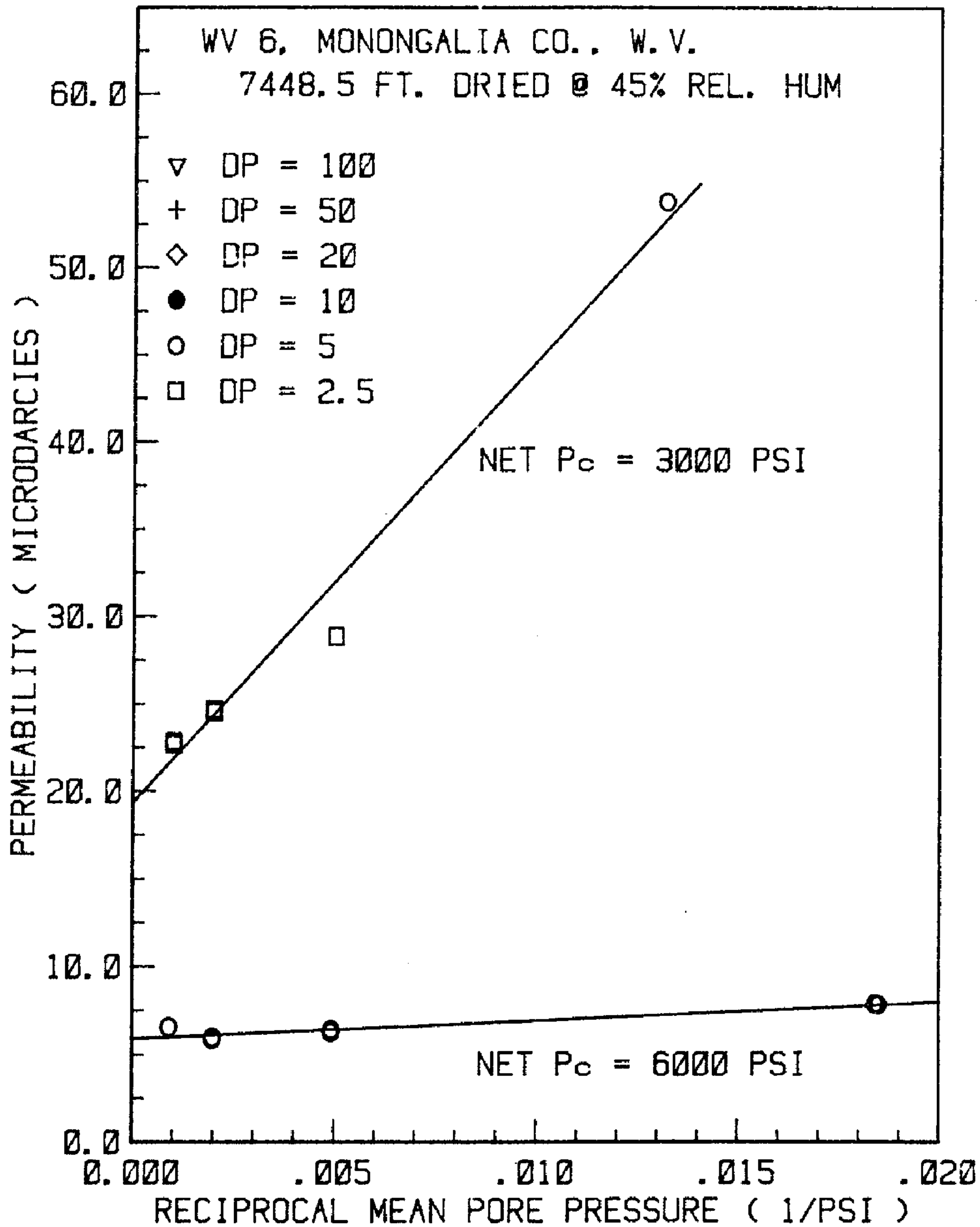
The Marcellus Shale was pressurized at 20,685 kPa (3,000 psi) net confining stress to start, and then taken up to 41,370 kPa (6,000 psi) net stress to simulate drawdown conditions. Gas flowed through this sample with remarkable ease, and excellent data were collected. The gas permeability data for the Marcellus Shale are shown in fig. 17, but a few explanations may be necessary for readers to understand how these are displayed.

4.2.3 IGT core analysis results and discussion

Gas flow through tight rocks is affected by a phenomenon called gas slippage. Simply put, gas is able to flow through small pores more easily at low pressure than at high pressure. The physics behind this has to do with the mean free path of a gas molecule and interactions between the gas and pores on a nanometer scale, but the effect can be visualized as emptying a room. High pressure gas is like a crowded room, where the molecules, like people, bunch up near the narrow exits, creating a backup. Low pressure gas is similar to a room containing just a few people, allowing the molecules (and people) to get through the exits more easily.

The gas slippage phenomenon was described by Klinkenberg (1941), along with the mathematical treatment to account for it, and it is known as the Klinkenberg Effect. The correction for this effect is to calculate the permeability to an ideal gas at infinite pressure, the so-called Klinkenberg correction, and use this value for the comparison of gas flow between different samples. The data are plotted as the inverse or reciprocal of pore pressure (i.e., 1/P, where P = pore pressure), so that the higher pressures are toward the left side of the graph, and infinite pressure is at the vertical or "Y" axis line. The location where the" best fit" line between the data points intercepts the Y axis is the Klinkenberg-corrected gas permeability, sometimes called "K infinity" and written as $K\infty$.

Gas shale in particular has more complex mechanisms for gas movement than the relatively simple gas slippage applied to tight sandstones by Klinkenberg (1941). In additional to directional sensitivity, viscous flow and diffusion both have been identified as important (Zhang et al., 2015). Modeling results suggest that shale gas permeability is strongly dependent on pore pressure and pore throat size. Viscous flow weakens with the decrease in pore pressure, and flow becomes dominated by gas slippage and Knudsen diffusion (Zhang et al., 2015).



17. Klinkenberg permeability to gas in the Marcellus Shale under two net stress conditions (Soeder et al., 1986).

The permeability of porous materials was first described mathematically in the 19th Century by a French engineer named Henry Darcy, who was investigating the movement of water through sand columns. Darcy likened fluid flow through a porous medium as being akin to electrical conductivity, in that some rocks or soils conduct fluids more easily than others, just as some metals conduct electricity more easily than others. In fact, he called the flow of water "hydraulic conductivity," because of its similarity to electrical conductivity.

The mathematical treatment of both electrical conductivity and hydraulic conductivity is similar. Darcy developed an equation that related the permeability of the porous medium to the flow rate of a fluid, the cross-sectional area of flow, the pressure drop, the fluid viscosity, and the flowpath length:

$$\mathbf{Q = kA\ (\Delta P/\mu\ L)}$$

In the equation above, Q is flow, the permeability is k, and the cross-sectional area of flow is A. The Greek letter delta (Δ) denotes a difference or a differential, P is pressure, the Greek letter mu (μ) is used as the symbol for viscosity, and L is the sample length. In the data, L and A (length and area) are set by the dimensions of the core plug sample, μ (viscosity) is a property of the nitrogen gas used as the measuring fluid, ΔP (pressure drop) is controlled by the pressures in the upstream and downstream tanks, and the Q or flow is measured to calculate a value for k.

The basic unit of permeability is called a darcy, defined by and named after Henry Darcy himself. A material with a permeability of one darcy will discharge fluid having a viscosity of one centipoise (approximately the viscosity of water at room temperature) at a rate of one cubic centimeter per second under a pressure gradient of one atmosphere per centimeter of length, through a cross sectional area of one square centimeter. The darcy is actually a fairly large unit, because Henry Darcy was working with water flowing through large columns of loose sand. Most conventional oil and gas reservoirs have permeability ranges around one thousandth of a darcy, or a millidarcy (md). Rocks like tight sandstones have permeabilities down near a millionth of a darcy, or a microdarcy (μd). [The Greek letter mu (μ) used here to represent "micro" should not be confused with the same symbol used earlier for viscosity.] Really tight rocks like shale may have permeabilities as low as a billionth of a darcy, or a nanodarcy (nd).

It is important to note the magnitude of these differences. A millidarcy is 10^{-3} darcy, a microdarcy is 10^{-6} darcy, and a nanodarcy is 10^{-9} darcy. There is a factor of 10^{6}, or a million between nanodarcy gas shale and millidarcy conventional reservoir rock. In practical terms, if a square meter of rock surface area in conventional reservoir produces one cubic meter of gas per second, the same surface area of shale will require a million seconds (roughly 11.5 days) to produce the same cubic meter of gas. This is the essence of the technical challenge to produce economical amounts of gas from shales.

The Standard International (SI) unit for permeability is the square meter, or m^2. One darcy is equal to about 10^{-12} m^2. Applying the SI permeability units to unconventional resources requires working with extremely small numbers: one µd is about 10^{-18} m^2 and one nd is 10^{-21} m^2. Most researchers generally consider the darcy to be a more practical unit, especially when expressed as md, µd, or nd.

So, returning to fig. 17, the Klinkenberg-corrected gas permeabilities in the Marcellus Shale sample from the WV-6 core are indicated in units of microdarcies where the best-fit line intercepts the Y-axis of the chart. Thus, the value for $K\infty$ on this particular core sample was about 19.6 µd at 20,685 kPa (3,000 psi) net confining pressure, and about 6 µd at 41,370 kPa (6,000 psi) net confining pressure.

The finding that doubling the net stress on shale reduces gas permeability by two-thirds has potentially important implications for long-term shale gas production. As gas is withdrawn and pore pressures decrease in the reservoir, the net overburden stress increases, reducing permeability. This is offset somewhat by increased permeability at lower pore pressures due to the greater importance of the Klinkenberg effect. Some modeling results suggest that these two factors may counteract each other during the drawdown of a shale gas well (Kulga et al., 2014). However, it still may become necessary to employ reservoir pressure management techniques on gas shales in the future.

The new Marcellus Shale wells in the Appalachian Basin have not been producing gas for long enough to experience the effects of net stress increases from drawdown. Over the next few decades, they probably will. More core analysis data on a variety of shale lithotypes are needed to better understand the petrophysical behavior of gas shale. Silica shale, clay shale, and calcareous shale can all be expected to behave differently under stress, partial water saturation, and with different gas chemistry. Although the shale gas industry has been doing core analysis, neither the data nor the samples have been made publicly available for independent analysis and interpretation.

Additional information that can be gleaned from fig. 17 includes the slope of the Klinkenberg line, which can be used to calculate the average width or aperture of the flowpaths along which the gas has traveled (Randolph and Soeder, 1986). Narrower flowpaths produce stronger gas slippage, resulting in a more pronounced increase in permeability at lower pore pressures. Thus, the 3,000 psi Net Pc line in the figure has a very steep slope indicating strong gas slippage and a narrow average flowpath aperture. The 6,000 psi Net Pc line, on the other hand, has a flatter slope, indicating weaker gas slippage and a wider average flowpath aperture.

This initially appears backwards, because one would expect the average flowpath widths to be narrower under the higher net confining pressure. The key was to include the flowpath tortuosity calculations, also done from the Klinkenberg slope, which indicated a much higher tortuosity at higher net stress. The combination of lower permeability, higher tortuosity and larger average pore size under high stress suggested that small, inter-connective pores were being squeezed shut by high stress. (Randolph and Soeder, 1986)

Optical microscope observations of coal microfractures containing fluorescent dyed epoxy injected under low and high net stress have showed exactly this: the smallest flowpaths closed down under increased stress while the larger flowpaths remained open (Soeder, 1990). The same phenomenon has not yet been observed directly in shale, largely because of challenges visualizing tiny intra-particle pore connections in this rock (Rodriguez et al., 2014). Nevertheless, a similar closure of small flowpaths in shale is expected to result from increased net stress.

In summary, the data shown in fig. 17, including the slopes and intercepts of the best-fit lines to gas permeability measurements were interpreted as follows:

- The smallest flowpaths in the shale were shut down completely under high stress.
- This resulted in only the larger flowpaths remaining open for gas flow, resulting in a larger *average* flowpath width at higher stress.
- The loss of the smallest flowpaths reduced the number of interconnections within the pore network, resulting in higher flowpath tortuosity and lower permeability.

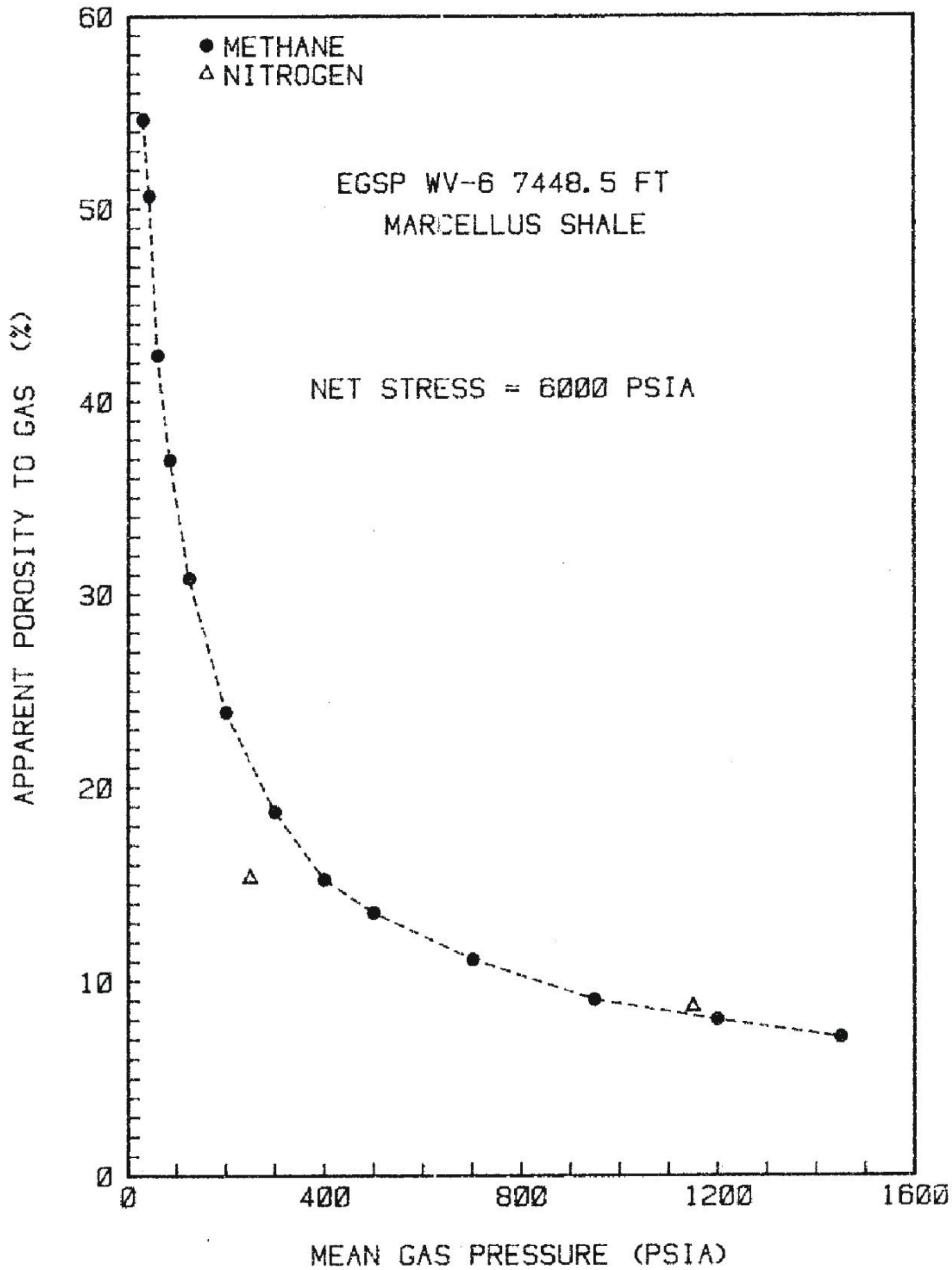
One of the other useful features of the CORAL was that it could measure the pore volume of a core sample under representative net confining stress. Pore volumes were measured using a technique known as Boyle’s Law, which defined the inverse proportion relationship between gas pressure and volume back in 1662. In other words, if the volume of a vessel is reduced by half, the pressure of the gas inside it is doubled. The CORAL used a calibrated, positive displacement pump to measure volume, and a very sensitive differential pressure transducer as a gas pressure sensor.

Porosity measurements were made by stabilizing gas pressure inside the core, while a somewhat higher pressure was stabilized in the system's reservoir vessels and flow lines. A valve was closed to lock this pressure into one side of the porosity differential pressure transducer. A valve to the test core was then opened, and the pressure on the other side of the transducer fell as gas from the lines expanded into this additional volume and entered the core.

The porosity could have been calculated directly by measuring the value of this pressure drop, but the accuracy would not have been as precise. Instead, the handle of the positive displacement pump was turned, slowly moving the displacement piston inward. Each revolution was calibrated to displace a small amount of volume as the piston traveled a fixed distance per turn up the cylinder. Turns of the handle were carefully counted until the displaced volume brought the gas pressure back into balance on both sides of the differential pressure transducer. The gas volume displaced by the pump (converted to standard temperature and pressure) was equal to the volume of the rock pores plus the gas lines downstream of the valve that was opened to the test core.

The gas line volumes had been measured previously using the same method but substituting a non-porous steel plug for the rock in the coreholder. The line volume was subtracted from the total volume measured, and the remainder as the pore volume of the rock. Porosity (usually abbreviated as the Greek letter φ) was calculated by dividing the bulk volume of the rock, measured with calipers on the core plug before loading, by the pore volume, and reported as a percent. This simple and elegant method became a powerful tool for determining the behavior of gas in the pores of shale.

Marcellus Shale porosity measurements on the WV-6 core are shown in fig. 18. This figure contains results from a number of different measurements that require explanation. The initial porosity measurements were done on the same sample of Marcellus Shale core using nitrogen gas at two different pressures as a cross-check. The pore volume from both measurements should have been identical, because Boyle's Law states that there is pressure-volume equivalence for any gas at any pressure. However, the two triangles on the figure show that a higher apparent pore volume was measured with nitrogen gas at the lower pressure.



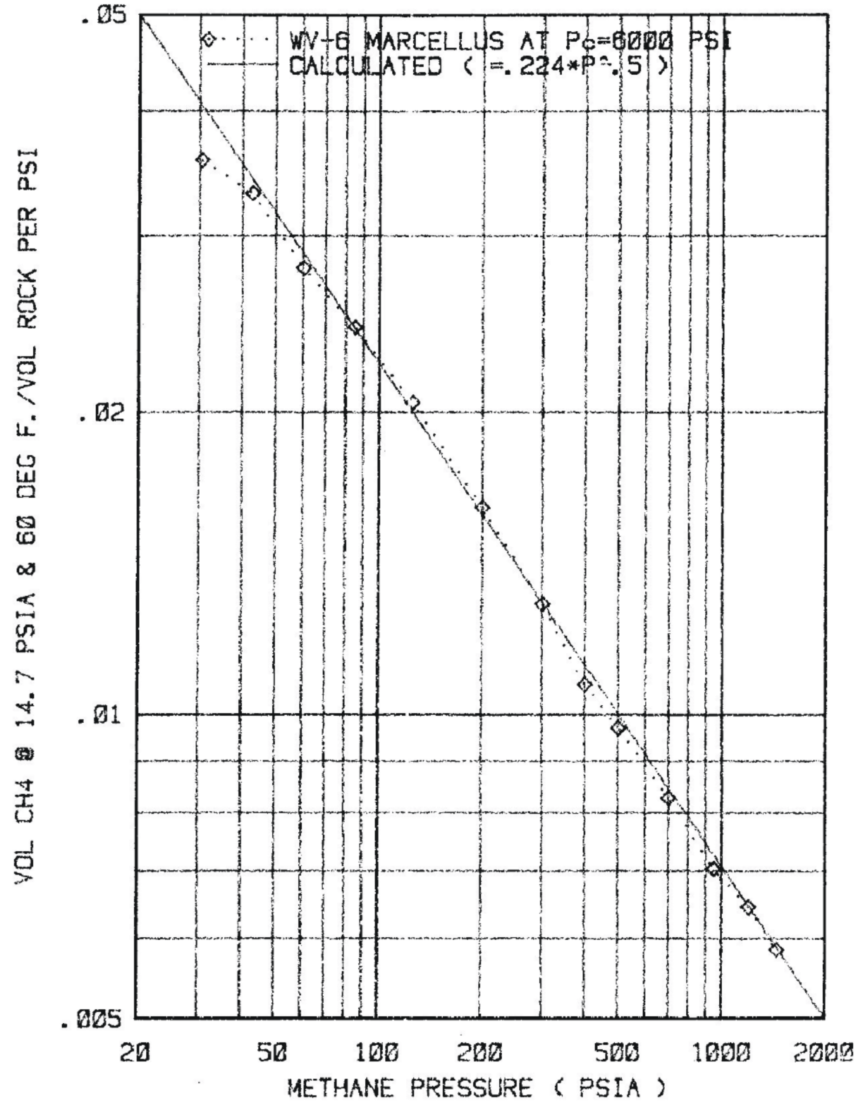
18. Pore volume of the Marcellus Shale reported as apparent porosity measured with nitrogen and methane at various gas pressures under 6,000 psi net confining stress (Soeder et al., 1986).

This is a sign that a phenomenon called gas adsorption is taking place. Adsorption occurs when gas molecules attach themselves to electrostatic surfaces inside the pores and pack tightly together at greatly increased density, allowing significant additional gas to fit into the pores. Adsorption of gas is a common occurrence in coal, which is composed almost totally of carbon, and some clay minerals also have adsorptive properties, so finding it in a black shale is not surprising. The difference between the two Boyle's Law porosity measurements on the Marcellus sample at different pressures is due to the effect of adsorbed gas. Because the adsorbed gas is held at a higher density, the contrast between adsorbed gas and free gas in the pores is less at high pressure, so the phenomenon is more pronounced at lower pressures.

These results prompted another gas porosity run on the WV-6 Marcellus Shale core using methane, the main component of natural gas. Methane is more chemically active and adsorptive than nitrogen, and the porosity was measured across a suite of gradually increasing pressures. The resulting data in fig. 18 follow a mathematical curve, tailing off as pressures increase.

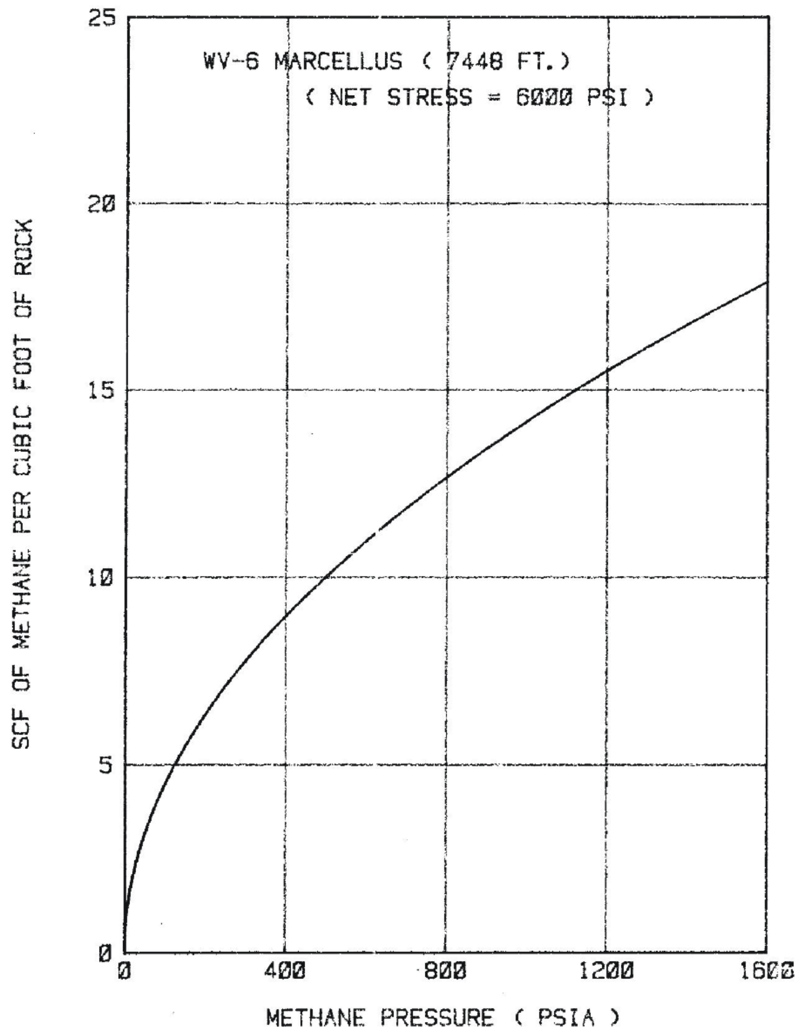
Plotting these data points on a log-log scale, as shown in fig. 19, gives a remarkably close fit between the data and the slope of a line. The mathematical function that describes the line shows that the amount of methane able to fit into the rock is equal to 0.224 times the square root of the pressure. This is called an adsorption isotherm and defines a pressure-dependent adsorption function at a particular temperature (room temperature in this case). Isotherms will have different slopes in other rocks, at other temperatures, and with other gases.

Adsorption sites in the Marcellus Shale might include clay minerals along with organic carbon. Nanoporous carbon has been observed in gas shales using a scanning electron microscope (Loucks et al., 2011). Laboratory experiments with carbon dioxide adsorption in organic-lean shales (Busch et al., 2008, 2009) suggest that clay minerals, especially swelling clay in shale may play an important role in gas adsorption, and may actually be more active than organic carbon materials for adsorbing gas. Analyses on a variety of shale types with different clay and carbon content may help to better define the phenomenon and clearly link certain minerals in the rock to adsorption.



19. Data from figure 18 shown on a log-log plot with a best-fit line (Soeder et al., 1986).

Data from the fig. 19 square root function were plotted on a linear graph to show the relation between methane content of the rock and gas pressure. Fig. 20 illustrates the unit volume of gas at STP per unit volume of rock as a function of pressure, based on the measurements shown in fig. 18. The curved line is due to adsorption; if this was strictly a pressure-volume relationship, the line would be ruler straight.



20. Natural gas potential in the Marcellus Shale from the methane data measured in figure 18 (Soeder et al., 1986).

When the curve is extended out to the value of 24,132 kPa (3,500 psi) reported for the measured, shut-in, initial gas pressure of the Marcellus Shale in the EGSP WV-6 well, this calculation shows a gas-in-place value for the Marcellus Shale of about 26.5 cubic meters of gas per cubic meter of rock (or 26.5 standard cubic feet (scf) of gas per cubic foot (ft^3) of rock—it is a "volume per volume" equivalence).

This is an important bit of data, because in 1980 the National Petroleum Council (NPC) had assessed the gas potential of Appalachian Basin shales at just 0.1 to 0.6 scf/ft^3 (National Petroleum Council, 1980). The value IGT measured on the Marcellus Shale core was an astounding 44 to 265 times greater than the NPC estimate. No one had ever reported this much gas in a black shale.

The results were published in a DOE report (Soeder et al., 1986) and a peer-reviewed paper in a (now discontinued) technical journal of the Society of Petroleum Engineers called SPE Formation Evaluation (Soeder, 1988). Because the engineering technology for reliably extracting economical quantities of natural gas from shale did not yet exist, there was little excitement about these findings at the time. Indeed, they were barely noticed. Developments in shale gas made great strides in 25 years, and the SPE article has now received dozens of citations in many other papers.

The DOE report and SPE paper contain a few findings of note, including a confirmation of the dual-porosity nature of shale. CORAL data showed that fractures account for less than 1 percent of the pore volume in a shale; the remaining 99+ percent is contained in the matrix. Yet the matrix is so impermeable that fractures are critical flowpaths for gas to move. Phil Randolph produced some calculations on the fracture width and spacing needed to produce reasonable permeabilities in shale, and found that fractures with apertures of only a few microns at a spacing of a few centimeters could provide significant flowpaths for gas to move through shale (Soeder, 1988, Table 3).

4.2.4 Advances in shale core analysis technology

A web search reveals that not many papers on the petrophysical behavior of gas shales have been published since the late 1980s. There were a few retrospective or summary publications between 1990 and 2005, but very little else until the current round of shale gas production got started. A notable paper from this time interval was a review of shale gas production by Curtis (2002), who concluded that shale gas reservoirs are complex systems with many different factors that influence the ability of the rock to produce commercial amounts of gas. Defining and sorting out these factors has been and remains a challenge.

Core analysis on the Marcellus Shale and other shale gas resources since 2008 has been largely restricted to a consortium of exploration and production companies that contribute money and samples for analysis to a commercial lab. The data produced by the lab are shared equally among the consortium members, but no one outside the consortium has access to any of the results. The member companies are bound by the consortium agreement not to release the data. These consortia have been set up on the Marcellus, Utica, Bakken and many other shale plays.

Non-industry scientists interested in the Marcellus Shale have been limited mostly to outcrop samples around the perimeter of the basin, or to sand-sized chips of drill cuttings from wells. Much can be done with drill cuttings in terms of geology and geochemistry, but it can be like trying to do forestry with sawdust. Drill core samples have generally not been made available to non-industry researchers except in very limited circumstances, and then often with non-disclosure agreements or other restrictions in place. Non-industry researchers plead for access to core at almost every scientific meeting.

When samples are available, researchers have applied new technology to shale pore structure and petrophysical studies. The development of nanotechnology has brought about the parallel development of advanced imaging systems. Ultra-high resolution CT scanners, neutron imaging systems, atomic force microscopes, advanced electron microscopes, and other technologies allow researchers to view and characterize shale pore structures at the nanometer scale (for a survey of applications, see Camp et al., 2013; and Rodriguez et al., 2014). Comparable developments in computer technology have enabled image analysis, image processing, and 3-D reconstruction on even small workstations. Scientists are making great strides toward understanding how fluids move through these rocks, including the behavior of gas and liquid phases in nanopores, and the nature of adsorbed gas.

Modern commercial core analysis of shale typically uses a technique known as the GRI Method. This measurement, developed at Stanford University in the 1980s with support from the Gas Research Institute (hence, the name) uses the decay rate of a pressure pulse to quickly determine the permeability of tight rocks (Walls et al., 1982). The method as originally developed was shown to provide reasonable results compared to traditional, steady-state permeability measurements on dry samples, but it has issues under partial fluid saturations (Soeder and Randolph, 1986). Modifications to the GRI technique, including the use of crushed samples instead of whole core plugs to speed up the measurements even further have led to more questions about the comparability and usefulness of the data (Civan and Devegowda, 2015).

The CORAL steady-state permeability method developed by Phil Randolph is much slower, but for research-quality data on shale cores it makes measurements under conditions that are more representative of the reservoir (Soeder and Randolph, 1986). The IGT apparatus was designed to impose a net confining stress equivalent to reservoir conditions, move gas through the rock under realistic flow gradients, and measure pore volumes available to gas at representative net overburden stresses. This is important, because shale gas permeability is sensitive to increases in net stress imposed during drawdown. For certain 21st Century applications, such as carbon dioxide storage in depleted gas shales (discussed in section 6.3), understanding this response is critical.

4.3 THE DEMISE OF UNCONVENTIONAL GAS RESEARCH PROGRAMS

Most of the DOE-funded gas shale programs ended during the Reagan Administration, when market-driven, industrial research was favored over government-funded studies. By the mid-1980s, many DOE fossil energy programs were winding down. Unconventional oil and natural gas research programs were hit hard, especially when compared to coal gasification and synthetic fuels research programs. Those programs had momentum from large investments in equipment and process technology, which made it harder to justify an abrupt shutdown.

The last major eastern gas shale project funded by DOE was completed in December 1986, with an experimental, 2,000-foot-long, air-drilled horizontal test well into the Huron Shale in West Virginia (Duda et al., 1991). At about this same time, DOE completed a hydraulic fracture test in the tight gas sand Multiwell Experiment in Colorado, followed by drilling a slanted borehole across it to intercept the fracture in a core. Some tight gas sand work in Texas supported by the Gas Research Institute continued into the 1990s (Soeder and Chowdiah, 1990), but this soon ended as well.

The Gas Research Institute, or GRI, was created in the late 1970s by officials at IGT who were seeking a stable way to fund natural gas research that did not depend upon government contracts or grants from private industry. The plan that eventually moved forward was for the Federal Energy Regulatory Commission (FERC) to levy a small tariff on gas being transmitted through interstate pipelines, and use the funds to support research on natural gas supply and utilization. FERC agreed to levy the tariff, but refused to simply hand the money over to IGT without some kind of oversight; requiring that a new entity be formed to distribute this funding in an equitable and competitive manner. Thus, GRI was created as a nonprofit, non-government organization (NGO) to competitively award and manage research projects for the benefit of the pipeline ratepayers.

The first president of GRI was Henry Linden, previously the president of IGT. Many IGT board members also sat on the GRI board. Many IGT member companies were also members of GRI. The GRI office was located in northwestern Chicago near O'Hare Airport, while IGT was on the south side of Chicago at the Illinois Institute of Technology. The existence of two non-profit institutes in the same town with similar names that had something to do with gas research was endlessly confusing.

The pipeline companies chafed under the gas research tariff, which many felt was unfair. When natural gas transmission was de-regulated in the 1990s, the tariff disappeared, and GRI found itself without a source of funding. It re-integrated with IGT, and the combined entity became the Gas Technology Institute, or GTI. By this time, IGT had moved from the campus of the Illinois Institute of Technology to a suburban location in Des Plaines, northwest of Chicago. The new GTI set up shop there, and continues to this day.

Oil imports into the United States continued to increase in the 1980s because the cost of oil production in many of the countries exporting petroleum to the United States were far lower than any domestic suppliers could hope to match. Many of the major oil exporting countries started relatively late as producers, benefitting from advances in oilfield technology and engineering.

Petroleum resources in Saudi Arabia, for example, were not significantly developed until the 1950s. By that time engineers had learned how to use gas drive to produce oil reservoirs, which eliminated the need for pump jacks, electricity, and associated infrastructure. The pressure of natural gas in a cap above the oil reservoir was retained, and used to drive the oil downward into a perforated section of well casing, essentially making the well free-flowing. The gas cap expands into pores that the oil previously occupied, maintaining the pressure and flow. When hooked up to a pipeline, the production of oil from these wells requires no more effort than opening a valve. Rumor had it in the mid-1980s that the Saudis could tolerate crude oil prices as low as $2 a barrel and still make a profit.

This was demonstrated in 1986 by the Great Oil Bust (Koepp, 1986). Oil prices controlled by the OPEC cartel had reached a record high of nearly $35 a barrel by the early 1980s. Many marginal oil fields in the United States and elsewhere were profitable at these prices. U.S. oil companies were hiring geologists and sending engineers out to develop new prospects. Many university geology faculty were leaving tenured professorships to take high paying jobs with oil companies. OPEC nations were supposed to keep oil exports within quotas set by the cartel, so the market wouldn't overload and prices would stay propped up at levels where everyone could make money. However, the actions of some OPEC members were becoming increasingly unpredictable.

Iran and Iraq went to war in the early 1980s. Each country started cheating on their OPEC quotas to raise a little extra cash for the war effort. The amounts were trivial at first, but as both sides grew more desperate, the volumes rose. Other member countries observed this and started cheating on their quotas as well. In addition, oil-producing countries outside of OPEC, such as Mexico, Great Britain, and Norway, were contributing a larger share to the global pool of oil production, and the cartel was losing control of supply.

Because of all the extra oil the cheaters were dumping on the market, Saudi Arabia was forced repeatedly to cut back production to maintain prices. Despite these efforts, between 1981 and 1986, the cost of oil gradually declined from about $35 to $26 per barrel. Warnings were sent to the cheaters, which were ignored. Finally, Saudi Arabia had enough and opened up the floodgates of oil production. A monstrous slug of oil hit the world market in April 1986 (Koepp, 1986). Almost overnight, the price of a barrel of crude oil fell from $26 to less than $10. All of the favorable prospects from marginal oilfields around the world that looked attractive at $35 a barrel and still possible at $26 were complete losers at $10.

Oil companies big and small immediately cut their exploration and production (E&P) staffs, which included firing most of the geologists and engineers. Whole cities with an oil-based economy like Houston suddenly had no oil jobs anywhere. People who worked as drillers and roughnecks on the rigs were also hurt, because with such low import prices almost no domestic wells were being drilled. It wasn't an overall recession; in fact, the fall in oil prices gave the national economy a significant boost. The bust only involved energy exploration and production jobs, which did not affect most Americans. Unemployment rates in Texas and Louisiana, however, reached as high as 13 percent (Koepp, 1986).

The oil glut essentially ended any remaining unconventional oil and gas research in the United States. When expensive imported oil became cheap imported oil, Americans' memories of the oil embargo from a decade earlier faded. Cheap oil convinced automobile manufacturers that Americans were no longer interested in small, flimsy, fuel-efficient cars, and that people wanted more substantial vehicles. The popularity of SUVs, pickup trucks, and minivans increased greatly among suburbanites in the 1990s, and automakers wasted no time in getting new vehicles on the market.

By the late 1980s, the DOE budget had been essentially zeroed out for research on natural gas supply, except to finish up a few ongoing projects. Priorities were changing at GRI as well, as it moved away from gas supply research and focused more on gas utilization technologies. Funding officially ended for the unconventional gas programs on eastern gas shale, western tight sand, and coalbed methane at the end of fiscal year 1992.

Many of the low-permeability flow measurement techniques and pore structure investigations developed at IGT for tight sands and shale found a new application in the 1990s for measuring water movement through the dense volcanic rocks at the proposed Yucca Mountain nuclear waste repository site in Nevada. Some of the USGS geology and hydrology investigations on the long-term storage of high level radioactive waste incorporated IGT-developed technology.

At this writing, the shale gas and oil boom that began in the mid-2000s also appears to have run its course. From a high of above $100 a barrel in mid-2014, crude oil prices had declined to below $40 a barrel by late 2015 (http://www.eia.gov/). Shale gas production helped create low prices for domestic natural gas by 2012, and many companies changed focus to liquids-rich shale plays like the Utica, Eagle Ford and Bakken. Unlike gas, oil is a global commodity, and before long there was an international oil oversupply. A slight faltering of the Chinese economy drove prices downward.

The response by industry has been to suspend drilling operations and lay-off employees, suggesting that 2015 may be a repeat of 1986. However, the wholesale shutdown of entire E&P departments seen in 1986 has not yet happened, and some people are even still receiving job offers. Limited drilling continues at reduced levels on specific prospects. Hopefully, one of the lessons learned from 1986 is that it is very difficult to rebuild E&P capability during the next boom when no one is left at the oil company who knows how to find oil and gas.

5. PRODUCTION OF MARCELLUS SHALE GAS

The modern Marcellus Shale gas play began in 2005. Although the use of the word "play" to describe a resource may sound frivolous, in oil and gas exploration, play is a legitimate term defined as a group of drilling prospects with a geologically similar source, reservoir and trap, which control gas migration, accumulation, and storage (Patchen, 1996). In more practical terms, a play means finding out where other people are drilling successfully for gas or oil and drilling as close to that place as possible. Thus, a successful oil or gas well in one location brings in many others.

The 21st Century boom in shale gas drilling did not simply come about as a bolt from the blue. There were several decades of history leading up to it that included the development of new drilling technology, new methods for hydraulic fracturing, and a certain degree of persistence by a fellow in Texas named George P. Mitchell, who was determined to produce commercial amounts of gas from an organic-rich black shale in the Fort Worth Basin.

Innovation by industry and favorable economics moved shale gas development forward, although a certain degree of credit should still be given to government research programs like the Eastern Gas Shales Project and the Multiwell Experiment. Without the data from government-funded research, it would have been much harder for the operators to know that the unconventional resources were there and available for production. The public-domain reports and documents from this research were often the first places the drilling companies went for information on the shales.

Government scientific agencies exist to provide the types of data needed for policy decisions that industry does not normally collect. For example, the U.S. Geological Survey was created in 1879 as the first government science agency because the U.S. Congress needed information about mineral resources in western lands made newly accessible by the expanding railroads. The railroads could not be counted on to supply this information in an unbiased manner, because they faced the potential taxation of any resources. Early USGS mineral assessments demonstrated to legislators the importance of obtaining accurate scientific data for the government to make sound decisions. Other data agencies like the National Weather Service, NOAA, the National Institutes of Health, NASA and DOE provide similar information.

Thirty years ago, shale gas was considered a marginal resource that could not physically be produced in large quantities, and even if it could, the economics would be awful. The drilling industry wouldn't go near it, except in very limited areas or as a secondary target. Yet the government persisted in collecting research data on the shales, completing a resource assessment and characterizing the rock properties. Even though no one knew how to produce the resource at the time, it represented such an enormous potential reserve of energy that it was important to collect the information for future use. These data are what turned out to be so useful when the modern shale play started. Solar power satellites, geothermal power, ocean energy, fusion power, and several other potential future energy resources are in a similar position today.

Natural gas production from U.S. wells is traditionally measured in increments of a thousand cubic feet, abbreviated MCF. The "M" in the abbreviation comes from the Roman numeral for 1,000. The metric equivalent of this volume is 28.32 cubic meters. At room temperature and atmospheric pressure, an MCF of gas would fill a space 10 feet high, 10 feet wide, and 10 feet deep, about the size of a small bedroom. A million cubic feet is a "thousand-thousand," so this is abbreviated MMCF using two Ms. Daily production amounts have a "D" on the end, such as MCFD or MMCFD.

Larger quantities of gas, such as the reserves remaining in the ground that have not yet been produced, are abbreviated differently: a billion cubic feet is BCF, and a trillion cubic feet is TCF. According to the Energy Information Administration (EIA), approximately 26.7 TCF of gas was used in the United States in 2014 (https://www.eia.gov/tools/faqs/faq.cfm?id=50&t=8). Some estimates for the total amount of recoverable gas in the Marcellus are as high as 500 TCF (Engelder, 2009), meaning that at current usage rates, the Marcellus Shale alone might be able to supply the entire United States with natural gas for nearly two decades.

5.1 BACKGROUND

Back in the 1950s, George P. Mitchell (1919-2013) was working as a consulting geologist on oil and natural gas prospects and trying to get a drilling company started with his brother and a few other partners. The fledgling company that would later become Mitchell Energy got their big break in north Texas, hitting gas and oil in more than 30 separate fields that the Mitchell brothers had acquired on a supposedly worthless lease. By the mid-1960s, Mitchell

Energy had become the nation's top independent gas producer. They merged with Devon Corporation in January 2002.

George Mitchell had been interested in the gas potential of the Barnett Shale since 1981. The Barnett is a black shale similar to the Marcellus that occurs in the Fort Worth Basin of Texas. The formation is named for a "typical exposure" of the unit at Barnett Springs, about 6.5 km (4 miles) east of the town of San Saba, Texas (Plummer and Moore, 1922). The Barnett Shale was assigned a probable Late Mississippian age (326-318 Ma) by Sellards (1932).

Like the Marcellus and other black shales, it was difficult to obtain economical amounts of gas from vertical wells in the Barnett. Mitchell Energy tried several different drilling techniques and reservoir stimulation methods over a period of about 18 years. These included massive hydraulic fracture stimulations like the one El Paso had done at Wagon Wheel in Wyoming, which did produce significant flows of gas but at very high cost. Still, George Mitchell believed in the potential of the Barnett Shale, and continued to apply innovative technology to produce the gas.

Mitchell Energy had participated in the DOE Eastern Gas Shales Project under a cost-sharing agreement in 1978 to drill and core a number of shale wells in Ohio. In December 1986, DOE completed an experimental horizontal test well into the Huron Shale in West Virginia (Duda et al., 1991). This was the first horizontal shale well drilled with air instead of mud, and it was 610 meters (2,000 feet) long. The well was drilled in a direction perpendicular to the primary natural fractures with the intent of intercepting existing fractures and improving the efficiency of natural gas recovery. Mitchell Energy began experimenting with horizontal wells in the Barnett Shale soon afterward.

By 1997, Mitchell had perfected the more cost-effective "light sand" frac technique in vertical shale wells and started trying it in horizontal wells. The horizontal wells produced considerably more gas than vertical boreholes, because a horizontal well is able to contact much more of the shale rock volume. The runs of production tubing in horizontal wells were significantly longer than in vertical wells, however, and in order to reduce downhole friction losses, a surfactant such as polyacrylamide was needed in the frac fluid to lubricate it, or make it "slick."

Thus, horizontal drilling and the staged, light sand slickwater frac became standard techniques for successfully producing commercial amounts of gas from shale in the early 21st

Century. (More details on the technology later.) A Barnett Shale gas drilling boom began in the Dallas-Fort Worth area in the late 1990s, including quite a few wells within the city limits of Fort Worth itself (Montgomery et al., 2005; Martineau, 2007).

George P. Mitchell received a Lifetime Achievement Award in Amsterdam on June 16, 2010 from the Gas Technology Institute for pioneering the hydraulic fracturing and drilling technologies that created the shale gas revolution. He died on July 26, 2013 at the age of 94.

In the summer of 2004, Southwestern Energy announced that the Fayetteville Shale in Arkansas had many of the same characteristics that made the Barnett Shale gas productive, which set off another gas drilling boom. Oil and gas producers familiar with the Barnett Shale rushed to northern Arkansas to get in on the action. Similar drilling booms followed on the Haynesville Shale in the Arkansas-Louisiana-Texas border region known as the ArkLaTex, and the Marcellus Shale in Pennsylvania and West Virginia.

Range Resources began the modern, high-volume Marcellus Shale gas production in the southwestern corner of Pennsylvania, and they remain a major producer in the area. In 2005, Range was drilling a well called Rentz#1 in Washington County, Pennsylvania, to test oil and gas prospects in the Lockport Dolomite, a Silurian-age (444-416 Ma) carbonate rock in the Appalachian Basin. It is older than the Marcellus Shale and located at greater depths.

The Lockport was originally deposited as a calcite-rich limestone, which was altered into a different rock called dolomite (named after the Italian mountains where it is common) by magnesium-enriched groundwater. The alteration process causes the calcite to recrystallize into a magnesium-calcium carbonate mineral also called dolomite (sometimes the rock is referred to as “dolostone” to distinguish it from the mineral). The mineral dolomite usually forms larger crystals than calcite, giving a sugary texture to the formerly fine-grained limestone, and the process often creates open porosity that may contain oil and gas.

The presence of hydrocarbons in the pores is not guaranteed, however. A mantra of petroleum geologists is that despite all the expertise in geology, geochemistry, and high-tech geophysics directed at oil and gas exploration, they never really know what’s down there until they get down there. And the only way to get down there is to drill.

The Rentz well came back with low porosity and poor gas shows from the target formation. Bill Zagorski, the Range Resources geologist in charge of the well, was left wondering what to do with this non-productive, dry hole. Zagorski had graduated with a degree in geology from the University of Pittsburgh and spent 30 years in the gas industry, so this wasn't his first gas well (Campbell, 2010).

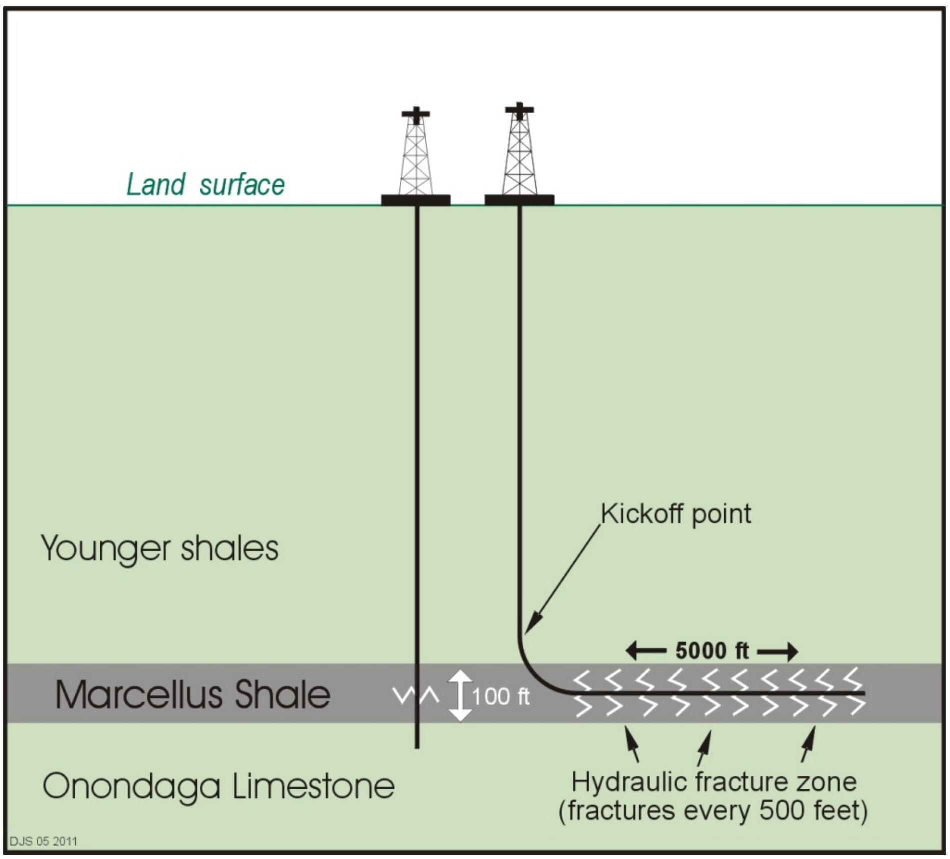
Zagorski found himself in Houston a few months later, trying to sell an interest in developing a shale gas prospect in Alabama using Mitchell Energy's production technology, when he realized that he had seen evidence of gas in a section of the Marcellus Shale penetrated by the Rentz well above the Lockport Dolomite (Durham, 2010). He researched what was known about gas resources in the Marcellus, which included reviewing many of the old DOE technical papers and EGSP reports, and got the go-ahead to try to re-complete the Rentz well in the Marcellus Shale.

Range Resources re-completed and hydraulically fractured the vertical Rentz#1 well in the Marcellus Shale, and got a significant return of initial gas production. Thus encouraged, they drilled the first few horizontal Marcellus wells in 2006 with mixed results, but after some trial and error, Range eventually found a modification to the Barnett frac formula used by Mitchell Energy that was effective on the Marcellus. The first successful horizontal Marcellus well, Gulla#9, came online in 2007, returning an initial gas production rate of nearly 140,000 cubic meters, or 4.9 million cubic feet of gas per day, which is quite exceptional for any gas well, and until then practically unheard of for gas shale. Zagorski considers Gulla#9 to be the discovery well for the Marcellus Shale, and the one that started the play.

Bill Zagorski received the Norman H. Foster Outstanding Explorer Award and was named "explorer of the year" by the American Association of Petroleum Geologists (AAPG) at their 2013 national meeting in Pittsburgh for his discoveries in the Marcellus Shale (Brown, 2013). Equally telling was the fact that AAPG held their first-ever annual meeting in Pittsburgh (and the first one east of the Mississippi since 1986) almost entirely because of Zagorski's development of the Marcellus Shale and everything that followed.

5.2 DRILLING

George Mitchell had discovered that one key to producing economical quantities of shale gas was the ability to drill horizontally or "laterally" through the rock, which contacts much more formation volume than drilling vertically. The common black shale thickness of only a few dozen meters (a few hundred feet) limits the amount of contact a single vertical well can have with the formation. Drilling horizontally, however, allows the wellbore to remain within the shale for long distances, penetrating hundreds of meters or thousands of feet of rock. The drilling is coupled with hydraulic fracturing to create high permeability flowpaths into the shale. Instead of the single hydraulic fracs done in vertical wells, the long horizontal boreholes allow for an entire series of hydraulic fractures to be spaced a few dozen meters (a few hundred feet) apart. There can be ten or more of these hydraulic fracture “stages” in a horizontal borehole, resulting in large volumes of gas production. A schematic diagram comparing the layout and configuration of a vertical borehole with a single hydraulic fracture and a horizontal borehole with multiple hydraulic fractures is shown in fig. 21. Drilling costs for a horizontal Marcellus well are approximately 2–3 times higher than for a vertical well, but the initial gas production potential can be 3–4 times greater (Engelder and Lash, 2008).



21. Illustration of the combination of horizontal drilling and hydraulic fracturing technology used for gas production from the Marcellus Shale in the Appalachian Basin, modified from Soeder and Kappel, 2009.

Near the end of the EGSP and MWX projects, DOE looked into the applications of horizontal or angled drilling on a variety of unconventional oil and gas reservoirs. In addition to the horizontal Huron Shale test well in West Virginia (Duda et al., 1991) described previously, an angled well was also drilled and cored at the Multiwell Experiment site in Colorado to intercept a vertical hydraulic fracture. DOE experimented with additional horizontal wells and multiple hydraulically fractured zones, working in collaboration with industry to develop the technology that would later be used to produce shale gas. Although these experimental wells were successful within their range of limited objectives, the widespread use of directional drilling and horizontal wells for shale gas production required better downhole sensors, improved electronics and communications, and some new thinking in drilling engineering.

These advances came about in the 1990s, driven by the needs of deepwater offshore oil drilling, and the larger fiscal resources available in this industry for research and development. As offshore rigs moved into deeper water, the engineering design of the platforms changed. Steel towers standing on the sea bed had worked fine in water a few dozen meters (a few hundred feet) deep. Drilling in kilometers (thousands of feet) of water required the use of semi-submerged, buoyant platforms held firmly in place by tensioned steel cables anchored into the seafloor.

When the rig needed to be moved, the old-fashioned steel towers could be floated a few meters off the bottom like an underwater skyscraper and towed with relative ease from one location to another. The tension leg platforms and their associated seabed anchor facilities, on the other hand, are much more elaborate, and require manned submersibles and deep-sea diving technology to release the anchors and rig up at a new location. Moving these platforms is expensive and time-consuming.

Industry decided to pursue directional drilling as a solution. If a driller could bore a well directionally into one reservoir trap, and then drill another well in a different direction from the same platform location to intercept a second reservoir trap, a great deal of gas and oil could be recovered without moving the rig. The players in the deepwater drilling game were willing and able to spend the sums of money needed to develop and improve directional drilling equipment to make this a reality. Some deepwater platforms now routinely drill as many as 60 separate wells from a single location.

Although directional drilling had been around since the 1930s, there were two problems that needed to be overcome to make it practical: steering the bit and knowing where it was located. When a Kelly Bushing is used to rotate the entire drill string from the surface to turn the bit, the borehole is not able to deviate much from a straight line. If a bend is too sharp, the rotating drill pipe will bind up and break. A more flexible drill pipe called a whipstock was introduced early on that was less prone to breaking, but it was still difficult to steer the bit and control the direction of the hole. The second major problem with directional drilling was that the driller had no way to accurately locate the downhole end of the borehole. There wasn't any way to tell from the surface, and early gyroscopes and telemetry were not very reliable.

The first technological advance in directional drilling was the downhole motor. U.S. patents for "self-propelled" drilling heads go back to at least 1949, where the idea was to supply power, either electrical or hydraulic, to some kind of downhole motor that would turn only the drill bit, eliminating the necessity of turning the entire drill string from the surface. Heavy steel drill pipe is flexible and can bend in a relatively tight radius without breaking if it doesn't need to rotate.

Most of the early downhole motor assembly designs were impractical. They tended to be large, inefficient, underpowered, and overheated easily. Once the deepwater oil companies dedicated significant financial backing to the efforts, the engineering and designs improved. A modern downhole motor uses hydraulic power, supplied by drilling mud pumped down the inside of the drill pipe under high pressure. There are several designs for providing power to the motor from the mud, ranging from spiral grooves built into the drill pipe to turbine-like spinning blades. The motor then turns the bit, which cuts the rock by using rotating steel and carbide teeth and applied pressure. The impeller, motor, and bit together are known as the "bottomhole assembly," and it is the only part of the drill string that rotates. With this configuration, wells can be drilled in virtually any direction, including horizontally. An example of a bottomhole assembly is shown in fig. 22.

Operators can steer the drill bit a number of ways. The simplest is to use a bent section of drill pipe near the bottomhole assembly to deviate the borehole orientation away from vertical (see fig. 22). Drillers can also steer the bit by changing the pressure being applied against the cutting face or varying the rotational speed. Advanced bits have thrust bearings that can be controlled from the surface to change the angle of the cutting head, and thus the direction of the borehole. Some of the recent advances in steering the bit now allow both the curve and the lateral to be drilled in one trip without having to pull the entire drill pipe out of the hole to change equipment after completing the curve. This saves time and improves the economics.

22. Photograph of bottomhole assembly laid down at the surface. Photo by Dan Soeder.

Drilling mud is not just a simple mixture of clay and water. It contains various stabilizers, lubricants, corrosion inhibitors, polymers, viscosity control agents, and other compounds, most of which are highly specialized and closely guarded trade secrets. Mud can be water-based or oil-based, including synthetic oil. Drilling mud serves multiple functions, including lubricating and cooling the bit, transporting rock cuttings back up to the surface, and maintaining enough pressure inside the borehole to prevent fluids from entering or the walls from collapsing. When used with a downhole motor, the pressurized mud also supplies hydraulic power to turn the drill bit.

The unit density or “weight” of the drilling mud is important for controlling the stability of a wellbore, and it is monitored and adjusted carefully. This is called balanced drilling. Mud weight is adjusted by adding minerals, typically barite, into the mud mix to increase the density, or water to lower it. Mud engineers track the pore pressures in the rocks, and the fracture gradient or rock strength. If the mud weight is underbalanced, or too low, oil and gas in the rocks can escape prematurely into the borehole, or the borehole walls could collapse. On the other hand, if the mud weight is too high, or overbalanced, it may exceed the hydraulic fracture gradient and crack the rock. This can result in drilling fluids moving into the formation, called lost circulation. The frac gradient and pore pressure vary with location and can even vary with depth in the same hole. Mud engineering is a precise science that requires detailed planning and a thorough understanding of downhole conditions to maintain a proper borehole.

Mud is typically pumped downhole through the inside of the drill pipe. It flows out of the cutter head through special vent holes or jets, cooling the drill bit and sweeping away the drill cuttings. The mud then returns to the surface through the annulus (the ring-like space between the outside of the drill pipe and the borehole wall), where it is captured and stored in a pit or tank until it is recirculated. The drill cuttings are filtered out through a series of vibrating screens called shale shakers, and are analyzed by an onsite geologist or mud-logging engineer to confirm the geology of the formation being drilled. This can be tricky because it is difficult to pinpoint the exact depth where the cuttings originated. It depends on the penetration rate of the bit and the travel time needed for the mud to return to the surface.

Advances in electronics and telemetry were also needed to accurately determine the length and direction of a horizontal borehole. In 1929, Sun Oil Company formed a joint venture with Sperry Gyroscope Company to apply Sperry’s gyroscope navigation technology to directional wells. The new entity, called Sperry-Sun, sought to provide operators with real-time information called Measurement While Drilling (MWD). The concept combined gyroscopic compass readings and continuous data transmission that would allow the downhole location of the drill bit and the configuration of the borehole to be monitored. Unfortunately, the goals were somewhat lofty and ahead of the available technology, giving the system a reputation for being inaccurate and unreliable.

Sun Oil sold off Sperry-Sun in 1981. It evolved into Sperry Drilling and was bought by Halliburton. A reliable MWD system was available to operators by the early 1990s thanks to improvements in mechanical components and solid state electronics for inertial navigation.

MWD consists of instrumentation that collects data on physical properties, such as pressure, temperature, and wellbore location in three-dimensional space while drilling. The measurements are made downhole, stored in solid-state memory, and then transmitted to the surface at fixed intervals. Data transmission methods vary; one of the more common techniques digitally encodes the data and transmits it to the surface as pressure pulses in the drilling mud. Other approaches use sonic or electrical impulses through the drill pipe, or fiber optics imbedded in a non-rotating drill string for telemetry. MWD tools that measure formation properties, such as density, resistivity, sonic velocity, gamma ray, etc., are known as logging-while-drilling (LWD). Although the use of these systems is expensive, knowing the exact location of the borehole and the downhole physical conditions in near real-time can be invaluable.

Directional drilling has its own set of terms (see Appendix A). The borehole is vertical until reaching a pre-determined depth above the target formation. This vertical stretch of hole is called the tophole. The depth at which the wellbore changes from vertical to some other orientation is the kickoff point. The location in three-dimensional space where the directional borehole intercepts the targeted producing formation is called the landing. The radius of the curve where the borehole changes direction from vertical to horizontal is known as the build or the build rate.

Directional drilling rigs used on the Marcellus Shale typically build a curve with a radius as tight as 150 meters (500 feet). Sometimes they will build a reverse curve in the opposite direction called a sail to gain enough horizontal space to build the main curve for a proper landing on the target. The horizontal stretch of the borehole is the lateral. The path of the lateral through the target formation is known as the trajectory.

On a map, directional drilling in the Marcellus Shale is laid out in patterns that look like the legs of a spider. The body of the spider is the drill pad. Multiple wells will originate from a single drill pad, ranging from 6 to 10 or more in number. The wellheads are spaced far enough apart at the surface to allow workover rigs and other equipment to have access. All the wells may be drilled immediately, followed by hydraulic fracturing and completion as a group, or they may be drilled and completed a few at a time because of limits on pipeline capacity or for other reasons.

Measuring the position of a bottomhole assembly that is kilometers below the surface is done by the determination of inclination and azimuth of the borehole. However, no matter how precise the measurements may be, small, systemic errors are compounded with depth, creating less precision for the measurement as holes grow longer. Instead of being plotted as a line, borehole positions are therefore drawn within "ellipses of uncertainty," which become larger with depth.

The maximum length of a lateral is determined by friction against the drill pipe. At some point, there is just too much drill pipe lying flat in a horizontal borehole for the driller to be able to push the bit any farther forward. Nevertheless, the lengths of some of these horizontal boreholes can be remarkable. The longest achieved so far onshore is the Eclipse Resources Purple Hayes #1 well in the Utica Shale, located in Guernsey County, Ohio, which is reported to possesses a lateral length of 18,544 ft. (3.5 miles or 5.6 km) and a total borehole length from the surface of about 27,046 feet or 8244 meters (Halliburton Press Release, Houston, May 31, 2016; Oil and Gas Investor, July 7, 2016). This is not typical for most Marcellus wells, although laterals half that length are common.

The laterals are drilled into the target shale in a direction that is usually perpendicular to the trend of the most prominent set of natural fractures, or joints. The idea is to drill across as many of these joints as possible, and use them as a gathering system to help bring gas to the well. In the Appalachian Basin, the main joint sets in the Devonian black shales trend northeast to southwest (Engelder, 2009), so the Marcellus Shale laterals are commonly drilled on trajectories oriented either to the northwest or to the southeast. Laterals are often drilled parallel to one another at the optimal spacing for the most efficient recovery of natural gas from hydraulic fracturing. This varies from about 300 to 600 meters (1,000 to 2,000 feet), depending on geologic properties of the rock and the type of frac treatment employed.

When several directional wells are drilled from the same pad, the positions of the vertical wells are controlled carefully to avoid interference. Once the kickoff point is reached, the wells diverge along horizontal trajectories designed to keep the ever-widening ellipses of uncertainty from touching one another. The art and science of driving directional boreholes sight unseen through deep layers of rock is called "geosteering," and the practitioners are extremely skilled.

5.2.1 Drill rigs

Drill rigs come in a variety of sizes for different uses. Those used for drilling onshore prospects like the Marcellus Shale are known as "land rigs." The smaller of these are mounted on trucks, and can be moved about as a single unit. Larger land rigs are modular, and are transported to a drill site as multiple components that are then assembled onsite.

Most modern drill rigs are powered by electric-hydraulic systems, using a bank of large diesel-powered generators to provide electricity for the rig's hydraulics. Because the Marcellus Shale is a continuous resource, many wells have been drilled in or near existing conventional gas fields to gain access to compressor stations and pipelines. A number of operators have modified their generators to run on the local natural gas supply instead of relatively expensive diesel. The Marcellus Shale play is located in an area that is industrialized and rather densely populated, and some operators have even been able to "plug in" their rigs to a nearby power line and drill using line power. Land rigs cost about $100,000–$500,000 per day to operate.

Historically, oil and gas drilling in the Appalachian Basin has employed relatively small equipment compared to the gigantic drill rigs common in Oklahoma, Texas, and the Louisiana Gulf Coast. Land-based drill rigs are classified by the height of the derrick, which determines how many 10-meter (30-foot) segments of drill pipe (called "joints" – not to be confused with the fracture joints described previously) can be recovered from a borehole with a single pull before being disconnected. Small rigs can only pull one joint of drill pipe at a time and are called "singles." Most of the Appalachian Basin drill rigs used in the past on conventional reservoirs could pull two joints at a time and are known as "doubles." The deep Marcellus Shale and the even deeper Utica Shale required the introduction of much larger rigs in Pennsylvania, Ohio and West Virginia called "triples" (fig. 23).

Once the length of drill pipe reaches the top of the derrick, the bottom joint must be unscrewed or uncoupled and the pipe set aside so the next segment can be pulled up. These pipe segments are stacked vertically in a rack, known as a stand, against the derrick. On a small metal platform near the upper part of the derrick called the monkey board, a rig hand fits the tops of drill pipes into the stand. This worker wears a special harness that can clip onto one of the slanted guy wires like a zip line in case a quick escape is required. If the drill pipe needs to stay out of the hole for any length of time, a hydraulic arm is used to transfer it from the stand into horizontal racks on the pad next to the rig.

23. Photograph of a “triple” drill rig in Greene County, Pennsylvania, in 2011 with a derrick about 120 feet high that can trip three joints of drill pipe at a time, shown in a vertical stack. Photo by Dan Soeder.

The process of pulling pipe from the hole is called tripping out, and the fewer drill pipe joints that have to be unscrewed, the faster everything can be removed. Thus, drill rigs with taller derricks that can pull three or even four joints at once allow for faster trip times from greater depths. Drillers have to trip out to replace a worn or broken bit, install casing, run measurement tools down the hole on a steel cable, and sometimes to recover core or fluid samples. Casing is stored horizontally on the pad next to the rig platform, and brought up to the rig floor one length at a time by the hydraulic arm for assembly and insertion. To trip back in and continue drilling, the threads on the drill pipes get some fresh lubricant (called pipe dope), the drill string is reassembled, and the whole process goes in reverse to get the bottomhole assembly back to the bottom of the hole.

The implement that actually cuts the hole is called the drillbit, or simply the bit. A conventional style is a rotary, tri-cone bit, which uses three rotating, interlocking cones with silicon carbide teeth to crush, break and grind the rock. When cores are needed, a hollow bit is used that has a rim encrusted with carbide or industrial diamonds to cut rock. Oil field cores range in diameter from 5 cm to 15 cm (2 to 6 in), with 8.8 cm (3.5 in) being the most common.

Shale drilling has become commonplace enough to have its own specialized bits. These generally consist of a one-piece steel body with fixed cutting teeth made of polycrystalline diamond composite (PDC). The PDC is a laminate of polycrystalline diamonds and carbide that is harder and more durable than carbide alone. These bits are designed to cut a smooth hole quickly, with directed jets on the face for high-pressure drilling mud to flush shale cake off the cutting teeth. Conventional drill bits commonly become bogged down by gummy mud from the soft shale. An interesting paradox in drilling is that soft rocks are often slower to drill than hard rocks.

The rig is operated from the doghouse, a small, office-sized trailer usually attached to the rig platform. Not long ago, a driller in the doghouse would control a throttle and a brake, and monitor the borehole depth and penetration rate with a simple pen on a drum recorder called the geolograph. These days, the doghouse is loaded with computer screens, joystick controllers, and electronics. Feeds supply real-time data to engineers on-site and back at the home office on depth, temperature, weight on bit, rate of penetration, and other properties of the rig.

At the top of the hierarchy of workers at a drill site is the tool pusher, who is the operating company management representative responsible for overseeing the overall rig and site operations. The driller is the person who is responsible for and actually operates the drill rig itself. Drilling engineers assist by monitoring the rig performance and progress of the hole. The mud logger collects cuttings samples and keeps track of the geology being penetrated. The rig geologist is responsible for geosteering and guiding the trajectory of the lateral. Regular members of the rig crew are known as roughnecks, and are in shorter supply these days because of hydraulics and automation.

5.2.2 Well casing and groundwater protection

A gas well is much more complicated than just a hole in the ground. Because of the need to protect aquifers, and to keep gas, oil, and groundwater out of places where they don't belong, boreholes are lined with casing, held in place by cement. Casing is made of heavy, threaded steel pipe, which screws together in segments approximately 10 meters (30 feet) in length. The connections have different styles of threads depending on the casing use, but most are a self-sealing type, like a tapered pipe thread. High-pressure casing uses flanges that lock together instead of threads.

Each length of casing that is made up of joined segments of a uniform diameter is known as a string. There are several concentric strings of casing in a well, with each successive casing string being smaller in diameter to fit inside the others and extend to a greater depth. As each string of casing is placed in the hole, it is cemented into place. A proper cement job is critical for sealing the casing, and it is left to cure before drilling proceeds. Land based wells like those in the Marcellus Shale commonly have two to four strings of casing, while offshore wells may have as many as 10 or 12.

Different casing configurations are used in different climates, but the following design is typical for Marcellus Shale wells in West Virginia and Pennsylvania. The initial penetration of the ground surface by a drill bit is called the "spud," and signals the start of the well. The hole only goes down to a depth of 10–20 meters (30–60 feet), and then a large-diameter string of casing, usually about 60 cm (24 inches) wide is installed as a mechanical barrier to support the sides of the hole in unconsolidated soil. This is known as the conductor casing.

The tophole continues downward through the shallow groundwater aquifers. This part of the drilling often uses an air-hammer rig, which links a pneumatic hammer action with rotation to quickly cut a clean, straight hole. At a depth of about 100 m (300 ft), drilling is paused and a second, narrower casing string known as the surface casing (sometimes called the water casing or coal casing) is run and cemented in place from the bottom of the hole to the surface. This casing is usually 35–50 cm (14–20 inches) in diameter, and is designed to isolate the gas well from the aquifers and coal seams. It is supposed to extend to the base of the deepest freshwater aquifer, but this exact depth varies with location and is highly debated. The casing protects the groundwater from gas or oil, and also protects the well from being flooded by groundwater.

A brief discussion on the basics of groundwater may be helpful to some readers. The fresh water in the pores of soils and shallow rocks started out as precipitation that entered the ground under the force of gravity in a process called infiltration. The continued migration of water downward through the rocks and soil is called percolation. Both activities together are known as recharge. Water flows out of the ground naturally at springs and in perennial streams. The water present in a stream when it is not raining (i.e., when there is no overland runoff) comes from the seepage of groundwater into the stream channel. At shallow depths, the rocks and soil contain both air and water in the pores, but this becomes 100% water as one moves downward. The boundary between the unsaturated and saturated zones is known as the water table. The level of water in an undisturbed groundwater well generally sits at the height of the water table.

To provide a reliable drink, a supply well must be deeper than the water table, the depth of which varies over the course of a year: it is highest in the spring after being recharged with rain and melted snow and lowest during the dry months of late summer and early autumn. In establishing the depth of a water supply well, drillers must take this annual fluctuation into account or the well could be dry for part of the year. Rocks and sediments that are groundwater-bearing are called aquifers.

Because most sedimentary rocks were deposited on the sea bottom, the original water in the pores, called the connate water, was salty. These salts have been flushed out of shallow aquifers by the influx of fresh groundwater. With increasing depth, however, the water in the pores gets saltier, because freshwater only penetrates so deep. It is also less dense than saltwater, so freshwater tends to “float” on top of the deeper saltwater. The upshot is that drinkable or “potable” groundwater is limited in depth. A well that goes too deep will tap into the salty water below the fresh; the deeper it goes, the saltier it gets. Saltwater at depth is referred to as formation water or brine.

Salts in water are known as total dissolved solids (TDS). The U.S. Environmental Protection Agency’s secondary standard for TDS in drinking water is 500 milligrams per liter (mg/L). The drinking water standard differs from the EPA definition for the lower limit of "fresh groundwater," which is a TDS level of 10,000 mg/L, or 10 parts per thousand. Such water is brackish and undrinkable, with a salt content about one third that of seawater. The fresh groundwater standard comes from the EPA Underground Injection Control (UIC) program, which conservatively defines the levels at which groundwater must be protected from injected waste. EPA drinking water standards can be found online: (https://www.epa.gov/ground-water-and-drinking-water/table-regulated-drinking-water-contaminants).

Most state regulations for protecting drinking water aquifers from oil and gas wells require that surface casing be set below the "deepest fresh groundwater." However, the base of the fresh groundwater is often not clearly defined. Attempts have been made to classify it as the deepest potable water, the deepest pumped aquifers within a county, or by a salinity or total dissolved solids standard, typically some fraction of seawater salinity. These regulations are developed at the state or local level, and can vary considerably from place to place. As such, the requirements are ambiguous. Groundwater protection advocates want surface casing set as deeply as possible, but operators don't want to set any more casing than necessary because of the cost.

So how does all this apply to the development of the Marcellus Shale? Neither Pennsylvania nor West Virginia have strict construction standards for domestic water supply wells, which creates a wide variability of risk depending on the design of any particular well. Most domestic water wells are less than 100 meters (300 feet) deep in West Virginia, and that is the typical depth for oil and gas well surface casing, including Marcellus Shale wells. The Commonwealth of Pennsylvania has been discussing groundwater protection standards for some time, but has not been able to reach a consensus. Pennsylvania regulations call for surface casing to be set to depths of 50 feet (15 meters) below the deepest fresh groundwater, defined as potable or usable. This depth has been highly debated, because the standard is somewhat ambiguous. The casing may go as deep as 200 feet (60 meters) below the base of the fresh groundwater if necessary to reach consolidated rock (Commonwealth of Pennsylvania, 2011). Surface casings in Pennsylvania are typically set between about 500–800 feet (150–240 meters) below the ground surface.

Regulatory authority for water withdrawals in West Virginia rests with the WV Department of Environmental Protection. Pennsylvania is more complicated, with the eastern part of the state regulated by the Delaware River Basin Commission (DRBC), the central part of the state under the Susquehanna River Basin Commission (SRBC), and the Pennsylvania Department of Environmental Protection (DEP) responsible for the Ohio River Basin and the remainder. The protocols for determining allowable withdrawal amount vary, with the river basin commissions being the most rigorous.

Once installed, and before drilling proceeds further, the surface casing and cement undergo a casing integrity test (CIT). Also known as a leak-off test (LOT), this procedure applies pressure to the inside of the set and cemented casing in excess of the maximum hydrostatic pressure expected at the depth of the casing shoe, and monitors it for leaks (Syed, 2011). State and Federal laws (30 CFR 250.427) require such tests to be run, and more elaborate tests can be compelled if necessary. Regulations prohibit continued drilling through bad casing, which must be replaced. There are also a number of downhole tools that can be employed if needed to evaluate the integrity of the cement.

The tophole drilling continues vertically until the kickoff point for the lateral is reached about 150 meters (500 feet) above the target shale. A third string of casing, known as the intermediate casing, is then set and cemented in place. The role of this casing string is to prevent gas, oil or brine in shallower formations above the target from entering the borehole and potentially migrating into other zones or the freshwater aquifers. The intermediate casing was often not used in the early days of the Marcellus Shale play, leaving exposed rocks in the vertical borehole. This led to some potential problems with gas migration into nearby water wells. Such "open-hole" completions are no longer considered best practice.

A final string of well casing, called the production casing, is installed in the finished hole. This is the slimmest casing string, usually only about 13 cm (5 inches) in diameter. It extends through all of the other casing strings from the surface down the vertical hole, through the curve, and along the entire length of the lateral to the very bottom end or toe of the hole. The production casing is cemented into place through the production zone to at least the base of the intermediate casing, although some operators may cement it all the way to the surface. This final casing string serves to channel all gas production directly to the surface inside a pipe, minimizing any opportunities to go astray.

5.2.3 Borehole cement

The cement used in an oil or gas well is not like a bag of ready-mix sold at the local home improvement store. Oilfield cement formulas are specialized, taking into account the weight and viscosity of the drilling mud the cement must displace, and the pressures of fluids in the formation that it must hold back. Oil well cement is rated by the American Petroleum Institute at different grades for various uses. When engineers design wells, they consider the various downhole conditions, such as the pump time needed to place the cement, downhole temperature, potential pressure effects, fluid loss, settling, and other factors that could affect the performance of the cement. The casing and cement are then specified for these particular well conditions.

Cement slurry is pumped down through the inside of the casing and distributed by a shoe at the bottom of the string so that it oozes up evenly into the annular space between the casing and the borehole wall. Spring-like centering collars are usually placed on casing strings at intervals to keep one string centered inside the next, which helps ensure an even distribution of cement pumped inside the annulus. As the cement fills the annular space outside the casing from the bottom upward, it displaces the drilling mud out of the hole.

A number of failures can occur during this step (Dusseault et al., 2000). If the viscosity and density of the cement are too different from the mud, the cement will not displace the mud uniformly, but push into it as a series of fingers. This can trap pockets of fluid in the cured cement, creating channels for flow. Fingering can be minimized by pumping the cement in slowly, but pumping it too slowly leads to another problem called static settling, where the slurry begins to separate out into water and solid components. Elevated downhole temperatures can cause the cement to set up more quickly than planned, reducing the time available for pumping. Angled or horizontal wells can have the fluid and solid phases in the cement slurry separate through a process called dynamic settling. Fluid loss from the slurry into permeable formations can result in thickening times that are too short, and changes in downhole stress as the well is produced can also cause cement instability.

Most cement failures do not occur with the cement itself, but at the bonding interface between the cement and casing or between the cement and borehole wall. Contamination of the slurry with small amounts of oil, excessive casing vibration, or failure of the cement to bond to preservative coatings or grease on the outside of the casing may create a microannulus, a small, concentric, vertical crack that allows fluids to migrate.

One mitigation method under investigation is foamed cements, which contain up to 20 percent volume nitrogen gas bubbles (Kutchko et al., 2012). Similar to expanding plastic foam used to seal doors and windows, foam cements are less dense, and have better space-filling and sealing properties than plain cement. The ideal foam cement contains the maximum number of gas bubbles possible in a given volume with enough cement remaining between the bubbles to keep them separate. Interconnected bubbles would be a disaster, creating flowpaths throughout the cement.

If well cement does fail for whatever reason, fixing it can be an expensive and tedious task. Drillers would much rather get the cement right the first time. Bad cement may require that the well casing be pulled and re-set. If this is not possible, another option is to repair the cement in place by perforating the casing and pressure-injecting new cement behind it in an operation known as a “squeeze job.”

When all goes well, the weight of the cement compressing the elastic steel casing ensures a tight bond between the cement and the casing as it cures. The integrity of the bond can be checked by a variety of methods. One common physical test is a pressure evaluation, such as a shoe top casing test or a liner top test, both of which are designed to determine if the cement is holding a seal. Another frequently used physical test is a temperature log—as the cement cures, it undergoes an exothermic reaction, releasing heat. Measuring the temperature on the inside of the casing is usually sensitive enough to detect the top of the cement. Some more esoteric tests use radioactive tracers and electromagnetic techniques, but these are expensive, rare, and generally only applied in special circumstances.

The most common method for checking the integrity of a cement job in a well is called a cement bond log. These are carried out using acoustic well log tools. There are three main types: 1) a tool that measures sonic impedance or loss of signal, 2) an ultrasonic imager, like a medical ultrasound, that can view gaps or voids in the cement behind the casing, and 3) a passive listening tool that can hear fluids moving behind the casing.

The impedance tool works on the principle that poorly bonded pipe will vibrate more freely than firmly cemented pipe, like the ringing of a free-standing wine goblet versus one held tightly in the hand. The data must be interpreted with caution because the engineering calculations, which were developed in 1960, contain some assumptions. The tool consists of a receiver placed a fixed distance below a transmitter. The calculation assumes this distance is fixed, the cement has a known strength, the casing is centered in the well, and the formation is uniform. The methodology provides a number called the cement bond index, but most engineers caution that it should only be used in combination with other tools.

Ultrasonic imaging tools employ an unfocused transducer and a resonance technique similar to medical imaging. The tool rotates rapidly as it moves, capturing many readings per revolution. It can detect the difference between fluid behind casing and solids behind casing and can produce images of voids and channels.

Cement bond analysis using any of these tools requires knowledge about the specifics of the cement job: slurries pumped, when and how fast, formations involved, length of set times, downhole temperatures, annulus size, and so on. Without this information, evaluating the cement job is difficult and subject to interpretation errors. The best way to reduce uncertainty in the interpretation is to run multiple tools that use different methods to measure the cement integrity. Few companies do this, however, because it is a significant added expense. Nevertheless, casing and cement are used to isolate the wellbore from the surrounding formations, and demonstrating such isolation is critically important to well integrity.

5.3 HYDRAULIC FRACTURING

Hydraulic fracturing is not a new technology. It was invented by Floyd Farris of Stanolind Oil and Gas Corporation in 1947, based on the results of a series of field experiments to fracture rocks using crude oil and naphtha gels in the Hugoton gas field in Grant County, Kansas. The modern, water-based technique was developed in 1953 (Montgomery and Smith, 2010). A patent was issued in 1949, granting exclusive rights for the Stanolind process to the Halliburton Oil Well Cementing Company. The first commercial hydraulic fracture stimulations were performed in 1949, using oil-based frac fluids on a well in Duncan, Oklahoma, and another well in Holliday, Texas (Fisher, 2010).

It is important to note that the term “fracking” is often used to describe the entire shale gas development process by some who oppose it. The overall shale gas development process consists of drilling, completion, stimulation, and production. The shale gas industry considers the frac (spelled without the “k”) to be the stimulation stage of development, and just one component of the total process. The imprecise use of “fracking” has resulted in a number of misunderstandings between shale gas proponents and opponents.

The completion stage of a well begins by creating holes or perforations through the production casing to allow the gas to enter. This is done using a perforating gun or “perf gun.” In the old days, actual bullets were employed, hence the name. Modern perf guns use shaped charges consisting of up to 60 grams of RDX, AMX, or HNS, all of which are military-grade high explosives. The detonations create holes in the casing between 6 and 20 mm in diameter (¼ to ¾ inch), with a depth into the rock from 10 cm to more than a meter, and there are generally 12–36 holes created per meter (4 to 12 holes per foot). Successive shots are turned at an angle of about 60 degrees from the previous shot to spiral the holes all around the casing.

A perf gun is composed of a carrier unit containing explosive charges attached to a detonation cord, and a remotely operated detonator that sets off the array of explosives simultaneously. The guns are designed to contain the explosive debris so that it can be removed from the well. Once a segment of production casing has been perforated, a pathway exists for frac fluid to enter the formation, and for oil or gas from the formation to flow back along the fractures, through the perforations, and up to the surface.

5.3.1 Hydraulic fracturing chemicals

The components of a hydraulic fracturing operation consist mostly of water, proppant sand, and a fraction of a percent of chemical additives. Chemical information about these additives is posted on the Frac Focus website (http://fracfocus.org/), voluntarily in some cases, and required by state permit in others. Although the chemicals are used in low concentrations, they are deployed at the drill site in large volumes. This is because the water, chemical, and sand mix is blended during the progress of the frac, where the types and amounts of chemicals added may change over the course of the stimulation. An examination of the Frac Focus website indicates that the most common chemical additives to frac fluid include methanol, isopropanol, crystalline silica, 2-butoxyethanol, ethylene glycol, hydrotreated petroleum distillates, sodium hydroxide, hydrochloric acid, ammonium chloride, ammonium and sodium persulfate, glutaraldehyde, and polyacrylamide (Soeder et al., 2014b).

The U.S. Environmental Protection Agency compiled a consolidated list from federal and state government documents, industry-provided data and other reliable sources of over 930 chemical compounds used or found in hydraulic fracturing, including 132 chemicals present in produced waters (USEPA, 2015). Chemical additives are used to clean the perfs, reduce friction loses downhole, provide corrosion resistance, inhibit scale build-up, and suppress downhole microbial growth. The complete list of chemicals can be found in Appendix A of the draft EPA drinking water impacts report, available online: https://cfpub.epa.gov/ncea/hfstudy/recordisplay.cfm?deid=244651.

One of the primary chemical additives to frac fluid is polyacrylamide, a friction reducer. This dry powder material creates an extremely slippery liquid known as “slickwater” when mixed with water. Slickwater is used to reduce pressure losses due to friction as the frac fluid is pumped to the formation down a long string of production casing. Downhole pressure losses affect the type of equipment and pressure ratings needed at the surface, and are described in more detail in the next section.

The biocide is probably the most hazardous of all the chemical additives in use. Biocides come in two general types: oxidizing or non-oxidizing (Kahrilas et al., 2014). Oxidizing biocides (such as bleach, peroxide, etc.) attack microbes, but also corrode equipment and damage rock formations. As such, most hydraulic fracturing operations use non-oxidizing biocides. These fall into two classes: lytic biocides that act by dissolving the cell walls of bacteria, and electrophilic biocides that act by binding themselves to bacterial cell walls (Kahrilas et al., 2014).

Biocides are necessary because if not repressed, bacteria introduced downhole with the frac fluids can consume organic and sulfate compounds, creating hydrogen sulfide gas (H_2S) as a byproduct. The H_2S causes the production gas to be “sour” and corrosive. It must be removed before the gas can be sold to a pipeline. H_2S is also toxic if breathed, so preventing it from being generated is important. Alternatives to biocides, such as treatment with ultraviolet light and other options have been tried, but have not been found to be as economical (Kahrilas et al., 2014).

The claim that “hundreds” of chemicals are added to frac fluid is a misunderstanding. While a great many chemicals have been tried over the history of hydraulic fracturing, no one adds hundreds or even dozens of chemicals to any individual frac. Advances in hydraulic fracturing technology have reduced the total number of chemicals used to maybe a half dozen in a single frac. Different chemicals may be used in different frac stages, but only a few are used in each (Soeder et al., 2014b). Many of the chemicals present in groundwater that people blame on Marcellus Shale hydraulic fracturing are actually coming from elsewhere. This is discussed in more detail in the environmental section.

Shale fracs tend to use less proppant sand than other kinds of fracs to maintain open fractures after pressure is released. These so-called “light sand” fracs are more effective on shale, and also minimize the use of viscous gels like guar gum to carry in proppant. Nevertheless, because of the high volume of hydraulic fracturing in shale, even light sand fracs end up using a lot of sand, which is required to be composed of evenly-sized, well-rounded, and high compressive strength quartz grains to work well as a proppant. The Jordan Sandstone in Wisconsin is one of the few formations that consistently meets these standards. Concerns have been raised about the damage to landscapes from the extensive mining of this frac sand (Parsen and Zambito, 2014).

Compounds known as “cross-linked gels” are used on some fracs for proppant transport, but these generally require a second chemical called a “breaker” to reduce the viscosity and allow the liquid to flow back out of the fracture. This adds costs, and the potential human and ecosystem health impacts of many of these chemicals are unknown. Short half-life radioactive tracers such as iodine or antimony isotopes are also sometimes added to the proppant to allow the height of the hydraulic fractures to be traced in the subsurface (Smith and Montgomery, 2015). The use of these tracers is common in vertical wells, where a wireline gamma log can be employed to detect the top and bottom of the propped fracture. In staged fractures along shale laterals, microseismic monitoring is a more effective technique.

Hydraulic fracturing in shale requires less proppant because “asperities” or natural rough spots are created on fracture walls that help prop open the fracture when pressure is released. Proppant sand often has a problem called “embedment” in shale where the hard quartz sand grains simply sink into the softer shale without propping open the fracture. Natural asperities in the rock essentially place shale against shale, reducing embedment.

5.3.2 The hydraulic fracturing process

A special high-pressure wellhead designed for hydraulic fracturing is known as a frac gate. This is installed at the surface, just above the main casing to allow equipment and materials carried by wireline to pass through, as well as to control the entry and exit of fluids on the well. A photograph of a frac gate is shown in fig. 24, where it is compared with the regular production wellhead.

24. Photographs of a massive fracture gate wellhead on a recently drilled Marcellus Shale well in Greene County, Pennsylvania, prior to hydraulic fracturing (L), and a production wellhead (i.e., Christmas tree) on a producing Marcellus Shale well (R). Photographed by Dan Soeder in 2011.

The main wellhead pressure valve at the top of the production casing string is left wide open during the frac job, because the proppant sand being pumped downhole and returning afterward would abrade any obstruction in its path (this valve can be seen in fig. 24 immediately below the frac gate). Abrasion by moving sand is a concern in all stimulations. Although production casing is typically made from half-inch (1.25 cm) thick, API-rated, high-tensile strength steel pipe, there have been rare cases where a hole was abraded in the curved part of the casing during the frac by sand particles racing through the turn.

Hydraulic fracturing operations in horizontal boreholes in a gas shale are carried out in stages. The stages begin at the end of the lateral, called the toe, and work backward in increments of about 150 m (500 ft.) toward the upward curve or heel. Each stage receives a hydraulic fracture treatment, which is then blocked off while the next stage is treated. When all the stages are completed, the barriers between stages are removed and production begins. The longer the lateral, the more fracture stages are needed. Marcellus Shale wells with 15 to 20 hydraulic fracture stages are not unusual. The Utica Shale superlateral in the Eclipse Resources

Purple Hayes #1 well described previously is reported to have had 124 individual frac stages (Halliburton Press Release, Houston, May 31, 2016).

Once all the materials, fluids, pumps, and other equipment are set up on a well pad, the hydraulic fracturing process begins by cleaning out the perf holes using a 15 percent solution of hydrochloric acid. Perforating casing with high explosives tends to jam pieces of steel and pulverized cement into the formation, and these need to be removed to open up the perf holes. After the acid is pumped down the well, the hydraulic fracturing system undergoes pressure testing and all the equipment is calibrated.

The high- and low-pressure systems on a frac are plumbed separately, so fluid from one cannot get into the other unless the operator allows it. The working parts of the pumps used to generate the frac pressure consist of positive displacement pistons inside high pressure steel cylinders. The rate at which these pistons advance can be controlled very precisely to maintain a specific flow volume and/or pressure. The pumps have safety cutoffs if pressure or volume parameters are exceeded, and the high pressure parts of the system also have relief valves to prevent critical components from blowing out.

The frac fluid is mixed in a blender, including the proppant sand, which is added by an auger feed. As the hydraulic frac begins, the pump rate is brought up slowly. Real-time measurements collect pressure data at the wellhead, downhole, and in the annulus behind the production casing. A flow meter on the blender measures the volume of fluid pumped downhole, and a densometer measures the amount of sand in the fluid. Engineers closely watch the wellhead, annulus, and bottomhole pressures, pump rate, fluid density and material parameters throughout the frac (fig. 25).

The pressure on the frac fluid is increased until it exceeds the formation strength and the rock cracks. This is called breakdown. Because water is virtually incompressible, as soon as the fractures are created and water begins flowing into them, more water must be added at the surface to maintain the pressure. The initial part of the fracture, called the pad, is made with slickwater only. Behind this, as the fracture opens up, sand is pumped in with the water to act as a proppant. The rate at which the sand is pumped is critical—too fast, and the proppant will be spread too thinly in the formation; too slow and the proppant won’t remain in suspension in the frac fluid, settling to the bottom of the well in a process called a screen-out. Fine-grained proppant is pumped into the fracture initially, followed by a coarser proppant as the fracture system develops.

25. Photograph showing a hydraulic fracturing operation in progress on a Marcellus Shale well in Greene County, Pennsylvania. Photo by Dan Soeder in 2011.

Water pressure and pump rates are maintained until the hydraulic fractures extend outward to distances as great as 300 meters (1,000 feet) from the well. The growth rates and lengths of fractures can be measured using a geophysical technique called microseismic monitoring. The fractures themselves do not have to be especially large to create high-permeability flow paths for gas in these ultra-tight rocks. Some of the permeability experiments at IGT (Soeder, 1988) suggested that the most important fractures for gas movement in shale were barely-visible hairline cracks, not the large, calcite filled veins sometimes prominent in cores.

When the first stage of hydraulic fracturing is finished, the pressure is released and a seal called a bridge plug is set into the production casing to close off the perforated and fractured zone from the rest of the well. These are typically solid cement or composite plugs, but some newer designs use a donut-like rubber cylinder called a packer equipped with a check valve that closes off the downhole treated zone against frac pressure in the next zone, but allows fluid and gas to flow uphole during production.

The perf gun is reloaded and lowered back into the well, where a second set of perforations is shot into the next length of casing. The hydraulic fracture treatment is repeated in this second stage, which is then closed off with another bridge plug or packer. The process continues stage by stage until reaching the heel. Depending on the size of each stage and the length of the laterals, a typical shale gas well hydraulic fracturing process usually takes about a week to ten days to complete.

One of the issues that engineers worry about when designing hydraulic fracturing treatments is the loss of downhole pressure due to friction. A Marcellus Shale horizontal well 2,300 meters (7,500 feet) deep and with a lateral 2,100 meters (7,000 feet) long requires frac fluid and proppant to be pushed through 4.5 km (nearly 3 miles) of 13 cm (5-inch) diameter pipe to reach the first stage near the toe. A pressure of 83,000 kPa (12,000 psi) applied to the frac fluid at the surface may only be about half of that, or 41,500 kPa (6,000 psi), down at the toe of the lateral.

There are limits to the pressures that can be applied at the surface—if the required pressure exceeds the pressure ratings of standard equipment, then higher pressure-rated valves, tubing, and casing are needed, which drives up the cost. Larger-diameter production casing will transmit pressure better, but the larger volume also requires more or bigger pumps to achieve flow rates that will keep the sand in suspension and avoid a screen-out, which also adds to the cost. The trade-offs among expected production, stimulated reservoir volumes, frac pressures, pump rates, tubing and casing strength, equipment requirements, volumes of materials, and costs are juggled daily by the financial people and engineers at production companies and service companies who plan hydraulic fracturing.

Gas in the Marcellus Shale is “overpressured,” which means that the initial gas pressure in the rock is higher than the hydrostatic pressure imposed by the column of frac water filling the well (Wrightstone, 2008). The gas pressure is therefore able to push the frac fluid out of the well in a process called “blowback,” which is designed to get as much of the liquid out as possible.

The expelled fluid is diverted into a holding tank or pond through a pipe called the “blooey line.” Because the well is not yet on production, in the past operators typically disposed of the gas that came up with the fluid by burning it off or flaring. The blooey line was fitted with a flare bucket, generally a metal can filled with burning, diesel-soaked rags hung on the end of the pipe to ignite any gas. Flaring is no longer permitted under recent revisions to the U.S. Clean Air Act New Source Performance Standards for wells to which these standards apply.

The water returned from the well after hydraulic fracturing is commonly referred to as “flowback fluid,” although this term has acquired regulatory meaning, and many researchers now prefer the more generic term “produced water.” In Marcellus Shale gas wells, the returned fluid typically starts out as relatively fresh water containing compounds from the fracturing fluid, and becomes increasingly salty over time (Hayes, 2009; Soeder and Kappel, 2009). Some people still make a distinction between the returned fresh water used in the frac as “flowback” and the saltier water from the formation as “produced water.” It is important to be aware of these conventions when reading the literature.

After the initial return of fluids, the flow of liquid can persist intermittently for weeks. Current practice for many operators is to filter out suspended solids and recycle the lower salinity produced water into another frac to reduce the waste volume and minimize the costs of disposal. High-TDS produced water that cannot be reused is called “residual waste” and is usually injected down Class II UIC disposal wells (Maloney and Yoxtheimer, 2012). Residual waste is a term used for waste produced by industrial processes, to distinguish it from municipal waste, produced by commercial and residential processes.

It is important to note that residual waste is not classified as hazardous waste. Hazardous wastes are regulated under Subtitle C of the U.S. Resource Conservation and Recovery Act (RCRA), while residual wastes are managed by state authorities under approved waste plans. While all oil and gas exploration and production wastes are exempted from the hazardous waste definition, EPA has published guidance encouraging operators to manage these wastes appropriately based on their characteristics, which in some cases would qualify these materials as hazardous waste if no exemption were provided.

Once gas production starts, the frac gate is replaced by a much less massive production wellhead called the Christmas tree (refer back to fig. 24). The outflow line from the Christmas tree goes through a gas-water separator, which is a tall, narrow tank with an outlet at the bottom for water and one at the top for gas. Gravity is used to separate the two fluids. The gas is further processed through ethylene glycol dryers to remove any remaining traces of water vapor before it goes into the gas transmission pipeline.

Water in gas pipelines must be avoided — under high pressures and low temperatures, it will form a solid, waxy, ice-like compound called methane hydrate, which incorporates methane gas as part of the crystal lattice structure. Methane hydrates occur naturally in cold, high-pressure environments like the bottom of the ocean or under Arctic permafrost, and have been investigated by DOE for years as a potential energy resource. If water enters a high-pressure gas transmission pipeline and it gets cold, the resulting hydrate formation can completely block the pipe, which does not endear a gas producer to a transmission company.

5.4 PRODUCED FLUIDS

A number of mysteries are associated with produced water from gas shales in general, and the Marcellus Shale in particular. The first is why so little is actually recovered. Generally, less than a quarter of the frac fluid (some estimates are less than 10%) used on the Marcellus returns as flowback (Zhou et al., 2016). This actually varies with location in the play – in some areas the Marcellus Shale returns more water than in others. Other shale plays return varying amounts; many less than half, but some shales produce more water than was injected.

No one is sure what happens to the frac water that remains downhole in Marcellus Shale wells. Some people think it enters the pores of the formation, while others suspect the water works its way downward under gravity into the bottoms of the fractures and stays there. It is also possible that the warm temperatures at depth and the large volumes of gas flow from Marcellus wells may return a significant portion of the water to the surface as vapor in the produced gas stream. Whether or not this actually happens is debatable, and accurate measurements of water volumes recovered over long time periods are needed to determine the mass balance.

The physics suggest that the gas flow pushes a portion of the fluid up the hole until the liquid phase becomes discontinuous, at which point it is no longer mobile. The gas will continue to push some individual slugs of water up to the surface for an additional time period, but it presumably flows around and past most of the discontinuous remaining liquid.

Some interesting anecdotes have been told about shale gas wells that were drilled and fractured to meet lease obligations, but then had to be shut-in for 6 months to a year waiting for pipeline construction to get to the location. When these wells were finally opened up for production, the amount of gas produced and the decline curves of gas production were significantly different than for wells that had been produced immediately after hydraulic fracture treatment. Many of the shut-in wells actually produced higher rates of gas, but some were also lower. Presumably, the shut-in wells had time for the frac fluids to migrate and settle differently than the wells that were produced immediately. Adjustment of the flow system to stresses from the frac might be another factor. Shut-in wells also typically produce less water overall, suggesting that a significant amount of it has actually migrated into the pore system.

A second mystery about the produced water is the high salinity. In 2008, a group of gas production companies formed a consortium called the Marcellus Shale Coalition, which funded the chemical analysis of produced waters recovered from a number of Marcellus Shale wells owned by the different member companies. The Gas Technology Institute (GTI) ran samples from a total of 19 Marcellus wells through a commercial water analysis lab following EPA protocols. GTI concluded that the produced water had a dissolved solids composition similar to other Appalachian brines but at higher concentrations (Hayes, 2009). The TDS content of Marcellus Shale produced water was found to be as high as 200 grams per liter (g/L), or about six times saltier than seawater. Chloride was present at more than 100 g/L, and various metals were present at hundreds of milligrams per liter.

A related mystery of produced water is the often unusual chemical composition of the TDS. Marcellus Shale waters typically contain concentrations of barium (Ba), strontium (Sr) and bromine (Br) at levels considerably higher than ocean water. It is unclear how the original connate water might have been fractionated to reach such extreme increases in salinity. A study by McIntosh (2012) found that the high bromine to chlorine ratio indicative of Marcellus Shale produced water may have been caused by evaporation of seawater past the sodium chloride (halite) saturation level. Sodium chloride concentration could not increase beyond this point, but other dissolved anions, such as bromide, could have continued to concentrate.

The high TDS of the produced water apparently reflects the very salty formation brines within the shale itself (Engle et al., 2011, McIntosh, 2012, Stewart et al., 2015). Formation brines occupy a relatively small percentage of the pore volume in gas shales (Engelder, 2012) and are generally a non-mobile fluid phase in these rocks. Since the days of the EGSP, it has been noted that Appalachian Basin Devonian shales rarely, if ever, produce any water (Soeder et al., 1986). This does not mean that the shales are dry, just that whatever water is in them is not mobile. Water may be present as layers of hydration on clays, for example, or as disconnected brine droplets in isolated pores that are unable to flow. Frac water entering the formation may contact this pre-existing water, and pick up the salts.

It is possible that osmotic forces equilibrate salinity through the migration of high TDS from the brines into the freshwater frac fluid (Blauch et al., 2009). This would be a relatively slow process in porous media, especially in tiny shale pores, and may explain why salinity in the produced water typically continues to increase over a period of weeks before reaching a plateau. However, geochemical trends of major elements (Haluszczak et al., 2013) and oxygen isotope data (Warner et al., 2012) in produced water are generally not consistent with this interpretation.

Formation water in the Oriskany Sandstone, below the Marcellus Shale, is known to contain elevated levels of Ba and Sr, convincing some operators that the TDS in the flowback water are coming from the Oriskany. Ba and Sr are more commonly associated with carbonates than with clastic rocks like sandstone or shale, but the Oriskany is sandwiched between the Onondaga and Helderberg Limestones (refer back to the quarry photo in fig. 5), which may be the source of the dissolved Ba and Sr.

A pathway for formation water from the Oriskany Sandstone to the Marcellus Shale is not apparent. Some people think the hydraulic fracs extend down to the Oriskany, but the Onondaga Limestone between it and the Marcellus is a formidable frac barrier. Geophysical data show that most Marcellus hydraulic fracs break upward into overlying shales, not downward into the limestone (Fisher, 2010). Perhaps the hydraulic fractures intercept natural fractures that extend upward from the Oriskany, and provide flowpaths for the brine. Vertical profiles of formation water chemistry across the Appalachian Basin may be needed to fully understand the dissolved solids content of deep brines.

Given the high TDS found in the produced water, the brines that do occur in the shale pores must be extremely concentrated. Geochemists at the USGS (Engle et al., 2011) and elsewhere have been investigating the concentration profiles of various dissolved ions in the produced water. Their results indicate the source of the TDS is liquid brines, not solid mineral crystals of salt in the shale pores that are dissolving in the frac fluid. Because different salt crystals have different solubility in water, the ratio of chlorine to bromine, for example, should change over time as one type of salt crystal dissolves faster than the other. These ratios are essentially constant in the produced water through time, indicating that the ions were already in solution before the frac fluid ever got there. Researchers at the University of Pittsburgh have shown that the Sr 86/87 isotopic ratio is unique enough that it can be used as a “fingerprint” to positively identify Marcellus Shale produced water in the environment (Chapman et al., 2012).

5.4.1 Naturally-occurring radioactive material

The geochemical conditions that preserve organic carbon and sulfide minerals in black shale also favor the precipitation of naturally-occurring radioactive material, or “NORM.” This consists of radioactive elements like uranium, thorium, potassium, and radium that were deposited with the shale. Because of the link between organic carbon and radioactive materials, shale intervals that contain the highest organic content, and therefore the most natural gas, are also the most radioactive. Horizontal boreholes are typically drilled through the most organic-rich, blackest, gassiest, and “hottest” layers of the Marcellus Shale. As such, there are concerns about the levels of NORM in both the drill cuttings from these black shales, and the produced water. NORM in the cuttings is primarily uranium, present in the Marcellus Shale as tiny grains of uranium oxide (Fortson, 2012). The NORM of concern in produced water is radium, which is fairly mobile in solution (Rowan et al., 2011).

The alternating black and gray shales in the Devonian section of the Appalachian Basin can be easily distinguished from one another in a drill hole by using a wireline well log that measures gamma radiation. Black shales containing NORM give a much higher response on a gamma radiation log than the gray shales. The presence of organic carbon also lowers the density of the black shales, compared to the more silica-rich gray units, and this can be detected on a wireline density log. This combination of high gamma and low density on wireline well logs has been used for many years to determine the boundaries and thicknesses of the different black shale units (Boyce, 2010).

No data on radioactive elements in the Marcellus produced water were supplied in the GTI report because the levels of TDS were so high that the relatively tiny amounts of radionuclides could not be detected (Hayes, 2009). Sodium and chloride were present at levels of hundreds of grams per liter, while radium rarely occurs above concentrations of a few micrograms to milligrams per liter. Other testing has reported radioactivity in the produced water above background levels.

Quantifying NORM in produced water has been challenging. Liz Rowan and her colleagues at the USGS (Rowan et al., 2011) used both historical public data and their own analyses on flowback samples to improve the knowledge base on dissolved radium content of produced waters. Marcellus Shale wells in southwestern Pennsylvania typically show flowback radiation levels to be at background, or even lower. Higher radiation levels have been found in produced fluids from Marcellus wells in northern and eastern Pennsylvania, indicating that there may be some regional trends in NORM.

Concerns are often raised that radioactivity in produced water often greatly exceeds drinking water standards. While this is true, no one is actually drinking produced water straight out of shale gas wells. Current practice recycles the produced water into subsequent fracs, and at the end, residual liquid waste is disposed of down deep UIC wells. In the early days of the Marcellus, however, radionuclides could have been an issue when flowback was run through municipal wastewater treatment plants and the outfall returned to streams. Publicly owned treatment works (POTW) focus mainly on suspended solids and do little to remove dissolved solids from the wastewater stream. As such, another town's water intake downstream could have taken in radionuclides. In a few cases, the Pennsylvania DEP has issued site remediation orders to private treatment facilities when the receiving stream exceeded radioactivity standards due to the discharge of NORM from treated oil and gas wastewater.

The USGS analyzed the sediments in streams below the outfalls of POTWs that had formerly treated Marcellus Shale produced waters (Skalak et al., 2014). No significant accumulation of radionuclides or associated alkali Earth metals (Ba, Ca, Na, or Sr) were found in the stream sediments, but in areas where brines from conventional oil and gas wells had been used on highways for de-icing, accumulations of Ra, Sr, Ca, and Na were found in adjacent soils (Skalak et al., 2014).

Organic compounds are also common in produced waters from Marcellus Shale wells (Orem et al., 2014). These naturally-occurring compounds include polycyclic aromatic hydrocarbons (PAHs), heterocyclic compounds, alkyl phenols, aromatic amines, alkyl aromatics (alkyl benzenes, alkyl biphenyls), long-chain fatty acids, and aliphatic hydrocarbons. Returned frac fluid contains additional organic chemicals, including solvents, biocides, and scale inhibitors. Total organic carbon (TOC) in Marcellus Shale produced water is as high as 5500 mg/L (Orem et al., 2014). Concentrations of hydraulic fracturing chemicals and TOC fall off rapidly within the first 20 days of production and water recovery, although a residual level of dissolved organic compounds may be present for up to 250 days after hydraulic fracturing.

Produced fluids are not the only source for NORM and organic materials. Long lateral wells drilled through black shale create large quantities (hundreds of tons) of fresh black shale drill cuttings that are often left on the surface. These materials may oxidize and weather over time, leaching toxic compounds and radionuclides into the groundwater for years.

Table 1 presents some analyses on a time series of produced water samples obtained from a Marcellus Shale well. The data were collected on a project at West Virginia University a number of years ago that was investigating methods for cleaning up produced water to recycle it as frac fluid. This has now become standard practice on Marcellus Shale gas wells.

The samples in Table 1 were collected immediately after completion of the gas well, 12 days after completion, 40 days after completion, and 112 days after completion to determine if the composition of the produced water changed over time. Conductivity is reported as microSiemens per centimeter, abbreviated µS/cm. Higher conductivity means the water has more dissolved solids (i.e. conductive ions) to carry electrons.

Using conductivity as an indication of TDS concentrations in the produced water, Table 1 shows a rather dramatic rise between the day 40 and day 112 samples. Fresh drinking water typically has a conductivity of less than 100 µS/cm, and the brackish water found in an estuary may be about 27,000 µS/cm. Seawater has a normal conductivity of about 54,000 µS/cm. Sample #4 in Table 1 has a conductivity of 190,100 µS/cm, or more than 3 ½ times that of seawater. The actual values for TDS, sodium (Na) and chlorine (Cl) are reported in grams per liter, not in the more conventional units of milligrams per liter, providing another indication that this water was extremely salty.

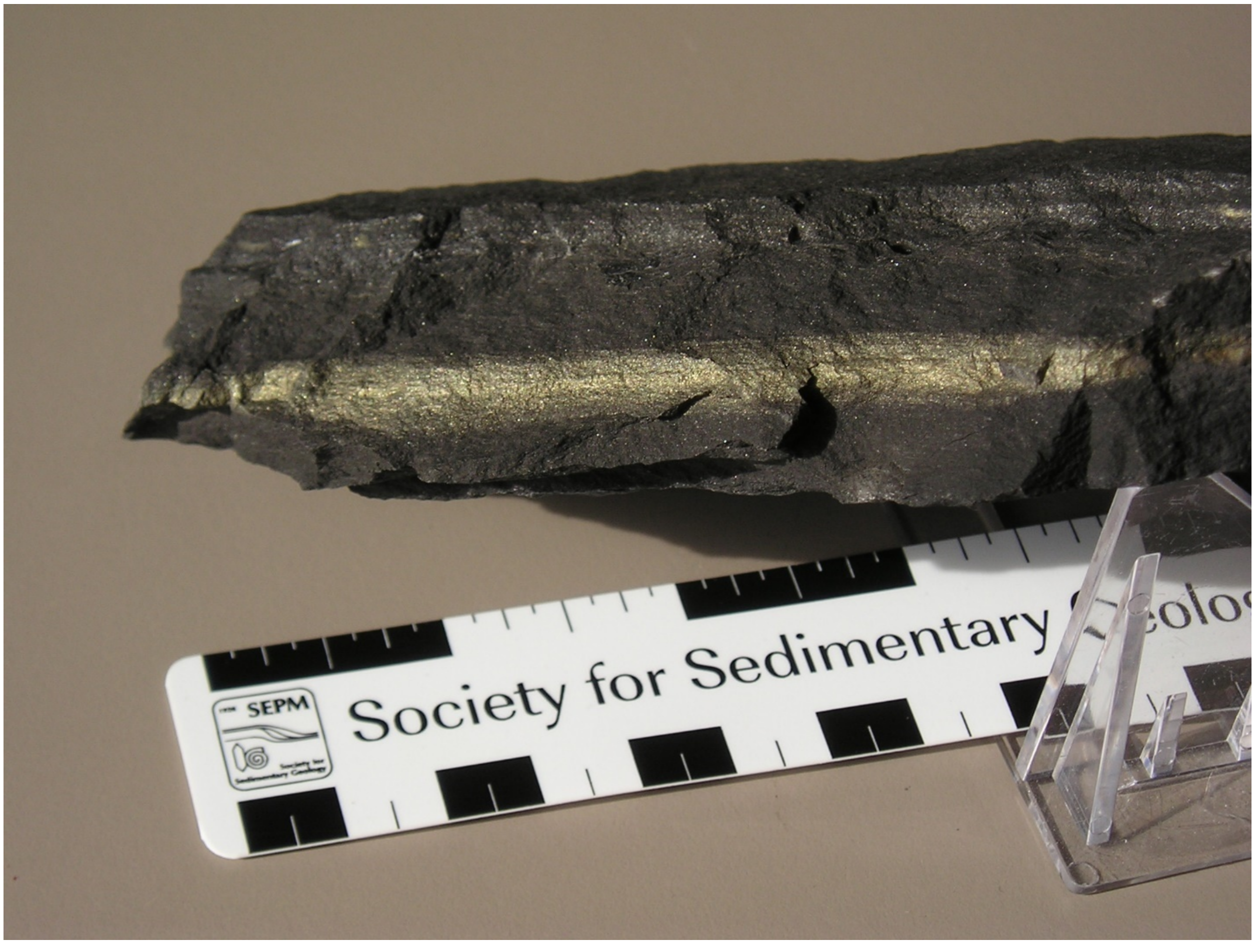
Table 1. Time-Series Flowback, Marcellus Shale Well

	1	2	3	4	< Sample	Detection
Unit	1/20/2010	2/1/2010	3/1/2010	5/13/2010	**<Date**	**Limit**
pH	7.60	6.07	6.42	6.28	pH	
µS/cm	23,655	16,807	44,610	190,100	Conductivity	
g/cm^3		1.01	1.03		Spec Grav	
mg/L	98.80	71.26	47.90		SO4	
mg/L	8.14	43.33	26.69		S	0.100
mg/L	71.00	130.00	47.90		SO4	
mg/L	1,128	1,851			COD	
mg/L	37.40	26.72	25.20		Total Fe	0.100
mg/L	29.34	15.29	21.54		Dissolved Fe	0.100
mg/L	319	1,749	1,382		Total Ca	0.100
mg/L	289	1,607	1,316		Dissolved Ca	0.100
mg/L	30.50	121.92	159.14		Total Mg	0.100
mg/L	24.42	105.14	121.58		Dissolved Mg	0.100
g/L	3.55	2.86	7.70		Total Na	0.100
g/L	3.37	2.48	7.70		Dissolved Na	0.100
mg/L		56.89	164.83		K	0.100
mg/L	<0.011	<0.011	439.49		Sr	0.011
mg/L			30.68		Dissolved Sr	0.012
mg/L	27.15	0.32	204.87		Ba	0.011
mg/L			14.23		Dissolved Ba	0.012
g/L	6.58	7.17	13.64		Cl	0.440
mg/L	44	220	40	74	TSS	2.37
g/L	8.80	12.61	33.80	185.51	TDS	3.40
	923	4,870	4,107		Hardness	
CPM	ND	ND			α Background	**radioactivity**
CPM	ND	ND			α	
CPM	51	32	72		β Background	
CPM	49	38	53		β	
CPM	424		449		γ Background	
CPM	406		420		γ	

The total suspended solids (TSS) content in Table 1 peaked about two weeks after the flowback began, suggesting that most of the fine materials had been flushed out of the well. The trends for Ba and Sr show little change between the first two samples, but then climb steeply in the third. Concentration of potassium (K) also rose significantly in the third sample. Geochemists at the USGS and the University of Pittsburgh have found similar variations of Ba and Sr concentrations in other flowback samples. An overall trend of gradually increasing concentrations over time contains occasional rapid concentration increases or "spikes" that then drop back to the original trend. Determining how and when these various ions were entrained in the produced water could be an important clue to the origin of the dissolved solids.

Radioactivity of the flowback water shown on Table 1 was measured for alpha (α), beta (β), and gamma (γ) radiation in values of counts per minute (CPM). Because radiation occurs naturally in the environment, measurements must be compared against background levels. The β and γ radiation values do not exceed background within the range of measurement error. Alpha radiation is easily blocked and difficult to measure in water samples; the values are given as "non-detects," or ND. The radioactivity data do not show any discernible trend over time like some of the other parameters.

The chemical oxygen demand on Table 1 measures the redox potential: how much oxygen is used to oxidize the reduced ions brought up from depth. The Marcellus Shale was deposited in anoxic bottom waters; in addition to preserving organic materials, the lack of oxygen also prevented any dissolved ions in the water, such as iron, from oxidizing. Instead, reduced iron precipitated in these euxinic shales as iron sulfide (FeS_2), laminated between layers of organic-rich, black mudrock (fig. 26). Iron sulfide commonly forms the mineral pyrite (also known as fool's gold) and the related mineral marcasite. Both of these will oxidize in air to iron oxide (rust), and sulfate, or SO_4. A familiar sulfate mineral is calcium sulfate ($CaSO_4$) or gypsum, which is used in plaster and drywall. Another sulfate compound is hydrogen sulfate, or H_2SO_4, which is better known as sulfuric acid. Sulfide minerals oxidizing into sulfuric acid in groundwater are the main cause of acid mine drainage in coal mining regions.



26. Photograph of layers of iron sulfide (pyrite, or "fool's gold") in the Union Springs Member of the Marcellus Shale. Photo by Dan Soeder.

5.5 NATURAL FRACTURES AND EMERGING TECHNOLOGIES

Natural fractures in low permeability rocks like the Marcellus Shale are required for economical rates of gas production. The permeability of the rock matrix itself is far too low for significant amounts of gas to flow from just the surface area of rock in contact with the borehole. As mentioned earlier, typical nanodarcy gas shale is a million times less permeable than a millidarcy conventional gas reservoir. A Marcellus well and the hydraulic fractures must connect with existing natural fractures that provide high-permeability flowpaths into a large volume of rock (Gottschling, 2007).

The hydraulic fracturing process opens and extends some existing fractures, creates new fractures, and causes blocks of rock to slide past one another slightly. This changes the distribution of open space in the formation, which must be accommodated elsewhere—occasionally by compression of the rock itself, but more often by closing down other, more distant, pre-existing natural fractures.

A sub-specialty of geology focuses on the origin and structure of fractures in rocks. Many rock types need a natural fracture system to produce oil, gas, and even drinking water, and quite a few details of the geological history of a rock formation can be determined from analysis of the fractures. Cracks in a rock can sometimes be more important than the rock itself.

As mentioned previously, natural fractures come in two basic types: joints, where the walls have simply pulled apart, and faults, where the walls have slid past each other (refer back to fig. 10). The orientation or direction of a fracture is called the strike, and the vertical angle it makes is known as the dip.

Two sets of vertical joints are prominent in the Marcellus Shale, and indeed in all of the Devonian shales of the Appalachian Basin (Engelder and Lash, 2008). The older set is known as the J1 fractures, and they strike 60–75° east of north, or to the east-northeast (ENE). These early fractures were created parallel to the axis of the Appalachian Basin as it subsided and filled with sediment. Engelder and Lash (2008) state that gas pressure generated within the shale during early burial exceeded rock strength, and created the J1 fractures in a process similar to hydraulic fracturing.

The second set of joints are called J2, which strike 315–345° from north, or to the northwest (NW). The J2 joints were formed by basin compression during the Allegheny Orogeny. The J2 fractures are oriented at more-or-less right angles to the J1 set, and the two together create an orthogonal fracture set responsible for the blocky shapes seen on shale outcrops, as shown in fig. 27. This photo of the Marcellus Shale type section in New York shows J1 joints crossing ENE from left to right, cut by the J2 joints oriented NW into the hillside at right angles.

Reconstruction of fracture formation requires an understanding of geologic history and careful observations of cross-cutting relationships to determine the order of events. The alignment of the ridges formed by the Allegheny Orogeny indicates that compressive stress from the Laurentia-Gondwana continental collision was directed toward the present-day northwest. The J2 joints are oriented in the direction of this compressive stress. Fractures form in the direction of compression because the walls move apart at right angles from the direction of maximum force. This is essentially what happens when firewood is split with a wedge – the wedge supplies compression at one end of the log, and the wood splits along the length.

27. Photograph of Marcellus Shale type section outcrop near Marcellus, New York, showing prominent J1 and J2 joint sets. Photo by Dan Soeder.

Two additional sets of joints, designated J0 and J3, are also present in the Marcellus Shale (Engelder and Lash, 2008). These are much less prominent than the J1 and J2 joint sets, and less important to gas production. The J0 joints are the oldest fractures, striking north-south, and are thought to have formed from increased overburden stress during the early stages of sedimentary burial. They are only important locally. The J3 joints are the youngest fractures, and not widely distributed. These are oriented east-northeast, and are related to elastic rebound after the thick, heavy ice sheets sitting on the shale during the last Ice Age melted at the end of the Pleistocene Epoch. They are limited to the northern, glaciated areas of the basin.

Artificially induced hydraulic fractures open up existing fractures and intercept others to provide flowpaths for the gas. The J1 fractures are thought to provide better gas conduits, because they are more laterally continuous than the J2 fractures. Horizontal wells in the Marcellus are typically drilled with an orientation to either the southeast or the northwest to cross the northeast strike of the J1 fractures, with the intent of intercepting as many of them as possible.

A hydraulic fracture from the lateral will be oriented in the direction of weakest stress in the rock, which in the Marcellus Shale would be the direction of the J1 fractures. A frac is engineered to force hydraulic fluid to enter and expand the J1 joints that have been intercepted by the lateral. The effectiveness of a frac depends on opening flowpaths in a direction perpendicular to the axis of the lateral, with the goal of contacting as much formation volume as possible. The frac also opens and expands the cross-cutting J2 set in areas away from the lateral. There is evidence that these two sets of fractures move slightly in a shearing motion as this takes place, which is beneficial to keeping the fractures open. Asperities on the fracture surface are offset by the shearing motion, and help to prop open the fractures. This reduces the amount of proppant sand needed. Ideally, the end result is a network of orthogonal fractures that drains gas from the rock in an efficient manner (Bruner and Smosna, 2011). However, the process is not without problems.

There is only so much space available underground. Pushing the walls apart on the J1 joints changes the minimum principal stress direction in the Marcellus Shale by imposing a new compressive stress at right angles to the ENE strike of the J1 joints. This compression to the northwest opens up new fractures parallel to the NW strike of the J2 fracture set. This means that hydraulic frac operations often end up initially creating fractures perpendicular to the lateral, but as the fracs extend outward, changes in the underground stress field cause them to change direction and run parallel to the lateral. This is much less efficient for the effective drainage of gas from the rock.

Because of changes in stress field orientation caused by the hydraulic fracturing process, some gas wells must be re-fractured after time intervals of months to years once the stresses have re-aligned with the regional stress gradient. A re-fracture treatment can open up new flowpaths perpendicular to the wellbore and produce more gas. However, mobilization and de-mobilization charges are a significant part of the total cost of a frac job, and bringing a crew back out to re-frac the well can be quite expensive. As such, engineers have designed several other types of fracture treatments that can reduce or avoid the need to re-frac.

One technique being applied on the Marcellus Shale and elsewhere is called a zipper frac. This treatment involves alternately fracturing matched zones in parallel laterals spaced about 300 meters (a thousand feet) apart in a back-and-forth pattern, stage by stage (Ghiselin, 2009). The zipper frac is designed to maximize borehole contact with the reservoir and to reduce the potential for stress fields introduced into the shale by one stage of the frac from interfering with the effectiveness of the next stage. When properly designed and executed, this hydraulic fracturing technique can be very effective at opening up a shale gas reservoir between a pair of laterals.

Similar to the zipper frac, a simultaneous frac involves two laterals that are fractured together. Instead of alternating side to side, a simultaneous frac treats matched stages of the two wells at the same time, to both minimize stress interference, and prevent communication between the fracture fairways (Gottschling, 2007). Wells treated with this technique reportedly yield a significantly higher initial gas production than individually fractured parallel wells.

Hydraulic fracturing with oil-based fluids in the Marcellus Shale deeply concerns some people as an alarming alternative to stimulating with water. It is important to note up front that the U.S. EPA signed a voluntary agreement in 2003 with BJ Services, Halliburton, and Schlumberger, three of the largest oilfield service companies performing hydraulic fractures, to NOT use diesel-based frac fluid. This agreement does not prevent the use of oil based muds and fluids for drilling, which some people have confused with oil-based hydraulic fracturing. Some operators did subsequently experiment with diesel-range petroleum additives for hydraulic fracturing, leading to EPA's issuance of guidance (Guidance #84) to more explicitly define the term "diesel fuels."

The original hydraulic fracturing process invented in 1947 by Floyd Farris of Stanolind Oil and Gas Corporation in the Hugoton gas field of Kansas did use crude oil and naphtha gels as the working fluids (Montgomery and Smith, 2010). The water-based frac was a more recent development, having been invented several years later. The only real advantage for using light oil, such as diesel fuel or kerosene, in a hydraulic fracturing operation is that if the target rock is preferentially water-wet, the oil will create fractures without infiltrating into the pore system and potentially plugging it up.

While this may be effective on certain water-bearing formations, the core analysis at IGT (Soeder, 1988) demonstrated that some and perhaps most of the Devonian black shales of the Appalachian Basin are preferentially oil wet (refer back to figs. 15 and 16). Using an oil-based liquid as a frac fluid would most likely result in a plugged well. In fact, an experimental frac using kerosene was tried on a Devonian shale well during the EGSP (Horton, 1981), with nearly disastrous results. The kerosene plugged up the pores of the shale to the point where it produced essentially zero gas flow, and the cleanup process was described in the report as "difficult."

Some other emerging technologies being applied to the Marcellus Shale include gas fracs, foam fracs, cryogenic fracs, and energy fracs. Reservoir stimulations using pressurized gas—carbon dioxide and nitrogen—instead of water were tried experimentally on Devonian shale during the EGSP (Horton, 1981). The advantages of gas fracturing include easier cleanup and less formation damage, especially on formations like tight gas sand that are preferentially water-wet. Disadvantages include a much higher cost, less effectiveness at initiating and growing the fracture, difficulty entraining and transporting the proppant, and a greater difficulty in controlling the growth of the fracture. For a shale like the Marcellus, which does not appear to be especially sensitive to water plugging-up pores, hydraulic fracturing is simply more economical and effective. Gas fracturing is used occasionally on the Marcellus for specific, specialized stimulations, but it is far less common than water-based hydraulic fracturing.

Foam fracs are a variation on a gas frac, where pressurized gas, usually nitrogen, is mixed with a liquid surfactant to create a high-pressure foam-like material capable of cracking the rock and carrying proppant into a fracture. The foam itself is designed to break down when pressure is released, leaving behind a residual amount of material to help prop open the fracture and allowing the nitrogen to escape from the well. Although they work well on shale, foam fracs are costly and used only in special circumstances.

Cryogenic fracs are a compromise between liquid and gas fracs, with the hope of having the best of both worlds. These were also tried on the EGSP, with limited success (Horton, 1981). The idea is to use the gas in liquid form as a hydraulic fluid to crack the rock and carry the proppant into the fractures. The gas then vaporizes, aiding in cleanup. Cryogenic liquid gases are quite expensive, and introducing such intensely cold fluids into the downhole environment can cause all sorts of problems. Steel casing may contract, become brittle and possibly split, cement may fracture or de-bond from the casing, and the expansion of ice as residual pore water freezes can cause formation damage near the wellbore. Liquid nitrogen, liquid carbon dioxide, and liquid methane were all tried on the EGSP. Except for methane, these gases must be removed from the produced natural gas before it can be sold to a pipeline, further increasing the expense. The economics are improved if the separated gas can be re-used in a subsequent stimulation.

Service companies these days offer stimulations using gases that liquefy at higher, non-cryogenic temperatures, such as propane and butane, with better results. These gases must still be recovered at the production wellhead before the natural gas can be placed into a pipeline, but the economics are better because cryogenic handling is not needed. Gas fracs are still more expensive than the same-sized hydraulic frac, however, and generally used only in special circumstances.

Energy fracs use chemical explosives to pressurize the rock, and are the oldest type of well stimulation technology. In the old days, these were done by dropping a lit stick of dynamite downhole, or using nitroglycerine. The problem with high explosives is that they transmit too much energy too quickly. They tend to thoroughly shatter the rock in the vicinity of the wellbore, but do not create the long permeable flowpaths into a reservoir desired for stimulation. Explosives often result in more formation damage than anything else. Modern energy fracs use a slower release explosive such as solid rocket propellant to achieve breakdown pressures in the rock without causing the formation damage from high explosive shock waves. This type of energy frac is called tailored pulse loading, and service companies continue to experiment with them.

Hydraulic fracturing is only used on formations at depths where the stress gradient will produce vertical fractures (King, 2012). This is generally considered to be greater than 2,500 feet or 775 meters, and applies to both vertical and horizontal wells. If a rock is too shallow, the low overburden pressure will result in a hydraulic fracture that breaks horizontally, or "pancakes," and does not contact the multiple layers that make up a typical shale reservoir. Sufficient overburden from the weight of the rocks above will prevent this, producing instead a much more efficient vertical fracture. This is because the rocks break in the direction of least stress, and when there is a lot of overburden, the least stress direction is horizontal. The rock splits from side to side, resulting in a vertical crack.

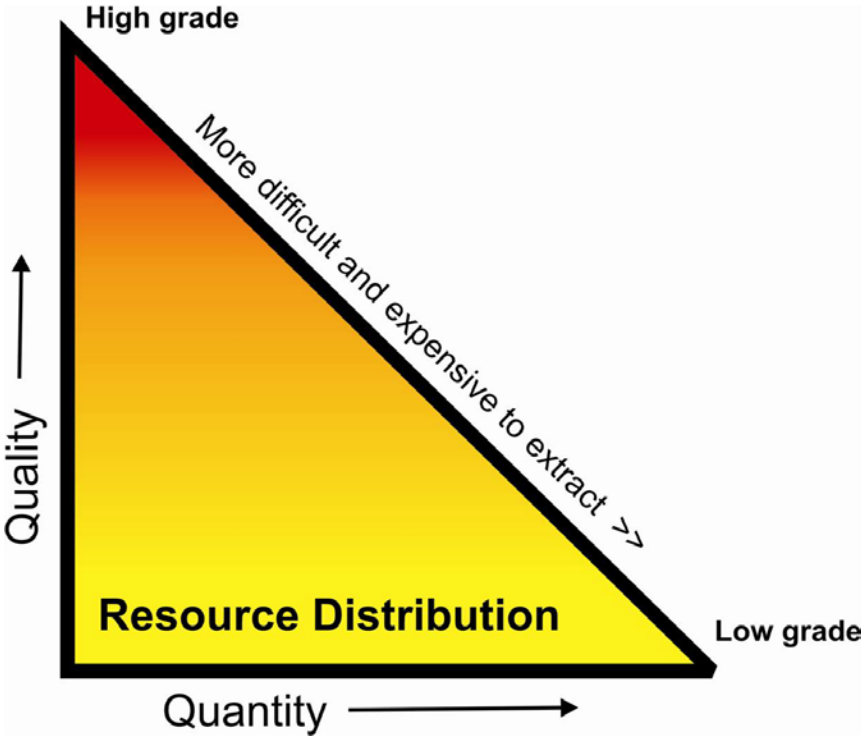
An alternative completion technique for formations too shallow to fracture is to drill them in a branched or "pinnate" pattern of side laterals off a main lateral resembling the structure of a feather (Long and Soeder, 2011). The multiple branched laterals can have a combined length of up to 4.5 km (15,000 feet) total. Pinnate drilling often uses a "coiled tubing" rig, which employs a flexible hose coiled on a drum to supply mud under hydraulic pressure to a steerable bottomhole assembly (Long and Soeder, 2011). The flexible hose allows for much tighter turns than steel drill pipe, but they are more limited in depth.

5.6 SHALE GAS RESOURCES

One of the most striking things about the Marcellus Shale and other shale gas resources is the huge amounts of hydrocarbons they contain. Gas resource estimates are built on a number of assumptions about the geology, gas generating potential, gas in place, and recoverable gas (Charpentier and Cook, 2011). As such, the uncertainty in the estimates is quite high, and the numbers are usually presented in a range ranked by probability. The USGS estimate for the Marcellus Shale gives a 95% probability that at least 43 TCF of gas will be recoverable, a 50% probability that 79 TCF will be recoverable, and a 5% probability of recovering 144 TCF. The mean for the Marcellus is 84 TCF of recoverable gas (Coleman et al., 2011). More recent refinements of the method with additional data have revised the upper end value for the Marcellus to as high as 367 TCF (Milici and Swezey, 2015).

More optimistic calculations done earlier by Engelder (2009) came up with an estimate that the Marcellus Shale has a 90% probability of yielding at least 221 TCF of gas, a 50% probability of yielding 489 TCF, and a 10% probability of yielding 867 TCF, assuming a power-law decline rate, 80-acre well spacing, and 50-year well life. Initial estimates for Marcellus Shale recoverable gas from the Energy Information Administration (EIA) were about 410 TCF (EIA, 2011), although the EIA has since reduced their estimates to around 144 TCF to be in line with the high-end numbers that came from the USGS in 2011. No matter how it is estimated, there is no doubt that the Marcellus Shale contains large quantities of natural gas.

When the quality or grade of most natural resources is plotted against the quantity, a triangle shape typically results (fig. 28). This is because the highest grade of any resource usually occurs in small amounts, with significantly larger amounts of lower-quality resource. Such a distribution is common for resources like iron ore, coal, gold, timber, diamonds, drinking water, and others. For every perfect one carat diamond, there are hundreds of others that are suitable only for making sandpaper. The ability to exploit a lower grade resource generally requires higher prices, improved technology or both (Soeder 2012a).



28. Illustration of the resource triangle showing the distribution of most natural resources, including natural gas, when quantity is plotted against quality. (Soeder 2012a)

The large volumes of gas present in black shale had been known for some time (Schrider and Wise, 1980). However, the early technology for recovering the gas was costly and only produced limited amounts of the resource. The application of directional drilling and hydraulic fracturing allowed gas to be recovered from shale at prices comparable to conventional reservoirs, and sometimes even cheaper. The Marcellus Shale in particular is located near the big interstate pipelines built to carry gas from the Gulf Coast to cities in the Mid-Atlantic and Northeast. In southwestern Pennsylvania where development began, connections were easily made between newly drilled shale gas wells and the major gas transmission lines passing through the area.

5.6.1 Resource assessment

The amount of gas generated within the Marcellus Shale is assessed from a geological standard called the source-rock quality. This assessment combines data for total organic carbon content, type of organic matter, and thermal maturity, and gives it a rating such as fair, good, excellent, etc. The source-rock quality of the Union Springs Member of the Marcellus Shale (the lower unit—refer back to the quarry exposure shown in fig. 7) is rated exceptional in southwestern Pennsylvania and northern West Virginia and excellent in western New York, western Pennsylvania, eastern Ohio, and western West Virginia (Bruner and Smosna, 2011). The source-rock quality of the upper Marcellus unit, the Oatka Creek Member, is rated exceptional in northwestern West Virginia and southeastern Ohio and excellent in west-central Ohio and southwestern Pennsylvania. The presence or absence of conditions favorable for the transformation of this organic matter into gas, such as burial history and thermal maturity are called the relative gas potential of the rock. A rock may have excellent source-rock quality, but if it has not been properly "cooked," it will have a low relative gas potential and not be very productive.

The gas content of the rock is known as gas-in-place (GIP). GIP is calculated from the geographic extent and stratigraphic thickness of the rock unit, combined with a value derived from the source-rock quality and relative gas potential. There are a number of assumptions built into such calculations, and the results can vary widely. GIP in the United States is expressed as billions of cubic feet of gas per square mile, and as trillions of cubic feet for the entire resource (Bruner and Smosna, 2011). Metric equivalents would be millions of cubic meters per square kilometer, and billions of cubic meters.

An early estimate for the GIP value of the Marcellus Shale was derived from the geochemical analyses done by the Monsanto Mound Laboratory in Ohio on the EGSP core (Zielinski and McIver, 1982). The Mound Lab estimate of 178 TCF for GIP is much lower than modern estimates. This is due in part to a smaller study area, which excluded parts of southern New York and northeastern Pennsylvania, and also because only a dozen of the 34 Appalachian Basin EGSP cores reached the Marcellus Shale or equivalents (these are NY-4, OH-1, OH-4, OH-7, OH-8, PA-1, PA-2, PA-3, PA-4, PA-5, WV-6 and WV-7—see fig. 12 map for locations).

Other resource assessments of the Marcellus have been done periodically over the years as more data became available (for example, see Kuuskraa and Wicks, 1984; or Charpentier et al., 1993).

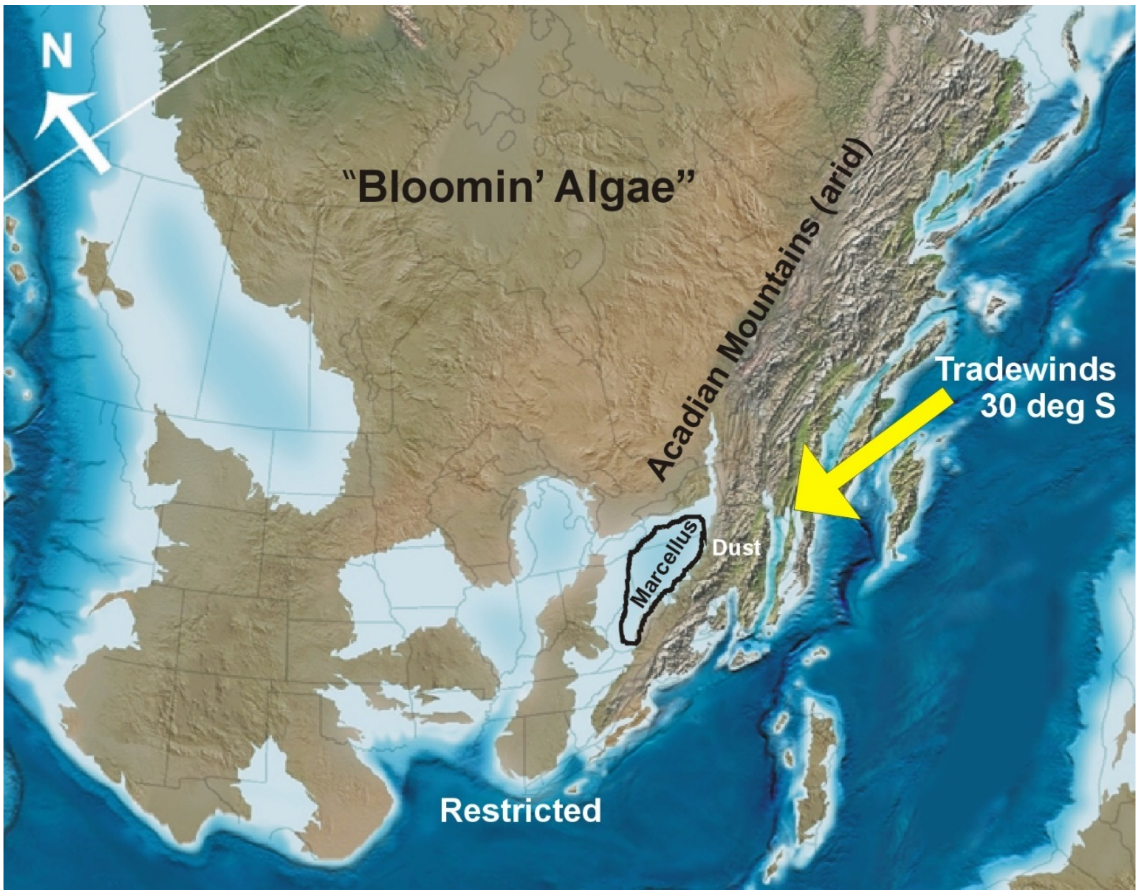
The wide range of estimates for GIP in the Marcellus and other U.S. domestic gas shales is a clear sign that a better understanding is needed of how gas is generated in the shale, and where it resides. Little is known about the basic petrophysics of gas and liquid movement from shale pores into fractures, and from there to a well.

Because shale pores are so small, interactions with pore fluids must be understood at the molecular level (Rodriguez et al., 2014). The nanometer-size pores in shale are approaching the scale of individual gas molecules, where phenomena like gas slippage are not well understood. Diffusion is probably a more important component of gas migration through shale pores than laminar flow. Significant amounts of gas are held in shale by adsorption, presumably on organic matter, but clays may also be important, as shown by adsorption studies on organic-lean shales (Busch et al., 2009). More knowledge about these processes would help to reduce the uncertainty in the assumptions used in the various estimates. Less uncertainty would lead to more constrained numbers, and provide more accurate estimates of GIP.

The amount of recoverable gas is always some fraction of the GIP, under the assumption that 100% of the gas will never be recovered, even under the best of circumstances. Hydraulic fractures don’t contact every part of the formation; some pores may be blocked with water or oil, and others may not be connected to flowpaths. The value for this recovery fraction varies from assessment to assessment. Engelder and Lash (2008) assumed a technically recoverable gas fraction of 10 percent from a Marcellus Shale GIP resource of about 500 TCF. A recent assessment by Clarkson (2013) reports an expected recovery of 40% to 60% of the total gas in place from shale reservoirs over a well lifetime of 10 to 25 years.

Why does the Marcellus Shale contain so much gas? Most geologists agree that the gas was derived from rich deposits of organic matter in the shale, formed from abundant marine algae that grew and died in the shallow Appalachian Sea during the time of Marcellus Shale deposition. Wrightstone (2011) suggested that the planktonic or floating marine plants were fertilized regularly by dust blown into the basin by trade winds off the arid Acadian Highland areas to the east, which would have added a host of mineral nutrients to the water column in the enclosed Appalachian Basin, including iron and phosphorous. Iron is a fertilizer for algae and has, in fact, been proposed as an additive to seawater for creating oceanic algal blooms that may help remove excess carbon dioxide greenhouse gas from the atmosphere (Powell, 2008).

Wrightstone (2011) describes explosions of plant growth in the Appalachian Sea from the periodic fertilization by dust-blown minerals as “bloomin’ algae” (fig. 29). He cites documentation from a modern algae bloom that occurred in the Tasman Sea after an epic Australian dust storm in 2009, and similar algal blooms in the Atlantic Ocean from dust storms off the Sahara Desert. Under a microscope, a significant part of the mineral matter in the Marcellus Shale appears to be small particles of quartz that are just the right size to be carried by the wind. Minerals from windblown Tioga volcanic ash might also have fertilized algae.



29. Illustration of “bloomin’ algae” in the Appalachian Basin during Marcellus Shale deposition. Modified after Wrightstone (2011); base map from Blakey

From a sedimentology standpoint, gas productive black shales appear to require low rates of sedimentation combined with significant organic input (Smith and Leone, 2010). Too much sediment dilutes the organic material and makes the shale leaner. Sparser amounts of mineral sediment allow organic matter to concentrate, generating more hydrocarbons.

Algal blooms create organic matter in the water column, which then migrates to the ocean bottom when the plants die and sink. This sedimentary organic material is known as sapropel. During the time of Marcellus Shale deposition, the enclosed, restricted Appalachian Basin would have had limited water circulation, similar to the modern Chesapeake Bay. Nutrient inputs to the Chesapeake from agricultural runoff or inadequate sewage treatment result in algal blooms. When the algae die and sink to the bottom, decay bacteria rapidly remove residual oxygen from the bottom waters and create anoxic conditions that preserve the organic material. Similar conditions may have helped preserve organic material in the Marcellus Shale.

5.6.2 <u>Other shales</u>

In terms of total natural gas resources for the United States, the Marcellus Shale is important, but by no means the only player. Development of the Barnett Shale in the Fort Worth Basin of Texas, the Fayetteville Shale in Arkansas, and the Haynesville Shale in Louisiana all pre-date the Marcellus play, and all are still producing.

As gas prices dropped from an oversupply caused by shale gas production, exploration and production companies turned their attention to liquids-rich shale plays such as the Eagle Ford in Texas, the Niobrara in Colorado, and the Utica in Ohio. The natural gas liquids in these formations are produced in the vapor phase, and accompany the natural gas production out of the well. They condense to liquids under reduced temperatures at the surface, hence their name "condensate." Operators in liquid-rich plays typically have gas processing plants near production wells to remove condensate such as ethane, butane, propane, hexane, and others, which are worth significantly more money than dry gas. Liquids can also be transported more easily than natural gas, which is mostly limited to pipelines. The Marcellus is known primarily as a dry gas producer, because thermal maturity is too high to have retained many natural gas liquids. However, the far western part of the play near the Ohio River produces the condensate ethane, an important component of polyethylene plastic, and many operators have focused here.

One of the problems with producing natural gas liquids from shale is known as "retrograde condensate." The natural gas liquids exist in a vapor phase under initial reservoir pressures and temperatures. If reservoir pressure management techniques are not applied during production, changes in downhole conditions may cause the vapors to condense into liquid form while still within the shale, resulting in the two-phase flow problem documented by IGT in the Huron Shale (refer back to fig.15). Producing both gas and liquid phases simultaneously from the tiny pore spaces and flowpaths in shale without losing permeability is a major engineering challenge.

The best known liquids-producing shales in the United States are the Mississippian-age Bakken Shale and the Three Forks Formation beneath it in the Williston Basin of North Dakota, where the liquids production is light crude oil. The production from this so called “tight oil” play is different than in more typical gas shales. The Bakken consists of an upper and lower black shale unit, and oil is most often produced from horizontal wells in a middle, unnamed limestone member between the two shales (LeFever et al., 2013). The oil is a very light crude, similar to home heating oil, and there are only a few U.S. refineries that can handle it. Most of these are located on the Gulf Coast, and the issues revolving around the movement of Bakken oil from the northern Great Plains to the Gulf via truck, railroad, or pipeline have been contentious on many levels.

Recent USGS assessments suggest that the Bakken-Three Forks may have recoverable reserves of 7.5 billion barrels of oil, and 6.7 TCF of natural gas (Gaswirth and Marra, 2015). North Dakota lacks much of the infrastructure required for handling the natural gas associated with oil production, and until recently operators were flaring it off, making parts of the North Dakota prairie appear in aerial and satellite views as brilliant as a large city at night. Such gas is now commonly being re-injected into the ground to maintain reservoir pressures and awaiting the arrival of transmission pipelines. The prolific Bakken-Three Forks has made North Dakota the second largest oil producing state in the nation, behind only Texas (EIA, 2014).

Texas is still ahead of North Dakota in oil production because of the Late Cretaceous-age Eagle Ford Shale, which is also a tight oil play, although it produces dry gas in the higher thermal maturity areas. The Eagle Ford extends south along the Gulf Coast into Mexico. The Mexican national oil company, PEMEX, was initially reluctant to get aboard the shale development bandwagon, but after observing significant production in Texas, they are showing interest in the Eagle Ford and other shales.

It is worth briefly mentioning production from the Utica Shale, a Middle Ordovician (470 Ma) black shale (fig. 30) in the Appalachian Basin that underlies the Marcellus in many areas

(Ryder et al., 1992). This superposition allows for “dual completion” wells, wherein two target formations are produced from a single borehole. The economics for this are extremely favorable, and a number of companies have been producing two or more shales from such “stacked plays.” The Utica extends farther into the northern, western, and eastern reaches of the basin than the Marcellus, and in eastern New York near the Hudson River, it fills buried grabens to thicknesses of up to 600 meters (2,000 feet). In Ohio, the Utica Shale extends westward from the Pennsylvania border to nearly the center of the state (Erenpreiss et al., 2011).

The liquids-rich production area of the Utica is in southeastern Ohio. Although the formation tends to have more carbonate and a lower organic content than the Marcellus, it is also deeper and thicker. The initial production (IP) from several Utica wells in Ohio has been astonishing, significantly exceeding Marcellus IP numbers in southwestern Pennsylvania. A recent assessment of the hydrocarbon resources in the Utica estimated that approximately 782 TCF of natural gas and liquids may be recoverable from this formation (Hohn et al., 2015). Compared to the mean of 84 TCF of recoverable gas assessed in the Marcellus by the USGS (Coleman et al., 2011), or even the more optimistic estimates by Engelder (2009) of 489 TCF of Marcellus gas, 782 TCF is significant.

Other shales of interest in the United States include the Rhinestreet and Ohio shales in the Appalachian Basin above the Marcellus, generally referred to as “Upper Devonian” by the drilling companies. These shales could also be tapped by dual completion wells. In fact, the stratigraphy at a few localities contains the Upper Devonian above the Marcellus, and the Utica below the Marcellus, suggesting a possibility where all three shale targets are completed.

Alabama is investigating possibilities with the Floyd Shale and the Conasauga Shale. Other well-known, organic-rich shales like the Antrim in the Michigan Basin, the New Albany in the Illinois Basin, and others are being explored for their gas potential. In Utah, the Mancos, Manning Canyon, Paradox, and Pierre-Niobrara shales have gas potential. The Niobrara has undergone significant development in the Denver-Julesburg Basin in Colorado and in places in Wyoming. It is also being assessed as a small producer in South Dakota (Soeder et al., 2015).

A potentially useful byproduct of increased natural gas production could be an increase in the supply of helium. Most commercial helium is produced by the natural radioactive decay of elements in the Earth, and becomes trapped with natural gas. Traditional production of this important element from conventional natural gas fields in Kansas, Oklahoma, and Texas has declined in recent decades, even as demand has risen. Cryogenic uses of liquid helium, and increased helium use in Homeland Security screening devices have caused prices to skyrocket. Helium contents in shale gas are typically low, but with improved separation technology, greater overall gas production, and high helium prices, there is a potential to develop new supplies.

30. Photograph of the Flat Creek Member of the black Utica Shale exposed at Flat Creek, New York. Photo by Dan Soeder, 2010.

5.7 RESOURCE DEVELOPMENT

The development of domestic shale gas stems from the so-called "energy crises" of the 1970s caused by the embargo of oil exports to the United States. The U.S. Department of Energy crafted a solution to these disruptions by broadening domestic energy production across a mix of natural resources. The Obama Administration has called this an "all of the above" energy strategy, where the idea was to lessen dependence on a single supply. Shale gas was one of these "all of the above" resources, and the persistence of people like George P. Mitchell carried it forward.

Is the "energy crisis" still a valid concern in the 21st Century? Do we really need domestic energy production in the United States? One major difference from the 1970s is that the United States now faces strong competition for world oil supplies from developing industrial countries such as China and India. Future supply disruptions of imported oil may be due more to economics than politics. Foreign oil producers could choose to sell their product to any country willing to pay the highest prices, and that might not be the United States. Secure domestic energy supplies are still important.

The extensive development of shale gas and oil in the twenty-teens has significantly changed energy economics in America and the world. Traditional pathways for the movement of energy, from the U.S. Gulf Coast to the Northeast, from Alaska to California, from the Middle East to Europe and the U.S. East Coast have all changed. Some U.S. pipelines have reversed flow, moving natural gas liquids from Appalachia to Gulf Coast refineries. Liquefied natural gas (LNG) import terminals on the U.S. East Coast are being reconfigured for exports. With the recent loosening of export restrictions imposed in 1975, oil from the Bakken Shale is being exported to China and Japan.

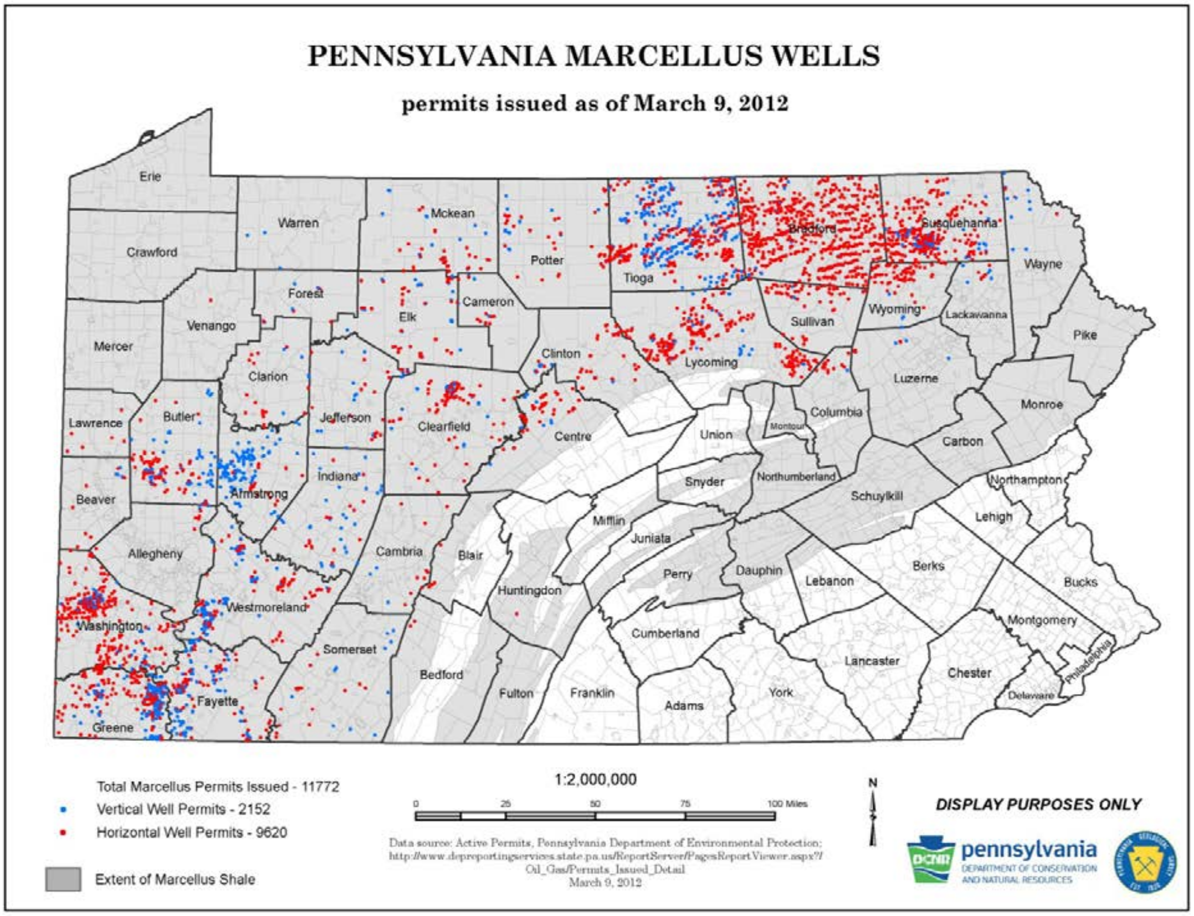
It is not just changes in the location of the fossil energy production that are disruptive. Abundant natural gas from shale is displacing other forms of fossil energy such as coal (Culver and Hong, 2016). This has devastated regional, coal-based economies in places like Appalachia, but has also produced significant environmental benefits by reducing overall U.S. carbon dioxide emissions. However, the environmental advantages of gas must be weighed against the disruptions caused to vulnerable populations by changing energy economics. Some in southern

West Virginia would argue that the environmental benefits of turning away from coal are not worth the cost.

There is no doubt that natural gas is a relatively clean and efficient fuel compared to other fossil energy sources. It is lower than both oil and coal in carbon dioxide emissions per Btu, and gas production is far less disruptive to land and water than surface (strip) mining of coal. Likewise, natural gas does not produce any of the hazardous combustion byproducts of coal, or the photochemical components of smog like gasoline. Shale gas may not be the ultimate energy solution for the United States, but it is a better alternative at present than any other fossil fuel for the environment.

Fig. 31 is a map from the Pennsylvania Department of Environmental Protection that shows the locations of nearly 12,000 Marcellus Shale gas drilling permits, including more than 9,600 for horizontal wells as of March 2012. (http://www.depweb.state.pa.us) The date on the map is not important, and the reason for including it was to show a trend. Most of the Marcellus Shale wells are located in either the southwest corner of Pennsylvania, or in the northeastern part of the state.

Southwestern Pennsylvania is where the play began, in Washington County where Range's discovery well, Gulla #9 was drilled in 2007. The shale is thinner here and not as productive as other parts of the play, but the interstate transmission pipelines run through this area on their way east, and were able to take in the Marcellus gas. The shale in this location produces both methane gas and the condensate ethane, which is valuable feedstock for making polyethylene plastic. The second most concentrated area for shale gas development is in the northeast corner of Pennsylvania near the New York state line. The well locations here line up along the valley and ridge topography in this part of the folded Appalachians. The Marcellus Shale is thicker and more gas productive than in the southwest, but there aren't many pipelines through northeastern Pennsylvania. Many of the permits shown on the map are undrilled leases that are waiting for a pipeline. Marcellus gas production in northeast PA is nearly pure methane without profitable condensate, and many operators are waiting for natural gas prices to climb back to profitable levels before spending the capital on a well.



31. Map of gas leases and completed Marcellus wells in Pennsylvania as of October 2010, modified from Pennsylvania Geological Survey

The take-home lesson is that impacts will be the greatest in areas of concentrated drilling, defined by the "sweet spots" in the play. Trying to predict the locations of future impacts requires trying to ascertain where the drillers and their rigs will be going. A continuous gas resource like the Marcellus has many factors besides geology that dictate the locations of future development.

A trend over the past few years has been to establish horizontal Marcellus wells in existing, small gas fields that are producing from conventional reservoirs such as sandstones, stratigraphically either above or below the shale. Such gas fields already have compressor stations, gas processing plants, and pipeline infrastructure in place, and it is quite economical to hook a Marcellus well into the existing gathering lines. As an added benefit, operators can often use production from the existing gas field to run the generators needed to operate their hydraulic drill rigs, thus saving considerable money on diesel fuel.

When counting wells, it is important to distinguish between leases, permits, drilling, and actual well completions. An assessment of completion reports from state records by Avary and Schmid (2012) determined that 1,469 horizontal and 499 vertical Marcellus shale wells had been reported as completed in Pennsylvania for a total count of 1,968. This compares to the 12,000 permits issued as of the same year shown in fig. 31. In West Virginia, the numbers are 1,398 vertical wells and 366 horizontal. This is a total of 3,682 Marcellus Shale wells within the play, of which 1,835 are horizontal.

In actuality, the number of drilled wells is much higher, because the completion reports lag months to years behind the drilling. Obtaining an accurate count of Marcellus wells is a challenging question that has many researchers stumped. The number in Pennsylvania is somewhere between the 12,000 permits issued and the 1,968 completion reports received. Narrowing it down further is anyone's guess, but there may be around 4,000 Marcellus wells to date.

5.7.1 **Social license**

The development of shale gas resources faces a barrier known as a "social license." This means that the community, which is likely to be affected by the noise, dust, lights, congestion and other inconveniences associated with the shale gas project must agree that it is worth doing. If operators expect to be met with a permit, rather than a protest, the community has to be convinced that the benefits outweigh the liabilities, and the level of acceptable risk is acknowledged.

Companies generally understand that careless or blatant environmental violations will only result in their losing access to the resource. Having the entire State of New York closed to shale gas drilling has made this point quite clear. As such, many companies recognize the need for community involvement.

Operators often work with township or county road authorities to route truck traffic onto roads that are already slated for repair, and then pay to replace the road after the wells are completed. Most operators avoid moving equipment and materials during the hours when school buses are operating. In some locations, temporary overland pipelines serve to move water around instead of a fleet of trucks.

Other, more direct community support from companies includes donations of parkland and baseball fields to a town, construction of recreation or youth centers, and helping to fund local charities. Operators recognize that these investments in a community are the necessary cost of a social license to do business.

A sociological study on the impacts of Barnett Shale drilling in Texas (Theodori, 2008) found some public perceptions that are applicable to the Marcellus. Surveys done in Texas compared counties with a population familiar with the drilling industry (identified as a more mature county) to those that were less familiar with it.

In less mature counties, the social and environmental impacts of the drilling were largely seen as being negative, although the economic and service related aspects were viewed positively. Negative factors included concerns about increased truck traffic, large volumes of freshwater use, higher tax rates, aquifer depletion, noise pollution, and water pollution. Positive factors included economic development, new jobs, better local police force protection, enhanced fire protection services, improved medical/health services, and financial benefits to schools. The bottom line was that the public tends to distrust the intrusion of the gas industry into a community and resent the environmental issues that accompany it, while at the same time the citizens welcome the economic and service-related benefits.

Tarrant County, which includes the City of Fort Worth, was considered a mature county because of the longer history of Barnett Shale production. Even here, public perceptions about risks and benefits of drilling were mixed. Theodori (2008) found that social and environmental factors are more likely to elicit a citizen response than an economic factor. In other words, potential water contamination from a frac fluid spill was the talk of the town, but the prospect of funding new schools with drilling taxes didn't garner much attention.

Most people who work in the shale gas development industry are sensitive about being associated with those who carry out bad practices. Individuals and companies who follow good practices rightly hold themselves above those who don't, bristle indignantly, and refuse to apologize for "bad operators." Apologies are not needed, but a little more self-policing is. Even though drillers often know of a bad operator, there is a great deal of ingrained reluctance throughout the industry to interfere, or tell someone "how to run their business." When the issue of self-policing is brought up, the standard answer from industry is that responsible companies will cease commercial interactions with the bad operators and eventually drive them out of business. All well and good, but this process is slow and allows a great deal of collateral damage to be done in the meantime.

At the worker level, firing incompetent, careless or sloppy employees may solve the problems at one site, but in boom times when workers are in short supply, these people just go down the road and get another job at the next drill rig, often without even a simple reference check or a phone call to a former employer to slow them down. The industry as a whole needs to do a better job internally at dealing with the bad apples, both the individuals and the companies. If responsible operators took action to call the regulators and stop the bad practices, it would benefit them, their industry, and society in general.

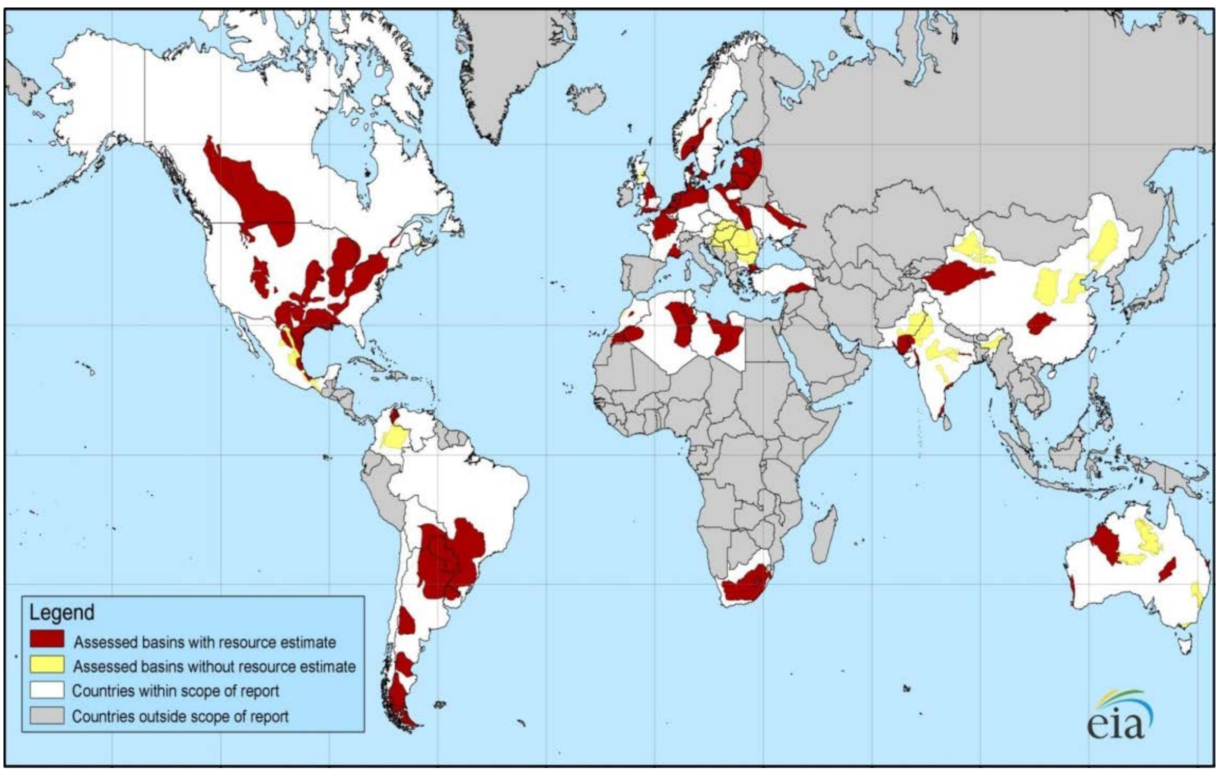
5.7.2 International resources

Gas and oil production from shales are of interest worldwide. Many countries who are limited on conventional hydrocarbon reservoirs are finding gas and oil-rich black shales to be a significant resource. Once George Mitchell's ideas about how to horizontally drill and hydraulically fracture these rocks became known, the exploration of shale energy resources took off nearly everywhere (fig. 32). Shales in Canada, Britain, Germany, Poland, Ukraine, China, India, Australia, South Africa, Argentina, Brazil, and other countries are being investigated for hydrocarbon potential. Estimates for shale gas resources in other countries are often very uncertain because data are sparse. Some Arctic sedimentary basins in Canada, for example, may have gas shales in them, but are so remote that no one has drilled or explored them yet.

A number of European countries are interested in domestic shale gas because of the high cost and political uncertainty inherent in importing natural gas. The day-to-day realities of environmental sensitivities in the Eurozone have made shale gas development much more challenging in Europe, however. France has banned hydraulic fracturing and is pushing for similar measures throughout the European Union.

Other countries are moving forward, albeit slowly. The United Kingdom has some potential gas shales in England. The British Royal Academy of Engineering and Royal Society (2012) investigated the technical risks associated with the extraction of shale gas and assessed ways that these can be managed. Germany has also been tentatively investigating potential environmental risks of shale gas development.

Poland is one of the countries trying to move away from a reliance on domestic coal and imported gas, and they are interested in developing domestic natural gas from Silurian black shales. These occur at depths of 3–4 km (about 10,000 to 13,000 feet) in a belt stretching from central Pomerania to the Lublin region (Konieczyńska et al., 2011). The Polish Geological Institute and the Voivodeship Inspectorate for Environmental Protection carried out an environmental impact assessment in 2011 on a shale gas well called Lebien LE-2H (Konieczyńska et al., 2011). This is one of the first such assessments ever done. The Polish scientists collected data on air, water, groundwater, ecosystems, and landscape impacts from the development of the Lebien LE-2H well, and concluded that when proper construction techniques were followed, environmental impacts of shale gas drilling were minimal and manageable.



32. Map of sedimentary basins worldwide containing assessed shale gas resources, modified from U.S. Energy Information Administration

6. RISKS TO THE ENVIRONMENT

In April 2012, Presidential Obama ordered the U.S. Department of Energy (DOE), U.S. Department of the Interior (DOI), and the U.S. Environmental Protection Agency (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 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 lifecycle 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., 2014). This is different from "environmental risk," which assesses the relative impacts of contaminants on receptors in terrestrial or aquatic ecosystems, and 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 on-site (Soeder et al., 2014), 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., 2014).

Large amounts of unbiased scientific data from shale gas development done under different circumstances in a variety of locations are needed to obtain a 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 a reluctance on the part of industry to cooperate with such studies, in particular involving groundwater (Soeder, 2015). A number of prominent hydrologists have been calling for detailed, field-based groundwater monitoring near shale gas 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. Department of Energy’s National Risk Assessment Partnership (NRAP) has been applied to assessing the engineering risks of shale gas (Soeder et al., 2014). 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, 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., 2014). The paper by King (2012) provides a detailed description of the factors contribution 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 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 comparing 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 couldn’t 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 environmental, 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 downtime in the field. This reduction of risk is good for the environment, along with being good for investors.

6.1 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 the Earth each day versus rare giant asteroid impacts once every ten millennia, and so on.

Acceptable risk is the cut-off 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 added to a standard house in Florida will significantly reduce the risk of damage from a low to moderate strength hurricane when compared to an unprotected house. Based on the discussion above, 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 percent 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 typically consist of 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 feet 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 about 100 m, or 300 feet, since most domestic water supply wells 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 economic 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, which is often extremely expensive, 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 PA 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 flowpath for gas to enter shallow aquifers. This practice appears to have corrected the engineering design flaw of open-hole completions and 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., 2014).

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 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.

6.2 ENVIRONMENTAL CONCERNS

There have been numerous articles, editorials, blogs, webpages, 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. But 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 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 non-technical 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” illustrates the depth of distrust that Americans have with 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 don’t 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 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.

A small sampling of recent scientific papers and reports that document the problems, risks, and non-issues that come with the development of shale gas includes 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. (2014), Vidic et al. (2013), Warpinski (2013), and Werner et al. (2015). Citations for all these papers can be found in the references section. A fully comprehensive listing would run to hundreds of titles, with dozens more are 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 don't 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, a number of 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 came up with a list of twenty 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 on-line (SEAB, 2011).

Congress requested the U.S. EPA in 2010 to investigate possible links between hydraulic fracturing and drinking water contamination. After nearly five years 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. The key findings of this nearly thousand page report (USEPA, 2015) include identifying the mechanisms by which hydraulic fracturing activities may impact drinking water resources above and below ground. 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 is 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 (2016) has recently taken issue with a number of statements in this report, including specifically the conclusion stated above. They found that the "lack of evidence for widespread, systemic impacts of hydraulic fracturing on drinking water resources" is not supported quantitatively, nor are the resources of interest 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 recommends that the EPA provide quantitative analysis that supports this conclusion, along with clarification and additional explanations.

The multiagency assessment of 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
7. Human health effects

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

6.2.1 The peer review process

Peer reviewed scientific literature is the primary method used by the scientific community for grappling with new ideas and findings. A good definition of peer review from the EPA is a “documented critical review of a specific major scientific and/or technical work product. Peer review is intended to uncover any technical problems or unresolved issues in a preliminary or draft work product through the use of independent experts. This information is then used to revise the draft so that the final work product will reflect sound technical information and analyses" (EPA, 2012). This book, for example, has been peer-reviewed both internally and externally by nearly a dozen different experts, who provided a lot 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; and 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 non-federal and non-tribal 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.

Oil and gas drilling is regulated by the states, and the regulations are periodically reviewed. A group known as STRONGER (for State Review of Oil and Natural Gas Environmental Regulations; http://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. (http://www.strongerinc.org/stronger-publishes-report-outcomes-hydraulic-fracturing-state-reviews/)

6.2.2 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 below.

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 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 & 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 (Baldassare, 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 pre-existing methane to be transported toward nearby domestic water wells (Soeder, 2012b). 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 pre-existing 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 (Kell, 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. Assessment 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 high volume hydraulic fracturing (HVHF) in the shale wells. This process sends pressure pulses down from the surface, and 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 GHG 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 GHG 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 percent less GHG 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 co-authors have in turn rebutted this claim.

A number of other assessments have examined the GHG 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 percent greater (Hultman et al., 2011) to only 1.8–2.4 percent 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.

A number of 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). Wellsite 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. 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., 2014). 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, quantifying air contamination issues, and investigating the potential for toxic metals, radionuclides, and organic compounds to leach from the black shale drill cuttings and other solid waste.

6.3 SHALE GAS IMPACTS

Drilling and production of natural gas, especially shale gas, is an industrial activity. 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 24/7, and 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 was an unusual sight. Some people can't 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 non-disclosure 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 has 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 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 produces very little of its own supply (Revkin, 2012). According to some calculations, the state-wide 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: learning from accidents, training workers not to make the same mistakes, changing procedures to avoid problematic situations in the first place, and fostering 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., 2014). 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.

6.3.1 Risk assessment

Environmental impacts can be short-term or long term. Short-term impacts are related to well construction, and 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 offsite, 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 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. Assessing 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 about 10 percent 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 percent 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 19th 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 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 POTWs would release at least 200 cubic meters 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 of 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.

6.3.2 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 Department of Environmental Protection (PADEP) inspection data (http://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, PADEP maintains a searchable and downloadable online database of oil and gas well violations at http://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 years of records in Texas and 24 years of records in Ohio for all oil and gas wells (not just shale gas), and 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 detected contamination of groundwater or disrupted water supply due to development of oil and gas or management of wastes.” 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 percent), 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 pre-date 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 common onsite 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% (Kell, 2011, Appendix F and G). Ohio recorded 144 contamination incidents on 33,304 wells, for an occurrence rate of 0.432% (Kell, 2011, Appendix D and C). Both states reported zero groundwater contamination incidents associated with well stimulation (hydraulic fracturing) during the time periods studied.

Another report from SUNY University 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 about 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 2,000 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.

6.4 HYDRAULIC FRACTURING CHEMICALS

High volume hydraulic fracturing 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., 2014).

Other industries use chemicals that are more toxic than any compounds on a drill site, and often in even 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.

6.4.1 The "Halliburton loophole"

In 2005, at the urging of then Vice President Dick Cheney, the oil field 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 oil field 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 an 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 non-disclosure 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 United States 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 didn't 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 web sites 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. A number of states now require the posting of chemicals used in hydraulic fracturing on FracFocus 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 was actually much simpler and cheaper. The basic chemicals listed above were all that were 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. But nobody routinely used hundreds of chemicals on a single job.

6.4.2 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 two to three hours. 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 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 as having originated from the frac fluid (DiGiulio et al., 2011). 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 monitoring wells was cited as a potential source of the contamination detected later in the water samples from these wells. As a result of this uncertainty, the results must be considered inconclusive.

An older case in West Virginia was noted in an EPA report (USEPA, 1987) where a hydraulic fracture treatment was performed in a vertical gas well drilled to a total depth of about 1,370 meters (4,500 feet), and located less than 300 meters (1,000 feet) 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 two years 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 years 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 meters (1,000 feet) and almost never beyond 600 meters (2,000 feet). Drinking water aquifers are usually shallower than 100 meters (300 feet). For the 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. Environmental Protection Agency, 2015).

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. 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 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 percent 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.

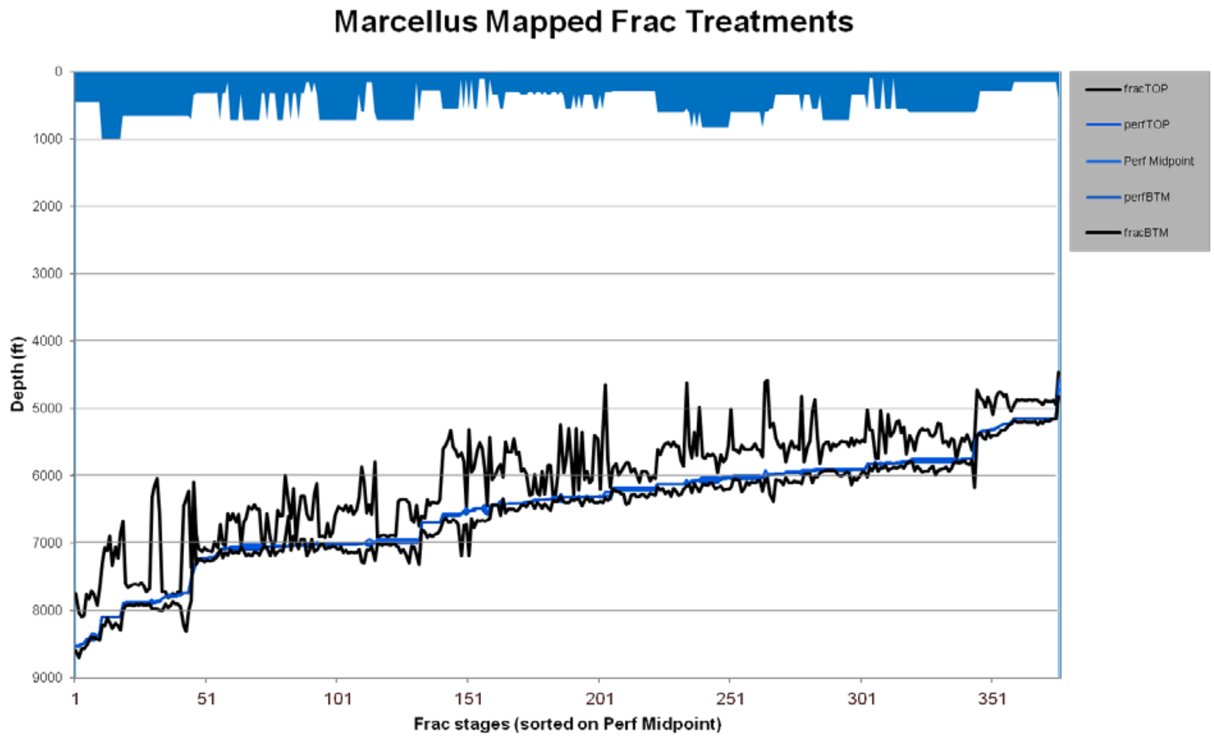
Flewelling and Sharma (2014) found that hydraulic fracturing affects a very limited portion of the rock overlying the target shale and is unable to create direct hydraulic communication with shallow aquifers. Any upward migration of fluid and brine that does occur is controlled by pre-existing permeability and hydraulic gradients, and 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) report 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 co-authors 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. 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 requires additional data.

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 said to be accurate to within cm (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 “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 fig. 33. This graph shows that laterals drilled through the Marcellus Shale range in depth from a bit more than 1.5 km (5,000 feet) in the northern part of the play to greater than 2.7 km (9,000 feet) along the eastern edge. The data in fig. 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 in blue along the top of the graph.



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, modified after Fisher, 2010

It is clear from the geophysical data in fig. 33 that the tops of the hydraulic fractures do not come anywhere near the depth of the aquifers, and in fact are a minimum of 1,067 meters (3,500 vertical feet) 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 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 a series of organic rich and 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.

6.5 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, recharge, and impact both terrestrial and aquatic ecosystems. Interestingly, the EPA drinking water study (U.S. Environmental Protection Agency, 2015) did not include 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 re-establish 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 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 needed later. Permanently draining, dismantling, and leveling drill pad impoundments after completion of the well removes the hazard.

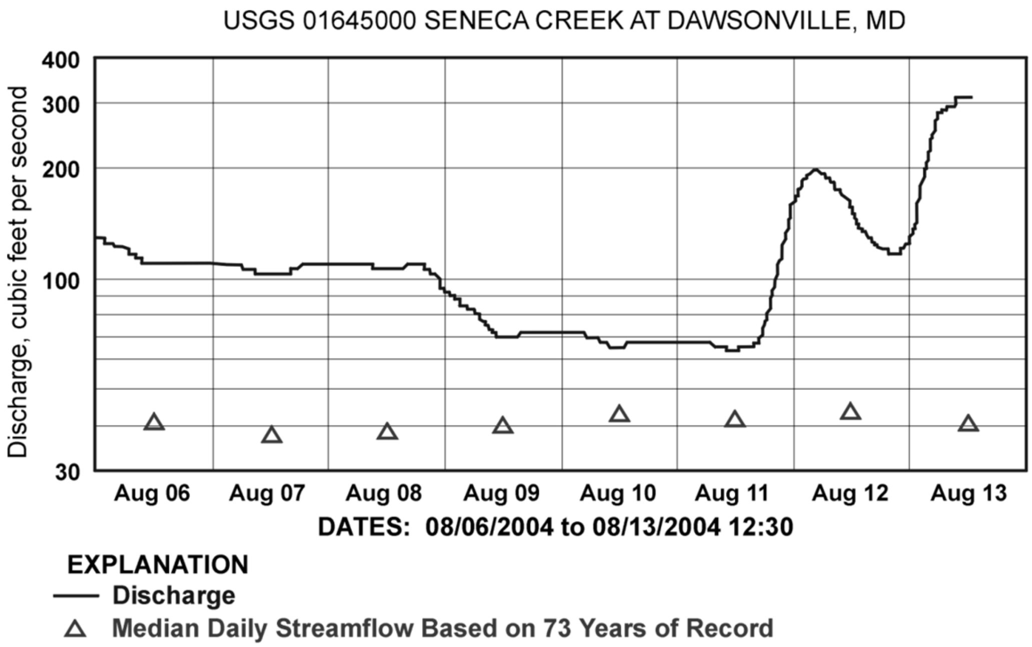
A better option is to use tanks instead of earthen impoundments, and a "closed cycle" process for drilling mud and frac fluid to ensure that all liquids are recovered and removed from the well site at the end of the drilling and hydraulic fracturing operations. The tanks themselves are the "ponds," which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

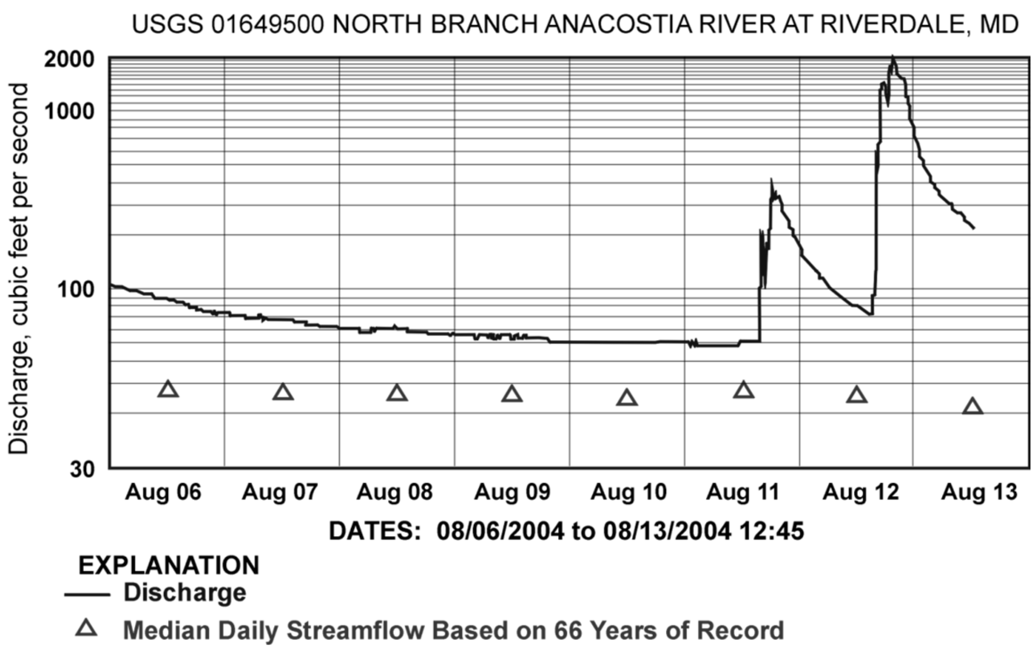
A typical manifestation of the cumulative effects of development on a landscape occurs in areas that have been urbanized, producing what hydrologists call "flashy" streams. Such streams can rise very quickly after a small amount of rain (hence, the term "flash flood") because of changes in the landscape 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 impacts aquatic habitat and in-stream biota.

As an example, fig. 34 compares stream flow records (called hydrographs) from two similar-size watersheds: the urbanized Anacostia River in Washington, DC, and 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 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 recent 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 hectares (8 acres) of impervious surface are added to a watershed from the construction of a 2 hectare (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 square km (2 square miles). Because other land use types are already impaired hydrologically to some degree, larger catchment areas were affected by the drill pad. For example, watersheds of 6.5 square km (2.5 square miles) were impacted on agricultural land, and watersheds of 13 square km (5 square miles) 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 five acre forest with a five acre drill pad will probably degrade nearby water resources. However, replacing a five 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 compliment 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.





34. A pair of hydrographs showing runoff from the same August 2004 storm events in similar-sized watersheds: Seneca Creek and the Anacostia River, modified from USGS

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 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 pre-existing roads in the area, they may require modifications such as widening, reinforcing bridges, or straightening curves to allow the super-sized Marcellus drilling equipment and supplies to pass (refer back to figs. 23 & 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 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.

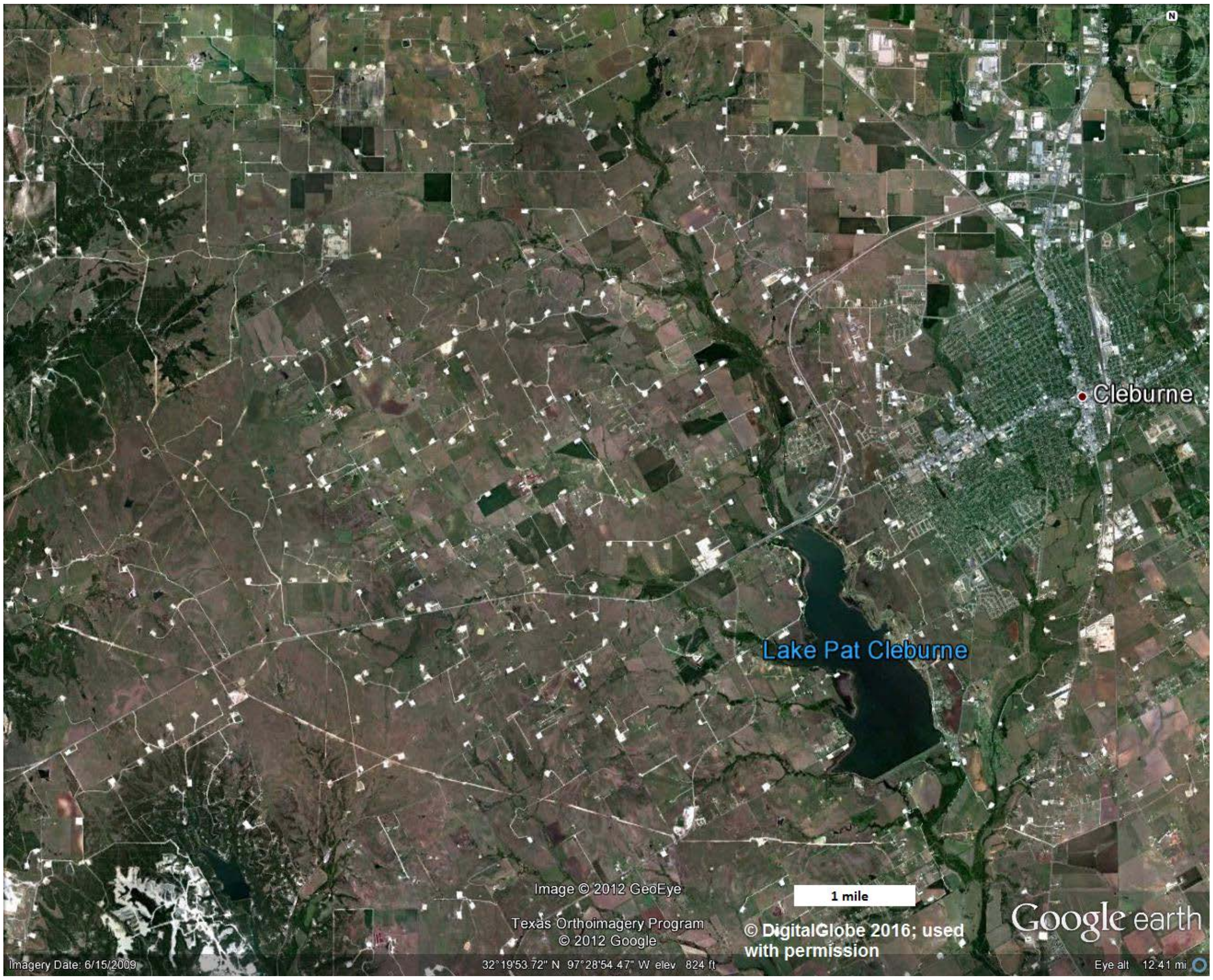
The hurried construction of drill pads, roads and impoundments during the initial boom days of Marcellus Shale development has left significant damage in Wetzel County, WV in the northwestern part of the state near the Ohio River. This is a land of steep slopes and narrow stream valleys. Well pads excavated 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 flood plains. 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 (fig. 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 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 square km (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 square km (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 on 0.324 square km (80 acres) spacing. This close spacing of well pads in Texas has resulted in significant landscape impacts, as shown in the satellite image in fig. 36.

35. Photograph of 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. Photo by Doug Mazer, used with permission.



36. Recent Google Earth satellite image of the Cleburne, Texas area southwest of Fort Worth.

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 square km, 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 between 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 onsite 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 multi-layer protection as casing in a well.

Many operators are dealing with the lack of pipelines in certain areas by drilling Marcellus Shale wells in pre-existing 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 square km (640 acres), which is currently considered the optimal spacing for 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 square km (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.

6.6 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 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 population 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 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 pre-existing 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., 2014). 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 onsite 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 onsite 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 use processes that do little or nothing to remove inorganic dissolved solids. In early 2011, PADEP 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 PADEP 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 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).

Table 2: Groundwater Risk per Production Phase

Production Activity	Potential GW 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 onsite: risk of leakage or surface spills
hydraulic fracturing	frac chemicals onsite: risk of leakage/spills; potential to intercept abandoned well
flowback and produced waters	high TDS waters onsite: risk of potential surface spills and leakage
long-term gas production	potential weathering of cuttings; well integrity and gas migration issues over time

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 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 (Engle et al. 2011). 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 byproducts (Hladik et al., 2014). The chlorination process for drinking water disinfection can create brominated tri-halo methane and halo acetic 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 (Engle et al., 2011). 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 percent of relatively fresh produced water was recycled into additional fracs. Highly saline produced water from later production occurs in lower volumes, but nearly 60 percent 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.

6.6.1 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 labs 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 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 web site (http://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 BTEX (benzene, toluene, ethylbenzene, and xylenes – the major water-soluble components of gasoline) and DRO (diesel-range organics), 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, PCBs (polychlorinated biphenyls) and organochlorine pesticides such as 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 pre-drilling 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 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 shows that benzene is not common within the Marcellus 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 offsite 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 up-gradient 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 (http://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. Environmental Protection Agency, 2015) 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 high volume hydraulic fracturing of the Marcellus or any other gas shale in the Potomac watershed. The WV oil and gas map website (http://tagis.dep.wv.gov/oog/) shows two Marcellus wells in the eastern WV 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.

A number of 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 anti-corrosion agent in slickwater formulations, and 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 in Section 3.3.1, 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. 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. 2014).

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: FracFocus web site: 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 byproduct 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; Szabo et al. 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 PADEP 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 dataset 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 γ 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, 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.

6.6.2 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 (fig. 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 (12 inch) diameter borehole drilled vertically through 30 meters (100 feet) of shale will produce a little more than 5 metric tons of drill cuttings. In contrast, the same diameter borehole drilled horizontally through 1,525 meters (5,000 feet) 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 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 fresh water 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).

37. Photograph of washed and dried Marcellus shale drill cuttings displayed in a lab dish. Photo by Dan Soeder

There have been instances of solid waste from CWT facilities setting off radiation alarms at some Pennsylvania landfills. The PADEP funded an investigation on the fate and 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 PADEP rescinding approvals for POTWs to dispose of biosolids by land application if they were accepting and 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., 2014). 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 mainstem 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 are completed on a pad and the equipment and chemicals 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.

6.7 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 meters (2,700 ft) from the wellbore in two directions. In comparison, a 1.5 km (5,000 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).

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 21st 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 have 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 non-swelling 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 non-potable 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 acid mine drainage (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. A number of geochemists are concerned about how the chemistry of AMD might react with the shale, and studies are underway 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 Susquehanna River Basin Commission (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 are treated like a factory; although, unlike other commercial uses, water withdrawals for shale gas development are regulated from the first gallon. The Delaware River Basin Commission (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 supplies much more of the water.

The SRBC estimates that the drilling industry in the basin needs a water allocation of about 114 million liters (30 million gallons) a day (Maykuth, 2011). 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. 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 about 0.24 percent 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 less dominant. These interactions can be observed more clearly in the Bakken and Niobrara plays on the upper Great Plains.

6.8 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.

6.8.1 Induced seismicity

Induced earthquakes are created by the actions of people. Earthquakes below magnitude 2 are rarely felt, and quakes large enough to cause damage to structures are generally above magnitude 4. Human activities don’t 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 pre-existing 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. 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 quakes were greater than magnitude 2.2 in Arkansas, and above magnitude 3 in Oklahoma. In both states, they ended once the injection was stopped. A similar series of earthquakes in northeastern Ohio was linked to the disposal of Marcellus Shale produced water down a UIC well near Youngstown.

A series of seismic events in April and May 2011 occurred at Preese Hall near Blackpool in the United Kingdom, 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, PA detected movement on a previously unidentified fault at a height of more than a half km (2,000 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.

6.8.2 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 over how much natural gas may be leaking as fugitive emissions. This is a concern to industry, who lose 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) indicates that most of the leakage may be from aging infrastructure on the delivery end, or "downstream" as the industry calls it. (Likewise, 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 is an issue with the entire natural gas distribution system nationwide.

McKenna (2011) reports a total for production-transmission-distribution losses of natural gas of about 1.5 percent 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 percent to 7.9 percent of their total production to the atmosphere. These very high estimates were generated using data that even the authors admit were questionable, although they have 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) challenges the findings of Howarth et al. (2011). Cathles and his co-authors indicate that Howarth and his co-authors significantly overestimated the losses from the system, and that the actual range of fugitive emissions from well drilling to delivery is much lower, less than 2 percent, 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 co-produced 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/Three Forks formations to try to maintain reservoir pressure and keep the oil moving toward production wells.

Flaring emissions wastes gas and lights up the night sky like a vision out of Dante. 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 drill the well until the gas can be put into a pipeline.

6.8.3 Abandoned wells

These old 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 Department of Environmental Protection 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 GHG 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 "bullseye," 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 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-meter (1,000 ft.) long vertical hydraulic fracture less than a centimeter wide would intercept a typical 30-cm (12 inch) 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-year 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-meter (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 and the abandoned well stopped flowing. It was 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 that are below the Marcellus are the more significant concern.

6.8.4 Silica dust

Many human health issues related to hydraulic fracturing operations usually turn on 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 OSHA respirable dust standards, but this should be measured and documented.

6.8.5 Economics

Financial arguments against shale gas have been made by several authors, primarily Berman (2010), who suggests that shale gas production is unsustainable, and investors in shale gas resources will likely go broke in fairly short order. Berman (2010) bases 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, 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 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 percent), the incoming brine isolates the gas into disconnected bubbles, creating a non-mobile phase that ceases to flow. Production at the wellhead ends abruptly.

Shale gas reservoirs typically do not contain mobile water, and hence do not water out. As stated earlier, the partial water saturation in shale pores is a non-mobile 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 repeat several times, and the full depletion of producible gas from horizontal shale wells could take many, many years. Production will 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. At the start of the play, Gottschling (2007) published numbers for EUR in individual, horizontal Marcellus Shale wells of 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 $4-6 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.

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 Gottschling’s (2007) estimate. These later wells benefitted 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. The Purple Hayes No. 1H well in Guernsey County, OH was drilled in 2016 by Eclipse Resources (Beims, 2016). It has a "superlateral" at a depth of about 9,000 feet (2.7 km) that spans a horizontal distance of 18,544 feet (approximately 3.5 miles or 5.6 km), a world record for onshore length at the time. Eclipse drilled the well in only 17.6 days, and completed it with 124 frac stages in 23.5 days, 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 feet (over 4 miles, or 6.7 km).

Lifecycle 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 CO2 storage wells (discussed in Chapter 7), the economics and environmental impacts improve. The details of lifecycle analysis are too complex for this discussion, but it is a useful tool to determine returns on investment, including costs to the environment.

The consensus among producers is that current reservoir drilling and stimulation methods are recovering about 10 percent of the GIP in the Marcellus Shale. Leaving 90 percent 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.

6.8.6 Social Issues

Oil and gas development in the Appalachian Basin goes back to Colonel Edwin L. Drake’s first commercial oil well in Titusville, PA in 1859, and social issues around 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 oil field 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 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 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 to the rush to develop the play, which further exacerbated the shortcomings of an inexperienced work force. As the play has matured, work crews gained experience, the pace of development has slowed, and environmental violations have 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 a 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 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, the influx of oil field 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 some lower-paid locals.

Another effect of the shale gas boom has been the increased value of a Commercial Driver's License, or 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 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 couldn't have cared less about a coal seam or other minerals under their land, and didn't quibble about not having ownership of it. But 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 five acre pad on someone's pasture with minimal compensation for the land owner, problems can ensue. The West Virginia Surface Owners Rights Organization (http://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 fig. 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. Safe well designs using intermediate casing, steel surface casing, and cement to protect and isolate potable groundwater aquifers, plus public disclosure of chemicals used in the hydraulic fracturing process, routine well safety reviews, and emergency response plans.

2. Water protection that includes safety testing groundwater supplies before and after operations, and a reduction in water use by employing non-potable water for hydraulic fracturing, and recycling wastewater whenever possible.

3. Emissions reduction for air quality that will focus on monitoring, employing less-polluting equipment, and making greater use of clean fuels like natural gas in engines.

4. Surface impact reductions of the "footprint" from drilling and completion operations, and limiting activities during certain time periods. Pipelines will be used to reduce truck traffic, and the land will be restored once operations are concluded.

5. Community engagement to improve the transparency of operations, share local socio-economic 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.

38. Photograph of Philadelphia artist Jennie Shanker's sculpture of a foam coffee cup executed in clay from the Marcellus Shale, and sitting on a slab of the same material. Photo by Dan Soeder.

7. QUESTIONS AND INVESTIGATIONS

As mentioned earlier, one of the great difficulties with assessing engineering and environmental risks from the development of the Marcellus Shale is the high degree of uncertainty with respect to many processes and parameters. Although a list of research needs can be rapidly invalidated by events, technological advances, new political priorities, or changes in program direction, research issues are still worth discussing because they provide insights into the state of the technology, and how it is evolving over time.

For example, water resource research needs for shale gas development described by Soeder and Kappel (2009) in a U.S. Geological Survey Fact Sheet were primarily linked to surface disposal of high-TDS produced water, which led to degradation of aquatic ecosystems and drinking water supplies. Just five years later, the widespread practice of recycling the flowback and ultimately disposing of residual waste down UIC wells has eliminated most of the surface water contamination concerns. So when Rozell and Reaven (2012) identified POTW wastewater disposal as the greatest risk for releasing shale gas fluids into the environment, their paper was already outdated.

On the other hand, many of the current research needs for water resources, including induced seismicity from excessive injection down UIC wells, problems related to methane migration, and the potential for toxic metals and radionuclides to leach out of black shale cuttings on the surface were not even mentioned in the USGS Fact Sheet. As technology and engineering practices evolve, the research topics evolve with them.

A number of overarching research issues do appear to have some staying power. These are the longer-term unknowns related to the shale gas resource itself and the general methodology used for production. Topics include: 1) better environmental monitoring and an improved understanding of the impacts of shale gas development on air, water, landscapes and ecosystems to reduce uncertainties in environmental risk assessments, 2) technology developments in drilling and production engineering that lead to more efficient natural gas and liquids recovery from shales, 3) the potential future use of depleted gas shale reservoirs for carbon dioxide sequestration and storage, and 4) the development of new utilization technologies to take advantage of the abundant natural gas being produced from shale. These are discussed in the sections below.

7.1 IMPROVED UNDERSTANDING OF ENVIRONMENTAL IMPACTS

Improved sensors for environmental monitoring and a broader range of data are needed to reduce uncertainties about shale gas development impacts in a number of areas, including air, water, landscapes, ecosystems, and human health issues (Soeder et al., 2014). Currently-available, commercial, electronic water-quality sensors measure a variety of field parameters, such as pH, conductivity, temperature, turbidity, etc. None at present directly measure the chemicals making up drilling mud or frac fluid. Recent research has investigated how the various field parameter measurements react to compounds associated with shale gas development (Harris, 2015). A better understanding of sensitivity thresholds and response patterns of these instruments will increase the utility of electronic monitoring for shale gas contaminants in streams and groundwater.

Future instruments under development include laser-induced breakdown spectroscopy (LIBS), a field-based analytical technique to directly measure the actual dissolved components in the water being monitored. A laser absorption spectroscopy gas sensor is also under development for measuring the methane concentration in the headspace of a monitoring well. Methane dissolved in groundwater is not a hazard, but exsolved methane in air at concentrations above the lower explosive limit definitely is.

Field-based studies are needed to truly understand the circumstances leading to environmental degradation from shale gas development (Jackson et al., 2013). Scientific data collection on shale gas well sites requires access to the location and knowledge about the drilling schedule. Because different environmental concerns arise at different phases of the well development process, communication between researchers and the operators is critical (Soeder et al., 2014).

Options for research access to shale gas well sites include commercial wells, transparent wells, and dedicated research wells. Commercial wells are those drilled on leased land by exploration and production companies to produce gas and oil. These are typically financed by capital from investors, and scientific studies require permission from both the operator and the landowner. A “transparent” well is installed on public land managed by a university or government agency that requires the operator to allow site access to researchers as part of the lease agreement. A research well is drilled on government-controlled land using public research funding, and scientific access is essentially unlimited (Soeder et al, 2014).

The simplest and least expensive option for gaining access to a shale gas well site is for researchers to obtain permission from an operator and landowner to study a commercial well. A number of companies have helped university and government scientists move forward this way in a variety of environmental research areas. Progress has been made toward measuring and understanding the environmental impacts of Marcellus Shale gas production on air quality (see Soeder et al., 2014 for details). Site-based studies have been done on hydraulic fracture growth and the potential for gas migration from the target shale (see Hammack et al., 2014 for details). Companies have provided produced water samples, drill cuttings, and mud samples for chemical analysis, and encouraged the development of remote sensing technology to locate abandoned wells.

An operator in West Virginia has provided extraordinary access to researchers from West Virginia University to several Marcellus Shale wells in an industrial park across the river from Morgantown. This site, known as the Marcellus Shale Energy and Environment Laboratory (MSEEL) has engaged a large number of researchers from WVU and Ohio State University, with the support of DOE (http://mseel.org/). It is still a commercial well site, however, and there are limits on what can be done (groundwater monitoring was prohibited for example, because the land owner is already responsible for remediating existing contamination and was concerned that new groundwater monitoring wells would find additional problems).

Transparent wells have been discussed by several different universities, but controversy about drilling and hydraulically fracturing shale gas wells on university land, challenges finding an exploration and production company willing to meet all of the conditions, and the low price of gas have derailed attempts thus far. Proposals for dedicated research wells on government land have been dismissed because of permit issues and a lack of funding (Soeder et al, 2014).

Unfortunately, commercial wellsite access and industry cooperation have not been extended to water resource studies, and this is not limited to the Marcellus play. Despite the thousands of shale gas and conventional wells drilled and hydraulically fractured in the United States and Canada, only a handful of groundwater monitoring studies have been carried out to date (Soeder, 2015). Even non-disruptive and non-intrusive studies like monitoring groundwater off the edge of the drill pad have gained little traction with industry or landowners.

Environmental assessments generally require some knowledge of baseline conditions to define environmental impacts. For example, if one notes that all the barn owls have disappeared in areas of shale gas development in northeastern PA, it would be important to have documentation that barn owls were actually present in these localities prior to the arrival of the drill rigs. Without such data, the barn owls could have vanished back when the railroad came through in 1906, and linking their disappearance to drilling is not valid.

Baseline assessments can be spatial or temporal. In other words, a comparison is done either side-by-side or before-and-after of an impacted environmental system versus an undisturbed one. An example of a side-by-side spatial comparison would be assessing the runoff characteristics of streams in two similar watersheds - one containing impervious surfaces and one without (refer back to the hydrographs in fig. 34 for an example). Such a study can give an indication of the effects of land use change. However, these are two separate pieces of land, and even though they may be superficially similar in many ways, small differences remain. Each watershed possesses at least a few unique characteristics that can complicate an analysis.

A temporal comparison would be the barn owl example given previously where there are data that pre-date the suspected disruption. These types of assessments tend to be somewhat more definitive than spatial comparisons because monitoring the exact same piece of ground in a “before-and-after” manner often shows more clearly the effects on specific environmental parameters. Collecting temporal baseline data from a potentially affected area does have one major drawback, however: it requires prior knowledge of a planned environmental disturbance, along with enough time to collect a sufficient amount of representative data before any impacts take place. Baseline data on surface water and groundwater are commonly collected for at least a year to determine seasonal variations. Such precursor data would then provide a baseline for assessing environmental changes introduced by the planned disturbance when it does occur.

Carrying out such temporal baseline studies has been a challenge on shale gas wells. Knowing precisely when and where a Marcellus Shale environmental disturbance might occur is difficult. Knowing a year ahead of time in order to gather baseline data is considerably more difficult. Even in cases where industry partners have joined the research and provided advance knowledge of where a shale gas well would be located, changes in drilling schedules or changes in economics can cause drilling to be sped up, delayed, or not happen at all (Soeder, 2010).

Environmental monitoring is less expensive and more precise when a set of indicators is used. For example, spilled drilling mud entering a stream might change the water temperature and raise the pH. Knowing that this response is typical for drilling fluids means that the pH and temperature alone could be monitored as environmental indicators (Harris, 2015). It is not also necessary to measure dissolved oxygen, redox potential, or the behavior of catfish. For the indicators to be useful, however, it is important to first understand how each parameter responds to environmental stressors and contaminants. Although a number of researchers have been investigating these for the Marcellus Shale (Chapman et al., 2012, Engle et al, 2011), a comprehensive set of shale gas monitoring indicators has yet to be established.

It is important to note the difference between routine monitoring programs that capture incidents, and a research investigation to characterize the impacts. In particular, as discussed previously in chapter 6, the issue of cumulative impacts is perhaps the most challenging. The accumulation of individual environmental events from multiple sites add up as more wells are constructed within a given area of land, and at some point may take environmental conditions across a threshold, causing damage greater than the individual wells alone. The example cited in chapter 6 was increased impervious surface area in a watershed, leading to catastrophic runoff events in a stream. However, cumulative impacts can apply to many other aspects of the environment, including air quality, flora, fauna, recreational opportunities, and others. Many people have called for the evaluation of cumulative impacts without clearly understanding what the term means. Federal actions that require an Environmental Impact Statement, such as the NEPA program, include an evaluation of cumulative impacts. For the Marcellus Shale, the only Environmental Impact Statements required so far have been for certain interstate pipeline projects.

The uncertainties surrounding potential environmental impacts from Marcellus Shale gas development are especially acute for water resources. The subsections below describe a number of perplexing scientific questions related to water issues and Marcellus Shale gas development. Some of the questions are long-standing, while others are recent developments that came about as more was learned about the shale.

7.1.1 Fate of injected frac water

When a multi-stage hydraulic fracture stimulation is completed on a gas shale, up to 15 million liters (4 million gallons) of water will have been pumped down the well under high pressure. Three quarters or more of the water pumped into the Marcellus Shale typically remains downhole, and in some cases less than 10 percent is recovered as flowback or produced water (Zhou et al., 2016).

Where does the frac water go? No one really knows. The Marcellus Shale is fairly dry; it is saturated with overpressured gas (Wrightstone, 2008), and although some partial water saturation is present in the range of about 10–30 percent of the pore volume (Engelder, 2012), there does not appear to be enough water to form a mobile, flowing phase (Soeder et al, 1986). Thus, a significant amount of the frac water injected downhole may simply imbibe into the pores of the shale and remain there, held under high capillary pressures.

The term "imbibe" is probably familiar to most people only in a tavern or saloon setting. In petrophysics, it means the ability of pores in a rock to take in fluid. The opposite of imbibition is drainage (both in rocks and in taverns). There is a small possibility that frac fluids may make their way along faults or old wells and imbibe into overlying or underlying formations that are at lower pressures and contain more pore volume. Although unlikely, this should be considered as a possible explanation for the low returns.

Some people argue that because the Appalachian Basin black shales appear to be preferentially oil wet (refer back to fig. 16 and the associated discussion), the water does not imbibe into the pores at all, but remains at the bottom of the fractures. If high organic content in shale is the cause of water repellency, then organic-lean gray shales may be preferentially water wet, and imbibe the frac fluid. Hydraulic fractures breaking above the Marcellus into the organic lean Mahantango may provide a conduit for frac water to move into the gray shale.

Another possibility is that the water attaches to clay minerals in the shale, adding layers of hydration. A significant amount of frac water may also evaporate into the gas downhole and emerge from the well with the gas as vapor, which has simply not been counted as part of the water balance calculation. Given the relatively warm temperatures at the depth of the Marcellus Shale and the enormous volumes of produced gas, this would not be surprising.

Understanding the fate of injected frac water is more than just an interesting scientific exercise. The frac water that remains downhole is being used as a *de facto* method of wastewater disposal. Recycling the flowback into the next frac disposes most of it downhole. Plans to use acid mine drainage water, briny groundwater, and even seawater for frac fluids all assume that much of it will remain in the ground.

A hydraulic fracture field experiment using tracers is one method that could help to answer some of these questions. Adding a chemical tracer to a representative hydraulic fracture treatment would positively distinguish the frac fluid from other formation waters. Field-based measurements including drilling back down to the target formation could gather hydrologic and geophysical data to determine the movement and fate of hydraulic fracture fluid in the ground, and assess what actually happens to it.

NETL carried out a tracer experiment on a Marcellus Shale drill site in Greene County, in southwestern Pennsylvania (Hammack et al., 2014). The operator allowed a volatile tracer to be added to the frac fluid, which was designed to vaporize and travel with the produced gas. This field test was primarily focused on gas migration and not the fate of frac water downhole. Gas from an overlying Upper Devonian sandstone was sampled periodically and tested for the tracer. No sign of the tracer has yet been found, but modeling results suggest that monitoring will need to continue for a number of years (Zhang et al., 2014).

7.1.2 High TDS in produced brine.

One of the mysteries about the Marcellus Shale is the origin of its somewhat unusual brines. The source of the high TDS concentrations, especially Sr and Ba in Marcellus produced waters is a mystery, and so is the odd chemistry. A number of researchers have been working on this from a geochemical modeling approach (e.g. Engle et al., 2011; McIntosh, 2012), but more field data would be helpful.

Comparing the geochemistry of Marcellus Shale produced fluids with that of other formation waters above and below could help place them into a larger context of Appalachian Basin brines. Factors such as the geologic history of basin-wide fluid migration, past volcanic activity and geothermal fluids, and mechanisms that concentrate the brines may all have had an influence on the dissolved solids content of formation waters. Formation water sampling while tophole drilling Marcellus wells in a variety of locations would be a way to help answer some of these questions. Continuous samples from the shallow aquifers to the Oriskany Sandstone will provide a robust profile.

Another suggestion is to take a pressure core from the Marcellus Shale as a vertical well penetrates this unit. A pressure core is cut and contained in a sealed core barrel, and recovered with the downhole fluids and pressures locked in. Nothing is lost as the core is brought to the surface. Total fluid content, geochemistry of the fluid under reservoir conditions, and changes in fluid composition as a function of pressure can be sampled and measured.

Obtaining samples of produced water collected at well sites can be challenging. Although some operators allow researchers onsite to collect and preserve samples directly from the separator or tanks, others are more cautious. Analyzing a bucket full of flowback water collected at random by a roughneck and handed over to scientists is not an ideal sample, but better than nothing. The current practice of recycling recovered water multiple times into successive fracs also complicates the geochemical analyses.

7.1.3 Stray gas in groundwater

The migration of methane gas in shallow groundwater was listed as one of the major environmental concerns of shale gas development at a 2014 National Ground Water Association meeting in Pittsburgh. Stories in the national news media often quickly conclude that the presence of flammable methane gas in a water supply must be related to nearby shale gas drilling activities. This is an oversimplification of a complex situation. The sources of stray gas, and the conditions that caused it to migrate into drinking water wells are notoriously difficult to pin down (Kell, 2012; Baldassare et al., 2014).

Shale gas wells, like all gas wells, are designed to contain the produced natural gas inside the production casing all the way to the surface. Unless this casing has leaks, gas from the target formation stays inside the pipe. If the well and production casing are properly constructed and intact, then gas from other sources must be entering the aquifer.

The presence of naturally-occurring methane gas in groundwater is not unusual, and there are many possible sources (Sharma et al., 2012). Investigations often reveal that stray gas was a problem in many water wells long before any gas drill rigs arrived on the scene. A document posted on the library page of the Colorado Oil and Gas Conservation Commission (2010) website (http://cogcc.state.co.us/) addresses some of the stray gas issues in Colorado dramatized by the media, and suggests that at least some of these pre-date gas drilling.

Along with migrating into an aquifer by upward movement from deeper geologic formations, microbiological processes can also generate *in situ* methane in shallow groundwater. There are a number of methods for assessing if methane in an aquifer is geological or biological in origin. One of technique uses carbon isotopes (Sharma and Baggett, 2011). Bacteria selectively process the isotopes, enriching biogenic gas with one particular isotope of carbon over another, while geological processes don't discriminate.

A second method for determining gas origin uses chemical composition to differentiate between geological and biological gas. Natural gas produced by the thermal maturation of organic matter buried in sediments often consists primarily of methane, with small amounts of propane, butane, ethane, and other more complex hydrocarbon compounds mixed in. Biogenic gas, on the other hand, consists of methane only, with occasionally some carbon dioxide, but it does not contain the higher weight hydrocarbons. Using these techniques, geochemists can distinguish between biogenic and thermogenic gas with a high degree of confidence.

A number of things can allow methane gas to leak into groundwater from a poorly constructed well, but the major cause of such leaks appears to be problems with the cement (Dusseault et al., 2000). Gas migration may occur when drilling mud or pumped cement is underbalanced (i.e., below pore pressure), and the gas enters the fluid. If there is a loss in hydrostatic pressure (such as fluids from the cement leaking off into the formation), or volume shrinkage within the curing cement, the gas may also find a flowpath upward.

The integrity of wellbore casing and cement is a concern in all oil and gas wells, not just Marcellus Shale wells. As such, responsible operators run a casing integrity test, or leak-off test, where the casing is pressurized and monitored for leaks before being perforated (Syed, 2011). This does not guarantee there will be no problems—wells can still suffer failures during the completion process, but any significant problems due to errors in the assembly of the casing are more likely to be detected by the test. Repairs can be made before proceeding any further.

A study of wellbore conditions in depleted oil and gas fields under consideration for carbon dioxide storage identified three possible routes by which gas could escape from an older well: 1) loss of wellbore integrity from deteriorated casing cement, 2) corrosion and failure of the steel well casing itself, and 3) improper methods of well abandonment (Watson and Bachu, 2009). The correct well abandonment techniques include installing a cement plug across casing perforations, squeezing cement under pressure into the perforations themselves, or placing a bridge plug in the casing above the perforations and capping it with cement. Performing these operations properly (which was not always done, especially in the old days) is critical to ensure gas does not leak from abandoned wells.

In cases where stray gas has been linked to a Marcellus well, poor well construction practices are usually to blame. Installing a faulty casing, not allowing the cement to properly cure, and new operators coming into a locality where they truly didn't understand subsurface conditions have all contributed to stray gas leakage (Baldassare, 2012).

Stray gas from a poorly constructed well can be difficult to track down and expensive to fix. An example of a well-done, challenging investigation from recent years is the Ohio Department of Natural Resources study on the Payne family home in Bainbridge Township, Geauga County, Ohio (Kell, 2012). The home in northeast Ohio, east of Cleveland, was lifted off its foundation by a basement methane gas explosion in December 2007. The initial investigation pointed to a recently drilled, vertical gas well nearby as the source of the gas.

The target for the gas well was the Silurian age Clinton Sandstone. The operators had penetrated the Dayton Formation above the Clinton, a zone of crumbly limestone known as the Packer Shell, and had trouble maintaining the stability of the hole. The well was open-hole completed, meaning that only a surface casing was set to protect fresh groundwater, and the production casing was run down past bare rock walls to the target zone.

The intent was to fill the annulus with cement sufficiently high above the production zone that a seal would be created to prevent gas in the Clinton from entering the open part of the wellbore annulus. However, because of blockage in the annulus by the unstable Packer Shell above the target formation, the cement pumped down the production casing didn't rise as high in the borehole as planned. Thus, gas from the Clinton Formation was able to bypass the insufficient cement seal, and enter the annulus, which was not vented through a bradenhead valve on the surface. Gas pressure built up against the bare rock walls, entered the bedrock, and then migrated upward into an overlying aquifer, where it traveled into the basement of the house.

This case study illustrates the complications of tracking down stray gas. The insufficient cement job in the gas well was the root cause of the problem, but determining how the gas got from there to the basement of the house is a complex story. The bradenhead was not being monitored, so no one realized gas pressure was building up in the annulus from the poor cement seal. The domestic water well being used by the homeowners was shallow, and did not contain elevated levels of methane. The residents did notice cloudy water from their taps a few days before the explosion, suggesting that the aquifer was being affected. An abandoned, deeper water well was eventually determined to be the conduit by which gas entered the house, but painstaking detective work was required to reconstruct the sequence of events (Kell, 2012).

The small northeastern Pennsylvania township of Dimock in Susquehanna County became a focus for stray gas issues when the concrete cover on the vault of a domestic water well split in two and flipped over on New Year's Day 2009, presumably from a methane gas explosion (Maykuth, 2012). Although there were no witnesses and some questions have been raised about what actually occurred, the media linked this event almost immediately to Marcellus Shale drilling in the area.

A study published by Osborn et al. (2011) from Duke University reported widespread methane in groundwater in northeast Pennsylvania, with levels up to 17 times higher near gas wells. Criticism has been leveled at this paper because of the lack of baseline data on groundwater conditions prior to drilling, and the absence of studies done on control sites outside the geologic and groundwater hydrology framework of northeast Pennsylvania.

Isotopic data on groundwater methane from the Duke study (Osborn et al., 2011) suggested that the gas was largely thermogenic in origin, i.e. that it came from a geologic source, rather than biologic. Although the Duke authors assumed this source was the Marcellus Shale, a look back at the geological cross-section in fig. 3 shows a number of possible sources. Demonstrating that the gas is thermogenic does not necessarily prove it came from a specific rock unit unless this is supported by additional gas chemistry data.

Noble gas chemistry in 113 samples from drinking-water wells overlying the Marcellus Shale and 20 above the Barnett led Darrah et al. (2014) to conclude that some stay gas was sourced from intermediate-depth strata, while other gas appeared to have come from the deeper target shale formations. In all cases, however, the loss of wellbore integrity from cement failures or faulty casings in the vertical part of the gas wells was identified as the cause of the releases. The noble gas data appeared to rule out any stray gas migration upward from depth through overlying geological strata due to horizontal drilling or hydraulic fracturing.

Noble gases like helium, argon, krypton, and xenon are generated within the crust of the Earth continuously from radioactive decay, and can be used to assess the travel time and origin of gases migrating within the Earth. The longer the gas has been in contact with rocks deep in the crust, the greater the noble gas content.

Regional groundwater methane surveys run by Cabot Oil & Gas in northeastern Pennsylvania aquifers found detectable concentrations of methane in nearly every domestic water supply well tested (Molofsky et al., 2013). The Cabot study used a total of 1,701 water samples, which was a much larger data set than the 68 wells used in the Duke study, and identified a trend of higher concentrations of methane gas in water samples related to topography, specifically stream valleys versus hilltops. However, water samples for the Cabot study were collected pre-drilling, so the data cannot be used to assess possible increases in groundwater methane as a result of shale gas development.

A third study using Chesapeake Energy's massive data set of 11,300 groundwater samples from northeastern PA found no statistical correlation at all between methane in groundwater and proximity to conventional or unconventional gas wells (Siegel et al., 2015). (Interestingly, this much larger data set found no trends related to topography, either.) Like the Cabot study, the Chesapeake data were also collected from domestic water wells prior to shale gas well development. Nevertheless, the authors attribute enough robustness to the data to support the statistical validity of their findings.

In the Marcellus play, most stray gas problems seem to occur in the northeastern counties of Pennsylvania, where the aquifers consist of low permeability, fractured bedrock. Fractured aquifers are notable for moving contaminants fairly long distances over short time periods (Freeze and Cherry, 1979). The presence of these fractured aquifers, primarily the Upper Devonian Catskill Formation and underlying Lock Haven Formation may be why the northeastern part of Pennsylvania seems to have far more stray gas issues than the other main segment of the Marcellus play in the southwestern part of the state.

Gas in the fractured aquifers of northeastern PA is probably coming from multiple sources, only one of which may be poorly-constructed Marcellus Shale gas wells. Other possible sources include upward migration of gas through natural fractures from relatively shallow, organic-rich shales, or biogenic gas already in the aquifer that is being mobilized by the drilling. There are several lines of evidence to support each of these interpretations, and the research challenge is to determine which of these may be valid. Those who believe the answer is simple and straightforward do not fully understand the issue.

Stray gas issues are not limited to the Marcellus play. A ranch owner in Parker County, Texas, filed a complaint with the state in 2010, claiming that natural gas in the ranch water well was coming from a nearby Barnett Shale drilling operation (Pope, 2012). Subsequent investigations determined that the Barnett wells were properly constructed, cemented and cased. The microseismic data showed that the hydraulic fractures had stayed within zone in the Barnett as designed. Groundwater chemistry data showed that methane was common in soils and groundwater throughout the region, and all of it was thermogenic.

The aquifer supplying the ranch well is underlain by the Strawn Formation, which produces gas from a number of small fields within a few miles of the ranch. It turned out that the water well in question had in fact been drilled completely through the aquifer and into a sandstone unit within the Strawn Formation. Analysis of the gas chemistry showed that the carbon dioxide and nitrogen content of the gas in the water well was a close match to gas from the Strawn Formation, and did not match that of the Barnett Shale.

The whole thing ended up in a big legal mess. The US EPA filed injunctions against the operator, the ranch owner filed a lawsuit, the state agency findings contradicted the EPA and forced the injunction to be lifted, and the gas company brought countersuits (Pope, 2012). If the ranch owner, the regulatory agencies, and the operator had all recognized the complexities of stray gas migration, perhaps this could have been handled differently. A stray gas incident always has two questions to answer: 1) what is the source of the gas, and 2) how or why is it being mobilized? Getting answers to these questions can often be a challenge, and usually take some time.

The saturation level of methane in water is pressure-dependent. At one atmosphere, the solubility limit is 28 mg/liter. If pressures change, such as when an aquifer is drawn down by pumping a well and then recovers, some methane may exsolve out of solution and reside in the gas phase as tiny bubbles in fractures. Under normal, slow groundwater flow gradients, the methane remains immobile, similar to the bubbles of gas that cling to the sides of a beer glass. However, if groundwater flow is increased, the higher velocity can detach the methane bubbles from the fracture wall and entrain them in the flow. Laboratory experiments suggest that the actual increase in groundwater velocity required to do this is quite small (Giri, 2013).

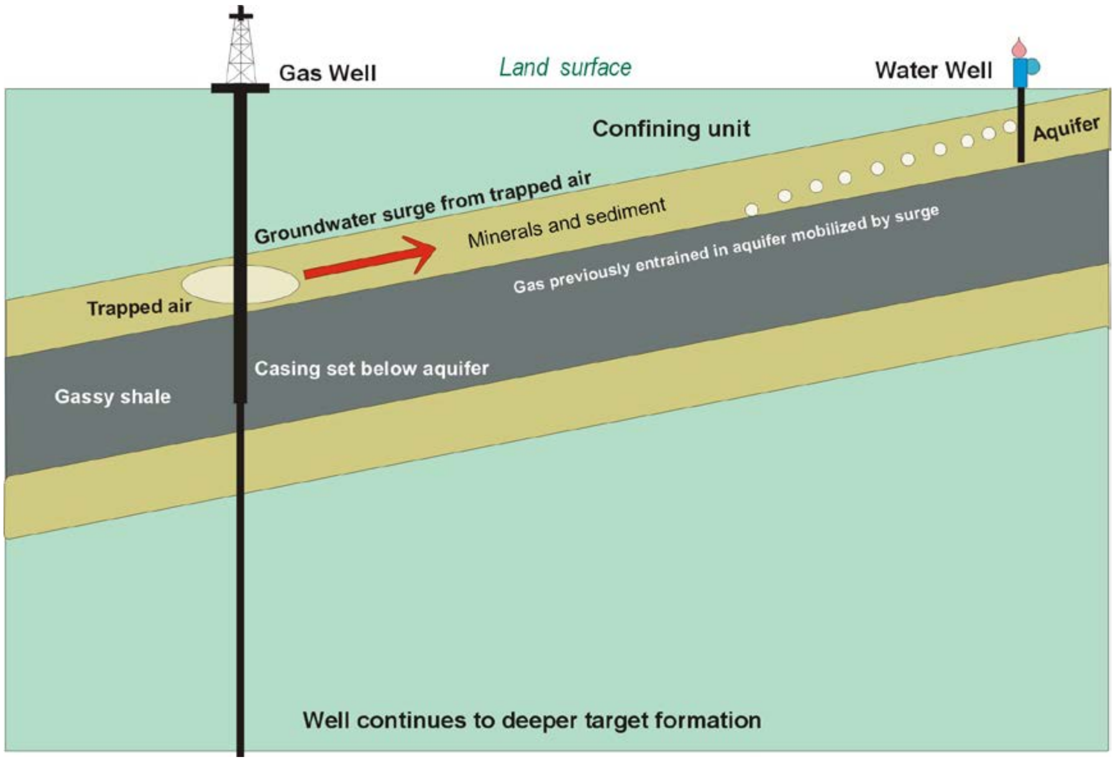
One factor that can increase groundwater flow velocity through a fractured aquifer is the presence of high-pressure, trapped air. Air can be introduced during the tophole drilling process if a pneumatic hammer bit is employed. Such bits are favored for their faster penetration rates than a rotary tri-cone bit, and also because they produce a straighter and cleaner hole. Compressed air at pressures as high as 2,413 kPa (350 psi) is circulated through the bit to cool it and remove cuttings. The sides of the borehole are bare rock and soil during this drilling, and directly exposed to the high-pressure air. The surface or coal casing is not emplaced until the well has penetrated about hundred meters or so (about 300 ft.). A confining layer or seal on the top of the aquifer could act as the trap where air accumulates.

A conceptual model is presented in fig. 39 to illustrate how this scenario might work in the fractured aquifers of NE Pennsylvania (Soeder, 2012b). High pressure air in the fracture system applies a strong gradient to the groundwater, causing it to surge away from the wellbore at an unusually high velocity. Such fast-moving water would pick up and carry along sediment and minerals from within the aquifer and also entrain methane gas bubbles. The methane may then accumulate as free gas in areas of lower pressure, such as the drawdown cones of producing water wells.

Could such a scenario actually happen? In 2012, a Marcellus Shale well near Sardis, West Virginia had been drilled open hole on air to a depth of about 100 meters (300 feet). As the drill string was being withdrawn to set surface casing, the bit got stuck at a depth of about 53 meters (175 feet), within a shallow groundwater aquifer. The air compressor was left running while the drillers struggled to free the bit, and according to a newspaper interview with a company vice president, the aquifer became “charged up with air.”

A short while later, abandoned groundwater wells nearby began flowing water, some fountaining as high as 3 meters (10 feet) into the air. A well as far away as 300 meters (1,000 feet) was reportedly affected. Field measurements found that the most significant groundwater flow between the gas well location and the surging water wells aligned with the orientation of the J2 joint set, indicating that natural fractures were a critical conduit.

A groundwater model constructed with the sparse amount of data made publicly available on the Sardis incident was able to show that the timing and magnitude of flow from the water wells was consistent with compressed air applying a pressure head on groundwater in an aquifer fracture system (Geng, et al., 2013). Although no methane gas was reported surging from the water wells at Sardis, additional modeling showed that a flow event of a similar magnitude in a fractured aquifer already charged with methane would readily mobilize the gas (Zhang and Soeder, 2015).



39. Illustration of alternative conceptual model for how gas well drilling might cause the migration of stray gas into water wells (Soeder 2012b)

The number of proven stray gas incidents related to shale gas development is actually quite small. To the homeowner with an exploded well vault or a house lifted off its foundations, it is, of course, a major tragedy. But the high-profile reporting and reposting of such unusual events in the media have led many people to think they are a lot more common than they are.

Plenty of real environmental problems do occur with water resources and Marcellus Shale gas production. Setting fire to a kitchen faucet may be a dramatic effect that helps to make good movies, but it is not one of the more pressing concerns.

7.1.4 <u>Watershed management practices and drilling</u>

The highest probability routes for water contamination from Marcellus Shale drilling activities are spills and leaks of fluids or chemicals on the pad entering groundwater or small streams. A number of locations in West Virginia contain mud pits buried after a well was drilled, and chemical seeps have been observed on the hillsides or stream banks below the pads years later. Some active drilling locations experienced leaks and seepage that are contaminating groundwater and small streams (refer back to fig. 35 for an example).

A survey of small watershed environmental impacts when different drilling practices are employed would be useful to regulatory agencies. An assessment of the effects from lined pads compared to unlined pads, the use of closed systems for drilling mud versus open mud pits, and offsite disposal of cuttings instead of onsite burial may show how practices affect outcomes. Such data could help industry and regulators implement better management practices to mitigate environmental impacts before they happen. One truism of environmental science is that it is almost always cheaper to prevent a mess than to clean one up.

As described earlier, a modeling project found land area thresholds in small watersheds, above which definitive impacts from a single drill pad were important (Fries, 2014). The size of the watershed affected depended on the land use, and larger catchment areas were affected on landscapes that had already been impaired to some degree (Fries, 2014).

Potential water quality and runoff changes in a small watershed with active Marcellus Shale gas well development have been monitored in West Virginia (Streets, 2012). The intent was to determine if drill pads and roads constructed in the watershed have affected streamflow or water quality, primarily from increased sediment influx. The subject stream is also a long-term research watershed for the West Virginia Water Resources Research Institute, and many years of baseline data were available. The new effort added more monitoring stations to increase the data coverage before the potential impacts were expected (Streets, 2012).

Major ions, metals, total dissolved solids, and volatile organic compounds would need to be measured in the laboratory from water samples to determine if contaminants were coming from a Marcellus Shale well. This is not something operators are going to provide voluntarily on a routine basis, but they might be willing to monitor small watersheds and shallow groundwater with electronic instrumentation. These instruments don’t measure contaminants directly, but instead record “field parameters” that include temperature, pH, conductivity, turbidity, dissolved oxygen, redox potential, and possibly others to provide basic data on chemical or environmental conditions in a stream. The key is determining how the field parameters can be linked to a chemical or fluid that might be found on a well site (Harris, 2015). Some of the companies that sell water quality measuring equipment commercially are pitching it as a “frack pack” or hydraulic fracturing package with little or no information on how the instruments can be expected to respond to produced liquids, drilling fluids, or frac chemicals.

Reports by state agencies that have deployed various instruments to measure field parameters suggest that results are inconsistent. Turbidity in particular seems to be challenging to measure. An assessment of some of the electronic monitoring devices under controlled laboratory conditions has resulted in a better understanding of performance, and may provide uniform specifications for real-time stream monitoring instrumentation in small watersheds containing active drilling sites (Harris, 2015).

Instruments for surface water monitoring could be set up at the mouth of the smallest watershed containing the drilling activity. Conductivity measurements can be used to monitor the amount of dissolved solids and provide warnings of the presence of flowback or formation brines in the stream. Acidity or pH is yet another fairly simple parameter to measure automatically in the field, which can show acid leaks from frac chemicals, or alkaline readings from cement or drilling mud. Even something as simple as monitoring water temperature can be useful—downhole fluids are likely to be much warmer than the water in a surface stream, and a sudden rise in stream temperature could signal a leak.

The data could be monitored using readouts and alarms in the drill rig doghouse. An early warning of a leak would allow the responsible party to stop or contain it, minimizing damage and reducing remediation costs (and possibly fines). Relatively inexpensive telemetry using mobile device Internet access and the data capabilities of the cell phone network could allow state agencies, environmental compliance officers at the operator's home office, or other interested parties to monitor these streams in real time around the clock.

7.1.5 Leaching of black shale cuttings and other solid waste

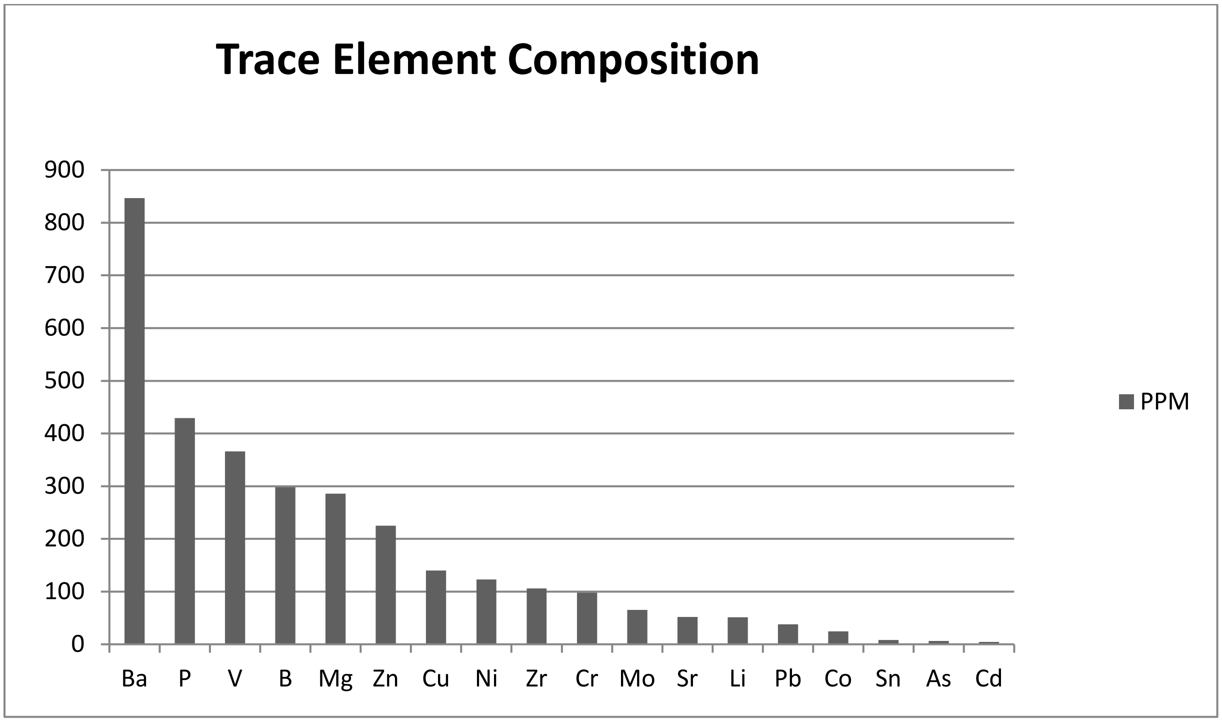
Drill cuttings (refer back to fig. 37) of black Marcellus Shale from deep horizontal boreholes contain reduced (sulfide) minerals that will oxidize at the surface and become more water-soluble and mobile. Some outcrops of Marcellus Shale contain a coating of fine sulfur crystals that were left behind as the sulfide minerals oxidized and were leached away (fig. 40). Iron sulfide in particular, which occurs in black shale as the mineral pyrite (refer back to fig. 26), will weather to iron oxide and sulfate compounds such as sulfuric acid if exposed to oxygen and fresh water. Sulfuric acid from oxidized pyrite is the main culprit for acid mine drainage in

Appalachian coal country, and there is indeed a worry that given the hundreds of metric tons of drill cuttings being created by horizontal boreholes kilometers long, production of gas from the Marcellus Shale could be leading to its own distinctive “acid mine drainage” problem.

40. Photograph of weathered Marcellus Shale outcrop samples from Franklintown, Pennsylvania, coated with tiny crystals of yellow sulfur. Photo by Dan Soeder.

Concerns about the radionuclides and metals that might be affiliated with the organic matter in the Marcellus Shale, and the potential for oxidation and leaching of these materials from cuttings left on the surface prompted a preliminary study in 2010 to assess the potential problem (Soeder, 2011). Fresh samples of Marcellus Shale cuttings were obtained from a drill rig operating near Waynesburg, PA. Marcellus Shale from the old EGSP WV-6 core (refer back to fig. 11), which had been kept dry but exposed to the air for over 30 years, was used to represent oxidized samples, and outcrop samples of Marcellus Shale from the U.S. Silica quarry near Berkeley Springs, West Virginia, (refer back to fig. 6) were assessed as rocks that had been fully oxidized and leached.

The Marcellus Shale samples were chemically analyzed and compared. Carbon, sulfur and hydrogen were assayed as organic and inorganic carbon, hydrogen as hydrocarbons, free moisture and bound water on clays, and sulfur in the form of sulfides and sulfates. An ICP analysis of a composite sample was performed to determine bulk rock elemental composition. The composite sample analysis is shown in fig. 41, which displays the major chemical components of the rock expected for pyritic, clay-rich, black shale.



41. Graph of trace elements in composite of Marcellus Shale drill cuttings, core and outcrops (data from Soeder, 2011)

EPA Toxicity Characteristics Leaching procedure 1311 was used to extract metals and radionuclides from the samples. The EPA procedure employs a weak acid to dissolve out any soluble and mobile metals from the test material to mimic acidic leaching conditions in a landfill. The metals were analyzed by inductively coupled plasma (ICP) spectrometry. Eight metals were quantified: silver, arsenic, barium, cadmium, chromium, mercury, lead, and selenium. Most of these were below the minimum reporting limit from the outcrop and cuttings samples, except for barium (Soeder, 2011).

The core samples contained higher amounts of leachable metals, including arsenic, barium, cadmium, and chromium. This was expected because in the cuttings, the metals would have been in the non-mobile, sulfide phase, and in the outcrop samples, they would have been oxidized and long gone. The core was expected to contain the metals in the mobile phase. One surprise was the barium—it was expected in the cuttings because the element is often used in drilling mud, and this is also true of the core. However, the presence of barium in the outcrop samples, which had never been exposed to drilling mud, suggests that it is common in the Marcellus Shale and may not be unusual as a component of the TDS in produced water.

The alpha radiation counts on the bulk rock samples ranged from background levels to about 8 times above background. Analysis on the leachate prepared for the ICP tests showed alpha counts at background levels. The outcrop samples had the lowest α count and lowest β count. The fresh cuttings were more radioactive than the outcrop but less than parts of the core. The upper part of the core was the most radioactive sample tested. The radioactivity data for the various samples are shown in table 3.

Table 3: Radioactivity Data from Marcellus Shale Outcrop (O), Core (C) and Drill (L) Cuttings

SDGroup Sample ID	RJLee Sample ID	Sampling Date	Alpha rate (raw cpm)	Beta rate (raw cpm)	Sample mass (g)	Alpha rate (µCi/kg)	Beta rate (µCi/kg)
C-Top	xxx-001	10/13/2010	4.80	6.73	0.02470	0.478	0.165
C-Mid	xxx-002	10/13/2010	1.07	4.10	0.04088	0.034	0.052
C-Bot	xxx-003	10/13/2010	1.47	5.73	0.03686	0.068	0.091
O-Top	xxx-004	10/14/2010	0.67	1.87	0.03162	0.008	0.016
O-Mid	xxx-005	10/14/2010	0.53	1.85	0.02900	at bkg	0.017
O-Bot	xxx-006	10/14/2010	0.57	2.67	0.03728	at bkg	0.029
L-Top	xxx-007	10/14/2010	1.40	5.37	0.03763	0.061	0.082
L-Mid	xxx-008	10/14/2010	1.30	5.23	0.03574	0.056	0.083
L-Bot	xxx-009	10/14/2010	1.57	3.23	0.01594	0.174	0.094
	average background		0.58 +/- 0.08	1.19 +/- 0.18			
	alpha efficiency		16.26% +/- 3.25				
	beta efficiency		61.65% +/- 12.33				

Results from this small, quick study suggest that black shales, like the Marcellus, contain minor but detectable amounts of heavy metals and other elements that can be detrimental to the environment if mobilized and concentrated in the soil or shallow groundwater. This information has raised some concerns, but additional analyses are needed to better define the fate and transport of leachate from black shale cuttings and positively identify the potential environmental hazards (Soeder, 2011). These studies are being carried out in much greater detail by analytical chemists at NETL (Stuckman, et al., 2015) on metals, radionuclides, and the organic components of the black shale.

Related geochemical studies of the Marcellus Shale have defined some of the processes that can mobilize metals from the shale, and also found some odd associations. The occurrence of uranium, for example, appears to be more closely associated with clay minerals instead of organic carbon, as always assumed, and the distribution of uranium within the rock follows hydrogen content, not carbon (Fortson et al., 2011). The geochemical conditions that favor the preservation of organic carbon also favor the presence of uranium, so although uranium is a good indicator of carbon content, it is not directly associated with the organic carbon.

The potential for black shale drill cuttings to weather and leach toxic metals at the surface needs to be linked with the geologic and geochemical properties of the rock. In the Marcellus, for example, the calcareous black shale facies probably contains enough carbonate to buffer any acid mobilization of oxidized metals (Chermak and Schreiber, 2014) but cuttings from the noncalcareous black shale lithology might have a greater potential to leach.

7.1.6 Fate and transport of frac chemicals

Natural attenuation (NA) is the process by which organic compounds break down in groundwater. Although natural attenuation processes and rates have been investigated extensively for BTEX, DRO, and other common organic chemicals, the literature on organic compounds used in hydraulic fracturing is sparser. Rogers et al. (2015) provide a framework for identifying the frac chemicals that may be both toxic and persistent in groundwater.

In particular, very few studies have been done on the biocides used to control downhole microbiological growth in the frac fluid. These compounds are used to prevent sulfate-reducing bacteria from generating hydrogen sulfide. They are also the most recalcitrant and difficult to break down if they get into shallow groundwater. A review of frac chemicals including biocides was assembled by Stringfellow et al. (2014), and Kahrilas et al. (2015) focused on just the biocides.

A number of researchers have been investigating NA of drilling fluids and frac chemicals, including scientists at Colorado State University, Ohio State University, and Carnegie Mellon University, as well as NETL and other national labs. NETL has been using flow-through sand columns to investigate the breakdown of chemicals; other researchers have been performing microcosm studies and chemical modeling.

The goals of these studies are to define the breakdown pathways and identify the daughter products of the frac chemicals of interest, as well as understanding the rate at which these reactions take place. Eventually, these data sets will be used in reactive transport groundwater flow models to determine how far away the accessible environment must be for a contaminant plume of any particular frac chemical in groundwater to be fully attenuated before reaching it. If the NA rate is too slow, it must either be enhanced by adding microbes or nutrients to the aquifer, or additional remediation measures such as reactive barriers or pump-and-treat must be employed.

7.2 PRODUCTION ENGINEERING RESEARCH

Methods of hydraulic fracturing have evolved over the past few years. Service companies from the Gulf Coast entering the Marcellus play early on obtained drinking-quality water from municipalities for hydraulic fracturing, used it once and then disposed of the produced water through a local POTW. A fresh supply of high-quality water was then brought in for the next frac job. Recall that this typically required 12–19 million liters or 3–5 million gallons of water per well. It was not necessary to use drinking water supplies for hydraulic fracturing. Much lower quality (and cheaper) water sources work well in a Marcellus Shale frac.

Operators switched from tap water to using untreated raw water from streams or effluent from POTWs for frac water. In 2011 after an appeal by the Pennsylvania DEP to stop taking produced water to POTWs for disposal, the industry began recycling produced water into the next frac. Recycling is less stressful to streams and aquatic ecosystems, and like other widely-used environmental practices it also has some tangible economic benefits.

Recycling provides savings on transportation costs, because the water is already at the well site. It also provides significant savings in disposal costs, which have increased fivefold in Pennsylvania over the past few years for high TDS waters. The low percentage of flowback normally recovered from a Marcellus Shale frac leaves most of the recycled water from a previous frac stranded downhole, effectively “disposed of” for free. This low recovery also means that there is not enough flowback to fully supply a subsequent frac, and significant amounts of “make up” water from other sources must be added to have enough volume.

Recycling flowback comes with several caveats. The water used in a hydraulic fracture treatment has to be essentially free of suspended solids, such as sediment. Total suspended solids (TSS) will plug up pores and microfractures if they are allowed to persist into the next frac job. As such, most of the onsite treatments of produced water are designed to remove the TSS. Techniques include advanced filtration systems, additives to clump or flocculate the clays, centrifuge-like settling processes, and other methods. The TSS filtration techniques currently in use at drill sites allow nearly all of the lower-salinity produced water to be recycled (Maloney and Yoxtheimer, 2012).

Hydraulic fracture water can contain moderate concentrations of TDS, but if the amount of dissolved solids gets too high, it will interfere with recycling when certain metals, like sodium or calcium, reach critical concentrations. The main slickwater additive used as a friction reducer is polyacrylimide, which is essentially a surfactant like detergent, and too much sodium or calcium in the water inhibits performance. The processes for treating high TDS waters onsite are complicated, and need to overcome problems with cost and throughput volumes.

Methods to recycle recovered produced water fall under a broader area of research that some people call environmentally-friendly drilling (EFD), a term coined at Texas A&M University to describe a set of management practices developed to reduce the environmental footprints of oil and gas production. Much of the engineering research has been supported by DOE to apply existing environmental protection technologies from other industries to develop technologies specifically for oil and gas wells. EFD includes everything from site selection criteria and construction methods to research on the processes used for compressing gas into a pipeline (see http://www.efdsystems.org/ for details).

Since 2005, the EFD program has been largely centered at the Houston Advanced Research Center (HARC) in Texas. HARC was founded by George Mitchell—the same George Mitchell of Barnett Shale fame. The EFD program is investigating a number of new technologies to reduce what is called energy sprawl, or the environmental footprint of energy production. For natural gas, especially shale gas drilling, some new technologies being tested include lightweight drill rigs with lower road impacts, natural gas-powered rigs to produce lower emissions than diesel engines, closed-loop mud systems to keep drilling mud in tanks and out of pits, and creative ideas for water processing and drill cuttings disposal.

Products coming out of the EFD program include interlocking, plastic mats for constructing temporary roads across wetlands and other sensitive areas. The mats are made from compression molded plastic, 2.5 meters (8 feet) x 4.25 meters (14 feet) in size, 10 cm (4 inches thick) and weigh about 454 kilograms (1,000 pounds) each. They are designed for truck traffic, and despite the bulk, they are lighter and more durable than old-style wooden planks or wooden board mats. When laid down and interlocked, they form a plastic road bed that can prevent damage to underlying soft ground.

The EFD program is also supporting research on methods of repairing microannular leaks in casing cement that may be responsible for some stray gas releases. A resin sealant originally developed for pipeline leaks has been adapted to repair cracks in cement. The resin is emplaced as a low viscosity liquid, and remains liquid until it encounters a significant pressure differential, such as that across the upstream and downstream ends of a crack, where it then sets up into a rubber-like elastomer, sealing the crack.

Production engineering research includes the development of more precise techniques for air-quality monitoring that reflect patterns of actual equipment use. Location is critical. The equipment can’t be too near a road, downwind of a wastewater treatment plant, too deep in the trees, etc. Determining the sources of emissions, acquiring activity data (engine run times and loads), and developing better dispersion calculations and modeling are critical to correctly assessing air pollution. Because many locations in the Marcellus region were already in non-attainment areas for air quality prior to drilling (Graham, 2011), baseline data are important. Many sources of air pollution are not necessarily related to the gas industry. In fact, preliminary analysis of NETL air quality monitoring data in Allegheny National Forest downwind of conventional oil and gas drilling operations showed no significant difference from a control site. (Pekney et al., 2014) New technology, including vapor monitoring, capture, and reuse is significantly reducing fugitive emissions from gas production.

Landscape impacts are being reduced through the application of more efficient technologies for drilling and fracturing known as “optimization” of gas production. This seeks to improve the efficiency of gas recovery from a specific volume of rock, using fewer wells, more effective stimulation, and flow optimization to produce more gas. It reduces the amount of costly infrastructure necessary to recover the gas, which not only saves money, but also lessens the environmental impact. Much of the design work is done by computer modeling.

An example of optimization would be determining the distance between laterals to obtain the most efficient gas production at the lowest cost. If the laterals are too far apart, a significant quantity of gas may not be recovered in the volume of shale between them. If the laterals are too close, the total amount of produced gas may be too small for favorable economics. The ideal spacing will achieve both the maximum physical recovery and sufficient volume for good economics.

Optimization is also being researched for water use. Computer models have been designed to consider the source of frac water, the transportation mechanism (pipeline or truck), the distance to the wellsite, and locations of other, nearby wellsites that can use the recycled water. Optimization of all these factors can improve the efficiency of water use on shale gas wells, which is good for the environment. Higher efficiency also usually translates into lower cost, and the adoption of an environmental practice by operators is more successful when it appeals to bottom-line economics.

Optimization methods of shale gas development are changing as the technology evolves. More efficient hydraulic fracturing procedures, for example, may contact more reservoir volume than previous methods, allowing the laterals to be spaced farther apart while still physically recovering significant amounts of the gas between them. The drilling industry is constantly looking at these various factors and trying to figure out what they can do to get more gas out of the rock for less money. Practices such as placing drill pads farther apart, or installing more wells on a pad reduces the overall cost of developing a play. If this is also more efficient, it often reduces environmental impacts as well.

By 2011, thanks to longer laterals, better fracs and optimization of production, drill pads on the Marcellus Shale play went from a spacing of 0.648 square km (160 acres) to a spacing of 1.295 square km (320 acres) and then to 2.59 square km (640 acres). Because of this optimization of lateral drilling, a single Marcellus Shale well pad now replaces 16 old-fashioned, individual vertical well pads on a spacing of 0.162 square km (40 acres) to recover gas from the same volume of shale. Ultra-long laterals on the Utica play in Ohio, described earlier for the Eclipse Resources Purple Hayes #1 well in Guernsey County with a lateral length of 18,544 ft. (3.5 miles or 5.6 km) are being drilled to improve efficiency and economics (Halliburton Press Release, Houston, May 31, 2016; Oil and Gas Investor, July 7, 2016). Such ultra-long laterals will further reduce surface disturbance by allowing even greater well spacing.

Even with the best completion techniques currently in use, operators are only recovering about 10 percent of the total Marcellus Shale gas in place. On Bakken Shale oil wells in North Dakota, the recovery is even lower, estimated at around 6% of the oil in place. Such low recoveries emphasize the need for better efficiency. Production methods that leave more than 90% of the resource in the ground certainly have room for improvement. Nevertheless, the recovery of just 6% of the oil in the Bakken Shale has transformed North Dakota into the nation’s second-largest oil-producing state, after only Texas. Imagine if the recovery could double to 12%. Or increase tenfold to 60%.

One possible method for improving the efficiency of shale production is pinnate drilling (see the discussion on emerging technologies in Chapter 5). The pinnate pattern drills side laterals off the main lateral, like the branches of a feather. Unlike hydraulic fracturing, which pushes aside the rock, opening up some flowpaths at the expense of closing down others, pinnate drilling actually removes rock material from the shale reservoir volume, allowing the formation to relax. Many people think that this may allow natural fractures to open, letting hydrocarbons move more readily to a wellbore.

Pinnate drilling is commonly used on coalbed methane wells where the target formation is either too shallow to frac, or too sensitive to the stresses a frac can induce. The coiled tubing rigs currently used for pinnate drilling can’t reach the depths required for shale gas, but this could change in the future. Drilling out these shales to reach economical reservoir volumes instead of hydraulically fracturing them could solve a multitude of environmental concerns, and produce more of the hydrocarbons in place than previously possible.

7.3 CARBON DIOXIDE SEQUESTRATION

A relatively recent research idea is to investigate depleted gas shale as a potential location to store or “sequester” carbon dioxide from the atmosphere. The idea is that after the natural gas has been extracted from these formations, perhaps the empty pore space within the rock can be refilled with carbon dioxide to help reduce the levels of this particular greenhouse gas in the atmosphere.

The issue of climate change is no longer controversial among scientists who have seen the evidence (National Academies of Science, 2005; National Research Council, 2011). However, as with hydraulic fracturing, there is a vocal opposition that confuses the issues, exploits small uncertainties, misrepresents facts, and denies the validity of data to stir debate. Thus, a brief discussion of the basic physics may be helpful.

The behavior of atmospheric carbon dioxide has been understood since Joseph Fourier first investigated radiative heat transfer back in 1827. Fourier discovered that the carbon dioxide molecule is transparent to short wavelengths of infrared radiation, but it blocks and absorbs the longer wavelengths. The Earth receives short-wave infrared from the sun that penetrates the atmosphere and heats the surface of the planet. The warm Earth then re-radiates this heat back into space as longer wavelengths of infrared radiation, which is absorbed by carbon dioxide in the air and warms the atmosphere (Pierrehumbert, 2011).

Carbon dioxide levels in the atmosphere have been steadily increasing since continuous measurements began in 1957 (http://www.esrl.noaa.gov/gmd/ccgg/trends/) on Mauna Loa in Hawaii. There is some debate about the source of this CO_2, but a prime suspect appears to be the combustion products of fossil fuels, which have been used in ever-increasing quantities by humans since the Industrial Revolution.

How this increase in atmospheric carbon dioxide translates into potential climate change is the source of most of the uncertainty. The mean global temperature increase of 0.8 degrees Celsius during the last century is actually greater than could be caused by anthropogenic greenhouse gas alone (Adair, 2012). This is because the Earth has been emerging from the most recent Ice Age for the past 12,000 years, and climates have been undergoing a natural warming. Any human-induced warming is superimposed on this natural background signal, making the two effects difficult to separate.

A report by the IPCC or Intergovernmental Panel on Climate Change (Solomon et al., 2007) has stated that if no effective carbon dioxide reductions are implemented by industrial nations, concentration of the gas in the atmosphere will likely increase from 390 parts per million (ppm) in 2007 to about 1250 ppm in 2100. The IPCC scientists estimate that mean global temperature will increase over the next century by approximately 3.4 degrees Celsius (6.1 degrees Fahrenheit).

Climate risk assessments are probability-based, and attempt to gauge both the magnitude of the projected temperature increases and the potential consequences. In the worst case, the IPCC assigns a one-in-six chance that temperature increases will exceed 5.4 degrees Celsius (9.7 degrees Fahrenheit), which would result in serious climate disruptions. The best case is a one-in-six chance that increases will be less than 2.0 degrees Celsius (3.6 degrees Fahrenheit), and be lost in the natural background.

Risk assessment considers not just the probability of an event, but also the consequences (Soeder et al., 2014). The consequences of a 5.4 degree Celsius temperature rise could be severe, including the potential melting of the polar ice sheets (Poore et al., 2000), which could raise sea levels by up to 76 meters (250 feet) and inundate significant amounts of coastal land. A one-in-six probability of this occurring may not sound like a significant risk. However, these are the same odds as Russian roulette, universally recognized as a very high-risk endeavor because of the potentially deadly consequences. Thus, although the probability of significant warming may not be high, the possible consequences make it a serious risk and justify reducing anthropogenic carbon dioxide levels in the atmosphere.

7.3.1 Geologic storage

A favored technology for removing excess carbon dioxide from the atmosphere is called geologic storage, which involves injecting the gas into geologic formations and storing it underground for long periods of time. Some of the rock units under consideration include depleted conventional natural gas or oil reservoirs, deep saltwater aquifers, unmineable coal seams, gas shales, and basalts (U.S. Department of Energy, 2012). Each has advantages and disadvantages in terms of practicality and cost.

Underground injection of carbon dioxide can be done with better economics when it is used to sweep residual oil out of old reservoirs. This is called enhanced oil recovery, or EOR, and it has been successful in a number of vintage oil fields in Texas and Louisiana. Carbon dioxide has also been injected into depleted conventional gas reservoirs with some success, notably the Frio Formation on the Gulf Coast, and also into several deep saline aquifers in the Midwest.

When carbon dioxide gas is put under high pressure, it transforms into a state known as a “supercritical fluid,” where it has the properties of both a gas and a liquid. Field demonstrations suggest that storing carbon dioxide in conventional rocks as a supercritical fluid is efficient, because it takes up less space than a compressed gas. Supercritical CO_2 will also dissolve into subsurface formation waters and brines, forming carbonic acid that can damage cement, steel tubulars, and even the formation seal itself.

Several groups of researchers have been considering the potential for carbon storage in depleted gas shales. Black shales have an adsorbed component of gas, and preliminary data indicate that adsorption may be significantly stronger for carbon dioxide than for methane (Busch et al., 2009). Many if not most gas shales also contain a non-mobile water phase (Soeder et al., 1986), suggesting that corrosion problems experienced with supercritical carbon dioxide storage in conventional reservoirs will be much less of an issue in gas shale.

One economic advantage of a productive gas shale like the Marcellus is that the pads, wellheads, hydraulically fractured boreholes, distribution pipelines and other infrastructure needed to transport and inject the gas are already be in place. When production ends, the well becomes a liability with additional costs to plug and abandon per state regulations. The owners may wish to transform this liability into an asset by converting the well for carbon dioxide injection.

Before getting to this point, however, laboratory experiments and field tests are needed to assess the capability of the Marcellus Shale to store carbon dioxide, and address some rock property concerns. The gas pressure in the pores acts to offset some of the weight of the rocks above, but producing the gas reduces this pressure. Since the weight of the rocks above remains the same, the "net" overburden pressure increases. Such an increase in net overburden stress has been observed to affect the pore-scale movement of fluids in the Marcellus Shale, closing down the smaller flowpaths, increasing flowpath tortuosity, and significantly reducing permeability to gas (refer back to the Klinkenberg permeability plots in fig. 17, and Soeder, 1988).

Shales are subject to a phenomenon called "hysteresis," where the gas permeability cannot be restored by simply returning to initial conditions after an excursion to high net stress. Evidence suggests that this is because the microscopic bumps and irregularities known as "asperities" that propped open the original pores have been altered or destroyed by crushing under high net stress, irrevocably changing the very structure of the rock. Studies on the Barnett Shale have suggested that stress-induced alterations of the rock are likely permanent (Vermylen, 2011).

The problems with hysteresis may preclude the use of depleted gas shales for subsequent carbon dioxide storage. However, by knowing that the phenomenon exists and planning for it, reservoir pressure management during production may help to preserve permeability. Such management might include injecting carbon dioxide along the perimeter of a shale gas reservoir at an earlier stage of drawdown to help maintain reservoir pressures and keep flowpaths open. If done carefully, such an injection could also help sweep the natural gas more efficiently from the shale and increase recovery. If it improves the economics, operators are more likely to adopt it as a practice.

7.3.2 Storage risk assessment

One of the main concerns about storing carbon dioxide in geologic formations is assuring that it will stay put and not return to the atmosphere. The various target formations mentioned earlier (depleted conventional natural gas or oil reservoirs, deep saltwater aquifers, unmineable coal seams, gas shales, and basalts) were all selected because of their potential abilities to contain the CO_2 underground. For example, a conventional gas reservoir requires the presence of a trap and seal to contain the natural gas (refer back to Chapter 3.2). Since we know the trap and seal held the natural gas in the reservoir over geologic time periods (or no hydrocarbons would have been produced in the first place), it should be able to hold CO_2 equally well. Or so one might think. In reality, things are more complicated than that.

There can be many reasons why a geologic formation won't retain CO_2. In the example above, perhaps during drawdown of the natural gas reservoir, pressures and stresses on the seal could have cracked the caprock. Perhaps these cracks stayed closed as the reservoir was depleted, but re-pressurizing it with carbon dioxide may allow the fractures to open up and release the gas. Carbon dioxide, especially in the supercritical state, is far more reactive than the main component of natural gas, methane. The CO_2 may attack minerals in fractures, quartz and carbonate cements in sedimentary rocks, and affect wellbore integrity. In fact, injecting CO_2 into a depleted gas field implies that the wells are already old, and wellbore cements and downhole casings may be even more susceptible to corrosion from CO_2 (Watson and Bachu, 2009).

As described earlier at the beginning of chapter 6, a number of DOE national labs, including NETL, Los Alamos, Lawrence Livermore, Lawrence Berkeley, and Pacific Northwest formed the National Risk Assessment Partnership, or NRAP to assess the risk of CO_2 migration from geological storage sites. The methodology for assuring the CO_2 stays in place is called Monitoring, Verification, and Accounting (MVA). Details are available on the NETL carbon storage website (http://www.netl.doe.gov/research/coal/carbon-storage/research-and-development), or in the DOE Carbon Sequestration Atlas (U.S. Department of Energy, 2012).

The NRAP research is focused on numerical modeling to assess how CO_2 plumes might escape a reservoir seal and migrate upward. Related projects are investigating the technology and methods used to monitor CO_2 in an underground reservoir, and detect any that might escape. Studies on geologic storage in basalt are investigating mineral reactions between the CO_2 and calcium feldspars to ultimately store the gas in a solid phase as calcium carbonate. Preliminary experiments in Iceland partially funded by DOE found that this process was more rapid than expected, with significant carbonate formation in as little as two years (Matter et al., 2016).

7.4 NEW USES FOR NATURAL GAS

Modern civilization was built on the use of fossil fuels. The Industrial Revolution came about because people learned to use coal to make steam, and then figured out how to use the steam to do useful work, like running a factory or moving goods long distances by powering a railroad locomotive or a ship. Oil and gas came along later and replaced coal in areas of transportation and certain industrial processes. These fossil fuels were developed because they were a low cost source of abundant energy.

Before fossil fuel, energy was derived from burning wood, water wheels, windmills, animal power and human muscles. Despite the many evils that have been laid at the feet of fossil fuel, it is undeniable that coal, oil and gas have displaced the need for animal and human muscles as a basic power source.

Many people are not aware that by 2002, many utility companies were becoming alarmed about impending natural gas supply shortages in the United States. Conventional gas fields in the Gulf Coast had been produced for decades and were in decline. No significant new conventional sources of natural gas had been found in North America, except perhaps in the Mackenzie Delta in the Canadian Arctic. Shale gas from vertical wells was a tiny percentage of the total supply, and George Mitchell's experiments with horizontal Barnett Shale wells in Texas were little more than a novelty.

Plans were made to build huge import terminals on the U.S. East Coast to bring in liquefied natural gas (LNG) from overseas. Importing LNG to supply a basic fuel would have placed America in the same political dilemma as importing crude oil: dependence on an energy resource from foreign suppliers who may or may not wish to sell.

LNG is held at cryogenic temperatures as cold as liquid nitrogen. If it escapes and vaporizes, it can create a very large amount of highly combustible gas. LNG has leaked in the past with devastating consequences.

Back in the 1940s, the East Ohio Gas Company in Cleveland was experimenting with LNG as an onsite storage method to supply gas needed for wartime industries. After experiencing high gas demand during several cold winters and faced with the cost of building an expensive new gas pipeline into the Cleveland area, the East Ohio Gas Company decided to try storing it inside the city as a liquid.

Several spherical tanks and one large cylindrical tank were set up to contain the LNG on the grounds of the East Ohio Gas facility on E. 61st Street, a few blocks from the Cleveland lakefront. During a routine ammonia refrigerant pumping procedure on the afternoon of October 20, 1944, the large cylindrical tank, designated Number 4 and constructed in 1942, suffered a failure on a seam and started leaking streams of LNG and vapor (Elliott et al., 1946).

The vapor ignited almost immediately, causing the entire tank to collapse and releasing 4,163,500 liters (1,100,000 gallons) of liquefied natural gas at a temperature of minus 160 degrees Celsius (-250 degrees Fahrenheit) onto the ground. Although rapidly vaporizing, large volumes of the liquid flowed downhill from the ruptured tank and into storm drains. It spread throughout a 20 block area via the sewer system, combining with air along the way to form an explosive mixture. About 10 minutes after the leak started, the gas in the sewer system found a source of ignition and exploded. Streets, sidewalks and hundreds of structures were destroyed in minutes. A second tank ruptured about 20 minutes later in the ensuing fire, which had flames that reportedly reached 850 meters (2,800 feet) in height. The disaster killed 128 people and injured 200–400 (Elliott et al., 1946). Slightly more than 2.5 square km (1 square mile) of Cleveland's east side was devastated. The location is still visible near the E. 55th Street exit off I-90 as an enclave of newer buildings set among the older, pre-war homes.

The U.S. Bureau of Mines investigation looked at everything from Nazi sabotage to a possible earthquake as the cause, and concluded that a combination of improper tank design, the use of low-quality wartime steel made brittle by the extremely cold cryogenic liquid, and a possible welding flaw all contributed to the failure of the cylindrical LNG tank (Elliott et al., 1946). As a result of this disaster, U.S. gas companies re-thought their storage options near cities, and now virtually all gas storage is underground in geological formations close to, but not inside cities.

Although Japan has had a successful history of importing LNG without facing a similar disaster (Hightower et al., 2004), construction of large LNG import terminals on the U.S. East Coast near major cities has been met with resistance.

The development of the Marcellus Shale and other gas shales has completely changed the gas supply equation. Marcellus Shale gas is supplying energy to cities in the northeastern United States more securely, and with far better economics than imported LNG. The existing LNG terminals are now being considered for exports, rather than imports. Natural gas liquids recovered in the Appalachian Basin are being sent to petrochemical plants to be made into plastics and other products. New plastics manufacturing capability has been built in West Virginia and Pennsylvania, which has not seen such factories in operation since the 1980s.

Current estimates by the DOE Energy Information Administration of ultimate recoverable natural gas resources in the United States of more than 1,000 TCF make the Mackenzie Delta look remote and expensive. Estimated ultimate recovery from the Marcellus (~ 490 TCF per Engelder, 2009) and the underlying Utica (~782 TCF per Hohn et al., 2015) add up to 1,272 TCF of gas and gas equivalents in the Appalachian Basin alone. Shale gas is expected to account for 35 percent of total domestic gas production by 2035, which is probably a conservative estimate.

So what should be done with all this gas? There are only so many hot water heaters, kitchen stoves, and furnaces out there. Traditional gas markets are not expanding, and with conservation, neither are overall energy markets. Shale gas has significantly increased the supply of natural gas in the United States, but by doing so without increasing demand it has caused prices to drop steeply.

U.S. gas prices at the wellhead that were above $11/MCF in 2008 during the height of the Marcellus drilling boom fell below $2/MCF by early 2012, due to an unusually warm winter, a slowly recovering economy, and oversupply. There was even talk of prices falling to zero because gas storage fields were full, demand was low, and gas distribution companies simply did not want to buy any more natural gas. This has not happened so far, but at this writing domestic prices are still under $3/MCF.

The low prices essentially brought an end to the drilling boom in the dry gas part of the Marcellus play during 2013. Many of the lease agreements signed at the beginning of the land rush in 2008 had a five year limit, meaning that at least one producing gas well had to be drilled on the lease to keep it active, or the lease would have to be re-negotiated, almost certainly at a higher price. Marcellus operators installed one or two wells onto land parcels, but these were only to preserve the lease. Gas prices got so low that many operators decided it was less costly to just walk away from the lease, and drilling in the dry gas part of the play has died down considerably.

Since 2013, Marcellus drilling has been focused on the condensate-rich part of the play in far western PA, the northern panhandle of WV, and some of the WV counties along the Ohio River where ethane is produced as a natural gas liquid. In addition to liquids-rich parts of the Marcellus, operators have focused on other natural gas liquid-rich or oil shale plays like the Utica Shale in Ohio, the Eagle Ford Shale in Texas, the Niobrara Shale in Colorado and Wyoming, and the Bakken Shale in North Dakota. However, the subsequent drop in international oil prices beginning in November 2014 hurt these liquids-rich prospects as well.

Expansion of the gas market would be beneficial to both consumers and producers, ensuring a stable supply of a clean, abundant fuel. Strategically, natural gas has a number of advantages over other primary energy sources.

A nationwide infrastructure for natural gas already exists in the United States - the investment in interstate gas pipelines made over half a century ago means that natural gas can readily be moved around the country from places it has historically been produced to places where it is needed. Pipelines are a very efficient method of transporting energy, giving gas a low carbon footprint for transportation. Shale gas in the Northeast is even more efficient to bring to market when production wells are located near pipelines that can transmit it to the big cities.

Expanding pipeline capacity into areas of new shale gas production has been a challenge, especially in parts of the Marcellus and Utica plays, which have not been historically productive locations. Typically shale gas and other gas resources have not been significantly produced in areas lacking pipelines. This is known as “stranded gas,” and represents a large, untapped energy resource.

The Bakken Shale play in North Dakota is possibly the most significant example of an area with stranded gas. Because the Bakken is an oil play, recovered crude oil is typically moved out by truck or by railroad. Until very recently, natural gas that was co-produced with the oil was flared off to get rid of it because industry was far more interested in the more valuable oil. Most operators are now re-injecting gas into the reservoir, but many thousands of cubic feet have been lost through flaring.

Natural gas does not require cracking or refining to use. What comes out of the ground at the wellhead is essentially the same substance entering the consumer's home. Some natural gas contains carbon dioxide, hydrogen sulfide, or liquids that must be removed before it can be put into a pipeline, but these processing steps are relatively simple compared to cracking and refining petroleum. The main component of natural gas is methane, which is odorless and colorless. Methyl mercaptan is added to natural gas as an odorant to make it detectable.

Crude oil is made up of a mixture of many different hydrocarbons, and the refining process is designed to produce a variety of products from this mix. Besides making gasoline and diesel fuel, crude oil is a critical feedstock for the petrochemical, pharmaceutical, and plastics industries. As such, burning petroleum for fuel is essentially the moral equivalent of cutting down the finest-grain, furniture-quality, hardwood timber in a forest and using it for a campfire. Coal also has uses as a chemical feedstock, and for specialized processes such as providing a carbon source for making steel. Natural gas is primarily used for combustion.

Natural gas burns cleaner than other fossil fuel in terms of emissions. The nearly pure methane that comprises natural gas produces only carbon dioxide and water as combustion products. Coal combustion produces sulfur compounds, selenium, mercury, arsenic, and ash. Petroleum combustion products include aldehydes, the major components of smog, ozone, and a variety of carcinogens. Because of the high hydrogen to carbon ratio, natural gas also has the lowest carbon dioxide emission per Btu of any carbon-based fossil fuel.

The U.S. government and several industry groups funded numerous research projects on the utilization of natural gas until the late 1990s. As supply shortages loomed and talk turned toward importing natural gas, the utilization research came to a standstill. Funding agencies declined to support research on new uses for natural gas when no one was sure there was even enough gas for current uses. High tech projects on natural gas-powered fuel cells and gas-to-liquids technology slowed to a crawl and are years behind their original schedules for commercialization.

Not all gas utilization technologies are complicated and high-tech, however. There are several simpler uses for natural gas that can be implemented quickly and don't require rocket science to understand (unless gas is actually used to power space vehicles, which is a possibility). Two lower-tech uses that can have significant impacts on the American economy are 1) natural gas-fueled vehicles, which could continue to decrease U.S. dependence on imported oil and produce much cleaner air in our smog-filled cities, and 2) natural gas-fueled electricity to replace coal and reduce our national greenhouse gas footprint. Both of these will have potentially huge environmental, national security, and economic benefits, and both can be implemented profitably right now using existing technology.

7.4.1 Transportation fuel

If natural gas was substituted for oil in just one sector of the petroleum economy—vehicle fuel—it would be sufficient to eliminate the need to import any foreign oil into the United States. The use of natural gas versus gasoline as vehicle fuels can be compared in terms of energy equivalence by using units of energy measurement. One of these is the British thermal unit, or Btu; equivalent to 251 calories or 1,054 joules. 1 MCF of natural gas, equivalent to a metric volume of 28.32 cubic meters, contains approximately a million Btus of energy. Thus, each cubic foot of natural gas has the energy equivalent of about 1,000 Btus.

Crude oil is measured in barrels; a barrel of oil contains 42 gallons or 159 liters of liquid. Only part of this total yields gasoline, however, with the rest going to jet fuel, diesel, petrochemicals, and other feedstocks. Figures published by the U.S. Energy Information Administration (2015) indicate that about half the volume of a barrel of crude oil, depending on grade and refining technique, is converted to gasoline in the refining process, which means that a standard barrel of oil will deliver about 80 liters (21 gallons) of gasoline.

In terms of energy value, 3.7853 liters (a gallon) of gasoline contains 125,000 Btus. The amount of natural gas needed to equal this much energy is about 3.54 cubic meters (125 cubic feet) at 25 degrees Celsius (77 degrees Fahrenheit) and under a pressure of 1 atmosphere. Thus, an MCF of natural gas contains the energy equivalent of about 8 gallons of gasoline.

According to the U.S. Energy Information Administration (2015), the United States consumes about 20 million barrels of oil per day, or about 7.1 billion barrels per year. After peaking in 2005 at 3.7 billion barrels, imported oil in 2015 was down to about 2.7 billion barrels annually, or roughly 37% of the total. In 2015, U.S. refineries processed slightly more than 7 billion barrels of crude oil, producing about 3.5 billion barrels of motor gasoline (U.S. Energy Information Administration, 2015).

So, in order to eliminate the import of 2.7 billion barrels of oil, the 1.35 billion barrels of gasoline and the 1.35 billion barrels of other petroleum products that would be refined from this oil need to be replaced by natural gas. Nearly all vehicles in the United States at present are powered by gasoline, consuming about 3.5 billion barrels of motor gasoline annually (U.S. Energy Information Administration, 2015). Thus, switching about 75 percent of these vehicles over to natural gas would completely offset the 2.7 billion barrels of imported oil. All the other products produced by refineries could be supplied by current levels of domestic crude oil production, and the U.S. would not need to import a single drop.

To meet this demand, domestic gas wells would need to produce an additional 400 billion cubic meters (14.175 TCF) of natural gas per year. Current national gas consumption is around 27 TCF per year (U.S. Energy Information Administration, 2015), so gas production would have to increase by about 50 percent to fuel all American vehicles.

If the Marcellus Shale contains about 85 TCF of recoverable natural gas, as the USGS conservatively estimates (Coleman et al, 2011), this one formation could provide enough fuel to power all U.S. vehicles for about six years. If it contains 410 TCF, the number many independent researchers think is possible, it could provide the United States with vehicle fuel for nearly three decades. And it is only one gas shale of many.

These are simplistic calculations and many people will certainly want to debate the details. The point of the discussion is that America should be seriously evaluating natural gas fueled vehicles as a nation. U.S. shales have more than enough natural gas to replace oil imports for many years. Perhaps it would be instructive to compare the cost and efficiency of vehicles fueled directly by natural gas with electric vehicles that use natural gas or coal-generated electricity to recharge. Such comparisons are beyond the scope of this discussion, but hopefully these assessments will be made.

Given the volatility of both natural gas and crude oil prices, no cost calculation was included in this chapter. However, a simple comparison of the cost of 21 gallons of gasoline derived from a single barrel of crude oil with the cost of the energy-equivalent 2.6 MCF of natural gas found that the cost of natural gas was about 10 percent of the cost of gasoline. Performance, range and space considerations also must be included in any realistic comparison.

Of course there are concerns. Energy guru Daniel Yergin (2011), writing in the Wall Street Journal, suggests that developing a transportation economy fueled by domestic natural gas could be a challenge because automakers and the fuel-supply industry are already dealing with a multitude of imperatives—more fuel-efficient cars, more biofuels, plug-in hybrid electric vehicles, and pure electric vehicles. He states that making a major push for natural-gas vehicles would add yet another set of mandates and incentives, including the creation of a costly new fueling infrastructure.

On the issue of infrastructure, a significant advantage that natural gas has over hybrids and electric vehicles is that the type of vehicle capable of running on natural gas is already widely distributed throughout the United States. Believe it or not, most people already own one. A standard, gasoline-powered automobile engine will run just fine on natural gas with a simple conversion.

Adapting a standard automobile to run on compressed natural gas, or CNG, requires little more than installing a compressed gas cylinder in the trunk (or another suitable location), and running a line from it to the engine. A few other amenities are necessary, like a pressure gauge, regulator, shut-off valve and DOT-approved cylinder, but a search of websites offering these conversions shows prices in the $1,000–$2,000 range, with about $1,500 being the median.

The usual design leaves the vehicle's gasoline tank in place, and adds the CNG cylinder as a second fuel source. One of these "bi-fuel" vehicles typically has a range of about 160 km (100 miles) or so on the CNG fuel, and then with the simple flip of a switch on the dashboard, it can go back to running on gasoline. Since most people don't drive this far in a day, the CNG tank can be refilled overnight with a home compressor, making the vehicle capable of running on natural gas nearly all the time.

Dr. Nigel Clark in the West Virginia University Center for Alternative Fuels, Engines and Emissions (CAFEE) has described the common engineering designs for natural gas powered engines as follows: 1) Lean burn spark ignited, which can produce high nitrogen oxide (NOx) emissions if run too lean; 2) Rich burn (stoichiometric) spark ignited, which uses a 3-way catalyst that produces low NOx and low methane emissions when hot; 3) high pressure direct injection, commonly used for small diesels by injecting natural gas directly into cylinder; and 4) dual-fuel engine, where natural gas is injected with diesel fuel, and replaces a percentage of the diesel needed to run the engine. All of these have various advantages and disadvantages depending on fuel mix, temperature, and load.

Some engineers who are familiar with the technology have expressed concerns that the composition of natural gas supplied to homes can vary over the course of a year, and this can be detrimental to transportation use. Although the energy value of delivered natural gas remains relatively constant, variations in the content of carbon dioxide, nitrogen, and other gases are not uncommon. While this makes little difference at the burner tip on a hot water heater, for example, it can cause significant variation in performance of internal combustion engines fueled by gas. Maintaining the composition of natural gas to established standards in a manner similar to gasoline would improve its viability as a transportation fuel.

As for the question of fueling infrastructure, natural gas is already widely distributed, and it is currently supplied to many service stations to heat their garages or convenience stores. Setting up a compressor and running a pipeline out to a dispenser on the pump island is all that is needed to begin fueling vehicles with natural gas. Among other advantages to a business offering retail CNG vehicle refueling, it does not add to leaking underground storage tank (LUST) liabilities, and there are no worries about running out of fuel to sell to customers because a tanker truck didn’t arrive.

This technology is neither difficult nor new. Natural gas-fueled vehicles were first developed in Italy during the 1930s. In western Canada, a glut of gas from the Deep Basin in Alberta made the bi-fuel technology popular in the 1980s. Compressed natural gas was sold at a number of service stations in the Calgary area at the time, and many people had home compressors. The pressure cylinder in the car was filled at home or at a service station using a high-pressure gas hose with a standardized bayonet connector fitting.

CNG vehicles also gained popularity in New Zealand during this same era. The 1980s-version of the vehicles had a dashboard switch to advance the spark on the distributor when running on CNG, because it didn’t require a delay to vaporize in the carburetor like gasoline. On modern cars with computer-controlled fuel injection, especially those able to adapt to various ratios of gasoline and ethanol fuel mixtures, a similar adjustment is probably not even necessary.

Low oil prices in the late 1980s, and a lack of government enthusiasm for the program killed the technology in Canada and New Zealand. It never really moved forward in the United

States, except in California, where CNG vehicles are sold to help meet clean air standards in Los Angeles and other cities. Nations that have embraced CNG vehicles with enthusiasm include Pakistan, India, and a number of countries in South America, such as Brazil and Argentina.

In the United States, the most common natural gas fueled vehicles at present are transit buses. These are fleet vehicles, which return nightly to a central garage with CNG refueling capabilities. For this idea to expand and make a serious dent in imported oil, CNG refueling capabilities must be added to people's homes and at widespread service station locations.

The greatest disadvantage of CNG as an automotive fuel is the volume needed to achieve a significant range. Natural gas simply does not have the energy density of gasoline, so a larger volume of fuel is needed to go the same distance. There are at least two possible ways to deal with this:

1) Live with less range. Americans typically suffer from "range anxiety," and are not happy with a vehicle unless it can potentially get them 400 or 500 miles on a single tank of fuel, even though their daily drives are often far less.

2) Live with less space. Giving up some cargo area to carry more fuel can make vehicles go longer ranges on CNG.

From a safety standpoint, driving around with a cylinder of CNG is no more inherently dangerous than having a sheet metal tank filled with 10–20 gallons of gasoline strapped to the bottom of a vehicle. In an accident, a leak from either could be a fire hazard, but the CNG, being lighter than air, would leak upward and disperse instead of running out along the ground seeking an ignition source. The placement of a CNG cylinder in a vehicle could be done in a manner that protects it as much as possible from damage in a collision, similar to the engineering that goes into locating a gasoline tank.

Because CNG cylinders are designed to hold high pressures, they are made from strong steel cylinders reinforced with graphite or nylon wrapping. These are significantly stronger than a thin, sheet metal gasoline tank, and more durable in an accident. An extended fire could cause a possible problem, but the cylinders are equipped with pressure relief valves to reduce pressure in a controlled manner. According to Dr. Nigel Clark of WVU, the safety record for CNG cylinders in traffic accidents has been very good.

In addition to cost, another major advantage CNG vehicles have over gasoline is on emissions. Because the methane molecule is so simple, natural gas combustion doesn't produce polluting chemicals like those created by burning hazardous ring-shaped hydrocarbons such as benzene and ethylbenzene, or complex organic molecules like toluene and xylene compounds, which make up the bulk of gasoline. Those combustion byproducts react with sunlight and moisture to form brown hazes or smog.

Despite 40 years of emissions controls and catalytic converters, the smog in U.S. cities from gasoline powered vehicles has not gone away. It is still not unusual for some cities to experience a number of days where the EPA Air Quality Index exceeds 100, which can cause problems for people with respiratory sensitivities. If natural gas replaces petroleum as a vehicle fuel, air quality in non-achievement areas will improve significantly.

One of the most harmful pollutants in smog is ozone, which forms from reactions among complex gasoline combustion products in the atmosphere like aldehydes, driven by sunlight. The ozone molecule, which is made up of three oxygen atoms, can cause serious human health effects, harm birds and mammals, damage vegetation, and crack rubber and polymer materials. Congress has debated recently about if, when, and how U.S. air pollution regulations ought to consider addressing ozone. Running cars on CNG instead of gasoline, especially in cities, would reduce ozone dramatically.

A significant source of groundwater contamination in the United States is BTEX from leaking underground gasoline storage tanks. The gasoline additive methyl tertiary butyl ether (MTBE), which was mandated to reduce wintertime smog, turned out to be another groundwater contaminant. It has since been replaced with ethyl alcohol or ethanol.

Each environmental problem solved for gasoline-powered transportation seems to lead into another one. Groundwater pollution from our extensive storage of gasoline in LUSTs has been far more harmful over much wider areas than any chemical or frac fluid spill from shale gas operations. If CNG replaced a large part of our gasoline usage, the problems inherent with LUST will be sharply reduced.

Some people have expressed concerns about potential greenhouse gas emissions from the leakage of methane in a natural gas vehicle fuel delivery and distribution system. Natural gas leaks are never desirable, which is why an odorant called methyl mercaptan is added to natural gas so it can be detected should a leak occur. Methane is indeed a more powerful greenhouse gas than carbon dioxide, but the main concern about natural gas leaks is explosions. Maintaining tight seals is important mostly for safety reasons.

In addition to cars and buses, heavy trucks such as tractor-trailer rigs or semi-trucks are also a potentially market for natural gas fuel. Both local and long-haul trucking make up one of the largest transportation fuel use sectors in the economy. Local delivery trucks burn large amounts of fuel in stop-and-go city traffic, and long haul trucks often run their diesel engines for days on end without ever shutting down.

In partnership with an oil company, one large truck stop chain is pursuing liquefied natural gas (LNG) refueling options. The capital costs of this are high—the company estimates that a single fueling island at a truck stop location with two cryogenic LNG dispensers on it could cost well over a million dollars. Despite this, one advantage the truck stop chain sees for LNG over CNG is that refueling times are significantly faster for large trucks. Truckers operate on tight schedules with restrictions on how many hours per day they are allowed behind the wheel. Refueling stops need to be quick with a rapid return to the road. Another positive feature of LNG is that the act of liquefying the gas also purifies it, resulting in essentially pure methane and avoiding the uncertainties inherent in the composition of CNG.

LNG and CNG as motor vehicle fuels are currently competing technologies. However, since both utilize the same basic fuel, it should be possible to make them complimentary. Given the abundance, national security benefits, reduced GHG emissions, and environmental improvements to air and water, substituting natural gas for petroleum-based vehicle fuels seems like an all-around win. Why it is not yet being done at significant scales is a mystery.

7.4.2 Electric power generation

Generation of electrical power in the United States uses a variety of primary energy sources, including coal, oil, nuclear, hydroelectric, biomass, wind/solar, geothermal, and natural gas. This diversity ensures that every energy source is not vulnerable to the same threat. The OPEC oil embargo clearly demonstrated the hazards of putting too many eggs in too few baskets. Forty years later, it is still wise to pursue an "all of the above" energy strategy.

Primary energy sources are those that create power, which can then be transmitted elsewhere to do work. Electricity is one of the steps in the transmission of power, which can only transform the primary energy source from one form to another; it cannot make new power. Efficiency is lost along the way. For example, burning coal heats up water to make steam. The steam turns a turbine, which turns a generator, which makes electricity. The electricity is transmitted through a distribution system of wires to a house, where it flows through the resistance heating element of an electric stove, and is converted back into heat to boil water in a kettle for tea. Wouldn't it have been more efficient to just burn the coal directly under the tea kettle? Absolutely. But then the tea kettle would have been committed to coal (and the resulting soot).

Electric power allows the kettle to be heated cleanly with primary energy sourced from wind, nuclear, solar, hydropower, or natural gas, as well as coal. Electricity has the ability to draw power from many different primary sources. As a potentially expanding market for natural gas, electrical generation provides an option for reducing the surplus natural gas supply.

Many older, coal-fired power plants are nearing the end of their design lifecycles. New generating plants will be locked into a particular fuel type for the design life of the facility, generally 30–50 years, so the selection of a primary power source is not always simple or obvious. Utility executives trying to decide how to power thousands of megawatts of new generating capacity have a bottom line to meet, and the choice among gas, coal, wind, nuclear, hydro, and other options is largely driven by two things: reliability and price. Nobody wants to build a power plant where they either can't find or can't afford the fuel to run it.

The large quantities of shale gas available in the United States would seem to make it a desirable choice for electrical power generation, but there is a complicated history to overcome. Electric utilities traditionally have had some anxieties about committing to natural gas.

The concerns go back at least to 1973, when many people thought conventional natural gas production had peaked. After the cold winters of 1977 and 1978 when some gas use was restricted because of supply shortages (due partly to price controls), Congress passed the Fuel Use Act, which forbade the use of natural gas to generate electricity. The Fuel Use act expired in 1987, when natural gas deregulation under the Reagan administration brought a large amount of new production, resulting in a gas bubble in the 1990s.

Several hundred gigawatts of natural gas generating capacity were built between 1997 and 2003, only to have the price of gas climb steeply after another apparent peak in conventional production in 2003/2004. Gas was available, but became expensive. Utilities began talking about importing LNG from overseas. Much of the new gas-powered generating capacity was idled, resulting in a number of bankruptcies.

Coal won out in the early 2000s because, despite all of its problems, coal suppliers could easily agree to 20, 30, or even 50 year-long contracts to supply power plants. A coal mine operator could set aside a prescribed tonnage of proven mine reserves for a power plant, and assure the plant operator that the delivery trains or barges will show up regularly for decades. They can even take the power plant people out to the mine and walk them around on the portion of the coal seam that has been reserved for their use.

A former DOE lab director used to point out that it cost more to have a truckload of topsoil delivered than a truckload of coal. Coal is literally cheaper than dirt. However, the economics of coal are largely driven by what are called "externalized costs." This means that most of the environmental costs for coal extraction and combustion are not included in the price of the fuel, but passed on to the taxpayers and the public. These costs include things like watershed damage and stream restoration from mountaintop removal mining operations, repairs of structures and property from damage caused by subsidence of underground mines, remediation of acid mine drainage in streams, disposal of coal ash into hazardous impoundments, and the public health costs of mercury, arsenic, and selenium emissions. Although coal mines are required to post financial assurance bonds, in most cases these have been historically insufficient to cover the costs of site restoration.

If the true environmental costs of coal were built into the price of coal-fired electricity, it would be far more expensive. In 2010 the Obama EPA began tightening regulations on the coal extraction industry and the electric power generating industry that is the largest user of coal. As a result, coal has become less economical as the formerly externalized costs were more tightly regulated by the EPA. Combined with the abundance of natural gas that became available when shale gas development took off in the twenty-teens, many power companies started to replace obsolete coal plants with natural gas-fired electricity. Nearly half the new generating capacity in the United States is now gas-fired. (See for example: https://www.firstenergycorp.com/content/fecorp/environmental/stewardship/generation/generation_plantsmap.html)

Natural gas power plants typically use a gas turbine that looks like a stationary jet engine to power a generator. The most efficient gas-fired power plants are "combined cycle" facilities that use the waste heat from gas turbine exhaust to boil water, which then powers additional steam turbines.

Electricity use fluctuates with the time of day, day of the week, and season of the year. Generating electricity is a dynamic process where the supply must be constantly adjusted to meet the demand. This is a complicated balancing act known as "dispatch." Electrical supply consists of a constant base load supplemented by a periodic peak load. Base load is supplied by the cheapest, steadiest power, and it almost always comes from sources that are difficult to start or stop quickly, such as big coal power plants, large hydroelectric dams, and nuclear power plants. These generating facilities produce a steady background level of electricity that is needed in the system to run basic functions. Peak loads occur when demand increases above this base supply, such as on a hot summer day when everyone cranks up the air conditioning, or in the evenings when all the lights come on.

Peak load electricity is usually more expensive to generate than base load, but it can be brought online quickly to meet sudden spikes in demand. Small steam plants, run-of-the-river hydro plants, and natural gas plants are often used for peak loads. The type of electricity supplied for this so-called "peak shaving" depends on both the cost and availability of power. More expensive generating capacity will be brought on only as the peak climbs above the available lower-cost supplies. The U.S. power grid is now interconnected in such a way that electricity supplies can be brought in or sent out over fairly long distances to meet these peak demands.

Using natural gas to produce large amounts of electricity blurs the distinction between base load and peak load. Unlike some power plants that are clearly base load, such as nuclear plants, and others that are clearly peak load, like pumped storage hydro, natural gas plants can be either or both. They can be built as small, single, quick-start units to generate a few megawatts, and come online quickly when needed. Or they can be built large to produce big power—thousands of megawatts from rows of gas turbines connected in parallel.

De-centralized or "scattered site" power production from numerous smaller, natural gas-fired power plants can improve the reliability of electrical delivery, especially if combined with the new smart grid technology that improves supply and demand monitoring. Power companies considering natural gas as a primary energy source have a number of options and strategies to sort through.

Any discussion of natural gas versus coal, wind, nuclear or any other sources of electricity must also consider costs. Both capital costs and operation/maintenance (O&M) costs drive the daily decisions in the real world of electrical supply and dispatching. It is not easy to compare the cost of electricity from different sources, because many factors contribute to it. Nevertheless, these data are collected by the U.S. Energy Information Administration (EIA), which distills them down for side-by-side comparisons in spreadsheets.

Table 4 summarizes the "levelized" cost of electricity from the EIA (U.S. Energy Information Administration, 2015). Although the data will soon become outdated in terms of absolute numbers, they are displayed to provide a relative comparison of cost among different primary power sources.

Table 4: Examples of Electricity Costs (2013 $/MWh)

Primary Power Source and (Capacity)	Levelized Capital Cost ($/MWh)	O&M Cost ($/MWh)*	Transmission Cost	Total LCOE
Coal-fired (85%)				
Conventional	$60.40	$33.60	$1.20	$95.20
Advanced Combustion	$76.90	$37.60	$1.20	$115.70
Advanced with CCS	$97.30	$45.90	$1.20	$144.40
Natural Gas-fired (87%)				
Combined Cycle	$14.40	$59.50	$1.20	$75.10
Advanced Combined Cycle	$15.90	$55.60	$1.20	$72.70
Advanced CC with CCS	$30.10	$68.90	$1.20	$100.20
Conventional Turbine	$40.70	$97.40	$3.50	$141.60
Advanced Turbine	$27.80	$82.30	$3.50	$113.60
Advanced Nuclear (90%)	$70.10	$24.00	$1.10	$95.20
Geothermal (92%)	$34.10	$12.30	$1.40	$47.80
Biomass (83%)	$47.10	$52.10	$1.20	$100.40
Wind (36%-38%)				
Onshore Wind	$57.70	$12.80	$3.10	$73.60
Offshore Wind	$168.60	$22.50	$5.80	$196.90
Solar (20%-25%)				
Photovoltaic	$109.80	$11.40	$4.10	$125.30
Solar Thermal	$191.60	$42.10	$6.00	$239.70
Hydroelectric (54%)	$70.70	$10.90	$2.00	$83.60

Source: 2015 Energy Outlook report, U.S. Energy Information Administration
LCOE: Levelized cost of electricity
$/MWh = dollars per megawatt hour
* O&M = Operation & Maintenance; includes (+) fuel cost and (-) tax subsidies
Capacity = percentage of time online

Several interesting things are shown in Table 4. The most expensive electricity overall is solar thermal, which has high capital costs and fairly high O&M costs. It is also only available less than a quarter of the time, which is shown on table 4 as the "capacity." The second most expensive electricity is offshore wind power, also with high capital costs, presumably due to the expense of construction in a marine environment. It, too is only available intermittently, with a capacity value of 36-38 percent. O&M costs for offshore wind are nearly double those for onshore wind, and transmission costs for offshore wind are also high, again probably because of the marine environment. When people wonder why more renewable energy is not available in the United States, these costs are the reason.

Along with the low capacity values, another concern with many of the renewable energy sources is that they don't often occur where the energy is needed. Geothermal energy is most efficient in volcanic areas with high geothermal gradients, but these tend to be far from population centers. Likewise, the best wind resource areas are often in the vast prairies of the Great Plains, but most of the population that needs the electricity is on the East and West Coasts.

Because of the intermittent nature of renewable energy sources like wind and solar, power storage has become a huge stumbling block to wider implementation. If power could be stored efficiently on a windy day to provide electricity on a calm day, many more wind turbines would be in use. Direct storage options include various types of rechargeable batteries, which are expensive, sometimes hazardous, and have significant efficiency losses, including some lithium ion batteries that create enough heat to catch on fire. Indirect power storage options include compressed air energy storage (CAES), where air is pressurized using an electric compressor and stored in an underground reservoir until needed. The flow of compressed air from the reservoir can drive a turbine and produce electricity. Another, similar option is called pumped-storage and involves water. Water is pumped to a reservoir on top of a hill during times of abundant electricity, and then when power is needed, hydroelectricity is generated by allowing the water to flow back downhill. Both of these alternatives are somewhat intrusive on the land, and neither is very efficient.

Coal-fired power plants are competitive in terms of cost, although when advanced combustion technologies are added, the price gets a bit higher. Adding carbon capture and storage (CCS) makes coal plants considerably more expensive. Allowing CO_2 to go up the stack is another externalized cost strategy. Non-carbon generating technologies, such as advanced nuclear, onshore wind, and geothermal are more cost competitive than coal with CCS.

Electricity generated with natural gas is very cost-competitive, especially when a combined cycle generation strategy is used. The costs shown on Table 4 clearly demonstrate the efficiency of a combined cycle turbine compared to a conventional turbine, which simply allows the exhaust to escape without any option for use of the waste heat. Even when CCS is employed on the combined cycle turbine, the costs are still considerably less than a conventional or even advanced gas turbine.

Power company executives look very closely at these costs. The capital cost to construct a generating facility varies with the size and type of technology used. Even the same power plant design can have different costs in different regions of the country, depending on the price of land, availability of cooling water, and other factors.

The operating cost of a power plant is not only technology-dependent, but also size-dependent, with larger facilities generally having a lower operating cost per unit of generating capacity. Fossil energy plants must also include fuel costs as part of the operating budget, and these can vary widely. For example, a plant using western, low-sulfur, lower Btu lignite coal will have different fuel costs than a similar plant using eastern, high-sulfur, higher Btu bituminous coal.

Large coal plants and onshore wind turbines are much more common sights around the United States than twice-as-expensive solar thermal or offshore wind power. However, if Congress requires CCS or a “carbon tax” on coal-generated electricity, it instantly becomes more expensive than other options, including nuclear, which explains why some utilities have been once again considering nuclear power.

The arrival of shale gas means that one issue power companies were significantly worried about with respect to natural gas—reliability of supply—is no longer a concern. The upper estimates of recoverable gas from the Marcellus Shale alone could supply power plants for decades, and when reserves from other shale formations are added in, natural gas-generated electricity could keep the lights on for centuries, assuming costs stay affordable.

Because the Marcellus Shale is an unconventional or continuous resource, the gas reserves are not restricted to reservoirs of limited size and area (Charpentier and Cook, 2011). Basically, a horizontal, hydraulically fractured well will produce significant amounts of gas pretty much anywhere within the play. Electric power plants located above productive Marcellus Shale areas could install their own gas supply wells as either a primary or supplemental source of fuel. There could easily be a 30-year supply of natural gas beneath electric power plant sites in Marcellus Shale country. Dedicated wells would free the power company from the fluctuating fuel prices that come with buying gas out of a pipeline. In fact, virtually any energy-intensive industrial operation within the Marcellus Shale play could produce gas locally for onsite fuel by simply drilling and hydraulically fracturing a few wells on their property. A steel mill in Pittsburgh, for example, could install horizontal wells to produce enough natural gas to supply a majority of their operations.

Many gas wells in the Marcellus Shale region are either capped or have not yet been drilled because there is no pipeline nearby to collect the stranded gas. If an operator can't find a pipeline near their lease sites, perhaps they can find a power line nearby. Commercial gas turbine electrical generators are relatively small, and some of these in the 50 MW range are even portable. A generator could be placed on the pad to turn the gas into electricity, which can then be sold into the grid.

A large number of small, gas-fired power plants distributed throughout the Marcellus Shale production region would provide reliable power during times of peak demand. This would contribute to an extremely dependable, low-cost electricity supply in the northeastern United States, making the region more attractive to industry. The ongoing development of the smart grid will allow such scattered site power generation to be added more easily and to be dispatched automatically.

8. SUMMARY AND CONCLUSIONS

The Marcellus Shale is a Devonian-age, organic-rich deposit of lithified black mud that occurs in the Appalachian Basin of the eastern United States. The Marcellus Shale and other black shales like it contain significant amounts of energy in the form of natural gas and natural gas liquids. Another potentially useful byproduct of higher natural gas production could be an increase in the supply of helium. The total shale gas resource is potentially large enough to replace all of America's oil imports, making the United States energy independent for the first time in decades and finally ending the so-called "energy crisis" of the 1970s. Domestic shale gas resources should last for many years, allowing time to develop advanced energy like solar power satellites, geothermal, ocean energy, and fusion power.

As a result of government studies like the Eastern Gas Shales Project, the size of the shale gas resource has been known or suspected for many years. However, the combined application of horizontal drilling and staged hydraulic fracturing was not fully developed until the 1990s. George Mitchell of Mitchell Energy applied this offshore deepwater drilling technology on the Barnett Shale in the Fort Worth Basin of Texas, and his persistence in adapting it for onshore black shales eventually paid off. Range Resources was the first to successfully apply the Mitchell-developed technology to the Marcellus Shale in 2007, and their achievement started the current play.

The shale gas recovery process is not without environmental concerns, which include potential impacts on air, water, landscapes, habitat, and ecosystems, some of which are known and others of which are still uncertain. The cumulative effects to the environment of full-scale resource development, including infill wells, pads, roads, pipelines and other planned infrastructure is not well-understood. However, there is reason to believe that all significant environmental impacts will be identified eventually and properly regulated. An ongoing need is to develop environmental indicators for shale gas to make monitoring easier.

The process of collecting data has been moving forward, but has also been bogged down with difficulties accessing drill sites for environmental monitoring, especially groundwater, challenges obtaining fresh drill core and fluid samples, and uncertainties over the magnitude of human health and ecosystem effects. Government agencies and other researchers have relied on cooperative arrangements with industry to conduct studies. Although these studies have resolved many uncertainties, others remain.

There are always going to be some land clearing, ecosystem and habitat disturbing, water resource affecting, air pollution impacts from developing a shale gas well. Nevertheless, there are no technical reasons why these near-term impacts cannot be reduced. A variety of ways to go about this are suggested below.

1) Operators must be required to construct wells properly and prove to an inspector that they have done so. Every well should be inspected several times during the drilling and completion process, and pass a post-hydraulic fracturing wellbore integrity test.

2) The "five operating principles" developed by Shell (see the end of chapter 6) should become the industry standard. In summary, these five principles are safe well design, water protection, lower emissions, reducing the surface footprint of operations, and community engagement.

3) Regulation of the industry must be based on risk assessment and facts. An incident that attracts the attention of the news media does not necessarily mean that the whole system is riddled with fatal design flaws, especially when most of these incidents are caused by human error.

4) Production companies should be required to meet stringent well construction standards, certify that crews are properly trained and supervised, and ensure that air, land, and water are protected and then restored by those who extract the gas.

5) Oil and gas exploration and production waste is exempted from RCRA part C, but operators should properly characterize and manage the waste. Operators should be handling materials that have the characteristics of hazardous waste **as** hazardous waste.

The facts don't support a ban on shale gas drilling and hydraulic fracturing. Although there are some real environmental concerns with shale gas, especially in boomtown situations, nearly all of these are human failings that can be addressed through regulations and enforcement.

The technology for extracting natural gas is proven and established. Approximately 99.5 percent of shale gas wells have been completed without incidents. Of the roughly one half of one percent of wells that have suffered an incident, virtually every one of these has been caused by a human failure to follow procedures, not by a failure in the procedure itself. When operators have found flaws in the procedures, such as gas migration from open-hole completions, the designs were quickly changed. Many studies assessing environmental risk have been published over the past few years, and none has been able to rigorously identify any systemic, fatal flaws inherent in the engineering of natural gas wells, including shale gas wells, that will inevitably result in environmental contamination. The reader is referred to the references section for details.

Questions certainly can be raised about the long-term performance of shale gas wells, including issues related to possible deterioration of cement or steel well casing (Watson and Bachu, 2009, Kutchko, et al., 2012), gas leakage and migration (Dusseault and Jackson, 2014; Ingraffea et al., 2014), and impacts on groundwater (Jackson, et al., 2013). Wellbore integrity is monitored periodically by responsible operators, and in the Appalachian Basin reportedly less than 3 percent of the wells leak (Vidic et al., 2013). On the other hand, the Wattenburg Field in the Denver-Julesburg Basin appears to suffer much higher rates of well integrity failure (Pétron et al., 2012), and similar high rates of failure have been reported in some Canadian fields (Dusseault and Jackson, 2014). Gaining a better understanding of the factors that affect the integrity of gas wells over long time periods is a critical uncertainty that must be addressed for the future development of gas resources, and for the potential storage of carbon dioxide in depleted gas shales. Life cycle analyses are needed to address long term economic viability and whether environmental and other costs of shale gas wells will be externalized.

Benefits of replacing petroleum as a vehicle fuel with natural gas opens up new markets for operators, and includes immediate improvements in air quality. Substituting natural gas for gasoline will dramatically reduce volatile organic compounds, photochemical smog, and ground-level ozone in the air of cities that are currently non-attainment areas. Replacing coal-fired electricity with natural gas virtually eliminates particulates, arsenic, selenium, mercury and other air emissions, along with ash.

Methane leakage from aging natural gas distribution lines and other infrastructure must be repaired, and it is in the best interest of both industry and society to do so. However, environmental degradation from GHG emissions of natural gas is comparatively minor in comparison to the net improvement of air quality by burning gas instead of coal or oil. The combustion of natural gas produces less carbon dioxide per Btu than coal or petroleum, and eliminates smog, toxic metals, VOCs, and particulates from the air. Although leaking methane is a powerful GHG, carbon dioxide is a much more abundant and persistent GHG.

Natural gas use improves water quality by offsetting the need for mountaintop removal coal mining, and by reducing the risk of groundwater contamination from BTEX stored in leaky underground gasoline tanks. Shale gas can supply enough energy to last for decades, and possibly centuries, allowing time for the development of new energy technologies.

Some people will argue that shale gas development merely trades one fossil-fuel dependency for another, and that the nation should just move forward with conservation and renewable energy. That can certainly be done, but it would significantly increase the cost of electricity. The cost comparison of electricity sources in Table 4 displays this clearly. Renewables like offshore and onshore wind, solar thermal, photovoltaic, geothermal and others are more expensive to construct, often not located where the energy is needed, or only supply energy intermittently with no efficient storage options. None of these are issues with fossil fuel-based generating plants. Renewable energy technology is still challenged by efficiency and cost. A number of national labs and universities are working on the issues, but solving the technical problems has not been easy.

Shifting the United States from a petroleum-based economy to a natural gas-based economy would send energy dollars to domestic locations instead of foreign shores. The development of domestic natural gas and oil resources would improve U.S. energy security by significantly reducing American dependence on imported oil. The lessons from the 1973-74 embargo are still relevant, and as a nation, the United States should avoid Friedrich Hegel's admonition that "The only thing we learn from history is that we learn nothing from history."

The gas drilling and production business has been creating significant numbers of American jobs and despite the cyclical nature and periodic down turns, it will continue to provide employment for many workers. Jobs can also be generated on the utilization end, converting existing vehicles to run on compressed natural gas, building new CNG or LNG-fueled vehicles, and finding other new uses for natural gas.

In his 2012 State of the Union address, President Obama identified increased domestic manufacturing, focused workforce education, and greater production of domestic energy, including natural gas, as important components for making America stronger as a nation. The President gave credit to the Eastern Gas Shales Project and other DOE and GRI-funded shale gas research programs when he said, "It was public research dollars, over the course of 30 years, that helped develop the technologies to extract all this natural gas out of shale rock—reminding us that government support is critical in helping businesses get new energy ideas off the ground." This was the first time a high-ranking government official had acknowledged the role of the 1980s shale gas research in the eventual development of the resource. Unfortunately, many of the participants from the 1980s, like Phil Randolph, were no longer around to hear it.

The benefits of producing natural gas from the Marcellus and other shales appear to outweigh the risks. None of the risks seem to be unmanageable. The actual threats posed by shale gas development do not warrant some of the reactions and rude behavior in public meetings. Everyone is entitled to their opinions, but not to their own set of facts.

The perception of risk is not the same as the calculation of risk. This is typified by people who are afraid of flying, but then drive to the airport without wearing a seat belt. It is important to understand that shale gas development risks are manageable and that the vast majority of people who work in the oil and gas industry are neither stupid nor callous. They recognize the risks and work diligently to reduce and control these. This is not altruism, but good business practice. Environmental problems cause damage, cost money, result in delays, and close off access.

The United States should move forward to produce the domestic energy resources in the Marcellus and other gas shales in a responsible, economic, and environmentally sound manner. If done with the proper stewardship, regulation, and oversight, it will provide a real solution to numerous environmental problems, the politics of imported oil, and urban air quality issues in one fell swoop. And that is something worth doing.

9. REFERENCES CITED

Author's note: Readers are cautioned that many of the citations are from websites, newspaper articles, blogs, trade magazines, and other sources that are not considered to be "scientific literature." Peer-reviewed, scientific journal articles and government reports were included as frequently as possible, but other sources were cited for the sake of completeness and to provide readers with additional details. - DJS

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10. ABOUT THE AUTHOR

Dan Soeder performs scientific research on gas shale and other unconventional fossil energy resources at the U.S. Department of Energy (DOE) National Energy Technology Laboratory in Morgantown, West Virginia. Before joining DOE in 2009, Mr. Soeder had been a hydrologist with the U.S. Geological Survey (USGS) in the Mid-Atlantic region since 1998, where he researched coastal hydrology, wetlands, water supply and groundwater contamination, and for three years chaired the Scientific and Technical Advisory Committee for the Delaware Estuary Program. He also spent 8 years on the Yucca Mountain Project in Nevada, where he coordinated USGS hydrologic and geologic field work. Prior to joining the USGS in 1991, Mr. Soeder carried out research on the geology of unconventional natural gas resources at the Institute of Gas Technology (now GTI) in Chicago, and worked as a contractor for DOE in Morgantown from 1979–1981, collecting and characterizing drill cores on the Eastern Gas Shales Project. Raised in Cleveland, he received a BS degree in geology from Cleveland State University in 1976, and an MS degree in geology from Bowling Green State University (Ohio) in 1978. He also holds an adjunct research scientist appointment with South Dakota School of Mines and Technology. He has three adult children, one grandchild, and lives with his wife Susan on a mountain farm atop the Marcellus Shale in West Virginia, three miles from the nearest well.

Dan Soeder at the Marcellus Shale type section (photographed in July 2016 by Scyller Borglum)

11. APPENDIX A: GLOSSARY AND ACRONYMS

adsorption	chemical attachment of gas molecules to electrostatic surfaces in rocks; not to be confused with absorption (the ability to soak up liquids)
advective transport	contaminant movement by bulk flow, such as an ink spill in a river carried downstream by the current (the ink spreading out in the water is diffusion)
AMD	Acid Mine Drainage; water contaminated by low pH from sulfides in coal
anisotropy	properties that are directionally dependent; i.e., not uniform or homogenous
annulus	the ring-like space between the outside of a drill pipe and the borehole wall
anoxic	water conditions containing little or no dissolved oxygen
anticline	a structural fold in which rocks are bent upward into an arch
Appalachian Basin	a large structural depression in the eastern United States filled with sedimentary rocks
asperities	natural rough spots on fracture walls
barrel	a measurement volume for oil = 42 gallons or 159 liters, abbreviated “bbl”
baseline study	an environmental impact assessment that performs “before and after” comparisons to determine effects
BCF	Billion Cubic Feet (of gas)
blooey line	the return line to a tank for frac water and gas recovered from a well
blowback	the process of using formation gas pressure to return frac fluid to the surface
bottomhole assembly	the steering gear, impeller, transmission, bit, and other components of a downhole drilling motor
bradenhead	a pressure relief valve on a wellhead for the annulus of a well
bridge plug	a seal used to close off the casing in a wellbore, often cemented in place
BTEX	benzene, toluene, ethylbenzene, and xylenes: components of gasoline
Btu	British thermal unit; a measure of energy equivalent to about 250 calories
build rate	the radius of the curve used to divert a vertical borehole into the horizontal plane
casing	heavy steel pipe used to line drill holes and control fluid movement; usually cemented in place
CCS	Carbon capture and storage; process of removing carbon dioxide from combustion gas products to keep it out of the atmosphere.
central site fracturing	a technique using a central impoundment for storing frac water that is sent via temporary pipelines to well pads
Christmas tree	nickname for the production wellhead on a gas well
CIT	Casing Integrity Test using pressure to ensure that newly installed casing does not leak; also called a leak-off test (LOT)
clay mineral	a type of silicate mineral composed of stacks of flat aluminosilicate sheets
CNG	Compressed Natural Gas: a vehicle fuel presently in use, standard natural gas compressed under 200–300 atmospheres (3000–4500 psi) of pressure
concretions	lens-shaped mineral growths in sedimentary rocks, usually formed around a fossil or some other debris
condensate	light petroleum liquids produced with natural gas; emerges from the well in the vapor phase and condenses to liquids at the surface
conductor casing	the uppermost casing string that keeps soil from collapsing into a borehole
continuous resource	a gas or oil resource accumulated throughout a rock formation that can be produced without the need for conventional reservoirs or traps
conventional oil/gas	Oil and gas-bearing rocks that require a source rock, thermal maturity,

	reservoir rock, trap and seal, and migration pathway to produce economical amounts of hydrocarbons
craton	igneous and metamorphic basement rocks of a continent; the continental crust underlying the sedimentary rocks
CWT	Centralized wastewater treatment: facilities that use flash distillation or membrane filtration to treat industrial wastewater, primarily for TDS
darcy	unit of permeability named after French hydrologist Henry Darcy
decline curve	the rate of decrease in gas production from a well over time
derrick	the tower-like portion of a drill rig that is raised up into the air
dip	the tilt of a geological structure in degrees from the horizontal (see strike)
dispatch	the art of balancing electricity supply and demand in a power system
DOE	U.S. Department of Energy
doghouse	field office on a drill rig platform from where the driller operates the rig
DOI	U.S. Department of the Interior (parent agency of USGS)
dolomite	a calcium-magnesium carbonate mineral named after the Italian mountain range; also a rock made from this mineral (sometimes called dolostone)
DRBC	Delaware River Basin Commission
drill core	a cylindrical rock sample cut by a hollow drill bit
drill cuttings	small rock chips created by the cutting heads of a drill bit
drilling mud	specialized fluid circulated down to a drill bit for cooling, lubrication, pressure balance, and cuttings removal
DRO	Diesel-range organics; a groundwater contaminant
dual completion	tapping two target formations in a stacked play from a single borehole
EFD	Environmentally Friendly Drilling: practices to reduce the environmental footprint of gas production
EGSP	Eastern Gas Shales Project, funded by DOE from 1975 to 1992
EIA	Energy Information Agency, a bureau of DOE
embedment	proppant sand sinking into soft shale instead of propping fractures open
endocrine disruptor	natural and synthetic chemicals that mimic the effects of hormones
EPA	U.S. Environmental Protection Agency
epeiric sea	a shallow inland sea on a continent (i.e., Hudson Bay, Baltic Sea)
ERDA	Energy Research and Development Administration, a predecessor to DOE
EUR	Estimated Ultimate Recovery; the total amount of oil and/or natural gas expected to be produced during the life of a well
euxinic	A low circulation bottom water environment, generally low in oxygen, which supports the deposition of sulfide minerals, such as pyrite, in sediments. The term is sometimes used interchangeably with anoxic, but the two are different.
externalized costs	transferring the environmental costs of a technology to taxpayers or others not directly using it
fault	fracture in a rock where the two sides have slipped past one another
FEP analysis	method of risk analysis based on Features, Events and Processes (FEP)
fissility	the ability of clay-rich shale to split into thin sheets
flowback fluid	the mix of frac water and formation water recovered after a frac; commonly called the more generic “produced water”
formation	A coherent geological unit that is thick enough and extensive enough to be portrayed on a map.
frac gate	a massive wellhead employed for pressure control during a hydraulic fracturing operation

framboids	small, cluster-like balls of pyrite that occur in black shale; name derived from the French word for raspberry (*framboise*) to describe their appearance
gas slippage	the “Klinkenberg effect,” in which gas flows more easily at lower pressure through small pore throats in low-permeability rocks
geolograph	An obsolete pen on drum recorder of drilling penetration rate on view to the driller in the doghouse (commonly called the jolly-graph)
geosteering	the art and science of guiding a directional borehole deep underground
GIP	Gas-In-Place: estimated total amount of gas contained in a geological formation; recoverable gas is a percentage of this
glutaraldehyde	A biocide commonly used in fracs to control sulfate-reducing bacteria downhole that can create sour gas.
Gondwana	an ancient proto-continent that contained modern Europe and Africa
GRI	Gas Research Institute; a nonprofit in Chicago created to fund gas research using pipeline tariff funds; now combined with IGT to form GTI
GTI	Gas Technology Institute: a nonprofit, natural gas R&D and educational institution in Des Plaines, IL west of Chicago, formed from IGT and GRI
HHS	U.S. Department of Health and Human Services
hydraulic fracture	engineered fracture in a rock used to create a high-permeability flowpath
HVHF	High volume hydraulic fracturing applied to shale gas wells
hydrograph	measurement of water level over time in a stream or a well
IAM	Integrated Assessment Model for site and system risk assessment
ICP	Inductively Coupled Plasma; a laboratory chemical analysis instrument
IGT	the former Institute of Gas Technology in Chicago; now known as the Gas Technology Institute or GTI
imbibe	The process by which a rock takes water into the pores; the opposite of imbibition is drainage.
intermediate casing	casing from the base of the surface casing to the kickoff point for the curve
joint (1)	fracture in a rock where the two sides have pulled apart without slipping
joint (2)	a drilling term for a single segment of drill pipe, joined with threads
karst	topography underlain by limestone bedrock containing solution cavities such as caves and sinkholes
Kelly Bushing	turntable on a drill rig platform that rotates a square piece of drill pipe (the Kelly), which turns the rest of the drill string downhole
kerogen	plant-derived organic material in lithified, sedimentary rocks; it comes in three different types depending on origin
kickoff point	depth at which a vertical borehole begins to curve toward the horizontal
lateral	the horizontal portion of a directional borehole
Laurentia	an ancient proto-continent that contained modern North America
LIBS	laser-induced breakdown spectroscopy; a field-based analytical technique
light sand frac	a frac formulation that uses less sand or proppant and is effective on shales
limestone	a class of sedimentary rocks formed largely of calcium carbonate ($CaCO_3$)
lipids	oily organic compounds in marine algae that form petroleum
lithification	the geologic process of turning soft sediment into hard rock
lithofacies	a particular sedimentary rock lithology linked to a depositional environment
lithology	classification of rock type based on mineral composition and texture
LNG	liquefied natural gas; a cryogenic liquid at liquid nitrogen temperatures
LUST	leaking underground storage tank; a common source of BTEX contamination in groundwater

LWD	logging while drilling; downhole tools that measure formation properties, such as density, resistivity, sonic velocity, gamma ray, etc. (see MWD)
Ma	Mega-annum, a geological abbreviation for a million years of time.
MCF	one thousand cubic feet of gas; the amount of gas in a 10-foot cube at room temperature and pressure, equals 28.3 cubic meters
MERC	Morgantown Energy Research Center: an old name for the National Energy Technology Laboratory under ERDA
METC	Morgantown Energy Technology Center: an old name for the National Energy Technology Laboratory under DOE
members	distinct geological sub-units within a formation
methane	odorless, colorless primary component of natural gas; chemical formula: CH_4
methyl mercaptan	odorant added to natural gas to make it detectable
microannulus	a through-going crack in well cement, usually formed along an interface
µS/cm	microSiemens per centimeter, a conductivity unit
microseismic	a geophysical method that uses sound waves to detect the height and location of hydraulic fractures
Middle Devonian	a geologic time period lasting from about 387 Ma to 374 Ma
MMCF	a million cubic feet of gas
MNA	monitored natural attenuation: a groundwater remediation process
monkey board	a small platform high up in the derrick for a rig worker to stand on while stacking drill pipe
MTBE	methyl tertiary butyl ether: a former gasoline additive for smog reduction
MTR	mountain top removal: a surface mining method that strips overburden off shallow coal seams and transfers it into adjacent stream valleys
MVA	Monitoring, verification and accounting for CO2 geologic storage
MW	Megawatt: a measurement of electricity, equal to a million watts
MWD	measurement while drilling; an important directional drilling technology that allows drillers to determine the downhole location of a drill bit (see LWD)
MWX	Multiwell Experiment; a DOE tight gas sand field project run in Colorado in the 1980s
NA	natural attenuation: a combination of geochemical and microbiological processes that degrade organic materials in shallow groundwater
natural gas	gas recovered from geological formations: primarily methane, sometimes containing other light hydrocarbons
NETL	National Energy Technology Laboratory of the DOE
NGO	Non-government organization; GRI is cited as an example
NGL	natural gas liquids; light liquids recovered with gas; see “condensate”
NORM	naturally occurring radioactive material; often associated with black shales and produced waters; technologically-enhanced NORM is called TENORM
NOx	Generic designation for nitrogen oxide emissions
NRAP	National risk assessment partnership for CO2 geologic storage
NSF	National Science Foundation
OPEC	Organization of Petroleum Exporting Countries, an oil cartel
orogeny	an episode of mountain building caused by plate tectonics
orthogonal fractures	a box-like set of natural fractures that trend at approximate right angles
PADEP	Pennsylvania Department of Environmental Protection (state agency)
PAHs	polycyclic aromatic hydrocarbons; organic compounds composed of multiple aromatic rings, often carcinogenic

paleontology	the study of fossil animals, plants, and ancient environments
Pangaea	a supercontinent formed by the collision that produced the Appalachian Mountains, and later split apart to create the Atlantic Ocean
PDC bit	polycrystalline diamond composite drill bit; commonly used on shale wells
peak shaving	electricity generated, usually expensively, to meet periods of high demand
perf gun	a device used to create holes (perforations) in the production casing to allow oil or gas to flow into a well
permeability	the ease with which a rock will allow a fluid to flow through it; analogous to electrical conductivity
petrophysics	the study of physical rock properties such as porosity, permeability, etc.
phyllosilicate	a silicate mineral with a sheet-like structure, such as mica
pinnate drilling	a feather-like directional drilling pattern that creates multiple branched laterals into a target formation
pipe dope	lubricant applied to the threads of drill pipe
plate tectonics	interaction of the crustal plates that make up the Earth; the plate edges can pull apart, descend beneath one another, or slide past one another
play	a group of geologically similar oil and gas drilling prospects
polyacrylamide	friction-reducing chemical commonly used to make “slickwater” frac fluid
porosity	the percentage of rock volume that consists of open space between the grains
POTW	Publicly-owned treatment works: a municipal wastewater treatment facility
produced water	frac and formation water produced with the gas, see “flowback”
production casing	the casing string that runs from the formation to the surface wellhead
proppant	granular material, commonly sand, injected with water during a hydraulic fracture treatment; props the fracture open when pressure is released
pyrite	a yellow, metallic, iron sulfide mineral (FeS_2), sometimes called “fool’s gold”
residual waste	the last bit of flowback that is not recycled into another frac; defined as non-hazardous industrial waste, commonly disposed of down UIC wells
ROM	reduced order model; simplified high fidelity model for risk assessment
roughnecks	the workers or regular members of a drill rig crew
RRC	Railroad Commission of Texas – the oil and gas regulatory agency in Texas.
sail	a reverse curve in the build to get enough space for a directional borehole to intercept the target
sapropel	organic material in sediment or ooze, primarily derived from decayed plants
screen-out	process in which frac fluid is pumped too slowly, causing proppant to settle out of suspension into the bottom of the well
severance	the practice of separating (“severing”) mineral rights ownership from land surface ownership, common in West Virginia and Maryland
severance tax	a tax on minerals extracted from the land
shale	a class of fine-grained, fissile sedimentary rocks formed from mud
siderite	an iron carbonate mineral ($FeCO_3$)
slickwater frac	a term for the hydraulic fracture process most commonly applied to Marcellus Shale; uses polyacrylamide to reduce downhole friction losses
sour gas	natural gas containing hydrogen sulfide (H_2S), a poisonous, corrosive gas
spud	a driller term for the start of a well; first penetration of the ground surface
squeeze job	a driller term for having to perforate and re-cement poorly bonded casing
SRBC	Susquehanna River Basin Commission
stacked play	multiple target formations within a single stratigraphic column

stoichiometric	The relative quantities and balance of reactants and products in chemical reactions, primarily combustion in this usage.
STP	Standard Temperature and Pressure for gas (room temperature at sea level)
stranded gas	Natural gas resources located in areas that do not have existing or sufficient pipeline capacity to move the gas to market.
stratigraphy	the study of relationships between rock layers and geologic time
strike	the directional orientation of a geological structure like a fracture (see dip)
subduction zone	a tectonic plate boundary where one plate descends beneath another
surface casing	the casing string that runs from the land surface to below the base of the deepest freshwater aquifer; sometimes called the water or coal casing
syncline	a structural fold in which rocks are bent downward into a trough
target	the point in 3-D space where a directional borehole intercepts the formation
TCF	trillion cubic feet (of gas)
TD	total depth; the bottom of a well, includes lateral length in horizontal wells
TDS	total dissolved solids; the amount of solids, such as salt, dissolved in water
TENORM	Technologically-enhanced NORM; naturally-occurring radioactive materials enhanced by human activities, such as a wastewater treatment process that removes TDS from produced water and creates concentrated radium salts.
terranes	a fragment of crustal material broken off from a tectonic plate and accreted onto another tectonic plate; terranes retain their original geology, which usually differs from their neighbors
tight oil play	a shale or low permeability limestone that produces primarily liquids
TOC	total organic carbon
toe	the far end of the lateral; the curve into the vertical part is called the heel
tool pusher	the management person who oversees the rig and the drill site operations
tophole	the vertical part of a shale gas well from the surface to the kickoff point
town gas	an old form of utility gas composed of carbon monoxide and hydrogen manufactured from coal and water
trajectory	the path of a horizontal or directional borehole through the target formation
trip-out	the act of removing or pulling drill pipe from a borehole; opposite of trip-in
turbidites	upward-fining, graded sediments deposited by a turbidity current
turbidity current	A high-density mixture of suspended sediment particles that flows rapidly downslope underwater. An avalanche would be a similar land version.
type section	location where a rock formation is well-exposed and was first described
UIC	underground injection control: a regulatory term for a chemical disposal well
UOG	Unconventional oil and gas: geologic formations that must be modified by some type of reservoir stimulation (such as hydraulic fracturing) to produce economical amounts of hydrocarbons.
USGS	U.S. Geological Survey; a bureau of the U.S. Department of the Interior
vugs	macroscopic, open voids in a rock that often contain mineral crystals
WVDEP	West Virginia Department of Environmental Protection (state agency)
WVGES	West Virginia Geologic and Economic Survey (state agency)
zipper frac	hydraulic fracturing of parallel laterals in a back-and-forth pattern

12. APPENDIX B: CONVERSION TABLE

Length

- 1 inch = 2.54 centimeters
- 1 foot = 0.3048 meter; 1 meter = 3.2808 feet
- 1 mile = 1.609 kilometer

Area

- 1 square mile = 640 acres = 2.589 square kilometers
- 1 acre = 43,560 square feet = 4047 square meters = 0.004047 square kilometers
- 1 square foot = 929 square centimeters

Volume

- 1 gallon = 3.785 liters
- 1 barrel of oil = 42 gallons = 159 liters
- 1 standard cubic foot of gas (scf) = 0.02832 cubic meters (at room temperature and pressure)
- 1 thousand cubic feet (MCF) = 28.32 cubic meters
- 1 million cubic feet (MMCF) = 28,320 cubic meters
- 1 billion cubic feet (BCF) = 28.3 million cubic meters
- 1 trillion cubic feet (TCF) = 28.3 billion cubic meters

Permeability

- 1 darcy = flow of 1 cp fluid under a head of 1 atm/cm, through a cross-section of 1 cm^2 at 1 cm^3/sec
- 1 darcy = 0.987 x 10^{-12} m^2 (SI unit)
- 1 darcy = 1,000 md, 1 million µd, and 1 billion nd

Pressure:

- 1 pound per square inch (psi) = 6.895 kiloPascals (kPa)
- 1 atmosphere = 14.7 psi

Temperature: Degrees Fahrenheit to degrees Celsius: (^{o}F-32) x 5/9 = ^{o}C

Mass: 1 pound = 0.4536 kilogram; 1 kilogram = 2.2 pounds

Energy: 1 British thermal unit (Btu) = 251 calories = 1,054 joules; 1 scf of gas = ~1,000 Btu

Age: 1 million years = Mega-annum = Ma (also, 1 thousand years = Ka; 1 billion years = Ga)

Source: Glover, Thomas J., 1997, Pocket Ref, Sequoia Publishing, Inc., Littleton, Colorado, 542 p.