THE ENVIRONMENTAL COSTS AND BENEFITS OF FRACKING

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Abstract

Unconventional oil and natural gas extraction fueled by horizontal drilling and hydraulic fracturing (fracking) is driving an economic boom, with consequences described as "revolutionary" to "disastrous". Reality lies somewhere in between. Unconventional energy generates income and, done well, can reduce air pollution compared to other fossil fuels and even water use compared to fossil fuels and nuclear energy. Alternatively, it could slow the adoption of renewables and, done poorly, release toxic chemicals into water and air. Based on research to date, some primary threats to water resources come from surface spills, wastewater disposal, and drinking-water contamination through poor well integrity. For air resources, an increase in volatile organic compounds and air toxics locally is a potential health threat, but the switch from coal to natural gas for electricity generation will reduce sulfur, nitrogen, mercury, and particulate pollution regionally. Data gaps are particularly evident for human health studies, the extent to which natural gas will displace coal compared with renewables, and the decadal-scale legacy issues of well integrity, leakage, and plugging and abandonment practices. Critical needs for future research include data for 1) estimated ultimate recovery (EUR) of unconventional hydrocarbons; 2) the potential for further reductions of water requirements and chemical toxicity; 3) whether unconventional resource development alters the frequency of well-integrity failures; 4) potential contamination of surface and ground waters from drilling and spills; 5) factors that could cause wastewater injection to generate large earthquakes; and 6) the consequences of greenhouse gases and air pollution on ecosystems and human health.

Keywords: horizontal drilling and hydraulic fracturing; induced seismicity; Marcellus and Barnett shale gas; tight sandstone formations, risks of water and air contamination; well integrity

1. Introduction

The past decade has seen tremendous change in the energy sector. Increased production of oil and natural gas in the United States has been driven largely by the extraction of "unconventional" resources of natural gas, oil, and other hydrocarbons locked inside tight sandstones, shales, and other low-permeability geological formations. These rocks were long known to contain hydrocarbons and to have served as source rocks for many conventional oil and gas fields. Because of their low porosity and permeability, however, the gas and oil in them were generally viewed as unrecoverable, at least at prices comparable to those of recent decades.

Recent advancements in hydraulic fracturing and horizontal drilling have changed that view (1,2). Drilling is now done kilometers underground and to horizontal distances of 2km or more, tracking shale, sandstone, and other formations as narrow as 30m thick. After horizontal drilling, the well is hydraulically fractured. From ~8,000 to 80,000 m^3 (2-20 million gallons) of water, proppants such as sand, and chemicals are pumped underground at pressures sufficient to crack impermeable rock formations (10,000-20,000 psi). The fractures induced by high-pressure, high-volume hydraulic fracturing provide the conductivity necessary to allow natural gas and oil to flow from the formation to the well and then up through the well to the surface.

The impacts that unconventional oil and natural gas have had on estimates of recoverable resources and production have been profound. Numerous countries, including Algeria, Argentina, Australia, Brazil, Canada, China, France, Libya, Mexico, Poland, Russia, South Africa, the U.S., and Venezuela, are estimated to possess at least ~3 x 10^{12} m^3 (~100 Tcf, trillion cubic feet or 1x10^{14} ft^3) of recoverable shale gas (1,3,4). Global estimates for recoverable shale gas are ~206 x10^{12} m^3, at least 60 years of current global usage in 2013, and global estimated shale oil resources are now 345 billion barrels (5). In the U.S., mean estimates for the technically recoverable shale gas resource doubled to 600-1000 Tcf (17-28 x 10^{12} m^3) in 2013, and the technically recoverable shale oil resource rose by 40% or 58 billion barrels (Bbbl; one barrel=42 U.S. gallons) (5,6). These substantial resource estimates remain best guesses because large-scale production of shale and other unconventional resources is still in its infancy.

Not only have recoverable resource estimates increased, but production of oil and natural gas has as well. In Canada, the production of light oil from shales, sandstones, and other impermeable formations rose from ~0 to >160,000 barrels per day in Saskatchewan, Alberta, and Manitoba alone (7). Daily production of natural gas from U.S. shale formations increased from <30 million m^3 (<1 billion ft^3; Bcf) per day in 2005 to >700 million m^3 (>25 Bcf) per day in 2012, accounting for 39% of domestic natural gas production that year.

One likely consequence of low-cost natural gas will be many more gas-centric economies around the world. Natural gas use in power generation is expected to grow by 60% in the U.S. over the next quarter century, largely at the expense of coal (8), although coal production is still projected to increase globally during that time (8). Chemical and other energy-intensive manufacturing is expected to increase by 20% over the next decade because of lower priced natural gas and natural gas liquids (feedstocks such as propane and butane) (9). Approvals for new liquid natural gas (LNG) export terminals have already been granted for 190 million m^3/day (6.6 Bcf/day), ~10% of 2013 U.S. daily production.

The impacts of increased shale oil and natural gas production on global energy economies are profound. At current prices of ~U.S.$100/barrel, for instance, the 345 billion barrel increase in global shale oil reserves is worth ~U.S.$35 trillion. Given the economic value of the oil and gas resources made available by hydraulic fracturing and related technologies around the world, society is virtually certain to extract more of these unconventional resources. The key issue, then, is how to produce them in a way that reduces environmental impacts to the greatest extent possible.

Public concerns about the environmental impacts of hydraulic fracturing have accompanied the rapid growth in energy production. These concerns include the potential for ground and surface water pollution, local air quality degradation, fugitive greenhouse gas emissions, induced seismicity, ecosystem fragmentation, and various community impacts. Many of these issues are not unique to unconventional oil and gas production. However, the scale of hydraulic fracturing operations is much larger than for conventional exploration onshore .

Moreover, extensive industrial development and high-density drilling is occurring in areas with little or no previous oil and gas production, often literally in peoples' backyards.

The goal of this review is to examine the environmental consequences of unconventional energy extraction and hydraulic fracturing. We begin by describing production estimates and decline curves for unconventional natural gas and oil wells, two important criteria for comparing environmental footprints on a unit-energy basis. We also examine water requirements and water intensity, comparing them to values for other fuels. We next examine issues of well integrity and the potential leakage of chemicals, brines, or gases. We include results from oil and gas and carbon-capture-and-storage (CCS) operations, as well as legacy issues associated with drilling millions of new wells globally. We then focus on water quality issues accompanying unconventional energy extraction, including potential drinking-water contamination and wastewater disposal. We examine the potential for induced seismicity associated with hydraulic fracturing and, more importantly, wastewater disposal. We conclude by comparing the emissions of hydrocarbons during fossil fuel extraction, distribution, and use, including new measurements of greenhouse gas emissions, interactions with ozone pollution, and discrepancies between bottom-up and top-down estimates of hydrocarbon emissions.

Throughout the paper, we provide research recommendations for each topic covered in the review. We also cover some environmental benefits and positive trends associated with unconventional energy extraction, including the potential for saving cooling water in thermoelectric power generation, increased water reuse and recycling, and the reduced air pollution and improved health benefits that can come from replacing coal with natural gas. We do not have the space to cover numerous important issues, most notably the critical social and community impacts associated with the unconventional energy boom.

2. Resource productivity and unconventional oil and gas development

The early-life productivity of the unconventional oil and gas resource

Resource productivity is the key to characterizing how much oil and natural gas will be extracted from an area and for estimating environmental metrics such as the freshwater and greenhouse gas (GHG) intensities of extraction (10,11,12). When assessing resource productivity, the productive unit differs for unconventional and conventional plays. In conventional fields, the oil and natural gas typically reside in high porosity and high permeability structural or stratigraphic traps, for instance anticlines or salt domes. Well productivity is often influenced by the number and proximity of surrounding wells. Productivity is therefore usually estimated at the field level. In contrast, the individual well is typically the estimated unit of production for unconventional resources (13). The low permeability of unconventional fields means that the productivity of a well is rarely influenced by surrounding wells, particularly early in well life when most of the oil and gas is produced (and recognizing that inadequate well spacing can still diminish the productivity of unconventional wells).

The productivity of an unconventional well is typically estimated using two factors: its initial production (IP) rate after well completion and its decline curve. The IP rate quantifies the maximum production from a well, usually averaged over the first month. The decline curve describes how quickly production decreases and forecasts how many years the well will produce. These two factors determine how much energy will ultimately be recovered and what the potential environmental impacts will be. Not surprisingly, the variables that determine IP rates and decline curves are complex and include geological factors, such as a formation's organic and inorganic sedimentary composition, its burial history and its natural fracturing, petrophysical factors including porosity and permeability, and engineering factors including the level of induced fracturing during well completion (14,15,16).

The IP rate and early production decline data provide the empirical basis for assessing the resource productivity of unconventional wells. Because these data can vary substantially at various scales within a region, "typical" wells must be selected in a statistically representative way. For instance, across five major U.S. shale plays in 2009, IP rates varied 2.5-fold within a given play for individual wells, even excluding the top and bottom 20% of wells (17).

Because the Barnett Shale in Texas was the first unconventional resource tapped using horizontal drilling and high-volume hydraulic fracturing, we examine the Barnett as a case study to illustrate production. In resource plays such as the Barnett, distinct "core" and "non-core" areas show higher productivity areas that are tapped in the initial years and lower productivity areas that are drilled later (18). From 2005, when large-scale horizontal drilling began in the Barnett, through 2011, the median IP rate increased 35% (19), from 44.7 million m^3/day (1.58 Bcf/day) to 61.0 million m^3/day (2.14 Bcf/day) (Figure 2.1). Similar year-to-year increases in IP rates have occurred in other unconventional plays. Part of the reason for increased production for newer wells is that companies learn as they go, tailoring their practices to local geology.

Another reason that IP rates have risen is because the intensity of extraction has increased. In 2005 the typical length of a horizontal drill in the Barnett Shale was ~600 m (2000 ft) (20). By 2011 it had grown 75% to 1,070 m (3,500 ft). Similarly, the typical volume of water used to fracture a well during this period almost doubled from 9.9 to 17.4 million liters (2.6 to 4.6 million gallons) (20). Drilling lengths and fracture treatment volumes are increasing proportionally faster than IP rates are in most resource plays, increasing extraction intensity (21).

Although production initially increases per well as operators drill out the most productive areas first, productivity for new wells eventually starts to fall. The median IP rate for 2012 vintage wells in the Barnett was only 1,650 Mcf/day, a 22% drop compared to 2011 (19). The drop occurred despite an average horizontal length (1175 m or 3850 ft) that was 10% greater than in 2011 and almost double the length in 2005. Production declines can be mitigated by improved technologies and practices, but the shift to lower quality acreage is eventually inevitable.

One aspect of unconventional energy extraction that has received almost no attention is the refracturing of wells. Operators are increasingly refracturing two to four years later to stimulate oil and gas production. Refracturing of 15 oil wells in the Bakken Shale yielded a 30% increase in EUR (22). In the Barnett Shale, where natural gas production declines 3-5 fold within a few years, refracturing increased EUR by 20% (23). As the price for oil or natural gas rises, refracturing will become increasingly common.

The challenge of estimating ultimate recovery from the unconventional oil and gas resource

Trends in IP rates are only part of the story for estimating unconventional resource productivity. The second component is the decline of production through time for individual wells (Figure 2.2). Long-term projections of well productivity are challenging for horizontally drilled and hydraulically fractured oil and gas fields because most wells have produced for less than a decade to date. A recent controversy over contrasting Marcellus Shale resource estimates made by the EIA and USGS highlight uncertainties in modeled production declines through time (29). Such projections are critical for estimating proven reserves and for deciding where to drill.

The most common approach for estimating the long-term cumulative productivity of wells, termed the estimated ultimate recovery (EUR), is decline-curve analysis (24). Its attractiveness lies in its simplicity – EURs can be established from IP rates and early-life production-decline data. Seminal work by Arps (25) in 1945 produced a decline curve model that has been widely used for decades to establish well EURs. Unfortunately, the Arps model yields unreasonably high EUR projections if applied using early-life production data of unconventional wells (24,26,27,28).

Newer exponential decline-curve techniques have been developed for unconventional resources that more reasonably predict unconventional well EURs. Ilk et al. (30) and Valko (28) independently proposed power-law exponential models for individual wells that yield reasonable EUR estimates. The rate-time form of Valko's model is shown in Eq. 1, where τ and n are the fitting parameters.

$$q(t) = q_i \exp\left[-\left(\frac{t}{\tau}\right)^n\right] \qquad \text{Eq. 1}$$

Such empirical power law exponential methods have yielded accurate EUR projections when compared to known EURs for synthetic data (30,31).

Patzek et al. (27) developed a simplified treatment of production physics for horizontal, hydraulically fractured wells and applied it to production data for 8,294 wells in the Barnett Shale. Their sample amounted to 63% of the ~13,000 horizontal wells drilled in the play between 2005 and 2012. The typical EUR per well was ~54 million m^3 (~1.9 Bcf), and the estimated EUR for the combined 8,294 Barnett combined was 280-570 x 10^9 m^3 (10 to 20 Tcf) (27). This range represents a third or so of that play's estimated recoverable potential of between 1.1-1.4 x 10^{12} m^3 (40 and 48 Tcf) (6,18). In the next section we will use analyses of EURs in the Barnett and other regions to estimate the water intensity of unconventional energy extraction and electricity generation.

Because the Barnett was the first shale-gas play exploited extensively using horizontal drilling and high-volume hydraulic fracturing, other plays have generally had fewer wells drilled and fewer years on which to project EUR. The proportion of untapped resource in those plays is even greater, as are the uncertainties in EUR. Regardless, the intensive development seen today for unconventional plays is likely to continue. A report from MIT (32) estimated that if the drilling rates seen in 2010 were maintained in the primary U.S. shale gas plays (~4,000 horizontal wells in total), the combined output of natural gas from those plays would rise to 850 million m^3/day (30 Bcf/day) by 2030. In fact, natural gas production is likely to reach that amount by 2015, because drilling activity shifted to more productive plays, including the Marcellus and Eagle Ford shales.

Emerging research questions regarding productivity and ultimate recovery

Estimates of resource productivity and their implications for the environmental footprint of unconventional oil and gas development are still developing. A more comprehensive approach is needed to understand how much energy will ultimately be extracted and what the environmental costs will be. Important research questions include:

1. What are the reservoir characteristics and fluid-transport mechanisms that govern resource storage and production in shale and other low-permeability formations?
2. What estimation techniques can provide the most accurate EURs for unconventional wells?
3. What are the technical pathways towards improving drilling strategies and well completion to enhance short- and long-term well productivity?
4. How effective can refracturing or other restimulation methods be at enhancing well productivity and maximizing ultimate recovery?

Progress is vital to determine a clearer picture of the productive capacity of unconventional resources and how intensive its development will be over the coming decades, particularly as unconventional natural gas is promoted as a bridge to a lower-carbon future (33,34,35).

3. Water requirements for unconventional energy extraction and electricity generation

Water requirements for the extraction of unconventional natural gas and oil

Water use for hydraulic fracturing and unconventional energy extraction is a primary public concern (36). In this section, we examine the water required for hydraulic fracturing and electricity generation. We also use EUR data described above to compare the water intensities of different fuels, including natural gas, oil, coal, nuclear, biofuels, solar, and wind. We examine issues of potential surface-water and groundwater contamination later in the review.

Hydraulic fracturing and horizontal drilling require considerable water. A lateral from a single well might be drilled 1-3 km sideways (see above) and divided into 20 or so ~100-m-long stages. Across many plays (37), including the Barnett, Marcellus, and Fayetteville shales, hydraulic fracturing typically requires anywhere from 8,000 to 80,000 m^3 (2 to 20 million gallons) of water for a single well (Table 3.1). An additional 25% water use is typically associated with drilling, extraction, and sand or proppant mining (20); in Table 3.1 we use a more conservative estimate of 1,900 m^3 (500,000 gallons) per well for these processes to account for different practices, such as whether air drilling is used (Table 3.1).

Some context is helpful for examining these numbers. Although the amount of water consumed is substantial, the volume is relatively small compared to agricultural and thermoelectric uses when examined over large areas. Across Texas, for instance, the amount of water used for hydraulic fracturing yearly is ≤1% of total water use (20).

The perspective changes, though, for smaller areas and specific windows of time. Shale-gas extraction in Johnson, Parker, and Wise counties of the Barnett comprised 10-30% of total water use for surface water and ground water (20). In counties associated with the Haynesville, Eagle Ford, and Barnett shales, unconventional energy extraction was responsible for 11%, 38%, and 18% of total groundwater use. Future water use at peak extraction is projected to be as high as 40-135% for specific counties in the Barnett, Haynesville, and Eagle Ford shales. The key point is that the water requirements can be high locally, even if the contribution statewide is smaller than for agriculture and power plants. This dynamic is also reflected in the history of water use in the Marcellus Shale of Pennsylvania; early in the shale-gas boom, too much water withdrawn from a few streams locally led to problems that were recognized by the state and rectified (38).

The estimates in Table 3.1 already incorporate the very positive trend of increased wastewater recycling for hydraulic fracturing, which reduces freshwater requirements. Prior to 2011, for instance, only 13% of waste water in the Marcellus shale was recycled for oil and gas operations; by 2011, 56% of waste water was recycled (39).

Water intensities for unconventional fuels and other energy sources

To compare the water used for hydraulic fracturing with other forms of energy extraction, water volumes must be converted to water intensities (volume used per energy generated). Table 3.1 includes estimates for EUR, the typical amount of energy recovery projected for individual wells (see Section 2 above). Across six plays, the EUR values per well ranged from 1.2-2.6 GJ (1.1-2.5 Bcf). Combining data for water requirements and EUR, the water intensity of extraction ranged from 6 to 11 L/GJ, or 8.6 L/GJ on average for the six plays (7.6 L/GJ for hydraulic fracturing alone) (Table 3.1). Although these values are the most relevant ones for comparing to other energy sources, most of the water is used for hydraulic fracturing during the early stage of well life. The short-term water intensity can also be normalized to the IP rates rather than to EUR values. For instance, assuming IP rates for 30 days, the Barnett data (~0.05 GJ) suggest a higher water intensity of ~21 L/GJ compared to 5.2 L/GJ over the well lifetime.

Surprisingly, given all of the attention that hydraulic fracturing receives for its water requirements, shale gas extraction and processing are less water intensive than most other forms of energy extraction except conventional natural gas and, especially, renewables such as wind and solar photovoltaics that consume almost no water (Table 3.2). The water intensities for coal, nuclear, and oil extraction are ~2x, 3x, and 10x greater than for shale gas, respectively. Corn ethanol production uses substantially more water because of the evapotranspiration of the plants, 1000 times more water than shale gas if the plants are irrigated (Table 3.2).

For electricity generation with fossil and nuclear fuels, cooling-water needs are far greater than the water used to produce the fuel. Here, too, shale gas is better than most other fossil fuels and nuclear energy (Table 3.2). Although the amounts of water withdrawn and consumed range greatly depending on the technologies used (e.g., once-through or closed-loop cooling vs. dry cooling, etc.), a natural gas combined cycle (NGCC) plant consumes half to one third of the water that a nuclear or pulverized coal power plant does, attributable to the higher energy content per carbon atom of methane as well as the greater efficiency of the CC plant (Table 3.2). The relative difference diminishes or disappears for dry-cooled power plants. Biofuels, particularly irrigated crops, and concentrated solar power use even more water than natural gas, coal, and nuclear do (Table 3.2). In contrast, renewable sources such as wind and solar photovoltaics use 100-times less water for electricity generation than all the other sources listed in Table 3.2 (47,48,49).

As the refracturing of wells becomes more common (see above), the water intensity of extraction will rise (Table 3.1). Refracturing 15 oil wells in the Bakken Shale yielded a 30% increase in EUR but required twice as much water as the original hydraulic fracturing step (22).

The relative water intensity (L/GJ) of the hydraulic fracturing was ~6 times higher for this "later" oil than for the earlier oil produced from the well. In the Barnett Shale, refracturing generated 7.1 million m^3 (0.25 Bcf) or 0.26 GJ of additional natural gas per well, a 20% increase in EUR (23). The 7,600-9,500 m^3 (2-2.5 million gallons) of water used to refracture each well, however, resulted in a water intensity of 32 L/GJ, higher than coal for extraction and processing but still below the water intensity for electricity generation compared to coal (Tables 3.1 and 3.2). As refracturing becomes more common, the water intensity of extraction will rise.

Many research opportunities exist at the water-energy nexus. Important research questions for water requirements and intensity include:

1) Can the volumes of water needed for well stimulation be reduced while maintaining or enhancing productivity?
2) To what extent can the fresh water used in hydraulic fracturing be replaced by non-potable water (e.g., recycled wastewater brines), hydrocarbons, supercritical CO_2, or other fluids?
3) How can the improvements in water reuse and recycling in the Marcellus and other areas be duplicated elsewhere?
4) How prevalent will refracturing be through time?
5) Under what circumstances may water limit future shale gas development in dry and water-scare areas of the world?

4. Well integrity and fracturing-induced stress

The importance of well integrity

Any well drilled into the earth creates a potential pathway for liquids and gases trapped underground to reach the surface. The same technologies that power the unconventional energy boom - horizontal drilling and hydraulic fracturing - create challenges for maintaining well integrity. Today's unconventional wells are typically longer, must curve to travel laterally, often access substantially overpressured reservoirs, and must withstand more intense hydraulic fracturing pressures and larger water volumes pumped underground than for traditional conventional oil an gas wells. Poor well integrity costs money and can impact human health and the environment.

In well leakage, fluids (liquids or gases) can migrate through holes or defects in the steel casing, through joints between casing, and through defective mechanical seals or cement inside or outside the well (52,53). A buildup of pressure inside the well annulus is called sustained casing pressure (SCP) and can force fluids out of the wellbore and into the environment. In external leaks, fluids escape between the tubing and the rock wall where cement is absent or incompletely applied. The leaking fluids can then reach shallow groundwater or the atmosphere.

Well operations and the passage of time can degrade well integrity. Perforations, hydraulic fracturing, and pressure-integrity testing can cause thermal and pressure changes that damage the bond between cement and the adjacent steel casing or rock, or that fracture the cement or surrounding caprock. Chemical wear and tear can also degrade steel and cement through reactions with brines or other fluids that form corrosive acids in water (e.g., carbonic or sulfuric acids derived from CO_2 or H_2S).

Tasks surrounding wellbore integrity fall into three phases: drilling, operations, and plug and abandonment. During drilling, the key steps for well integrity are to limit damage to the surrounding rock and to prevent high-pressure formational fluids from entering the well. Drillers must balance the high fluid pressure of the reservoir with the hydrostatic pressure of drilling mud, steel, and cement to prevent blowouts such as the Deepwater Horizon disaster in the Gulf of Mexico. Gas in pore spaces and pockets within intermediate layers must also be prevented from entering the well during drilling.

The operational phase of wellbore integrity includes wellbore completion and the extended life and performance of the well. Fluids must be kept inside the well and within the target formation using steel casing (tubes), cement, and mechanical components that isolate the fluids and seal the spaces between the production tubing, the outside casing(s), and the surrounding rock.

When a well is no longer commercially viable, it has to be plugged and abandoned (P&A) (54). Mechanical or cement barriers, such as packers, at different depths are used to prevent fluids from migrating up or down the well. Improperly abandoned wells provide a short-circuit that connects the deeper layers to the surface.

In this review, we primarily emphasize well integrity for drilling and operations, examining P&A practices only as pathways for contamination. Blowouts can have enormous environmental consequences but are rare and easily recognized (e.g., only 4 of 3,533 Marcellus wells drilled from 2008-2011 experienced blowouts) (55). All phases of well life are governed by state and federal regulations, complemented by industry best practices (56). Nonetheless, well integrity sometimes fails, in the rarest cases leading to explosions at the surface (57). Understanding how often and why failures occur is critical for improving the safety of hydraulically fractured wells and for minimizing environmental contamination.

Field observations of wellbore-integrity failure

There are few definitive studies of the frequency, consequences, and severity of well integrity. One metric of well performance is the occurrence of sustained casing pressure, described above. It reflects the failure of one or more barriers in a well such as casing or cement (and recognizing that the failure of a single barrier does not always result in environmental contamination) (58).

Results from surveys of wells offshore (52) and onshore (59) show distinct differences in rates of SCP, reflecting the importance of geology and well construction. In the Gulf of Mexico, 11-12% of wells in an 8,000-well survey showed SCP on outer casing strings, with results ranging from 2 to 29% across fields (52). In Alberta, companies reported that 3.9% of 316,000 wells showed evidence of SCP, with one region east of Edmonton having 15.3% SCP (59). Davies et al. (60) recently reviewed well integrity and SCP globally. For studies with >100 wells, SCP was found to range from 3% to 43% of wells in Bahrain, Canada, China, Indonesia, the U.K., the U.S., and offshore Norway and the Gulf of Mexico; 12 of 19 studies showed SCP values for ≥10% of wells. Publicly available data for well failure rates are still relatively scarce.

Regulations in Alberta require testing for gas migration (GM) in the soil around wellheads. Erno and Schmitz (61) measured surface casing leakage for 1,230 oil and gas wells near Lloydminster, Canada. Across their dataset, 23% of wells showed surface and soil gas leakage, from 0.01 to 200 m^3 CH_4/day. Watson and Bachu (59) examined industry-reported data across Alberta that suggested lower occurrences of gas migration (0.6% of wells). In a test area east of Edmonton, however, where soil tests were mandated rather than being based on self-reported data, 5.7% wells (1,187 out of 20,725) showed gas migration. Particularly relevant for today, the wells that were slanted or deviated from vertical were 3 to 4 more times more likely than purely vertical wells to show SCP and GM (>30% of 4,600 wells for each) (59).

Kell (62) compiled groundwater contamination incidents from oil and gas operations in Ohio and Texas. For a 25-year period, the state of Ohio acknowledged 185 cases of groundwater contamination caused primarily by failures of wastewater pits or well integrity. Ohio had about 60,000 producing wells, for an incident rate of about 0.1% (~5 in 100,000 producing well-years). The rate for Texas was lower with 211 total incidents, ~ 0.02% or 1 in 100,000 producing well-years. Interestingly, Kell's (62) study also included 16,000 horizontal shale gas wells in Texas, none associated with reported groundwater contamination.

Field-scale investigations are also available from EPA's regulatory data on mechanical well integrity violations. Combined with sustained casing pressure and groundwater incidents, these data provide an overview of rates at which barrier failures occur (generally 1-10% of wells); however, reported rates of groundwater contamination are lower (0.01-0.1% of wells) (58). Such data from regulatory violations provide a lower bound for possible environmental problems because not all well failures are identified. What is needed is more randomized, systematic testing of potential groundwater contamination to complement industry's self-reported data.

Mechanisms of wellbore-integrity failure

Steel casing and Portland cement are the key barriers keeping liquids and gases from reaching the environment. Casing leaks can occur through faulty pipe joints, corrosion, or mechanical failure due to thermal stresses or over-pressuring (52). Vignes and Aadnøy (63) found that leaks through steel tubing and casing accounted for most failures in offshore Norway. Schwind et al. (64) observed that 90% of casing failures were attributable to faulty connections.

Steel corrosion is the most common chemical attack on wells (65,66). Experiments and models show that corrosion occurs quickly in CO_2- and H_2S-bearing brines, typically tens of mm/year, with local geology and brine chemistry playing important roles in wellbore integrity (67). Watson and Bachu (59) found that the most significant predictors of SCP or GM in Alberta were insufficient cement height and exposed casings, both correlated with external corrosion. Chemical inhibitors, cathodic protection, and corrosion-resistant alloys are all used to reduce steel corrosion.

Defects in Portland cement also create pathways for leaks. Poor primary cement can occur by the development of fluid channels, casings that are not centered in the well, poor bonding and shrinkage, and losses of cement into the surrounding rock (68). Well operations can also damage cement through temperature and pressure changes (52,69). Examples include the insertion and removal of equipment in the well (tripping), pressure testing of casing strings, hydraulic fracturing, and production or injection of fluids of contrasting temperatures. Rish (70) considered the development of microannuli from these processes at the cement-casing or cement-formation interfaces as a chief cause of integrity failures.

Experimental studies and field sampling reveal how pathways for leaks form and evolve. Increasing or decreasing pressure within the casing of simulated wells above 4,000-7,000 psi resulted in the formation of a permeable microannulus at the casing-cement interface (69). A typical hydraulic fracturing pressure used in the U.S. is 10,000-20,000 psi. Carey et al. (71) and Crow et al. (72) cored through old CO_2-exposed wells and found evidence for CO_2 migration outside the casing along the cement-steel and cement-formation interfaces.

The very long-term fate (>50 years) of wellbore systems is rarely considered. Mature oil and gas fields are pressure-depleted in their pore spaces, and typically there is insufficient fluid potential to reach the surface through abandoned wells. However, new technologies such as enhanced oil and gas recovery and hydraulic fracturing are often applied in older fields, leading to higher reservoir pressures that could send fluids up or through the older wells. In addition, new applications such as CO_2 sequestration re-pressurize depleted oil and gas fields and require centuries of storage security. Long-term studies of well integrity would be useful for oil and gas production, CO_2 sequestration, and other energy-related endeavors.

Deriving a conceptual model for old wellbores is difficult. Steel will corrode and cement reacts and transforms, but neither disappears quickly. Laboratory and field studies have shown self-healing of leakage pathways in some cement and steel systems (66). Carey et al. (71) observed carbonate precipitates filling gaps at the cement-rock interface, and Huerta et al. (73) and Luqot et al. (74) found that the permeability of fractured cement decreased with time. In addition, the rock surrounding the borehole will eventually creep into the annulus, particularly for important caprock seals such as shales and evaporites.

Unplugged wells also create legacy issues. The number of unplugged wells in New York State, for instance, grew from 35,000 to 48,000 between 1994 and 2012, despite requirements to plug abandoned wells (75). Improperly abandoned orphan wells that lack a responsible owner (e.g., 5,987 wells in Texas) and generous allowances for idle wells (e.g., 15 years in California) can lead to greater problems from abandoned wells. More studies are needed to consider the legacy effects of past drilling and the future drilling of millions of new oil and gas wells.

Research questions and recommendations on well integrity

Based on the needs described above, we outline five research questions related to well integrity for horizontal drilling and hydraulic fracturing:

1) Do horizontal drilling and hydraulic fracturing lead to higher stresses that require engineering safeguards to be reevaluated, particularly the mechanical properties of steel and cement?

2) Are failures in well integrity during the first decade less or more common than in the past? Better understanding is needed for well-failure statistics and well age, including tests of the assertion that improvements in rules, regulations, and best practices make well integrity better today than historically.

3) How can we obtain more systematic, randomized testing of well integrity beyond reported violations? Mechanical integrity tests specific to hydraulic fracturing are also needed to demonstrate integrity, including looking at migration outside the casing using acoustics or temperature logs.

4) What are the emissions of methane and other gases during the drilling and operations of wells as well as after plugging and abandonment?

5) How do we predict the legacy effects of older wells (>25 or 50 years) for GHG emissions and potential groundwater contamination?

We need improved geomechanical models for how hydraulic fracturing affects the wellbore environment and how fluids move through rock formations. Drilling companies and regulators may also want to apply the Area-of-Review concept to hydraulically fractured wells; proposed for geologic carbon sequestration, the concept encourages companies to identify and plug all boreholes, including improperly abandoned wells, that may serve as conduits for fluid movement between the injection formation and overlying drinking-water aquifers. Finally, research on GHG emissions should be linked to research on how hydraulic fracturing changes pressure-saturation fields in reservoirs and surrounding formations in ways that could alter GHG emissions from abandoned wells and aquifers (see below).

5. Risks to Ground- and Surface-Water Resources

The potential for drinking-water contamination

Maintaining well integrity and reducing surface spills and improper wastewater disposal are central to minimizing contamination from the hundreds of chemicals found in fracturing fluids and from naturally occurring contaminants such as salts, metals, and radioactivity found in oil and gas waste waters (37,76). Several recent reviews have discussed the potential water risks of unconventional energy development (37,77,78,79).

In principle, hydraulic fracturing could open incipient fractures (cracks) thousands of meters underground, connecting shallow drinking-water aquifers to deeper layers and providing a conduit for fracturing chemicals and formational brines to migrate upwards. In practice, this occurrence is unlikely because of the depths of most target shale and tight-sand formations (1,000-3,000 m) and because micro-seismic data show that man-made hydro-fractures rarely propagate >600 m (2,80,81). A somewhat more plausible scenario would be for man-made fractures to connect to a natural fault or fracture, an abandoned well, or some other underground pathway, allowing fluids to migrate upwards (82,83).

A simpler pathway for groundwater contamination, though, is through poor well integrity (see above). In the first study to test for potential drinking-water contamination associated with unconventional energy extraction, Osborn et al. (84) analyzed groundwater wells for 68 homes overlying the Marcellus Shale in Pennsylvania. They found no evidence for increased salts, metals, or radioactivity in drinking water of homes within 1km of shale-gas wells. They did find 17-times higher methane concentrations for the homes, plus higher ethane concentrations and $^{13}CH_4$ isotopic signatures that were consistent with a thermogenic (i.e., fossil fuel) source (average $\delta^{13}CH_4$ values of $-37\pm7‰$ and $-54\pm 11‰$ for homes $\leq$1 km and >1 km, respectively; $P < 0.0001$).

Jackson et al. (85) analyzed additional drinking-water wells for 141 homes in the Marcellus region of PA, providing extensive isotopic and gas-ratio data to identify the source of elevated natural gas concentrations and the potential mechanism of stray-gas leakage. Both the stable-isotope ($\delta^{13}CH_4$ and $\delta^{13}C_2H_6$) and gas-ratio data (e.g., $[^4He]/[CH_4]$ and $[CH_4]/[C_2H_6]$) suggested stray gas contamination from Marcellus gas in some homeowners' water and from shallower Upper-Devonian gases in others. The researchers concluded that casing and cementing issues were the likeliest causes for the fugitive gas migration that they observed in the shallow aquifers.

Cases of groundwater contamination have been strongly debated and universally controversial. Some researchers suggested that the higher methane levels observed close to gas wells occurred naturally, resulting primarily from a topographic effect of higher [CH_4] in valley bottoms (86). The effect is real across the study area but was less important than distance to gas wells in the statistical analysis of Jackson et al. (85). Additionally, some natural thermogenic methane is found in many PA aquifers (84,85,86). For instance, Sloto (87) sampled drinking-water wells in 20 homes in Sullivan County, PA, and found two homes with >1 mg CH_4/L (4.1 and 51.1 mg CH_4/L). The latter value was comparable to the highest values found in the stray gas studies mentioned above. However, ethane concentrations in the Sullivan County samples were low, and the ratio of methane to ethane was ~2,000, orders of magnitude higher than in the data of Jackson et al. (85).

Some occurrence of stray-gas contamination from shale gas extraction is hardly surprising given the history of well integrity described above. In a recent survey, industry drilling experts selected methane migration through casing and cementing problems as one their top 20 environmental concerns for horizontal drilling and hydraulic fracturing (36). Analyses of state records for the Marcellus Shale from 2010 to 2013 revealed that PA wells failed at rates of 3% to 6% in the first three years of well life (79,88). More broadly, state regulatory agencies confirmed 116 cases of well-water contamination in recent years associated with drilling activities in Pennsylvania, Ohio, and West Virginia (89). In contrast, a recent scientific study in Arkansas's Fayetteville Shale found no evidence of drinking-water contamination for 127 homes in the region (90).

Less clear is the extent to which hydraulic fracturing has contaminated drinking water directly. The most controversial case is probably the ongoing investigation in Pavillion, WY, which is now being led by the state of Wyoming. There, EPA investigators found the carcinogen benzene at 50 times safe levels in ground water, plus hazardous pollutants such as toluene and 2-Butoxyethanol (2-BE), a solvent that is common in hydraulic fracturing fluids (91). Although part of the controversy concerns the lack of pre-drilling data at the site, one aspect is very different from typical practices. Hydraulic fracturing in this tight sandstone formation occurred as shallowly as 322 m, and local drinking water wells were as deep as 244 m (91). A lack of vertical separation between fracturing and drinking water increases hydraulic connectivity and the likelihood of contamination.

Recent research on other aspects of drinking-water quality and horizontal drilling and hydraulic fracturing includes the potential for higher concentrations of metals and other elements near gas wells as well as increases in endocrine-disrupting chemicals. Fontenot et al. (92) sampled 100 drinking-water wells overlying the Barnett Shale and documented significantly higher levels of arsenic, selenium, strontium, and total dissolved solids in water wells < 3km from shale gas wells. Kassotis et al. (93) found that estrogenic and androgenic activities in water samples from a drilling-rich area of western Colorado were substantially higher than in reference sites with limited drilling operations. However, both studies need follow-up testing to confirm results.

Isolating waste waters from surface and ground waters

One of the biggest challenges for protecting water resources from all oil and gas activities is the waste water generated during production. Oil and gas operations in the U.S. alone generate more than 2 billion gallons (7.6×10^9 L) of waste water a day. Wastes, such as drill cuttings, and waste water generated during exploration, development, and production of crude oil and natural gas are categorized by the U.S. EPA as "special wastes" exempted from federal hazardous waste regulations under Subtitle C of the Resource Conservation and Recovery Act (RCRA).

Waste water from oil and gas exploration is generally classified into flowback and produced waters. “Flowback water” is defined here as the fluids that return to the surface after the step of hydraulic fracturing and before oil and gas production begins, primarily during the days to weeks of well completion . It is comprised of 10-40% of the injected fracturing fluids and chemicals pumped underground that return to the surface (e.g., 1 million of 4 million gallons) mixed with an increasing proportion of natural brines from the shale formations through time (37).

"Produced water" is the fluid that flows to the surface during extended oil and gas production. It primarily reflects the chemistry and composition of deep formation waters and capillary-bound fluids. These naturally occurring brines are often saline to hyper-saline (35,000 to 200,000 mg/L total dissolved solids) (37) and contain potentially toxic levels of elements such as barium, arsenic, and radioactive radium (37,94,95). The balance of flowback and produced waters across the Marcellus Formation of PA in 2011 was 43% flowback and 45% produced waters (the remainder being drilling fluids), with an increasing proportion of produced waters to be expected as the wells age (39). Surprisingly, very few samples of flowback and produced waters have been analyzed and published, especially for regions outside the Marcellus Shale.

Waste water from hydraulic fracturing operations is disposed of in several ways. Deep underground injection of wastewater comprises >95% of disposal in the U.S. (96). Approximately 30,000 Class II injection wells are used to dispose >2 billion gallons of brine from oil and gas operations daily in states such as TX, CA, OK, KS, ND, and OH. In contrast, deep injection of wastewater is not permitted in Europe unless the water is used to enhance oil and gas recovery. Waste water in the U.S. is also sent to private treatment facilities or, increasingly, is recycled or reused (see above). In 2011, companies reported that 56% of waste water from the Marcellus of PA was recycled, with most of the remaining 44% sent to private water-treatment facilities (39). More recently, wastewater is increasingly sent to facilities with advanced treatment technologies such as desalination (37).

Other disposal methods are less common and far less preferable. Some states still allow waste water to be sent to municipal or other publicly owned water-treatment facilities, despite the facilities being unprepared to handle the volumes and chemicals involved. A handful of states still allow untreated waste water to be sprayed onto roads for dust control (e.g., NY, WV, and MI) or directly onto lands, both undesirable options. An experimental application of ~300,000 L of flowback water on 0.2 ha of forest in WV killed more than half the trees within two years (97). A beneficial-use clause (EPA's 40 CFR 435.50) in the U.S. allows operators to release waste water directly into the environment if an operation is west of the 98^{th} meridian (i.e., relatively arid) and if "the produced water has a use in agriculture or wildlife propagation", such as for watering cattle. This practice is relatively uncommon but still occurs.

Two pathways that are particularly important for potential water contamination from waste waters are 1) surface leaks and spills from wellpads and wastewater holding ponds, and 2) inadequate treatment before wastewater discharge. For the first pathway, >100 violations associated with spills and leaks were reported for PA since 2008 (37). In Weld County, Colorado, an area with a high density of hydraulically fractured wells, Gross et al. (98) documented 77 surface spills (~0.5% of active wells) affecting ground water for a one-year period beginning in July of 2010. Measurements of BTEX (benzene, toluene, ethylbenzene, and xylene) in ground water at the sites exceeded National Drinking Water maximum contaminant levels (MCLs) in 90, 30, 12, and 8% of the samples, respectively. Remediation steps were effective at reducing BTEX levels in 84% of the spills as of May 2012 (98).

The second pathway is inadequate treatment before wastewater discharge. Ferrar et al (99) documented discharge from water treatment facilities in PA with TDS values ~4-times the concentration of sea water (120,000 mg/L) and with elevated levels of barium, radium, and organics, such as benzene. Warner et al. (100) studied the effluent from a treatment facility and found that it successfully removed >90% of metals. However, salt concentrations in the effluent were several times higher than seawater, were 5,000 to 10,000 times more concentrated than in river water upstream from the facility, and were responsible for ~80% of the total salt budget for the river at the point of release. Radium activities in the stream sediments near the discharge point were also 200 times higher than in background sediments just upstream and above levels requiring disposal at a licensed radioactive waste facility (100). Shortly after the study was published, the company announced plans to dredge sediments for ~500 ft below the discharge point.

Previous papers focusing on wastewater issues provide a more detailed overview and examples of the important issues surrounding wastewater disposal and high-volume hydraulic fracturing (37,77,78,79). Examples of issues not covered here include the potential formation of carcinogenic trihalomethanes in drinking water, particularly associated with Br release, the disposal of radioactive drill cuttings, and the water footprint required to dilute salts released into surface waters. One factor in particular, the sheer volume of waste water generated from conventional and unconventional oil and gas operations (~1 trillion gallons or ~3.8×10^9 m^3 annually in the U.S.), makes this aspect of environmental stewardship particularly important. It also leads directly to another public concern: the potential for induced seismicity.

Research questions and recommendations for potential water contamination

Given public concerns for water quality associated with unconventional resource extraction, the number of peer-reviewed studies that have examined potential water contamination is surprisingly low. Important research questions include:

1) To what extent does the presence of natural-gas contamination in a minority of drinking-water wells represent stray-gas contamination alone or, instead, the first sign of potential chemical contamination?
2) What are the constituents and concentrations contained in flowback and produced waste waters, including organics, metals, and naturally occurring radioactive materials (NORMs), particularly outside of the Marcellus Shale region?
3) What are the safest ways to treat waste water from oil and gas operation, maximizing water recycling and reuse (see Water Requirements section above)?
4) What geochemical tools can best differentiate the sources (deeper and shallower hydrocarbon formations) and mechanisms (e.g., leakage from poorly constructed wells, annulus release, migration along faults from depth, or naturally occurring methane) of potential contamination from oil and gas, salts, metals, and radioactivity?
5) What are the best forensic tools for separating the legacy of previous conventional oil and gas extraction and coal mining in surface and ground waters from potential hydraulic-

fracturing and produced-water contaminants?

6. Induced Seismicity

Induced seismicity associated with high-volume hydraulic fracturing and energy extraction has received considerable attention in the U.S. and, especially, the U.K. We briefly examine the evidence for induced seismicity in two steps of unconventional energy extraction: hydraulic fracturing, which rarely induces earthquakes large enough to be felt by people (termed "felt earthquakes"), and deep injection of wastewater, which has caused significantly higher-energy earthquakes. The U.S. National Research Council (101) provides an overview of induced seismicity for energy technologies in general.

Seismic concerns: hydraulic fracturing versus wastewater injection

The reactivation of faults from hydraulic fracturing, wastewater disposal, and other processes such as CO_2 sequestration occurs by increasing the pore pressure and, therefore, reducing the effective stress within a fault zone (e.g., 101,102). This increased pressure allows the elastic energy stored in rock to be released more easily, much like removing weight from a box makes it easier to slide along the floor (103,104). Injecting fracturing fluids or wastewater underground can intersect a fault zone directly (105) or transmit a pulse in fluid pressure that reduces the effective stress on a fault.

Felt seismicity attributed to hydraulic fracturing has been documented in only a handful of cases, none of the earthquakes greater than magnitude (M_w) 4.0 (104). At the Etsho and Kiwigana fields in the Horn River Basin of Canada, for instance, earthquakes up to 3.8 M_w were reported in 2009, 2010, and 2011 (106). In 2011, hydraulic fracturing induced 2.3-2.8-M_w tremors in both the Eola Field in Oklahoma, USA, and in Lancashire, UK (107,108). In some cases faults are targeted directly for operations because fault planes are often associated with natural, highly permeable fracture zones that can increase rates of gas production (109).

Nevertheless, the number of reported examples of induced seismicity attributable to hydraulic fracturing is small compared to other anthropogenic triggers such as mining and dam impoundment (Fig. 6.1).

Induced seismicity associated with wastewater injection is uncommon but generates higher-energy events (110). Many more felt earthquakes have also accompanied wastewater disposal than have accompanied hydraulic fracturing. Between 1967 and 2000, geologists observed a steady background rate of 21 earthquakes M_w 3.0 or greater in the central U.S. per year (104). Starting in 2001 when shale gas and other unconventional energy sources began to grow, the rate rose steadily to ~100 such earthquakes annually, peaking in 2011 with 188; scientists with the U.S. Geological Survey attributed the increased rate primarily to deep-water injection of waste water from oil and gas operations in the region (104).

The magnitude of earthquakes accompanying wastewater injection is also larger than for hydraulic fracturing, with earthquakes up to M_w 5.7 attributed to injection (110). In 2011 alone, earthquakes of M_w 4.0 to 5.3 were linked to deep wastewater injection in locations such as Youngstown (Ohio), Guy (Arkansas), Snyder and Fashing (TX), and Trinidad (Colorado), the latter associated with wastewater disposal from coalbed methane extraction (103,104). The largest earthquake that may have been caused by a nearby deep injection well associated with hydraulic fracturing was a 5.7-M_w event near Prague, Oklahoma in 2011 that destroyed 14 homes and injured two people, one of three at the location ≥5.0 M_w (104,110). In this case, the events may have been primed by an earlier large and distant earthquake (Maule, Chile; M_w=8.8) that unlocked faults critically loaded by wastewater disposal locally (111). Additional research is needed to understand loading and the triggers for induced seismicity more completely. Deep injection of waste water has long been known to induce seismicity. Felt earthquakes associated with any form of fluid injection are uncommon but can reach magnitudes sufficient to damage buildings and injure people. The likelihood of their occurrence can be reduced by basic safeguards (102). Zoback (103) proposed five steps to reduce seismicity induced by wastewater injection, hydraulic fracturing, or any other process that involves pumping fluids underground at high volumes and pressures: 1) avoid injection into active faults or faults in brittle rock; 2) limit injection rates and formation types to minimize increases in pore pressure; 3) install local seismic monitoring arrays when there is seismicity potential; 4) establish protocols in advance to modify operations if seismicity is triggered; and 5) reduce injection rates or abandon wells if seismicity is triggered.

Future research to reduce risks associated with induced seismicity

Additional research into earthquake frequencies and magnitudes should help scientists better predict the potential for large, low-frequency events. Relevant questions for future research include:

1) To what extent and by what mechanism(s) does pressure in a fault increase with injection? Fluid can be pumped directly from the wellbore into the fault (105), but the importance of other potential routes for pressure pulses, such as through new or pre-existing fractures or permeable beds, is less clear (102).
2) What factors most affect the size of felt earthquakes, including the temperature and volume of the fluid injected, injection rates and pressures, and injection depth?
3) Which faults are most likely to reactivate during hydraulic fracturing or wastewater injection?

Accurately mapping faults, stress fields, and historical seismicity will be useful a priori for identifying which faults are critically stressed. Better methods are also needed for real-time monitoring to predict fault reactivation.

7. The air impacts of unconventional resources

The stages of extraction and processing for unconventional energy extraction

Along with the issues surrounding water quantity and quality and induced seismicity, detrimental air emissions and reduced air pollution are both possible with unconventional energy use. Extracting fossil fuel resources from low-permeability formations is an industrial process that emits air pollutants at each stage of operation. Compared to conventional extraction, unconventional natural gas and oil extraction often requires a higher well density (up to 1 well per 10 ha) and more sustained drilling to maintain production levels because of the rapid decline in well production through time (see Section 2). Because drilling can continue for decades across a region, ongoing emissions from production, processing, and transmission likely will continue as well. In contrast to these emissions, replacing coal with natural gas for power generation would substantially reduce emissions of carbon dioxide (CO_2), particulate matter (PM), nitrogen oxides (NOx), sulfur dioxide (SO_2), and metals such as mercury (Hg) associated with electricity generation (see below). Moore et al. (112) provide a comprehensive review of the air impacts of unconventional natural gas development.

Air emissions from unconventional energy extraction and use begin with the months-long construction of the production infrastructure, from well-site preparation to construction of pipeline networks, compressor stations, and processing facilities. Infrastructure preparation, including building access roads, clearing a 3- to 5-acre well pad, and drilling, generates emissions of CO_2, PM, and NOx from diesel-powered truck traffic and off-road equipment. The well-completion step is shorter, lasting days to weeks for a single well and as long as a month or two for multiple wells drilled on one pad. High-power diesel engines are also used for pumping the water, proppant (e.g., sand), and chemicals underground during hydraulic fracturing.

During well completion, natural gas and oil start flowing up the well accompanied by some of the water and chemicals used to fracture the rock. Completion practices and regulations differ by regions and companies. Sometimes the flowback water is pumped into an open wastewater pit dug on site (see above), from which methane and volatile organic compounds (VOCs) can flow to the air. Increasingly, however, flowback mixtures are contained in tanks, sometimes open, sometimes closed, with vapors either vented or flared. Once an unconventional well has been stimulated and completed, production operations are similar to those for conventional oil and natural gas extraction.

Potential emissions during production and processing (e.g., dehydration and separation) include "fugitive emissions" of natural gas or oil vapors from equipment leaks, intentional venting from oil and produced-water storage tanks and wastewater ponds, and incomplete combustion during flaring. Fugitive emissions will reflect the produced-gas composition, including the greenhouse gas methane, varying amounts of VOCs, including aromatics such as the carcinogen benzene and the hazardous air pollutant toluene, and, sometimes, contaminants such as hydrogen sulfide (H_2S). Natural gas produced with natural-gas liquids and oil ("wet gas") will be richer in VOCs than a well producing mostly natural gas ("dry gas"). Natural-gas-powered compressor engines and flaring units at pads and centralized processing and compression facilities also contribute CO_2, CO, NOx, VOCs such as formaldehyde, PM (soot), polycyclic aromatic hydrocarbons (PAHs) and, potentially, SO_2 emissions from H_2S oxidation.

Some evidence suggests that emissions are relatively small for most facilities and components, with a small percentage having large leaks (113,114). Even when most sites have fairly low emissions, however, the regional aggregate of thousands of well pads can sometimes be substantial.

The composition of emissions and their potential impacts

To evaluate the air impacts of unconventional energy extraction locally and downwind, and the effectiveness of mitigation practices, air-quality managers need information about the composition, volume, and sources of emissions. Two approaches have traditionally been used: emissions inventories, including modeling, and atmospheric measurements. Emission inventories typically rely on a handful of chemical composition profiles to estimate fugitive emissions for total VOCs from individual source categories in a producing field (115,116,117). These average profiles are derived from a small number of analyses of local raw natural gas and oil or liquid condensate composition, modeled chemical composition of vapors emitted from oil or liquid condensate storage tanks and dehydrators, or default emissions profiles for engine exhaust provided by the EPA or other sources.

In contrast to these fairly general inventory estimates, detailed chemical measurements of air composition in oil and natural gas basins are increasingly common. Measurements have shown enhanced concentrations of methane, >20 non-methane hydrocarbons, and air toxics 116,118,119). The observed air toxics include H_2S (in sour gas and oil producing regions), methanol (an antifreeze additive), higher-molecular-weight alkanes (C_{6+}), and compounds known or suspected to cause cancer or other health effects, including the aromatics benzene, toluene, ethylbenzene, and xylenes (120,121,122).

An air sampling study in Garfield County, CO, showed that the highest concentrations of >20 potentially toxic hydrocarbons, including aromatics and higher mass alkanes, were found downwind <500 feet from wellpads during flowback operations (121). Gases vented from open-top tanks containing flowback water were the likeliest source (121). By design, open evaporation ponds are used commonly across the western US to dispose of produced waters and are also a source of VOCs and air toxics, although few scientific studies are available on this topic (123,124).

How large are VOC and greenhouse gas emissions and what are their main drivers?

Actual air emissions differ regionally, depending on natural gas and oil composition, separation requirements, and different state regulations (125). Based on industry surveys in 2006, estimates of the fraction of natural gas production vented or flared on federal lands in the western U.S. ranged from 0.34% to 5% (126). In contrast, 29-36% of the natural gas extracted with crude oil from the Bakken shale in North Dakota was vented or flared between May 2011 and December 2012, primarily because of a lack of access to pipelines and processing infrastructure (127).

In Pennsylvania, estimates of NOx, VOCs, PM, and SO_2 emissions from shale gas development and production are poorly constrained, varying by a factor of 2 to 5; nevertheless, natural-gas-powered compressor stations placed every 50-100 miles to push natural gas through gathering and transmission pipelines were estimated to be the largest source of emissions for most pollutants from oil and gas operations in PA (>80% for VOCs, >50% for NOx, >60% for PM and 0-60% for SO_2) (128).

In the official Colorado inventory for the Denver basin, >6,000 oil and condensate storage tanks are responsible for >70% of total VOC emissions from all sources in the region, even with stringent controls in place (129). State estimates of uncontrolled emissions of total VOCs from storage tanks are based on a single emission factor derived from a 2002 modeling study (13.7 lb VOC per barrel of oil or condensate produced). To quantify actual emissions, the uncontrolled emission factor is first multiplied by the production volume of oil or condensate multiplied by four empirical coefficients: estimated control efficiency of flares (95%), rule penetration in the region (92.56%, the fraction of operations that have implemented the required mitigation), rule effectiveness (80%) and capture efficiency (75%, with the remaining 25% of the vapors being vented) (129,130). An intensive airborne measurement campaign in May of 2012 showed that the state estimate of total VOC emissions from oil and gas operations in the Denver Basin was only half the estimate obtained from actual field measurements (131).

Total methane emissions associated with natural gas extraction regionally and nationally remain uncertain and are a topic of considerable research (132). Official EPA estimates of methane emissions annually from natural gas production operations have fluctuated greatly over the last decade, ranging between <0.2% (133) and 1.5% (134,135) of gross natural gas production nationally, and before losses during centralized processing, transmission, and distribution are included. Based on direct measurements at 190 natural gas production sites across the U.S. (out of 514,637), Allen et al. (136) estimated that national emissions from natural gas production operations in 2011 were ~ 0.42% of gross production, slightly lower than the estimate of 0.49% based on the 2013 EPA inventory and EIA production statistics. They found that equipment leaks and pneumatic devices at production sites were the largest methane sources from production operations nationally. Their detailed measurements also revealed large differences in process-level emissions across regions and the presence of large emitters within most regions, highlighting an opportunity to reduce high-emission sources.

In contrast to these bottom-up emission measurements and inventory estimates, recent atmospheric studies using airborne and tall-tower measurements have found substantially larger regional-scale leakage rates in two producing basins studied in the western U.S. Karion et al. (119) estimated that 55 000 ± 15 000 kg CH_4 hr^{-1} leaked to the atmosphere in the Uinta Basin, a rate corresponding to 6.2%−11.7% of total natural gas production in the region. Pétron et al. (131) measured ~4% leakage in the oil and gas producing Denver Basin (CO). In these two basins, at least, aggregated methane emissions appear to be substantially larger than the USEPA 2013 estimated 1.4% total leak rate for natural gas systems from wells to end-users.

Research is also underway to examine methane leakage during natural gas transmission and distribution. There are ~2.2 million miles of natural gas distribution mains in the U.S. and hundreds of thousands of miles of higher-pressure transmission lines. Based on EPA inventories, losses during transmission and distribution are an estimated 0.7% of total production, the largest loss of any step in the natural gas supply chain (115). Other estimates of the amount of gas lost during natural gas transport include 1.4% for Russia (137) and, several decades ago, 5.3% for the U.K. (138). In the U.S., 1.6% of natural gas that enters a company's distribution network on average is never metered (based on data from 174 gas-distribution companies with >1,000 pipeline miles in the U.S.), an amount that sets an upper bound on the losses during distribution (139).

New methane mapping technologies have allowed researchers to publish the first maps of pipeline leakage of natural gas across cities (139,140). Boston and Washington, D.C., had ~3,400 and ~5,900 leaks across their 800 and 1,500 road miles, respectively (Figure 7.1) (139,140). The presence of cast-iron piping, some of it more than a century old, was the number one predictor of leaks across the distribution system (140). Companies range substantially in how aggressively they replace their cast-iron pipelines (141), ranging from only two years remaining to full replacement in Cincinnati (Duke Energy of Ohio) to 140 years before full replacement in Baltimore (Baltimore Gas and Electric) (Figure 7.1). A creative partnership in 2001 between the distribution companies in Ohio and the Ohio Public Utility Commission, which sets cost recovery rates for natural gas pipeline repairs, led to the most rapid replacement of cast-iron pipes in the U.S. over the past decade.

Two inverse modeling studies (142,143) constrained with atmospheric measurements and a recent synthesis (114) suggest that total methane emissions from anthropogenic activities in the U.S., including oil and gas production, were ~50% higher than EPA estimates (115). Miller et al. (143) identified the largest discrepancy in the south-central US and suggested that emissions from oil and gas operations in the region could be underestimated by as much as a factor of five. Although more work is needed, a consensus is emerging that methane losses are larger than current EPA estimates. Whether they are large enough to offset the advantage in methane's combustion efficiency compared to coal in electricity generation is still unclear (~3.2% lost gas in total) (144). Even if they are, better information on the sources of leaks will help reduce future leakage, reduce GHG emissions, and improve local and regional air quality.

To what extent will hydraulic fracturing and unconventional resource extraction alter total greenhouse gas emissions in the future? Lower energy prices from increased supply would likely increase energy consumption overall and encourage switching to natural gas from other energy sources, including coal, nuclear and renewables. Based on the National Energy Modeling System (NEMS) projections from the U.S. Energy Information Administration, Newell and Raimi (145) concluded that oil and gas pricing would fall substantially in the U.S. under a "high natural gas and oil resource" scenario compared with a reference scenario. Total energy use would be ~3% higher as a result, but greenhouse gas emissions would still be ~0.5% lower than in the reference scenario, largely due to natural gas displacement of coal for electricity generation. They and other researchers concluded that increased natural gas supply might decrease greenhouse gas emissions slightly in the U.S. and globally but is unlikely to alter global greenhouse gas concentrations substantially (145,146,147). The possibility of increased total emissions depends in part on the extent to which cheaper natural gas and oil reduce the market penetration of renewables and nuclear power.

Unconventional energy use can improve or impair air quality

Unconventional energy development has the potential to decrease emissions of some pollutants, particularly when replacing coal with natural gas for power generation (148). As stated earlier, natural gas burned for electricity generates half the CO_2 that coal does during combustion. If leaks of natural gas can be minimized, the greenhouse gas benefits of this transformation would be substantial, particularly as a bridge to a renewables-based future. Approximately 1-3 kg NO_x per MWh and 2-10 kg SO_2 per MWh are emitted from coal-fired power plants most likely to be replaced by natural gas (149). Burning natural gas emits almost no SO_2 or mercury (Hg) and less NO_x and particulates than burning coal does. Natural gas burning also does not generate billions of tons of toxic coal ash each year that can impact water and air quality and human health. The air quality benefits from electricity generation are substantial compared to coal-fired power.

Reducing leaks and emissions associated with unconventional natural gas and oil development will also help improve air quality and safety. The potential impacts of oil and natural gas operations are affected by the location, magnitude, and composition of emissions and by local weather. In the atmosphere, NOx, VOCs, and SO_2 emitted by oil and gas sources can contribute to the formation of secondary pollutants such as fine particles and ozone. Ozone, VOCs and PM monitoring in or near oil and gas fields in Wyoming, Utah, and Colorado have identified rural and urban regions where emissions from oil and gas operations are contributing substantially to high pollution episodes (122,150,151).

Exposure studies to specific air contaminants released during oil and gas development are rare. McKenzie et al. (121) conducted a health impact assessment based on measured VOC concentrations in Garfield County, CO, showing that residents living < ½ mile from gas wells were at greater risk for health effects from natural gas development than were residents living farther away. Another set of air samples collected at a 16-well pad in Garfield County showed elevated levels of VOCs, some at levels with multiple potential health effects, as well as methylene chloride, a toxic solvent used on-site (152). Colborn et al. (153) researched > 300 chemicals used in natural gas operations and called for more complete disclosure to inform air and water monitoring efforts. Esswein et al. (154) showed that wellpad workers at hydraulic fracturing sites were exposed to silica dust at levels up to 10-times higher than the NIOSH Recommended Exposure Limit, even while wearing dust masks.

Systematic studies to assess air quality impacts in national parks in the US are limited but of increasing concern (155,156). Emissions from natural gas flaring in North Dakota may be contributing to fine particle formation (e.g., ammonium nitrate, ammonium sulfate and black carbon) and impairing visibility in Theodore Roosevelt National Park, a Class 1 area protected under the Clean Air Act (157).

Traditionally, emission inventories and atmospheric dispersion and chemistry models have been used to evaluate the impacts of oil and gas activities on air quality (155,158). These tools are also a central piece in State Implementation Plans (SIP) to restore regional air quality compliance with federal standards (129) and in Environmental Impact Statement (EIS) studies to reduce the consequences of future oil and gas development. As discussed above and by other authors (159), the accuracy of these emission inventories is often questionable. Systematic research should be undertaken to evaluate current inventories and to improve them, with the objective of reducing emissions further.

How effective are mitigation practices?

Large knowledge gaps still exist for potential and actual emissions. Here, we focus on one example of successful mitigation for methane emissions during the natural gas well completion step using green completion configurations (Figure 7.2). Allen et al. (136) measured total methane emissions during flowback operations at a subset of 24 hydraulically fractured gas wells (out of 8,077 new U.S. gas wells fractured in 2011). Flowback events lasted between 4 and ~300 hours. Reduced emissions configurations for completions (i.e., “green completions”) were used at 15 of the 24 wells.

The largest reduction in emissions occurred at three wells that used the most advanced completion equipment to separate natural gas from flowback water and send it to the gas pipeline (Figure 7.2). Measured emissions at these three wells were 2-3 Mcf methane or <0.01% of the estimated potential emissions. Operators at twelve other wells also used some green-completion approaches. They sent the initial flowback water to open-top tanks. Within a few hours they separated the water from the gas, which was either flared or fed to the sales line. In this case, actual emissions ranged from 0.5 to 800 Mcf CH_4, still lower than each well's estimated potential emissions (22 Mcf to 54,000 Mcf) if all the gas had been vented during the flowback period (136). The data illustrate the effectiveness of green-completion activities and the enormous spread in potential and actual emissions (Figure 7.2).

The EPA New Source Performance Standards (NSPS) (135) issued in 2012 require green completions, where technically feasible, at all new gas wells that are hydraulically fractured by 2015 and also require controls on new oil and condensate storage tanks with potential emissions of >6 tons/yr. These rules should substantially reduce methane and VOC emissions in the many states where controls are not yet required.

Research needs

1. Emission inventories are the tool of choice for environmental impact assessments and air quality management. Systematic and independent efforts at regional and national scales are needed to evaluate some of the underlying assumptions of inventories, increase their accuracy, track changes through time, and assess the effectiveness of emission-reduction programs.
2. Long-term monitoring and short-term intensive studies of air quality in and near oil and gas fields will provide independent measurements with which to evaluate the emissions and potential health impacts from fossil fuel extraction and distribution.
3. The potential for reducing emissions of methane, ozone precursors and air toxics is substantial. Updated systems design and more effective mitigation technologies can help

reduce emissions, as will more effective leak-detection and repair programs. Emissions from aging, abandoned, or plugged wells remain largely unknown.

4. A lack of single and cumulative exposure and health studies for workers and residents near hydraulically fractured oil and gas wells severely limits conclusions about any potential health impacts. Health-related studies are one of the biggest gaps in unconventional energy research.

8. Conclusions

Throughout this paper we have presented future research needs and opportunities. Rather than repeating them, we end with a brief discussion of principles for helping to reduce the environmental footprint of hydraulic fracturing and unconventional energy extraction in general.

One recommendation is for greater transparency from companies and regulating agencies (160,161). Although companies and most states in the U.S. now provide some information about the chemicals used in hydraulic fracturing (e.g., the frackfocus.org disclosure registry), approximately one in five chemicals is still classified as a trade secret. Phasing out the use of toxic chemicals entirely would boost public confidence in the process further. Other examples of transparency are to disclose data for mud-log gases and production-gas and water chemistry to regulatory agencies and, ideally, publicly, and to end the use of non-disclosure clauses for legal settlements with homeowners over issues such as groundwater contamination. The challenge is to balance the needs of companies with those of public safety.

One of the biggest research gaps today is the need for short- and long-term studies of the potential effects of unconventional energy extraction on human health. Virtually no comprehensive studies have been published on this topic (76,162,163,164). Nevertheless, decisions on when and where to drill are already being decided based on this issue. France and Bulgaria have bans on hydraulic fracturing that are directly associated with perceived health risks. In the U.S., New York State has a moratorium on high-volume hydraulic fracturing until a review of the potential health effects is completed.

The importance of baseline studies prior to drilling is increasingly recognized as a critical need. Pre-drilling data would include measurements of ground- and surface-water attributes, air quality, and human health. In this review, we have not covered the many critical issues of social and community impacts of the unconventional energy boom. One suggestion is to create a baseline community needs and assets assessment (CNAA) to address potential social impacts (164). The CNAA should identify what jobs will be available to local workers, develop citizen stakeholder forums and reporting mechanisms, update transportation planning and safety training, and implement strong consumer protections (164).

A fourth recommendation is to place particular focus on surface and near-surface activities rather than on what occurs deep underground. Surveys of groundwater contamination suggest that most incidents originate from the surface, including faulty wells, wastewater disposal, and spills and leaks from surface operations. These problems may be reduced through best management practices or regulations. There are additional risks associated with hydraulically fractured wells connecting with old, abandoned wells that are not properly sealed. Increased attention to improving well integrity in shale gas operations and considering potential interactions between hydraulic fracturing and abandoned wells would help reduce environmental risks and impacts.

Lastly, we believe that state and federal governments are under-investing in legacy funds in the U.S., the European Union, and elsewhere for addressing future problems accompanying the unconventional energy boom. Drilling millions of new oil and natural gas wells will inevitably lead to future issues (e.g., see Well Integrity section above). Pennsylvania, for instance, currently has no severance tax on oil and gas production and took in only ~$200 million yearly in impact fees from 2011 to 2013. Most of this money was used to fund county and state operations, with $16 million from the fund allocated to current environmental initiatives in 2012 and 2013, including habitat restoration, flood protection, and abandoned well plugging. To place these numbers in the broader context, PA produced >$10 billion worth of natural gas in 2013 alone. At this rate, very little money will be available years to decades in the future when Marcellus and other wells age, leading to the kinds of shortfalls that some states face today from past industrial activities.

The biggest uncertainty of all is what the future energy mix across the world will be. Compared to coal, natural gas has many environmental benefits, and replacing old coal-fired power plants with new natural gas plants makes sense. However, natural gas and shale oil are still fossil fuels, releasing greenhouse gases when burned. Will natural gas be a bridge fuel to a cleaner, renewables-based future? How long will the bridging take? Will natural gas be used to supplement renewables in the future or instead become the world's primary energy source? Will the unconventional energy boom lower energy prices, making conservation less valuable and slowing the adoption of renewables? Societies face difficult choices that can be informed by strong, inter-disciplinary research. The answers to these questions will drive earth and environmental sciences for decades.

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Table 3.1. Water use, estimated ultimate recovery (EUR), and water intensity for shale and tight sandstone gas.

Resource Play	Frack Water per Well (Liters gallons)	EUR GJ, Bcf	Water Intensity for Fracking (L/GJ)	Water Intensity for Extraction (L/GJ)	Water Intensity for Refracking (L/GJ)	Wastewater Generated Per Well[h] (L gallons)
Bakken[a]	8,700,000 2,300,000	—	—	—	—	—
Barnett[b]	10,600,000 2,800,000	2.0, 1.9	5.2	6.1	32	12,400,00 3,300,000
Denver[c]	10,600,000 2,800,000	1.2, 1.1	9.1	10.8		4,000,000 1,100,000
Fayetteville[d]	19,700,000 5,200,000	2.3, 2.1	8.7	9.6	—	—
Haynesville[e]	21,500,000 5,670,000	2.6, 2.5	8.2	8.9	—	—
Marcellus[f]	14,800,000 3,900,000	1.9, 1.8	7.8	8.8	—	5,200,000 1,400,000
Woodford[g]	15,700,000 4,160,000	2.3, 2.2	6.8	7.6	—	—
Average	**14,500,000 3,800,000**	**2.1, 1.9**	**7.6**	**8.6**	**32**	**7,200,000 1,900,000**

[a] Data for the Bakken Shale (165).
[b] Data for the Barnett Shale (20,27,29,40).
[c] Data for the Denver Basin (37,41).
[d] Data for the Fayetteville Shale (42).
[e] Data for the Haynesville Shale (20,43).
[f] Data for the Marcellus Shale (37,39,44).
[g] Data for the Woodford Shale (45,46).
[h] Data for the first four years of wastewater production; amounts will increase somewhat as the wells age.

Table 3.2 Water intensity for extraction, processing, and electricity generation of different energy sources.

Energy Source	Water for Extraction (L/GJ, Gallons/MMBTU)	Water for Extraction & Processing (L/GJ, Gallons/MMBTU)	Water Consumption Intensity of Electricity Generation (L/MWh)[a,b,c]
NG, Conventional[d]	0.7, 0.2	1.9, 6.7	—
NG, Unconventional[e]	8.6, 2.4	15, 4.1	—
NG Combined Cycle (once through)	— —	— —	520
NG Combined Cycle (closed loop)	— —	— —	850
Pulverized Coal (once through)[a,b,c]	9.0, 2.5	27, 7.5	1400
Pulverized Coal (closed loop)[a,b,c]	9.0, 2.5	27, 7.5	1900
Saudi Arabian Crude[a]	79, 22	110, 32	—
Oil Shale[f]	200, 57	240, 67	—
Oil Sands[a]	—	110, 31	—
Nuclear (once through)[a,b,c]	14, 4	47, 13	1700
Corn Ethanol (unirrigated)[a,b]	300, 83	430, 119	2100
Corn Ethanol (irrigated)[a,b]	14,000, 3,800	14,000, 3,800	16000
Solar Photovoltaic[a,b,c]	0, 0	0, 0	10
Concentrated solar power[a,b,g]	— —	— —	3100
Wind[a,b,c]	0, 0	0, 0	4

[a] Data from Mielke et al. (47)
[b] Data from Fthenakis and Kim (48)
[c] Data from Macknick et al. (49)
[d] Data from Grubert et al. (50) and Clark et al. (42).
[e] Data from this study and Clark et al. (42).
[f] Data from Mangmeechai et al. (51)
[g] Hybrid trough

Figure 1.1 Basins with assessed shale gas and shale oil resources as of June, 2013 (5). The figure does not show additional tight sand formations.

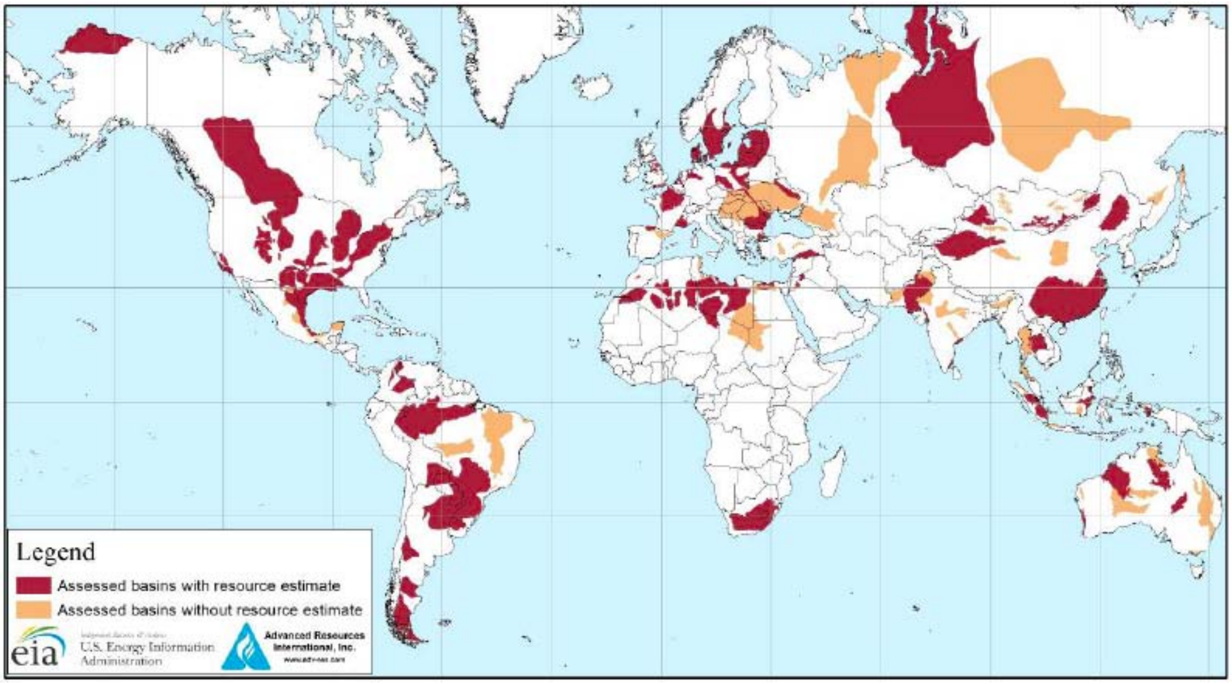


Figure 2.1: Median Initial Production (IP) rate (Mcf/day) by year for Barnett Shale horizontal wells by vintage from 2005 to 2012 [19]. Note drop in IP in 2012.

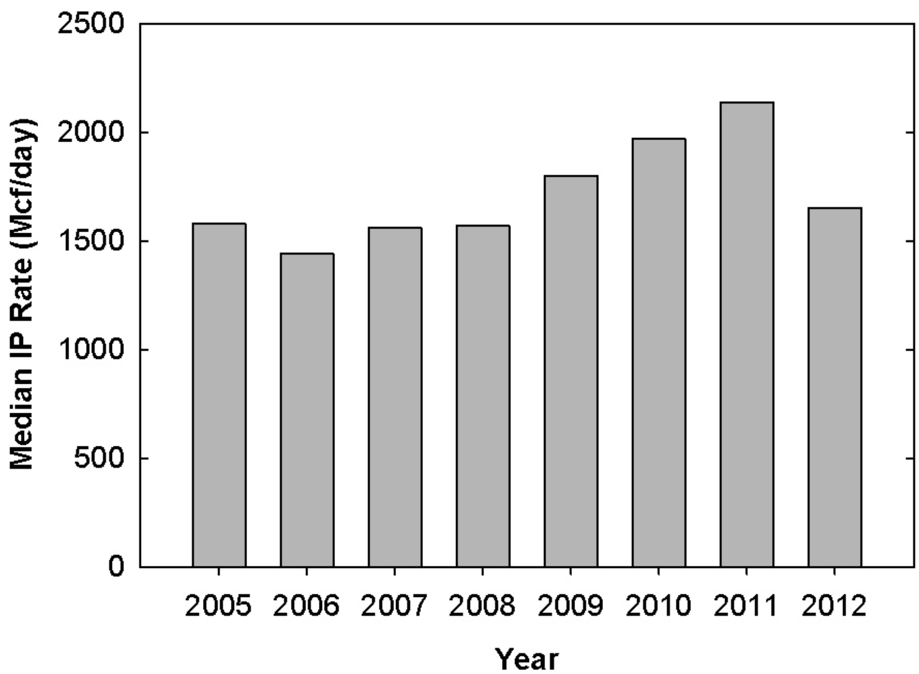


Figure 2.2: Normalized aggregate production declines for oil from Bakken shale horizontal well ensembles from 2009 to 2013 (19).

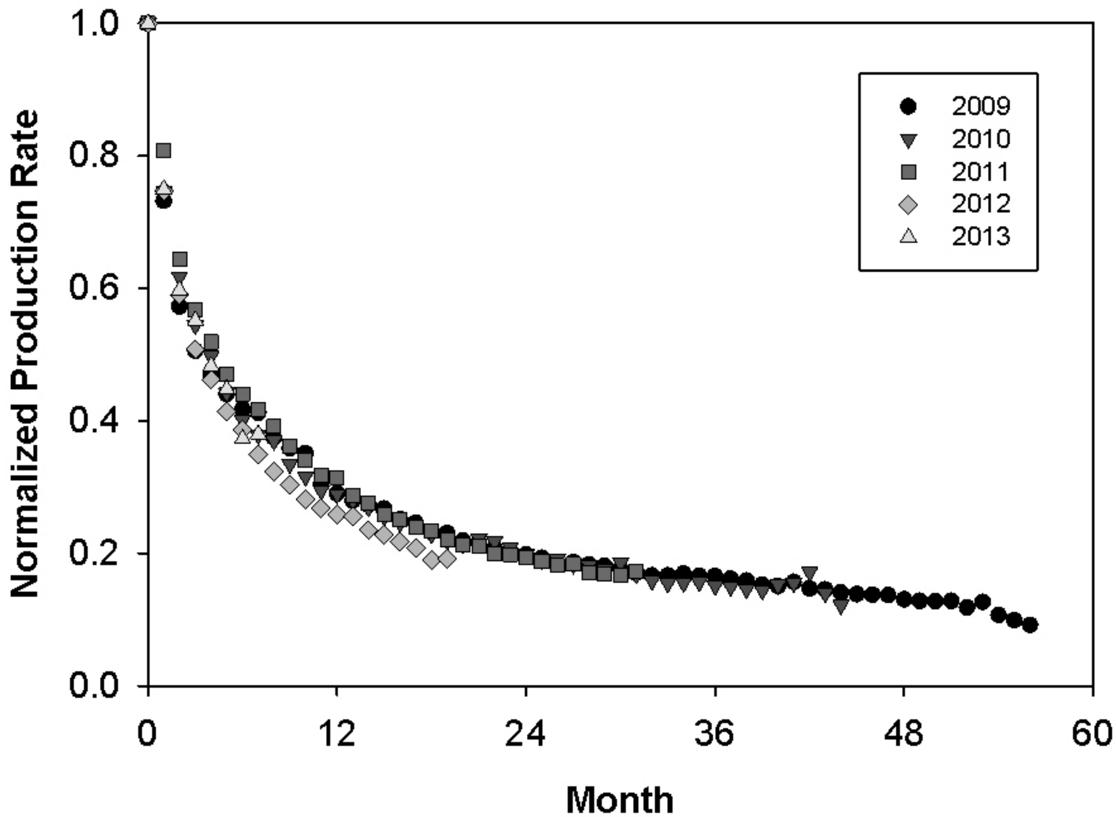


Fig 6.1. Record of 199 published induced earthquakes that have occurred since 1929. Updated from Davies et al. (102).

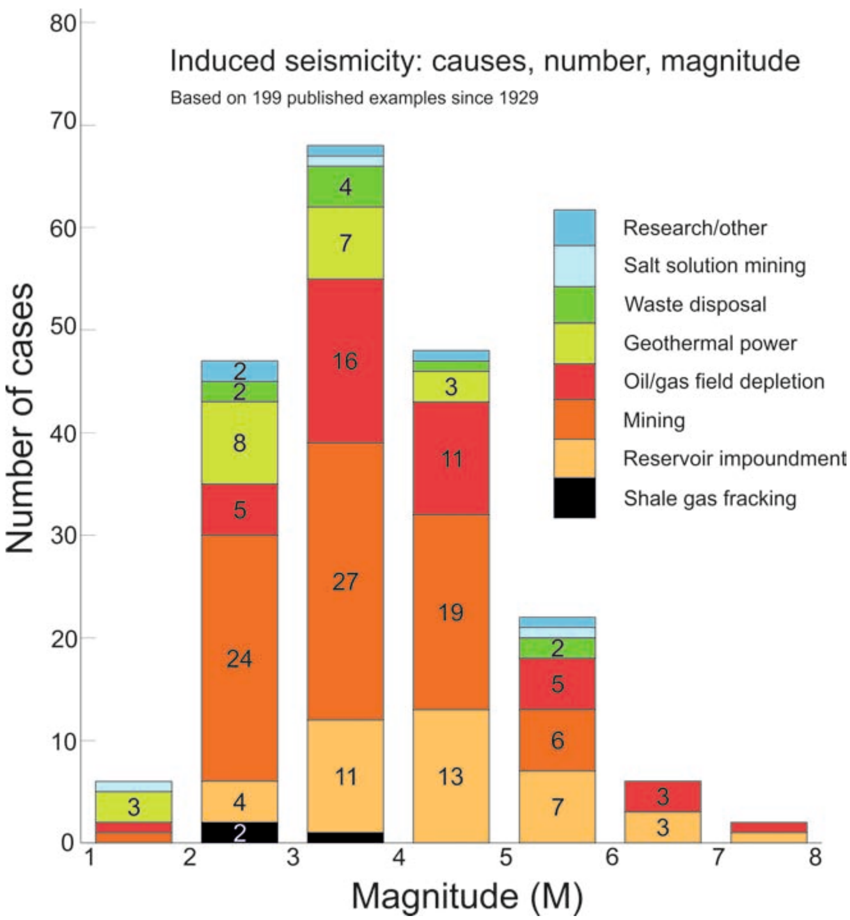
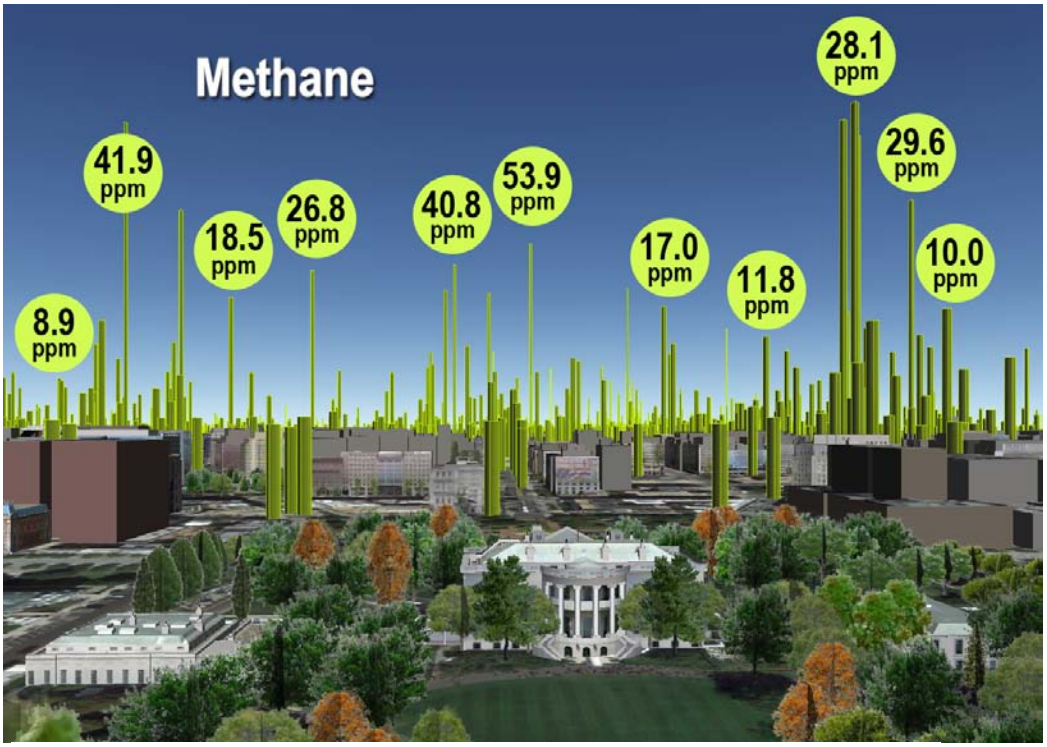


Figure 7.1. Upper panel: Methane concentrations from natural gas pipeline leaks near the White House in Washington, D.C.(data from Jackson et al. (140)). Because some leaks are closer than others, the heights of the bars do not scale perfectly to concentrations from this perspective. Lower panel: Number of years remaining to replace all cast-iron pipes in different U.S. cities based on actual replacement rates from 2004 to 2013.



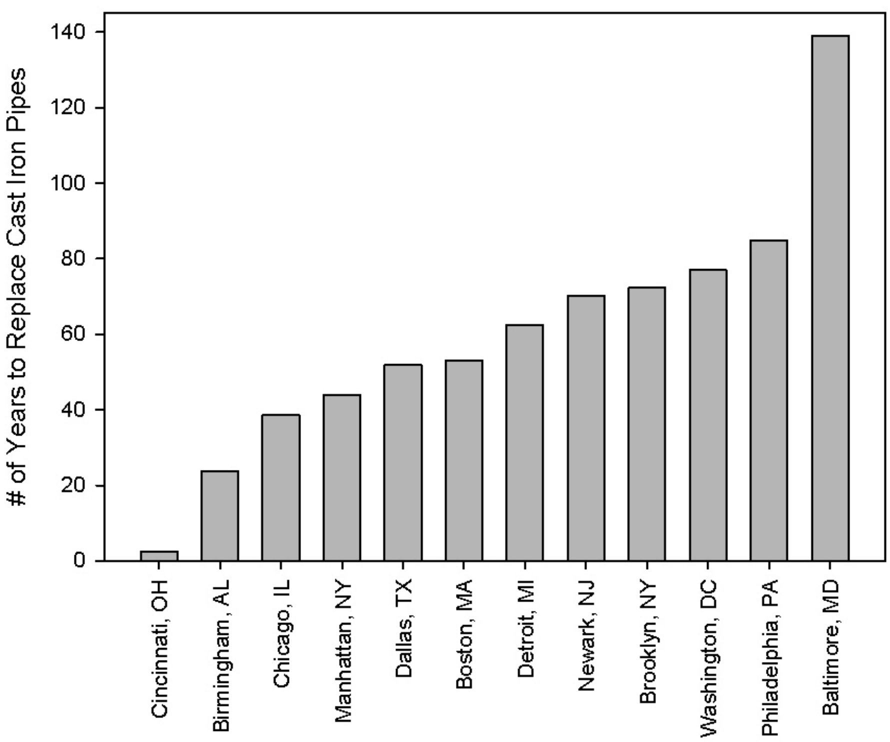
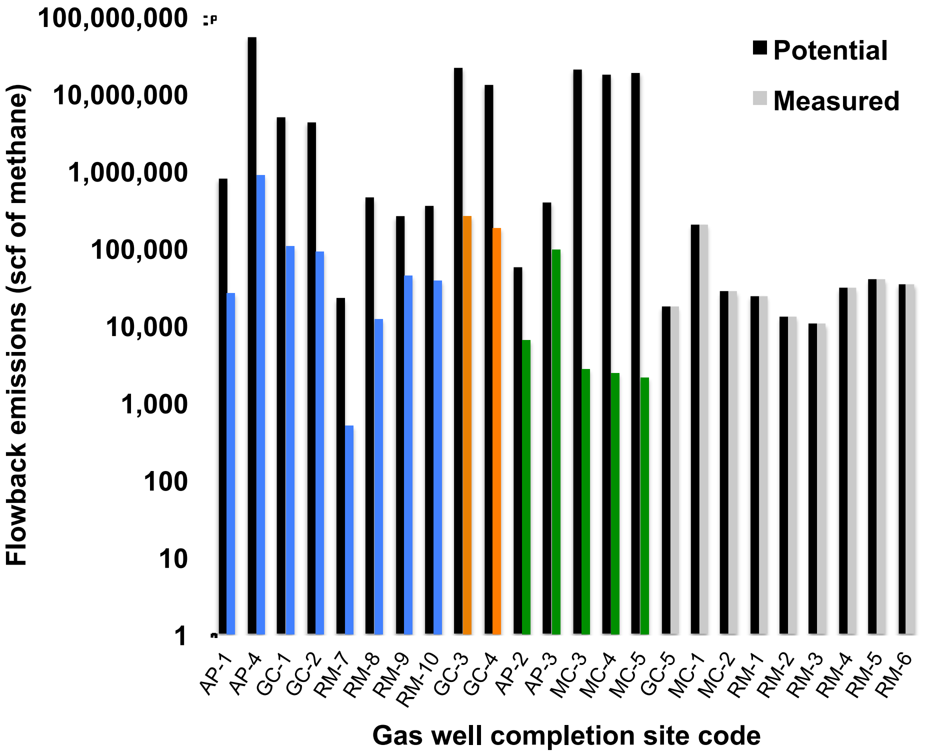


Figure 7.2. Potential (black) and actual (colored or gray) methane emissions for 24 completion flowback events studied by Allen et al. (136). Some levels of emission controls were used at 15 sites with 3 configurations of "green completion" while 9 sites (shown in gray) had no controls at all during the entire flowback event. See Allen et al. (136) for more details on the flowback configurations and emissions results.



Flowback configurations
with emission controls

Flowback configuration
without emission controls