In addition to the principal subsurface stresses, other geomechanical and reservoir characteristics and operational factors affect fracture creation, geometry, and propagation.[1] These include initial reservoir pressure and saturation, injected fluid pressure or injection rate, geomechanical rock characteristics, reservoir heterogeneity, tensile strength, fluid type within fractures, and reservoir permeabilities (Kim and Moridis, 2015). Fracture creation is a complex process that involves interactions between multiple properties. For example, as described by Daneshy (2009), fracture height depends on a combination of parameters and processes including the material properties of geologic formations, pore pressures, stress differences in adjacent formations, shear failure (slippage) at the fracture tip, and the reorientation of the fracture as it crosses an interface between formations. Injection rates, the initial water saturation of the formation, and the type of fluid injected also have effects on fracture creation and propagation (Kim and Moridis, 2015, 2013).

Numerical modeling techniques have been developed to describe fracture creation and propagation and to provide a better understanding of this complex process (Kim and Moridis, 2013). 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 types of advanced models are: permeability, porosity, Young's modulus, Poisson's ratio, and tensile strength, as well as heterogeneities associated with these parameters.[2] Some investigations using these models 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 leads to greater leakoff. These findings demonstrate that elevated pore pressure can cause shear failure, thus further affecting matrix permeability, flow regimes, and leakoff (Daneshy, 2009). Computational investigations have also indicated that slower injection rates can increase the amount of leakoff (Kim and Moridis, 2013).

In addition to their use in research settings, analytical and numerical modeling approaches are used by oil and gas companies 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. The industry models range from simpler (typically two-dimensional) theoretical models to computationally more complicated and accurate three-dimensional models.

In addition to computational approaches, monitoring of hydraulic fracturing operations can provide insights into fracture development. Monitoring techniques involve both operational monitoring methods and "external" methods that are not directly related to the production operation. Operational monitoring refers to the monitoring of parameters including pressure, flow rate, fluid density, and additive concentrations using surface equipment and/or downhole sensors (Eberhard, 2011). This monitoring is conducted to ensure that the operation is proceeding as planned and to

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

determine if operational parameters need to be adjusted. Interpretation of pressure data can be used to better understand fracture behavior (e.g., Kim and Wang, 2014). Anomalies in operational monitoring data can also indicate whether an unexpected event has occurred, such as communication with another well (see Section 6.3.2.3).

The volume of fluid injected is typically monitored 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 the growth of the vertical fractures, and additional information is needed to accurately predict the extent of fracture growth.

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, or caliper logs (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 one or more 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). Tiltmeters, which measure extremely small deformations in the earth, can be used to determine the direction and volume of the fractures and, within certain distances from the well, to estimate their dimensions (Lecampion et al., 2005).

6.3.2. Migration of Fluids through Pathways Related to Fractures/Formations

As noted 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 fluid movement. The following subsections describe and evaluate potential pathways for the migration of fracturing fluids, hydrocarbons, or other formation fluids from producing formations to drinking water resources. They also present cases where the existence of these pathways has been documented. As described above, potential subsurface migration pathways for fluid flow out of the production formation are categorized as follows: (1) flow of fluids into the production zone via induced fractures and out of the production zone via flow through the formation, (2) fracture overgrowth out of the production zone, (3) migration via fractures intersecting offset wells and

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

other artificial structures, and (4) migration via fractures intersecting other geologic features. 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.

In many cases (depending on fracture depth, height, and direction), the distance between the producing formation and the drinking water resource is one of the most important factors affecting the possibility of fluid migration between these formations (Reagan et al., 2015; Jackson et al., 2013c). This distance varies substantially among shale gas plays, coalbed methane plays, and other areas where hydraulic fracturing takes place in the United States (see Table 6-2). 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 mile (1.6 km) or greater. This is reflected in the Well File Review, which found that the largest proportion of wells used for hydraulic fracturing—an estimated 6,200 wells (27%)—had 5,000 to 5,999 ft (1,524 to 1,828 m) of measured distance along the wellbore between the induced fractures and the reported base of protected ground water resources (U.S. EPA, 2015o).[1] However, as shown in Table 6-2, operations in the Antrim and the New Albany plays take place at relatively shallower depths, with distances of 100 to 1,900 ft (30 to 579 m) between the producing formation and the base of drinking water resources. The Well File Review indicated that 20% of wells used for hydraulic fracturing (an estimated 4,600 wells) were located in areas with less than 2,000 ft (610 m) between the fractures and the base of protected ground water resources (U.S. EPA, 2015o). In coalbed methane plays, which are typically shallower than shale gas plays, these separation distances can be even smaller. For example, 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 (30 m) (Watts, 2006).

Some hydraulic fracturing operations are conducted within formations that contain drinking water resources (see Table 6-2). 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 (WYOGCC, 2014; Wright et al., 2012). Vertical gas wells in this area target the lower Eocene Wind River Formation and the underlying Paleocene 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. Hydraulic fracturing in rock formations that meet a state or federal definition of an underground source of drinking water is also known to take place in coalbed methane operations in the Raton Basin (U.S. EPA, 2015l), in the Powder River Basin of Montana and Wyoming (as described in Chapter 7), and in several other coalbed methane plays. In one field in Alberta, Canada, there is evidence that fracturing in the same formation as a drinking water resource (in combination with well integrity

[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.

problems; see Section 6.2.2.2) led to gas migration into water wells (Tilley and Muehlenbachs, 2012). However, no information is available on other specific incidents of this type.

Table 6-2. 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 (2004). See Figures 2-2 and 2-4 in Chapter 2 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])
Shale plays			
Antrim	600 to 2,200 [183 to 671]	70 to 120 [21 to 37]	300 to 1,900 [91 to 579]
Barnett	6,500 to 8,500 [1,981 to 2,591]	100 to 600 [30 to 183]	5,300 to 7,300 [1,615 to 2,225]
Eagle Ford	4,000 to 12,000 [1,219 to 3,658]	250 [76]	2,800 to 10,800 [853 to 3,292]
Fayetteville	1,000 to 7,000 [305 to 2,134]	20 to 200 [6 to 61]	500 to 6,500 [152 to 1,981]
Haynesville-Bossier	10,500 to 13,500 [3,200 to 4,115]	200 to 300 [61 to 91]	10,100 to 13,100 [3,078 to 3,993]
Marcellus	4,000 to 8,500 [1,219 to 2,591]	50 to 200 [15 to 61]	2,125 to 7,650 [648 to 2,332]
New Albany	500 to 2,000 [152 to 610]	50 to 100 [15 to 30]	100 to 1,600 [30 to 488]
Woodford	6,000 to 11,000 [1,829 to 3,353]	120 to 220 [37 to 67]	5,600 to 10,600 [1,707 to 3,231]
Coalbed methane basins			
Black Warrior (Upper Pottsville)	0 to 3,500 [0 to 1,067]	< 1 to > 70 [< 1 to > 21]	As little as zero[b]
Powder River (Fort Union)	450 to >6,500 [137 to 1,981]	75 [23]	As little as zero[b]
Raton (Vermejo and Raton)	< 500 to > 4,100 [< 152 to > 1,250]	10 to >140 [3 to >43]	As little as zero[b]
San Juan (Fruitland)	550 to 4,000 [168 to 1,219]	20 to 80 [6 to 24]	As little as zero[b]

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])

[a] For coalbed methane, values are given for the specific coal units noted in parentheses.
[b] Formation fluids in producing formations meet the definition of drinking water in at least some areas of the basin.

The overall frequency of occurrence of hydraulic fracturing in aquifers that meet the definition of drinking water resources across the United States is unknown. 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% 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 ground water resources reported by well operators (U.S. EPA, 2015o).[1] An analysis of produced water composition data maintained by the U.S. Geological Survey (USGS) provides insight into the geographic distribution of this practice. The USGS produced water database contains results from analyses of samples of produced water 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 continental United States.[2] Just over 5,000 of these samples, which were obtained from wells located in 37 states, reported total dissolved solids (TDS) concentrations. Because the database does not track whether samples were from wells that were hydraulically fractured, we 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. This yielded 1,650 samples from wells located in Alabama, Colorado, North Dakota, Utah, and Wyoming.[3,4] The TDS concentrations among these samples ranged from approximately 90 mg/L to 300,000 mg/L. Samples from approximately 1,200 wells in Alabama, Colorado, Utah, and Wyoming reported TDS concentrations at or below 10,000 mg/L. This analysis, in conjunction with the result from the Well File Review, suggests that, while the overall frequency of occurrence may be low, the activity may be concentrated in some areas of the country.

[1] The 95% confidence interval reported in the Well File Review indicates that this phenomenon could have occurred in as few as 0.1% of the wells or in as many as 3% of the wells.
[2] We 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.
[3] See Chapter 2, Text Box 2-1, which describes how commercial hydraulic fracturing began in the late 1940s.
[4] For this analysis, we 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, we 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 EPA using the assumptions described in Section 2.3.1. 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.

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 flow of injected fluids (or displacement of formation fluids due to injection) through the formation matrix during or after a hydraulic fracturing treatment. 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., 2013c). However, there is limited information available on the fate of injected fluids that are not recovered during production (i.e., leakoff) or displaced formation fluids for cases where hydraulic fracturing takes place within or close to drinking water resources.

Leakoff into shale gas formations may be as high as 90% or more of the injected volume (see Section 7.2 and Table 7-2). The actual amount of leakoff depends on the amount of injected fluid, the hydraulic properties of the reservoir (e.g., permeability), 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] However, despite the potentially large volume of fluid that may be lost into the formation, the flow of this fluid is generally 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).[3] It has been suggested that these processes can sequester the fluids in the producing formations permanently or for geologic time scales (Engelder, 2012; Byrnes, 2011).

A limited number of studies in the literature have evaluated a combination of certain conditions that can facilitate migration of fluids despite these processes. Myers (2012b) suggests that migration of injected and/or formation fluids into the overburden may be possible in cases where there is a significant vertical hydraulic gradient, sufficient permeability, density-driven buoyancy, and the displacement of formation brines by large volumes of injected fluid. Flewelling and Sharma (2014) note that, for migration to occur, an upward hydraulic gradient would be necessary, particularly for brine that is denser than the ground water in the overlying formations; in the case of natural gas, though, buoyancy would provide an upward flux A limited number of studies in the literature have evaluated a combination of certain conditions that can facilitate migration of fluids despite these processes. Myers (2012b) suggests that migration of injected and/or formation fluids into the overburden may be possible in cases where there is a significant vertical hydraulic gradient, sufficient permeability, density-driven buoyancy, and the displacement of formation

[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).

brines by large volumes of injected fluid. Flewelling and Sharma (2014) note that for migration to occur, an upward hydraulic gradient would be necessary, particularly for brine that is denser than the ground water in the overlying formations; in the case of natural gas, though, buoyancy would provide an upward flux (Vengosh et al., 2014). Some natural conditions could create this upward hydraulic gradient in the absence of any effects from hydraulic fracturing (Flewelling and Sharma, 2014). 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—corresponding 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). Furthermore, fracturing fluid would likely be sequestered in the immediate vicinity of the fracture network due to capillary tension (Engelder, 2012).

Over-pressurization of producing formations due to the injection of large amounts of fluid during hydraulic fracturing may support the upward hydraulic gradient for fluid migration (Myers, 2012b). Myers' modeling results suggest that significant pressure buildup that occurs at the location of fluid injection may not return to pre-hydraulic fracturing levels for up to a year. However, these findings have been disputed in the literature due to certain suggested limitations of the original study (e.g., extensive simplification of the model, lack of accurate characterization of regional flow, misrepresentation of saturation conditions in shale formations), and they have been found to be physically implausible given the hydrogeologic characteristics of actual sedimentary basins (Cohen et al., 2013; Flewelling et al., 2013; Vidic et al., 2013; Saiers and Barth, 2012). Some researchers have also suggested that pressure perturbations due to hydraulic fracturing operations are localized to the immediate vicinity of the fractures, due to the very low permeabilities of shale formations (Flewelling and Sharma, 2014). However, there are emerging studies indicating that pressure impacts of hydraulic fracturing operations may extend farther than the immediate vicinity and may create risk of induced seismicity (Skoumal et al., 2015). Following hydraulic fracturing operations, a large-scale depressurization would be expected over the longer term due to hydrocarbon production, which may counteract any short-term localized pressure effects of hydraulic fracturing during production and cause fluids to flow primarily toward the fracture network (Flewelling and Sharma, 2014).

In responses to these critiques, Myers (2013, 2012a) states that they do not prove his original hypothesis or findings wrong, but instead highlight the need for complex three-dimensional modeling and detailed data collection for improving the understanding of the process and risks to drinking water resources. Myers (2013, 2012a) argues that, given the large volume of hydraulic fracturing operations in formations such as the Marcellus, these formations would have to hold very large volumes of water that would be imbibed into the shale. Furthermore, he notes that migration of these fluids into overlying formations may be facilitated by existing fractures or out-of-zone fracturing (as discussed in the following sections).

6.3.2.2. Fracture Overgrowth out of the Production Zone

Fractures that extend out of the intended production zone into another formation or an unintended zone within the same formation could provide a potential fluid migration pathway into drinking water resources (Jackson et al., 2013c). This migration could occur either through the fractures themselves or in connection with other permeable subsurface features or formations (see Figure 6-5). 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 potential 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).

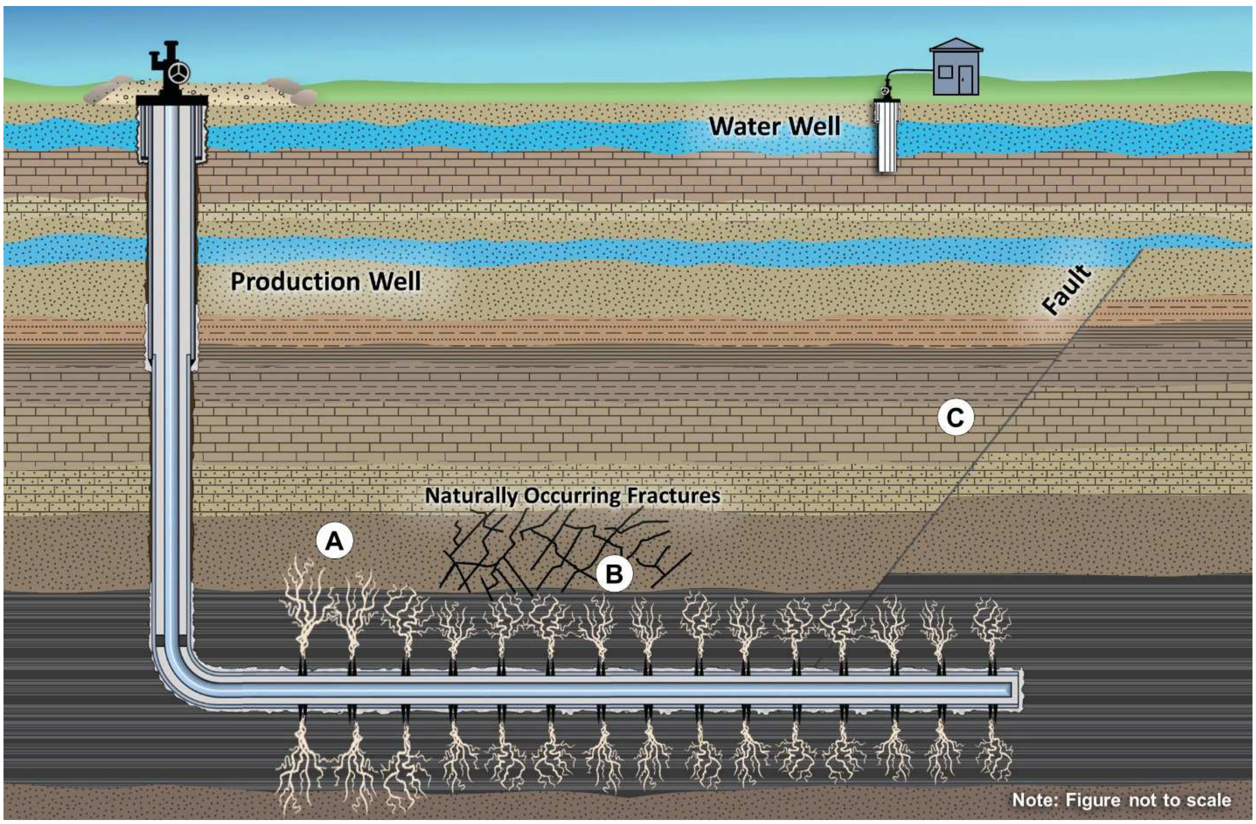

Figure 6-5. Conceptualized depiction of potential pathways for fluid movement out of the production zone: (a) induced fracture overgrowth into over- or underlying formations; (b) induced fractures intersecting natural fractures; and (c) induced fractures intersecting a transmissive fault.

Thickness and depth of production formation are important site specific factors for each operation.

The fracture's geometry (see 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 and microdeformation field monitoring techniques (Fisher and Warpinski, 2012). These data indicate typical fracture heights extending from tens to hundreds of feet. 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 for at least 1,500 ft (477 m), while the maximum thickness of the formation is generally 350 ft (107 m) or less (MCOR, 2012). However, the majority of fractures 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 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 (305 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 caused by hydraulic fracturing (Hammack et al., 2014). At three of the six wells, fractures extending between 1,000 and 1,900 ft (305 and 579 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 that is sometimes referred to as an upper barrier to hydraulic fracture growth. However, all microseismic events were at least 5,000 ft (1,524 m) below drinking water aquifers, as the Marcellus Shale is one of the deepest target formations (see Table 6-2), and no impacts to drinking water resources or another local gas-producing interval were identified. See Text Box 6-3 for more information on the Greene County site.

Similarly, in Dunn County, North Dakota, there is evidence of out-of-zone fracturing in the Bakken Shale (U.S. EPA, 2015j). At the Killdeer site (see Section 6.2.2.1 and Chapter 5, Text Box 5-12), 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. Industry experience also indicates that out-of-zone fracturing may be fairly common in the Bakken and that produced water from many Bakken wells has Madison Group chemical signatures (Arkadakskiy and Rostron, 2013b, 2012b; Peterman et al., 2012).

Text Box 6-3. 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 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 vertical gas wells completed in Upper Devonian/Lower Mississippian zones 3,800 to 6,100 ft (1,158 to 1,859 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 will be necessary to confirm that no impacts to overlying zones have occurred (Zhang et al., 2014a).

Extreme vertical fracture growth 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 these thief zones may prevent fractures from reaching shallower formations or growing to extreme vertical lengths, it is important to note that they do allow fluids to migrate out of the production zone into these receiving formations, which could 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 the fractures are unlikely to extend into drinking water resources (Kim and Moridis, 2015).

Modeling studies have identified other factors that 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). Modeling and monitoring studies generally agree that physical constraints on fracture propagation will prevent induced fractures from extending from deep zones directly into drinking water resources (Kim and Moridis, 2015; Flewelling et al., 2013; Fisher and Warpinski, 2012).

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 ground water unit. Migration was assessed immediately after hydraulic fracturing and for up to a 2-year time period during the production stage. The potential migration pathway was assumed to be a permeable fracture or fault connecting the producing formation to the shallower ground water unit. Such a pathway may be either entirely hydraulically induced (due to fracture overgrowth in a case where the separation distance is limited, as discussed below), or may be a smaller induced fracture connecting to a natural, permeable fault or fracture (as discussed in Section 6.3.2.4). For the purposes of this study, the pathway was assumed to be pre-existing, and Reagan et al. (2015) did not model the fracturing process itself.

The subsurface system evaluated in the modeling investigation included a horizontal well used for hydraulic fracturing and gas production, the connecting fracture or fault between the producing formation and the aquifer, and a shallow vertical water well in the aquifer (see Figure 6-5). The parameters and scenarios used in the study are shown in Table 6-3; 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. Over-pressurization during hydraulic fracturing may create an additional driving force for upward migration. Results of this investigation, which represents a typical production period, indicate a generally downward water flow within the connecting fracture (from the aquifer through the connecting fracture into the hydraulically induced fractures in the production zone) and some upward migration of gas (Reagan et al., 2015). In certain cases, gas breakthrough (i.e., 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, driving the fluid migration toward the production well, was occurring in the reservoir. Simulations including a producing gas well showed only a few instances of breakthrough, while simulations without gas production tended to result in breakthrough; these 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 available for migration in hydraulically induced fractures prior to production.

Table 6-3. 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 6-5, Figure 6-6, and Figure 6-7 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
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)

Based on the results of the Reagan et al. (2015) 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. In contrast, Reagan et al. (2015) found 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 producing gas well, the gas may 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 for 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 amount of migrating gas depended upon the permeability of the connecting feature: the higher the permeability, the larger the amount. The 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 their assessment.

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 injected fluids or displaced subsurface fluids move through newly created fractures into an offset well or its fracture network, resulting in well communication (Jackson et al., 2013c). This may be a concern, particularly in shallower formations where the local least principal stress is vertical (resulting in more horizontal fracture propagation) and where there are shallow drinking water wells in the same formation.

The offset well can be an abandoned, inactive, or active well; if the well has also been used for hydraulic fracturing, the fracture networks of the two wells might intersect. The situation where hydraulic fractures unintentionally propagate into other existing, producing 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). Figure 6-6 provides a schematic to illustrate fractures that intercept an offset well, and Figure 6-7 depicts how the fracture networks of two wells can intersect.

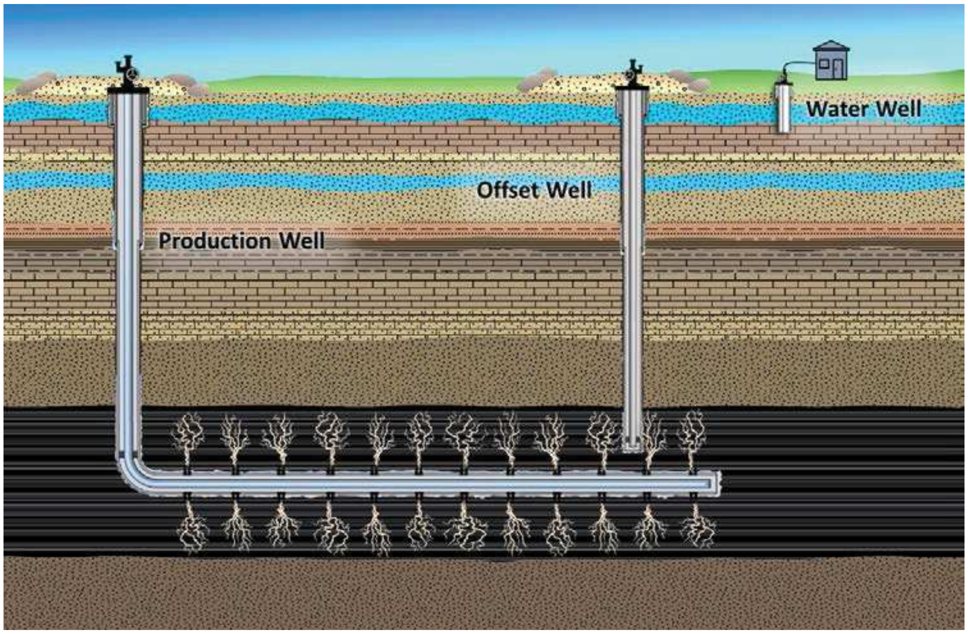

Figure 6-6. Induced fractures intersecting an offset well (in a production zone, as shown, or in overlying formations into which fracture growth may have occurred).

This image shows a conceptualized depiction of potential pathways for fluid movement out of the production zone (not to scale).

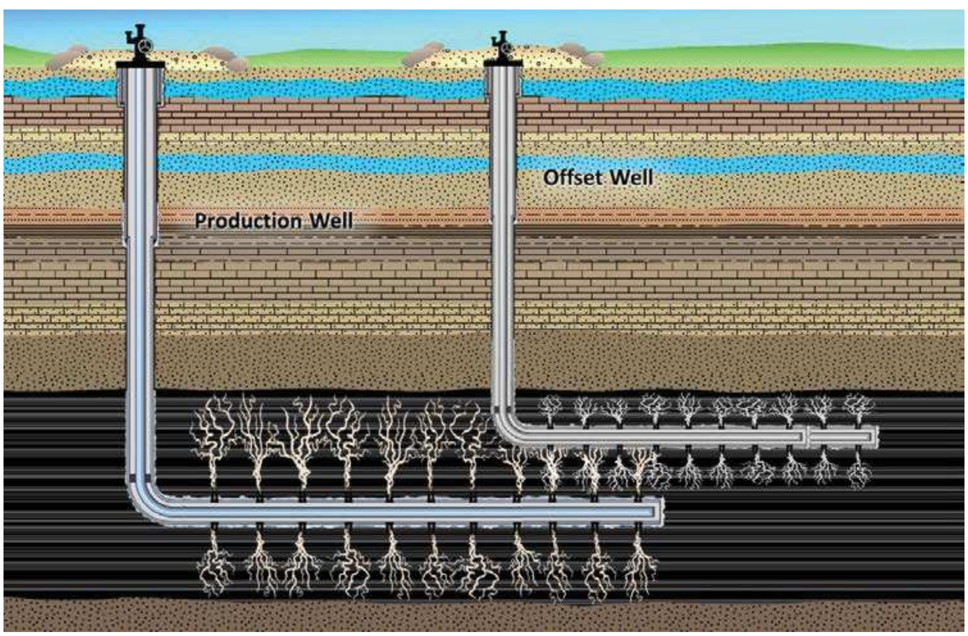

Figure 6-7. Well communication (a frac hit) via induced fractures intersecting another well or its fracture network.

This image shows a conceptualized depiction of potential pathways for fluid movement out of the production zone (not to scale).

Instances of well communication have been known to occur and are described in 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 (Vaidyanathan, 2014). In some cases, well communication incidents have led to documented production and/or environmental problems. A study from the Barnett Shale noted two cases of well communication, one with a well 1,100 ft (335 m) away and the other with a well 2,500 ft (762 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. The EPA (2015n) recorded 10 incidents in which fluid spills were attributed to well communication events (see Chapter 7 for more information).[1] The subsurface effects of frac hits have not been extensively studied, but these cases demonstrate the possibility of fluid migration via communication with other wells and/or their fracture networks. More generally, well communication events may indicate fracture behavior that was not intended by the treatment design.

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 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 (2,414 m), measured 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.[2]

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, 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 (305 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

[1] Line numbers 163, 236, 265, 271, 286, 287, 375, 376, 377, and 380 in Appendix B of U.S. EPA (2015n).
[2] The numbers of wells cited in the study reflect separate analyses, and the numbers cited are not additive.

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 (1,219 m) apart, but rose to nearly 50% in wells less than 1,000 ft (305 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.

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 (see Table 6-2), hydraulic fracturing treatments tend to enter portions of the reservoir that have already been fractured as 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 may 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 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 may occur during a well communication event. However, if the offset well is not able to withstand the pressure of the fracturing fluid, well components may fail, allowing fluid to migrate out of the well. The highest pressures most wells will face during their life spans occur during fracturing. 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 may 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, 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 (see Text Box 6-4) 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 any formations that are uncemented along the wellbore.

Text Box 6-4. Well Communication at a Horizontal Well near Innisfail, Alberta, Canada.

In most cases, well communication during fracturing may only result in a pressure surge accompanied by a drop in gas production and additional flow of produced water or 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 an estimated 19,816 gallons (75 m^3) of fracturing fluid, brine, gas, 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. 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 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.

In older wells near a hydraulic fracturing operation, plugs and cement may have degraded 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 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 natural gas migration had been caused by well communication events with old, abandoned wells (PA DEP, 2009b). The Interstate Oil and Gas Compact Commission (IOGCC, 2008) estimates that over 1 million wells may have been drilled in the United States prior to a formal regulatory system, and the status and location of many of these wells are unknown. Various state programs exist to plug identified orphaned wells, but they face the challenge of identifying and addressing a large number of wells.[1] For example, 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 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).

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 ground water unit (see Section 6.3.2.2). In 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.) More specifically, this analysis was designed to assess transport through deteriorating cement between the subsurface formations and the outermost casing, through voids resulting from incomplete cement coverage, through breached tubing, or in simpler well installations without multiple casings. 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 the previous section, the study investigated the effect of multiple well- and formation-related variables on potential fluid migration (see Table 6-3).

Based on the simulation results, an offset well pathway may have a greater potential for gas release from the production zone into a shallower ground water unit than the fault/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; the offset well pathway may have a significantly lower pore volume compared to the fault/fracture pathway, which reduces possible gas storage in the connecting feature and increases the speed of buoyancy-dependent migration. However, as with the fault/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. Therefore, any incidents of gas breakthrough observed in this study were found to be limited in both duration and magnitude.

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 fault/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 creating a pressure gradient toward the production well. Only scenarios without the mitigating feature of gas production result in any 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 gas well is operating. The producing formation and aquifer permeabilities appear not to be significant factors for upward gas migration via this pathway. In addition, Reagan et al. (2015) found the permeability of the connecting offset well to be one of the main factors affecting the migration of gas to the aquifer and the water well. Very low permeabilities (less than 1 mD) lead to no migration of gas into the aquifer regardless of the vertical separation distance, whereas larger permeabilities present a greater potential for gas breakthrough.

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 28,000 abandoned mines in the United States and is adding new mines to its inventory every year (BLM, 2013a). 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, 2015o). The analysis suggests that emplacing cement within such zones may 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 fault or fracture zones in conjunction with hydraulic fracturing has been recognized as a potential contamination hazard for several decades (Harrison, 1983). 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 natural "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 may allow for more significant flow pathways for migration of fluids out of the production zone (Jackson et al., 2013c; Myers, 2012a). Figure 6-4 illustrates the concept of induced fractures intersecting with natural faults or fractures extending out of the target reservoir.

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., Weng et al., 2011; Dahi Taleghani and Olson, 2009; Vulgamore et al., 2007). Small natural fractures, known as "microfractures," could affect fluid flow patterns near the induced fractures by increasing the effective contact area. Conversely, the natural microfractures could act as capillary traps for the fracturing fluid during treatment (contributing to fluid leakoff) and potentially hinder hydrocarbon flow due to lower gas relative permeabilities (Dahi Taleghani et al., 2013). Rutledge and Phillips (2003) suggested that, for a hydraulic fracturing operation in East Texas, pressurizing existing fractures (rather than creating new hydraulic fractures) may be the primary process that controls enhanced permeability and fracture network conductivity at the site. Ciezobka and Salehi (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. However, there is very little attention given in the literature to studying unintended fluid migration during hydraulic fracturing operations due to existing microfractures.

In some areas, larger-scale geologic features may affect potential fluid flow pathways. As discussed in Text Box 6-2, baseline measurements taken before shale gas development show evidence of thermogenic methane in some shallow aquifers, suggesting that natural subsurface pathways exist and allow for naturally occurring migration of gas over millions of years (Robertson et al., 2012). There is also evidence demonstrating that gas undergoes mixing in 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). 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 hydraulic fractures. When faults are present, relatively larger microseismic responses are seen and larger fracture growth can occur, as described below. Concentrated 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 (Ciezobka and Salehi, 2013).

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 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 can extend laterally for thousands of feet.) In the Fisher and Warpinski (2012) data set (see 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 (see Section 6.3.2.2 and Text Box 6-3). The authors suggested that clusters of microseismic events may have occurred where preexisting small faults or natural fractures were present above the Marcellus Shale. At a site in Ohio, Skoumal et al. (2015) found that hydraulic fracturing induced a rupture along a pre-existing fault approximately 0.6 miles (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 miles (1 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. Myers (2012a, 2012b) found that a highly conductive fault could result in rapid (<1 year) fluid migration from a deep shale zone to the surface (as described in Section 6.3.2.1). Other researchers reject the notion that open, permeable faults would coexist with hydrocarbon accumulation (Flewelling et al., 2013), although it is unclear whether the existence of faults in low permeability reservoirs would affect the accumulation of hydrocarbons because, under natural conditions, the flow of gas may be limited due to capillary tension. Results from another recent modeling study suggest that, under specific circumstances, interaction with a conductive fault could result in fluid migration to the surface only on longer (ca. 1,000 year) time scales (Gassiat et al., 2013). Rutqvist et al. (2013) found that, while somewhat larger microseismic events are possible in the presence of faults, repeated events and aseismic 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 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 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).

Other conditions in addition to the physical presence of a pathway would need to exist for fluid migration to a drinking water resource to occur. The modeling study conducted by (Reagan et al., 2015) 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 natural and well-based factors may increase the potential for fluid migration into drinking water resources. For example, in the Mamm Creek area of Colorado (see Section 6.2.2.2), well integrity and drilling-related problems likely acted in concert with natural fracture systems to result in a gas seep into surface water and shallow ground water (Crescent, 2011).

6.4. Synthesis

In the injection stage of hydraulic fracturing, operators inject fracturing fluids into a well under high pressure. These fluids flow through the well and into the surrounding formation, where they increase pore pressure and create fractures in the rock, allowing hydrocarbons to flow through the fractures and up the well.

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 drinking water 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 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

Potential pathways for impacts on drinking water (i.e., the movement of hydrocarbons, formation brines, or other fracturing-related fluids into drinking water resources), may be linked to one or more components of the well and/or features of the subsurface system. If present, these potential pathways can, in combination with the high pressures under which fluids are injected and pressure changes within the subsurface, have an impact on 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 the development of one pathway within this system does not necessarily result in an impact to a drinking water resource. For example, if cracks were to form in the cement of a well, the vertical distance between the production zone and a drinking water resource (and the multiple layers of rock in between) could isolate and protect the drinking water aquifer if pressures were insufficient to allow fluid movement to the level of the drinking water resource. Conversely, if an undetected fault were present in a rock formation, intact cement within the production well could keep fluids from migrating up along the well to the fault and protect drinking water resources.

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. These higher stresses may contribute to the formation of potential pathways associated with the casing or cement that can result in the unintentional movement of fluids through the production wellbore if the well cannot withstand the stresses experienced during hydraulic fracturing operations (see Section 6.2).

Multiple barriers within the well, including casing, cement, and a completion assembly, isolate hydrocarbon-bearing formations from drinking water resources. However, inadequate construction, defects in or degradation of the casing or cement, or the absence of redundancies such as multiple layers of casing, can allow fluid movement, which can then affect the quality of drinking water resources. Ensuring proper well design and mechanical integrity—particularly proper cement placement and quality—are important actions for preventing unintended fluid migration along the wellbore.

6.4.1.2. Fluid Movement within Subsurface Geologic Formations

Potential subsurface pathways for fluid migration 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 fractures intersecting with faults or natural fractures (see Section 6.3).

Vertical separation between the production zone where hydraulic fracturing operations occur and drinking water resources, and lateral separation between wells undergoing hydraulic fracturing and other wells can reduce the potential for fluid migration that can impact drinking water resources.

Well communication incidents or "frac hits" have been reported in New Mexico, Oklahoma, and other locations. While some operators design fracturing treatments to communicate with the fractures of another well and optimize production, unintended communication between two fracture systems can lead to spills in the offset well and is an indicator of hydraulic fracturing treatments extending beyond their planned design. Surface spills from well communication incidents have been documented in the literature, which provides evidence for occurrence of frac hits. Based on the available information, frac hits most commonly occur on multi-well pads and when wells are spaced less than 1,100 ft (335 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 an impact on drinking water resources associated with hydraulic fracturing operations in Bainbridge, Ohio. Failure to cement over-pressured formations through which the production well passed—and proceeding with the 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 (see Section 6.2.2.2).

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

There are other cases where hydraulic fracturing could be a contributing cause to impacts on drinking water resources, or where the specific mechanism that led to an impact on a drinking water resource cannot be definitively determined. For example:

- Migration of stray gas into drinking water resources involves many potential routes for migration of natural gas, including poorly constructed casing and naturally existing or induced fractures in subsurface formations. Multiple pathways for fluid movement may be working in concert in northeastern Pennsylvania (possibly due to cement issues or sustained casing pressure) and the Raton Basin in Colorado (where fluid migration may have occurred along natural rock features or faulty well seals). 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 (see Text Box 6-2).

- 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 well stimulation, can work together to create a pathway for fluids to migrate toward drinking water resources (see Sections 6.2.2.2 and 6.3.2.4).

Additionally, some hydraulic fracturing operations involve the injection of fluids into formations where there is relatively limited vertical separation from drinking water resources. The EPA identified an estimated 4,600 wells that were located in areas with less than 2,000 ft (610 m) of vertical separation between the fractures and the base of protected ground water resources.

There are places in the subsurface where oil and gas reservoirs and drinking water resources co-exist in the same formation. Evidence we examined suggests that some hydraulic fracturing for oil and gas occurs within formations where the ground water has a salinity of less than 10,000 mg/L TDS. By definition, this results in the introduction of fracturing fluids into formations that meet the Safe Drinking Water Act (SDWA) salinity-based definition of a 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.

The practice of injecting fracturing fluids into a formation that also contains a drinking water resource directly affects the quality of that water, since it is likely some of that fluid remains in the formation following hydraulic fracturing. 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 drinking water contamination. Data limitations in most of those cases (including the unavailability of information in litigation settlements resulting in sealed documents) make it impossible to definitively assess whether or not hydraulic fracturing was a cause of the contamination in these cases.

6.4.2. Factors Affecting Frequency and Severity of Impacts

Proper cementing across oil-, gas-, or water-bearing zones prevents the movement of brines, gas, or hydraulic fracturing fluids along the well into drinking water resources. The likelihood of contamination is reduced when the well is fully cemented across these zones; however, this is not the case in all hydraulically fractured wells, either because the cement does not extend completely through the base of the drinking water resource or the cement that is present is not of adequate quality. Fully cemented surface casing that extends through the base of drinking water resources is a key protective component of the well. Most, but not all, wells used in hydraulic fracturing operations have fully cemented surface casing.

Deviated and horizontal wells, which are increasingly being used in hydraulic fracturing operations, may exhibit more casing and cement problems compared to vertical wells. Sustained casing pressure—a buildup of pressure within the well annulus that can indicate the presence of small leaks—occurs more frequently in deviated and horizontal wells compared to vertical wells. Cement integrity problems can also arise as a result of challenges in placing cement in these wells, because they are more challenging than vertical wells to center properly.

Older wells may exhibit more integrity problems compared to newer wells, which may be an issue if older wells are hydraulically fractured or re-fractured. Degradation of the casing and cement as they age or the cumulative effects of stresses exerted on the well over time may result in changes in well integrity. Integrity problems can also be associated with the inadequate design of wells that were constructed pursuant to older, less stringent requirements. Well components that are subject to corrosive environments, high pressures, or other stressors tend to have more problems than wells without these additional stressors.

The extent of subsurface fluid migration within subsurface rock formations and the potential for the development of pathways that can adversely affect drinking water depend on site-specific characteristics. These include the physical separation between the production zone and drinking water resources, the geological and geomechanical characteristics of the formations, hydraulic fracturing operational parameters, and the physical characteristics of any connecting feature (e.g., abandoned wells, faults, and natural fractures).

As noted above, vertical separation between the production zone and drinking water resources protects drinking water. Additionally, the proximity of wells undergoing hydraulic fracturing to other wells increases the potential for the formation of pathways for fluids to move via these wells to drinking water resources. For example, if there is a deficiency in the construction of a nearby well (or degradation of the well components), that well could serve as a pathway for movement of fracturing fluids, methane, or brines that might affect a drinking water resource. If the fractures were to intersect an uncemented portion of a nearby wellbore, the fluids could migrate along that wellbore into any uncemented formations.

Fractures created during hydraulic fracturing can extend out of the target production zone. Out-of-zone fracturing could be a concern for fluid migration if the hydraulic fracturing operation is not designed to address site-specific conditions, for example if the production zone is thin and fractures propagate to unintended vertical heights, or if the production zone is not horizontally continuous and fractures extend to unintended horizontal lengths. The presence of natural faults or fractures can affect the extent of hydraulic fractures. When faults are present, relatively larger microseismic responses are seen during hydraulic fracturing, and larger fracture growth can occur than in the absence of natural faults or fractures. However, modeling studies indicate that fluid migration from deep production zones to shallow drinking water resources along natural faults and fractures or offset wells is unlikely. These studies indicate that, in both cases, gas available for migration is limited to the amount that existed in the fractures and pore space of connecting features following hydraulic fracturing prior to production. Following the completion of a hydraulic fracturing treatment, depressurization of the production formation surrounding the fractures due to hydrocarbon production would make upward fluid migration into drinking water resources unlikely to occur.

Based on the information presented in this chapter, the increased deployment of hydraulic fracturing associated with oil and gas production activities, including techniques such as horizontal drilling and multi-well pads, may increase the likelihood that these pathways could develop. This, in turn, could lead to increased opportunities for impacts on drinking water resources.

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 can be observed and measured at the surface. Furthermore, while there is a significant amount of information available on production wells in general, there is little information that is specific to hydraulic fracturing operations and much of this data is not readily accessible, i.e., in a centralized, national database.

6.4.3.1. Limited Availability of Information Specific to Hydraulic Fracturing Operations

There is extensive information 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, based on the long history of oil and gas production activities, we know how production wells are constructed and have performed over time. Over the years, many studies have documented how these wells are constructed, how they perform, and the rates at which they experience problems that can lead to the formation of pathways for fluid movement. However, because we do not know which of these wells were hydraulically fractured, we cannot definitively determine whether the rates at which integrity problems arise (or other data pertaining to oil and gas wells in general) directly correspond 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 resources 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 meet 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, including MIT results, 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 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.

There are also a limited number of published monitoring studies or sampling data that provide evidence to assess whether formation brines, injected 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 in the subsurface 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 2).

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.

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 integrity problems that can contribute to 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 states or 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 also no systematic collection, reporting, or publishing of empirical baseline (pre-drilling and/or pre-fracturing) and post-fracturing monitoring data 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. Ideally, data from ground water monitoring are needed to complement theories and modeling on potential pathways and fluid migration.

While some of the types of impacts described above may occur quickly (i.e., on the scale of days or weeks, as with integrity problems or well communication events), other impacts (e.g., in slow-moving, deep ground waters) may only occur or be able to be detected on much longer timescales. Given the surge in the number of modern high-pressure hydraulic fracturing operations dating from the early 2000s, evidence of any fracturing-related fluid migration affecting a drinking water resource (as well as the information necessary to connect specific well operation practices to a drinking water impact) could take years to discover.

The limited amount of information hinders our ability to evaluate whether—or how frequently—drinking water impacts are occurring (or the potential for these impacts to occur) or to tie possible impacts to specific well construction, operation, or 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 or suspected contamination in areas where hydraulic fracturing occurs.

6.4.4. Conclusions

Fluids can migrate from the wellbore and surrounding subsurface formations due to inadequate casing or cement, and via natural and man-made faults, fractures, and offset wells or mines (see Text Box 6-5). To prevent fluid migration through the wellbore or through subsurface pathways, wells must have adequate casing and cement, and induced fractures must not intersect existing fractures or permeable zones that lead to drinking water resources. Evidence shows that the quality of drinking water resources may have been affected by hydraulic fracturing fluids escaping the wellbore and surrounding formation in certain areas, although conclusive evidence is currently limited.

Text Box 6-5. Research Questions Revisited.

How effective are current well construction practices at containing fluids—both liquids and gases—before, during, and after fracturing?

- Wells that were designed with uncemented intervals of casing across porous or permeable zones, wells in which cementing does not resist formation or operational stresses, and wells in which cementing does not meet design specifications have the potential to promote unintended subsurface fluid movement. Even in optimally designed wells, metal casings and cement can degrade over time, either as a result of aging or of exposure to stresses exerted over years of operations. See Section 6.2.2.2.
- We have limited information on the degree to which wells are designed and constructed with the multiple layers of casing that can withstand hydraulic fracturing pressures and contact with injected and produced fluids. We also are lacking information about whether wells have suitable cements that can prevent fluid movement outside the wellbore and between the production zone and drinking water resources. We also do not have information on the degree to which mechanical integrity is verified before or after hydraulic fracturing operations. See Section 6.2.2.1.

Can subsurface migration of fluids—both liquids and gases—to drinking water resources occur and what local geologic or artificial features might allow this?

- The presence of artificial penetrations, especially poorly constructed offset wells or undetected abandoned wells, mines, or other subsurface structures, provides pathways that, in the presence of a driving force, could allow for fluid movement to shallow geologic zones such as drinking water resources. See Section 6.3.2.3.

- Intersections of induced fractures with transmissive faults or naturally occurring fractures or porous/permeable rock zones can allow fluids to move out of the targeted fracture areas. However, modeling studies indicate that fluid migration from production zones to drinking water resources along natural faults and fractures is unlikely. See Section 6.3.2.4.
- Some hydraulic fracturing operations involve the injection of fluids into formations where there is relatively limited vertical separation from drinking water resources. Other hydraulic fracturing is performed within formations that meet the SDWA or state salinity-based definition of a source of drinking water, in addition to the broader definition of a drinking water resource developed for this assessment. See Section 6.3.2.

6.5. References for Chapter 6

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