5. 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 USGS 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 5 yr 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wastewater disposal as the greatest risk for releasing shale gas fluids into the environment, their paper was already outdated.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.

Several 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 following sections.

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., 2014b). Currently available commercial electronic water-quality sensors measure a variety of field parameters, such as pH, conductivity, temperature, turbidity, etc. None at present directly measures 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 used 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., 2014b).

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

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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., 2014b).

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. Several 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 (for details, see Soeder et al., 2014b). Site-based studies have been done on hydraulic fracture growth and the potential for gas migration from the target shale (for details, see Hammack et al., 2014). 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 West Virginia University 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 landowner 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 in 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 not moved forward because of permit issues and a lack of funding (Soeder et al., 2014b).

Unfortunately, commercial well site 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 nondisruptive and nonintrusive 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 Pennsylvania, 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. These baseline data generally benefit both research efforts and industry liability mitigation.

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 (for an example, refer back to the hydrographs in Fig. 34). 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 resources 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; Rowan et al., 2015), 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 the Land and Watershed Impacts section of Chapter 4, the issue of cumulative impacts is perhaps the most challenging. The accumulation of individual environmental events from multiple sites adds up as more wells are constructed within a given area of land, and at some point, it may take environmental conditions across a threshold, causing damage greater than the individual wells alone. The example cited in Chapter 4 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 National Environmental Policy Act (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 following subsections 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 stem from questions raised by research on the shale.

Fate of Injected Frac Water

When a multistage hydraulic fracture stimulation is completed on a gas shale well, 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% 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 ~10%–30% 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 it 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 Shale 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 AMD 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).

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. Several researchers have been working on this from a geochemical modeling approach (e.g., McIntosh, 2012; Rowan et al., 2015), but more field data would be helpful.

A comparison of 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 basinwide 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, the geochemistry of the fluid under reservoir conditions, and the 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 on-site 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 it is better than nothing. The current practice of recycling recovered water multiple times into successive fracs also complicates the geochemical analyses.

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 NGWA 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 (Veil, 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 it 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 techniques 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 do not discriminate in this way.

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.

Several 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 flow path 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 did not understand subsurface conditions have all contributed to stray gas leakage (Veil, 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 (Veil, 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 Sandstone 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 did not 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 annular pressure 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 (Veil, 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 a biologic source. Although the Duke authors assumed this source was the Marcellus Shale, a look back at the geological cross section in Figure 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 Earth's crust continuously from radioactive decay and can be used to assess the travel time and origin of gases migrating within Earth. The longer the gas has been in contact with rocks deep in the crust, the greater the noble gas content (Darrah et al., 2014).

Regional groundwater methane surveys run by Cabot Oil and 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 1701 water samples, which was a much larger data set than the 68 wells used in the Duke study, and it 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 Pennsylvania 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 attributed 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 Pennsylvania 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 (Veil, 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 was 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 U.S. 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 (Veil, 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? (2) How or why is it being mobilized? Getting answers to these questions can often be a challenge and usually takes some time.

The saturation level of methane in water is pressure-dependent. At 1 atm, the solubility limit is 28 mg/L. 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 tricone bit, and also because they produce a straighter and cleaner hole. Compressed air at pressures as high as 2413 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 they are 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 (~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 Figure 39 to illustrate how this scenario might work in the fractured aquifers of NE Pennsylvania (Veil, 2012). 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 ~100 m (300 ft). As the drill string was being withdrawn to set surface casing, the bit got stuck at a depth of ~53 m (175 ft), 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 m (10 ft) into the air. A well as far away as 300 m (1000 ft) 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 were 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

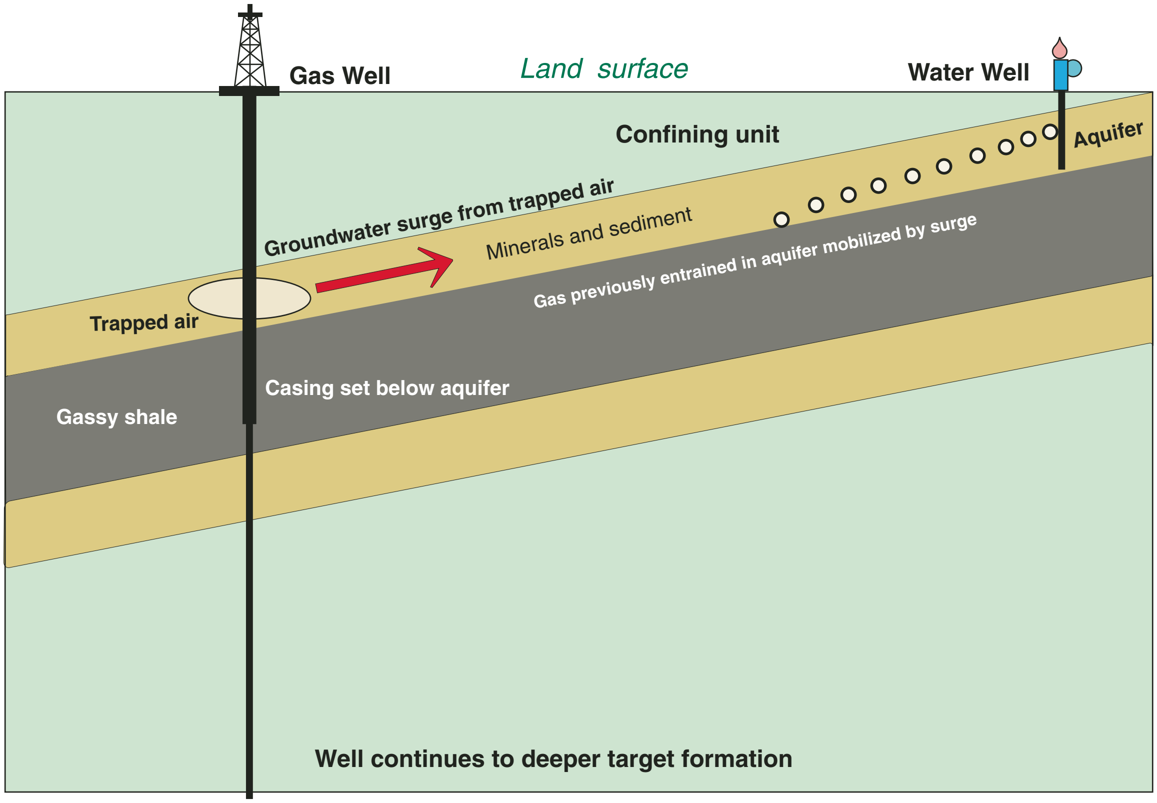

Figure 39. A conceptual model for how gas well drilling might cause the migration of stray gas into water wells. Gas from underlying units slowly migrating updip in an aquifer is suddenly mobilized by a flow surge caused by high-pressure drilling air trapped in the aquifer. Field tests will determine if this is a likely explanation.

flow event of a similar magnitude in a fractured aquifer already charged with methane would readily mobilize the gas (Zhang and Soeder, 2015).

The number of proven stray gas incidents related to shale gas development is quite small. To the homeowner with an exploded well vault or a house lifted off its foundations, it is, of course, a major tragedy. However, 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 actually 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.

Watershed Management Practices and Drilling

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. Several 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 have experienced leaks and seepage that contaminated groundwater and small streams (for an example, refer back to Fig. 35).

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 off-site disposal of cuttings instead of on-site 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 do not measure contaminants directly, but instead they 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 that can be measured automatically in the field, and it 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.

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 (Figure 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 freshwater. Sulfuric acid from oxidized pyrite is the main culprit for AMD 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 “AMD”-like problem.

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, Pennsylvania. Marcellus Shale from the old EGSP WV-6 core (refer back to Fig. 11), which had been kept dry but was exposed to the air for over 30 yr, 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

Figure 40. Weathered Marcellus Shale outcrop samples from Franklintown, Pennsylvania, coated with tiny crystals of yellow sulfur, presumably left behind from the oxidation and leaching of sulfide minerals such as pyrite. Photograph is by Daniel J. Soeder.

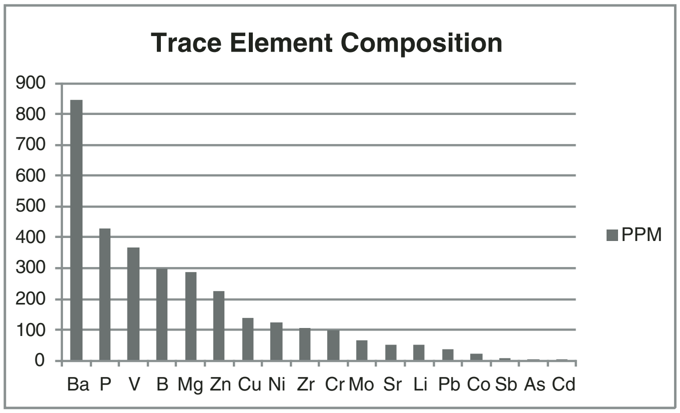

Figure 41. Trace elements in composite of Marcellus Shale drill cuttings, core, and outcrops. PPM—parts per million.

organic and inorganic carbon, hydrogen as hydrocarbons, free moisture and bound water on clays, and sulfur in the form of sulfides and sulfates.

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 nonmobile, 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.

An ICP analysis of a composite sample was performed to determine bulk rock elemental composition. The composite sample analysis is shown in Figure 41, which displays the trace element composition of the rock expected for pyritic, clay-rich, black shale.

The alpha radiation counts on the bulk rock samples ranged from background levels to ~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.

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

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				

cpm—counts per minute.

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 they have 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 Shale, 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.

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) provided 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.

Several 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 laboratories. 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 to understand 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.

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 on-site 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, and too much sodium or calcium in the water inhibits performance. The processes for treating high-TDS waters on-site 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 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 m (8 ft) × 4.25 m (14 ft) in size and 10 cm (4 in.) thick, and they weigh ~454 kg (1000 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, and then be lifted up when no longer needed and used elsewhere.

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 it 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 cannot 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 nonattainment 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 well site, and locations of other, nearby well sites 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 reduce 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 km^2 (160 acres) to a spacing of 1.295 km^2 (320 acres) and then to 2.59 km^2 (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 km^2 (40 acres) to recover gas from the same volume of shale. Ultralong 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 (Beims, 2016). Such ultralong 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 ~10% 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 (U.S. Energy Information Administration, 2014). 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 3). 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 flow paths 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 cannot 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 could produce more of the hydrocarbons in place than was previously possible.

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. Earth receives short-wave infrared from the Sun that penetrates the atmosphere and heats the surface of the planet. The warm planet then reradiates 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 (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 °C during the last century is actually greater than could be caused by anthropogenic greenhouse gas alone (Adair, 2012). This is because Earth has been emerging from the most recent Ice Age for the past 12,000 yr, 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 Intergovernmental Panel on Climate Change (IPCC; 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 ppm in 2007 to ~1250 ppm in 2100. The IPCC scientists estimate that mean global temperature will increase over the next century by ~3.4 °C (6.1 °F).

Climate risk assessments are probability based, and they 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 °C (9.7 °F), which would result in serious climate disruptions. The best case is a one-in-six chance that increases will be less than 2.0 °C (3.6 °F), and therefore changes will be lost in the natural background.

Risk assessment considers not just the probability of an event, but also the consequences (Soeder et al., 2014b). The consequences of a 5.4 °C 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 m (~250 ft) 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.

Geologic Storage in Shale

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, 2015). 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 oilfields in Texas, Louisiana, and Wyoming. 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 storage of 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, which 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 nonmobile 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 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 to 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 flow paths, increasing flow-path tortuosity, and significantly reducing permeability to gas (refer back to the Klinkenberg permeability plots in Fig. 17; see also 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 flow paths 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.

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 1). 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 will not 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 cap rock. Perhaps these cracks stayed closed as the reservoir was depleted, but repressurizing 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 may 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 in the risk assessment methodology discussion in Chapter 4, a number of DOE national laboratories, 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 (www.netl.doe.gov/research/coal/carbon-storage/research-and-development), or in the *U.S. Carbon Utilization and Storage Atlas* (U.S. Department of Energy, 2015).

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 to 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 2 yr (Matter et al., 2016).

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 on-site 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 20 October 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 L (1,100,000 gallons) of liquefied natural gas at a temperature of –160 °C (–250 °F) 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 min 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 ~20 min later in the ensuing fire, which had flames that reportedly reached 850 m (2800 ft) in height. The disaster killed 128 people and injured 200–400 (Elliott et al., 1946). Slightly more than 2.5 km^2 (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, prewar 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 rethought 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 EIA of ultimate recoverable natural gas resources in the United States of more than 1000 TCF make the Mackenzie Delta look remote and expensive. Estimated ultimate recovery from the Marcellus Shale (~490 TCF per Engelder, 2009) and the underlying Utica Shale (~782 TCF per Hohn et al., 2015) adds up to 1272 TCF of gas and gas equivalents in the Appalachian Basin alone. Shale gas is expected to account for 35% 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 of shale gas. 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 5 yr 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 renegotiated, 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 Pennsylvania, the northern panhandle of West Virginia, and some of the West Virginia 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 it 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 coproduced 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 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 through 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 do not 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.

Transportation Fuel

If natural gas were 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 1054 J. Just 1 MCF of natural gas, equivalent to a metric volume of 28.32 m^3, contains approximately a million Btus of energy. Thus, each cubic foot of natural gas has the energy equivalent of ~1000 Btus.

Crude oil is measured in barrels; a barrel of oil contains 42 gallons or 159 L 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 (2015b) 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 ~80 L (21 gallons) of gasoline.

In terms of energy value, 3.7853 L (1 gallon) of gasoline contains 125,000 Btus. The amount of natural gas needed to equal this much energy is ~3.54 m^3 (125 ft^3) at 25 °C (77 °F) under a pressure of 1 atmosphere. Thus, 1 MCF of natural gas contains the energy equivalent of ~8 gallons of gasoline.

According to the U.S. Energy Information Administration (2015b), the United States consumes ~20 million barrels of oil per day, or ~7.1 billion barrels per year. After peaking in 2005 at 3.7 billion barrels, imported oil in 2015 was down to ~2.7 billion barrels annually, or roughly 38% of the total. In 2015, U.S. refineries processed slightly more than 7 billion barrels of crude oil, producing ~3.5 billion barrels of motor gasoline (U.S. Energy Information Administration, 2015b).

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 ~3.5 billion barrels of motor gasoline annually (U.S. Energy Information Administration, 2015b). Thus, switching ~75% 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, 2015b), so gas production would have to increase by ~50% to fuel all American vehicles.

If the Marcellus Shale contains ~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 6 yr. 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 ~10% 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 (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 U.S. Department of Transportation (DOT)–approved cylinder. A search of websites offering these conversions shows prices in the \$1000–\$2000 range, with about \$1500 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 ~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 do not 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 at 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 (NO_x) emissions if run too lean; (2) rich burn (stoichiometric) spark ignited, which uses a three-way catalyst that produces low NO_x and low methane emissions when hot; (3) high-pressure direct injection, commonly used for small diesels by injecting natural gas directly into the 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 because it is piped in, there are no worries about running out of fuel to sell to customers because a tanker truck did not 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 did not 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 (644 or 805 km) 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 they 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 West Virginia University, 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 does not 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 by-products react with sunlight and moisture to form brown hazes or smog.

Despite 40 yr 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 nonachievement 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 significant 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 would 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 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 complementary. Given the abundance, national security benefits, reduced greenhouse gas 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.

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. However, the tea kettle would have to be 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 life cycles. New generating plants will be locked into a particular fuel type for the design life of the facility, generally 30–50 yr, 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, hydropower, and other options is largely driven by two things: reliability and price. Nobody wants to build a power plant where they either cannot find or cannot 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 it 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-yr-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 would show up regularly for decades. They could even take the power plant people out to the mine and walk them around on the portion of the coal seam that had been reserved for their use.

A former DOE laboratory 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 instead they are 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 AMD 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, which 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 2008–2009 timeframe, 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.

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 the 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 hydroelectric 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 hydropower, 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.

Decentralized 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 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. EIA, 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.

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%. 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.

TABLE 4. EXAMPLES OF ELECTRICITY COSTS (2013 $/MWh)

Primary power source (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 (CC)	$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 (2015). LCOE—levelized cost of electricity; $/MWh—dollars per megawatt hour; capacity—percentage of time online; CCS—carbon capture and storage (CO_2).

*O&M—Operation and maintenance, includes (+) fuel cost and (–) tax subsidies.

Along with the low capacity values, another concern with many of the renewable energy sources is that they do not 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, can be 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 ever 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 yr 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 on-site 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 cannot 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.

Large numbers 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.

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