Chapter 2

Hydraulic Fracturing, Oil and Gas Production, and the U.S. Energy Sector

2. Hydraulic Fracturing, Oil and Gas Production, and the U.S. Energy Sector

This chapter provides general background information useful for understanding the in-depth technical chapters that follow. We describe the process and purpose of hydraulic fracturing and the situations and settings in which it is used (Section 2.1). Then, to place hydraulic fracturing in the context of well site operations, we describe activities from site assessment and selection through production to site closure. This helps illustrate the intensive nature of activities during the relatively short hydraulic fracturing phase during the life of a production well (Section 2.2). Finally, we characterize the prevalence of hydraulic fracturing in the United States, its importance in the oil and gas industry today and into the future, and its role in the U.S. energy sector (Sections 2.3 and 2.4).

2.1. What is Hydraulic Fracturing?

Hydraulic fracturing is a stimulation technique used to increase production of oil and gas. Hydraulic fracturing involves the injection of fluids under pressures great enough to fracture the oil- and gas-production formations. Hydraulic fracturing fluid transfers the pressure generated by equipment at the surface into the subsurface to create fractures, and it carries and places the proppant into the fractures so that they remain "propped" open after the injection pumping pressure is terminated (Gupta and Valkó, 2007). Oil and gas can then flow through the fractures into the well and through the well to the surface. Hydraulic fracturing has been used since the late 1940s and for the first almost 50 years was used in vertical wells in conventional hydrocarbon reservoirs.[1] Hydraulic fracturing is still used in these settings, but the process has evolved; technological developments have led to the use of hydraulic fracturing in low-permeability (unconventional) hydrocarbon reservoirs that could not otherwise be profitably produced (see Text Box 2-1). Wells stimulated by hydraulic fracturing may be vertical, deviated, or horizontal in orientation (see Figure 2-1), and they may be newly drilled or older at the time the fracturing is done.

[1] A conventional reservoir is a reservoir in which buoyant forces keep hydrocarbons in place below a sealing caprock. Reservoir and fluid characteristics of conventional reservoirs typically permit oil or natural gas to flow readily into wellbores. The term is used to make a distinction from shale and other unconventional reservoirs, in which gas might be distributed throughout the reservoir at the basin scale, and in which buoyant forces or the influence of a water column on the location of hydrocarbons within the reservoir are not significant.

Text Box 2-1. Is Hydraulic Fracturing "New"?

Hydraulic fracturing in one form or another has been in use since the late 1940s, when a fracturing technique was patented by the Stanolind Oil and Gas Company and licensed to the Halliburton Oil Well Cementing Company. There are precedents that go back even further: reports from the early days of the oil and gas industry in the mid-19th century show producers trying to increase production by pumping fluids or dropping explosives into wells (Montgomery and Smith, 2010). Throughout its history, hydraulic fracturing has been used as a production technique to increase, or "stimulate," production from a well (some hydraulic fracturing methods are used to stimulate production in water wells, which is outside the scope of this report).

The groundwork for the transformation to modern hydraulic fracturing was laid in the 1970s and early 1980s, when a coalition of private companies, government agencies, and industry groups began sponsoring research into shale gas development technologies. During that period, Congress began to offer tax incentives to induce producers to apply the developing technologies in the field (Wang and Krupnick, 2013; EIA, 2011a; Yergin, 2011). The first horizontal wells were drilled in the mid-1980s in the Austin Chalk oil-bearing formation in Texas (Pearson, 2011; Haymond, 1991). Directional drilling and other emerging technologies matured in the late 1990s. In 2001, the Mitchell Energy company found a way to economically fracture the Barnett Shale in Texas. The company was bought by Devon Energy, a company with advanced experience in horizontal drilling. In 2002, seven wells were drilled and developed in the Barnett Shale using both horizontal drilling and hydraulic fracturing. Fifty-five more wells were completed in 2003 (Yergin, 2011). The techniques were rapidly adopted and further developed by others. By 2003/2004, modern hydraulic fracturing in the Barnett Shale was producing more gas than all other shale gas wells in the rest of the country (mostly shallow shale gas production in the Appalachian and Michigan Basins, see Section 2.4.1) (DOE, 2011b; Montgomery and Smith, 2010). By 2005, the new techniques were being used in low-permeability hydrocarbon plays outside of Texas, and modern hydraulic fracturing soon became the industry standard, driving the surge in U.S. production of natural gas.

Despite the long history of hydraulic fracturing, the culmination of technical innovations in the early 2000s represent an appreciable change. These innovations have made hydraulic fracturing economical enough to become standard practice in the oil and gas industry. Modern hydraulic fracturing (sometimes referred to as high-volume hydraulic fracturing) is characterized by the use of long horizontal wells and higher volumes of more complex mixtures of water, proppants, and chemical additives for injection as compared to earlier fracturing practices. Wells are often deep and long: shale gas production wells are commonly 5,000 to 13,500 ft (1,524 to 4,115 m) deep with long horizontal sections of 2,000 to 5,000 ft (610 to 1,524 m) or more in length. Other important advances occurred in oil and gas geophysical survey techniques (such as downhole telemetry and 3D seismic imaging) (Wang and Krupnick, 2013; EIA, 2011a). Hydraulic fracturing continues to be conducted in vertical production wells as well as conventional reservoirs using some of these newer techniques. Modern hydraulic fracturing has made it possible to extract resources in previously untapped hydrocarbon-bearing geologic settings, altering and expanding the geographic range of oil and gas production activities.

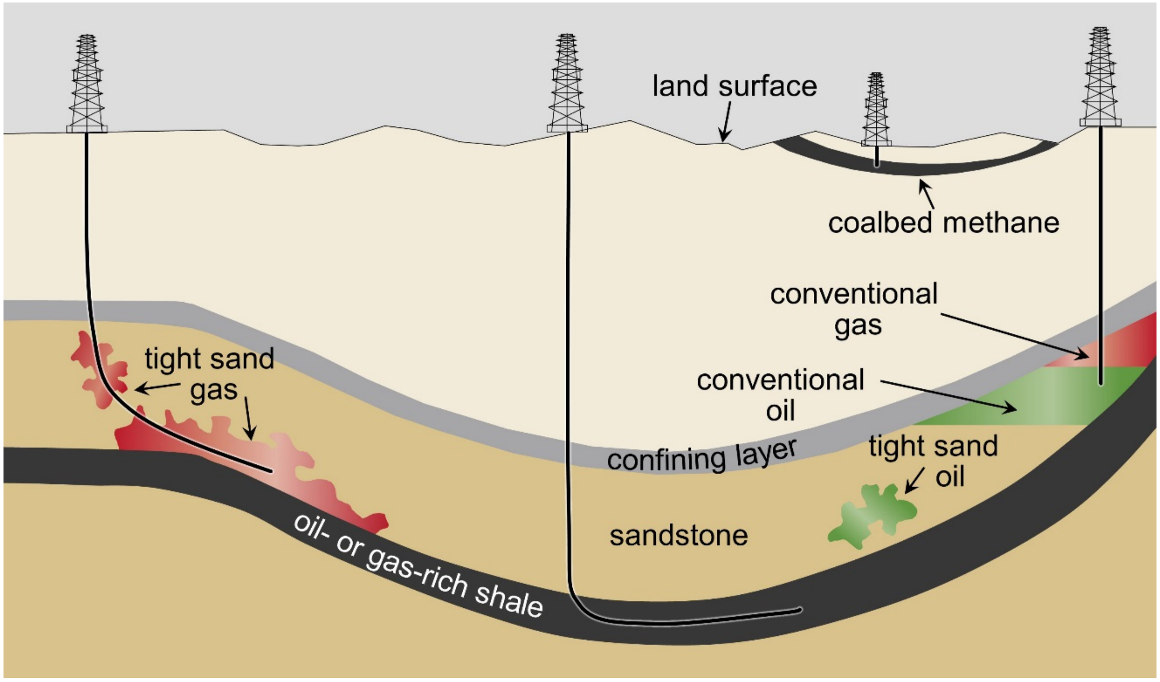


Figure 2-1. Schematic cross-section of general types of oil and gas resources and the orientations of production wells used in hydraulic fracturing.

Shown are conceptual illustrations of types of oil and gas wells. A vertical well is producing from a conventional oil and gas deposit (right). In this case, a thin, gray confining layer serves to "trap" oil (green) or gas (red). Also shown are wells producing from unconventional formations: a vertical coalbed methane well (second from right); a horizontal well producing from a shale formation (center); and a deviated well producing from a tight sand formation (left). Note: Figure not to scale. Modified from USGS (2002) and Newell (2011).

Historically, oil and gas have been extracted from conventional reservoirs that develop when hydrocarbons formed in deeper geologic source formations migrate until they accumulate underneath an impermeable layer (see Figure 2-1). Extraction practices vary. In settings where a reservoir is permeable enough and under enough pressure to yield a relatively high rate of hydrocarbon flow into a well, the economic extraction of oil and/or gas may be as simple as using a drilled well to enable hydrocarbons to flow to the surface under the natural pressure of the reservoir. In other cases, producers may inject water and/or carbon dioxide under pressure into the reservoir via one or more nearby wells to help move and enhance production of the oil and gas. But essentially, producers are drawing on hydrocarbons that have already accumulated in a relatively accessible form.

Hydraulic fracturing is one of several methods used to enhance production from oil and gas reservoirs. It is distinct from other methods of hydrocarbon extraction (known generally as enhanced recovery techniques) that involve injecting fluids to influence either reservoir pressure, fluid viscosity, or both. The primary purpose of hydraulic fracturing is to increase the surface area of the reservoir rock by creating fractures that are propped open, allowing the hydrocarbon to flow from the rock through the fractures to the well and through the well up to the surface.

Hydraulic fracturing, in conjunction with horizontal and directional drilling, has made it possible to economically extract oil and gas from "unconventional" geologic formations (see Text Box 2-2), such as the relatively low permeability shales in which oil and gas form (see Figure 2-1). With modern horizontal drilling techniques, producers can, for example, drill a single well that follows the contours of a relatively thin, horizontal shale formation. Such drilling allows fracturing to be conducted in a long horizontal section of the well that accesses an extensive portion of the oil- or gas-bearing formation. Unconventional formations include:

- ***Shales.*** Organic-rich black shales are the source rocks in which oil and gas form on geologic timescales. Shales have very low permeability, and the hydrocarbons are contained in the pore space in the shales. Some shales produce predominantly gas and others predominantly oil; often there will be some coproduction of gas from oil wells and coproduction of liquid hydrocarbons from gas wells (USGS, 2013a; EIA, 2011a).
- ***Tight formations.*** "Tight" sands (sandstones), siltstone, carbonates, etc., are relatively low permeability, non-shale, sedimentary formations that can contain hydrocarbons. The hydrocarbons are contained in the pore space of the formations. There is a continuum in permeability between "tight" formations which require hydraulic fracturing to be produced economically and sandstone (and other) formations that do not. In the literature, "tight gas" is generally distinguished from "shale gas," while oil resources from shale and tight formations are frequently lumped together under the label "shale oil" or "tight oil" (Schlumberger, 2014; USGS, 2014a).
- ***Coalbeds.*** Hydraulic fracturing can be used to extract methane (the primary component of natural gas) from coal seams. In coalbeds, the methane is adsorbed to the coal surface rather than contained in pore space or structurally trapped in the formation. Pumping the injected and formation water out of the coalbeds after fracturing serves to depressurize the coal, thereby allowing the methane to desorb and flow into the well and to the surface (USGS, 2000).

Text Box 2-2. "Conventional" Versus "Unconventional."

The terms "conventional" and "unconventional" are widely used in the literature to distinguish types of oil and gas reservoirs, plays, wells, production techniques, and more. In this report, the terms are used to distinguish different types of hydrocarbon resources: "conventional" resources are those that can economically be extracted using long-established technologies, and "unconventional" resources are those whose extraction has become economical only with the advances that have occurred in modern hydraulic fracturing (often coupled with directional drilling) in recent years.

Note that as modern hydraulic fracturing has become industry standard, the word "unconventional" is less apt than it once was to describe these resources. In a sense, "the unconventional has become the new conventional" (NETL, 2013).

Although the goal of stimulation by hydraulic fracturing is the same wherever it is employed, the way it is accomplished varies due to a number of factors. General location and geologic conditions, whether the well is existing or newly drilled, the proximity of the well to infrastructure and raw materials, operator preferences, and other factors can affect how a hydraulic fracturing operation is designed and carried out. Technological advances have made it possible to drill deeper and longer horizontal wells, to conduct fracturing through longer portions of the well, and to place multiple wells on a single well pad (NETL, 2013; Montgomery and Smith, 2010). Many facets of hydraulic fracturing-related technology have changed since they were first pioneered (see Text Box 2-1). How hydraulic fracturing is practiced now (especially in the long horizontal wells) is different from how it was conducted during the first decades of its use. As operators gain experience with both evolving and new technologies, practices will continue to change.

The following three maps show the locations of major shale oil and gas resources, tight gas resources, and coalbed methane resources, respectively, in the continental United States (see Figure 2-2, Figure 2-3, and Figure 2-4). These maps represent resources that are being exploited now or could be exploited in the future. Hydraulic fracturing continues to be used to enhance production in conventional reservoirs (not shown), although it is uncertain how often this occurs.

The formations hydraulically fractured for gas or oil vary in their depth below the surface. For example, the Marcellus Shale (found primarily in Pennsylvania, New York, and West Virginia) is found at depths of 4,000 to 8,500 ft (1,200 to 2,600 m), the Barnett Shale (Texas) is found at depths of 6,500 to 8,500 ft (2,000 to 2,600 m), and the Haynesville-Bossier Shale (Louisiana and Texas) is found at depths of 10,500 to 13,500 ft (3,200 to 4,100 m) (NETL, 2013). These represent some of the largest gas-producing shale formations or shale plays. However, some other plays are shallower. Parts of the Antrim (Michigan), Fayetteville (Arkansas), and New Albany (Indiana and Kentucky) shale plays, for example, are less than 2,000 ft (600 m) deep (NETL, 2013; GWPC and ALL Consulting, 2009). Exploitation of thin coal seams often takes place close to the surface as well. In the San Juan Basin (New Mexico), coal seams are 550 to 4,000 ft (170 to 1,200 m) deep; in the Powder River Basin (Wyoming and Montana) they are 450 to greater than 6,500 ft (140 to 2,000 m) deep, and in the Black Warrior Basin (Alabama and Mississippi) depths can range from the ground surface to 3,500 ft (1,100 m) (ALL Consulting, 2004). See Chapter 6 for more information on the depths of these formations and plays.

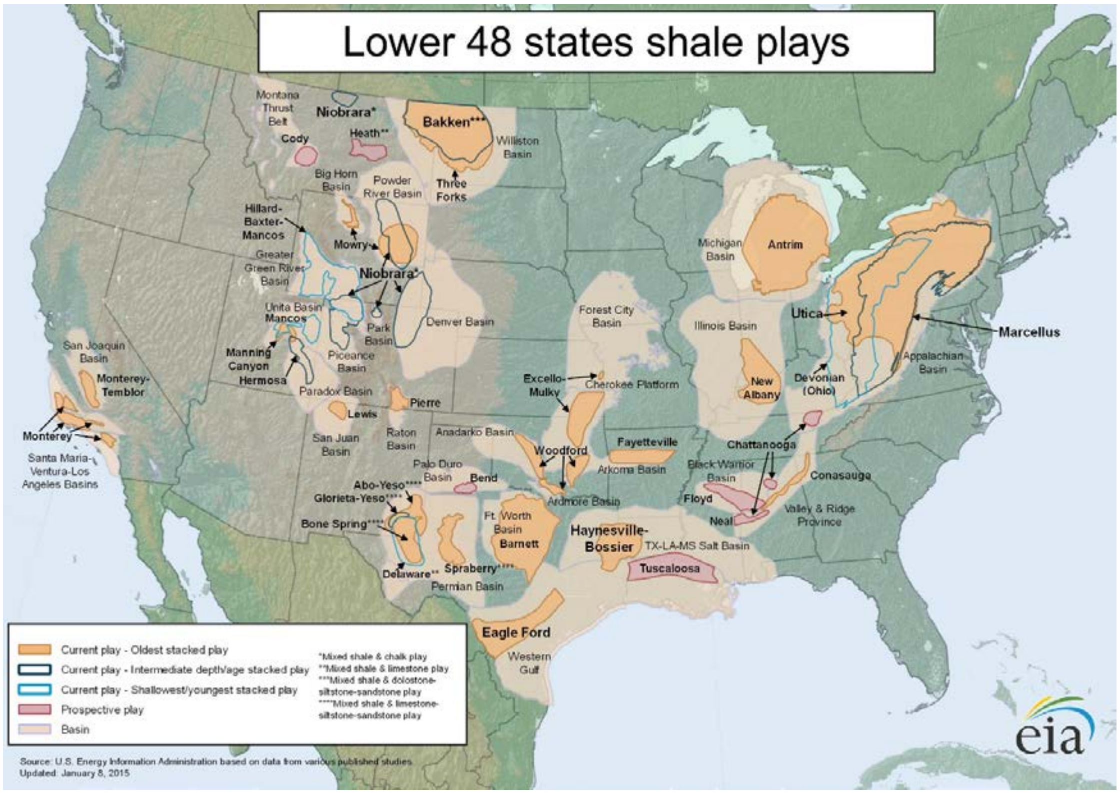
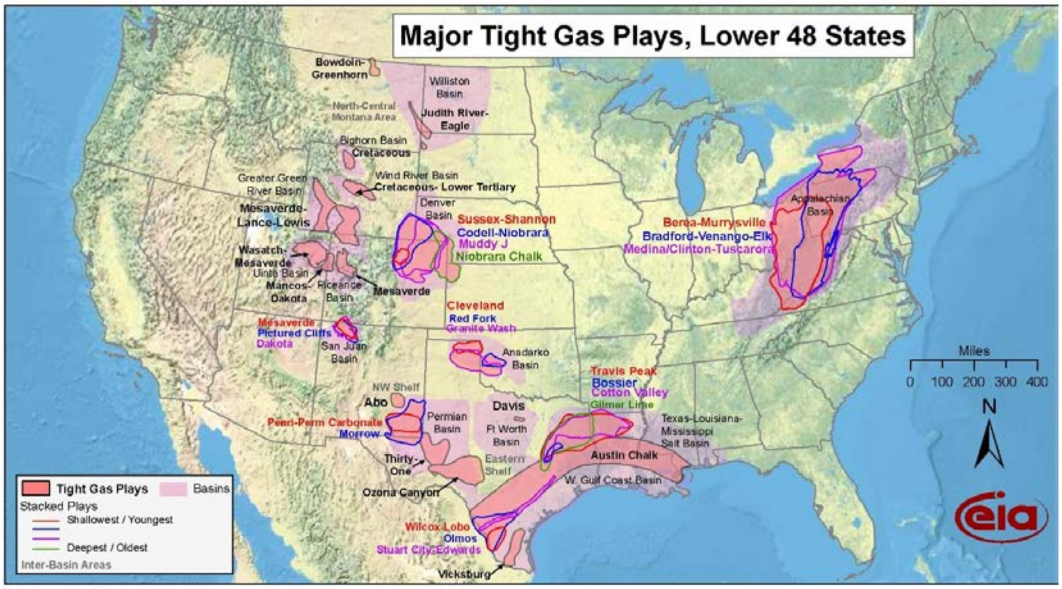


Figure 2-2. Shale gas and oil plays in the lower 48 United States.

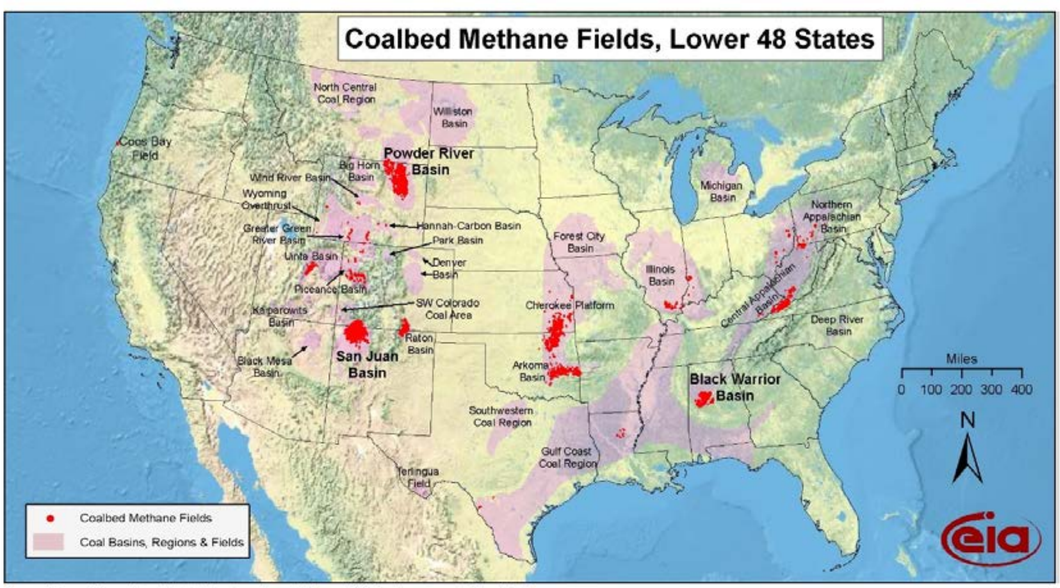
Source: EIA (2015b).



Source: Energy Information Administration based on data from various published studies
Updated: June 6, 2010

Figure 2-3. Tight gas plays in the lower 48 United States.

Source: EIA (2011b).



Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Figure 2-4. Coalbed methane fields in the lower 48 United States.

Source: EIA (2011b).

2.1. Hydraulic Fracturing and the Life of a Well

Hydraulic fracturing itself is a relatively short-term process, with the timeframe for a typical fracturing treatment being two to 10 days during which fluids are injected into the well to fracture the oil- and gas-bearing geologic formations (Halliburton, 2013; NYSDEC, 2011). However, it is a period of intense activity— the most activity that takes place at a well site during its existence.

In this section, we briefly describe some of the supporting and ancillary activities that take place at the well site, from initial site development through production and ultimately to closure (see Figure 2-5). This time period likely ranges from years to decades, depending on factors such as rate of depletion of the oil or gas, cost of production, and the price of oil and gas. The rate of oil and gas depletion in the reservoir is somewhat uncertain in unconventional formations because there is relatively little history on which to base predictions.

The overview of well operations presented in this section is broad and is provided to illustrate common activities and describe some specific operational details. The details of well preparation, operations, and closure vary from company to company, from play to play, from jurisdiction to jurisdiction, and from well to well. The various activities involved in well development and operations can be conducted by the well owner and/or operator, owner/operator representatives, service companies, or other third parties contractors working for the well owner.

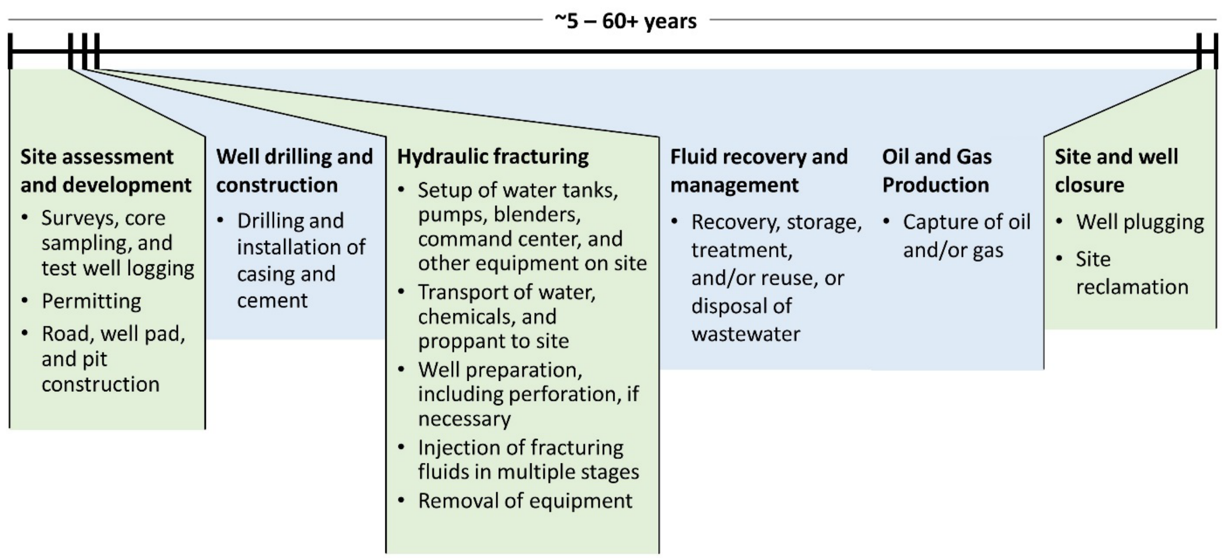


Figure 2-5. Generalized timeline and summary of activities that take place during the operational phases of an oil or gas well site operation in which hydraulic fracturing is used.

Relative duration of phases is approximate.

2.1.1. Site and Well Development

Numerous activities occur to assess and develop the site and to drill and construct the production well before hydraulic fracturing and production can occur.

2.1.1.1. Site Assessment and Development

Identifying a geologically suitable well site requires integrating data from geophysical surveys (including seismic surveys) that help to delineate subsurface features with other geologic information from rock core samples. Cores may be obtained while drilling exploratory wells or test holes. Core samples provide firsthand information on the characteristics of the oil- or gas-bearing formation, such as porosity, permeability, and details about the quantities and qualities of the hydrocarbon resource. Drilling rates and drill cuttings help identify the strata being drilled through and can help confirm and correlate stratigraphy and formation depths, including the depths of water-bearing formations.[1] Well logging (also known as wireline logging) is especially useful combined with core analysis for understanding the properties of formations (Kundert and Mullen, 2009).[2]

Logistical factors involved in the selection of the well drilling site include topography; proximity to facilities such as roads, pipelines, and water sources; well spacing considerations; well setback requirements; potential for site erosion; location relative to environmentally sensitive areas; and proximity to populated areas (Drohan and Brittingham, 2012; Arthur et al., 2009a). Before developing the site and initiating well drilling, the oil and gas company (or their representative) obtains a mineral rights lease, negotiates with landowners, and applies for a drilling permit from the appropriate state and local authorities. During the project, leases and permissions are also needed for other activities including performing seismic surveys and drilling exploratory holes (Hyne, 2012). This initial site assessment phase of the process may take several months (King, 2012).

Site preparation is necessary to enable equipment and supplies to reach the well area. Typically, the site is surveyed first, and then an access road may need to be built to accommodate truck traffic (Hyne, 2012). The operator then levels and grades the site to manage drainage and to allow equipment to be hauled to and placed on site. Next, the operator may excavate and grade several impoundments or storage pits near the well pad. In some cases, steel tanks may be used to hold fluids instead of, or in addition to, pits. The pits may hold water intended for drilling fluids, materials generated during drilling such as used drilling mud and drill cuttings, or the flowback and produced waters after fracturing (Hyne, 2012). Pit construction is generally governed by local regulations; federal regulations may also apply on federal and Indian Country. In some areas, regulations may require pits to be lined to prevent fluid seepage into the shallow subsurface or may

[1] Drill cuttings are ground rock produced by the drilling process.

[2] Well logging consists of a continuous measurement of physical properties in or around the well with electrically powered instruments to infer formation properties. Measurements may include electrical properties (resistivity and conductivity), sonic properties, active and passive nuclear measurements, measurements of the wellbore, pressure measurement, formation fluid sampling, sidewall coring tools and others. Measurements may be taken via a wireline, which is a wire or cable that is used to deploy tools and instruments downhole and that transmits data to the surface.

prohibit pits altogether. Some sites have piping along the surface of the well pad or in the shallow subsurface that delivers water used for hydraulic fracturing, removes flowback and produced water, or transports the oil and gas once production begins (Arthur et al., 2009a).

After site and well pad preparation, drill rigs and associated equipment (e.g., the drill rig platform, drilling mud system components, generators, chemical storage tanks, blowout preventer, fuel storage tanks, cement pumps, drill pipe, and casing) are moved on and off the pad at the different stages of well drilling and completion. During drilling and completion, well pads can range in size from less than an acre to several acres depending on the scope of the operations (King, 2012; NYSDEC, 2011).

Well Drilling and Construction

Construction of the production well involves the drilling of the hole (or wellbore), along with the installation and cementing of a series of casing strings to support the wellbore and isolate and protect both the hydrocarbons being produced and any water-bearing zones through which the well passes.[1] In certain settings, some portions of the well can be completed as open holes.[2] Details on these and other well construction activities are presented in Chapter 6 and Appendix D.

The operator begins drilling by lowering and rotating the drill string, which consists of the drill bit, drill pipe (see Figure 2-6), and drill collars (heavy pieces of pipe that add weight to the bit). The drill pipe attaches to the drill bit, rotating and advancing the bit; as drilling advances, new sections of pipe are added at the surface, enabling the drilling to proceed deeper (Hyne, 2012). A drilling fluid is circulated during drilling.[3] The drilling fluid, which may be water-based or oil-based, is pumped down to the drill bit, where it cools and lubricates the drill bit, counterbalances downhole pressures, and lifts the drill cuttings to the surface (King, 2012).

Although all wells are initially drilled vertically, finished well orientations include vertical, deviated, and horizontal. The operator selects the well orientation that will provide access to the targeted zone(s) within a formation and that will align the well with existing fractures and other geologic structures to optimize production. Deviated wells may be “S” shaped or continuously slanted. Horizontal wells have lateral sections oriented approximately 90 degrees from the vertical portion of the well. In wells completed horizontally, the lengths of these laterals can range from 2,000 to 5,000 ft (610 to 1,524 m) or more (Hyne, 2012; Miskimins, 2008; Bosworth et al., 1998).[4] Horizontal wells are instrumental in accessing productive areas of thin and laterally extensive oil- and gas-bearing shales. Although the portion of hydraulically fractured wells that are horizontal is growing, in some areas, such as California, hydraulic fracturing is still primarily conducted in vertical wells (CCST, 2015).

[1] Casing is steel pipe that is lowered into a wellbore. Casing extends from the bottom of the hole to the surface.
[2] An open hole completion is a well completion that has no casing or liner set across the reservoir formation, allowing the produced fluids to flow directly into the wellbore.
[3] Drilling fluid is any of a number of liquid and gaseous fluids and mixtures of fluids and solids (as solid suspensions, mixtures, and emulsions of liquids, gases, and solids) used when drilling boreholes (Schlumberger, 2014).
[4] A lateral is a horizontal section of a well.

Figure 2-6. Pulling drill pipe onto the drilling platform.

Source: Joshua Doubek, Wikicommons, CC-BY-SA-3.0.

The drilling and well construction proceeds with repeated steps (the drill string is lowered, rotated, drilled to a certain depth, pulled out, and then the casing is lowered into the hole, set, and cemented). Successively smaller diameters of casing are used as the hole is drilled deeper (see Figure 2-7). Selection and installation of the casing strings is important for several purposes, including isolating hydrocarbon reservoirs from nearby aquifers, isolating over-pressured zones, and transporting hydrocarbons to the surface (Hyne, 2012). Newly installed casing strings are cemented in place before drilling continues (or before the well is completed in the instance of the production casing). The cement protects the casing from corrosion by formation fluids, stabilizes the casing and the wellbore, and prevents fluid movement along the well between the outside of the casing and wellbore (Renpu, 2011). The well can be cemented continuously from the surface down to the production zone of the well. Partially cemented wells are also possible with, for example, cement from the surface to some distance below the deepest fresh water-bearing formation and perhaps cement across other deeper formations. Chapter 6 and Appendix D contain more details on casing and cement.

Figure 2-7. Sections of surface casing lined up and being prepared for installation at a well site in Colorado.

Photo credit: Gregory Oberley (U.S. EPA).

When drilling, casing, and cementing are finished, the well can be completed in the production zone in several ways. The production casing may be cemented all the way through the production zone and perforated prior to hydraulic fracturing in the desired locations. Alternatively, operators may use an open hole completion, in which the casing is set just into the production zone and cemented. The remainder of the wellbore within the production zone is left open with no cement (Hyne, 2012). Once all aspects of well construction are completed, the operator can remove the drilling rig, install the wellhead, and prepare the well for stimulation by hydraulic fracturing and subsequent production.

2.1.1. Hydraulic Fracturing

Hydraulic fracturing is typically a short, intense, repetitive process requiring specialized equipment and (for high volume horizontal wells) large amounts of water, chemicals, and proppant. Machinery and equipment are often brought to the site mounted on trucks and remain that way during use. Tanks, totes, and other storage containers of various sizes holding water and chemicals are also transported and installed on site. Figure 2-8 shows a well pad prepared for hydraulic fracturing with the necessary equipment and structures.

Figure 2-8. Hydraulic fracturing operation in Troy, PA.

Site with all equipment on site in preparation for injection. Source: NYSDEC (2011).

2.1.1.2. Injection Process

Prior to injection, hydraulic fracturing fluids are mixed using specialized feeding and mixing equipment. The mixing is generally performed mechanically on a truck-mounted blender and is electronically monitored and controlled by the operator in a separate van (see Chapter 5). Numerous hoses and pipes are used to transfer hydraulic fracturing fluid components from storage units to the mixing equipment and ultimately to the wellhead.

A wellhead assembly is temporarily installed on the wellhead during the fracture treatment to allow high pressures and volumes of proppant-laden fluid to be injected into the well. Pressures required for fracturing can vary widely depending on depth, formation pressure, and rock type. Fracturing pressures have been reported ranging from 4,000 psi to 12,000 psi (Ciezobka and Salehi, 2013; Abou-Sayed et al., 2011; Thompson, 2010). The pressure during fracturing is measured using pressure gauges, which can be installed at the surface and/or downhole (Ross and King, 2007). Figure 2-9 shows two wellheads side-by-side being prepared for fracturing.

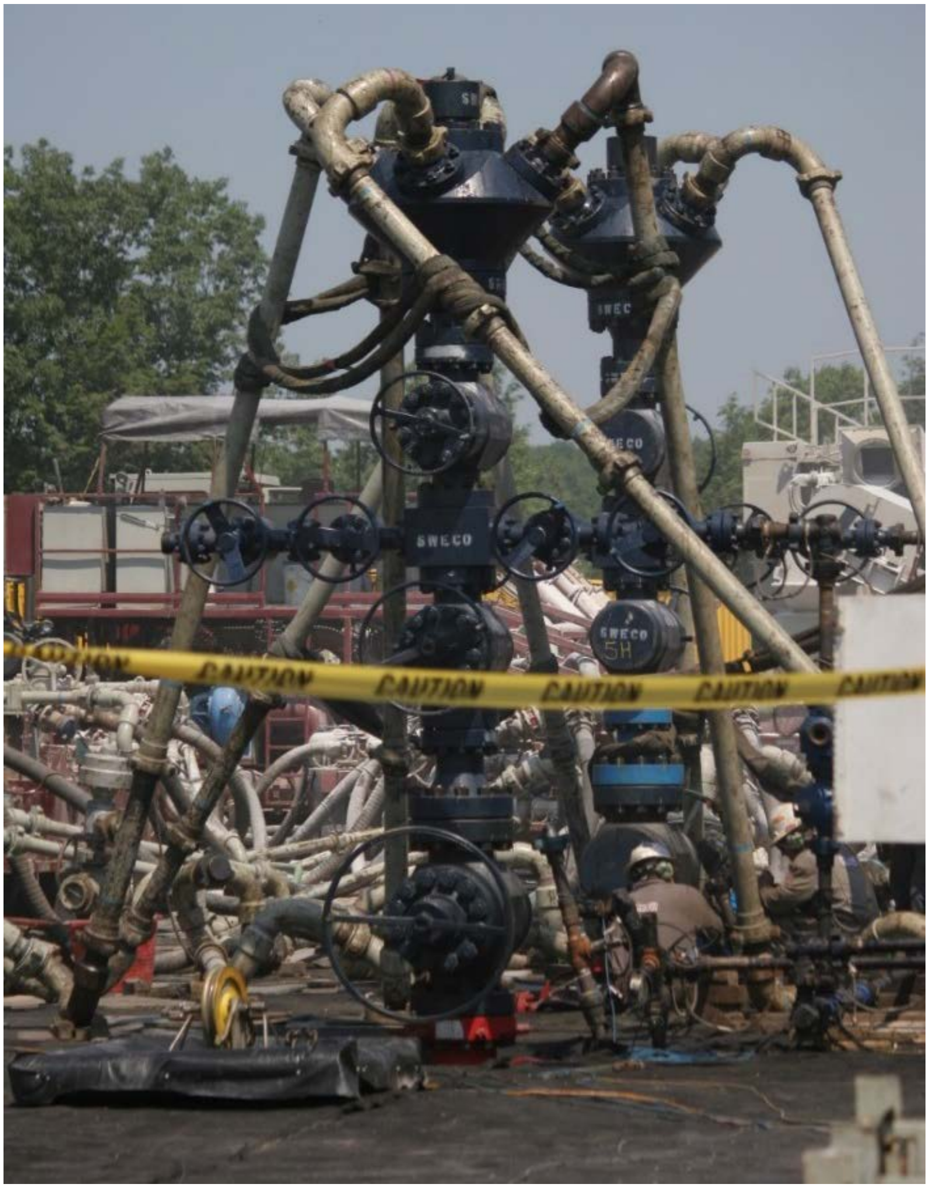


Figure 2-9. Two wellheads side-by-side being prepared for hydraulic fracturing at a well site in Pennsylvania.

Photo credit: Mark Seltzer (U.S. EPA).

The entire length of the well in the production zone is not fractured all at once; instead, shorter lengths or segments of the well in the production zone are isolated and fractured in “stages” (Lee et al., 2011). Each stage of a fracturing job can consist of phased injection of different fluids consisting of varying components (i.e., chemicals and additives). These different fluids (1) remove excess drilling fluid or cement from the formation (often using acid) (GWPC and ALL Consulting, 2009), (2) initiate fractures (“pad fluid” without proppant), (3) carry the proppant (Hyne, 2012), and (4) flush the wellbore to ensure that all proppant-laden fluids reach the fractures. Each phase requires moving up to millions of gallons of fluids around the site through various hoses and lines, blending the fluids, and injecting them at high pressures down the well.

The total number of stages depends on the formation properties and the orientation and length of the well. As technology has improved, the lengths of laterals in horizontal wells and the numbers of stages per well have tended to increase (NETL, 2013; Pearson et al., 2013). The number of stages per well can vary, with several sources suggesting that between 10 and 20 is typical (GNB, 2015; Lowe et al., 2013). The full range reported in the literature is much wider, with one source documenting between 1 and 59 stages per well (Pearson et al., 2013) and others reporting values within this range (NETL, 2013; STO, 2013; Allison et al., 2009). For more details on hydraulic fracturing stages, see Chapter 5, Section 5.2.

The induced fractures are designed to achieve the optimum drainage of hydrocarbons from the reservoir formations. Engineers can design fracture systems using modeling software that requires a significant amount of data on formation permeability, porosity, in situ stress, mineralogy, and geologic barrier locations, among other factors (Holditch, 2007). Microseismic monitoring during fracturing can be used to characterize the horizontal and vertical extent of the fractures created and assist with the design of future fracturing jobs (Cipolla et al., 2011). Post-fracture monitoring of pressure or tracers can also help characterize the results of a fracturing job. More details of injection, fracturing, and related monitoring are provided in Chapter 6 and Appendix D.

2.1.1.3. Fracturing Fluids

The fracturing fluids injected into the well serve a variety of purposes and require chemical additives to perform properly (see Chapter 5, Section 5.3). Depending on the geologic setting, reservoir geochemistry, production type, proppant size, and other factors, operators typically choose to use one of several common types of fracturing fluid systems (Arthur et al., 2014; Spellman, 2012; Gupta and Valkó, 2007). Water-based fracturing fluids are the most common, but other fluid types can be used such as: foams or emulsions made with nitrogen, carbon dioxide, or hydrocarbons; acid-based fluids; and others (Montgomery, 2013; Saba et al., 2012; Gupta and Hlidek, 2009; Gupta and Valkó, 2007; Halliburton, 1988). The most common water-based fluid systems are slickwater formulations, which are typically used in very low permeability reservoirs, and gelled fracturing fluids, which can be used in reservoirs with higher permeability (Barati and Liang, 2014).[1,2] More details of hydraulic fracturing fluid systems are discussed in Section 5.3. Importantly, chemical usage in the industry is continually changing as processes are tested and refined by companies. Shifts in fluid formulations are driven by economics, technological developments, and concerns about environmental and health impacts.

[1] Slickwater is a type of fracturing fluid that consists mainly of water with a very low portion of additives like polymers that serve as friction reducers to reduce friction loss when pumping the fracturing fluid downhole (Barati and Liang, 2014).

[2] Gelled fluids are fracturing fluids that are usually water-based with added gels to increase the fluid viscosity to aid in the transport of proppants (Spellman, 2012; Gupta and Valkó, 2007).

The largest constituent of a typical hydraulic fracturing fluid is water (see Figure 2-10). The water sources used for hydraulic fracturing base fluid include ground water, surface water, treated wastewater, and reused flowback or produced water from other wells (URS Corporation, 2011; Blauch, 2010; Kargbo et al., 2010).[1] The water may be brought to the production well site via trucks or piping, or it may be locally sourced (for example, pumped from a local river or obtained from a water well tapping local ground water). Selection of water sources depends upon availability, cost, quality of the water, and the logistics of delivering it to the site. Chapter 4 provides additional details on water acquisition and the amount of water used for hydraulic fracturing.

Figure 2-10. Water tanks (blue, foreground) lined up for hydraulic fracturing at a well site in central Arkansas.

Photo credit: Martha Roberts (U.S. EPA).

Proppants are, by volume, second to the base fluid in the hydraulic fracturing fluid system. Silicate minerals, most notably quartz sand, are the most commonly used proppants. Increasingly, silicate proppants are being coated with resins that help prevent development and flowback of particles or fragments of particles. Ceramic materials, such as those based on calcined (heated) bauxite or calcined kaolin (mullite) are also used as proppants due to their high strength and resistance to crushing and deformation (Beckwith, 2011).

[1] Base fluid is the fluid into which additives and proppants are mixed to formulate a hydraulic fracturing fluid.

Additives comprise relatively small percentages of hydraulic fracturing fluid systems, generally constituting ≤2.0% of the fluid (GWPC and ALL Consulting, 2009). The EPA analyzed additive data in the EPA FracFocus project database 1.0 and estimated that hydraulic fracturing additives in 2011 and 2012 totaled 0.43% of the total amount of fluid injected for hydraulic fracturing (U.S. EPA, 2015a). Note that this small percentage can total tens of thousands of gallons of chemical additives for a typical high-volume hydraulic fracturing job (see Chapter 5, Section 5.4 for details on additive volumes). A given additive may consist of a single chemical ingredient, or it may have multiple ingredients. The mix of chemicals used in any particular fracturing job is influenced by the properties of the target formation, the amount and type of proppant that needs to be carried, operator preference, and to some degree, by local or regional availability of chemicals and potential interactions between chemicals (King, 2012). Chapter 5 includes details on the number, types, and estimated quantities of chemicals that can be used in hydraulic fracturing.

2.1.2. Fluid Recovery, Management, and Disposal

When the injection pressure is reduced at the end of the fracturing process, the direction of fluid flow reverses, with some of the injected hydraulic fracturing fluid flowing into the well and to the surface along with some naturally-occurring fluids from the production zone (NYSDEC, 2011). The fluid is initially a portion of the injected fluid, which decreases over the first few weeks or months until produced water originating from the fractured oil- or gas-bearing rock formation predominates. This recovery of produced water continues over the life of the well (Barbot et al., 2013). Chapter 7 presents descriptions and discussions of the composition and quantities of fluids recovered at the well, referred to as flowback and produced water.

The hydraulic fracturing flowback and produced water (sometimes referred to as hydraulic fracturing wastewater), as well as any other liquid waste from the well pad itself (e.g., rainwater runoff), is typically stored on-site in impoundments (see Figure 2-11) or tanks. This wastewater can be moved offsite via truck or pipelines. The majority of these hydraulic fracturing wastewaters nationally are managed through disposal into deep Class II injection wells regulated under the Underground Injection Control (UIC) program under the Safe Drinking Water Act (see Chapter 8). Other management strategies include treatment followed by discharge to surface water bodies, or reuse for subsequent fracturing operations either with or without treatment (U.S. EPA, 2012f; U.S. GAO, 2012). Decisions regarding wastewater management are driven by factors such as cost (including costs of storage and transportation), availability of facilities for treatment, reuse, or disposal, and regulations (Rassenfoss, 2011). Wastewater management is yet another aspect of fracturing-related oil and gas production that is changing significantly. Chapter 8 contains details of the treatment, reuse and recycling, and disposal of wastewater.

Figure 2-11. Impoundment on the site of a hydraulic fracturing operation in central Arkansas.

Photo credit: Caroline E. Ridley (U.S. EPA).

2.1.3. Oil and Gas Production

After hydraulic fracturing, equipment is removed and partial site reclamation may take place if drilling of additional wells or laterals is not planned (NYSDEC, 2011). Operators may dewater, fill in, and regrade pits that are no longer needed. Parts of the pad may be reseeded, and the well pad may be reduced in size (e.g., from 3 to 5 acres (1 to 2 hectares) during the drilling and fracturing process to 1 to 3 acres (0.4 to 1 hectares) during production) (NYSDEC, 2011).

Wells may be shut-in immediately after completion if there is no infrastructure to receive the product or if prices are unfavorable. Prior to bringing a well into production, the operator typically runs a production test to determine the maximum flow rate the well can sustain and to optimize equipment settings (Hyne, 2012; Schlumberger, 2006). Such tests may be repeated throughout the life of the well. During production, monitoring (e.g., mechanical integrity testing, corrosion monitoring), including any compliance with state monitoring requirements, may be conducted to enable operators to be sure that the well is operating as intended.

In the case of gas wells, the produced gas typically flows through a flowline to a separator that separates the gas from water or any liquid hydrocarbons (NYSDEC, 2011). The finished gas is sent to a compressor station where it is compressed to pipeline pressure and sent to a pipeline for sale. Production at oil wells proceeds similarly, although oil/water or oil/water/gas separation occurs most typically on the well pad, no compressor is needed, and the oil can be hauled (by truck or train) or piped from the well pad.

During the life of the well it may be necessary to perform workovers to maintain or repair portions or components of the well and replace old equipment. Such workovers involve ceasing production and removing the wellhead, and may include cleaning out sand or deposits from the well, repairing casing, replacing worn well components such as tubing or packers, or installing or replacing lift equipment to pump hydrocarbons to the surface (Hyne, 2012). In some cases, wells may be recompleted after the initial construction, with re-fracturing if production has decreased (Vincent, 2011). Recompletion also may include additional perforations in the well at a different interval to produce from a different formation than originally done, lengthening the wellbore, or drilling new laterals from an existing wellbore.

As of 2012, Shires and Lev-On (2012) suggested that the rate of re-fracturing in natural gas wells was about 1.6%. Analysis for the EPA's 2012 Oil and Gas Sector New Source Performance Standards indicated a re-fracture rate of 1% for gas wells (U.S. EPA, 2012d). In the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks (U.S. EPA, 2015g), the number of gas wells that were re-fractured in a given year as a percent of the total existing population of hydraulically fractured producing gas wells in a given year ranges from 0.3% to 1% across the 1990-2013 period.

2.1.1.4. Production Rates and Duration

The production life of a well depends on a number of factors, such as the amount of hydrocarbons in place, the reservoir pressure, production rate, and the economics of well operations. It may be as short as three or four years in deep-water, high-permeability formations and as long as 40 to 60 years in onshore tight gas reservoirs (Ross and King, 2007). In hydraulically fractured wells in unconventional reservoirs, production is often characterized by a rapid drop followed by a slower decline compared to conventional hydrocarbon production wells (Patzek et al., 2013). However, most modern, high-volume fractured wells are less than a decade old. Consequently, there is a limited historical basis to determine the full extent of the production decline (Patzek et al., 2013) and to ultimately determine how much they will produce.

2.1.4. Site and Well Closure

Once a well reaches the end of its useful life, it is plugged, and the well site is closed. If a wellbore is not properly plugged, fluids from higher pressure zones may eventually migrate through the wellbore to the surface or to other zones such as fresh water aquifers (NPC, 2011b). Plugging is usually performed according to state regulations governing the locations and materials for plugs (Calvert and Smith, 1994). Operators typically use cement plugs placed across fresh water formations and oil or gas formations (NPC, 2011b). Some surface structures can be left in place, and the local topography and land cover are restored to predevelopment conditions to the extent possible, per state regulations. The wellhead and any surface equipment are removed. Impoundments are dewatered, filled in, and graded. The well casing is typically cut off below the surface and a steel plate or cap is emplaced to seal the top of the casing and wellbore (API, 2010a), although there may also be an aboveground marker used in some locations. Some states require notification of the landowner or a government agency of the location of the well.

2.2. How Widespread is Hydraulic Fracturing?

Hydraulic fracturing activity in the United States and worldwide is substantial. One industry cumulative estimate stated that by the time of writing in 2010, close to 2.5 million fracture treatments had been performed globally (Montgomery and Smith, 2010). In 2002, the Interstate Oil and Gas Compact Commission (IOGCC) stated that close to 1 million wells had been hydraulically fractured in the United States since the 1940s (IOGCC, 2002). A recent U.S. Geological Survey (USGS) publication analyzed 1 million hydraulically fractured wells and 1.8 million hydraulic fracturing treatment records from the United States from 1947 to 2010 (USGS, 2015). Although some form of hydraulic fracturing has been used for more than 60 years, the technological advancements that combined hydraulic fracturing and directional drilling in the early 2000s resulted in the new era of modern hydraulic fracturing, which uses higher volumes of fracturing fluids than were typically used in prior decades. Modern hydraulic fracturing is typically associated with horizontal wells producing from unconventional shale reservoirs, but hydraulic fracturing continues to be done in vertical wells in conventional reservoirs also. This ongoing mix of traditional and modern hydraulic fracturing activities makes estimates of the total number of hydraulic fracturing wells challenging.

The following series of images illustrates hydraulic fracturing activities and the scale of those activities in the United States. Figure 2-12 (taken in Springville Township, in northeastern Pennsylvania) and Figure 2-13 (taken near Williston, in northwestern North Dakota) show individual well pads in the context of the local landscape. Landsat images in Figure 2-14 and Figure 2-15 provide satellite views of areas in northwest Louisiana and southeast Wyoming, respectively, where hydraulic fracturing activities currently occur as identified by the well pads in the images. These images serve to illustrate activity at a wider scale, though they are not representative of all hydraulic fracturing activities in the eastern or western United States. The light red circles around some of the well pads identify them as hydraulic fracturing wells that were reported by well operators to the FracFocus registry (as summarized in the EPA FracFocus project database 1.0) (U.S. EPA, 2015b). (The FracFocus well locations reflect information in the EPA FracFocus project database for well operations reporting hydraulic fracturing activities between January 2011 and February 2013. The Landsat images are from a later period, July and August of 2014, so additional well pads in the images now may be represented in the FracFocus registry.)

Figure 2-12. Aerial photograph of a well pad and service road in Springville Township, Pennsylvania.

Image © J Henry Fair / Flights provided by LightHawk.

Figure 2-13. Aerial photograph of hydraulic fracturing activities near Williston, North Dakota.

Image © J Henry Fair / Flights provided by LightHawk.

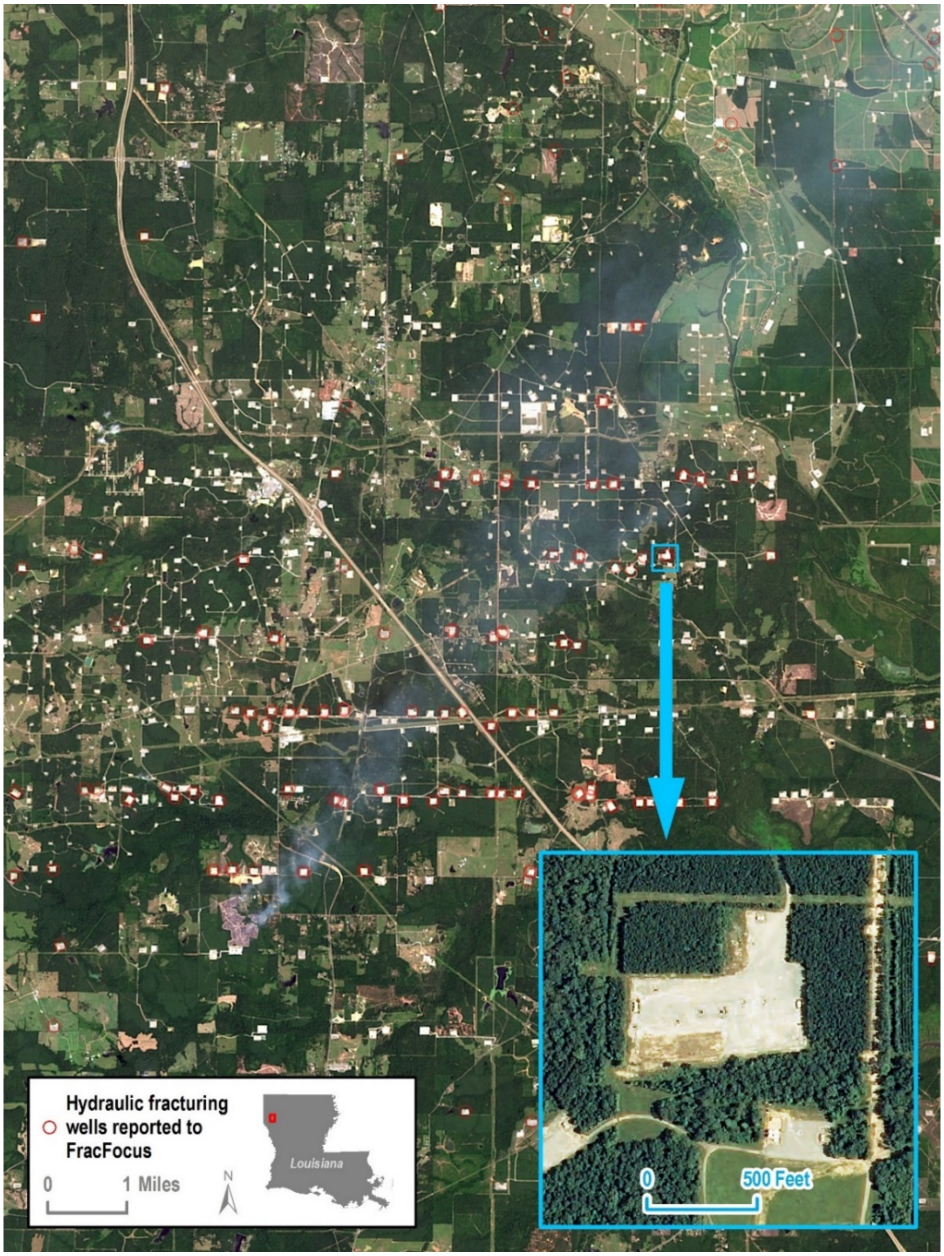


Figure 2-14. Landsat photo showing hydraulic fracturing well sites near Frierson, Louisiana.

Source: Imagery from USGS Earth Resources Observation and Science, Landsat 8 Operational Land Imager (scene LC80250382014232LGN00) captured August 20, 2014 and accessed on May 1, 2015 from USGS's EarthExplorer (http://earthexplorer.usgs.gov/).
Inset imagery from USDA National Agriculture Imagery Program (entity M 3209351_NE 15_1_20130703_20131107) captured July 3, 2013 and accessed May 1, 2015 from USGS's EarthExplorer (http://earthexplorer.usgs.gov/).
FracFocus well locations are from the EPA FracFocus project database 1.0 (U.S. EPA, 2015b).

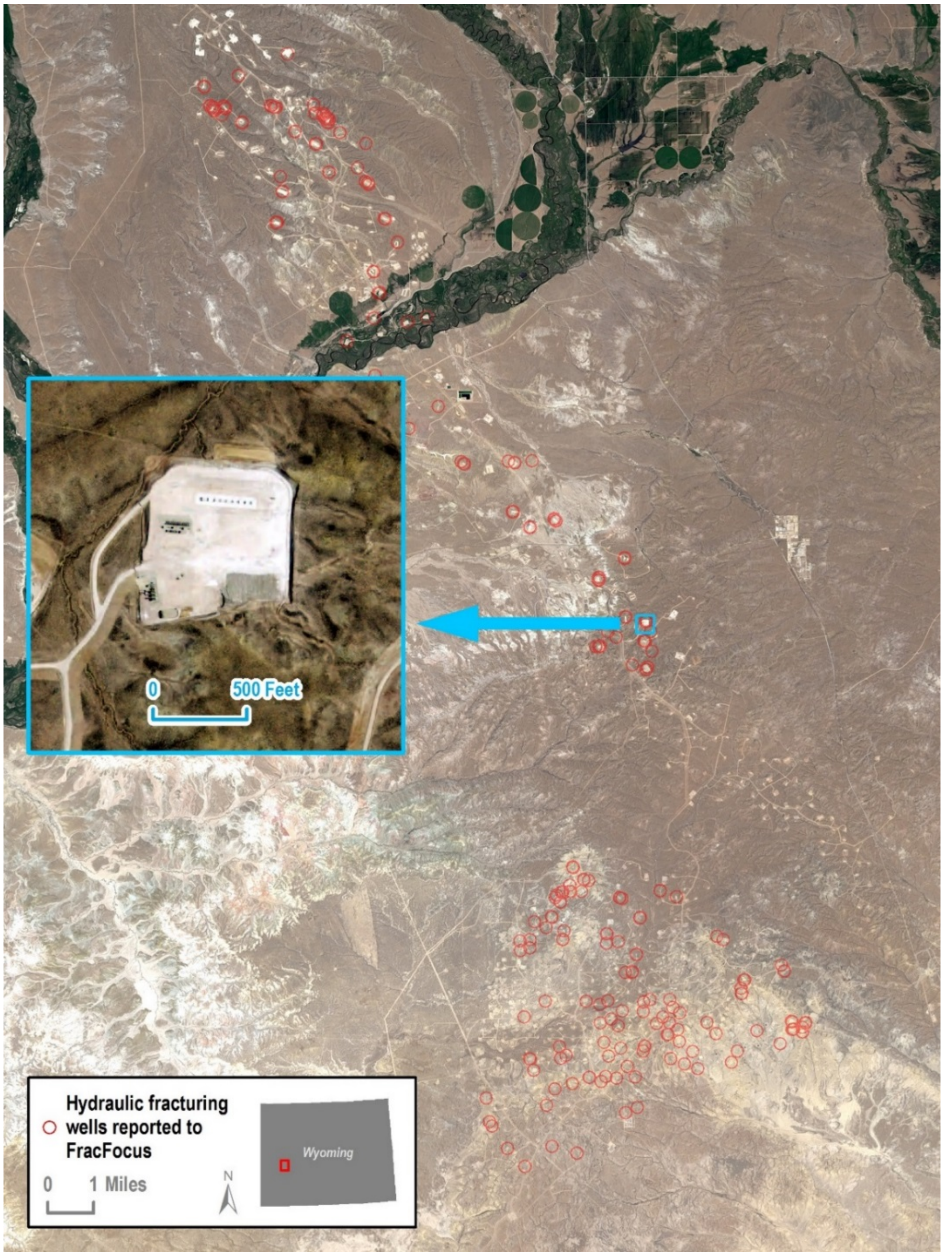


Figure 2-15. Landsat photo showing hydraulic fracturing well sites near Pinedale, Wyoming.

Source: Imagery from USGS Earth Resources Observation and Science, Landsat 8 Operational Land Imager (scene LC80370302014188LGN00) captured July 7, 2014 and accessed May 1, 2015 from USGS's EarthExplorer (http://earthexplorer.usgs.gov/).
Inset imagery from USDA National Agriculture Imagery Program (entity M 4210927_NW 12_1_20120623_20121004) captured June 23, 2012 and accessed May 1, 2015 from USGS's EarthExplorer (http://earthexplorer.usgs.gov/).
FracFocus well locations are from the EPA FracFocus project database 1.0 (U.S. EPA, 2015b).

The maps in Figure 2-16 show recent changes nationally in the geography of oil and gas production through the increased use of horizontal drilling, which occurs together with hydraulic fracturing.

Some traditional oil- and gas-producing parts of the country, such as Texas, have seen an expansion of historically strong production activity as a result of the deployment of horizontal drilling and modern hydraulic fracturing. Pennsylvania, a century ago one of the leading oil- and gas-producing states, has seen a resurgence in oil and gas activity. Other states currently experiencing a steep increase in production activity, such as North Dakota, Arkansas, and Montana, have historically produced less oil and gas and are therefore undergoing new development.

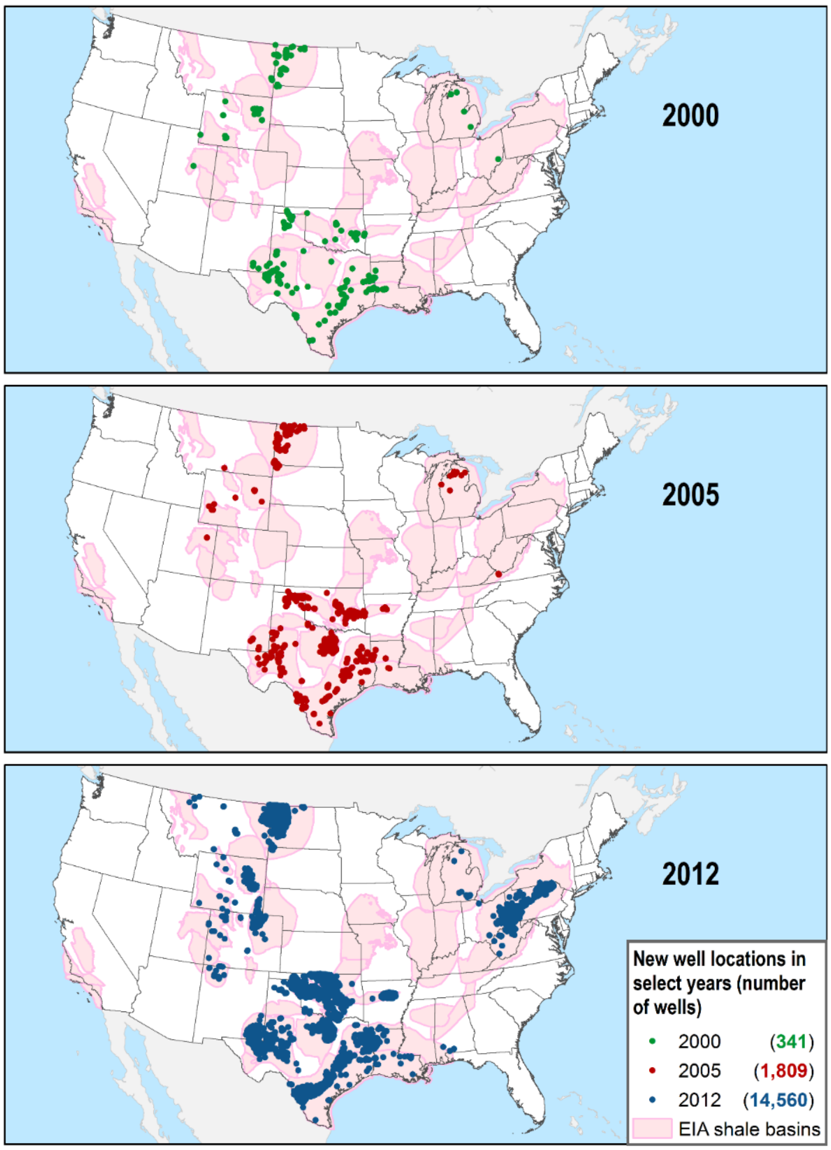


Figure 2-16. Location of horizontal wells that began producing oil or natural gas in 2000, 2005, and 2012, based on data from DrillingInfo (2014a).

2.2.1. Number of Wells Fractured per Year

We estimate that from roughly 2011 to 2014, approximately 25,000 to 30,000 new oil and gas wells were hydraulically fractured each year. Additional, pre-existing wells (wells more than one year old that may or may not have been hydraulically fractured in the past) were also likely fractured each year. Since the early 2000s, the percentage of all hydraulically fractured wells that are either horizontal or deviated has steadily grown. Our estimates are based on data detailed below from several public and private sector organizations that track drilling and various aspects of hydraulic fracturing activity. There is no complete database or registry of wells that are hydraulically fractured in the United States. Another source of uncertainty is the rate at which relatively new hydraulic fracturing wells are re-fractured or the rate at which operators use older, existing wells for hydraulic fracturing. Future trends in the number of wells hydraulically fractured per year will be affected by the cost of well operation and the price of oil and gas. Scenarios of increasing, flat, and decreasing hydraulic fracturing activity all appear to be possible (Weijermars, 2014).

The number of wells reported to the FracFocus registry provides a low estimate of the number of hydraulically fractured wells.[1] As of early April 2015, the FracFocus registry reported receiving information on a cumulative total of approximately 95,000 fracturing jobs, or roughly 22,400 per year over the 51-month period from January 2011 through March 2015 (GWPC, 2015). In a more detailed review of FracFocus data from 2011 and 2012, the EPA found there were approximately 14,000 and 22,500 fracturing jobs reported to the FracFocus website in those years, respectively, across 20 states (U.S. EPA, 2015a). These 2011 and 2012 numbers are likely underestimates of wells hydraulically fractured annually, in part because FracFocus reporting was voluntary for most states for at least a portion of 2011 to 2012 (though the increase from 2011 to 2012 in part reflects more states requiring reporting to the registry). Hydraulic fracturing practices may alternately (or in addition to FracFocus) be tracked by states. Compared to state records of hydraulic fracturing from North Dakota, Pennsylvania, and West Virginia in 2011 and 2012, we found that the count of wells based on records submitted to FracFocus was an underestimate of the number of fracturing jobs in those states by an average of approximately 30% (see Text Box 4-1).

An additional estimate of the number of hydraulically fractured wells can be obtained from DrillingInfo, a commercial database compiling data from individual state oil and gas agencies (DrillingInfo, 2014a). The data indicate an increase in the number of new hydraulically fractured wells drilled each year, from approximately 12,800 in 2000 to slightly more than 21,600 in 2005, to nearly 23,000 in 2012. The number of new horizontal wells (which are likely all hydraulically fractured) show a significant increase, from 344 (about 1% of all new production wells) in 2000, to 1,810 in 2005, to 14,560 (nearly 41% of all new production wells) in 2012 (see Figure 2-16).

[1] The FracFocus registry was developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. Oil and gas well operators can use the FracFocus registry to disclose information about hydraulic fracturing well locations, and water and chemical use during hydraulic fracturing operations. Submission of information to FracFocus was initially voluntary (starting in January 2011), but now about half of the 20 states represented in FracFocus have enacted reporting requirements for well operators that either mandate reporting to FracFocus or allow it as one reporting option. FracFocus data are discussed in more detail in Chapter 4 (regarding water volumes) and Chapter 5 (regarding chemical use). For more information see www.fracfocus.org and U.S. EPA (2015a).

Because DrillingInfo data do not directly report whether a well has been hydraulically fractured, we relied on properties of the well and the oil or gas producing formation to infer which wells were hydraulically fractured and when. First, we assumed that *all* horizontal wells were hydraulically fractured in the year they started producing. Second, we assumed that all wells within a shale, coalbed, or low-permeability formation, regardless of well orientation, were hydraulically fractured in the year they started producing.[1]

We used well-specific data provided by oil and gas well operators to the EPA to supplement our estimates of hydraulic fracturing using DrillingInfo data (U.S. EPA, 2015o). Matching wells in each dataset using API well numbers, we found that 80% of 171 newly drilled wells known to be fractured in 2009 and 2010 according to their well files were correctly identified as fractured using well and formation properties in DrillingInfo.[2] We did not correctly identify all of the vertical or deviated wells that were known to be fractured. (We were unable to identify wells for which hydraulic fracturing was inferred using the properties in DrillingInfo but were not fractured.) This comparison suggests that the estimates of hydraulically fractured wells from DrillingInfo are likely underestimates.

Another source of estimates is from a U.S. Geological Survey publication that reviewed data from the commercial IHS database of U.S. oil and gas production and well data (USGS, 2015). The study period was from 1947 through 2010. The authors estimated a total of approximately 277,000 hydraulically fractured wells between 2000 and 2010 (compared to close to 212,000 during the same time period estimated based on DrillingInfo data). This is roughly 25,000 wells per year over that time period. Approximately three-quarters of these wells were vertical. Reflecting advances in directional drilling technology over the decade ending in 2010, the percentage of total wells fractured that were horizontal or deviated wells grew from less than 10% to over 60%.

Well counts tracked by Baker Hughes provide another estimate of new wells fractured annually. Since 2012, this oilfield service company has published a quarterly count of new wells spudded; it includes only new inland U.S. wells "identified to be significant consumers of oilfield services and supplies."[3] A reported total of 36,824 oil and gas wells were spudded in the United States in 2012, with new wells per quarter fluctuating between about 8,500 and 9,500 (Baker Hughes, 2014b). While 100% of new wells are probably not hydraulically fractured (see below for estimates of hydraulic fracturing rates in new wells), a count of new wells also does not include hydraulic fracturing taking place in older, existing wells.

---

[1] The assignment of formation type (shale, coalbed, low-permeability, or conventional) for each well was based on a crosswalk of information on basin/play provided in DrillingInfo (2014a) with expert knowledge of those basins/plays at EIA (2012a). If formation type could not be determined, it was considered conventional by default. This is similar methodology to that used by the EPA for its greenhouse gas inventory (U.S. EPA, 2013c).

[2] An API well number is a unique identifying number given to each oil and gas well drilled in the United States. The system was developed by the American Petroleum Institute.

[3] To spud a well is to start the well drilling process by removing rock, dirt, and other sedimentary material with the drill bit.

Data collected under the EPA's Greenhouse Gas Reporting Program (GHGRP) provide information on completions and workovers with hydraulic fracturing (i.e., re-fracturing) of gas wells. Data reported to GHGRP for years 2011 to 2013 suggest that 9-14% of the gas wells reported to be hydraulically fractured in each year were pre-existing wells undergoing re-fracturing (U.S. EPA, 2014e).[1] The GHGRP requirements do not include reporting of re-fracturing in oil wells, and other data sources for information specifically on re-fracturing of existing oil wells compared to initial fracturing of oil wells were not identified. For comparison, an EPA survey of an estimated 23,200 oil and gas production wells that were hydraulically fractured by nine oil and gas service companies in 2009 and 2010 suggests that 42% of the wells were pre-existing (i.e., more than one year old) when they were hydraulically fractured (U.S. EPA, 2015o). Differences in data (including data from different years and data from gas wells only (GHGRP) versus oil and gas wells, for instance), definitions, and assumptions used to estimate the percentage of pre-existing wells hydraulically fractured in a year could account for the different results.

In summary, determination of the national scope of hydraulic fracturing activities in the United States is complicated by a lack of a centralized source of information and the fact that well and drilling databases each track different information. There is also uncertainty about whether information sources are representative of the nation, whether they include data for all production types, whether they represent only modern (high volume) hydraulic fracturing, and whether they include activities in both conventional and unconventional reservoirs. Taking these limitations into account, however, it is reasonable to assume that between approximately 25,000 and 30,000 new wells (and, likely, additional pre-existing wells) were hydraulically fractured each year in the United States from about 2011 to 2014.

2.2.2. Hydraulic Fracturing Rates

Estimates of hydraulic fracturing rates, or the proportion of all oil and gas production wells that are associated with hydraulic fracturing, also indicate widespread use of the practice. Based on an assessment described above of data from DrillingInfo (2014a), hydraulic fracturing rates have increased over time. From 2005 to 2012, rates of hydraulic fracturing increased from 57% to 64% of all new production wells (including oil wells, gas wells, and wells producing both oil and gas).

In 2009, industry consultants stated that hydraulic fracturing was used on nearly 79% of all wells and more than 95% of "unconventional" wells (IHS, 2009). A 2010 article in an industry publication noted "some believe that approximately 60% of all wells drilled today are fractured" (Montgomery and Smith, 2010). Of 11 important oil and gas producing states that responded to an IOGCC survey (Arkansas, Colorado, Louisiana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, and West Virginia), ten estimated that 78% to 99% of new oil and gas wells in their states were hydraulically fractured in 2012; Louisiana was the one exception, reporting a fracturing rate of 3.9% in 2012 (IOGCC, 2015). Although estimates of fracturing rates are variable, largely ranging from near 60% to over 90% (as described above), they are often higher for gas wells than they are for oil wells. A 2010 to 2011 industry survey of 20 companies involved in natural gas production

[1] The GHGRP reporting category that covers re-fracturing is "workovers with hydraulic fracturing."

found that 94% of the wells that they operated were fractured; among those, roughly half were vertical and half were horizontal (Shires and Lev-On, 2012).

2.3. Trends and Outlook for the Future

Fossil fuels are the largest source of all energy generated in the United States. They currently comprise approximately 80% of the energy produced (EIA, 2014f). However, the mix of fossil fuels has shifted in recent years. Coal, the leading fossil fuel produced by the U.S. since the 1980s, has experienced a significant decrease in production. In 2007, coal accounted for approximately 33% of U.S. energy production, and by 2013 it decreased to approximately 24% (EIA, 2014f). On the other hand, natural gas production has risen to unprecedented levels, and oil production has resurged to levels not seen since the 1980s (see Figure 2-17). Oil went from accounting for 15% of U.S. energy production to 19% between 2007 and 2013, and natural gas (both dry and liquid) went from 31% to 35% (EIA, 2014f).

Below, we discuss recent and projected shifts in oil and natural gas production that can primarily be attributed to hydraulic fracturing and directional drilling technologies.

2.3.1. Natural Gas (Including Coalbed Methane)

Natural gas production in the United States peaked in the early 1970s, reached those levels again in the mid-1990s, and between the mid- to late-2000s has increased to even higher levels (see Figure 2-17). The recent increase in total gas production has been driven almost entirely by shale gas (see Figure 2-18).

As natural gas prices fell between 2008 and 2012 (EIA, 2014e), drilling of new natural gas wells declined markedly (EIA, 2014g) (see Figure 2-19). Nevertheless, natural gas production is expected to increase over the coming decades (see Figure 2-18). EIA (2013b) predicts that shale gas production will more than double between 2011 and 2040 and that the portion of total natural gas production represented by shale gas will increase from one-third to one-half. The EIA projects steady growth in the development of tight gas as well (about a 25% increase in production over the 30-year period) and delayed growth in the development of coalbed methane resources, for which production is not expected to increase again until sufficiently high natural gas prices are realized around 2035. Overall, the EIA projects that the share of U.S. natural gas production from shales, tight formations, and coalbeds will increase from 65% in 2011 to nearly 80% in 2040.

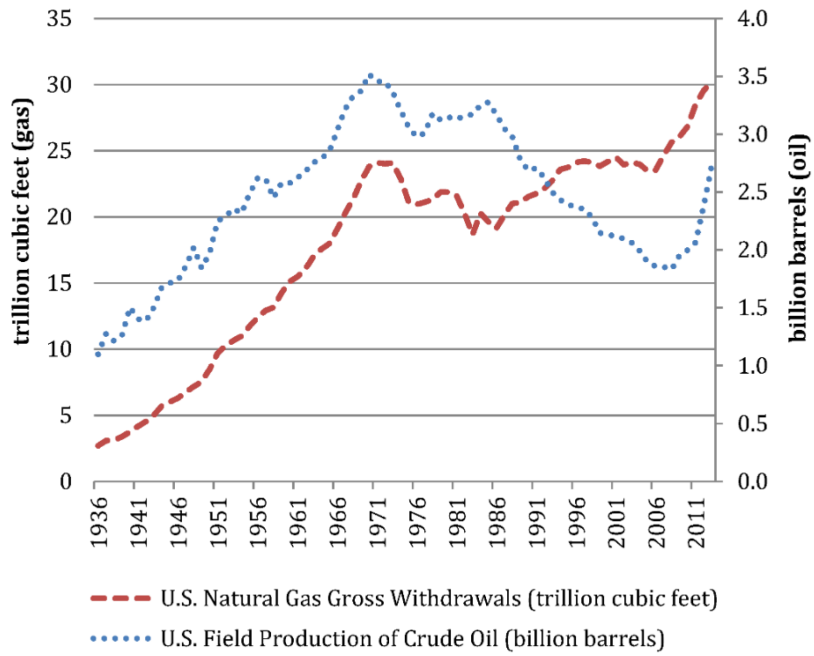


Figure 2-17. Trends in U.S. oil and gas production.

Source: EIA (2013d) and EIA (2014d).

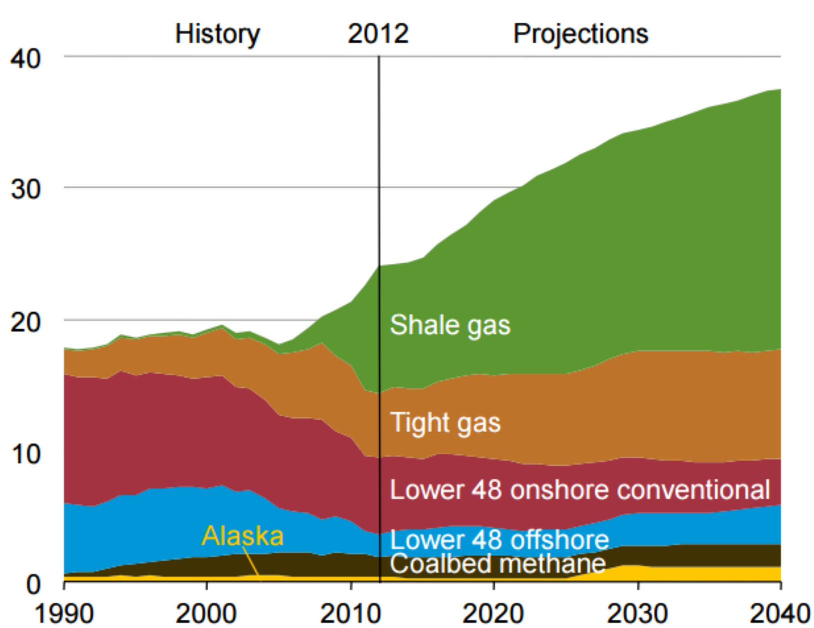


Figure 2-18. Historic and projected natural gas production by source (trillion cubic feet).

Source: EIA (2014a).

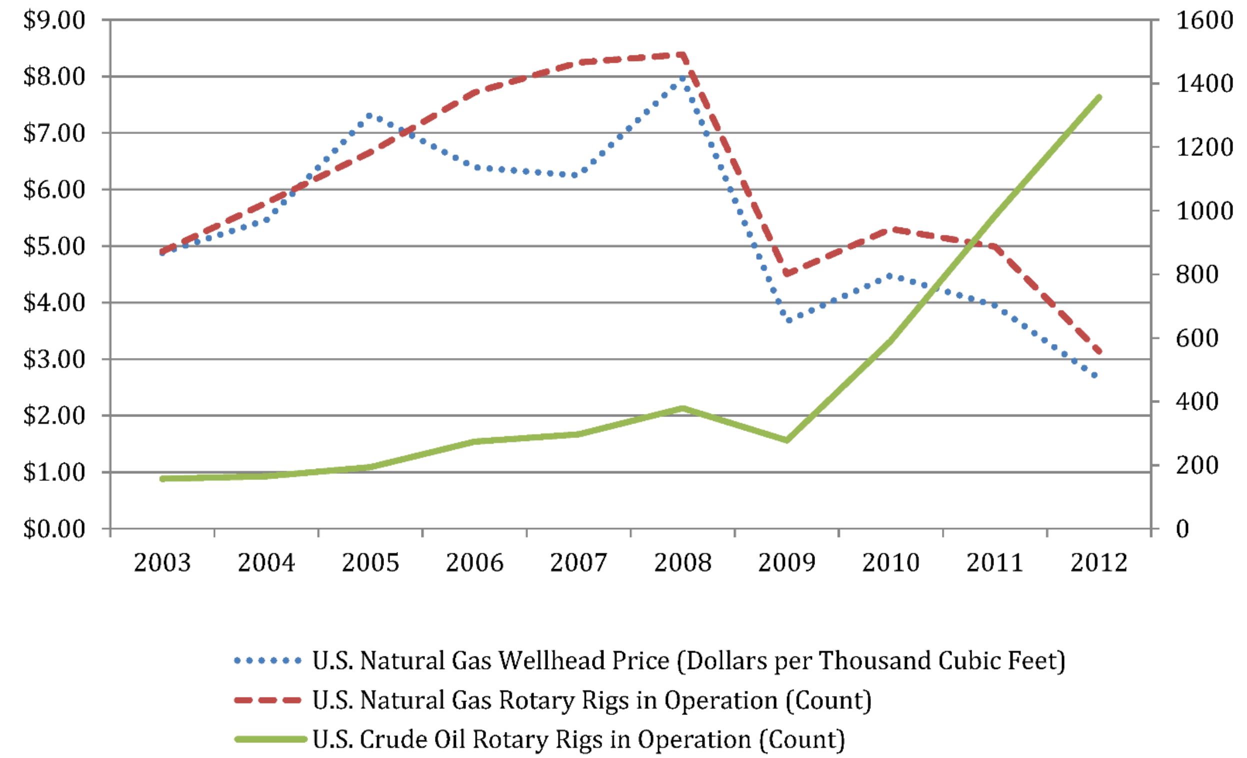


Figure 2-19. Natural gas prices and oil and gas drilling activity, 2008–2012.

Source: EIA (2014e), EIA (2014g), and EIA (2013b).

Shale gas production varies by play (see Figure 2-20a). Until 2010, the Texas Barnett Shale was the play with the most production. Although production from the Barnett Shale is still significant, production has increased sharply in other plays. By 2012, production from the Haynesville play (on the Louisiana/Texas border) surpassed that in the Barnett play, and by 2013 the Marcellus Shale (in the Appalachian Basin underlying Pennsylvania, West Virginia, and other states) was the play with the most production. Because technically recoverable resources are an order of magnitude higher in the Marcellus than in any other U.S. shale gas play, it is likely that the Marcellus Shale will be very active in shale gas production for the foreseeable future (EIA, 2011a).[1]

In the 1970s, most tight gas production in the United States was in the San Juan Basin centered in New Mexico. As modern hydraulic fracturing came into common usage in the mid-2000s, the lead in tight gas production shifted to Texas (especially East Texas) and the Rocky Mountain states (Vidas and Hugman, 2008).

[1] Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs (EIA, 2013c).

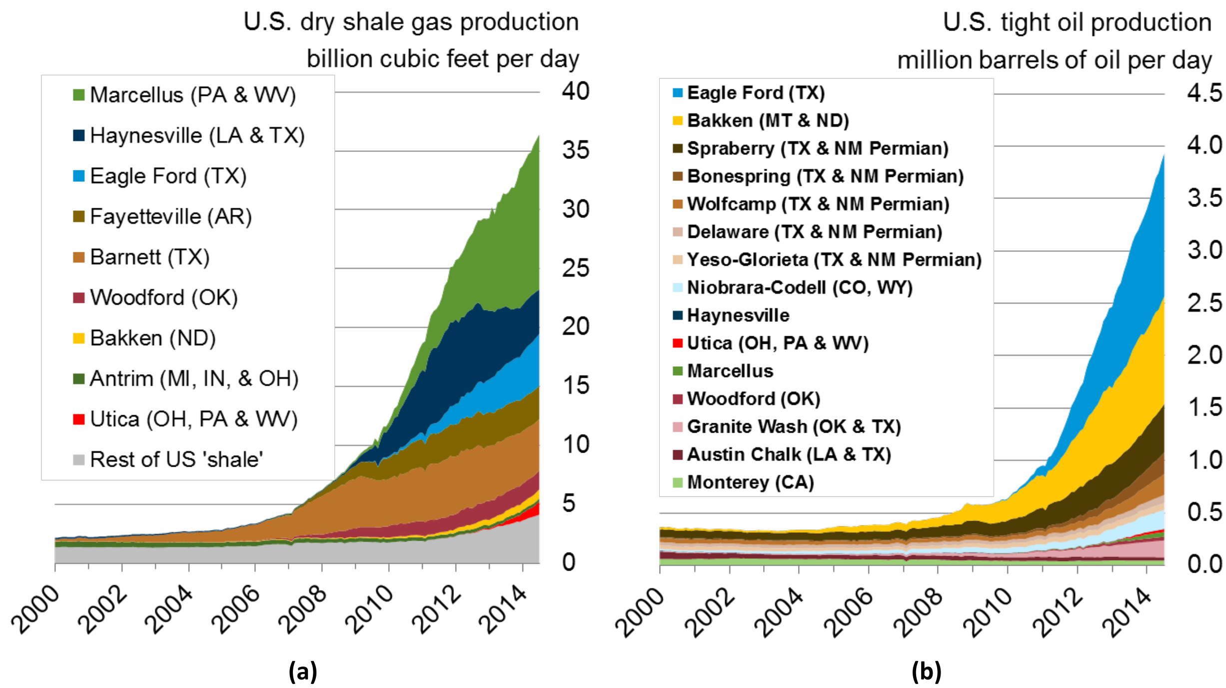


Figure 2-20. (a) Production from U.S. shale gas plays, 2000–2014, in billion cubic feet per day; (b) Production from U.S. tight oil plays, 2000-2014.

Tight oil includes oil from shale and other tight formations, plus lease condensate from natural gas production. Source: EIA (2012c).

Modern coalbed methane production techniques were pioneered in the Black Warrior Basin in Alabama and in the San Juan Basin (Vidas and Hugman, 2008). With the use of hydraulic fracturing, most coalbed methane production in the United States now comes from the San Juan Basin and from Rocky Mountain Basins (e.g., the Uinta-Piceance Basin in Colorado and Utah and the Powder River Basin centered in Wyoming) (Vidas and Hugman, 2008).

2.3.2. Oil

The EIA data indicate that as drilling activity for natural gas declined between 2008 and 2012, drilling for oil increased by a similar order of magnitude (see Figure 2-19). Figure 2-21 shows past and projected future trends in U.S. oil production and importation (EIA, 2013a). Note that this graph shows production and importation in millions of barrels (bbl) *per day*. The current surge in tight oil production is expected to continue until the latter part of the current decade and then taper, while conventional oil production is projected to remain fairly level. However, downward trends in the price of oil since mid-2014 are not reflected in these projections.

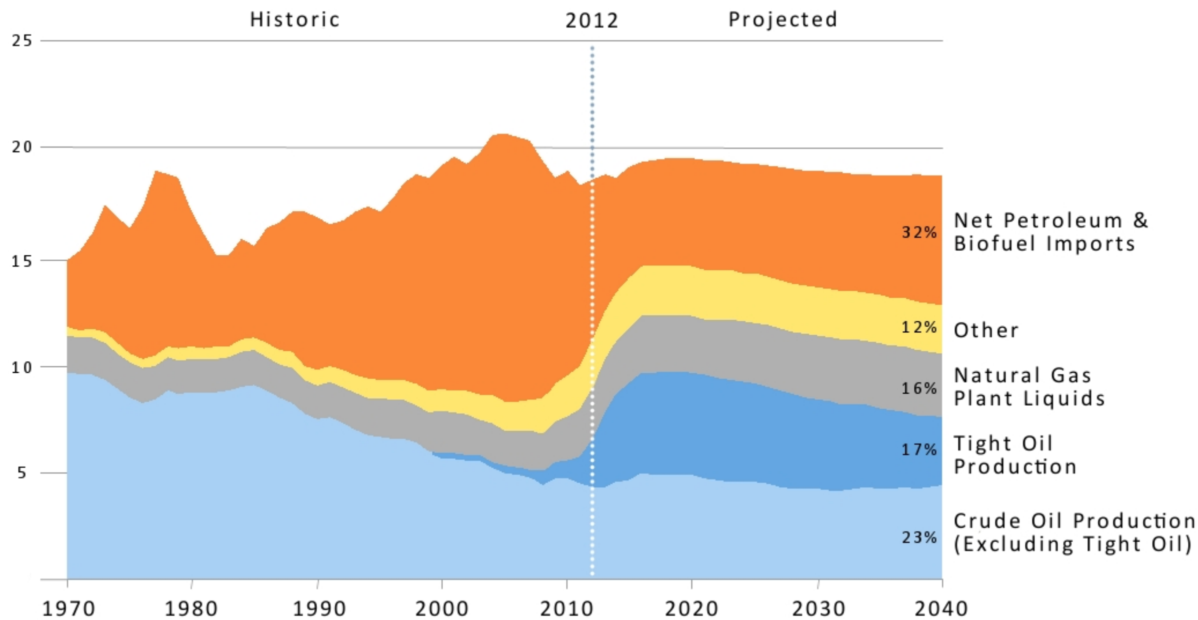


Figure 2-21. U.S. petroleum and other liquid fuels supply by source, past and projected future trends (million barrels per day).

Source: EIA (2013a).

Like shale gas production, tight oil production varies by play (Figure 2-20b). The Bakken Shale play, centered in western North Dakota, is important for shale oil production with production increasing from 123 million bbl (20 billion L) in 2011 to 213 million bbl (34 billion L) in 2012. Proved reserves in the Bakken have increased from almost 2 billion to over 3 billion bbl (316 billion L to 503 billion L). The Eagle Ford play in Texas is another major area of shale oil activity, with production increasing from 71 million bbl (11 billion L) in 2011 to 210 million bbl (33 billion L) in 2012, and proved reserves increasing from 1.25 billion to 3.4 billion bbl (199 billion to 536 billion L) (EIA, 2014b). Oil production from the Eagle Ford surpassed that from the Bakken in 2013 (EIA, 2014h). Among other shale oil plays that might become important in future domestic U.S. oil production, the Niobrara (centered in Colorado) and Austin Chalk (in Texas, Louisiana, and Mississippi) are believed to have quantities of recoverable resources on the same order of magnitude as the Bakken and Eagle Ford plays (EIA, 2012b).

2.4. Conclusion

Since about 2005, the combination of hydraulic fracturing and horizontal drilling pioneered in the Barnett Shale have become widespread in the oil and gas industry. Hydraulic fracturing is now a standard industry practice and has significantly contributed to a surge in U.S. production of both oil and gas. Modern hydraulic fracturing has resulted in additional types of geological formations being tapped, and sometimes these formations are located in regions of the country new to intensive oil and gas exploration and production. In other areas, the improved techniques have made possible a resurgence of production.

An estimated 25,000 to 30,000 new wells drilled in the United States were hydraulically fractured as a production-enhancing technique in each year from 2011 to 2014. Additional pre-existing wells were also fractured. Since the early 2000s, the percentage of all hydraulically fractured wells that are either horizontal or deviated has steadily grown. Reserves of oil and gas that are now accessible with modern hydraulic fracturing are considerable, and if technical improvements outpace depletion of oil and gas resources, the quantity of resources that are deemed economically and technically recoverable may continue to grow. Given current trends, it appears likely that hydraulic fracturing will continue to play an important role in the oil and gas industry, and the United States' energy portfolio, in the decades ahead.

2.5. References for Chapter 2

Abou-Sayed, IS; Sorrell, MA; Foster, RA; Atwood, EL; Youngblood, DR. (2011). Haynesville shale development program: From vertical to horizontal. Paper presented at North American Unconventional Gas Conference and Exhibition, June 14-16, 2011, The Woodlands, TX.

ALL Consulting (ALL Consulting, LLC). (2004). Coal bed methane primer: New source of natural gas and environmental implications. Tulsa, OK: U.S. Department of Energy, National Petroleum Technology Center. http://bogc.dnrc.mt.gov/PDF/Web%20Version.pdf

Allison, D; Folds, DS; Harless, DJ; Howell, M; Vargus, GW; Stipetich, A. (2009). Optimizing openhole completion techniques for horizontal foam-drilled wells. Paper presented at SPE Eastern Regional Meeting, September 23-25, 2009, Charleston, WV.

API (American Petroleum Institute). (2010a). Isolating potential flow zones during well construction [Standard] (1st ed.). (RP 65-2). Washington, DC: API Publishing Services. http://www.techstreet.com/products/preview/1695866

Arthur, JD; Bohm, B; Cornue, D. (2009a). Environmental considerations of modern shale gas development. Paper presented at SPE Annual Technical Conference and Exhibition, October 4-7, 2009, New Orleans, LA.

Arthur, JD; Layne, MA; Hochheiser, HW; Arthur, R. (2014). Spatial and statistical analysis of hydraulic fracturing activities in U.S. shale plays and the effectiveness of the FracFocus chemical disclosure system. In 2014 SPE hydraulic fracturing technology conference. Richardson, TX: Society of Petroleum Engineers. http://dx.doi.org/10.2118/168640-MS

Baker Hughes. (2014b). Well count. U.S. onshore well count [Database]. Houston, TX: Baker Hughes, Inc. Retrieved from http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-wellcountus

Barati, R; Liang, JT. (2014). A review of fracturing fluid systems used for hydraulic fracturing of oil and gas wells. J Appl Polymer Sci Online pub. http://dx.doi.org/10.1002/app.40735

Barbot, E; Vidic, NS; Gregory, KB; Vidic, RD. (2013). Spatial and temporal correlation of water quality parameters of produced waters from Devonian-age shale following hydraulic fracturing. Environ Sci Technol 47: 2562-2569.

Beckwith, R. (2011). Proppants: Where in the world. J Pet Tech 63: 36-41.

Blauch, ME. (2010). Developing effective and environmentally suitable fracturing fluids using hydraulic fracturing flowback waters. Paper presented at SPE Unconventional Gas Conference, February 23-25, 2010, Pittsburgh, PA.

Bosworth, S; El-Sayed, HS; Ismail, G; Ohmer, H; Stracke, M; West, C; Retnanto, A. (1998). Key issues in multilateral technology. Oilfield Rev 10: 14-28.

Calvert, DG; Smith, DK. (1994). Issues and techniques of plugging and abandonment of oil and gas wells. Paper presented at SPE Annual Technical Conference and Exhibition, September 25-28, 1994, New Orleans, LA.

CCST (California Council on Science and Technology). (2015). An independent scientifc assessment of well stimulation in California, Volume 1: Well stimulation technologies and their past, present, and potential future use in California. Sacramento, CA. http://www.ccst.us/publications/2015/2015SB4-v1.pdf

Ciezobka, J; Salehi, I. (2013). Controlled hydraulic fracturing of naturally fractured shales: A case study in the Marcellus Shale examining how to identify and exploit natural fractures. (SPE-164524-MS). Ciezobka, J; Salehi, I. http://dx.doi.org/10.2118/164524-MS

Cipolla, C; Weng, X; Mack, M; Ganguly, U; Gu, H; Kresse, O; Cohen, C. (2011). Integrating microseismic mapping and complex fracture modeling to characterize hydraulic fracture complexity. Paper presented at SPE Hydraulic Fracturing Technology Conference, January 24-26, 2011, The Woodlands, TX.

DOE (U.S. Department of Energy). (2011b). Shale gas Applying technology to solve americas energy challenges. Available online at http://groundwork.iogcc.org/topics-index/shale-gas/topic-resources/shale-gas-applying-technology-to-solve-americas-energy-challe

DrillingInfo, Inc., . (2014a). DI Desktop June 2014 download [Database]. Austin, TX: DrillingInfo. Retrieved from http://info.drillinginfo.com/

Drohan, PJ; Brittingham, M. (2012). Topographic and soil constraints to shale-gas development in the northcentral Appalachians. Soil Sci Soc Am J 76: 1696-1706. http://dx.doi.org/10.2136/sssaj2012.0087

EIA (Energy Information Administration). (2011a). Review of emerging resources: U.S. shale gas and shale oil plays. United States Department of Energy. http://www.eia.gov/analysis/studies/usshalegas/

EIA (Energy Information Administration). (2011b). Shale gas and oil plays, lower 48 States [Map]. Available online at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm

EIA (Energy Information Administration). (2012a). Formation crosswalk. Washington, DC: U.S. Energy Information Administration.

EIA (Energy Information Administration). (2012b). Today in energy: Geology and technology drive estimates of technically recoverable resources. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/todayinenergy/detail.cfm?id=7190

EIA (Energy Information Administration). (2012c). What is shale gas and why is it important? [December 5]. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/energy_in_brief/article/about_shale_gas.cfm

EIA (Energy Information Administration). (2013a). Analysis & projections: AEO2014 early release overview. Release date: December 16, 2013. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/forecasts/aeo/er/executive_summary.cfm

EIA (Energy Information Administration). (2013b). Annual energy outlook 2013 with projections to 2040. (DOE/EIA-0383). Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/forecasts/archive/aeo13/pdf/0383(2013).pdf

EIA (Energy Information Administration). (2013c). Technically recoverable shale oil and shale gas resources: an assessment of 137 shale formations in 41 countries outside the United States (pp. 730). Washington, D.C.: Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/analysis/studies/worldshalegas/

EIA (Energy Information Administration). (2013d). U.S. field production of crude oil. Release date: September 27, 2014. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpus1&f=a

EIA (Energy Information Administration). (2014a). Annual energy outlook 2014 with projections to 2040. (DOE/EIA-0383(2014)). Washington, D.C.: U.S. Energy Information Administration. http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf

EIA (Energy Information Administration). (2014b). Natural gas. U.S. crude oil and natural gas proved reserves. With data for 2012. Table 2. Principal tight oil plays: oil production and proved reserves, 2011-12. Release date: April 10, 2014. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/naturalgas/crudeoilreserves/

EIA (Energy Information Administration). (2014d). Natural gas. U.S. natural gas gross withdrawals. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm

EIA (Energy Information Administration). (2014e). Natural gas: Natural gas prices [Database]. Washington, DC: U.S. Energy Information Administration. Retrieved from http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

EIA (Energy Information Administration). (2014f). October 2014 month energy review. (DOE/EIA-0035(2014/10)). Washington, D.C.: U.S. Energy Information Administration. http://www.eia.gov/totalenergy/data/monthly/archive/00351410.pdf

EIA (Energy Information Administration). (2014g). Petroleum & other liquids. Crude oil and natural gas drilling activity. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/dnav/pet/pet_crd_drill_s1_a.htm

EIA (Energy Information Administration). (2014h). Today in energy: Tight oil production pushes U.S. crude supply to over 10% of world total. Washington, DC: U.S. Energy Information Administration. http://www.eia.gov/todayinenergy/detail.cfm?id=15571.

EIA (Energy Information Administration). (2015b). Lower 48 states shale plays. Available online at http://www.eia.gov/oil_gas/rpd/shale_gas.pdf

GNB (Government of New Brunswick). (2015). FAQs hydraulic fracturing (fraccing). New Brunswick, Canada. http://www2.gnb.ca/content/dam/gnb/Corporate/pdf/ShaleGas/en/FAQ_HydraulicFracturing.pdf

Gupta, DVS; Hlidek, BT. (2009). Frac fluid recycling and water conservation: A case history. In 2009 Hydraulic fracturing technology conference. Woodlands, Texas: Society of Petroleum Engineers. http://dx.doi.org/10.2118/119478-MS

Gupta, DVS; Valkó, P. (2007). Fracturing fluids and formation damage. In M Economides; T Martin (Eds.), Modern fracturing: enhancing natural gas production (pp. 227-279). Houston, TX: Energy Tribune Publishing Inc.

GWPC (Groundwater Protection Council). (2015). FracFocus - chemical disclosure registry. Available online at http://fracfocus.org/

GWPC and ALL Consulting (Ground Water Protection Council (GWPC) and ALL Consulting). (2009). Modern shale gas development in the United States: A primer. (DE-FG26-04NT15455). Washington, DC: U.S. Department of Energy, Office of Fossil Energy and National Energy Technology Laboratory. http://www.gwpc.org/sites/default/files/Shale%20Gas%20Primer%202009.pdf

Halliburton. (1988). Primer on Hydraulic Fracturing. Provided to EPA on March 2, 2011. Available at Docket ID: EPA-HQ-ORD-2010-0674-1634. (HESI-3031). Halliburton. http://www.regulations.gov/#!documentDetail;D=EPA-HQ-ORD-2010-0674-1634

Halliburton. (2013). Hydraulic fracturing 101. Available online at http://www.halliburton.com/public/projects/pubsdata/hydraulic_fracturing/index.html

Haymond, D. (1991). The Austin Chalk - An overview. HGS Bulletin 33: 27-30, 32, 34.

Holditch, SA. (2007). Chapter 8: Hydraulic fracturing. In JD Clegg (Ed.), Petroleum engineering handbook (pp. IV-323 - IV-366). Richardson, TX: Society of Petroleum Engineers. http://store.spe.org/Petroleum-Engineering-Handbook-Volume-IV-Production-Operations-Engineering-P61.aspx

Hyne, NJ. (2012). Nontechnical guide to petroleum geology, exploration, drilling and production. In Nontechnical guide to petroleum geology, exploration, drilling and production (3 ed.). Tulsa, OK: PennWell Corporation.

IHS (Global Insight). (2009). Measuring the economic and energy impacts of proposals to regulate hydraulic fracturing. Prepared for American Petroleum Institute. Lexington, MA: IHS Global Insight. http://s3.amazonaws.com/propublica/assets/natural_gas/ihs_gi_hydraulic_fracturing_task1.pdf

IOGCC (Interstate Oil and Gas Compact Commission). (2002). States experience with hydraulic fracturing. A survey of the interstate oil and gas compact commission. IOGCC (Interstate Oil and Gas Compact Commission). http://energyindepth.org/docs/pdf/IOGCC%20Hydraulic%20Fracturing%20Study%2007-2002.pdf

IOGCC (Interstate Oil and Gas Compact Commission). (2015). Groundwork: hydraulic fracturing - state progress. Available online at http://groundwork.iogcc.ok.gov/topics-index/hydraulic-fracturing/state-progress

Kargbo, DM; Wilhelm, RG; Campbell, DJ. (2010). Natural gas plays in the Marcellus Shale: Challenges and potential opportunities. Environ Sci Technol 44: 5679-5684. http://dx.doi.org/10.1021/es903811p

King, GE. (2012). Hydraulic fracturing 101: What every representative, environmentalist, regulator, reporter, investor, university researcher, neighbor and engineer should know about estimating frac risk and improving frac performance in unconventional gas and oil wells. SPE Hydraulic Fracturing Technology Conference, February 6-8, 2012, The Woodlands, TX.

Kundert, D; Mullen, M. (2009). Proper evaluation of shale gas reservoirs leads to a more effective hydraulic-fracture stimulation. Paper presented at SPE Rocky Mountain Petroleum Technology Conference, April 14-16, 2009, Denver, CO.

Lee, DS; Herman, JD; Elsworth, D; Kim, HT; Lee, HS. (2011). A critical evaluation of unconventional gas recovery from the marcellus shale, northeastern United States. K S C E Journal of Civil Engineering 15: 679-687. http://dx.doi.org/10.1007/s12205-011-0008-4

Lowe, T; Potts, M; Wood, D. (2013). A case history of comprehensive hydraulic fracturing monitoring in the Cana Woodford. In 2013 SPE annual technical conference and exhibition. Richardson, TX: Society of Petroleum Engineers. http://dx.doi.org/10.2118/166295-MS

Miskimins, JL. (2008). Design and life cycle considerations for unconventional reservoir wells. In 2008 SPE Unconventional Reservoirs Conference. Richardson, TX: Society of Petroleum Engineers. http://dx.doi.org/10.2118/114170-MS

Montgomery, C. (2013). Fracturing fluid components. In A Bunder; J McLennon; R Jeffrey (Eds.), Effective and Sustainable Hydraulic Fracturing. Croatia: InTech. http://dx.doi.org/10.5772/56422

Montgomery, CT; Smith, MB. (2010). Hydraulic fracturing - History of an enduring technology. J Pet Tech 62: 26-32.

NETL (National Energy Technology Laboratory). (2013). Modern shale gas development in the United States: An update. Pittsburgh, PA: U.S. Department of Energy. National Energy Technology Laboratory. http://www.netl.doe.gov/File%20Library/Research/Oil-Gas/shale-gas-primer-update-2013.pdf

Newell, R. (2011). Shale gas and the outlook for U.S. natural gas markets and global gas resources. Presentation presented at US EIA presentation at OECD Meetings, June 21, 2011, Paris, France.

NPC (National Petroleum Council). (2011b). Plugging and abandonment of oil and gas wells. (Paper #2-25). Washington, DC: National Petroleum Council (NPC).

NYSDEC (New York State Department of Environmental Conservation). (2011). Revised draft supplemental generic environmental impact statement (SGEIS) on the oil, gas and solution mining regulatory program: Well permit issuance for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus shale and other low-permeability gas reservoirs. Albany, NY: NY SDEC. http://www.dec.ny.gov/energy/75370.html

Patzek, TW; Male, F; Marder, M. (2013). Gas production in the Barnett Shale obeys a simple scaling theory. PNAS 110: 19731-19736. http://dx.doi.org/10.1073/pnas.1313380110

Pearson, CM; Griffin, L; Wright, CA; Weijers, L. (2013). Breaking up is hard to do: creating hydraulic fracture complexity in the Bakken central basin. In 2013 SPE hydraulic fracturing technology conference. Richardson, TX: Society of Petroleum Engineers. http://dx.doi.org/10.2118/163827-MS

Pearson, K. (2011). Geologic models and evaluation of undiscovered conventional and continuous oil and gas resourcesUpper Cretaceous Austin Chalk, U.S. Gulf Coast. In US Geological Survey Scientific Investigations Report. (20125159). U.S. Geological Survey. http://pubs.usgs.gov/sir/2012/5159/

Rassenfoss, S. (2011). From flowback to fracturing: Water recycling grows in the Marcellus shale. J Pet Tech 63: 48-51.

Renpu, W. (2011). Advanced well completion engineering (Third ed.). Houston, TX: Gulf Professional Publishing.

Ross, D; King, G. (2007). Well completions. In MJ Economides; T Martin (Eds.), Modern fracturing: Enhancing natural gas production (1 ed., pp. 169-198). Houston, Texas: ET Publishing.

Saba, T; Mohsen, F; Garry, M; Murphy, B; Hilbert, B. (2012). White paper: Methanol use in hydraulic fracturing fluids. (1103844.000 0101 0711 TS26). Maynard, MA: Exponent.

Schlumberger (Schlumberger Limited). (2006). Fundamentals of formation testing. Sugar Land, Texas. http://www.slb.com/~/media/Files/evaluation/books/fundamentals_formation_testing_overview.pdf

Schlumberger (Schlumberger Limited). (2014). Schlumberger oilfield glossary. Available online at http://www.glossary.oilfield.slb.com/

Shires, T; Lev-On, M. (2012). Characterizing pivotal sources of methane emissions from unconventional natural gas production - summary and analysis of API and ANGA survey responses. Washington, DC: American Petroleum Institute. American Natural Gas Alliance.

Spellman, FR. (2012). Environmental impacts of hydraulic fracturing. In Environmental impacts of hydraulic fracturing. Boca Raton, Florida: CRC Press.

STO (Statoil). (2013). Shale facts: drilling and hydraulic fracturing, how it's done, responsibly. (Global Version, April 2013). Stavanger, Norway. http://www.statoil.com/no/OurOperations/ExplorationProd/ShaleGas/FactSheets/Downloads/Shale_DrillingHydraulicFacturing.pdf

Thompson, AM. (2010) Induced fracture detection in the Barnett Shale, Ft. Worth Basin, Texas. (Master's Thesis). University of Oklahoma, Norman, OK.

U.S. EPA (U.S. Environmental Protection Agency). (2012d). Oil and natural gas sector: standards of performance for crude oil and natural gas production, transmission, and distribution. Background supplemental technical support document for the final new source performance standards. Washington, D.C. http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf

U.S. EPA (U.S. Environmental Protection Agency). (2012f). Study of the potential impacts of hydraulic fracturing on drinking water resources: Progress report. (EPA/601/R-12/011). Washington, DC: U.S. Environmental Protection Agency, Office of Research and Development. http://nepis.epa.gov/exe/ZyPURL.cgi?Dockey=P100FH8M.txt

U.S. EPA (U.S. Environmental Protection Agency). (2013c). Inventory of U.S. greenhouse gas emissions and sinks: 1990-2011. Washington, DC: U.S. Environmental Protection Agency, Office of Atmospheric Programs. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf

U.S. EPA (U.S. Environmental Protection Agency). (2014e). Greenhouse gas reporting program, Subpart W - Petroleum and natural gas systems. Washington, D.C.

U.S. EPA (U.S. Environmental Protection Agency). (2015a). Analysis of hydraulic fracturing fluid data from the FracFocus chemical disclosure registry 1.0 [EPA Report]. (EPA/601/R-14/003). Washington, D.C.: Office of Research and Development, U.S. Environmental Protection Agency. http://www2.epa.gov/hfstudy/analysis-hydraulic-fracturing-fluid-data-fracfocus-chemical-disclosure-registry-1-pdf

U.S. EPA (U.S. Environmental Protection Agency). (2015b). Analysis of hydraulic fracturing fluid data from the FracFocus chemical disclosure registry 1.0: Project database [EPA Report]. (EPA/601/R-14/003). Washington, D.C.: U.S. Environmental Protection Agency, Office of Research and Development. http://www2.epa.gov/hfstudy/epa-project-database-developed-fracfocus-1-disclosures

U.S. EPA (U.S. Environmental Protection Agency). (2015g). Inventory of U.S. greenhouse gas emissions and sinks: 1990-2013. (EPA 430-R-15-004). Washington, D.C. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Main-Text.pdf

U.S. EPA (U.S. Environmental Protection Agency). (2015n). Review of well operator files for hydraulically fractured oil and gas production wells: Well design and construction [EPA Report]. (EPA/601/R-14/002). Washington, D.C.: Office of Research and Development, U.S. Environmental Protection Agency.

U.S. GAO (U.S. Government Accountability Office). (2012). Energy-water nexus: Information on the quantity, quality, and management of water produced during oil and gas production. (GAO-12-156). Washington, D.C. http://www.gao.gov/products/GAO-12-156

URS Corporation. (2011). Water-related issues associated with gas production in the Marcellus shale: Additives use flowback quality and quantities regulations on-site treatment green technologies alternate water sources water well-testing. (NYSERDA Contract PO Number 10666).

USGS (U.S. Geological Survey). (2000). Coal-bed methane: Potential and concerns [Fact Sheet]. (Fact Sheet 123-00). http://pubs.usgs.gov/fs/fs123-00/fs123-00.pdf

USGS (U.S. Geological Survey). (2002). Natural gas production in the United States [Fact Sheet]. (USGS Fact Sheet FS-113-01). Denver, CO.

USGS (U.S. Geological Survey). (2013a). Map of assessed shale gas in the United States, 2012. http://pubs.usgs.gov/dds/dds-069/dds-069-z/

USGS (U.S. Geological Survey). (2014a). Energy glossary and acronym list. Available online at http://energy.usgs.gov/GeneralInfo/HelpfulResources/EnergyGlossary.aspx#t

USGS (U.S. Geological Survey). (2015). Trends in hydraulic fracturing distributions and treatment fluids, additives, proppants, and water volumes applied to wells drilled in the United States from 1947 through 2010data analysis and comparison to the literature. (U.S. Geological Survey Scientific Investigations Report 20145131). Reston, VA. http://dx.doi.org/10.3133/sir20145131

Vidas, H; Hugman, B. (2008). Availability, economics, and production potential of North American unconventional natural gas supplies. (F-2008-03). Washington, DC: The INGAA Foundation, Inc. http://www.ingaa.org/File.aspx?id=7878

Vincent, M. (2011). Restimulation of unconventional reservoirs: when are refracs beneficial? Journal of Canadian Petroleum Technology 50: 36-52. http://dx.doi.org/10.2118/136757-PA

Wang, Z; Krupnick, A. (2013). A retrospective review of shale gas development in the United States. What let to the boom? (RFF DP 13-12). Washington, DC: Resources for the Future. http://www.rff.org/RFF/documents/RFF-DP-13-12.pdf

Weijermars, R. (2014). US shale gas production outlook based on well roll-out rate scenarios. Appl Energ 124: 283-297. http://dx.doi.org/10.1016/j.apenergy.2014.02.058

Yergin, D. (2011). The quest : energy, security and the remaking of the modern world. In The quest : energy, security and the remaking of the modern world. New York, NY: Penquin Press.