Text Box 6-3 (continued). Stray Gas Migration.

there than in the southern part of the state. Christian et al. (2016), Mcphillips et al. (2014), Molofsky et al. (In Press), and Wilson (2014) all identified correlations between the presence of methane in water wells and certain geologic, hydrographic, and geochemical parameters, such as valley locations and the presence of coal beds.

Stray gas migration can be a technically complex phenomenon to study, in part because there are many potential sources and routes for migration. When a particular site lacks detailed monitoring data, especially baseline measurements, determination of sources and migration routes is complicated and challenging. Examining the concentrations and isotopic compositions of methane and higher molecular weight hydrocarbons such as ethane and propane can aid in determining the source of stray gas (Tilley and Muehlenbachs, 2012; Baldassare, 2011; Rowe and Muehlenbachs, 1999). Isotopic composition and methane-to-ethane ratios can help determine whether the gas is thermogenic or biogenic in origin and whether it is derived from shale or other formations (Gorody, 2012; Muehlenbachs et al., 2012; Barker and Fritz, 1981). Isotopic analysis can also be used to identify the strata where the gas originated and provide evidence for migration mechanisms (Darrah et al., 2014). For example, isotope-based techniques have been used to investigate the potential sources of methane in drinking water wells in Dimock, Pennsylvania (Hammond, 2016), and Jackson et al. (2013c) found evidence of potential Marcellus gas contamination in some Pennsylvania drinking water wells using stable-isotopic ratios, while other wells in the area appeared to be contaminated by shallower sources (not associated with gas production).

However, determining the source of methane does not necessarily establish the migration pathway. Multiple researchers (e.g., Siegel et al., 2015; Jackson et al., 2013c; Molofsky et al., 2013; Révész et al., 2012; Osborn et al., 2011) have described biogenic and/or thermogenic methane in groundwater supplies in Marcellus gas production areas, although the sources and pathways of migration are generally unknown. Well casing and cementing issues may be an important source of stray gas problems (Jackson et al., 2013c); however, other potential subsurface pathways are also discussed in the literature. Zhang and Soeder (2016) suggested that air-drilling practices used to construct the vertical component of gas wells can affect methane migration by creating groundwater surges in the shallow subsurface. The type of well may also play a role; in one study, deviated gas wells in Canada were three to four times more likely than vertical wells to have evidence of gas migration to the surface (Jackson et al., 2013b).

In the absence of data on specific pathways, some researchers have investigated geographic correlations. Jackson et al. (2013c) and Osborn et al. (2011) found that thermogenic methane concentrations in well water increased with proximity to Marcellus Shale production sites. In contrast, Molofsky et al. (2013) found the presence of gas to be more closely correlated with topography and elevation, and (Siegel et al., 2015)found no correlation between methane in groundwater and proximity to production wells. Kresse et al. (2012) investigated methane concentration and isotopic geochemistry in shallow groundwater in the Fayetteville Shale area, and found no evidence that the water had been influenced by shale gas activities. Similarly, Li and Carlson (2014), while not ruling out potential leakage pathways from deeper reservoirs, found no systematic correlation between increasing well drilling density in the Wattenberg Field in Colorado and near-surface stray gas concentrations.

EPA conducted retrospective case studies to investigate stray gas in northeastern Pennsylvania and the Raton Basin of Colorado. As described in the northeastern Pennsylvania case study report, *Retrospective Case Study in Northeastern Pennsylvania: Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (U.S. EPA, 2014f), 27 of 36 drinking water wells within the study area (75%) contained elevated methane concentrations. For some of the wells, the EPA concluded that the methane (of both thermogenic and biogenic origin) was naturally occurring gas, not attributable to gas exploration activities. In others, it

(Text Box 6-3 is continued on the following page.)

Text Box 6-3 (continued). Stray Gas Migration.

appeared that methane had entered the water wells following well drilling and hydraulic fracturing. In most cases, the methane in the wells likely originated from intermediate formations between the production zone and the surface; however, in some cases, the methane appears to have originated from deeper layers such as those where the Marcellus Shale is found (U.S. EPA, 2014f). The Raton Basin case study examined the Little Creek Field, where potentially explosive quantities of methane entered drinking water wells in 2007. As described in the EPA's *Retrospective Case Study in the Raton Basin, Colorado: Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (U.S. EPA, 2015k), the methane was found to be primarily thermogenic in origin, modified by biologic oxidation (U.S. EPA, 2015k). Secondary biogeochemical changes related to the migration and reaction of methane within the shallow drinking water aquifer were reflected in the characteristics of the Little Creek Field groundwater (U.S. EPA, 2015k).

The sources of methane in the two studies could be determined with varying degrees of certainty. Narrowly identifying the most likely pathway(s) of migration has been more difficult. In northeastern Pennsylvania, while the sources could not be definitively determined, the Marcellus Shale could not be excluded as a potential source in some wells based on isotopic signatures, methane-to-ethane ratios, and isotope reversal properties (U.S. EPA, 2014f). The Pennsylvania Department of Environmental Protection (PA DEP) cited at least two operators for failure to prevent gas migration at wells within the study area. Evidence cited by the state included isotopic comparison of gas samples from drinking water wells, water bodies, and gas wells; inadequate cement jobs; and sustained casing pressure (although, under Pennsylvania law, oil or gas operators can be cited if they cannot disprove the contamination was caused by their well using pre-drilling samples) (Llewellyn et al., 2015). A separate study (Ingraffea et al., 2014) showed that wells in this area had higher incidences of mechanical integrity problems relative to wells in other parts of Pennsylvania. While the study did not definitively show that stray gas was linked to construction problems, it does imply that there may be more difficulties in constructing wells in this area. In the Little Creek Field in the Raton Basin, the source of methane was identified as the Vermejo coalbeds. While the nature of the migration pathway is unknown, modeling suggests that it could have occurred along natural rock features in the area and/or along a gas production well (U.S. EPA, 2015k). Because the production wells were shut in shortly after the incident began, the wells could not be inspected to determine whether a mechanical integrity failure in the wellbore was a likely cause of the migration.[1]

These two case studies illustrate the considerations involved with understanding stray gas migration and the difficulty in determining sources and migration pathways. To more conclusively determine sources and migration pathways, studies in which data are collected on mechanical integrity and hydrocarbon gas (e.g., methane, ethane) concentrations both before and after hydraulic fracturing operations, in addition to the types of data summarized above, would be needed.

In the Wattenberg Field in Colorado, Li et al. (2016a) investigated the concentration of various ions in water from an uncontaminated aquifer, an aquifer containing thermogenic methane, and produced water from oil and gas wells to understand the transport of aqueous- and gas-phase fluids at the site. The results indicated that the methane that was contaminating water wells was not transported with aqueous phase fluids; the authors suggested that this can provide evidence for migration mechanisms, because certain pathways (e.g., migration from improperly sealed well

[1] Shutting in a well refers to sealing off a well by either closing the valves at the wellhead, a downhole safety valve, or a blowout preventer.

casings) could potentially result in gas-phase but not aqueous-phase migration. See Text Box 6-4 for another example of an investigation into the occurrence of stray gas in drinking water wells.

Text Box 6-4. Parker County, Texas.

Peer-reviewed studies have been conducted within the Barnett Shale area, which includes Parker County, Texas. These include sampling studies of private water well composition, noble gas content, and isotopic signatures of natural gases, as well as analysis of existing water sample data. Disagreement exists about the origin of the increased natural gas in private well water.

One suggested possibility is that production casing annuli could serve as a migration pathway for natural gas from formations located between the Barnett and the Trinity to reach overlying intervals (including the Trinity aquifer) (Darrah et al., 2014). However, using measurements of hydrocarbon and noble gas isotopes, Wen et al. (2016) suggests the source of methane in the Trinity aquifer water wells is directly from the underlying Strawn Formation and not from pathways associated with the gas production wells although the timing of methane entry into the Strawn is not known.

6.2.2.2 Pathways Related to Cement

Fluid movement can result from inadequate well design or construction (e.g., cement loss or other problems that arise in cementing of wells) or degradation of the cement over time (e.g., corrosion or the formation of microannuli), which may, if undetected and not repaired, cause the cement to succumb to the stresses exerted during hydraulic fracturing.[1] The well cement must be able to withstand the subsurface conditions and the stresses encountered during hydraulic fracturing operations. This section presents data and information that can help indicate that pathways within the cement are present or allowing fluid movement.

Uncemented zones can allow fluids or brines to move into drinking water resources. If a fluid-containing zone is left uncemented, the open annulus between the formation and casing can act as a pathway for migration of that fluid. Fluids can enter the wellbore along any uncemented section of the wellbore if a sufficient pressure gradient is present. Once the fluids have entered the wellbore, they can travel up along the entire uncemented length of the wellbore as shown in Pathway 2 of Figure 6-4.

As mentioned in Section 6.2.2.1, Fleckenstein et al. (2015) found uncemented gas zones to be a significant factor in barrier failures in wells in the Wattenberg basin in Colorado. A report on the Pavillion field by AME (2016) identified a similar set of risk factors for fluid migration including: uncemented production casing, shallow surface casing, and the presence of both an intermediate pressurized gas zone and a permeable groundwater zone encountered in the same production wellbore.

Because of their low density and buoyancy, gaseous fluids such as methane will migrate up the wellbore if an uncemented wellbore is exposed to a gas-containing formation. Gas may then be able

[1] Microannuli are very small openings that form between the cement and its surroundings and that may serve as pathways for fluid migration to drinking water resources.

to enter other formations (including drinking water resources) if the wellbore is uncemented and the pressure in the annulus is sufficient to force fluid into the surrounding formation (Watson and Bachu, 2009; Harrison, 1985). The rate at which the gas can move will depend on the difference in pressure between the annulus and the formation (Wojtanowicz, 2008). See Chapter 10 for a discussion of practices, such as well testing, that can decrease the frequency of such gas migration that could impact drinking water quality.

In several cases, poor or failed cement has been linked to stray gas migration (Text Box 6-3). A Canadian study found that uncemented portions of casing were the most significant contributors to gas migration (Watson and Bachu, 2009). The same study also found that 57% of all casing leaks occurred in uncemented segments. In the study by Darrah et al. (2014) (Section 6.2.2.1), using isotopic data, four clusters of gas contamination were linked to poor cementing. In three clusters in the Marcellus and one in the Barnett, gas found in drinking water wells had isotopic signatures consistent with intermediate formations overlying the producing zone. This suggests that gas migrated from the intermediate units along the well annulus, along uncemented portions of the wellbore, or through channels or microannuli.

Cementing of the surface casing is the primary aspect of well construction intended to protect drinking water resources. Most states require the surface casing to be set and cemented from the level of the lowermost drinking water resource to the surface (GWPC, 2014). Most wells—including those used in hydraulic fracturing operations—have such cementing in place. Among the wells represented in the Well File Review, surface casing was found to be fully cemented in 93% of wells. Of these, an estimated 55% of wells (12,600 wells) were cemented to below the operator-reported protected groundwater resource; in an additional 28% of wells (6,400 wells), the operator-reported protected groundwater resources were fully covered by the next cemented casing string.[1,2,3] A portion of the annular space between the casing and the operator-reported protected groundwater resources was uncemented in at least 3% of wells (600 wells) (U.S. EPA, 2015n).[4]

Improper placement of cement can lead to defects in external mechanical integrity. For example, an improper cement job can be the result of loss of cement during placement into a formation with

[1] In the Well File Review, protected groundwater resources were as reported by well operators. For most wells represented in the Well File Review, protected groundwater resources were identified based on state or federal authorization documents. Other data sources used by well operators included aquifer maps, data from offset production wells, open hole log interpretations by operators, operator experience, online databases, and references to a general requirement by the oil and gas agency.

[2] The research that the EPA reviewed used various terms to describe subsurface water resources that are used/potentially used for drinking water. Where another term is relevant to describing the author's research, we use that term; for the purpose of this assessment, all of these terms are considered to fall within the assessment's definition of "drinking water resources." See Chapter 2 for additional information on the definition of a drinking water resource.

[3] 6,400 wells (95% confidence interval: 500 – 12,300 wells).

[4] 600 wells (95% confidence interval: 10 – 1,800 wells). The well files representing an estimated 8% of wells in the Well File Review did not have sufficient data to determine whether the operator-reported protected groundwater resource was uncemented or cemented. In these cases, there was ambiguity either in the depth of the base or the top of the operator-reported protected groundwater resource. An additional 6% of wells represented had surface casing set below the reported protected groundwater resource depth, but because the protected groundwater depth was based on a nearby water well depth, the true base of the protected groundwater resource may be deeper, leaving uncertainty as to whether the surface casing in these wells is set deeper than the base of the protected groundwater resource.

high porosity or fractures, causing a lack of adequate cement across a water- or brine-bearing zone. Additionally, failure to use cement that is compatible with the anticipated subsurface conditions, failure to remove drilling fluids from the wellbore, and improper centralization of the casing in the wellbore can all lead to the formation of channels (i.e., small connected voids) in the cement during the cementing process (McDaniel et al., 2014; Sabins, 1990). If the channels are small and isolated, they may not lead to fluid migration. However, if they are long and connected, extending across multiple formations, or connecting to other existing channels or fractures, they can present a pathway for fluid migration. Figure 6-4 shows a variety of pathways for fluid migration that are possible from failed cement jobs.

One example of how hydraulic fracturing of a well with insufficient and improperly placed cement led to contamination occurred in Bainbridge Township, Ohio. This incident was well studied by the Ohio Department of Natural Resources (ODNR, 2008) and by an expert panel (Bair et al., 2010). The level of detail available for this case is not typically found in studies of such events but was collected because of the severity of the impacts and the resulting legal action. The English #1 well was drilled to a depth of 3,900 ft (1,200 m) below ground surface (bgs) in October 2007 with the producing formation located between 3,600 and 3,900 ft (1,100 and 1,200 m) bgs. Overlying the producing formation were several uneconomic formations containing over-pressured gas (i.e., gas at pressures higher than the hydrostatic pressure exerted by the fluids within the well).[1] The original cement design required the cement to be placed 700 – 800 ft (210 – 240 m) above the producing formation to seal off these areas. During cementing, however, both the spacer fluid and cement were lost in the subsurface, and the cement did not reach the intended height.[2] Despite the lack of sufficient cement, the operator proceeded with hydraulic fracturing.

During the hydraulic fracturing operation in November 2007, about 840 gal (3,200 L) of fluid flowed up the annulus and out of the well. When the fluid began flowing out of the annulus, the operator immediately ceased operations and shut in the well; this caused the pressure in the wellbore to increase. About a month later, there was an explosion in a nearby house where methane had entered from an abandoned and unplugged drinking water well connected to the cellar (Bair et al., 2010). In addition to the explosion, the over-pressured gas entering the aquifer resulted in the contamination of 26 private drinking water wells with methane. The wells, some of which had histories of elevated methane prior to the incident, were taken off-line. By 2010, all of the well owners had been connected to a public water supply (Tomastik and Bair, 2010).

Contamination at the Bainbridge Township site was the result of inadequate cement. The ODNR determined that failure to cement the over-pressured gas formations, proceeding with the hydraulic fracturing operation without adequate cement, and the extended period during which the well was shut in all contributed to the contamination of the aquifer with stray gas (ODNR, 2008). Cement logs found the cement top was at 3,640 ft (1,110 m) bgs, leaving the uneconomic gas-producing formations and a portion of the production zone uncemented. The surface casing was 253 ft (77 m) deep and cemented to the surface. Hydraulic fracturing fluids flowing out of the

[1] Hydrostatic pressure is the pressure exerted by a column of fluid at a given depth. Here, it refers to the pressure exerted by a column of drilling mud or cement on the formation at a particular depth.

[2] Spacer fluid is a fluid pumped before the cement to clean drilling mud out of the wellbore.

annulus provided an indication that hydraulic fracturing had created a path from the producing formation to the well annulus in addition to the uncemented gas zones. Because the well was shut in, the pressure in the annulus could not be relieved, and the gas eventually traveled through natural fractures surrounding the wellbore into local drinking water aquifers (during the time the well was shut in, natural gas seeped into the well annulus and pressure built up from an initial pressure of 90 psi (0.6 MPa) to 360 psi (2.5 MPa)). From the aquifer, the gas moved into drinking water wells and from one of those wells into a cellar, resulting in the explosive accumulation of gas.

The Well File Review found that 3% of all hydraulic fracturing jobs (800 jobs) reported a mechanical integrity failure that allowed fluid to enter an annular space (U.S. EPA, 2016c).[1] The mechanical integrity failures generally resulted in hydraulic fracturing fluid entering the annular space between the casing and formation or between two casings, and were generally noted by increases in annular pressure or fluid bubbling to the surface. Other possible mechanisms for the failures include casing leaks, cement failure, and fractures extending above the height of the cement. (See Section 6.3.2.2 for additional information on fracture overgrowth.) While failures were noted, these do not necessarily indicate there was movement of fluid into a drinking water resource. In most cases, when problems occurred, the hydraulic fracturing operation was stopped and operators addressed the cause of the failure before hydraulic fracturing operations resumed; however, in 0.5% of the hydraulic fracturing jobs (100 jobs) with identified failures, there was no additional barrier between the annular space with fluid and protected drinking water resources.[2] While it could not definitively be determined whether fluid movement into the protected drinking water resource occurred, in these cases, all of the protective barriers intended to prevent such fluid migration failed, leaving the groundwater resource vulnerable to contamination.

While limited literature is available on construction (including cementing) flaws in hydraulically fractured wells, several studies have examined construction flaws in oil and gas wells in general. One study that examined reported drinking water contamination incidents in Texas identified 10 incidents related to drilling and construction activities among 250,000 oil and gas wells (Kell, 2011). The study noted that many of the contamination incidents were associated with wells that were constructed before Texas revised its regulations on cementing in 1969 (it is not clear how old the wells were at the time the contamination occurred). Because this study relied on reported incidents, it is possible that other wells exhibited mechanical integrity issues but did not result in contamination of a drinking water well or were not reported. Therefore, this should be considered a low-end estimate of the number of mechanical integrity issues that could be tied directly to drilling and construction activities. It is important to note that the 10 contamination incidents identified were not associated with wells that were hydraulically fractured (Kell, 2011).

Several investigators have studied violations information from the PA DEP online violation database to evaluate the rates of and possible factors contributing to mechanical integrity problems, including those related to cement. The results of these studies are summarized in Table 6-2.

[1] 800 jobs (95% confidence interval: 10 – 1,700 jobs).

[2] 100 jobs (95% confidence interval: 10 – 300 jobs).

Table 6-2. Results of studies of PA DEP violation data that examined mechanical integrity failure rates.

Study	Violations investigated	Wells studied	Data timeframe	Key findings[a]
Considine et al. (2012)	Violations resulting in environmental damage	3,533	2008–2011	Of 845 environmental damage incidents (which resulted in 1,144 violations), approximately 10% were related to casing or cement problems. The overall violation rate dropped from 52.9% of all wells in 2008 to 20.8% of all wells in 2011.
Davies et al. (2014)	Failure of one of the barriers preventing fluid migration	8,030	2005–2013	Approximately 5% of wells received this type of violation. The incident rate increased to 6.3% when failures noted on forms, but not resulting in violations, were included.
Ingraffea et al. (2014)	Violations and inspection records indicating structural integrity loss	3,391	2000–2012	Wells in unconventional reservoirs experienced a rate of structural integrity loss of 6.2%, while the rate for conventional wells was 1%.
Vidic et al. (2013)	Construction violations related to casing or cement	6,466	2008–2013	Approximately 3.4% of wells received this type of violation.
Olawoyin et al. (2013)	All violations	2,001	2008–2010	Analysis of 2,601 violations from 65 operators based on weighted risks found that potentially risky violations increased 342% over the study period, while total violations increased 110%.
Brantley et al. (2014)	Violations related to well construction issues	7,234	2005 – 2013	Over the period studied, a total of 3.4% of well operators received violations for construction issues. Violations in any given year ranged from 0.6% to 10.8%. Also, 0.24% of wells were cited for methane migration.

[a] While all of these studies used the same database, their results vary because they studied different timeframes and used different definitions of what violations constituted a mechanical integrity problem or failure.

Because a significant portion of Pennsylvania's recent oil and gas activity is in the Marcellus Shale, many of the wells in these studies were most likely used for hydraulic fracturing. For example, Ingraffea et al. (2014) found that approximately 16% of the oil and gas wells drilled in the state between 2000 and 2012 were completed in unconventional reservoirs, and nearly all of these wells were used for hydraulic fracturing. Wells drilled in unconventional reservoirs experienced higher rates of structural integrity loss, as defined by the authors, than conventional wells drilled during the same time period (Ingraffea et al., 2014). The authors did not compare rates of structural integrity loss in conventional wells that were and were not hydraulically fractured; they assumed that unconventional wells were hydraulically fractured and conventional wells were not.

Violation rates resulting in environmental damage among all Pennsylvania wells dropped from 52.9% in 2008 to 20.8% in 2011 (Considine et al., 2012), and the drop may be due to a number of factors. Violations related to failure of cement or other well components represented a minority of all well violations (i.e., among wells that were and were not hydraulically fractured). Of 845 events that caused environmental damage, including but not limited to contamination of drinking water resources, Considine et al. (2012) found that about 10% (85 events) were related to casing and cement problems. The rest of the incidents were related to site restoration and spills; the violations noted are confined to those incidents that caused environmental damage (i.e., the analysis excluded construction flaws that did not have adverse environmental effects). In addition, two wells (0.06%) were found to have contributed to methane migration into drinking water. Ingraffea et al. (2014) identified a significant increase in mechanical integrity problems such as casing leaks, sustained casing pressure, and insufficient cement from 2009 to 2011, rising from 5% to 6% of all newly drilled oil and gas wells, followed by a decrease beginning in 2012 to about 2% of all wells, a reduction of approximately 100 violations among 3,000 wells from 2011 to 2012. The rise in mechanical integrity problems between 2009 and 2011 coincided with an increase in the number of wells in unconventional reservoirs.

While all of the studies shown in the table used the same database, their results vary, not only because of the different timeframes studied, but also because they used different definitions of what violations constituted a mechanical integrity problem or failure. For example, Considine et al. (2012) considered all events resulting in environmental damage—including effects such as erosion—and found a relatively high violation rate. Davies et al. (2014) and Ingraffea et al. (2014) investigated violations related to mechanical integrity, while Vidic et al. (2013) looked only at mechanical integrity violations resulting in fluid migration out of the wellbore; these more specific studies found relatively lower violation rates. Olawoyin et al. (2013) performed a statistical analysis that weighted violations based on risk and found that the most risky violations included those involving pits, erosion, waste disposal, and blowout preventers.

Another source of information on contamination caused by wells is positive determination letters (PDLs) issued by the PA DEP. PDLs are issued in response to a complaint when the state determines that contamination did occur in proximity to oil and gas activities. The PDLs take into account the impact, timing, mechanical integrity, and formation permeability; liability is presumed for wells within a given distance if the oil and gas operator cannot refute that they caused the contamination, based on pre-drilling sampling (Brantley et al., 2014).[1] Brantley et al. (2014) examined these PDLs, and concluded that, between 2008 and 2012, the water supplies of approximately seven properties were impacted; depending on the assumptions used to determine how many unconventional gas wells affected a single property; this equates to a rate of 0.12 to 1.1% of the 6,061 wells begun in that timeframe. While these oil and gas wells were linked to contamination of wells and springs, the

[1] Under Pennsylvania's Oil and Gas Act, operators of oil or gas wells are presumed liable if water supplies within 1,000 ft (305 m) were impacted within 6 months of drilling, unless the claim is rebutted by the operator; this was expanded to 2,500 ft (762 m) and 12 months in 2012.

mechanisms for the impacts (including whether fluids may have been spilled at the surface or if there was a pathway through the well or through the subsurface rock formation to the drinking water resource) were not described by Brantley et al. (2014).

While the studies discussed above present possible explanations for higher violation incidences in unconventional wells that are likely to be hydraulically fractured, it should be noted that other explanations not specific to hydraulic fracturing are also possible. These could include different inspection protocols and different formation types.

Cementing in horizontal wells, which are commonly hydraulically fractured, presents challenges that can contribute to higher rates of mechanical integrity issues. The observation by Ingraffea et al. (2014) that wells drilled in unconventional reservoirs (which are horizontal in Pennsylvania) experience higher rates of structural integrity loss than conventional wells is supported by conclusions of Sabins (1990), who noted that horizontal wells have more cementing problems because they are more difficult to center properly and can be subject to settling of solids on the bottom of the wellbore. Cementing in horizontal wells presents challenges that can contribute to higher rates of mechanical integrity issues.

Thermal and cyclic stresses caused by intermittent operation also can stress cement (King and King, 2013; Ali et al., 2009). Increased pressures and cyclic stresses associated with hydraulic fracturing operations can contribute to cement integrity losses and, if undetected, small mechanical integrity problems can lead to larger ones. Temperature differences between the (typically warmer) subsurface environment and the (typically cooler) injected fluids, followed by contact with the (typically warmer) produced water, can lead to contraction of the well materials (both casing and cement), which introduces additional stresses. Similar temperature changes may occur when multiple fracturing stages are performed. Because the casing and cement have different mechanical properties, they may respond differently to these stress cycles and debond.

Several studies illustrate the effects of cyclic stresses. Dusseault et al. (2000) indicate that wells that have undergone several cycles of thermal or pressure changes will almost always show some debonding between cement and casing. Another laboratory study by De Andrade et al. (2015) found that cycling temperatures between 61°F and 151°F (16°C and 66°C) at 35 bar pressure (2.5 MPa) led to the formation of cracks in cement across both shale and sandstone formations. Cement damage was more significant in sandstone formations and worsened with each thermal cycle. A similar study by Roy et al. (2016) at ambient pressure did not find any cracks larger than 200 microns with temperature fluctuation between -40°F and 158°F (-40°C and 70°C), although numerical modeling of the same scenario predicted that cracks up to 1 to 10 microns would form, which would not have been detected by the methods used. Microannuli formed by this debonding can serve as pathways for gas migration, in particular because the lighter density of gas provides a larger driving force for migration through the microannuli than for heavier liquids.[1] One laboratory study indicated that microannuli on the order of 0.01 in (0.25 mm) could increase effective cement permeability from 1 nD (1×10^{-21} m^2) in good quality cement up to 1 mD (1×10^{-15} m^2) (Bachu and Bennion, 2009). This six-order magnitude increase in permeability shows that even small

[1] Microannuli can also form due to an inadequate cement job, e.g., poor mud removal or improper cement placement rate.

microannuli can significantly increase the potential for flow through the cement. Typically, these microannuli form at the interface between the casing and cement or between the cement and formation. Debonding and formation of microannuli can occur through intermittent operation, pressure tests, and workover operations (Dusseault et al., 2000).[1] While a small area of debonding may not lead to fluid migration, the microannuli in the cement resulting from the debonding can serve as initiation points for fracture propagation if re-pressurized gas enters the microannulus (Dusseault et al., 2000).

A number of modeling studies have indicated that fractures can propagate upwards from existing defects in cement or areas with poorer bonding (Kim et al., 2016; Roy et al., 2016; De Andrade et al., 2015). Feng et al. (2015) showed that fractures in cement tended to propagate upwards along the wellbore instead of radially. Modeling studies have also shown that cements with lower Young's modulus tend to propagate fractures more slowly than stiffer cements (Kim et al., 2016; Feng et al., 2015).[2]

The Council of Canadian Academies (2014) found that the repetitive pressure surges occurring during the hydraulic fracturing process would make maintaining an intact cement seal more of a challenge in these wells. Wang and Dahi Taleghani (2014) performed a modeling study, which concluded that hydraulic fracturing pressures could initiate annular cracks in cement. Another study of well data indicated that cement failure rates are higher in intermediate casings compared to other casings (McDaniel et al., 2014). The failures occurred after drilling and completion of wells, and the authors surmised that the cement failures were most likely due to cyclic pressure stresses caused by drilling. Theoretically, similar cyclic pressure events could also be experienced in the production casing during multiple stages of hydraulic fracturing. Mechanical stresses associated with well operation or workovers and pressure tests also may lead to small cracks in the cement, which may provide migration pathways for fluid.

Corrosion can lead to cement failure. Cement can fail to maintain integrity as a result of degradation of the cement after the cement is set. Cement degradation can result from attack by corrosive brines or chemicals such as sulfates, sulfides, and carbon dioxide that exist in formation fluids (Renpu, 2011). These chemicals can alter the chemical structure of the cement, resulting in increased permeability or reduced strength and leading to loss of cement integrity over time. Additives or specialty cements exist that can decrease cement susceptibility to specific chemicals.

6.2.2.3 Well Age

Hydraulic fracturing within older (legacy) wells has the potential to impact drinking water resources, either due to inadequate design and construction or degradation of the well components over time that afford pathways for the unintended migration of fluids. While new wells can be specifically designed to withstand the stresses associated with hydraulic fracturing operations,

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[1] A workover refers to any maintenance activity performed on a well that involves ceasing operations and removing the wellhead. Depending on the purpose of the workover and the tools used, workovers may induce pressure changes in the well.

[2] Young's modulus, a ratio of stress to strain, is a measure of the rigidity of a material.

older wells, which are sometimes used in hydraulic fracturing operations, may not have been designed to the same specifications, and their reuse for this purpose could be a concern.

Aging and extended use of a well contribute to casing corrosion and degradation, and the potential for fluid migration related to compromised casing tends to be higher in older wells. For example, exposure to corrosive chemicals such as hydrogen sulfide, carbonic acid, and brines can accelerate corrosion (Renpu, 2011). Ajani and Kelkar (2012) studied wells in Oklahoma and found a correlation between well age and mechanical integrity issues. Specifically, in wells spaced between 1,000 and 2,000 ft (300 and 600 m) from a well being fractured, the likelihood of impact on the well (defined in the study as a loss of gas production or increase in water production) rose from approximately 20% to 60% as the well's age increased from 200 days to over 600 days. Age was also found to be a factor in mechanical integrity problems in a study of wells drilled offshore in the Gulf of Mexico (Brufatto et al., 2003).

The Well File Review (U.S. EPA, 2016c, 2015n) provides evidence that fracturing does occur in older wells, including re-entering existing wells to fracture them for the first time or re-fracturing in wells that have been previously fractured. The Well File Review found that the median age of wells being initially fractured was 45 days, with well ages at time of fracturing ranging from 8 days to nearly 51 years. While 64% of the wells studied in the Well File Review were fractured within 6 months of the well spud date, the median age for wells being re-fractured was 6 years.[1,2] An estimated 11% of fracture jobs studied in the Well File Review were re-completions in a different zone than the original fracture job and 8% were re-fractures in the same zone as the original fracture job.[3,4]

The Well File Review also found that well component failures appeared to occur more frequently in older wells that were being re-completed or re-fractured.[5] The failure rate in hydraulic fracturing jobs involving re-completions and re-fractures was 6%, compared to 2% for hydraulic fracturing jobs in wells that had not been previously fractured.[6,7] While the confidence levels overlap, there is an indication that re-fractured and re-completed wells are more likely to suffer a failure of one or more components during hydraulic fracturing operations.

Frac strings, which are specialized pieces of casing inserted inside the production casing, can be used to protect older casing during fracturing. However, the effect of hydraulic fracturing on the cement on the production casing in older wells is unknown. One study on re-fracturing of wells noted that the mechanical integrity of the well was a key factor in determining the success or failure of the fracture treatment (Vincent, 2011). The Well File Review (U.S. EPA, 2016c) found that

[1] Spudding refers to starting the well drilling process by removing rock, dirt, and other sedimentary material with the drill bit.

[2] 64% of wells (95% confidence interval: 48 – 77% of wells).

[3] 11% of jobs (95% confidence interval: 5 – 23% of jobs).

[4] 8% of jobs (95% confidence interval: 5 – 12% of jobs).

[5] The Well File Review defines a failure as a defect in a well component that allows fluid to flow into an annular space.

[6] 6% failure rate (95% confidence interval: 2 – 19% failure rate).

[7] 2% failure rate (95% confidence interval: 0.5 – 8% failure rate).

failures occurred more frequently in completions using frac strings, with failures occurring 20% of the time, compared to failures occurring 0.9% of the time when a frac string was not used.[1,2]

Note that there are also potential issues related to *where* these older wells are sited. For example, some wells could be in areas with naturally occurring subsurface faults or fractures that could not be detected or fully characterized with the technologies available at the time of construction. It is also possible that, in areas of historic petroleum exploration, old abandoned wells can be present which may have been improperly plugged or have degraded over time.[3] These wells could serve as pathways for fluid migration if they are located within the fracture network of the well; see Section 6.3.2.

6.2.2.4 Sustained Casing Pressure

Sustained casing pressure illustrates how the issues related to casing and cement discussed in the preceding sections can work together and be difficult to differentiate.[4] It is an indicator that pathways within the well related to the well's casing, cement, or both allowed fluid movement to occur. Sustained casing pressure can result from casing leaks, uncemented intervals, microannuli, or some combination of the three, which can be an indication that a well has lost mechanical integrity. Sustained casing pressure can be observed when an annulus (either the annulus between the tubing and production casing or between any two casings) is exposed to a source of nearly continuous elevated pressure. Goodwin and Crook (1992) found that sudden increases in sustained casing pressure occurred in wells that were exposed to high temperatures and pressures. Subsequent logging of these wells showed that the high temperatures and pressures led to shearing of the cement/casing interface and a total loss of the cement bond. Aly et al. (2015) demonstrated methods using a combination of chemical analysis, isotopic analysis, well logs, and drilling records to identify the most likely source of fluids causing sustained casing pressure.

Sustained casing pressure occurs more frequently in older wells and horizontal or deviated wells. One study found that sustained casing pressure becomes a greater concern as a well ages. Sustained casing pressure was found in less than 10% of wells that were less than a year old, but was present in up to 50% of 15-year-old wells (Brufatto et al., 2003). While these wells may not have been hydraulically fractured, the study demonstrates that older wells can exhibit more mechanical integrity problems. Fleckenstein et al. (2015) also found that older wells exhibited more barrier failures, including sustained casing pressure. They reported that 3.53% of the wells in the study with under-pressured intermediate gas zones developed sustained casing pressure, although it is likely the sustained casing pressure was due to poor well design (i.e., under older standards) rather

[1] 20% failure rate (95% confidence interval: 10 – 36% failure rate).

[2] 0.9% failure rate (95% confidence interval: 0.8 – 1.0% failure rate).

[3] An abandoned well refers to a well that is no longer being used, either because it is not economically producing or it cannot be used because of its poor condition.

[4] Sustained casing pressure is pressure in any well annulus that is measurable at the wellhead and rebuilds after it is bled down, not caused solely by temperature fluctuations or imposed by the operator (Skjerven et al., 2011). If the pressure is relieved by venting natural gas from the annulus to the atmosphere, it will build up again once the annulus is closed (i.e., the pressure is sustained). The return of pressure indicates that there is a small leak in a casing or through uncemented or poorly cemented intervals that exposes the annulus to a pressured source of gas. It is possible to have pressure in more than one of the annuli.

than well age. Watson and Bachu (2009) found that a higher portion of deviated wells had sustained casing pressure compared to vertical wells. Increased pressures and cyclic stresses (Syed and Cutler, 2010) during hydraulic fracturing and difficulty in cementing horizontal wells (Sabins, 1990) also can lead to increased instances of sustained casing pressure (Muehlenbachs et al., 2012; Rowe and Muehlenbachs, 1999).

Sustained casing pressure can be a concern for several reasons. If the pressures are allowed to build up to above the burst pressure of the exterior casing or the collapse pressure of the interior casing, the casing may fail. Increased pressure can also cause gas or liquid to enter lower-pressured formations that are exposed to the annulus either through leaks or uncemented sections. Laboratory experiments by Harrison (1985) demonstrated that over-pressurized gas in the annulus could cause rapid movement of gas into drinking water resources if a permeable pathway exists between the annulus and the groundwater. Over-pressurization of the annulus is commonly relieved by venting the annulus to the atmosphere; however, this does not address the underlying problem in the well and can result in additional releases of methane to the atmosphere.

One example of an area where sustained casing pressure is common is Alberta, Canada, where 14% of the wells drilled since 1971 experienced serious sustained casing flow. This was defined in a study by Jackson and Dusseault (2014) as more than 10,594 ft^3 (300 m^3)/day at pressures higher than 0.48 psi/ft (11 kPa/m) of depth times the depth of the surface casing. Another study in the same area found gas in nearby drinking water wells had a composition consistent with biogenic methane mixing with methane from nearby coalbed methane and deeper natural gas fields (Tilley and Muehlenbachs, 2012).

In a few cases, sustained casing pressure in wells that have been hydraulically fractured may have been linked to drinking water contamination, although it is challenging to definitively determine the actual cause. In one study in northeastern Pennsylvania, methane to ethane ratios and isotopic signatures were used to investigate stray gas migration into domestic drinking water (U.S. EPA, 2014f). Composition of the gas in the water wells was consistent with that of the gas found in nearby gas wells with sustained casing pressures; other possible sources of the gas could not be ruled out. Several gas wells in the study area were cited by the PA DEP for having elevated sustained casing annulus pressures. One such case included four well pads with two wells drilled on each pad in southeastern Bradford County. The wells, drilled between September 2009 and May 2010, were 6,890 to 7,546 ft (2,100 to 2,300 m) deep and had surface casing to 984 ft (300 m). The casing below the surface casing was uncemented. All four wells experienced sustained casing pressure, with pressures ranging from 483 to 909 psi (3.3 to 6.3 MPa). Methane appeared in three nearby domestic drinking water wells in July 2010. Investigation into the cause of the methane contamination identified the drilled gas wells with sustained casing pressure as the most likely cause. The likely path was over-pressured gas from intermediate zones above the Marcellus Shale entering the uncemented well annulus and traveling up the annulus and along bedding planes which intersected the well annulus.[1] The determination was based on multiple lines of evidence, including: no methane present in a pre-drill sample, increases in methane after the wells had been

[1] A bedding plane is the surface that separates two layers of stratified rocks.

drilled, similar isotopic composition of the gas in the domestic wells and the gas in the annular space of the gas wells, and the presence of bedding planes which intersected the uncemented portion of the gas wells leading upwards toward the domestic wells (Llewellyn et al., 2015).

Adequate well design, detection (i.e., through annulus pressure monitoring), and repair of sustained casing pressure reduce the potential for fluid movement. (See Chapter 10 for additional discussion of practices that can reduce the frequency or severity of impacts to drinking water quality.) Watson and Bachu (2009) found that regulations requiring monitoring and repair of sustained casing vent flow or sustained casing pressure had a positive effect on lowering leak rates. The authors also found injection wells initially designed for the higher pressures associated with injection (vs. production) experienced sustained casing pressure less often than those that were retrofitted (Watson and Bachu, 2009). As mentioned above, Fleckenstein et al. (2015) found that placing the surface casing below all potential sources of drinking water and cementing intermediate gas zones significantly reduced sustained casing pressure.

Another study in Mamm Creek, Colorado, obtained similar results. The Mamm Creek field is in an area where lost cement and shallow, gas-containing formations are common. All the wells in the formation were hydraulically fractured (S.S. Papadopulos & Associates, 2008). A number of wells in the area have experienced sustained casing pressure, and methane has been found in several drinking water wells along with seeps into local creeks and ponds. In one well, drilled in January 2004, four pressured gas zones were encountered during drilling and there was a lost cement incident, which resulted in the cement top being more than 4,000 ft (1,000 m) lower than originally intended. Due to high bradenhead pressure (661 psi, or 4.6 MPa), cement remediation efforts were implemented (Crescent, 2011; COGCC, 2004).[1] The operator of this well was later cited by the Colorado Oil and Gas Conservation Commission (COGCC) for causing natural gas and benzene to seep into a nearby creek. The proposed route of contamination was contaminants flowing up the well annulus and then along a fault. The proposed contamination route appeared to be validated because, once remedial cementing was performed on the well, methane and benzene levels in the creek began to drop (Science Based Solutions LLC, 2014). In response to the incident, the state instituted requirements to identify and cement above the top of the highest gas-producing formation in the area and to monitor casing pressures after cementing.

A study in the Woodford Shale in Oklahoma examined how various cement design factors affected sustained casing pressure (Landry et al., 2015). The study focused on wells in the Cana-Woodford basin, a very deep basin at 11,000 to 15,000 ft (3,400 to 4,600 m) below ground surface, where the depth, long laterals, fracture gradients, and low permeability of the formations in the basin make cementing a challenge. One operator had seven test wells in the basin, of which six exhibited sustained casing pressure, usually after hydraulic fracturing operations. In early designs, the operator had not been using centralizers on the horizontal sections of the well, because they increased the frequency of stuck pipe. However, improvements in centralizer design allowed the operator to use centralizers more frequently on later well designs, and the operator tried several different techniques to address the sustained casing pressure problems, with varying results:

[1] Bradenhead pressure is pressure between two casings in an oil and gas well.

- In three of the wells, the operator used three different techniques: a conventional cement job with a water-based drilling mud and single slurry design; oil-based mud with single slurry design; and a foamed cement to cement the vertical portion of the well from the kickoff point up with conventional water-based cement on the lateral. All three of these wells experienced sustained casing pressure after hydraulic fracturing operations.
- In a fourth well, in 2013, the operator used centralizers, with three centralizers per every two casing joints along the lateral and one centralizer per joint in the vertical section. The design also involved an enhanced spacer fluid to remove drilling mud and a self-healing cement in the upper portion of the well. While some channeling was detected in this well, the channels were not connected and did not lead to sustained casing pressure.

The operator constructed an additional 21 wells using the same technique as was performed in the fourth well, and 20 did not show any sustained casing pressure after fracturing. This study shows the importance of cement design factors, such as casing centralization and mud removal, in preventing sustained casing pressure.

Not every well that shows positive pressure in the annulus poses a potential problem. Sustained pressure is only a problem when it exceeds the ability of the wellbore to contain it or when it indicates leaks in the cement or casing (TIPRO, 2012). A variety of management options are available for managing such pressure including venting, remedial cementing, and use of kill fluids in the annulus (TIPRO, 2012).[1] While venting may be a common method to address sustained casing pressure, it does not address the underlying mechanical integrity failure and is only a temporary solution. Furthermore, venting releases fluids at the wellhead which, if gaseous, can contribute to increased atmospheric emissions, or if liquid, potential spills on the surface.

6.3 Fluid Migration Associated with Induced Fractures within Subsurface Formations

This section discusses potential pathways for fluid movement associated with induced fractures and subsurface formations (outside of the well system described in Section 6.2). It examines the potential for fluid migration into drinking water resources by evaluating the development of migration pathways within subsurface formations, the flow of injected and formation fluids, and important factors that affect these processes.

Fluid movement requires both a physical pathway (e.g., via the interconnected pores within a permeable rock matrix or via a fracture in the rock) and a driving force.[2] In subsurface formations, fluid movement is driven by the existence of a hydraulic gradient, which depends on elevation and pressure and is influenced by fluid density, composition, and temperature (Pinder and Celia, 2006).

[1] A kill fluid is a weighted fluid with a density that is sufficient to overcome the formation pressure and prevent fluids from flowing up the wellbore.

[2] Permeability (i.e., intrinsic or absolute permeability) of formations describes the ability of water to move through the formation matrix, and it depends on the rock's grain size and the connectedness of the void spaces between the grains. Where multiple phases of fluids exist in the pore space, the flow of fluids also depends on relative permeabilities.

In the context of hydraulic fracturing, two key factors govern fluid migration during and after the hydraulic fracturing event:

- Pressure differentials in the reservoir, which are influenced both by initial subsurface conditions and by the pressures created by injection and production regimes. Specific factors that may influence pressure differentials include structural or topographic features, over-pressure in the shale reservoir, or a temporary increase in pressure as a result of fluid injection during hydraulic fracturing (Birdsell et al., 2015a).
- Buoyancy, which is driven by density differences among and between gases and liquids. Fluid migration can occur when these density differences exist in the presence of a pathway (Pinder and Gray, 2008).

During hydraulic fracturing, pressurized fluids leaving the well create fractures within the production zone and then enter the formation through these newly created (induced) fractures. Unintended fluid migration can result from this fracturing process. Migration pathways to drinking water resources could develop as a result of changes in the subsurface flow or pressure regime associated with hydraulic fracturing; via fractures that extend beyond the intended formation or that intersect existing natural faults or fractures; and via fractures that intersect offset wells or other artificial structures (Jackson et al., 2013d). These subsurface pathways may facilitate the migration of fluids by themselves or in conjunction with the well-based pathways described in Section 6.2. Fluids potentially available for migration include both fluids injected into the well (including leakoff) and fluids already present in the formation (including brine or natural gas).[1]

The potential for subsurface fluid migration into drinking water resources can be evaluated during two different time periods (Kim and Moridis, 2015):

1. *Following the initiation of fractures in the reservoir, prior to any oil or gas production.* The injected fluid, pressurizing the formation, flows through the fractures and the fractures grow into the reservoir. Fluid leaks off into the formation, allowing the fractures to close except where they are held open by the proppant (Adachi et al., 2007). Fractures will generally continue to propagate until the fluid lost to leakoff is equal to the fluid injection rate (King and Durham, 2015).
2. *During the production period, after fracturing is completed and pressure in the fractures is reduced.* At this time, fluids (including oil/gas and produced water) flow from the reservoir into the well. As fluids are withdrawn from the formation, pore pressure decreases; as a result, the effective stress applied to fractures increases and (in the absence of proppant) fractures will close (Aybar et al., 2015).

Note that these two time periods vary in duration. As described in Chapter 3, the first period of fracture creation and propagation (i.e., the hydraulic fracturing itself) is a relatively short-term process, typically lasting 2 to 10 days, depending on the number of stages in the fracture treatment

[1] Leakoff is the fraction of the injected fluid that infiltrates into the formation and is not recovered (i.e., it "leaks off" and does not return through the well to the surface) during production (Economides et al., 2007). Fluids that leak off and are not recovered are sometimes referred to as "lost" fluids.

design. On the other hand, operation of the well for production covers a substantially longer period (depending on many factors such as the amount of hydrocarbons in place and economic considerations), and can be as long as 40 or 60 years in onshore tight gas reservoirs (Ross and King, 2007).

The following discussion of potential subsurface fluid migration into drinking water resources focuses primarily on the physical movement of fluids and the factors affecting this movement. Section 6.3.1 describes the basic principles of subsurface fracture creation, geometry, and propagation, to provide context for the discussion of potential fluid migration pathways in Section 6.3.2. Geochemical and biogeochemical reactions among hydraulic fracturing fluids, formation fluids, subsurface microbes, and rock formations are another important component of subsurface fluid migration and transport. See Chapter 7 for a discussion of the processes that affect pore fluid biogeochemistry and influence the chemical and microbial composition of produced water.

6.3.1 Overview of Subsurface Fracture Growth

Fracture initiation and growth is a highly complex process due to the heterogeneous nature of the subsurface environment. As shown in Figure 6-5, fracture formation is controlled by the three in situ principal compressive stresses: the vertical stress, the maximum horizontal stress, and the minimum horizontal stress. During hydraulic fracturing, pressurized fluid injection creates high pore pressures around the well. Fractures form when this pressure exceeds the local least principal stress and the tensile strength of the rock (Zoback, 2010; Fjaer et al., 2008).

Fractures propagate (increase in length) in the direction of the maximum principal stress; they are tensile fractures that open in the direction of least resistance and then propagate in the plane of the greatest and intermediate stresses (Nolen-Hoeksema, 2013). Deep in the subsurface, the maximum principal stress is generally in the vertical direction, because the overburden (the weight of overlying rock) is the largest single stress. Therefore, in deep formations, fracture orientation is expected to be vertical. This is the scenario illustrated in Figure 6-5. At shallower depths, where the rock is subjected to less pressure from the overburden, more fracture propagation is expected to be in the horizontal direction. Using tiltmeter data from over 10,000 fractures in various North American shale reservoirs, Fisher and Warpinski (2012) found that induced fractures deeper than about 4,000 ft (1,000 m) are primarily vertical (see below for more information on tiltmeters). Between approximately 4,000 and 2,000 ft (1,000 and 600 m), they observed that fracture complexity increases, and fractures shallower than about 2,000 ft (600 m) are primarily (though not entirely) horizontal.[1] However, local geologic conditions can cause fracture orientations to deviate from these general trends (Ryan et al., 2015). Horizontal fracturing can also occur in deeper

[1] Fracture complexity is the ratio of horizontal-to-vertical fracture volume distribution, as defined by Fisher and Warpinski (2012). Fracture complexity is higher in fractures with a larger horizontal component. For the reasons explained above, this is more likely to occur at shallower depths. However, even in shallow zones, fractures are unlikely to be completely horizontal. As noted by Fisher and Warpinski, “All of the fractures do not necessarily turn horizontal; they might have significant vertical and horizontal components with more of a T-shaped geometry.” In the Fisher and Warpinski data set, the maximum horizontal component of the fractures is approximately 70%.

settings in some less-common reservoir environments where the principal stresses have been altered by salt intrusions or similar types of geologic activity (Jones and Britt, 2009).

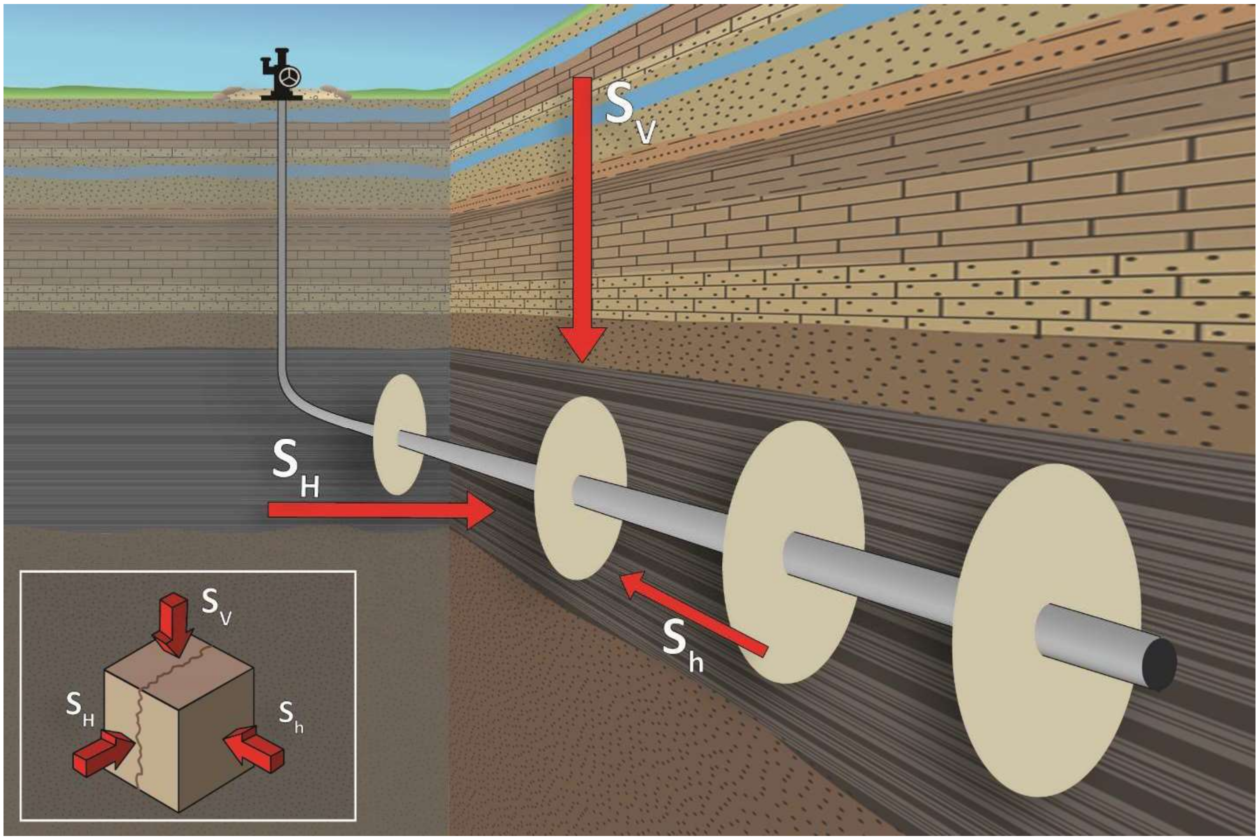


Figure 6-5. Hydraulic fracture planes (represented as ovals), with respect to the principal subsurface compressive stresses: S_V (the vertical stress), S_H (the maximum horizontal stress), and S_h (the minimum horizontal stress).

In addition to the principal subsurface stresses, a variety of factors and processes affect the complex process of fracture creation, propagation, geometry, and containment.[1] Computational modeling techniques have been developed to simulate fracture creation and propagation and to provide a better understanding of this complex process (Kim and Moridis, 2013).[2] Modeling hydraulic fracturing in shale or tight gas reservoirs requires integrating the physics of both flow and geomechanics to account for fluid flow, fracture propagation, and dynamic changes in pore volume and permeability. Some important flow and geomechanical parameters included in these

[1] Fracture geometry refers to characteristics of the fracture such as height and aperture (width).

[2] There are different kinds of mathematical models. Analytical models have a closed-form solution and therefore are relatively simple to solve. In contrast, computational models (also called numerical models) require more extensive computational resources and are used to study the behavior of complex systems.

types of advanced models are: permeability, porosity, Young's modulus, Poisson's ratio, and tensile strength, as well as heterogeneities associated with these parameters.[1]

Based on modeling and laboratory experiments (e.g., by Khanna and Kotousov, 2016; Li et al., 2016c; Li et al., 2016b; de Pater, 2015; Kim and Moridis, 2015; Lee et al., 2015; Narasimhan et al., 2015; Smith and Montgomery, 2015; Wang and Rahman, 2015; Kim and Moridis, 2013), below are some of the factors that have been noted in the literature as influencing fracture growth:

- Geologic properties of the production zone such as rock type and composition, permeability, thickness, and the presence of pre-existing natural fractures;
- The presence, composition, and properties of the liquids and gases trapped in pore spaces;
- Geomechanical properties, including tensile strength, Young's modulus, and the pressure at which the rock will fracture;
- Characteristics of the interface (boundary) between adjacent rock layers; and
- Operational characteristics, including injection rate and pressure, the properties of the hydraulic fracturing fluids, and fracture spacing.

Some modeling investigations have indicated that the vertical propagation of fractures (due to tensile failure) may be limited by shear failure, which increases the permeability of the formation and allows more fluid to leak off into the rock. These findings demonstrate that elevated pore pressure can cause shear failure, thus further affecting matrix permeability, flow regimes, and leakoff (Daneshy, 2009).

It is important to note that, while computational modeling is a useful tool to understand complex systems, modeling has limitations and associated uncertainties. All models rely on assumptions and simplifications, and there is, as stated by Ryan et al. (2015), "currently no single numerical approach that simultaneously includes the most important thermo-hydromechanical and chemical processes which occur during the migration of gas and fluids along faults and leaky wellbores." Uncertainties in selecting values for input parameters and potentially inadequate field data for model verification limit the reliability of model predictions.

In addition to their use in research applications, analytical and numerical modeling approaches are used to design hydraulic fracturing treatments and predict the extent of fractured areas (Adachi et al., 2007). Specifically, modeling techniques are used to assess the treatment's sensitivity to critical parameters such as injection rate, treatment volumes, fluid viscosity, and leakoff. Existing models range from simpler (typically two-dimensional) theoretical models to computationally more complicated three-dimensional models.

Monitoring of hydraulic fracturing operations can also provide insights into fracture development. Monitoring techniques involve both operational monitoring methods and "external" methods not

[1] As described in Section 6.2.2.2, Young's modulus, a ratio of stress to strain, is a measure of the rigidity of a material. Poisson's ratio is a ratio of transverse-to-axial (or latitudinal-to-longitudinal) strain, and it characterizes how a material is deformed under pressure. See Zoback (2010) for more information on the geomechanical properties of reservoir rocks.

directly related to the production operation. Operational monitoring refers to the monitoring of pressure and flow rate, along with related parameters such as fluid density and additive concentrations, using surface equipment and/or downhole sensors (Eberhard, 2011). This monitoring is conducted to ensure the operation is proceeding as planned and to determine if operational parameters need to be adjusted. Interpretation of pressure data can be used to better understand fracture behavior (Kim and Wang, 2014). For example, pressure data from previous hydraulic fracturing operations can indicate whether a geologic barrier to fracture growth exists and whether the barrier has been penetrated, or whether fractures have intersected with natural fractures or faults (API, 2015). Anomalies in operational monitoring data can also indicate whether an unexpected event has occurred, such as communication with another well (Section 6.3.2.3).

As described in Chapter 4, the volume of fluid injected is typically monitored and tracked to provide information on the volume and extent of fractures created (Flewelling et al., 2013). However, numerical investigations have found that reservoir gas flows into the fractures immediately after they open from hydraulic fracturing, and injection pressurizes both gas and water within the fracture to induce further fracture propagation (Kim and Moridis, 2015). Therefore, the fracture volume can be larger than the injected fluid volume. As a result, simple estimation of fracture volume based on the amount of injected fluid may underestimate fracture growth, and additional information (e.g., from geophysical monitoring techniques) is needed to accurately predict the extent of induced fractures.

External monitoring technologies can also be used to collect data on fracture characteristics and extent during hydraulic fracturing and/or production. These monitoring methods can be divided into near-wellbore and far-field techniques. Near-wellbore techniques include the use of tracers, temperature logs, video logs, and caliper logs that measure conditions in and immediately around the wellbore (Holditch, 2007). However, near-wellbore techniques and logs only provide information for, at most, a distance of two to three wellbore diameters from the well and are, therefore, not suited for tracking fractures for their entire length (Holditch, 2007).

Far-field methods, such as microseismic monitoring or tiltmeters, are used if the intent is to estimate fracture growth and height across the entire fractured reservoir area. Microseismic monitoring involves placing geophones in a position to detect the very small amounts of seismic energy generated during subsurface fracturing (Warpinski, 2009).[1] Monitoring these microseismic events gives an idea of the location and size of the fracture network, as well as the orientation and complexity of fracturing (Fisher and Warpinski, 2012). Using the results of microseismic monitoring in conjunction with other information, such as time-lapse, multicomponent seismic data (collected with surface surveys), can provide additional information for understanding fracture complexity and the interaction between natural and induced fractures (D'Amico and Davis, 2015). The Well File Review (U.S. EPA, 2016c) found that microseismic monitoring was conducted at 0.5% (100) of the hydraulic fracturing jobs studied.[2] Tiltmeters, which measure extremely small deformations in the earth, can be used to determine the direction and volume of the fractures and,

[1] Typical microseismic events associated with hydraulic fracturing have a magnitude on the order of -2.5 (negative two and half) (Warpinski, 2009).

[2] 100 jobs (95% confidence interval: 40 – 300 jobs).

within certain distances from the well, to estimate their dimensions (Lecampion et al., 2005). Other monitoring techniques, such as seismic surveys, can also be used to gather information about the subsurface environment. For example, Viñal and Davis (2015) demonstrated the use of time-lapse multi-component seismic surveys to monitor changes in the overburden due to hydraulic fracturing. Chapter 10 provides additional discussion of factors and practices, such as site monitoring, that can reduce the frequency or severity of impacts to drinking water quality.

6.3.2 Migration of Fluids through Pathways Related to Fractures/Formations

As described above, subsurface migration of fluids requires a pathway, induced or natural, with enough permeability to allow fluids to flow, as well as a hydraulic gradient physically driving the movement. The following subsections describe and evaluate potential pathways for the migration of hydraulic fracturing fluids, hydrocarbons, or other fluids from producing formations to drinking water resources. They also present cases where the existence of these pathways has been documented. The potential subsurface migration pathways are categorized as follows: (1) migration out of the production zone through pore space in the rock, (2) migration due to fracture overgrowth out of the production zone, (3) migration via fractures intersecting offset wells or other artificial structures, and (4) migration via fractures intersecting other geologic features, such as permeable faults or pre-existing natural fractures. Although these four potential pathways are discussed separately here, they may act in combination with each other or in combination with pathways along the well (as discussed in Section 6.2) to affect drinking water resources.

The possibility of fluid migration between a hydrocarbon-bearing formation and a drinking water resource can be related to the vertical distance between these formations (Reagan et al., 2015; Jackson et al., 2013d). In general, as the separation distance between the production zone and a drinking water aquifer decreases, the likelihood of upward migration of hydraulic fracturing to drinking water aquifers increases (Birdsell et al., 2015a). The separation distance between hydraulically fractured producing zones and drinking water resources (and these formations' depth from the surface) varies substantially among shale gas plays, coalbed methane plays, and other areas where hydraulic fracturing takes place in the United States (Figure 6-6 and Table 6-3). Many hydraulic fracturing operations target deep shale zones such as the Marcellus or Haynesville/ Bossier, where the vertical distance between the top of the shale formation and the base of drinking water resources may be 1 mi (1.6 km) or greater. This is reflected in the Well File Review, in which approximately half of the wells were estimated to have 5,000 ft (2,000 m) or more of measured distance along the wellbore between the point of the shallowest hydraulic fracturing and the operator-reported base of the protected groundwater resource (U.S. EPA, 2015n).[1] Similarly, in a review of FracFocus data from over 40,000 wells across the United States, Jackson et al. (2015) found that the median depth of wells used for hydraulic fracturing was 8,180 ft (2,490 m) and the mean depth was 8,290 ft (2,530 m).

[1] In the Well File Review, measured depth represents length along the wellbore, which may be a straight vertical distance below ground or may follow a more complicated path, if the wellbore is not straight and vertical. True vertical separation distances were not reported in the Well File Review. Measured distance along a well is equal to the true vertical distance only in straight, vertical wells. Otherwise, the true vertical distance is less than the measured distance.

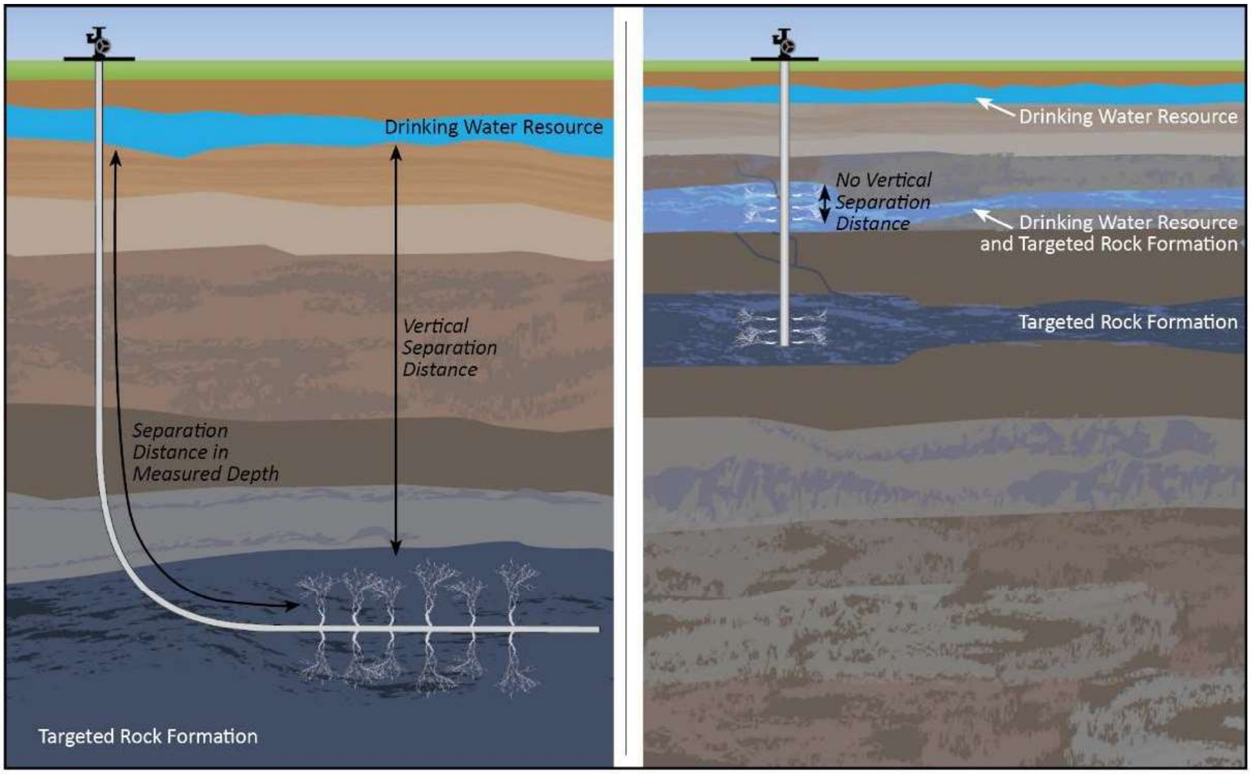


Figure 6-6. Vertical distances in the subsurface separating drinking water resources and hydraulic fracturing depths.

However, as shown in Table 6-3, some hydraulic fracturing operations occur at shallower depths or in closer proximity to drinking water resources. For example, both the Antrim and the New Albany plays are relatively shallow, with distances of 100 to 1,900 ft (31 to 580 m) between the producing formation and the base of drinking water resources. In the Jackson et al. (2015) review of FracFocus data, 16% of wells reviewed were within 1 mi (1.6 km) of the surface and 3% were within 2,000 ft (600 m) of the surface.[1] The distribution of the more shallow hydraulically fractured wells varied nationally but was concentrated in Texas, California, Arkansas, and Wyoming. For example, in California and Arkansas, 88% and 85% of hydraulically fractured wells, respectively, were within about 5,000 ft (2,000 m) of the surface. Overall, the Well File Review found a higher proportion of relatively shallow wells—the data in the Well File Review indicated that 20% of wells used for hydraulic fracturing (an estimated 4,600 wells) had less than 2,000 ft (600 m) between the shallowest point of the fractures and the base of protected groundwater resources (U.S. EPA, 2015n).[2] This is likely because the Well File Review results are more representative of hydraulic fracturing operations across the country; Jackson et al. (2015) acknowledge that their analysis

[1] Jackson et al. (2015) use true vertical depth data from FracFocus; this represents the depth of the well but not necessarily the depth of the fractures. The depth of the fractures may be shallower than the true vertical depth of the well, though Jackson et al. (2015) note that most states do not require operators to submit information on the true vertical depth to the top of the fractures.

[2] 4,600 wells (95% confidence interval: 900 – 8,300 wells). The Well File Review defines this separation distance as the measured depth of the point of shallowest hydraulic fracturing in the well, minus the depth of the operator-reported protected groundwater resource.

underestimates the occurrence of relatively shallow hydraulic fracturing for states in which FracFocus reporting is not required.

Table 6-3. Comparing the approximate depth and thickness of selected U.S. shale gas plays and coalbed methane basins.

Shale data are reported in GWPC and ALL Consulting (2009) and NETL (2013); coalbed methane data are reported in ALL Consulting (2004) and U.S. EPA (2004a). See Chapter 3 for information on the locations of these basins, plays, and formations.

Basin/play/ formation[a]	Approx. depth (ft [m] below surface)	Approx. net thickness (ft [m])	Distance between top of production zone and base of treatable water (ft [m])[b]
Shale plays			
Antrim	600 to 2,200 [200 to 670]	70 to 120 [20 to 37]	300 to 1,900 [90 to 580]
Barnett	6,500 to 8,500 [2,000 to 2,600]	100 to 600 [30 to 200]	5,300 to 7,300 [1,600 to 2,200]
Eagle Ford	4,000 to 12,000 [1,000 to 3,700]	250 [76]	2,800 to 10,800 [850 to 3,290]
Fayetteville	1,000 to 7,000 [300 to 2,000]	20 to 200 [6 to 60]	500 to 6,500 [200 to 2,000]
Haynesville-Bossier	10,500 to 13,500 [3,200 to 4,120]	200 to 300 [60 to 90]	10,100 to 13,100 [3,080 to 3,990]
Marcellus	4,000 to 8,500 [1,000 to 2,600]	50 to 200 [20 to 60]	2,125 to 7,650 [648 to 2,330]
New Albany	500 to 2,000 [200 to 600]	50 to 100 [20 to 30]	100 to 1,600 [30 to 490]
Woodford	6,000 to 11,000 [2,000 to 3,400]	120 to 220 [37 to 67]	5,600 to 10,600 [1,700 to 3,230]
Coalbed methane basins			
Black Warrior (Upper Pottsville)	0 to 3,500 [0 to 1,100]	< 1 to > 70 [< 1 to > 20]	As little as zero[c]
Powder River (Fort Union)	450 to >6,500 [140 to >2,000]	75 [23]	As little as zero[c]
Raton (Vermejo and Raton)	< 500 to > 4,100 [< 200 to > 1,300]	10 to >140 [3 to >43]	As little as zero[c]
San Juan (Fruitland)	550 to 4,000 [170 to 1,000]	20 to 80 [6 to 20]	As little as zero[c]

[a] For coalbed methane, values are given for the specific coal units noted in parentheses.

[b] The base of treatable water is defined at the state level; the information in the table is based on depth data from state oil and gas agencies and state geological survey data.

[c] Formation fluids in producing formations meet the salinity threshold that is used in some definitions of a drinking water resource in at least some areas of the basin. See the discussion after Text Box 6-5 for more information about this definition.

In coalbed methane plays, which are typically shallower than shale gas plays, vertical separation distances can be even smaller. In the Raton Basin of southern Colorado and northern New Mexico, approximately 10% of coalbed methane wells have less than 675 ft (206 m) of separation between the gas wells' perforated intervals and the depth of local water wells. In certain areas of the basin, this distance is less than 100 ft (31 m) (Watts, 2006). In California, nearly half of the hydraulic fracturing has occurred at depths less than about 900 ft (300 m) (CCST, 2015b), with hundreds of wells in the San Joaquin Valley between 150 ft (46 m) and 2,000 ft (600 m) deep (Jackson et al., 2015).

Some hydraulic fracturing operations are conducted within formations containing drinking water resources (Table 6-3). One example of hydraulic fracturing taking place within a geologic formation that is also used as a drinking water source is in the Wind River Basin in Wyoming (Digiulio and Jackson, 2016; WYOGCC, 2014b; Wright et al., 2012). Vertical gas wells in this area target the lower Wind River Formation and the underlying Fort Union Formation, which consist of interbedded layers of sandstones, siltstones, and mudstones. The Wind River Formation also serves as the principal source of domestic, municipal, and agricultural water in this rural area. There are no laterally continuous confining layers of shale in the basin to prevent upward movement of fluids. While flow in the basin generally tends to be downward, local areas of upward flow have been documented (Digiulio and Jackson, 2016). Assessing the relative depths of drinking water resources and hydraulic fracturing operations near Pavillion, Wyoming, Digiulio and Jackson (2016) found that approximately 50% of fracture jobs were within 1,969 ft (600 m) of the deepest domestic drinking water well in the area, and that 10% were within 820 ft (250 m) (Digiulio and Jackson, 2016). Among the wells evaluated by DiGiulio and Jackson, the shallowest fracturing occurred at 1,057 ft (322 m) below ground surface, which is comparable to depths targeted for drinking water withdrawal in the formation. See Text Box 6-5 for more information on Pavillion, Wyoming.

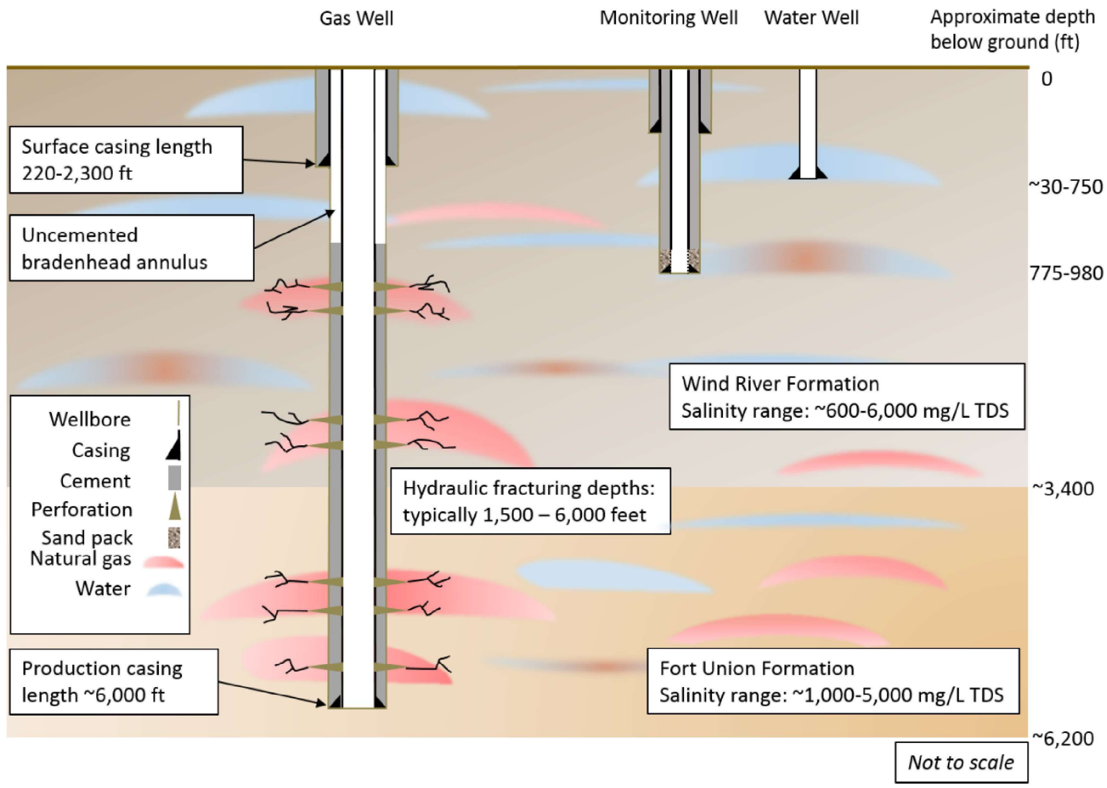
Text Box 6-5. Pavillion, Wyoming.

The Pavillion gas field is located east of the town of Pavillion, Wyoming. In addition to gas production, the field is also home to rural residences that rely on approximately 40 private wells to supply drinking water. The oldest known domestic water well in the field dates to 1934 (AME, 2016). Gas production in the field began in 1960 and, by the 2000s, it had grown to producing from at least 180 wells. Most of these gas wells were drilled since 1990, and approximately 140 to 145 were not plugged as of mid-2016 (AME, 2016; Digiulio and Jackson, 2016).

In the Pavillion gas field the same geologic formation that is used to produce hydrocarbons supplies the area's drinking water (Digiulio and Jackson, 2016). Water wells draw from the Wind River Formation, and gas is extracted from both the Wind River Formation and the underlying Fort Union Formation. The Wind River Formation contains variably permeable strata with lenses of relatively higher permeability rock enriched with natural gas. Water quality is typically freshest nearer the surface, and there is no rock formation acting as a natural barrier to separate the drinking water from hydrocarbons (Digiulio and Jackson, 2016). There is approximately 200 ft (60 m) vertical distance separating the deepest domestic well in the field from the shallowest hydraulic fracturing, although there is approximately 2.5 mi (4 km) lateral distance between them (AME, 2016; Digiulio and Jackson, 2016).

(Text Box 6-5 is continued on the following page.)

Text Box 6-5 (continued). Pavillion, Wyoming.



Following complaints by area residents about changes to their water quality in the mid-2000s, state and federal agencies began a series of investigations, centering on various aspects of the site and supporting differing conclusions about the source and mechanism of the water quality changes (AME, 2016).

Twenty-five pits that were used to dispose of drill cuttings, drilling mud, and spent drilling fluids near some of the water wells were also investigated as a potential source of the groundwater contamination. Based on these evaluations, soil and/or groundwater remediation was performed at approximately six of the pits, no further action was recommended at approximately twelve pits, and the remaining pits are receiving further investigation (AME, 2016).

Samples collected from two monitoring wells at depths between those of the drinking water and active intervals in gas production wells show elevated pH, unexpectedly high potassium values, and several organic constituents, including natural gas, alcohols, phenols, glycols, and benzene, toluene, ethylbenzene, and xylenes (BTEX) (Digiulio and Jackson, 2016). The potential source of chemicals in these two monitoring wells include formation water, contaminants remaining after well construction (AME, 2016) and hydraulic fracturing and other oil and gas activities (Digiulio and Jackson, 2016).

Water samples collected from domestic wells contain dissolved methane and some contain high sodium and sulfate concentrations. Organic chemicals have also been detected in some domestic wells (AME, 2016; Digiulio and Jackson, 2016). These same investigators suspect that pit proximity explains the origin of organic chemicals. In addition, natural gases from intermediate depths not hydraulically fractured are likely moving along some gas wellbores, potentially into zones used for drinking water (AME, 2016).

(Text Box 6-5 is continued on the following page.)

Text Box 6-5 (continued). Pavillion, Wyoming.

Of about 40 production wells at which pressure was measured on the bradenhead annulus between the production and surface casings, about 25% exhibited sustained casing pressure consistent with an ongoing source of gas and/or liquid. Gas samples collected from bradenhead annuli, production tubing and casing, and water wells indicate that the samples have similar gas compositions. This suggests a common origin, which is consistent with long-term migration from a deeper source (AME, 2016; WYOGCC, 2014b).

Production wells may be the source of gas migration, and groundwater immediately around some of the disposal pits has been affected (AME, 2016). However, the investigative reports conclude that identifying the precise source(s) of the water quality issues is challenging due to the lack of comprehensive pre-drilling water quality and other baseline monitoring, the unique hydrogeologic setting, and the difficulty of identifying specific geologic or well pathways.

In other cases, hydraulic fracturing takes place in formations that are not currently being used as sources of drinking water, but that meet the salinity threshold that is used in some definitions of drinking water resources.[1] This occurs in low-salinity coal-bearing formations in the Raton Basin of Colorado (U.S. EPA, 2015k), the San Juan Basin of Colorado and New Mexico (U.S. EPA, 2004a), the Powder River Basin of Montana and Wyoming (as described in Chapter 7), and in several other coalbed methane plays. Hydraulic fracturing in these regions occurs in formations characterized by total dissolved solids (TDS) values substantially lower than the 10,000 mg/L TDS value used in the federal definition of an underground source of drinking water.[2] Across various basins, coalbed methane operations have been reported to occur in formations with 300 to 3,000 mg/L TDS and at depths as shallow as 350 ft (110 m) (U.S. EPA, 2004a). In one field in Alberta, Canada, there is evidence that fracturing in the same formation as a drinking water resource (in combination with mechanical integrity problems; see Section 6.2.2.4) led to gas migration into water wells (Tilley and Muehlenbachs, 2012).

California is another area where hydraulic fracturing occurs in shallow zones with low-salinity groundwater. A study by the California Council on Science and Technology (CCST, 2015b) found that 3% of the hydraulic fracturing in the state occurred within 2,000 ft (600 m) of the surface. In California's San Joaquin Valley, hydraulic fracturing appears to have been conducted in formations with a TDS of less than 1,500 mg/L (CCST, 2014). Another study in California examined the TDS values of water samples taken during oil and gas activities and found that 15% to 19% of the oil and

[1] For the purposes of this discussion, the federal definition of an underground source of drinking water is used. Pursuant to 40 CFR 144.3, an underground source of drinking water is "an aquifer or its portion which supplies any public water system; or which contains a sufficient quantity of groundwater to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/L TDS; and which is not an exempted aquifer." This definition is used by the EPA's Underground Injection Control Program, which regulates injection wells (but not hydrocarbon production wells).

[2] This salinity threshold is used as a point of comparison only. While the definition of an underground source of drinking water is not exactly the same as the definition of a drinking water resource (and many states have their own definitions of protected drinking water zones), the former provides a useful frame of reference when considering the ability of an aquifer to potentially serve as a source of drinking water.

gas activities in Kern County, California, occurred within zones containing water with less than 3,000 mg/L TDS (Kang and Jackson, 2016).[1]

The overall frequency at which hydraulic fracturing occurs in formations that meet the definition of drinking water resources across the United States is uncertain. Some information, however, that provides insights on the occurrence and geographic distribution of this practice is available. According to the Well File Review, an estimated 0.4% (90) of the 23,200 wells represented in that study had perforations used for hydraulic fracturing that were placed shallower than the base of the protected groundwater resources reported by well operators (U.S. EPA, 2015n).[2] Additional information is available from a database of produced water composition data maintained by the U.S. Geological Survey (USGS). The USGS produced water database contains results from analyses of samples of produced water, including (among other data) samples collected from more than 8,500 oil and gas production wells in unconventional formations (coalbed methane, shale gas, tight gas, and tight oil) within the contiguous United States.[3] Just over 5,000 of these samples, which were obtained from wells located in 37 states, reported TDS concentrations. Because the database does not track whether samples were from wells that were hydraulically fractured, the EPA selected samples from wells that were more likely to have been hydraulically fractured by restricting samples to those collected in 1950 or later and to those that were collected from wells producing from tight gas, tight oil, shale gas, or coalbed methane formations.[4] This yielded 1,650 samples from wells located in Alabama, Colorado, North Dakota, Utah, and Wyoming, with TDS concentrations ranging from approximately 90 mg/L to 300,000 mg/L.[5] Of the 1,650 samples, approximately 1,200 (from wells in Alabama, Colorado, Utah, and Wyoming) reported TDS concentrations at or below 10,000 mg/L, indicating that hydraulic fracturing there may have occurred within formations that meet the salinity threshold that is used in some definitions of a drinking water resource. This analysis, in conjunction with the result from the Well File Review, suggests that the overall frequency of this occurrence is relatively low, but is concentrated in particular areas of the country.

6.3.2.1 Flow of Fluids Out of the Production Zone

One potential pathway for fluid migration out of the production formation into drinking water resources is advective or dispersive flow of injected or displaced fluids through the formation matrix. In this scenario, fluids (such as those "lost" to leakoff, which are not recovered during

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[1] Kern County accounts for 85 percent of the hydraulic fracturing that occurs in California (CCST, 2015b).

[2] 90 wells (95% confidence interval: 10 – 300 wells).

[3] The EPA used the USGS Produced Water Geochemical Database Version 2.1 (USGS database v 2.1) for this analysis (http://energy.cr.usgs.gov/prov/prodwat/). The database is comprised of produced water samples compiled by the USGS from 25 individual databases, publications, or reports.

[4] See Chapter 3, Text Box 3-1, which describes how commercial hydraulic fracturing began in the late 1940s.

[5] For this analysis, the EPA assumed that produced water samples collected in 1950 or later from shale gas, tight oil, and tight gas wells were from wells that had been hydraulically fractured. To estimate which coal bed methane wells had been hydraulically fractured, the EPA matched API numbers from coal bed methane wells in the USGS database v 2.1 to the same API numbers in the commercial database DrillingInfo, in which hydraulically fractured wells had been identified by the EPA using the assumptions described in Section 3.4. Wells with seemingly inaccurate (i.e., less than 12 digit) API numbers were also excluded. Only coalbed methane wells from the USGS database v 2.1 that matched API numbers in the DrillingInfo database were retained for this analysis.

production) would flow through the pore spaces of rock formations, moving from the production zone into other formations. In deep, low-permeability shale and tight gas settings and where induced fractures are contained within the production zone, flow through the production formation has generally been considered an unlikely pathway for migration into drinking water resources (Jackson et al., 2013d).

Leakoff into shale gas formations can be as high as 90% or more of the injected volume (Table 7-2). The actual amount of leakoff depends on multiple factors, including the amount of injected fluid, the concentration of different components in the fracture fluid, the hydraulic properties of the reservoir (e.g., permeability), the composition of the formation matrix, the capillary pressure near the fracture faces, and the period of time the well is shut in following hydraulic fracturing before the start of production (Kim et al., 2014; Byrnes, 2011).[1,2] Researchers generally agree that the subsequent flow of this "lost" leakoff fluid is controlled or limited by processes such as imbibition by capillary forces and adsorption onto clay minerals (Dutta et al., 2014; Dehghanpour et al., 2013; Dehghanpour et al., 2012; Roychaudhuri et al., 2011) and osmotic forces (Zhou, 2016; Wang and Rahman, 2015; Engelder et al., 2014).[3,4] It has been suggested that these processes can sequester the fluids in the producing formations permanently or for geologic time scales (Engelder et al., 2014; Engelder, 2012; Byrnes, 2011). Birdsell et al. (2015b) made quantitative estimates of the amount of fluid that could be imbibed in shale formations. Their results indicate that between 15% and 95% of injected fluid volumes may be imbibed in shale gas systems, while amounts are lower in shale oil systems (3% to 27% of injected volumes). In modeling investigations, O'Malley et al. (2015) found that it is likely that most hydraulic fracturing fluid that does not flow back is stored in rock pore spaces (i.e., having displaced the gas that was present there) and not fractures. The amount that can be stored in fractures is highly dependent on the effective interconnected pore lengths.

If the injected fluid is not sequestered in the immediate vicinity of the fracture network, migration into drinking water resources would likely require a substantial upward hydraulic gradient (e.g., due to the pressures introduced during injection for hydraulic fracturing), particularly for brine that is denser than the groundwater in the overlying formations (Flewelling and Sharma, 2014). In the presence of natural gas, buoyancy of the less dense gas could potentially provide an upward flux (Vengosh et al., 2014). However, Flewelling and Sharma (2014) indicated that pressure

[1] Relative permeability is a dimensionless property allowing for the comparison of the different abilities of fluids to flow in multiphase settings. If a single fluid is present, its relative permeability is equal to 1, but the presence of multiple fluids generally inhibits flow and decreases the relative permeability (Schlumberger, 2014).

[2] Shutting in the well after fracturing allows fluids to move farther into the formation, resulting in a higher gas relative permeability near the fracture surface and improved gas production (Bertoncello et al., 2014).

[3] Imbibition is the displacement of a nonwetting fluid (i.e., gas) by a wetting fluid (typically water). The terms wetting or nonwetting refer to the preferential attraction of a fluid to the surface. In typical reservoirs, water preferentially wets the surface, and gas is nonwetting. Capillary forces arise from the differential attraction between immiscible fluids and solid surfaces; these are the forces responsible for capillary rise in small-diameter tubes and porous materials. These definitions are adapted from Dake (1978).

[4] The contrast in water activity between brine and fresh water generates very substantial osmotic pressure differences that will drive fluids into the shale matrix. The osmosis process requires a semi-permeable membrane and a concentration gradient to allow the solvent to pass through it. The clay in the shale formation can provide a function similar to a membrane (Zhou, 2016).

perturbations due to hydraulic fracturing operations are localized to the immediate vicinity of the fractures, due to the very low permeabilities of shale formations; this means that hydraulic fracturing operations are unlikely to generate sufficient pressure to drive fluids into shallow drinking water zones. Some natural conditions could also create an upward hydraulic gradient in the absence of any effects from hydraulic fracturing. However, these natural mechanisms have been found to cause very low flow rates over very long distances, yielding extremely small vertical fluxes in sedimentary basins. These translate to some estimated travel times of 100,000 to 100,000,000 years across a 328 ft (100 m) thick layer with about 0.01 nD (1×10^{-23} m^2) permeability (Flewelling and Sharma, 2014). In an area of the Permian Basin with over-pressured source rocks, Engle et al. (2016) concluded that chemical, isotopic, and pressure data suggest that there is little potential for vertical fluid migration to shallow zones in the absence of pathways such as improperly abandoned wells (Section 6.3.2.3).

To account for the combined effect of capillary imbibition, well operation, and buoyancy in upward fluid migration, Birdsell et al. (2015a) conducted a numerical analysis over five phases of activity at a hypothetical Marcellus-like hydraulic fracturing site: a pre-drilling steady state, the injection of fluids, a shut-in period, production, and the continued migration of hydraulic fracturing fluids after the well is plugged and abandoned. They quantified how much hydraulic fracturing fluid flows back up the well after fracturing, how much reaches overlying aquifers, and how much is permanently sequestered by capillary imbibition (which is treated as a sink term). Their results affirmed that, without a pathway such as a permeable fault or leaky wellbore, it is very unlikely that hydraulic fracturing fluid from a deep shale could reach an overlying aquifer. However, the study did indicate that upward migration on the order of 328 ft (100 m) could occur through relatively low-permeability overburden, even if no discrete, permeable pathway exists.

6.3.2.2 Fracture Overgrowth out of the Production Zone

Fractures extending out of the intended production zone into another formation, or into an unintended zone within the same formation, could provide a potential fluid migration pathway into drinking water resources (Jackson et al., 2013d). This migration could occur either through the fractures themselves or in connection with other permeable subsurface features or formations (Figure 6-7). Such “out-of-zone fracturing” is undesirable from a production standpoint and may occur as a result of inadequate reservoir characterization or fracture treatment design (Eisner et al., 2006). Some researchers have noted that fractures growing out of the targeted production zone could potentially contact other formations, such as higher conductivity sandstones or conventional hydrocarbon reservoirs, which may create an additional pathway for migration into a drinking water resource (Reagan et al., 2015). In addition, fractures growing out of the production zone could potentially intercept natural, preexisting fractures (discussed in Section 6.3.2.4) or active or abandoned wells near the well where hydraulic fracturing is performed (discussed in Section 6.3.2.3).

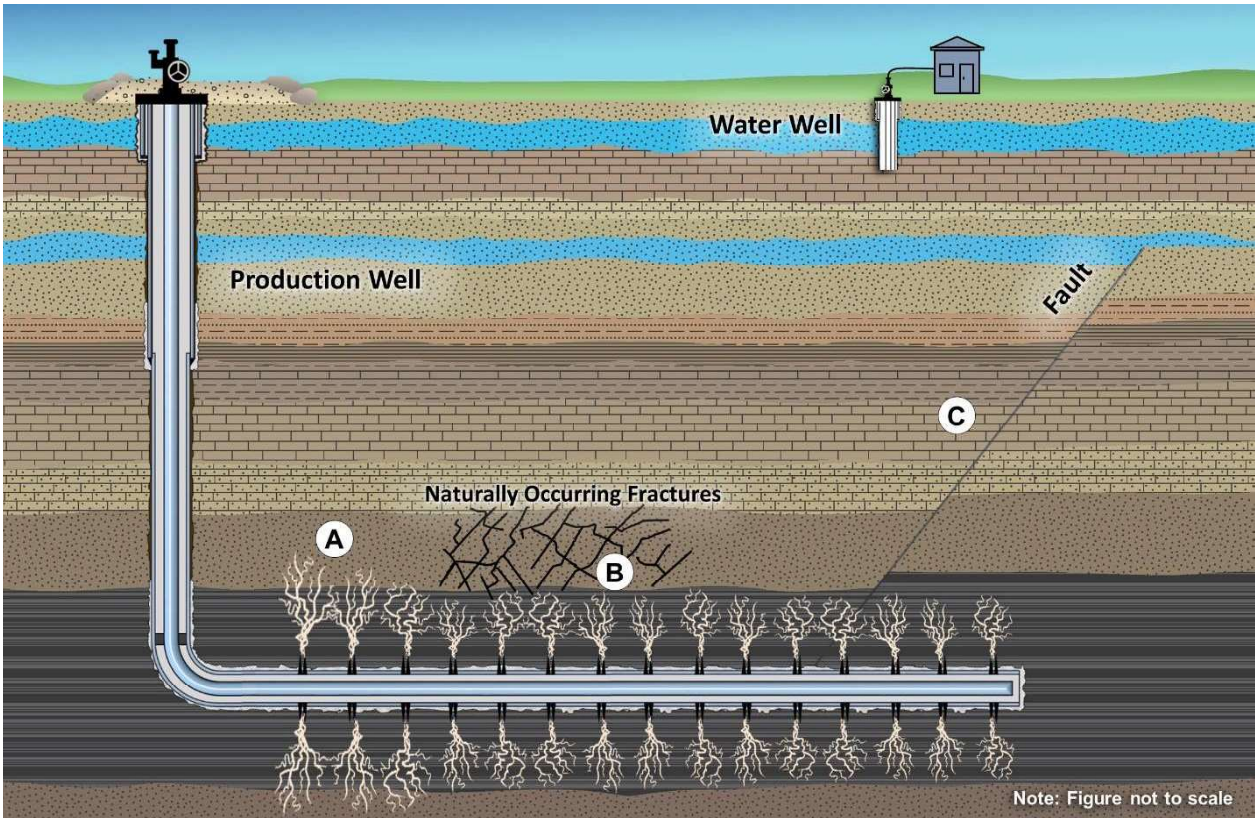


Figure 6-7. Conceptualized depiction of potential pathways for fluid movement out of the production zone: (a) induced fracture overgrowth into over- or underlying formations; (b) induced fractures intersecting natural fractures; and (c) induced fractures intersecting a permeable fault.

The fracture's geometry (Section 6.3.1) affects its potential to extend beyond the intended zone and serve as a pathway to drinking water resources. Vertical heights of fractures created during hydraulic fracturing operations have been measured in several U.S. shale plays, including the Barnett, Woodford, Marcellus, and Eagle Ford, using microseismic monitoring and tiltmeters (Fisher and Warpinski, 2012). These data indicate typical fracture heights extending from tens to hundreds of feet.[1] Davies et al. (2012) analyzed this data set and found that the maximum fracture height was 1,929 ft (588 m) and that 1% of the fractures had a height greater than 1,148 ft (350 m). This may raise some questions about fractures being contained within the producing formation, as some Marcellus fractures were found to extend vertically for at least 1,500 ft (460 m), while the maximum thickness of the formation is generally 350 ft (110 m) or less (MCOR, 2012). However, the majority of fractures within the Marcellus were found to have heights less than 328 ft (100 m), suggesting limited possibilities for fracture overgrowth exceeding the separation between shale reservoirs and shallow aquifers (Davies et al., 2012). This is consistent with modeling results found by Kim and Moridis (2015) and others, as described below. Where the producing formation is not

[1] As described in Section 6.3.1, microseismic data represent the small amounts of seismic energy generated during subsurface fracturing. The Fisher and Warpinski dataset includes the top and bottom depths of mapped fracture treatments in the four shale plays mentioned, giving the maximum propagation length.

continuous horizontally, the lateral extent of fractures may also become important. For example, in the Fisher and Warpinski (2012) data set, fractures were found to extend to horizontal lengths greater than 1,000 ft (300 m).

Results of National Energy Technology Laboratory (NETL) research in Greene County, Pennsylvania, are generally consistent with those reported in the Fisher and Warpinski (2012) data set. Microseismic monitoring was used at six horizontal Marcellus Shale wells to identify the maximum upward extent of brittle deformation (i.e., rock breakage) caused by hydraulic fracturing (Hammack et al., 2014). At three of the six wells, fractures extending between 1,000 and 1,900 ft (300 and 580 m) above the Marcellus Shale were identified. Overall, approximately 40% of the microseismic events occurred above the Tully Limestone, the formation overlying the Marcellus Shale. The microseismic data suggest that fracture propagation occurs above the Tully Limestone, which is sometimes referred to as an upper barrier to hydraulic fracture growth (Hammack et al., 2014). However, all microseismic events were at least 5,000 ft (2,000 m) below drinking water aquifers, as the Marcellus Shale is one of the deepest shale plays (Table 6-3), and no impacts to drinking water resources or another local gas-producing interval were identified. See Text Box 6-6 for more information on the Greene County site.

Text Box 6-6. Monitoring at the Greene County, Pennsylvania, Hydraulic Fracturing Test Site.

Monitoring performed at the Marcellus Shale test site in Greene County, Pennsylvania, evaluated fracture height growth and zonal isolation during and after hydraulic fracturing operations (Hammack et al., 2014). The site has six horizontally drilled wells and two vertical wells that were completed into the Marcellus Shale. Pre-fracturing studies of the site included a 3D seismic survey to identify faults, pressure measurements, and baseline sampling for isotopes; drilling logs were also run. Hydraulic fracturing occurred April 24 to May 6, 2012, and June 4 to 11, 2012. Monitoring at the site included the following:

- **Microseismic monitoring** was conducted during four of the six hydraulic fracturing jobs on the site, using geophones placed in the two vertical Marcellus Shale wells. These data were used to monitor fracture height growth above the six horizontal Marcellus Shale wells during hydraulic fracturing.
- **Pressure and production data** were collected from a set of existing vertical gas wells completed in Upper Devonian/Lower Mississippian zones 3,800 to 6,100 ft (1,200 to 1,900 m) above the Marcellus. Data were collected during and after the hydraulic fracturing jobs and used to identify any communication between the fractured areas and the Upper Devonian/Lower Mississippian rocks.
- **Chemical and isotopic analyses** were conducted on gas and water produced from the Upper Devonian/Lower Mississippian wells. Samples were analyzed for stable isotope signatures of hydrogen, carbon, and strontium and for the presence of perfluorocarbon tracers used in 10 stages of one of the hydraulic fracturing jobs to identify possible gas or fluid migration to overlying zones (Sharma et al., 2014a; Sharma et al., 2014b).

As of September 2014, no evidence was found of gas or brine migration from the Marcellus Shale (Hammack et al., 2014), although longer-term monitoring is necessary to confirm that no impacts to overlying zones have occurred (Zhang et al., 2014a).

Similarly, in Dunn County, North Dakota, there is evidence suggestive of out-of-zone fracturing in the Bakken Shale (U.S. EPA, 2015i). At the Killdeer site (Section 6.2.2.1), hydraulic fracturing fluids and produced water were released during a rupture of the casing at the Franchuk 44-20 SWH well. Water quality characteristics at two monitoring wells located immediately downgradient of the Franchuk well reflected a mixing of local Killdeer Aquifer water with deep formation brine. Ion and isotope ratios used for brine fingerprinting suggest that Madison Group formations (which directly overlie the Bakken in the Williston Basin) were the source of the brine observed in the Killdeer Aquifer, and the authors concluded that this provides evidence for out-of-zone fracturing (U.S. EPA, 2015i). Industry experience also indicates that out-of-zone fracturing could be fairly common in the Bakken and that produced water from many Bakken wells has Madison Group chemical signatures (Arkadakskiy and Rostron, 2013; Arkadakskiy and Rostron, 2012; Peterman et al., 2012).

Fracture growth from a deep formation to a near-surface aquifer is generally considered to be limited by layered geological environments and other physical constraints (Fisher and Warpinski, 2012; Daneshy, 2009). For example, differences in in-situ stresses in layers above and below the production zone can restrict fracture height growth in sedimentary basins (Fisher and Warpinski, 2012). High-permeability layers near hydrocarbon-producing zones can reduce fracture growth by acting as a "thief zone" into which fluids can migrate, or by inducing a large compressive stress that acts on the fracture (de Pater and Dong, 2009, as cited in Fisher and Warpinski, 2012). Although thief zones may prevent fractures from reaching shallower formations or growing to extreme vertical lengths, they do allow fluids to migrate out of the production zone into receiving formations, which could (depending on site-specific conditions) potentially contain drinking water resources. A volumetric argument has also been used to discuss limits of vertical fracture growth; that is, the volumes of fluid needed to sustain fracture growth beyond a certain height would be unrealistic (Fisher and Warpinski, 2012). However, as described in Section 6.3.1, fracture volume can be greater than the volume of injected fluid due to the effects of pressurized water combined with the effects of gas during injection (Kim and Moridis, 2015). Nevertheless, some numerical investigations suggest that, unless unrealistically high pressures and injection rates are applied to an extremely weak and homogeneous formation that extends up to the near surface, hydraulic fracturing generally induces stable and finite fracture growth in a Marcellus-type environment and fractures are unlikely to extend into drinking water resources (Kim and Moridis, 2015).

Modeling studies have identified other factors that can affect the containment of fractures within the producing formation. As discussed above, additional numerical analysis of fracture propagation during hydraulic fracturing has demonstrated that contrasts in the geomechanical properties of rock formations can affect fracture height containment (Gu and Siebrits, 2008) and that geological layers present within shale gas reservoirs can limit vertical fracture propagation (Kim and Moridis, 2015). In another modeling study, Myshakin et al. (2015) applied a multi-layered geologic model to study whether fracture growth can extend upward through overlying strata and reach drinking water resources in a Marcellus Shale-type environment. Most fractures were predicted either to extend upward to the overlying layer (about 46%) or to remain in the Marcellus Shale (about 34%). About 20% of the fractures were predicted to extend further upward into or above the overlying limestone. These model results are consistent with microseismic events observed above the Tully Limestone in Greene County, Pennsylvania (Hammack et al., 2014), where the fracture heights ranged from 0 to 700 ft (0 to 200 m) and most of the fractures terminated less than 100 ft (31 m) above the top of the Marcellus.

If fractures were to propagate from the production zone to drinking water resources, other factors would need to be in place for fluid migration to occur. Using a numerical simulation, Reagan et al. (2015) investigated potential short-term migration of gas and water between a shale or tight gas formation and a shallower groundwater unit, assuming that a permeable pathway already exists between the two formations. Note that, for the purposes of this study, the pathway was assumed to be pre-existing, and Reagan et al. (2015) did not model the hydraulic fracturing process itself.

The subsurface system evaluated in the Reagan et al. (2015) modeling investigation included a horizontal well used for hydraulic fracturing and gas production, a connecting pathway between the producing formation and the aquifer, and a shallow vertical water well in the aquifer (Figure 6-7). The parameters and scenarios used in the study are shown in Table 6-4; two vertical separation distances between the producing formation and the aquifer were investigated, along with a range of production zone permeabilities and other variables used to describe four production scenarios. The horizontal well was assigned a constant bottomhole pressure of half the initial pressure of the target reservoir, not accounting for any over-pressurization from hydraulic fracturing. (As noted in Section 6.3.2.1, over-pressurization during hydraulic fracturing can create an additional driving force for upward migration.) In the simulation, migration was assessed immediately after hydraulic fracturing and for up to a 2-year simulation period representing the production stage.

Results of this modeling investigation indicate a generally downward water flow within the connecting fracture (i.e., flow from the aquifer through the connecting fracture into the hydraulically induced fractures in the production zone) with some upward migration of gas (Reagan et al., 2015). In certain simulated cases, gas breakthrough (the appearance of gas at the base of the drinking water aquifer) was also observed. The key parameter affecting migration of gas into the aquifer was the production regime, particularly whether gas production (which drives migration toward the production well) was occurring in the reservoir. Simulations that included a producing gas well showed only a few instances of breakthrough, while simulations without gas production (i.e., that assumed the well was shut-in) tended to result in breakthrough. When gas breakthrough did occur, the breakthrough times ranged from minutes to 20 days. However, in all cases, the gas escape was limited in duration and scope, because the amount of gas available for immediate migration toward the shallow aquifer was limited to that initially stored in the hydraulically induced fractures after the stimulation process and prior to production. These simulations indicate that the target reservoir may not be able to replenish the gas that was available for migration prior to production.

Based on the results of the Reagan et al. (2015) modeling study, gas production from the reservoir appears likely to mitigate gas migration, both by reducing the amount of available gas and depressurizing the induced fractures (which counters the buoyancy of any gas that may escape from the production zone into the connecting fracture). Production at the gas well also creates pressure gradients that drive a downward flow of water from the aquifer via the fracture into the producing formation, increasing the amount of water produced at the gas well. Furthermore, the effective permeability of the connecting feature is reduced during water (downward) and gas (upward) counter-flow within the fracture, further retarding the upward movement of gas or allowing gas to dissolve into the downward flow. However, Reagan et al. (2015) did find an increased potential for gas release from the producing formation in cases where there is no gas production following hydraulic fracturing. The potential for gas migration during shut-in periods following hydraulic fracturing and prior to production may be more significant, especially when out-of-zone fractures are formed. Without the effects of production, gas can rise via buoyancy, with any downward-flowing water from the aquifer displacing the upward-flowing gas.

Reagan et al. (2015) also found that the permeability of a connecting fault or fracture may be an important factor affecting the potential upward migration of gas (although not as significant as the production regime). For the cases where gas escaped from the production zone, the maximum volume of migrating gas depended upon the permeability of the connecting feature: the higher the permeability, the larger the volume. The modeling results also showed that lower permeabilities delay the downward flow of water from the aquifer, allowing the trace amount of gas that entered into the fracture early in the modeled period to reach the aquifer, which was otherwise predicted to dissolve in the water flowing downward in the feature. Similarly, the permeabilities of the target reservoir, fracture volume, and the separation distance were found to affect gas migration, because they affected the initial amount of gas stored in the hydraulically induced fractures. In contrast, the permeability of the drinking water aquifer was not found to be a significant factor in the assessment.

Table 6-4. Modeling parameters and scenarios investigated by Reagan et al. (2015).

This table illustrates the range of parameters included in the Reagan et al. (2015) modeling study. See Figure 6-7, Figure 6-8, and Figure 6-9 for conceptualized illustrations of these scenarios.

Model parameter or variable	Values investigated in model scenarios
All scenarios	
Lateral distance from connecting feature to water well	328 ft (100 m)
Vertical separation distance between producing formation and drinking water aquifer	656 ft (200 m); 2,625 ft (800 m)
Producing formation permeability range	1 nD (1 x 10^{-21} m^2); 100 nD (1 x 10^{-19} m^2); 1 µD (1 x 10^{-18} m^2)
Drinking water aquifer permeability	0.1 D (1 x 10^{-13} m^2); 1 D (1 x 10^{-12} m^2)
Initial conditions	Hydrostatic
Production well bottom hole pressure	Half of the initial pressure of the producing formation (not accounting for over-pressurization from hydraulic fracturing)
Production regime	Production at both the water well and the gas well; Production at only the water well; Production at only the gas well; No production

Model parameter or variable	Values investigated in model scenarios
Fracture pathway scenarios	
Connecting feature permeability	1 D (1 x 10^{-12} m^2); 10 D (1 x 10^{-11} m^2); 1,000 D (1 x 10^{-9} m^2)
Offset well pathway scenarios	
Lateral distance from production well to offset well	33 ft (10 m)
Cement permeability of offset well	1 µD (1 x 10^{-18} m^2); 1 mD (1 x 10^{-15} m^2); 1 D (1 x 10^{-12} m^2); 1,000 D (1 x 10^{-9} m^2)

6.3.2.3 Migration via Fractures Intersecting with Offset Wells and Other Artificial Structures

Another potential pathway for fluid migration is one in which hydraulic fracturing fluids or displaced subsurface fluids move through newly created fractures into an offset well or its fracture network, resulting in a process called well communication (Jackson et al., 2013d). The offset well can be an abandoned (i.e., plugged), inactive, or actively producing well. In addition, if the offset well has also been used for hydraulic fracturing, the fracture networks of the two wells might intersect. The situation where hydraulic fractures propagate to (and inject fluid into and/or cause pressure increases in) other existing wells or hydraulic fractures is referred to as a "frac hit" and is known to occur in areas with a high density of wells (Jackson et al., 2013a).

Frac hits can be more common in unconventional production settings compared to conventional production settings, due to the closer/denser well spacing (King and Valencia, 2016). Figure 6-8 provides a schematic to illustrate fractures that intercept an offset well, and Figure 6-9 depicts (in a simplified illustration) how the fracture networks of two such wells might intersect. This can be a particular concern in shallower formations, where the local least principal stress is vertical (resulting in more horizontal fracture propagation), and in situations where there are drinking water wells in the same formation as wells used for hydraulic fracturing.

Instances of well communication have been known to occur and are described in well records and the oil and gas literature. For example, an analysis of operator data collected by the New Mexico Oil Conservation Division (NM OCD) in 2013−2014 identified 120 instances of well communication in the San Juan Basin between 2007 and 2013 (Vaidyanathan, 2014). In some cases, well communication incidents have led to documented production and/or environmental problems. A study in the Barnett Shale noted two cases of well communication, one with a well 1,100 ft (340 m) away and the other with a well 2,500 ft (760 m) away from the initiating well; ultimately, one of the offset wells had to be re-fractured because the well communication halted production (Craig et al., 2012). In some cases, the fluids that intersect the offset well flow up the wellbore and spill onto the surface. In its report *Review of State and Industry Spill Data: Characterization of Hydraulic Fracturing-Related Spills*, the EPA (2015m) recorded 10 incidents in which fluid spills were attributed to well communication events (see Text Box 5-10 for more information on this effort).[1] The Well File Review (U.S. EPA, 2016c) reports that 1% of the wells (an estimated 280 wells) represented in the study reported a frac hit, where the hydraulic fracturing operation documented in the Well File Review led to communication with a nearby well.[2] (It was not possible to determine whether fluids reached protected groundwater resources during these frac hits based on information in the well files.) While the subsurface effects of frac hits have not been extensively studied, these cases demonstrate the possibility of fluid migration via communication with other wells and/or their fracture networks. More generally, well communication events can indicate fracture behavior that was not intended by the treatment design.

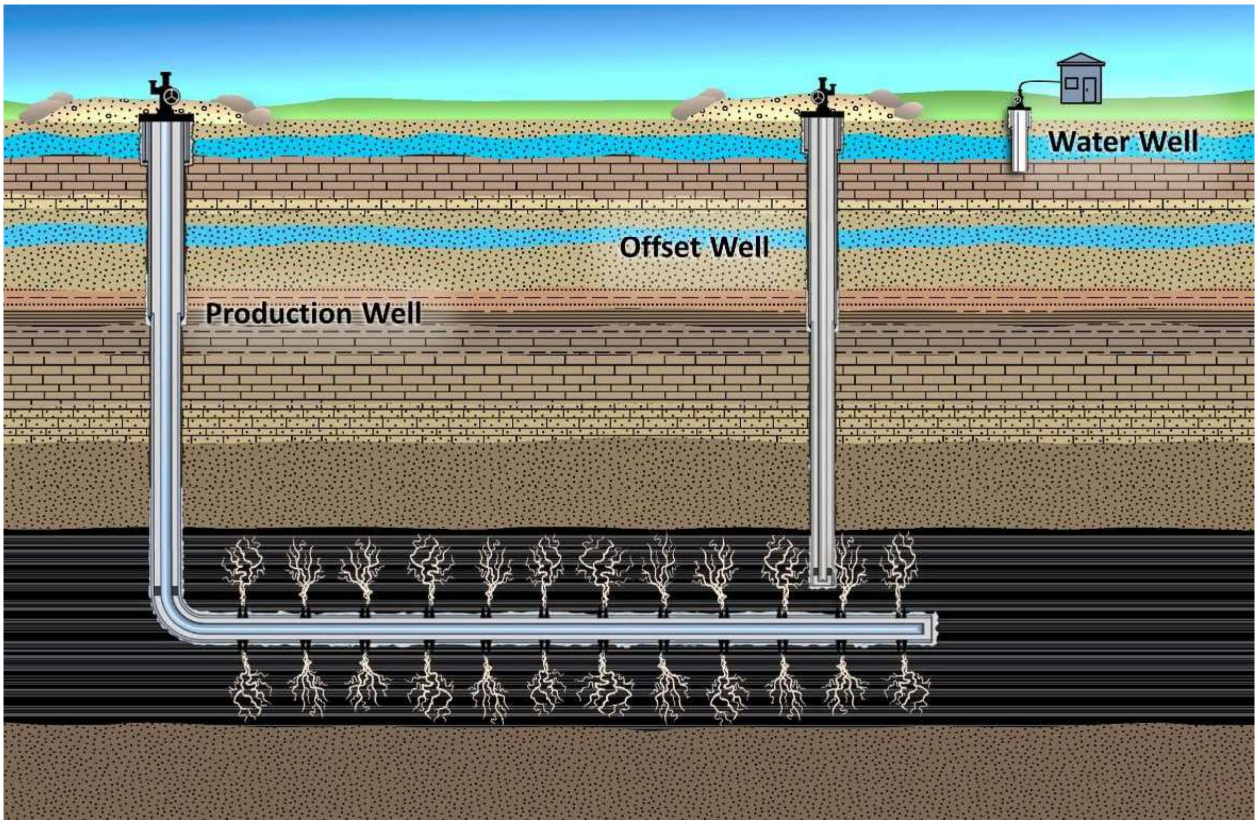


Figure 6-8. Induced fractures intersecting an offset well (in a production zone, as shown, or in overlying formations into which fracture growth may have occurred).
This image shows a conceptualized depiction of potential pathways for fluid movement out of the production zone (not to scale).

[1] These spills are represented by line numbers 163, 236, 265, 271, 286, 287, 375, 376, 377, and 380 in Appendix B of U.S. EPA (2015m).

[2] 280 wells (95% confidence interval: 240 – 320 wells).

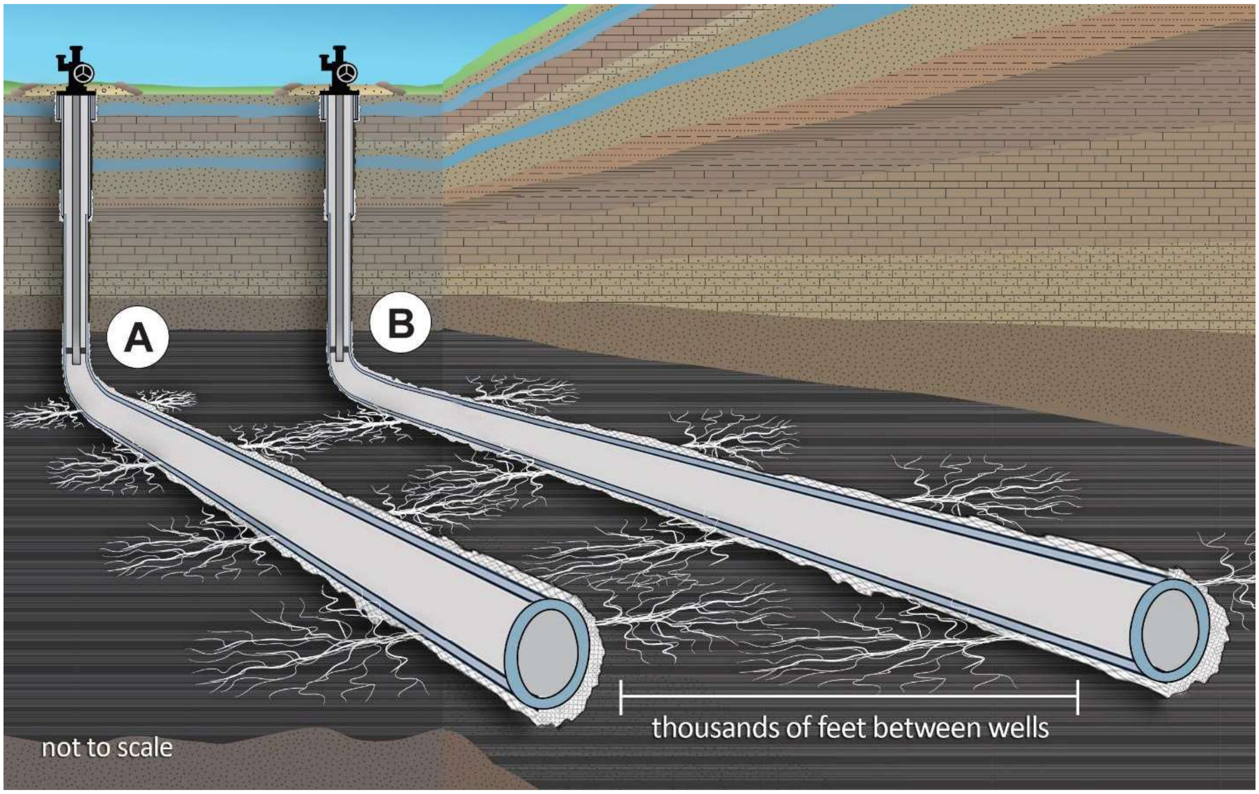


Figure 6-9. Well communication (a frac hit).
This image shows a conceptualized depiction of the fractures of a newly fractured well (Well A) intersecting the existing fracture network created during a previous hydraulic fracturing operation in an offset well (Well B). Evidence of this interaction may be observed in the offset well as a pressure change, lost production, and/or introduction of new fluids. Depending on the condition of the offset well, this can result in fluid being spilled onto the surface, rupturing of cement and/or casing and hydraulic fracturing fluid leaking into subsurface formations, and/or fluid flowing out through existing flaws in the casing and/or cement. (Figure is not to scale.)

A well communication event is usually observed at the offset well as a pressure spike, due to the elevated pressure from the originating well, or as an unexpected drop in the production rate (Lawal et al., 2014; Jackson et al., 2013a). Ajani and Kelkar (2012) performed an analysis of frac hits in the Woodford Shale in Oklahoma, studying 179 wells over a 5-year period. The authors used fracturing records from the newly completed wells and compared them to production records from surrounding wells. The authors assumed that sudden changes in production of gas or water coinciding with fracturing at a nearby well were caused by communication between the two wells, and increased water production at the surrounding wells was assumed to be caused by hydraulic fracturing fluid flowing into these offset wells. The results of the Oklahoma study showed that 24 wells had decreased gas production or increased water production within 60 days of the initial gas production at the nearby fractured well. A total of 38 wells experienced decreased gas or increased water production up to a distance of 7,920 ft (2,410 m), which the study authors defined as the distance between the midpoints of the laterals; 10 wells saw increased water production from as far away as 8,422 ft (2,567 m). In addition, one well showed a slight increase in gas production rather than a decrease.[1]

Other studies of well communication events have relied on similar information. In the NM OCD operator data set, the typical means of detecting a well communication event was through pressure changes at the offset well, production lost at the offset well, and/or fluids found in the offset well. In some instances, well operators determined that a well was producing fluid from two different formations, while in one instance, the operator identified a potential well communication event due to an increase in production from the offset well (Vaidyanathan, 2014). In another study, Jackson et al. (2013a) found that the decrease in production due to well communication events was much greater in lower permeability reservoirs. The authors note an example where two wells 1,000 ft (300 m) apart communicated, reducing production in the offset well by 64%. These results indicate that the subsurface interactions of well networks or complex hydraulics driven by each well at a densely populated (with respect to wells) area are important factors to consider for the design of hydraulic fracturing treatments and other aspects of oil and gas production.

The key factor affecting the likelihood of a well communication event and the impact of a frac hit is the location of the offset well relative to the well where hydraulic fracturing was conducted (Ajani and Kelkar, 2012). In the Ajani and Kelkar (2012) analysis, the likelihood of a communication event was less than 10% in wells more than 4,000 ft (1,000 m) apart, but rose to nearly 50% in wells less than 1,000 ft (300 m) apart. Well communication was also much more likely with wells drilled from the same pad. The affected wells were found to be in the direction of maximum horizontal stress in the field, which correlates with the expected direction of fracture propagation. Modeling work by Myshakin et al. (2015) is generally consistent with these results, indicating that the risk of fluid movement through pre-existing wellbores or open faults is negligible unless hydraulic fractures are located very close to these features.[2]

Statistical modeling by Montague and Pinder (2015) investigated the probability that a hypothetical new well used for hydraulic fracturing within the area of New York underlain by the Marcellus Shale would intersect an existing wellbore. The results indicated that this probability would be from 0 to 3.45%. The model incorporated the depth of the hypothetical new well, the vertical growth of induced fractures, and the depth and locations of existing nearby wells. The model also assumed that the existing wells are vertical and fracture growth is not impacted by nearby wells or existing fractures. However, the authors concluded that the inclusion of horizontal wells within the data set could increase the chance of intersection with induced fractures.

Well communication may be more likely to occur where there is less resistance to fracture growth. Such conditions may be related to existing production operations (e.g., where previous hydrocarbon extraction has reduced the pore pressure, changed stress fields, or affected existing fracture networks) or the existence of high-permeability rock units (Jackson et al., 2013a). As Ajani and Kelkar (2012) found in the Woodford Shale, one of the deepest major shale plays (Table 6-3), induced fractures tend to enter portions of the reservoir that have already been fractured as

[1] The numbers of wells cited in the study reflect separate analyses, and the numbers cited are not additive.

[2] In the Myshakin et al. (2015) paper, the authors do not quantify or explain what is meant by "very close."

opposed to entering previously unfractured rocks, ultimately causing interference in offset wells. Mukherjee et al. (2000) described this tendency for asymmetric fracture growth toward depleted areas in low-permeability gas reservoirs due to pore pressure depletion from production at offset wells. The authors note that pore pressure gradients in depleted zones would affect the subsurface stresses. Therefore, depending on the location of the new well with respect to depleted zone(s) and the orientation of the existing induced fractures, the newly created fracture can be asymmetric, with only one wing of the fracture extending into the depleted area and developing significant length and conductivity (Mukherjee et al., 2000). The extent to which the depleted area affects fracturing depends on factors such as cumulative production, pore volume, hydrocarbon saturation, effective permeability, and the original reservoir or pore pressure (Mukherjee et al., 2000). Similarly, high-permeability rock types acting as thief zones may also cause preferential fracturing due to a higher leakoff rate into these layers (Jackson et al., 2013a).

In addition to location, the potential for impact on a drinking water resource also depends on the condition of the offset well. (See Section 6.2 for information on the mechanical integrity of well components.) In their analysis, Ajani and Kelkar (2012) found a correlation between well communication and well age: older wells were more likely to be affected. If the cement in the annulus between the casing and the formation is intact and the well components can withstand the stress exerted by the pressure of the fluid, nothing more than an increase in pressure and extra production of fluids would occur during a well communication event. However, if the offset well is not able to withstand the pressure of the hydraulic fracturing fluid, well components could fail (Figure 6-4), allowing fluid to migrate out of the well.

The highest pressures most hydraulic fracturing wells will face during their life spans occur during the process of fracturing (Section 3.3). In some cases, temporary equipment is installed in wells during fracturing to protect the well against the increased pressure. Therefore, many producing wells may not be designed to withstand pressures typical of hydraulic fracturing (Enform, 2013) and can experience problems when fracturing occurs in nearby wells. Depending on the location of the weakest point in the offset well, this could result in fluid being spilled onto the surface; rupturing of cement and/or casing and hydraulic fracturing fluid leaking into subsurface formations; and/or fluid flowing out through existing flaws in the casing and/or cement. (See Chapters 5 and 7 for additional information on how such spills can affect drinking water resources.) For example, a documented well communication event near Innisfail, Alberta, Canada (Text Box 6-7) occurred when several well components failed, because they were not rated to handle the increased pressure caused by the well communication (ERCB, 2012). In addition, if the fractures were to intersect an uncemented portion of the wellbore, the fluids could potentially migrate into formations that are uncemented along the wellbore.

In older wells near a hydraulic fracturing operation, plugs and cement can degrade over time; in some cases, abandoned wells may never have been plugged properly. Before the 1950s, most well plugging efforts were focused on preventing water from the surface from entering oil fields. As a result, many wells from that period were abandoned with little or no cement (NPC, 2011b). This can be a significant issue in areas with legacy (i.e., historic) oil and gas exploration and when wells are re-entered and hydraulically fractured (or re-fractured) to increase production in a reservoir. In one study, 18 of 29 plugged and abandoned wells in Quebec were found to show signs of leakage (Council of Canadian Academies, 2014). Similarly, a PA DEP report cited three cases where migration of natural gas had been caused by well communication events with old, abandoned wells, including one case where private drinking water wells were affected (PA DEP, 2009c). In Tioga County, Pennsylvania, following hydraulic fracturing of a shale gas well, an abandoned well nearby produced a 30 ft (9 m) geyser of brine and gas for more than a week (Dilmore et al., 2015).

Text Box 6-7. Well Communication at a Horizontal Well near Innisfail, Alberta, Canada.

In most cases, well communication during fracturing results in a pressure surge accompanied by a drop in gas production and additional flow of produced water or hydraulic fracturing fluid at an offset well. However, if the offset well is not capable of withstanding the high pressures of fracturing, more significant damage can occur.

In January 2012, fracturing at a horizontal well near Innisfail in Alberta, Canada, caused a surface spill of fracturing and formation fluids at a nearby operating vertical oil well. According to the investigation report by the Alberta Energy Resources Conservation Board (ERCB, 2012), pressure began rising at the vertical well less than two hours after fracturing ended at the horizontal well.

Several components of the vertical well facility—including surface piping, discharge hoses, fuel gas lines, and the pressure relief valve associated with compression at the well—were not rated to handle the increased pressure and failed. Ultimately, the spill released, in addition to gas, an estimated 19,816 gal (75,012 L^3) of hydraulic fracturing fluid, brine, and oil covering an area of approximately 656 ft by 738 ft (200 m by 225 m).

The ERCB determined that the lateral of the horizontal well passed within 423 ft (129 m) of the vertical well at a depth of approximately 6,070 ft (1,850 m) below the surface in the same formation. The operating company had estimated a fracture half-length of 262 to 295 ft (80 to 90 m) based on a general fracture model for the field.[1] While there were no regulatory requirements for spacing hydraulic fracturing operations in place at the time, the 423 ft (129 m) distance was out of compliance with the company's internal policy to space fractures from adjacent wells at least 1.5 times the predicted half-length. The company also did not notify the operators of the vertical well of the hydraulic fracturing operations. The incident prompted the ERCB to issue *Bulletin 2012-02—Hydraulic Fracturing: Interwellbore Communication between Energy Wells*, which outlines expectations for avoiding well communication events and preventing adverse effects on offset wells.

Various studies estimate the number of abandoned wells in the United States to be significant. The Interstate Oil and Gas Compact Commission (IOGCC, 2008) estimates that over one million wells were drilled in the United States prior to the enactment of state oil and gas regulations, and the status and location of many of these wells are unknown. A recent estimate of wells completed before the adoption of statewide well abandonment criteria in 1957 in Pennsylvania placed the range at 305,000 to 390,000 wells in the state, with more than 176,000 of those wells likely abandoned pre-1957 (Dilmore et al., 2015). As of 2000, PA DEP's well plugging program reported that it had documented 44,700 wells that had been plugged and 8,000 that were in need of plugging, and approximately 184,000 additional wells with an unknown location and status (PA

[1] The fracture half-length is the radial distance from a wellbore to the outer tip of a fracture propagated from that well (Schlumberger, 2014).

DEP, 2000). A similar evaluation from New York State found that the number of unplugged wells was growing in the state despite an active well plugging program (Bishop, 2013). In the Midwest, Sminchak et al. (2014) examined two areas of historical oil and gas exploration as part of an investigation of potential carbon dioxide sequestration sites. They found that a 4.3 mi by 4.3 mi (6.9 km by 6.9 km) square area in Michigan contained 22 abandoned oil and gas wells and a 9.3 mi by 9.3 mi (15.0 km by 15.0 km) square area in Ohio contained 359 abandoned oil and gas wells.

Various state programs exist to plug identified orphaned wells, but they face the challenge of identifying and addressing a large number of wells.[1] In some cases, remote sensing technologies can be used to identify wells for which no records exist. For example, an NETL study in Pennsylvania found that helicopter-based high-resolution magnetic surveys can be used to accurately locate wells with steel casing; wells with no steel casing exhibit weak or no magnetic anomaly and are not detected by such surveys (Veloski et al., 2015). Chapter 10 includes a discussion of factors and practices, including those related to active and abandoned wells near hydraulic fracturing operations, that can reduce the frequency of impacts to drinking water quality.

The Reagan et al. (2015) numerical modeling study included an assessment of migration via an offset well as part of its investigation of potential fluid migration from a producing formation into a shallower groundwater unit (Section 6.3.2.2). For the offset well pathway, it was assumed that the hydraulically induced fractures intercepted an older offset well with deteriorated components. (This assessment can also be applicable to cases where potential migration may occur via the production well-related pathways discussed in Section 6.2) The highest permeability value tested for the connecting feature represented a case with an open wellbore. A key assumption for this investigation was that the offset well was already directly connected to a permeable feature in the reservoir or within the overburden.

Similar to the cases for permeable faults or fractures discussed in Section 6.3.2.2, the study investigated the effect of multiple well- and formation-related variables on potential fluid migration (Table 6-4). Based on the simulation results, an offset well pathway can have a greater potential for gas release from the production zone into a shallower groundwater unit than the fracture pathway discussed in Section 6.3.2.2 (Reagan et al., 2015). This difference is primarily due to the total pore volume of the connecting pathway within the offset well; if the offset well pathway has a significantly lower pore volume compared to the fracture pathway, this would reduce possible gas storage in the connecting feature and increase the speed of buoyancy-dependent migration. However, as with the fracture scenario, the gas available for migration in this case is still limited to the gas that is initially stored in the hydraulically induced fractures. Accordingly, any incidents of gas breakthrough in the model results were limited in both duration and magnitude.

In their modeling study, Reagan et al. (2015) found that production at the gas well (the well used for hydraulic fracturing) also affects the potential upward migration of gas and its arrival times at the drinking water formation due to its effect on the driving forces (e.g., pressure gradient). Similar to the fracture cases described in Section 6.3.2.2, production in the target reservoir appears to mitigate upward gas migration, both by reducing the amount of gas that might otherwise be

[1] An orphaned well is an inactive oil or gas well with no known (or financially solvent) owner.

available for upward migration and by creating a pressure gradient toward the production well. Only scenarios without the mitigating feature of gas production result in upward migration into the aquifer. This assessment also found a generally downward water flow within the connecting well pathway, which is more pronounced when the production well is operating and there is de-pressurization within the fractures. The producing formation and aquifer permeabilities appear not to be significant factors for upward gas migration via this pathway. Instead, Reagan et al. (2015) found the permeability of the connecting well to be the key factor affecting the migration of gas to the aquifer and the water well. Very low permeabilities (less than 1 mD, or 1×10^{-15} m^2) for the connecting well lead to no migration of gas into the aquifer regardless of the vertical separation distance, whereas larger permeabilities presented a greater potential for gas breakthrough.

Brownlow et al. (2016) also modeled communication with an abandoned well. The modeling exercise was based on operator data from the Eagle Ford Shale. Two types of cases were modeled: cases with an open (unplugged) abandoned well (which the authors note are known to occur in Texas) and cases with an abandoned well that was converted into a water well after the lower portion of the well had been filled with drilling mud (a practice allowed in Texas until 1967). The modeling results indicated that fluid could potentially migrate up both types of abandoned wells, with relatively greater flow rates in open abandoned wells and in abandoned wells closer to the well used for hydraulic fracturing. Similar to the Reagan et al. (2015) study, the production regime was also a key factor; when production and flowback were included in the simulation, they were found to inhibit upward migration. Modeled flow rates through the mud-filled well were comparable to those found by Reagan et al. (2015) with higher flows predicted through the open well.

A similar study was conducted by Nowamooz et al. (2015), who modeled a hypothetical well in the Utica Shale in Quebec. They assumed a 7.9 in (200 mm) wellbore with an approximately 2 in (51 mm) annulus space filled with intact cement. The researchers varied the permeability of the cement from 1 μD (1×10^{-19} m^2) to 1 mD (1×10^{-15} m^2). The results indicated that, at the highest permeability of 1 mD, a flow of methane of 1.02×10^{-2} ft^3/day (2.9×10^{-4} m^3/d) was possible. This was two orders of magnitude higher than the flow when the cement permeability was 1 μD (1×10^{-19} m^2). The wellbore permeabilities used by Nowamooz et al. (2015) appear to be consistent with actual permeabilities observed in the field, which can vary widely. For example, a study of 31 abandoned oil and gas wells in Pennsylvania found effective permeability values along the wellbores in the range of 10^{-6} to 10^2 mD (1×10^{-21} to 1×10^{-13} m^2) (Kang et al., 2015).

In the same way that fractures can propagate to intersect offset wells, they can also potentially intersect other artificial subsurface structures including mine shafts or solution mining sites. No known incidents of this type of migration have been documented. However, the Bureau of Land Management (BLM) has identified over 48,000 abandoned mines in the United States and is adding new mines to its inventory every year (BLM, 2015). In addition, the Well File Review identified an estimated 800 cases where wells used for hydraulic fracturing were drilled through mining voids, and an additional 90 cases of drilling through gas storage zones or wastewater disposal zones (U.S.

EPA, 2015n).[1,2] The analysis suggests emplacing cement within such zones can be challenging, which, in turn, could lead to a loss of zonal isolation (as described in Section 6.2) and create a pathway for fluid migration.

6.3.2.4 Migration via Fractures Intersecting Geologic Features

Potential fluid migration via natural, permeable fault or fracture zones in conjunction with hydraulic fracturing has been recognized as a potential contamination hazard for several decades (Harrison, 1983). Natural fracture systems have a strong influence on the success of a fracture treatment, and the topic has been studied extensively from the perspective of optimizing treatment design (e.g., Dahi Taleghani and Olson, 2011; Weng et al., 2011; Vulgamore et al., 2007). While porous flow in unfractured shale or tight sand formations is assumed to be negligible due to very low formation permeabilities (as discussed in Section 6.3.2.1), the presence of small natural fractures known as "microfractures" within tight sand or shale formations is widely recognized, and these fractures affect fluid flow and production strategies. Naturally occurring permeable faults and larger-scale fractures within or between formations can potentially allow for more significant flow pathways out of the production zone (Jackson et al., 2013d). Figure 6-7 illustrates the concept of induced fractures intersecting with permeable faults or fractures extending out of the target reservoir.[3]

The specific effects of natural fractures on fluid migration, and the mechanisms by which these effects occur, are not completely understood. While naturally occurring microfractures can impact the growth of induced fractures (e.g., by affecting the tensile strength of a shale layer), studies based on modeling and monitoring data generally do not indicate that they contribute to fracture growth in a way that could affect the frequency or severity of impacts. Microfractures could affect fluid flow patterns near the induced fractures by increasing the effective contact area. Conversely, these microfractures could act as capillary traps for the hydraulic fracturing fluid during treatment (contributing to fluid leakoff) and potentially hinder hydrocarbon flow due to lower gas relative permeabilities (Dahi Taleghani et al., 2013). Ryan et al. (2015) suggested that some natural fracture processes/patterns (such as the presence of two subvertical fracture sets) can contribute to upward gas migration, while others (such as small fracture sets with low connectivity that are confined to individual geologic layers) can preclude it.

In some areas, larger-scale geologic features may affect potential fluid flow pathways. As discussed in Text Box 6-3, baseline measurements taken before shale gas development show evidence of thermogenic methane in some shallow aquifers, suggesting that, in some cases, natural subsurface pathways exist and might allow for naturally occurring migration of gas over geologic time (Robertson et al., 2012). There is also evidence demonstrating that gas undergoes mixing in

[1] 800 wells (95% confidence interval: 10 – 1,900 wells).

[2] 90 wells (95% confidence interval: 50 – 100 wells).

[3] Faults and fractures can exhibit a range of permeabilities. For example, permeable (also referred to as "transmissive" or "conductive") faults or fault segments have enough permeability to allow fluids to flow along or across them, while others are relatively impermeable and can serve as barriers to flow. These differences in permeability are associated with geologic conditions such as rock type, depth, and stress regime. Generally, when researchers refer to the potential for migration via natural geologic features, it is assumed that these features are sufficiently permeable to serve as a pathway.

subsurface pathways (Baldassare et al., 2014; Molofsky et al., 2013; Fountain and Jacobi, 2000). Warner et al. (2012) compared recent sampling results to data published in the 1980s and found geochemical evidence for migration of fluids through natural pathways between deep underlying formations and shallow aquifers—pathways that the authors suggest could lead to contamination from hydraulic fracturing activities. In northeastern Pennsylvania, there is evidence that brine from deep saline formations has migrated into shallow aquifers over geologic time, preferentially following certain geologic structures (Llewellyn, 2014). However, this depends on local geologic characteristics and does not appear to happen in all locations; for example, in the Monongahela River Basin in West Virginia, shallow groundwater samples did not show evidence of mixing with deep brines (Boothroyd et al., 2016). As described in Chapter 7, karst features (created by the dissolution of soluble rock) can also serve as a potential pathway of fluid movement on a faster time scale.

Monitoring data show that the presence of natural faults and fractures can affect both the height and width of induced hydraulic fractures. When faults are present, relatively larger microseismic responses are seen and larger fracture growth can occur, as described below. Rutledge and Phillips (2003) suggested that, for a hydraulic fracturing operation in East Texas, pressurizing existing fractures (rather than creating new hydraulic fractures) was the primary process that controlled enhanced permeability and fracture network conductivity at the site. Salehi and Ciezobka (2013) used microseismic data to investigate the effects of natural fractures in the Marcellus Shale and concluded that fracture treatments are more efficient in areas with clusters or "swarms" of small natural fractures, while areas without these fracture swarms require more thorough stimulation. These microseismic data show that swarms of natural fractures within a shale formation can result in a fracture network with a larger width-to-height ratio (i.e., a shorter and wider network) than would be expected in a zone with a low degree of natural fracturing.

A few studies have used monitoring data to specifically investigate the effect of natural faults and fractures on the vertical extent of induced fractures. A statistical analysis of microseismic data by Shapiro et al. (2011) found that fault rupture (movement along a fault) from hydraulic fracturing is limited by the extent of the stimulated rock volume and is unlikely to extend beyond the fracture network. However, as demonstrated by microseismic data presented by Vulgamore et al. (2007), in some settings, the fracture network—and, in this case, the possibility of fault rupture—could extend laterally for thousands of feet. In the Fisher and Warpinski (2012) data set (Section 6.3.2.2), the greatest fracture heights occurred when the hydraulic fractures intersected pre-existing faults. Similarly, Hammack et al. (2014) reported that fracture growth seen above the Marcellus Shale is consistent with the inferred extent of pre-existing faults at the Greene County, Pennsylvania, research site (Section 6.3.2.2 and Text Box 6-6). The authors suggested that clusters of microseismic events may have occurred where preexisting small faults or natural fractures were present above the Marcellus Shale. Viñal (2015) used time-lapse multi-component seismic monitoring to monitor the overburden of the Montney Shale during a hydraulic fracturing operation in Alberta, Canada. The researchers found increases in the anisotropy in the overburden, which they interpreted as fractures being propagated along natural faults out of the shale and into the overburden. At a site in Ohio, Skoumal et al. (2015) found that hydraulic fracturing induced a rupture along a pre-existing fault approximately 0.6 mi (1 km) from the hydraulic fracturing operation. Using a new monitoring method known as tomographic fracturing imaging, Lacazette and Geiser (2013) also found vertical hydraulic fracturing fluid movement from a production well into a natural fracture network for distances of up to 0.6 mi (1.0 km). However, Davies et al. (2013) questioned whether this technique actually measures hydraulic fracturing fluid movement.

Modeling studies have also investigated whether hydraulic fracturing operations are likely to reactivate faults and create a potential fluid migration pathway into shallow aquifers. Results from one study suggest that, under specific circumstances, interaction with a permeable fault could result in fluid migration to the surface but only on relatively long (ca. 1,000 year) time scales (Gassiat et al., 2013). These findings have been disputed in the literature due to certain suggested limitations of the study, including the model setup, assumptions, and calibration; unrealistic fault representation; lack of constraints on fluid overpressure; and exclusion of the capillary imbibition effect (Birdsell et al., 2015b; Flewelling and Sharma, 2015). In response to these critiques, the authors stated that their work was a parametric study in which the model geometry, parameter, and boundary conditions were defined based on data collected from multiple shale gas basins, and the objective of the study was not to calibrate results to a specific site (Lefebvre et al., 2015). Other researchers reject the notion that open, permeable faults coexist with hydrocarbon accumulation (Flewelling et al., 2013). However, it is unclear whether the existence of faults in low permeability reservoirs affects the accumulation of hydrocarbons because, under natural conditions, the flow of gas may be limited due to capillary tension.

Like the other pathways discussed in this section, other conditions in addition to the physical presence of a permeable fault or fracture would need to exist for fluid migration to a drinking water resource to occur. The modeling study conducted by Reagan et al. (2015) and discussed in Section 6.3.2.2 indicates that, if such a permeable feature exists, the transport of gas and fluid flow would strongly depend upon the production regime and, to a lesser degree, the features' permeability and the separation between the reservoir and the aquifer. In addition, the pressure distribution within the reservoir (e.g., over-pressurized vs. hydrostatic conditions) will affect the fluid flow through fractures/faults. As a result, the presence of multiple geologic and well-related factors can increase the potential for fluid migration into drinking water resources. For example, in the Mamm Creek area of Colorado (Section 6.2.2.4), mechanical integrity and drilling-related problems likely acted in concert with natural fracture systems to result in a gas seep into surface water and shallow groundwater (Crescent, 2011). A similar situation occurred in southeastern Bradford County, Pennsylvania (discussed in Section 6.2), where natural fractures intersected an uncemented casing annulus and allowed gas to flow from the annulus into nearby domestic wells and a stream (Llewellyn et al., 2015).

Other modeling studies investigating the potential of fluid migration related to existing faults and fractures have given mixed results. Pfunt et al. (2016) performed modeling based on conditions in the North German Basin, i.e., deep geological settings where undisturbed cap rocks are present between the fractured formation and shallow aquifers. Their modeling indicated that the hydraulic fracturing fluid did not reach the near-surface area either during hydraulic fracturing operations or in the long-term in the presence of highly permeable pathways (fault zones, fractures). Like previous modeling studies, the authors found that the injection pressure and permeability of the connecting fault are two important factors that control upward fluid migration.

Rutqvist et al. (2013) found that, while somewhat larger microseismic events are possible in the presence of faults, repeated events and a seismic slip would amount to a total rupture length of 164 ft (50 m) or less along a fault, not far enough to allow fluid migration between a deep gas reservoir (approximately 6,562 ft or 2,000 m deep) and a shallow aquifer. A follow-up study using more sophisticated three-dimensional modeling techniques also found that deep hydraulic fracturing is unlikely to create a direct flow path into a shallow aquifer, even when hydraulic fracturing fluid is injected directly into a fault (Rutqvist et al., 2015). Similarly, a modeling study that investigated potential fluid migration from hydraulic fracturing in Germany found potential vertical fluid migration up to 164 ft (50 m) in a scenario with high fault zone permeability, although the authors note this is likely an overestimate because their goal was to "assess an upper margin of the risk" associated with fluid transport (Lange et al., 2013). More generally, results from Rutqvist et al. (2013) indicate that fracturing along an initially impermeable fault (as is expected in a shale gas formation) would result in numerous small microseismic events that act to prevent larger events from occurring (and, therefore, prevent the creation of more extensive potential pathways).

Schwartz (2015) modeled methane flow through a hypothetical permeable fault at a well in Germany. Methane flow was modeled through a permeable leakage zone that was 0.1 ft by 13 ft (0.03 m by 4 m) with an assumed permeability in the range of approximately 100 D to of 10,000 D (1×10^{-10} m^2 to 1×10^{-8} m^2). The model indicated that methane could reach a drinking water aquifer approximately 2,953 ft (900 m) above the gas zone in about a half a day and reach a maximum flow after two days. According to the model results, methane entering the aquifer led to an increase in pH, the release of negatively charged constituents such as chromium, and the adsorption of positively charged ions such as arsenic. Decreasing the permeability of the leakage zone by a factor of 100 increased the travel time by a factor of four. In another study, Myshakin et al. (2015) modeled brine migration through a natural and induced fracture network. Their results indicated that the main pathway for vertical migration of hydraulic fracturing fluid to overlying layers is through the induced fractures, and not the natural fractures. The location of hydraulic fractures relative to each other affects the extent of brine migration into overburden layers; compared to single fractures separated by large distances, closely spaced fractures were associated with higher pressures in—and, consequently, more brine migration into—overlying layers.

6.4 Synthesis

In the injection stage of the hydraulic fracturing water cycle, operators inject hydraulic fracturing fluids into a well under pressure that is high enough to fracture the production zone. These fluids flow through the well and then out into the surrounding formation, where they create fractures in the rock, allowing hydrocarbons to flow through the fractures, to the well, and then up the production string.

The production well and the surrounding geologic features function as a system that is often designed with multiple elements that can isolate hydrocarbon-bearing zones and water-bearing zones, including groundwater resources, from each other. This physical isolation optimizes oil and gas production and can protect drinking water resources via isolation within the well (by the casing and cement) and/or through the presence of multiple layers of subsurface rock between the target formations where hydraulic fracturing occurs and drinking water aquifers.

6.4.1 Summary of Findings

In this chapter, we consider impacts to drinking water resources to occur if hydraulic fracturing fluids or other subsurface fluids affected by hydraulic fracturing enter and adversely impact the quality of groundwater resources. Potential pathways for fluid movement to drinking water resources may be linked to one or more components of the well and/or features of the subsurface geologic system. If present, these potential pathways can, in combination with the high pressures under which fluids are injected and pressure changes within the subsurface due to hydraulic fracturing, result in the subsurface movement of fluids to drinking water resources.

The potential for these pathways to exist or form has been investigated through modeling studies that simulate subsurface responses to hydraulic fracturing, and demonstrated via case studies and other monitoring efforts. In addition, the development of some of these pathways—and fluid movement along them—has been documented. It is important to note that, if multiple barriers afforded by the well design and the presence of subsurface rock formations are present, the development of a pathway within this system does not necessarily result in an impact on a drinking water resource.

6.4.1.1 Fluid Movement via the Well

A production well undergoing hydraulic fracturing is subject to higher stresses during the relatively brief hydraulic fracturing phase than during any other period of activity in the life of the well. If the well cannot withstand the stresses experienced during hydraulic fracturing operations, pathways associated with the casing and cement can form that can result in the unintended movement of fluids into the surrounding environment (Section 6.2).

Multiple barriers within the well, including casing, cement, and a completion assembly can, if present, isolate hydrocarbon-bearing formations from drinking water resources located at a different depth. However, inadequate construction, defects in or degradation of the casing or cement, and/or the absence of redundancies such as multiple layers of casing and proper emplacement of cement can allow fluid movement into drinking water resources. Various studies of wells in the Marcellus Shale showed failure rates between 3 and 10%, depending on the type of failure studied (contamination of drinking water resources may or may not have occurred at these wells). The EPA's Well File Review found that 3% of all hydraulic fracturing jobs involved a downhole mechanical integrity failure, which generally resulted in hydraulic fracturing fluid entering the annular space between the casing and formation or between two casing strings.

Ensuring proper well design and mechanical integrity—particularly proper cement placement and quality—are important actions for preventing unintended fluid migration along the wellbore. While not all of the mechanical integrity failures described above resulted in fluid movement to—or contamination of—a drinking water resource, aspects of well design that lead to increased failure rates have the potential to increase the frequency or severity of impacts to drinking water quality associated with hydraulic fracturing operations.

6.4.1.2 Fluid Movement within Subsurface Geologic Formations

Potential subsurface pathways for fluid migration to drinking water resources include flow of fluids out of the production zone into formations above or below it, fractures extending out of the production zone or into other induced fracture networks, intersections of fractures with abandoned or active wells, and hydraulically induced fractures intersecting with faults or natural fractures (Section 6.3).

Vertical separation between the zone where hydraulic fracturing operations occur and drinking water resources reduces the potential for fluid migration to impact the quality of drinking water resources. However, not all hydraulic fracturing operations are characterized by large vertical distances between the production zone and drinking water resources. In coalbed methane plays, which are typically shallower than shale gas plays, these separation distances can be smaller than in other types of formations. Also, in certain areas, hydraulic fracturing is known to take place in formations containing water that meets the salinity threshold that is used in some definitions of a drinking water resource.

Lateral separation between wells undergoing hydraulic fracturing and other wells (including active and abandoned wells) also reduces the potential for fluid migration to impact drinking water resources. While some operators design fracturing treatments to communicate with the fractures of another well and optimize oil and gas production, unintended communication between two wells or their fracture systems can lead to spills in an offset well, which is an indicator of hydraulic fracturing treatments extending beyond their planned design. These well communication incidents, or "frac hits," have been reported in New Mexico, Oklahoma, and a few other locations. Surface spills from well communication incidents have also been documented. Based on the available information, frac hits most commonly occur on multi-well pads and when wells are spaced less than 1,100 ft (340 m) apart, but they have been observed at wells up to 8,422 ft (2,567 m) away from a well undergoing hydraulic fracturing.

6.4.1.3 Impacts to Drinking Water Resources

We identified some example cases in the literature where the pathways associated with hydraulic fracturing resulted in an impact on the quality of drinking water resources.

One of these cases took place in Bainbridge Township, Ohio, in 2007. Failure to cement over-pressured formations through which a production well passed—and proceeding with the hydraulic fracturing operation without adequate cement and an extended period during which the well was shut in—led to a buildup of natural gas within the well annulus and high pressures within the well. This ultimately resulted in movement of gas from the production zone into local drinking water aquifers (Section 6.2.2.2). Twenty-six domestic drinking water wells were taken off-line and the houses were connected to a public water system after the incident due to elevated methane levels.

Casings at a production well near Killdeer, North Dakota, ruptured in 2010 following a pressure spike during hydraulic fracturing, allowing fluids to escape to the surface. Brine and tert-butyl alcohol were detected in two nearby monitoring wells. Following an analysis of potential sources, the only source consistent with the conditions observed in the two impacted water wells was the well that ruptured during hydraulic fracturing. There is also evidence that out-of-zone fracturing occurred at the well (Sections 6.2.2.1 and 6.3.2.2).

There are other cases where contamination of or changes to the quality of drinking water resources near hydraulic fracturing operations were identified. Hydraulic fracturing remains a potential contributing cause in these cases. For example:

- Migration of stray gas into drinking water resources involves many potential routes, including poorly constructed casing and naturally existing or induced fractures in subsurface formations. Multiple pathways for fluid movement may have worked in concert in northeastern Pennsylvania (possibly due to cement issues or sustained casing pressure), the Raton Basin in Colorado (where fluid migration may have occurred along natural rock features or faulty well seals), and the Wattenberg field in Colorado (where the surface casing depth and the presence of uncemented gas zones are major factors in determining the likelihood of mechanical integrity failures and contamination). While the sources of methane identified in drinking water wells in each study area could be determined with varying degrees of certainty, attempts to definitively identify the pathways of migration have generally been inconclusive (Text Box 6-3).
- At the East Mamm Creek drilling area in Colorado, inadequate placement of cement allowed the migration of methane through natural faults and fractures in the area. This case illustrates how construction issues, sustained casing pressure, and the presence of natural faults and fractures, in conjunction with elevated pressures associated with hydraulic fracturing, can work together to create a pathway for fluids to migrate toward drinking water resources (Sections 6.2.2.2 and 6.3.2.4).

Additionally, there are places in the subsurface where oil and gas resources and drinking water resources co-exist in the same formation. Evidence we examined indicates that some hydraulic fracturing for oil and gas occurs within formations where the groundwater has a salinity of less than 10,000 mg/L TDS. By definition, this results in the introduction of hydraulic fracturing fluids into formations that meet both the Safe Drinking Water Act's salinity-based definition of an underground source of drinking water and the broader definition of a drinking water resource developed for this assessment. According to the data we examined, these formations are generally in the western United States, e.g., near Pavillion, Wyoming. Hydraulic fracturing in a drinking water resource may be of concern in the short-term (where people are currently using these zones as a drinking water supply) or the long-term (if drought or other conditions necessitate the future use of these zones for drinking water).

There are other cases in which production wells associated with hydraulic fracturing are alleged to have caused contamination of drinking water resources. Data limitations in most of those cases (including the unavailability of information in litigation settlements resulting in sealed documents) make it difficult to assess whether or not hydraulic fracturing was a cause of the contamination.

6.4.2 Factors Affecting Frequency or Severity of Impacts

The multiple barriers within the hydraulic fracturing well and the presence of subsurface low-permeability geologic formations between the production zone and drinking water resources isolate fluids from drinking water resources. Because of this, any factors that affect the integrity of the system comprised of the well and the surrounding geology have the potential to affect the frequency or severity of impacts on drinking water quality. The primary factors that can affect the frequency or severity of impacts are: (1) the construction and condition of the well that is being hydraulically fractured, (2) the amount of vertical separation between the production zone and formations that contain drinking water resources, and (3) the location, depth, and condition of nearby wells or natural faults or fractures.

The presence and condition of the well's casing and cement are key factors that affect the frequency or severity of impacts to drinking water resources. Even in wells where there is substantial vertical separation (e.g., thousands of feet), defects in the well can, in theory, allow fluid movement over significant vertical distance. For example, fully cemented surface casing that extends through the base of drinking water resources is a key protective component of the well. Risk evaluation studies of a limited number of injection wells show that, if the surface casing is not set deeper than the bottom of the drinking water resource, the risk of aquifer contamination increases a thousand-fold. A review of wells that were hydraulically fractured in the Wattenberg field in Colorado showed that wells with fewer casing and cementing barriers across gas-bearing zones exhibited higher rates of failures. Most, but not all, wells used in hydraulic fracturing operations have fully cemented surface casing.

The absence of or defects in casing or cement can be the result of inadequate design or construction, including fewer layers of protective casing or when cement is incomplete (i.e., not present across all oil-gas- or water-bearing formations), of inadequate quality, or improperly emplaced. Wells that were constructed pursuant to older, less stringent requirements have a greater likelihood of exhibiting mechanical integrity problems associated with inadequate design and/or construction.

Deviated and horizontal wells may exhibit more casing and cement problems compared to vertical wells. Some (but not all) studies have shown that sustained casing pressure—a buildup of pressure within the well annulus that can indicate the presence of leaks—occurs more frequently in deviated and horizontal wells compared to vertical wells. Cement integrity problems can arise as a result of challenges in centering the casing and placing the cement in these wells. Absent efforts to ensure the emplacement of sufficient cement that is of adequate integrity, the increased use of these wells in hydraulic fracturing operations has the potential to increase the frequency at which associated cementing problems occur. This, in turn, has the potential to increase the frequency of impacts to the quality of drinking water resources.

Even in optimally designed wells, degradation of the casing and cement as they age or due to the cumulative effects of formation or operational stresses exerted on the well over time (e.g., cyclic stresses in multi-stage fractures) can impact the mechanical integrity of the well and affect the frequency of impacts to drinking water quality. Older wells exhibit more mechanical integrity problems compared to newer wells when hydraulically fractured or re-fractured. If mechanical integrity issues exist but are not detected and subsequently addressed, hydraulic fracturing fluids or other fluids can move into drinking water resources and the concentrations of contaminants in those drinking water resources—and therefore the severity of the impact—can increase.

In areas where there is little or no vertical separation between the production zone and drinking water resources, there is a greater potential to increase the frequency or severity of impacts to drinking water quality. For example, when the vertical separation is relatively small and other subsurface pathways (e.g., artificial penetrations) are present, the potential for these pathways to provide a more direct link between the production zone and a drinking water resource is greater than if there is a large separation. As described above, there are places where hydraulic fracturing operations occur in formations meeting the salinity threshold that is used in some definitions of a drinking water resource. The practice of injecting hydraulic fracturing fluids into a formation that also contains a drinking water resource can affect the quality of that water, because it is likely some of that fluid remains in the formation following hydraulic fracturing. The properties (e.g., chemical composition, toxicity, etc.) of hydraulic fracturing fluids or naturally occurring fluids that migrate to drinking water resources can affect the severity of the impact on the quality of those resources (see Chapter 9 for more information on the chemicals used in hydraulic fracturing fluids).

Where the separation between the production zone and drinking water resources is small, and where natural or induced fractures that transect the layers between these formations are present, there is a potential for increased frequency of impacts to drinking water quality via induced or natural fractures or faults. (Impacts via well-related pathways can also be a concern in these situations, as described above.)

Research shows that fractures created during hydraulic fracturing can extend out of the production zone, and that the vertical component of fracture growth is generally greater in deeper formations than shallow formations. Out-of-zone fracturing could be a concern in deeper formations if there is little vertical separation between the production zone and a deep drinking water resource and fractures propagate to unintended vertical heights. If out-of-zone fracturing is not detected (e.g., via monitoring) and subsequently addressed, the impacts to the quality of drinking water resources associated with fluid movement via these induced fractures have the potential to become more severe.

Regardless of the extent of the vertical separation between the production zone and drinking water resources, the presence of active or abandoned wells near hydraulic fracturing operations can increase the potential for hydraulic fracturing fluids to move to drinking water resources. For example, a deficiency in the construction of a nearby well (or degradation of the well's components), can provide a pathway for movement of hydraulic fracturing fluids, methane, or brines that might affect drinking water quality. If the fractures intersect an uncemented portion of a nearby wellbore, the fluids can potentially migrate along that wellbore into any formations where the well is not cemented.

The frequency of impacts to the quality of drinking water resources may increase where wells are densely spaced (particularly in shallow hydraulic fracturing operations where more fracture propagation is expected to be in the horizontal direction). The frequency of impacts may also be higher in mature oil and gas fields that pre-date the use of construction/plugging methods that can withstand the stresses associated with hydraulic fracturing operations. In these mature fields, wells tend to be older so degradation is a concern, and the location or condition of abandoned wells may not be documented. Based on the information presented in this chapter, the increased use of hydraulic fracturing in horizontal wells and in multiple wells on a single pad can increase the likelihood that these pathways could develop. This, in turn, could increase the frequency at which impacts on drinking water quality occur.

See Chapter 10 for a discussion of factors and practices that can reduce the frequency or severity of impacts to drinking water quality.

6.4.3 Uncertainties

Generally, less is known about the occurrence of (or potential for) impacts of injection-related pathways in the subsurface than for other components of the hydraulic fracturing water cycle, which tend to be easier to observe and measure. Furthermore, while there is a large amount of information available on production wells in general, there is little information that is both specific to hydraulic fracturing operations and readily accessible across the states to form a national picture.

6.4.3.1 Limited Availability of Information Specific to Hydraulic Fracturing Operations

There is extensive information available on the design goals for hydraulically fractured oil and gas wells (i.e., to address the stresses imposed by high-pressure, high-volume injection), including from industry-developed best practices documents. Additionally, many studies have documented how production wells have historically been constructed, how they perform, and the rates at which they experience problems that can lead to pathways for fluid movement. However, because of possible differences in well construction and operational practices, it is unknown how historical well performance studies apply to wells used in hydraulic fracturing operations.

Because wells that have been hydraulically fractured must withstand many of the same downhole stresses as other production wells, we consider studies of the pathways for impacts to drinking water quality in production wells to be relevant to identifying the potential pathways relevant to hydraulic fracturing operations. However, without specific data on the as-built construction of wells used in hydraulic fracturing operations, we cannot definitively state whether these wells are consistently constructed to withstand the stresses they may encounter.

There is also, in general, very limited information available on the monitoring and performance of wells used in hydraulic fracturing operations. Published information is sparse regarding mechanical integrity tests (MITs) performed during and after hydraulic fracturing, the frequency at which mechanical integrity issues arise in wells used for hydraulic fracturing, and the degree and speed with which identified issues are addressed. There is also little information available regarding MIT results for the original hydraulic fracturing event in wells built for that purpose, for wells that are later re-fractured, or for existing, older wells not initially constructed for hydraulic fracturing but repurposed for that use.

These limitations on hydraulic fracturing-specific information make it difficult to provide definitive estimates of the rate at which wells used in hydraulic fracturing operations experience the types of mechanical integrity problems that can contribute to the movement of hydraulic fracturing fluids or other fluids to drinking water resources.

There is also a limited number of peer-reviewed published studies based on groundwater sampling that provide evidence to assess whether formation brines, hydraulic fracturing fluids, or gas move in unintended ways through the subsurface during and after hydraulic fracturing. Subsurface monitoring data (i.e., data that characterize the presence, migration, or transformation of fluids within subsurface formations related to hydraulic fracturing operations) are scarce relative to the tens of thousands of oil and gas wells that are estimated to be hydraulically fractured across the country each year (see Chapter 3 for more information on the occurrence of hydraulic fracturing in the United States).

Information on fluid movement within the subsurface and the extent of fractures that develop during hydraulic fracturing operations is also limited. For example, limited information is available in the published literature on how flow regimes or other subsurface processes change at sites where hydraulic fracturing is conducted. Instead, much of the available research, and therefore the literature, addresses how hydraulic fracturing and other production technologies perform to optimize hydrocarbon production. In addition, much of the published data on fracture propagation are for shale formations, and no large-scale data sets on fracture growth in other unconventional formations exist or are publicly available.

These limitations on hydraulic fracturing-specific information make it difficult to provide definitive estimates of the rate at which wells used in hydraulic fracturing operations experience the types of mechanical integrity problems that can contribute to unintended fluid movement.

6.4.3.2 Limited Systematic, Accessible Data on Well Performance or Subsurface Movement

While the oil and gas industry generates a large amount of information on well performance as part of operations, most of this is proprietary, or otherwise not readily available to the public in a compiled or summary manner. Therefore, no national or readily accessible way exists to evaluate the design and performance of individual wells or wells in a region, particularly in the context of local geology or the presence of other wells and/or hydraulic fracturing operations. Many states have large amounts of operator-submitted data, but information about construction practices or the performance of individual wells is typically not in a searchable or aggregated form that would enable assessments of well performance under varying settings, conditions, or timeframes. Although it is collected in some cases, there is no collection, reporting, or publishing of baseline (pre-drilling and/or pre-fracturing) and post-fracturing monitoring data on a national basis that could indicate the presence or absence of hydraulic fracturing-related fluids in shallow zones and whether or not migration of those fluids has occurred. (See Chapter 10 for additional discussion of data limitations.) Ideally, data from groundwater monitoring are needed to complement theories and modeling on potential pathways and fluid migration.

While some of the types of impacts described above can occur quickly (i.e., on the scale of days or weeks, as with mechanical integrity problems or well communication events), other impacts (e.g., in slow-moving, deep groundwater) may be detectable only on much longer timescales. Without comprehensive collection and review of information about how hydraulic fracturing operations perform, fluid movement could occur without early detection, which could, in turn, increase the severity of any resultant impacts to drinking water quality. For example, testing the mechanical integrity of wells, monitoring the extent of the fractures that form, and conducting pre- and post-hydraulic fracturing water quality monitoring can detect fluid movement (or the potential for fluid movement) and provide opportunities to mitigate or minimize the severity of impacts associated with unforeseen events.

The limited amount of available information also hinders our ability to evaluate how frequently drinking water impacts are occurring, the probability that these impacts occur, or to what extent they are tied to specific well construction, operation, and maintenance practices. This also significantly limits our ability to evaluate the aggregate potential for hydraulic fracturing operations to affect drinking water resources or to identify the potential cause of drinking water contamination in areas where hydraulic fracturing occurs. The absence of this information greatly limits the ability to make quantitative statements about the frequency or severity of these impacts.

6.4.4 Conclusions

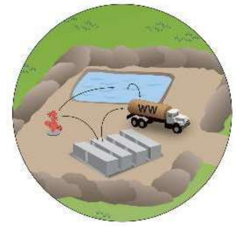
The production well and the surrounding geologic features function as a system that provides multiple barriers that can isolate hydrocarbon-bearing zones and water-bearing zones, including drinking water resources. Because of this, factors affecting the integrity of any of these barriers have the potential to adversely affect the quality of drinking water resources.

We have identified a number of pathways by which hydraulic fracturing fluids can reach and affect the quality of drinking water resources. These pathways include migration via inadequate casing and/or cement in the hydraulic fracturing well, fluid movement in the subsurface via fractures extending out of the target zone, or vertical fluid movement via other natural or artificial structures.

The primary factors affecting the frequency or severity of impacts to drinking water quality associated with hydraulic fracturing operations include the condition of the casing and cement of the production well and their placement relative to drinking water resources, the extent of the vertical separation between the production zone and drinking water resources, and the presence and condition of offset wells or natural faults or fractures near the hydraulic fracturing operation.

There is evidence that, in some cases highlighted in the literature, these pathways have formed and the quality of drinking water resources has been impacted. We do not know the frequency of such impacts associated with the injection stage of the hydraulic fracturing water cycle, however. This is related to the following: the subsurface environment is geologically complex, the relevant production processes cannot be directly observed, and publicly available data that can support an evaluation of the impacts of hydraulic fracturing on the quality of drinking water resources is, in general, very limited.

Chapter 7. Produced Water Handling



Abstract

Produced water is a byproduct of hydrocarbon production and flows to the surface through the production well, along with oil and gas. Operators must store and dispose of (or in some cases treat) large amounts of non-potable produced water, either on site or off site, and spills or releases of produced water have the potential to impact drinking water resources. Unlike produced water from conventional oil and gas production, produced water generated following hydraulic fracturing initially contains returned hydraulic fracturing fluids. Much of the hydraulic fracturing fluid remains below ground; the median amount of fluid returned to the surface is 30% or less. Up to several million gallons of water can be produced from each well, with production generally decreasing with time.

Produced water contains several classes of constituents: salts, metals, radioactive materials, dissolved organic compounds, and hydraulic fracturing chemicals and their transformation products (the result of reactions of these chemicals in the subsurface). The concentrations of these constituents change with time, as the initially returning hydraulic fracturing fluid blends with formation water. Typically, this means that the produced water becomes more saline with time. Produced water composition and volume vary from well to well, both among different formations and within formations. A large number of organic compounds have been identified in produced water, many of which are naturally occurring petroleum hydrocarbons; some are known hydraulic fracturing chemicals. Only a few transformation products have been identified, and they include chlorinated organics.

Spills and releases of produced water with a variety of causes have been documented at different steps in the production process. The causes include human error, equipment or container failure (for instance, pipeline, tank or storage pit leaks), accidents, and storms. Unauthorized discharges may account for some releases as well. An estimated half of the spills are less than 1,000 gal (3,800 L). A small number of much larger spills has been documented, including a spill of 2.9 million gal (11 million L). Both short- and long-term impacts to soil, groundwater, and surface from spills have occurred. For many spills, however, the impacts are unknown. The potential of spills of produced water to affect drinking water resources depends upon the release volume, duration, and composition, as well as watershed and water body characteristics.

Data are lacking to characterize the severity and frequency of impacts on a nationwide scale. Suspected local-scale impacts often require an extensive multiple lines-of-evidence investigation to determine their cause. Further, when investigations do take place, the lack of baseline water quality data can make it difficult to determine the cause and severity of the impact. In such cases, additional data are necessary to determine the full extent of the impact of releases of produced water.

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7. Produced Water Handling

7.1 Introduction

Water is a byproduct of oil and gas production. After the hydraulic fracturing of the formation is completed, the injection pressure is reduced, and a possible inactive period where the well is "shut in" is completed, water is allowed to flow back from the well to prepare for oil or gas production.[1] This return-flow water may contain chemicals injected as part of the hydraulic fracturing fluid, chemicals naturally occurring in the formation, or the products of reactions that take place in the formation. Initially this water, sometimes called flowback, is mostly hydraulic fracturing fluid, but as time goes on, water chemistry becomes more similar to water associated with the formation. For formations containing saline water (brine), the salinity of the returned water increases as time passes as the result of increased contact time between the hydraulic fracturing fluid and the formation and inclusion of an increased portion of formation water. For this assessment, and consistent with industry practice, the term produced water is used to refer to any water flowing from the oil or gas well.

Produced water is piped directly to an injection well or stored and accumulated at the surface for eventual management by injection into disposal wells, transport to wastewater treatment plants, reuse, or in some cases, placement in evaporation pits or permitted direct discharge. See Text Box ES-11 and Section 8.4 for discussion of these management practices.

Produced water spills and releases can occur due to several causes, including events associated with pipelines, transportation, blowouts, and storage. Impacts to drinking water resources can occur if this released water enters surface water bodies or reaches groundwater. Such impacts may result in the water becoming unfit for consumption, either through obvious taste and odor considerations or the constituents in the water exceeding hazard levels (Chapter 9). Once released to the environment, transport of chemical constituents depends on the characteristics of the:

- Spill (volume, duration, concentration);
- Fluid (density as influenced by salinity);
- Chemicals (volatility, sorption, solubility); and
- Site-specific environmental characteristics (surface topography and location of surface water bodies, the type of the soil and aquifer materials, layering and heterogeneity of rocks, and the presence of dissolved oxygen and other factors needed to support biodegradation, and the presence of inorganic species that affect metal transport).

This chapter provides characterization of produced water and also provides background information for the coverage of wastewater disposal and reuse in Chapter 8. Chapter 7 addresses the characteristics of produced water including per-well generation of produced water. Chapter 8 considers management of this water, now called wastewater, at an aggregate level, and thus

[1] There can be no shut-in period at all or it can last several weeks (Stepan et al., 2010).

discusses state, regional, and national estimates of treatment volumes. While Chapter 7 considers impacts from several types of unintentional releases, Chapter 8 focuses on impacts that are associated with wastewater management practices. One specific issue, leakage from pits and impoundments, is introduced in Chapter 7 as one of several avenues for accidental releases, with a more detailed exploration of the use of pits in wastewater management presented in Chapter 8.

Chapter 7 begins with a review of definitions for flowback and produced water in Section 7.1.1. Definitions are followed by a discussion in Section 7.2 of water volumes per well, first presenting data on the volume and percent of hydraulic fracturing fluid returned to the surface and then presenting data on the volume of water returned during production. These data all represent the response of individual wells. Because of the need to have aggregated volumes for estimating wastewater treatment loadings, estimates of total volumes are given in Section 8.2.

Chapter 7 continues with discussion of the chemical composition of produced water (Section 7.3). Because the composition of produced water is only known through analysis of samples, laboratory methods and their limitations are described in Section 7.3.1. Time-dependent changes in composition are discussed via three specific examples in Section 7.3.3, followed by discussion of five types of constituents: salts, metals, radioactive materials, organics, and known hydraulic fracturing additives in Section 7.3.4. The chemical and geological processes controlling the chemical composition of produced water are described in Appendix E. Spatial and temporal trends in the composition of produced water are illustrated with examples from the literature and data compiled for this report (Section 7.3.5).

The potential for impacts on drinking water resources of produced water releases and spills are described based on reported spill incidents (Section 7.4), and examples of spills from specific sources and data compilation studies are given in Section 7.4.2. The potential for impacts is described using contaminant transport principles in Section 7.6. The chapter concludes with a discussion of uncertainties and knowledge gaps, factors that influence the severity of impacts, and major findings (Section 7.7).

7.1.1 Definitions

Multiple definitions exist for the terms flowback and produced water. Appendix Section E.1 gives examples of definitions used by different organizations. These differing definitions reflect differing usage of the terms among various groups and that produced water reflects the continuously varying mixture between returning injection fluid and formation water. The majority of produced water definitions are fundamentally similar. The following definition is used in this report for produced water: any type of water that flows from the subsurface through oil and gas wells to the surface as a by-product of oil and gas production. Thus produced water can variously refer to returned hydraulic fracturing fluid, formation water alone, or a mixture of the two.

The term flowback has two major meanings. First is the process used to prepare the well for production by allowing excess liquids and proppant to return to the surface. The second use of the term is to refer to fluids predominantly containing hydraulic fracturing fluid that return to the surface. Because formation water can contact and mix with injection fluids, the distinction between returning hydraulic fracturing fluid and formation water is not clear. Definitions of flowback are operational in the sense that they include some characteristic of the oil and gas operation (i.e., fluids returning within 30 days). These reflect that during the early phases of operation, a higher concentration of chemical additives is expected and later, water is characteristic of the formation. Because we use existing literature in our review, we do not introduce a preferred definition of flowback, and describe all water flowing from the well as produced water.

7.2 Volume of Hydraulic Fracturing Flowback and Produced Water

Veil (2015) estimated that, in 2012, all types (i.e., from conventional and unconventional reservoirs) of U.S. onshore and offshore oil and gas production generated 8.90 x 10^{11} gal (3.37 x 10^{12} L) of produced water. More details and state-level estimates are given in Section 8.2. This section presents information on flowback and produced water volume over various time scales, and where possible, on a per-well and per-formation basis, because characteristics and volume of flowback and produced water vary by well, formation, and time.

The amount of produced water from a well varies and depends on several factors, including production, formation, and operational factors. Production factors include the amount of fluid injected, the type of hydrocarbon produced (gas or liquid), and the location within the formation. Formation factors include the formation pressure, the interaction between the formation and injected fluid (capillary forces), and reactions within the reservoir. Operational factors include the volume of the fractured production zone that includes the length of well segments and the height and width of the fractures. Certain types of problems also influence water production, including possible loss of mechanical integrity and subsurface communication between wells, both of which can result in an unexpected increase in water production (U.S. GAO, 2012; Byrnes, 2011; DOE, 2011a; GWPC and ALL Consulting, 2009; Reynolds and Kiker, 2003).

The processes that allow gas and liquids to flow are related to the conditions along the faces of fractures. Byrnes (2011) conceptualized fluid flow across the fracture face as being composed of three phases. The first is characterized by forced imbibition of fluid into the reservoir and occurs during and immediately following fracture stimulation.[1] Second is fluid redistribution within the reservoir rock, due to capillary forces. Estimates have shown that 50% or more of fracturing fluid could be captured within the Marcellus shale if imbibition drives water 2 to 6 in (5 to 15 cm) into the formation (Engelder, 2012; Byrnes, 2011; He, 2011). In the last phase, water flows out of the formation when the well is opened and pressure is reduced in the wellbore and fractures. The purpose of this phase is to recover as much of the injected fluid as possible (Byrnes, 2011) to allow higher oil or gas flow rates. The length of the last phase and, consequently, the amount of water removed, depends on factors such as the amount of injected fluid, the permeability and relative permeability of the reservoir, capillary pressure properties of the reservoir rock, and the pressure near the fracture faces.[2] The well can be shut in for varying time periods depending on operator scheduling, surface facility construction and connection thereto, or other reasons.

[1] The displacement of a non-wet fluid (i.e., gas) by a wet fluid (typically water). Adapted from Dake (1978).

[2] When multiple fluids (water, oil, gas) occupy portions of the pore space, the permeability to each fluid depends on the fraction of the pore space occupied by the fluid and the fluid's properties. As defined by Dake (1978), when this effective permeability is normalized by the absolute permeability, the resulting relationship is known as the relative permeability.

7.2.1 Flowback of Injected Hydraulic Fracturing Fluid

The amount of water produced by wells within the first few days following fracturing varies from formation to formation. Wells in the Mississippi Lime and Permian Basin can produce 1 million gal (3.8 million L) in the first 10 days of production. Wells in the Barnett, Eagle Ford, Granite Wash, Cleveland/Tonkawa Sand, Niobrara, Marcellus, and Utica Shales can produce 300,000 to 1 million gal (1.14 to 3.78 million L) within the first 10 days. Haynesville wells produce less, about 250,000 gal (950,000 L) (Mantell, 2013). Data show that the rate of water produced during the flowback period decreases as time passes (Ziemkiewicz et al., 2014; Hansen et al., 2013; Hayes, 2009).

It is not possible to specify precisely the amount of injected fluids that return in the flowback, because there is not a clear distinction between flowback and produced water, and the indicators (e.g., salinity and radioactivity, to name two) are not routinely monitored (GWPC and ALL Consulting, 2009). Rather, flowback estimates usually relate the amount of produced water measured at a given time after fracturing as a percentage of the total amount of injected fluid. Estimates of the fraction of injected hydraulic fracturing fluid that returns as flowback are highly variable (U.S. EPA, 2016d; Vengosh et al., 2014; Mantell, 2013; Vidic et al., 2013; Minnich, 2011; Xu et al., 2011). The maxima are less than 85% in all but one of the examples given in Table 7-1, Table 7-2, and Table 7-3, and most of the median values are less than 30%. In some cases, the amount of flowback is greater than the amount of injected hydraulic fracturing fluid, and the additional water comes from the formation (Nicot et al., 2014) or from a conductive pathway from an adjacent formation (Arkadakskiy and Rostron, 2013). See Appendix Section E.2.1 for more details.

Table 7-1. Data from one company's operations indicating approximate total water use and approximate produced water volumes within 10 days after completion of wells.
From Mantell (2013).

Formation	Approx. total average water use per well (million gal)	Produced water (flowback) within the first 10 days after completion		Produced water as a percentage of average water use per well	
		Low estimate (million gal)	High or only estimate (million gal)	Low estimate (% of total water use)	High or only estimate (% of total water use)
Gas shale plays (primarily dry gas)					
Barnett[a]	3.4	0.3	1.0	9%	29%
Marcellus[a]	4.5	0.3	1.0	7%	22%
Haynesville	5.4	--	0.25	--	5%
Liquid plays (gas, oil, condensate)					
Mississippi Lime	2.1	--	1.0	--	48%

Formation	Approx. total average water use per well (million gal)	Produced water (flowback) within the first 10 days after completion		Produced water as a percentage of average water use per well	
		Low estimate (million gal)	High or only estimate (million gal)	Low estimate (% of total water use)	High or only estimate (% of total water use)
Cleveland/ Tonkawa	2.7	0.3	1.0	11%	37%
Niobrara	3.7	0.3	1.0	8%	27%
Utica	3.8	0.3	1.0	8%	26%
Granite Wash	4.8	0.3	1.0	6%	21%
Eagle Ford	4.9	0.3	1.0	6%	20%

[a] Mantell (2011) reported produced water for the first 10 days at 500,000 to 600,000 gal for the Barnett, Fayetteville and Marcellus Shales.

Table 7-2. Additional short-, medium-, and long-term produced water estimates.

Location–formation	Produced water as percentage of injected fluid	Reference	Comment
Estimates without reference to a specific data set			
Unspecified Shale	5% – 35%	Hayes (2011)	
Marcellus Shale	10% – 25%	Minnich (2011)	Initial flowback
ND–Bakken	25%	EERC (2013)	
Estimates with reference to specific data evaluation			
Short duration			
Marcellus Shale	10%	Clark et al. (2013)	0 – 10 days
TX—Barnett	20%	Clark et al. (2013)	0 – 10 days
TX—Haynesville	5%	Clark et al. (2013)	0 – 10 days
AR—Fayetteville	10%	Clark et al. (2013)	0 – 10 days
Medium duration			
WV—Marcellus	8%	Hansen et al. (2013)	30 days
Marcellus Shale	24%	Hayes (2011, 2009)	Average from 19 wells, 90 days

Location–formation	Produced water as percentage of injected fluid	Reference	Comment
Long duration			
TX—Barnett	~100%[a]	Nicot et al. (2014)	72 months
WV—Marcellus	10% – 30%	Ziemkiewicz et al. (2014)	Up to 115 months
TX—Eagle Ford	<20%	Nicot and Scanlon (2012)	Lifetime
Unspecified duration			
PA—Marcellus	6%	Hansen et al. (2013)	

[a] Approximate median with large variability: 5th percentile of 20% and 90th percentile of 350%.

Table 7-3. Flowback water characteristics for wells in unconventional reservoirs.
Source: U.S. EPA (2016d). The formation-level data used to develop Tables 7-3 and 7-4 appear in Appendix Table E-1.

Resource type	Well type	Fracturing fluid (million gal)			Flowback (percent of fracturing fluid returned)		
		Weighted average	Range	Data points	Weighted average	Range	Data points
Shale	Horizontal	4.2	0.091–24	80,388	7%	0%–580%	7,377
	Directional	1.4	0.037–20	340	33%	1%–57%	36
	Vertical	1.1	0.015–19	5,197	96%	2%–581%	57
Tight	Horizontal	3.4	0.069–12	7,301	12%	0%–60%	75
	Directional	0.05	0.046–4	3,581	10%	0%–60%	342
	Vertical	1	0.016–4	10,852	4%	0%–60%	130

7.2.2 Produced Water Volumes

Mantell (2013, 2011) described the amount of produced water over the long term as high, moderate, or low for several formations. Wells in the Barnett Shale, Cleveland/Tonkawa Sand, Mississippi Lime, and the Permian Basin can produce more than 1,000 gal (3,800 L) of water per million cubic feet (MMCF) of gas. The most water-productive of these can be as high as 5,000 gal (19,000 L) per MMCF of gas. As a specific example, a high water producing formation in the western United States was described as producing 4,200 gal (16,000 L) per MMCF of gas for the life of the well (McElreath, 2011). The well was fractured and stimulated with about 4 million gal (15 million L) of water and returned 60,000 gal (230,000 L) per day in the first 10 days, followed by 8,400 gal (32,000 L) per day in the remainder of the first year. The Niobrara, Granite Wash, Eagle Ford, Haynesville, and Fayetteville Shales are relatively dry formations (with small amounts of naturally occurring formation water) and produce between 500 and 2,000 gal (1,900 to 7,600 L) of produced water per MMCF of gas (Mantell, 2013). The Utica and Marcellus Shales are viewed as drier still and produce less than 200 gal (760 L) per MMCF of gas.

Wells producing in various formation show high produced water volume variability, including the Barnett Shale, which was attributed by Nicot et al. (2014) to a few wells with exceptionally high water production. Some of these wells produced more than the amount of injected fracturing fluid.

Wells in conventional and unconventional reservoirs produce differing amounts of water. Individual hydraulically fractured wells producing gas from the Marcellus Shale produced more water than hydraulically fractured wells in conventional wells in Pennsylvania (Lutz et al., 2013). However, on a per-unit of gas produced basis, wells producing from the Marcellus Shale generate less water (35%), than those in the conventional formations.

The EPA (2016d) reported characteristics of long-term produced water for hydraulically fractured shale and tight formations (Table 7-4). For shale, horizontal wells produced more water (1,100 gal/day; 4,200 L/day) than vertical wells (500 gal/day; 1,900 L/day). Typically, this would be attributed to the longer length of the production zone in horizontal laterals than in vertical wells.

Table 7-4. Long-term produced water generation rates (gal/day per well) for wells in unconventional reservoirs.

Source: U.S. EPA (2016d). The formation-level data used to develop Tables 7-3 and 7-4 appear in Appendix Table E-1.

		Long-Term Produced Water Generation Rates (gal per day per well)		
Resource type	**Well type**	**Weighted average**	**Range**	**Data points**
Shale	Horizontal	1,100	0–29,000	43,893
	Directional	820	0.83–12,000	1,493
	Vertical	500	4.8–51,000	12,551
Tight	Horizontal	980	10–120,000	4,692
	Directional	390	15–8,200	10,784
	Vertical	650	0.71–2100	34,624

In an example from the Pennsylvania Marcellus Shale, the EPA determined that, for vertical wells in unconventional reservoirs, 6% of water came from drilling, 35% from flowback, and 59% from long-term produced water; for horizontal wells, the corresponding numbers were 9%, 33%, and 58% (U.S. EPA, 2016d). This result agrees with the U.S. Department of Energy (DOE, 2011a) who concluded that the characteristic small amount of produced water from the Marcellus Shale was due either to its low water saturation or low relative permeability to water (see Section 6.3.2.1). For these dry formations, low shale permeability and high capillarity cause water to imbibe into the formation, where some is retained permanently.

7.2.2.1 Time Trends

High rates of water production (flowback) typically occur in the first few months after hydraulic fracturing, followed by rates reduced by an order of magnitude (e.g., Nicot et al., 2014). In many cases half of the total produced water from a well is generated in the first year. Similarly, the EPA (2016d) reported a general rule of thumb that, for unconventional reservoirs, the volume of flowback (which occurs over a short period of time) is roughly equal to the volume of long-term produced water. These trends in produced water volumes occur within the timeline of hydraulic fracturing activities (Section 3.3), and show that the large, initial return volumes of flowback last for several weeks, whereas the lower-rate produced water phase can last for years (Figure 7-1).

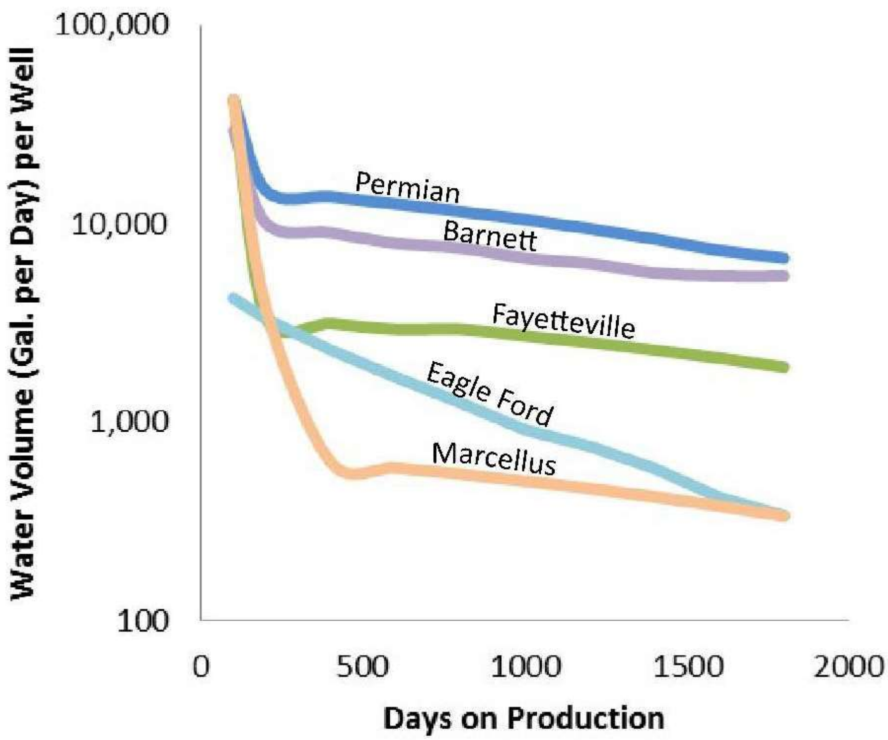


Figure 7-1. Generalized examples of produced water flow from five formations.
Actual produced water flows vary by location, play, basin, and amount of water used for hydraulic fracturing (EWI, 2015). Figure used with permission.

7.2.2.2 Coalbed Methane

Water is pumped from coal seams to reduce pressure so that gas adsorbed to the surface of the coal can flow to the production well (Guerra et al., 2011). Consequently, CBM tends to produce large volumes of water early on: more than conventional gas-bearing formations (U.S. GAO, 2012) (Figure 7-2). Within producing CBM formations, water production can vary for unknown reasons (U.S. GAO, 2012). As an example, data show that CBM production in the Powder River Basin produces 16 times more water than that in the San Juan Basin (U.S. GAO, 2012).

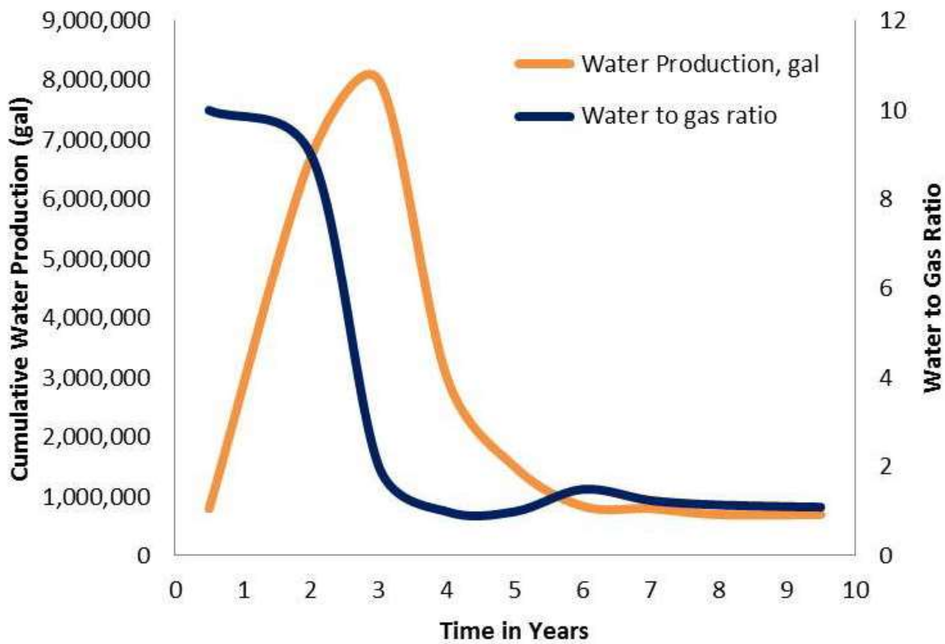


Figure 7-2. Typical produced water volume for a coal bed methane well in the western United States.
Source: Guerra et al. (2011).

7.3 Chemical Composition of Produced Water

For hydraulically fractured wells, the chemical composition of produced water changes from being similar to the injected hydraulic fracturing fluid to reflecting a mixture of hydraulic fracturing fluids, naturally occurring hydrocarbons, transformation products, and formation water. Initial produced water data show continuous changes in chemical composition and reflect processes occurring in the formation (Section 7.3.3). The data presented on longer-term produced water represent water that is primarily associated with the formation, rather than the hydraulic fracturing fluid (Section 7.3.4). Unlike the hydraulic fracturing fluid, the composition of which may be disclosed, compositional data on produced water comes from laboratory analysis of samples. Because of this reliance, we first discuss sampling and analysis of produced water, and especially note the limitations of existing analytical methods for organic chemicals and radionuclides.[1] It is important to note that the analytical methods can differ depending on the purpose of the analysis. Specifically, advanced laboratory methods have been used to identify unknown organic constituents of produced water (Section 7.3.1), routine methods are used for pre-drilling sampling, and a combination of methods may be needed for assessing environmental impacts (Section 7.4.2.5).

7.3.1 Determination of Produced Water Composition

Recent advances in analytical methods for produced water have allowed detection and quantification of a broad range of organic compounds, including those associated with hydraulic

[1] Chemical components of produced water are described below.

fracturing fluid (Section 7.3.4.7 and Appendix E.3.5.). These studies make clear that standard analytical methods are not adequate for detecting and quantifying the numerous organic chemicals, both naturally occurring and anthropogenic, that are now known to occur in produced water (Lester et al., 2015; Maguire-Boyle and Barron, 2014; Thurman et al., 2014). Similarly, methods commonly applied for the analysis of radionuclides in drinking water may suffer from analytical interferences that result in poor data quality (Maxwell et al., 2016; Ying et al., 2015; Zhang et al., 2015b; Nelson et al., 2014; U.S. EPA, 2014i, 2004b). In these instances, alternative methods that have been developed to support the nuclear materials production and waste industry provide more reliable approaches to ensure adequate detection limits and avoid sample matrix interferences that are anticipated for the high salinity and concentrations of organic constituents that may be present in produced water samples.[1] Development of advanced or non-routine methods for both organics and inorganics (especially radium) suggests that data generated from earlier methods may be less reliable that those developed by the new methods (Nelson et al., 2014), and that advanced analytical techniques are needed to detect or quantify some analytes.

The compositional data that follow in this chapter and Appendix E rely on the analytical procedures used in measurement and were summarized as noted from numerous produced water studies or compilations, such as the U.S. Geological Survey (USGS) produced water database (Blondes et al., 2014).

7.3.2 Factors Influencing Produced Water Composition

Several interacting factors influence the chemical composition of produced water: (1) the composition of injected hydraulic fracturing fluids, (2) the targeted geological formation and associated hydrocarbon products, (3) the stratigraphic environment, and (4) subsurface processes and residence time (Barbot et al., 2013; Chapman et al., 2012; Dahm et al., 2011; Blauch et al., 2009).

The mineralogy and structure of a formation are determined initially by deposition, when rock grains settle out of their transporting medium (Marshak, 2004). Generally, shale forms from clays that were deposited in deep, oxygen-poor marine environments, and sandstone can form from sand deposited in shallow marine environments (Ali et al., 2010; U.S. EPA, 2004a). Coal forms when carbon-rich plant matter collects in shallow peat swamps. In the United States, coal formed in both freshwater (northern Rocky Mountains) and marginal-marine environments (Alabama's Black Warrior formation) (NRC, 2010; Horsey, 1981). Consequently, shale and sandstone produced water are expected to be saline, and CBM water may be much less so.

7.3.3 Produced Water Composition During the Flowback Period

The chemistry of produced water changes over time, especially during the first days or weeks after hydraulic fracturing. Generally, produced water concentrations of cations, anions, metals, naturally occurring radioactive material (NORM), and organics increase as time goes on (Barbot et al., 2013; Haluszczak et al., 2013; Chapman et al., 2012; Davis et al., 2012; Gregory et al., 2011; Blauch et al.,

[1] For guidance in planning, implementing, and assessing projects that require laboratory analysis of radionuclides, see U.S. EPA (2004b).

2009). The causes include precipitation and dissolution of salts, carbonates, sulfates, and silicates; pyrite oxidation; leaching and biotransformation of organic compounds; and mobilization of NORM and trace elements. Concurrent precipitation of sulfates (e.g., $BaSO_4$) and carbonates (e.g., $CaCO_3$) alongside decreases in pH, alkalinity, dissolved carbon, and microbial abundance and diversity occur over time after hydraulic fracturing (Orem et al., 2014; Barbot et al., 2013; Murali Mohan et al., 2013; Davis et al., 2012; Blauch et al., 2009; Brinck and Frost, 2007). Leaching of organics appears to be a result of injected and formation fluids associating with shale and coal strata (Orem et al., 2014). Concentrations of organics in CBM produced water decrease with time, possibly due to the depletion of coal-associated water through formation pumping (Orem et al., 2007).

7.3.3.1 Total Dissolved Solids

Produced water total dissolved solids concentrations (TDS) increase by varying degrees because of the formation's geological origin. As an example, TDS concentrations increased to upper bound values in samples from four Marcellus Shale gas wells (Chapman et al., 2012) (Figure 7-3). The increased TDS was composed of increased sodium, calcium, and chloride (Chapman et al., 2012; Blauch et al., 2009). Similarly, TDS in flowback from the Westmoreland County wells started low and exceeded that of typical seawater (35,000 mg/L) within three days (Chapman et al., 2012). In a similar study, wells with hydraulic fracturing fluid containing less than 1,000 mg/L saw TDS concentrations increase above a median value of 200,000 mg/L within 90 days (Hayes, 2009).

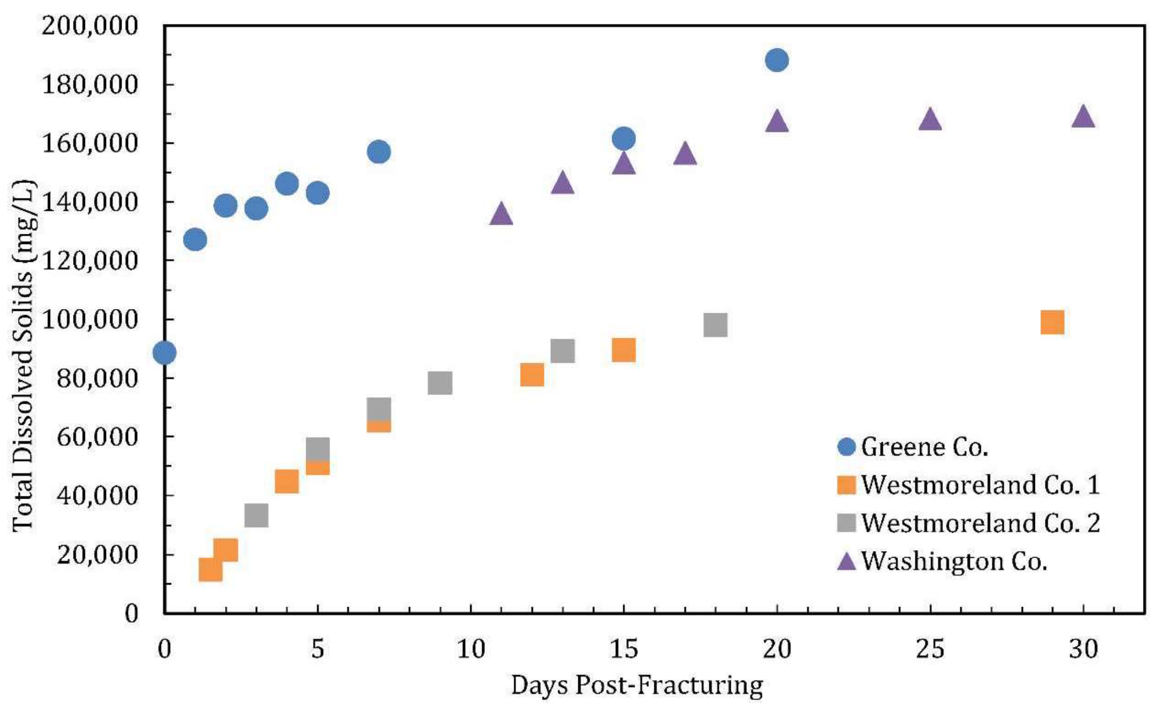


Figure 7-3. TDS concentrations measured through time for injected fluid (at 0 days), and produced water samples from four Marcellus Shale gas wells in three southwest Pennsylvania counties.

Data from Chapman et al. (2012).

7.3.3.2 Radionuclides

Shales and sandstones naturally contain various radionuclides (Sturchio et al., 2001).[1] Radium in pore waters or adsorbed onto clay particles and grain coatings can dissolve and return in produced water (Langmuir and Riese, 1985). Available data indicate that radium and TDS concentrations in produced water are positively correlated (Rowan et al., 2011; Fisher, 1998), likely because radium remains adsorbed to mineral surfaces when salinity is low, and then desorbs into solution with increased salinity (Sturchio et al., 2001). As an example, over the course of 20 days, radium concentration in flowback from a Marcellus Shale gas well increased by almost a factor of four (Chapman et al., 2012; Rowan et al., 2011) (Figure 7-4).

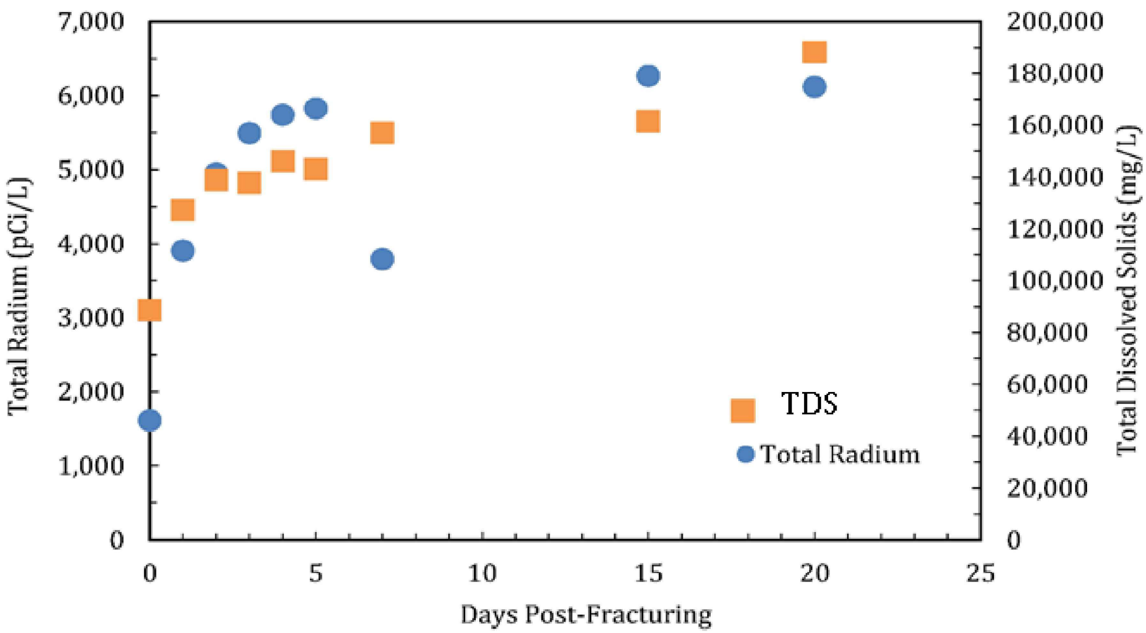


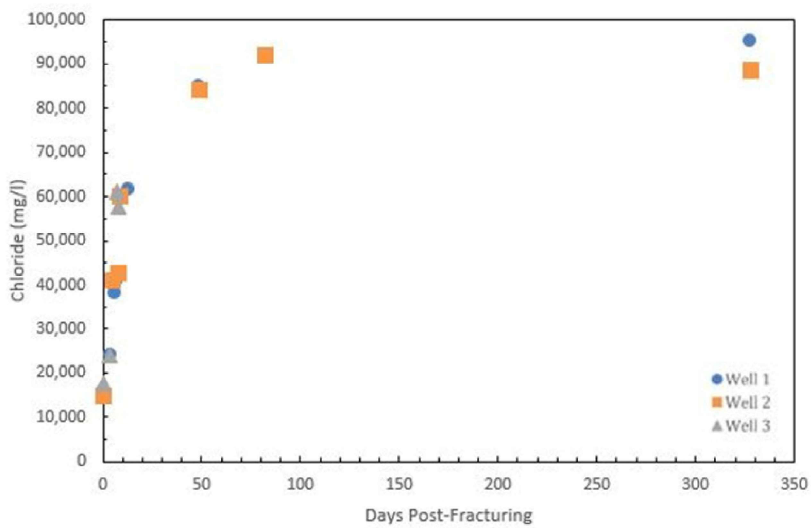
Figure 7-4. Total radium and TDS concentrations measured through time for injected (day 0), and produced water samples Greene County, PA, Marcellus Shale gas wells.
Data from Rowan et al. (2011) and Chapman et al. (2012).

7.3.3.3 Dissolved Organic Carbon

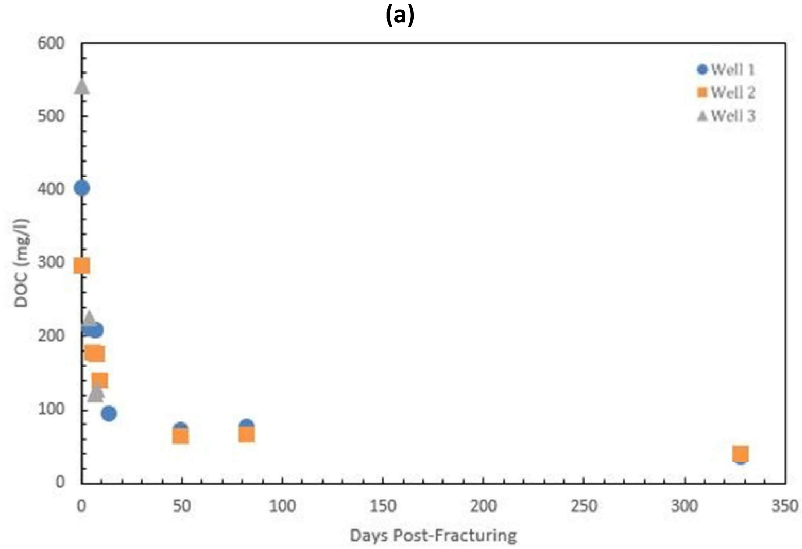
Dissolved organic carbon (DOC) concentrations decrease from initial levels in shales and coalbeds (Murali Mohan et al., 2013; Orem et al., 2007). This occurs while TDS and chloride concentrations are increasing (Barbot et al., 2013; Chapman et al., 2012). DOC sorption, dilution with injected or formation water, biochemical reactions, and microbial transformation may all cause decreased concentrations of DOC during flowback. Injected organics can include gel polymer formulations, namely guar gum; petroleum distillates; and ethyl and ether glycol formulations, which can serve as food sources for microbes. (Wuchter et al., 2013; Arthur et al., 2009b; Hayes, 2009). In coalbeds,

[1] Hydraulic fracturing fluids typically do not contain radioactive material (Rowan et al., 2011). However, reusing produced water can introduce radioactive material into hydraulic fracturing fluid. See Section 7.3.4.6 and PA DEP (2015b).

water contacting the coal may become depleted in DOC to the degree that when outside water of lower DOC is produced, the resulting DOC concentrations in the produced water are reduced (Orem et al., 2014).



(a)



(b)

Figure 7-5. (a) Increasing chloride (Cl) and (b) decreasing DOC concentrations measured through time for samples from three Marcellus Shale gas wells on a single well pad in Greene County, PA.

Data from Cluff et al. (2014). Reprinted with permission from Cluff, M; Hartsock, A; Macrae, J; Carter, K; Mouser, PJ. (2014). Temporal changes in microbial ecology and geochemistry in produced water from hydraulically fractured Marcellus Shale Gas Wells. Environ Sci Technol 48: 6508-6517. Copyright 2014 American Chemical Society.

As an example, produced water DOC concentrations decreased from their initial levels twofold from the hydraulic fracturing fluid and initial samples (Figure 7-5b) followed by a decrease of 11-fold over nearly 11 months. The DOC leveled off several months after hydraulic fracturing, presumably as a result of in situ attenuation processes (Cluff et al., 2014). As DOC was decreasing, chloride concentrations increased five- to six-fold. These chloride concentrations increased linearly during the first two weeks (Cluff et al., 2014) and then later approached higher levels (Figure 7-5a). The pattern in the DOC and chloride levels reflected the changing composition of the produced water—initially high in DOC from hydraulic fracturing additives and low in salinity, then higher in salinity and lower in DOC reflecting the chemistry of formation water. The changing composition of produced water suggests that the potential concern for produced water spills also changes: initially the produced water may contain more hydraulic fracturing chemicals, and later the concern may shift to the impact of high salinity water.

7.3.4 Produced Water Composition

The chemical composition of produced water continues to change after the initial flowback period. Produced water may contain a range of constituents, but in widely varying amounts. Generally, these can include:

- Salts, including those composed from chloride, bromide, sulfate, sodium, magnesium and calcium;
- Metals including barium, manganese, iron, and strontium;
- Radioactive materials including radium (radium-226 and radium-228);
- Oil and grease, and dissolved organics (including BTEX);[1]
- Hydraulic fracturing chemicals, including tracers and their transformation products; and
- Produced water treatment chemicals.[2]

We discuss these groups of chemicals and then conclude by discussing variability within formation types and within production zones.

7.3.4.1 Similarity of Produced Water from Conventional and Unconventional Reservoirs

Produced water generated from unconventional reservoirs is reported to be similar to produced water from conventional reservoirs in terms of TDS, pH, alkalinity, oil and grease, TOC, and other organics and inorganics (Wilson, 2014; Haluszczak et al., 2013; Alley et al., 2011; Hayes, 2009; Sirivedhin and Dallbauman, 2004). Although produced water salinity varies within and among shales and tight formations, produced water is typically characterized as saline (Lee and Neff, 2011; Blauch et al., 2009). Produced water from coalbeds may have low TDS if the coal source bed was formed in freshwater. Saline produced water is also enriched in major anions (e.g., chloride, bicarbonate, sulfate); cations (e.g., sodium, calcium, magnesium); metals (e.g., barium, strontium);

[1] BTEX is an acronym representing benzene, toluene, ethylbenzene, and xylenes.

[2] Some chemicals are added to produced water for the purpose of oil/water separation, improved pipeline flow, or equipment maintenance, including prevention of corrosion and scaling in equipment (Cal/EPA, 2016). Generally the chemicals serve as clarifiers, emulsifiers, emulsion breakers, floating agents, and oxygen scavengers. Among proprietary formulations, a few specific chemicals have been disclosed including low concentrations of benzene, toluene, and inorganics (acetic acid, ammonium chloride, cupric sulfate, sodium hypochlorite).

naturally occurring radionuclides (e.g., radium-226, radium-228) (Chapman et al., 2012; Rowan et al., 2011); and organics (e.g., hydrocarbons) (Orem et al., 2007; Sirivedhin and Dallbauman, 2004).

7.3.4.2 Variability in Produced Water Composition Among Unconventional Reservoirs

Alley et al. (2011) compared geochemical parameters of shale gas, tight gas, and CBM produced water. This comparison aggregated data on produced water from original analyses, peer-reviewed literature, and public and confidential government and industry sources and determined the statistical significance of the results.

As shown in Table 7-5, Alley et al. (2011) found that of the constituents of interest common to all three types of produced water from unconventional reservoirs (calcium, chloride, potassium, magnesium, manganese, sodium, and zinc):

1. Shale gas produced water had significantly different concentrations from those of CBM;
2. Shale gas produced water constituent concentrations were significantly similar to those of tight gas, except for potassium and magnesium; and
3. Five tight gas produced water constituent concentrations (calcium, chloride, potassium, magnesium, and sodium) were significantly similar to those of CBM (Alley et al., 2011).

The degree of variability between produced waters of these three resource types is consistent with the degree of mineralogical and geochemical similarity between shale and sandstone formations, and the lack of the same between shale and coalbed formations (Marshak, 2004). Compared to the others, shale gas produced water tends to be more acidic, as well as enriched in strontium, barium, and bromide. CBM produced water is alkaline, and it contains relatively low concentrations of TDS (one to two orders of magnitude lower than in shale and sandstone). It also contains lower levels of sulfate, calcium, magnesium, DOC, sodium, bicarbonate, and oil and grease than typically observed in shale and sandstone produced waters (Alley et al., 2011; Dahm et al., 2011; Benko and Drewes, 2008; Van Voast, 2003).[1]

Table 7-5. Compiled minimum and maximum concentrations for various geochemical constituents in produced water from shale gas, tight gas, and CBM produced water.
Source: Alley et al. (2011).

Parameter	Unit	Shale gas[a]	Tight Gas Sands[b]	CBM[c]
Alkalinity	mg/L	160–188	1,424	54.9–9,450
Ammonium-N	mg/L	-	2.74	1.05–59
Bicarbonate	mg/L	ND–4,000	10–4,040	-
Conductivity	µS/cm	-	24,400	94.8–145,000
Nitrate	mg/L	ND–2,670	-	0.002–18.7

[1] Several regions had low representation in the Alley et al. (2011) data set, including the Appalachian Basin (western New York and western Pennsylvania), West Virginia, eastern Kentucky, eastern Tennessee, and northeastern Alabama.

Parameter	Unit	Shale gas[a]	Tight Gas Sands[b]	CBM[c]
Oil and grease	mg/L	-	42	-
pH	SU[d]	1.21–8.36	5–8.6	6.56–9.87
Phosphate	mg/L	ND–5.3	-	0.05–1.5
Sulfate	mg/L	ND–3,663	12–48	0.01–5,590
Radium-226	pCi/g	0.65–1.031	-	-
Aluminum	mg/L	ND–5,290	-	0.5–5,290
Arsenic	mg/L	-	0.17	0.0001–0.06
Boron	mg/L	0.12–24	-	0.002–2.4
Barium	mg/L	ND–4,370	-	0.01–190
Bromide	mg/L	ND–10,600	-	0.002–300
Calcium	mg/L	0.65–83,950	3–74,185	0.8–5,870
Cadmium	mg/L	-	0.37	0.0001–0.01
Chloride	mg/L	48.9–212,700	52–216,000	0.7–70,100
Chromium	mg/L	-	0.265	0.001–0.053
Copper	mg/L	ND–15	0.539	ND–0.06
Fluorine	mg/L	ND–33	-	0.05–15.22
Iron	mg/L	ND–2,838	0.015	0.002–220
Lithium	mg/L	ND–611	-	0.0002–6.88
Magnesium	mg/L	1.08–25,340	2–8,750	0.2–1,830
Manganese	mg/L	ND–96.5	0.525	0.002–5.4
Mercury	mg/L	-	-	0.0001–0.0004
Nickel	mg/L	-	0.123	0.0003–0.20
Potassium	mg/L	0.21–5,490	5–2,500	0.3–186
Sodium	mg/L	10.04–204,302	648–80,000	8.8–34,100
Strontium	mg/L	0.03–1,310	-	0.032–565
Uranium	mg/L	-	-	0.002–0.012
Zinc	mg/L	ND–20	0.076	0.00002–0.59

-, No value available; ND, non-detect. If no range, but a singular concentration is given, this is the maximum concentration.

[a] *n* = 541. Alley et al. (2011) compiled data from USGS (2006); McIntosh and Walter (2005); McIntosh et al. (2002) and confidential industry documents.

[b] *n* = 137. Alley et al. (2011) compiled data from USGS (2006) and produced water samples presented in Alley et al. (2011).

[c] Alley et al. (2011) compiled data from Montana GWIC (2009); Thordsen et al. (2007); ESN Rocky Mountain (2003); Rice et al. (2000); Rice (1999); Hunter and Moser (1990).

[d] SU = standard units.

7.3.4.3 General Water Quality Parameters

Data characterizing the content of produced water from unconventional reservoirs in 12 shale and tight formations and CBM basins were evaluated for this assessment. These reservoirs and basins include parts of 18 states, but the data do not allow for comparison of trends over time.

For most reservoirs, the amount of available general water quality parameter data is variable (see Appendix Table E-2 for an example). Average pH levels range from 5.87 to 8.19, with typically lower values for shales. Larger variations in average specific conductivity are seen among unconventional reservoirs and range from 213 microsiemens (μS)/cm in the Bakken Shale to 184,800 μS/cm in Devonian sandstones (Appendix Table E-2). Shale and tight formation produced waters are enriched in suspended solids, as reported concentrations for total suspended solids and turbidity exceed those of coalbeds by one to two orders of magnitude.

The average dissolved oxygen (DO) concentrations of CBM produced water range from 0.39-1.07 mg/L (Appendix Table E-3). By comparison, well-oxygenated surface water can contain up to 10 mg/L DO at 59 °F (15 °C) (U.S. EPA, 2012a). Thus, coalbed produced water is either hypoxic (less than 2 mg/L DO) or anoxic (less than 0.5 mg/L DO) and, if released to surface waters, could contribute to aquatic organism stress (USGS, 2010; NSTC, 2000).

7.3.4.4 Salinity and Inorganics

The TDS profile of produced water from unconventional reservoirs is dominated by sodium and chloride, with large contributions to the profile from mono- and divalent cations (Sun et al., 2013; Guerra et al., 2011). Shale and sandstone produced waters tend to be characterized as sodium-chloride-calcium water types, whereas CBM produced water tends to be characterized as sodium chloride or sodium bicarbonate water types (Dahm et al., 2011). Elevated levels of bromide, sulfate, and bicarbonate are also present (Sun et al., 2013). Elevated strontium and barium levels are characteristic of Marcellus Shale produced water (Barbot et al., 2013; Haluszczak et al., 2013; Chapman et al., 2012). Data representing shales and tight formations are presented in Appendix Table E-4.

Marcellus Shale produced water salinities range from less than 1,500 mg/L to over 300,000 mg/L, as shown by Rowan et al. (2011). By comparison, the average salinity concentration for seawater is 35,000 mg/L.

Of the CBM data presented in Appendix Table E-5, differences are evident between the Black Warrior and the three western formations (Powder River, Raton, and San Juan). The Black Warrior is higher in average chloride, specific conductivity, TDS, TOC, and total suspended solids, and lower in alkalinity and bicarbonate than the other three. These differences are due to the saline or brackish conditions during deposition in the Black Warrior, and its older geologic age that contrasts with the freshwater conditions for the younger western basins. The TDS concentration of CBM produced water can range from 170 mg/L to nearly 43,000 mg/L (range composited from Dahm et al. (2011) and Benko and Drewes (2008); see also Van Voast (2003)).[1]

7.3.4.5 Metals

The metals content of produced water from unconventional reservoirs varies by well and site lithology. Levels of iron, magnesium, and boron were within ranges known for conventional produced water (Hayes, 2009). Produced water from unconventional reservoirs may also contain low levels of heavy metals (e.g., chromium, copper, nickel, zinc, cadmium, lead, arsenic, and mercury as found by Hayes). Data illustrating metal concentrations in produced water appear in Appendix Tables E-6 and E-7.

7.3.4.6 Naturally Occurring Radioactive Material (NORM) and Technologically Enhanced Naturally Occurring Radioactive Material (TENORM)

Geologic environments contain naturally occurring radioactive material (NORM). Radioactive materials commonly present in shale and sandstone sedimentary environments include uranium, thorium, radium, and their decay products. Elevated formation uranium levels have been used to identify potential areas of natural gas production for decades (Fertl and Chilingar, 1988). Shales that contain significant levels of uranium include the Barnett in Texas, the Woodford in Oklahoma, the New Albany in the Illinois Basin, the Chattanooga Shale in the southeastern United States, and a group of black shales in Kansas and Oklahoma (Swanson, 1955).[2] When exposed to the environment in produced water, NORM is called *technologically enhanced* naturally occurring radioactive material (TENORM).[3] Water soluble forms of TENORM are present in most produced water from unconventional reservoirs, but particularly so in Marcellus Shale produced water (Rowan et al., 2011; Fisher, 1998).

Due to insolubility under prevailing reducing conditions encountered within shale formations, only low levels of uranium and thorium are found in produced water, typically in the concentrated form of mineral phases or organic matter (Nelson et al., 2014; Sturchio et al., 2001). Conversely, radium, a decay product of uranium and thorium, is known to be relatively soluble within the redox range encountered in subsurface environments (Sturchio et al., 2001; Langmuir and Riese, 1985). As noted in Section 7.3.3.2, radium and TDS produced water concentrations are positively correlated (Rowan et al., 2011; Fisher, 1998); therefore, in formations containing radium, increasing TDS concentration indicates likely increasing radium concentration.

[1] From a similar dataset, Dahm et al. (2011) report TDS concentrations from a composite CBM produced water database (n = 3,255) for western basins that often are less than 5,000 mg/L (85% of samples).

[2] Marine black shales are estimated to contain an average of 15–60 ppm uranium depending on depositional conditions (Fertl and Chilingar, 1988).

[3] The U.S. EPA Office of Air and Radiation's website (https://www.epa.gov/radiation/technologically-enhanced-naturally-occurring-radioactive-materials-tenorm) states that TENORM is produced when activities such as uranium mining or sewage sludge treatment concentrate or expose radioactive materials that occur naturally in ores, soils, water, or other natural materials. Formation water containing radioactive materials contains NORM, because it is not exposed; produced water contains TENORM, because it has been exposed to the environment.