

Advanced Well Stimulation Technologies

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This section provides background information on the currently available well-treatment technologies for increasing the rate of oil flow from the reservoir to the well. This type of treatment is called well stimulation and is used for situations where the natural reservoir flow characteristics are not favorable and need to be improved for effective oil recovery. The review covers the materials and methods used to perform the three commonly used well stimulation methods: (1) hydraulic fracturing, (2) acid fracturing, and (3) matrix acidizing. In addition this section reviews the materials and methods used to perform well drilling, construction, and completion which also play a role in well stimulation. The main points identified here that are used in subsequent sections to help understand the application of well stimulation technologies for oil production in California are:

(1) The design of a hydraulic fracture is a function of reservoir flow and mechanical characteristics. Reservoirs that have relatively better flow characteristics (within the range of these characteristics where well stimulation is needed) and are relatively weak mechanically tend to require less intensive fracturing, which leads to a relatively smaller volume of fracture fluid used. Reservoirs that have relatively poor flow characteristics and are relatively strong mechanically tend to require more intensive fracturing, which leads to a relatively larger volume of fracture fluid used.

(2) Acid fracturing is commonly limited in application to carbonate reservoirs, i.e., those rich in limestone and dolomite. This is significant because California's oil resources are primarily found in silica-rich rock rather than carbonate rock.

(3) Matrix acidizing for silica-rich reservoirs typically has a very limited penetration distance from the well into the reservoir. Therefore matrix acidizing in silica-rich rock has a limited effect on larger-scale reservoir flow characteristics, with the possible exception of reservoirs where natural fracture flow paths are effective in which acidizing may open up natural fractures by dissolving plugging material.

The term stimulation with respect to petroleum production refers to a range of activities used to increase the production of oil from petroleum reservoirs (a body of rock containing oil in pore spaces or natural fractures) by increasing the permeability of the materials through which oil flows to the well. There are two distinct situations that lead to the use of stimulation technologies. The first is damage induced by well drilling and construction and through oil production operations (Economides, Hill, Ehlig-Economides, and Zhu, 2013). Damage may occur in the form of blockage of perforations in the well casing

through which oil flows, e.g., by scale formation (mineral precipitation) or sand production from the reservoir into the well (Ghalambor and Economides, 2002). Damage can also occur to the rock in the immediate vicinity of the well as a result of mechanical disturbances and chemical interaction with the fluids (drilling mud) used during the drilling of the well bore. For example pores may be plugged as a result of drilling mud plugging the rock pores, migration of fine particles in the rock, or swelling of clays in the rock (Ghalambor and Economides, 2002). Mechanical damage in the form of crushing and compaction of the rock may occur as a result of creating the perforations through the casing, a process carried out by literally shooting a projectile through the steel casing to punch holes to connect the well to the reservoir (Ghalambor and Economides, 2002). Techniques to correct these adverse impacts of well construction by clearing blockages in the well, or restoring the permeability of the rock, are termed *well stimulation*.

The term *stimulation* also refers to the use of techniques to enhance the natural permeability of the undisturbed rock containing the reservoir (a rock formation) to the point that it can provide economic rates of oil production (permeability is the ability of the rocks to conduct fluid including oil or water). In this event, stimulation technologies may be applied that increase reservoir permeability sufficiently to allow enhanced rates of oil production. This stimulation is also on occasion termed *well stimulation*, but is perhaps more precisely called *reservoir stimulation* (Economides et al., 2013). However throughout the remainder of this report, the focus will be on stimulation technologies whose purpose is to increase reservoir permeability, and these technologies will be referred to by the term *well stimulation* (WST), or simply *stimulation*. This is in accord with the definition of well stimulation in section 3157 of Division 3 of Chapter 1 of the California Public Resources Code.

This report section presents a review of stimulation technologies for increasing reservoir permeability. This section does not review stimulation technologies used to repair damage induced by well drilling and oil production.

2.1 The Purpose of Stimulation Technologies

As described above the production of oil from a reservoir depends on reservoir permeability, but it is also a function of the thickness of the reservoir, viscosity of the oil produced, well radius, and other factors. As a result, an exact permeability threshold for the use of WST does not exist (Holditch, 2006). However, the likelihood that well stimulation is needed to economically produce oil increases as the reservoir permeability falls below 1 millidarcy (md) ($9.87 \times 10^{-16} \text{ m}^2$ or $1.06 \times 10^{-14} \text{ ft}^2$) (e.g., King, 2012).

An oil reservoir is typically classified as *unconventional* if well stimulation is required for economical production. Guidelines concerning the classification of petroleum resources (World Petroleum Council, 2011) categorize a reservoir as unconventional if it is spatially extensive and yet not significantly affected by natural flow processes. The oil in the Bakken play in North Dakota is an example of such an accumulation. A different and quantitative definition proposed by Cander (2012) is shown in Figure 2-1, in which the

permeability of the reservoir and viscosity of the oil are used to define conventional and unconventional. This definition is a more useful guide to the conditions amenable to well stimulation, in part because it does not include the geographic aspect (“large area”) of the first definition.

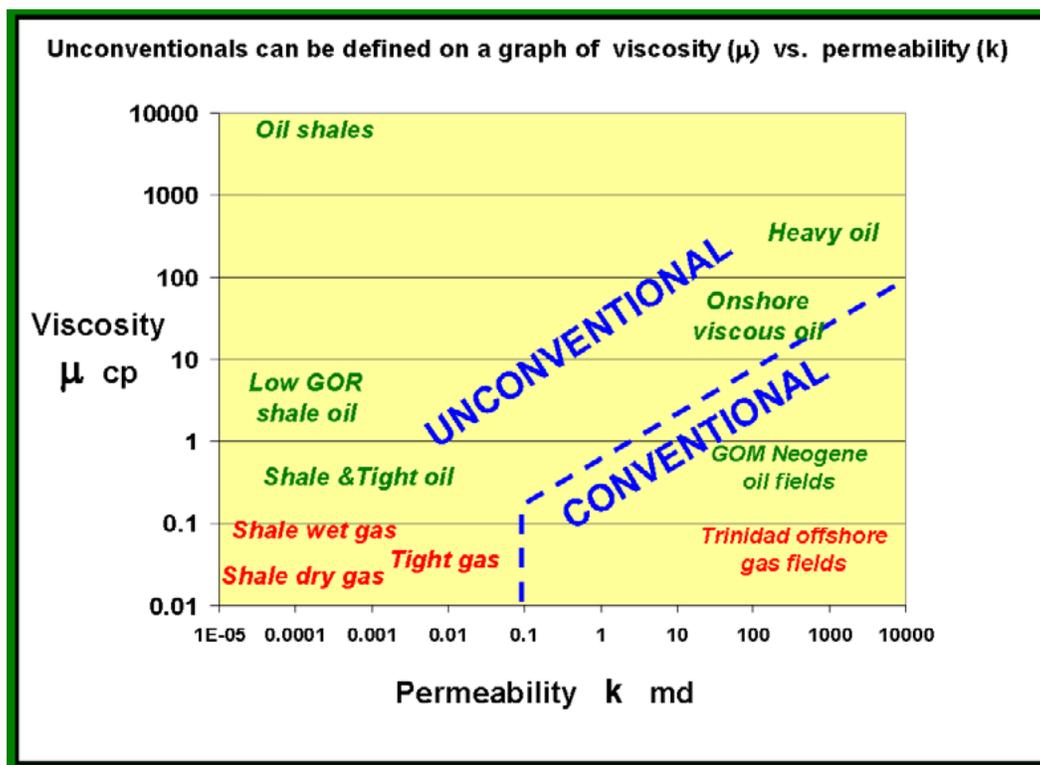


Figure 2-1. Definition of unconventional hydrocarbon resource (Cander, 2012)

The threshold between conventional and unconventional is defined by practical considerations. Unconventional resources require the use of technology to alter either the rock permeability or the fluid viscosity in order to produce the oil at commercially competitive rates. Conversely, conventional resources can be produced commercially without altering permeability or viscosity (Cander, 2012). This report focuses on WST for reservoirs that are unconventional due to low permeability, but this definition of unconventional oil resources also highlights methods for reservoirs that are unconventional due to high oil viscosity. Thermal methods are used to allow production of exceedingly viscous oil (Prats, 1982). Such hydrocarbons are called “viscous oil” or “heavy oil.” Thermal methods lower oil viscosity by heating the reservoir, most commonly through steam or hot water injection (Farouq Ali, 2003). According to the California Division of Oil, Gas and Geothermal Resources (DOGGR), a majority of the oil produced onshore in California now involves steam injection (DOGGR, 2010).

There are three main WST: hydraulic fracturing either utilizing proppant (traditional hydraulic fracturing) or acid (also known as acid fracturing) and matrix acidizing. (Economides and Nolte, 2000). Because these methods do not reduce oil viscosity, they are primarily targeted at tight (low permeability) rock formations containing gas or lower-viscosity oil, although they may be used in combination with thermal stimulation for heavy oil.

The main technologies currently used for the production of most unconventional reservoirs are horizontal drilling combined with some form of hydraulic fracturing (McDaniel and Rispler, 2009). Because of this close association, horizontal wells are also discussed in this report. Relatively simple geologic systems have nearly horizontal deposition and layer boundaries and typically have much longer dimensions along the direction of bedding as compared with the dimension perpendicular to bedding. Horizontal drilling allows a well to access the reservoir over a longer distance than could be achieved with a traditional vertical well. An example of horizontal and vertical wells is shown in Figure 2-2 for the Eagle Ford play in Texas, which consists of a calcium-carbonate rich mudstone called a marl. In this case, the horizontal well intercepts about 5,000 m (16,400 ft) of reservoir as compared with about 80 m (262 ft) by the vertical well.

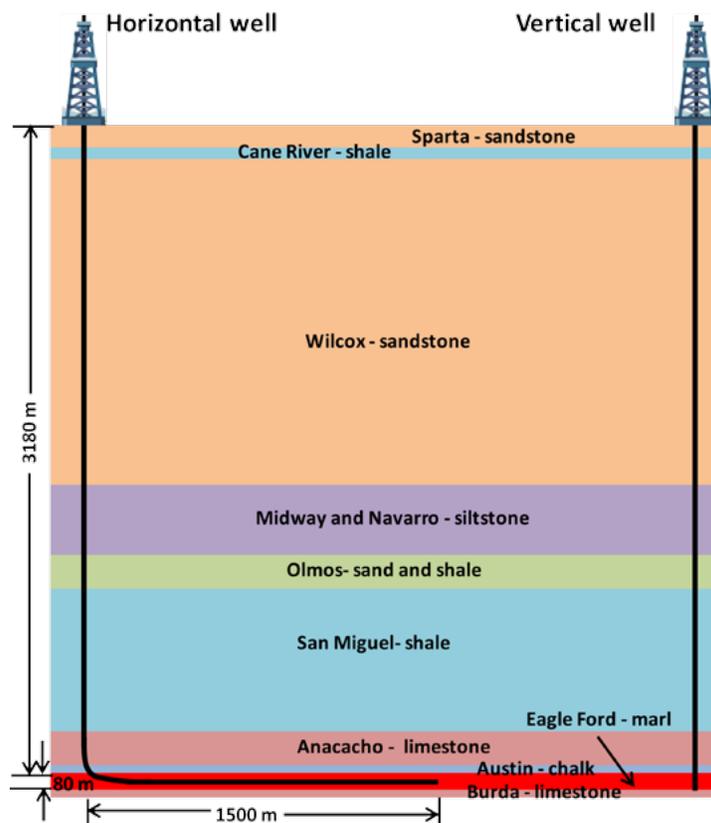


Figure 2-2. Example of horizontal and vertical wells in the Eagle Ford play (stratigraphy from Cardneaux (2012))

Hydraulic fracturing induces fractures by injecting fluid into the well until the pressure exceeds the threshold for fracturing. The induced fractures emanate from the well into the reservoir and provide a high-permeability pathway from the formation to the well, as shown on Figure 2-3. One of the goals of the fracturing operation is to only fracture rock within the target reservoir. After fracturing, a fine granular material (e.g., sand) known as a “proppant,” is introduced into the fractures to prevent the natural overburden stress (compressive) from closing the fractures after the injection pressure is removed. The creation of a highly permeable fracture network connecting the reservoir to the well significantly reduces the average distance that oil must migrate through the low-permeability reservoir rock in order to reach the well. Another variation of hydraulic fracturing is called acid fracturing, where acid is injected instead of proppant. The acid etches channels into the fracture surfaces which then prevents the natural overburden stress from closing the fractures and allows fluid flow pathways to remain along the fractures even after the injection pressure is removed.

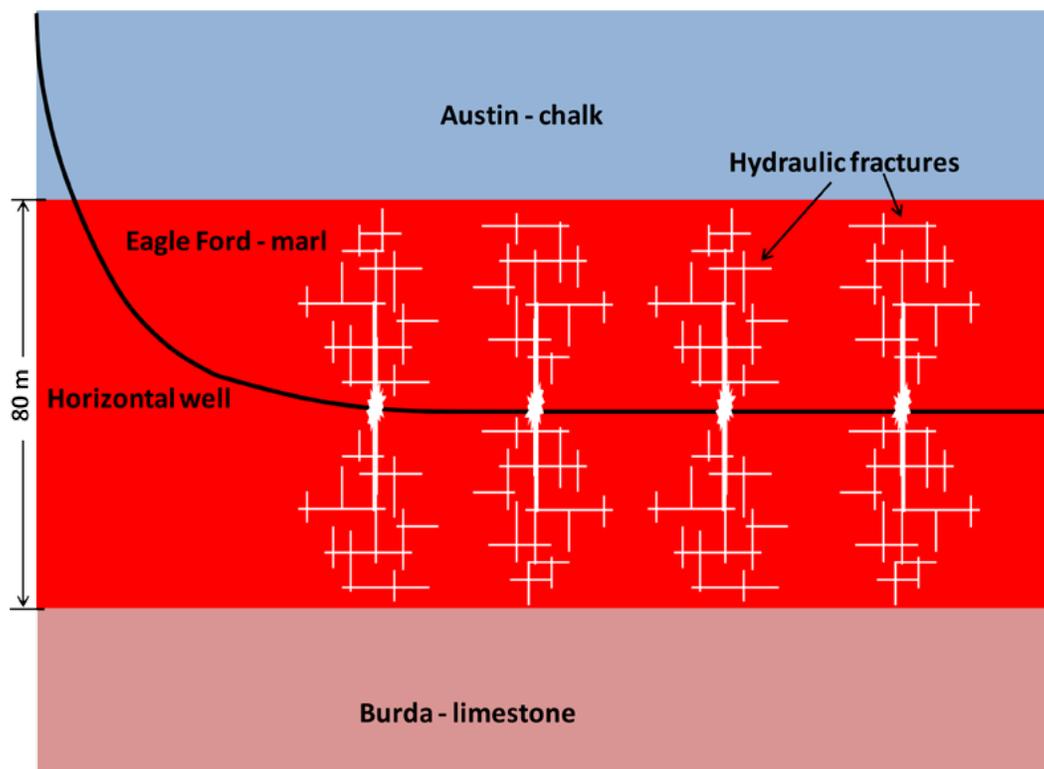


Figure 2-3. Hydraulic fractures initiated from a series of locations along a cased and perforated horizontal well.

Matrix acidizing involves injecting acidic fluids at pressures below the fracture pressure, such that the acid dissolves acid-soluble minerals in the rock matrix. The end result is enhanced flow pathways through the rock matrix. By comparison, however, the penetration into the formation of enhanced permeability caused by matrix acidizing is not typically as extensive as it is after hydraulic fracturing with proppant or acid. The two important exceptions in carbonate reservoirs are the creation of more deeply penetrating channels, known as wormholes, and deeper acid penetration into more permeable fractures of naturally fractured reservoirs (Economides et al., 2013).

Well drilling and construction, hydraulic fracturing, and matrix acidizing are discussed in more detail below.

2.2 Well Drilling and Construction

Well drilling, construction, and completion are necessary steps for conducting production operations from the vast majority of hydrocarbon reservoirs (some shallow hydrocarbon deposits, such as oil sands, can be mined from the surface). Well construction involves the installation of well casing and cement that seals the annular space between the casing and the formation as drilling proceeds. Well casing and cement provide the main barriers against contamination of groundwater by native (e.g., deeper and more saline groundwater), injected, or produced fluids during well operation

Well completion following construction configures and optimizes the well for hydrocarbon production. Completion includes (as needed) sand control, perforation of the production casing, and installation of production tubing. As mentioned above, completion can also include well stimulation to remove formation damage caused by drilling, construction, and other completion activities.

2.2.1 Vertical Wells

Until the 1980s, the vast majority of oil wells were drilled as vertical wells (US Energy Information Administration (EIA), 1993). Although the use of horizontal-well technology has steadily increased since that time, vertical wells are still being drilled for oil production. (Horizontal wells, discussed in Section 2.2.2, are an important technological development for production from unconventional reservoirs.)

Nearly all oil wells (vertical or horizontal) are drilled using the rotary drilling method (Culver, 1998; Macini, 2005). The first major oil discovery using rotary drilling was made at Spindletop near Beaumont, Texas, in 1901 (Geehan and McKee, 1989). There are a number of other methods used to drill wells in general, but most of these alternative methods are used for wells less than 600 m deep (ASTM, 2014) and therefore are not suitable for most oil wells, which average over 1,500 m deep in the US (US EIA, 2014).

2.2.1.1 Rotary Drilling Process and Drilling Muds for Onshore Oil Wells

The rotary drilling process is conducted from a drilling rig at the ground surface. The drill bit and other components, such as weights called drill collars, make up the bottom-hole assembly that is connected to the first section of drill pipe, and then is put in place below the drilling rig floor to begin. The drill pipe is connected to a square or hexagonal pipe called the “kelly.” The kelly is turned by a motor via the rotary table in the floor of the drilling rig and a kelly bushing that connects to the kelly. Alternatively, a newer system known as “top drive” can be mounted to the rig derrick that turns the drill pipe (Macini, 2005). In either case, the rotational coupling with the drill string (collectively the drill pipe and bit) permits vertical movements such that the desired downward force can be applied to the drill bit while it is rotating. (More recent technology has led to the development of downhole motors which drive rotation of the drill bit; therefore, rotation of the drill pipe is not required. This technology is particularly important for directional drilling and will be discussed further in Section 2.2.2.) When the hole has been drilled deep enough to hold the bottom-hole assembly and drill pipe, another section of pipe is added and the process is repeated.

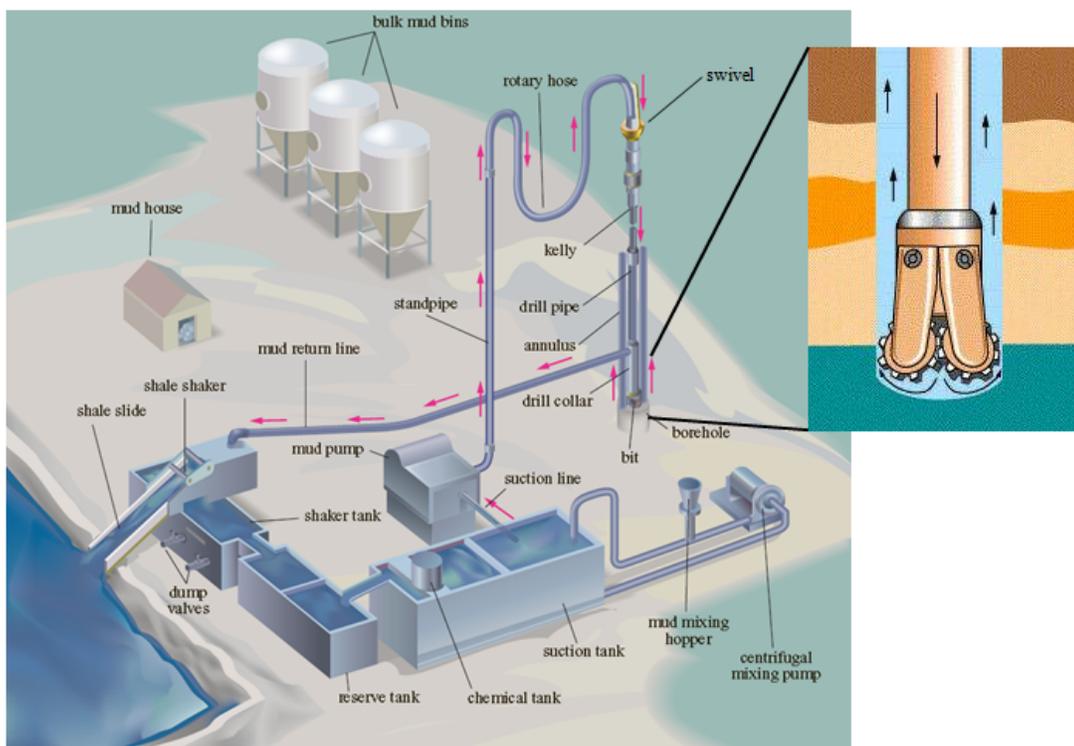


Figure 2-4. Drilling mud circulation system. Arrows indicate mud flow direction (modified from Macini (2005) and Oil Spill Solutions (2014))

As drilling proceeds, the bit is supplied with drilling mud, which is denser and more viscous than water, through a nonrotating hose that connects to the top of the kelly through a connection called a swivel. Drilling mud flows down the drill string and exits through ports on the face of the drill bit. This action flushes drill cuttings away from the drilling face and up the annulus between the drill pipe and the borehole wall or casing pipe. The circulating mud exits the annulus and is recycled back to the well after the cuttings have been separated from the mud (Varhaug, 2011). Figure 2-4 shows the components of the drilling mud circulation system.

Drilling muds have several important functions. As mentioned previously, the mud continuously cleans the cuttings off the bit face and transports them out of the hole. In the same vein, the mud limits the rate at which cuttings settle in the borehole annulus, so that the drill bit is not quickly buried by cuttings whenever the mud flow is temporarily stopped. The mud also serves to lubricate and cool the drill bit. Finally, the mud provides hydraulic pressure to help stabilize the borehole walls and control native fluid pressures in the rock, to prevent an uncontrolled release (blowout) of these fluids through the borehole. The energy of the flowing drilling mud also drives the bit rotation when a downhole motor is used.

There are three basic types of drilling muds: (1) aqueous-based mud; (2) hydrocarbon-based mud; and (3) gas, aerated, or foam muds (Khodja, Khodja-Saber, Canselier, Cohaut, and Bergaya, 2013), in which the classification is based on the predominant fluid in the mud. One of the critical factors that influences the choice of mud used is the clay content of shale encountered by the borehole. Shales make up about 75% of drilled formations, and about 70% of borehole problems can be associated with shale instability (Lal, 1999). Clay hydration caused by water-based muds often lead to reduced rock strength and instability in the borehole. This can result in a variety of problems, including borehole collapse, tight borehole, stuck pipe, poor borehole cleaning, borehole washout, plastic flow, fracturing, and lost circulation and well control (Lal, 1999). Furthermore, borehole wash-out in the shale sections can result in problems for cementing the casing in these sections and impedes the ability to isolate zones and control leakage along the well outside the casing (Brufatto et al., 2003; Chemerinski and Robinson, 1995). Because of these issues surrounding interaction of water with shale, oil-based muds are considered more suitable for drilling through shale. However, because of environmental issues associated with the use and disposal of drilling muds, more suitable water-based muds for drilling through shale continue to be developed (Deville et al., 2011). Another strategy used to minimize the environmental effects of drilling muds is to use water initially to penetrate the freshwater aquifer zone, then progress to more complex, water-based inhibitive muds, and then to oil-based muds at greater depth (Williamson, 2013).

2.2.1.2 Well Casing and Cementing

Wells are secured at discrete intervals as the borehole is being drilled by installing a steel pipe with diameter slightly smaller than the borehole diameter. This pipe, termed casing,

is then fixed in place by filling the annulus between the pipe and the borehole wall with cement. After installing the casing, the pathway for fluid movement along the borehole is restricted to the circular interior of the casing. The casing provides mechanical support to prevent borehole collapse and hydraulically isolates flow inside the casing from the rock formations around the well. Furthermore, the casing, in combination with the cement, impedes fluid movement along the borehole outside the casing between the different formations encountered, as well as to the ground surface. This function is referred to as “zonal isolation” (Nelson, 2012; Bellabarba et al., 2008).

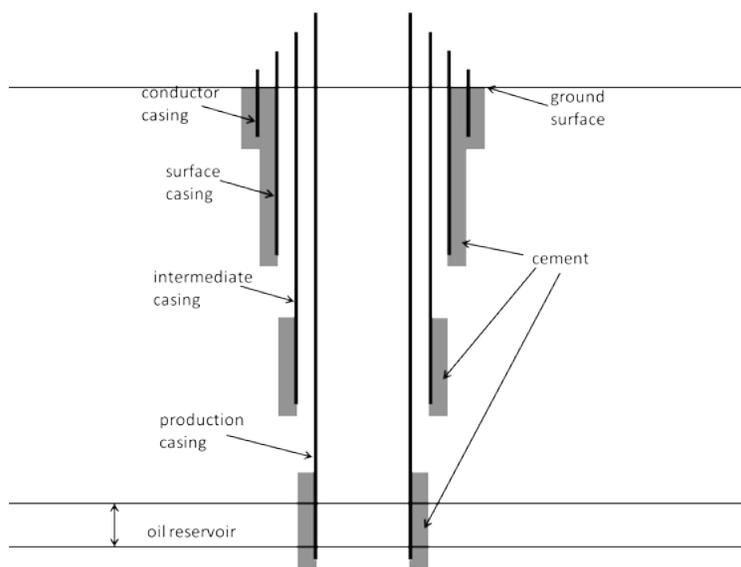


Figure 2-5. Schematic cross section of well casing and cement configuration. Casing extends above ground surface for connection to wellhead. (Redrawn and modified from API, 2009)

Zonal isolation is accomplished by filling the annulus between the casing and the formation with cement, which bonds the casing to the formation. There are different types of cements that are used depending on conditions of depth, temperature, pressure, and chemical environment (Lyons and Plisga, 2005). Cement placement and curing processes have to address numerous factors for the cement to be an effective barrier to fluid movement behind the casing (American Petroleum Institute (API), 2010). After placement and curing of the cement, API guidelines recommend that each section of cemented casing is pressure tested to ensure that the cement is capable of withstanding the pressures to be used during well operations (API, 2009 and 2010). Furthermore, wireline logging tools should be run after the cement job to verify that the well is correctly cemented and there are no hydraulic leakage paths. This is accomplished using acoustic tools (sonic and ultrasonic) that can determine the quality of the cement bond and can detect channels (API, 2009; Griffith et al., 1992).

The first casing to be installed is called the conductor casing (essentially a pipe with diameter larger than any of the other casings in the well), shown in Figure 2-5. This casing prevents the typically weak surficial materials from collapsing into the drill hole. The conductor casing is either driven into the ground by a pile driver or placed in the hole after drilling (API, 2009). The length of the conductor casing is normally 30 to 50 m (98.4 to 164 ft) (Macini, 2005), but generally less than 91 m (299 ft) in length (Burdylo and Birch, 1990). If the conductor pipe is not cemented, it is not strictly considered as part of the well casing (Macini, 2005).

The next casing installed is called the surface casing. The purpose of the surface casing is to protect freshwater aquifers from drilling mud and fluids produced during the life of the well, and to isolate these zones from overlying and underlying strata. The surface casing is necessarily smaller in diameter than the conductor casing and is typically about 91 m (299 ft), but can extend farther up to about 305 m (1,000 ft) in depth (King, 2012). Once the target depth for the surface casing is reached, the surface casing is inserted into the borehole and the annulus between the casing and the borehole wall and conductor casing are cemented. The casing extends from the bottom of the hole to the ground surface.

The surface casing (or conductor casing if it is cemented) is used to anchor the wellhead, which provides the interface between the well and equipment attached to the wellhead above the ground surface. During drilling operations, an operational and safety valve system called a blowout preventer is attached to the wellhead. After drilling is complete, the blowout preventer is replaced by a different valve system called a Christmas tree, which is used for production operations (Macini, 2005).

Drilling then proceeds until the next casing, which could be the production casing or an intermediate casing (needed for deeper wells). In either situation, the next section of casing is assembled and inserted into the borehole, and the annulus is cemented. The production casing is the last section of casing that either enters the reservoir (if the production is to be done through an open hole) or extends throughout the production interval of the borehole. In some instances, a production liner is used that does not extend the full length of the hole. Instead, the liner hangs off the base of and is sealed to the intermediate casing and is not always cemented.

The casing is subject to hydraulic and mechanical stress, including axial tension caused by its own weight as well as dynamic stresses caused by installation and operational activities, external fluid pressures from the formation during cementing operations, and internal fluid pressure during drilling and operations. Thermal stresses are also present. These stresses need to be taken into account when selecting casing type and size (Lyons and Plisga, 2005). For systems that will be used for hydraulic fracturing, the high levels of fluid pressure imposed also need to be taken into account for casing selection (API, 2009).

Cementing the annulus of the casing is essential for control of leakage along the well outside the casing. After a casing segment has been put into the borehole, cement is injected to displace the drilling mud. Oilfield cements are calcium silicate type (Portland) cements containing additives depending on well depth, temperature, and pressure conditions, borehole rock characteristics, and chemical environment (Economides, Watters, and Dunn-Norman, 1998).

Additives are used for a variety of reasons, including altering the curing time, controlling water loss and solids/water separation, and preventing gas migration—among other things. Water loss and curing reactions that result in shrinkage cracking have been identified as significant factors leading to leakage behind the casing (Dusseault et al., 2000). Various polymers are typically used to prevent water loss (Economides et al., 1998), and magnesium oxide is used to cause an expansion of the cement upon curing (Joy, 2011). The ability of the cement to withstand stresses and borehole flexure without fracturing is increased by the addition of elastomeric fibers such as polypropylene (Sounthararajan, Thirumurugan, and Sivakumar, 2013; Shahriar, 2011).

After the desired volume of cement has been introduced to the well, drilling mud is again added to continue driving the cement through the well. When the cement reaches the bottom of the hole, the cement continues to displace the mud ahead of it upward along the outside annulus of the casing. The injection ends when the cement fills the annulus to the top of the casing. Deep intermediate or production casings may not be cemented to the top of the casing. This is because the high fluid pressure associated with the dense cement slurry over these longer intervals can fracture the formation (King, 2012). Once the cement sets, the residual cement and any remaining items from the cement operation that are at the bottom of the hole are drilled out to continuing deepening the borehole. A simple schematic of the casing and cement configuration is shown in Figure 2-5.

A number of problems can occur that lead to incomplete cementing around the casing. These include mixing of the cement and the drilling mud, poor displacement of the drilling mud by the cement, off-center casing that contacts the borehole wall, and gas migration through the cement prior to setting (American Petroleum Institute, 2010; King, 2012). Any of these could lead to incomplete cement behind the casing and the potential for leakage along the casing. To avoid mixing between the cement and the drilling mud, a chemical washer is injected ahead of the cement to help clean out the drilling mud and provide a fluid gap between the cement and the drilling mud. Wiper plugs are placed just in front of and behind the cement slug that is injected, also to prevent cement contamination by the drilling mud (Nelson, 2012). Casing centralizers are used to position the casing in the middle of the borehole to avoid trapping mud between the casing and the borehole wall (leading to mud channels in the cement). Additives are used to reduce cement shrinkage and permeability during setting, and to accelerate setting times, to avoid gas migration problems in the cement (Bonett and Pafitis, 1996).

Leakage along wells is considered the most likely route for injected fracturing fluids or reservoir fluids to migrate into overlying strata (King, 2012). Both casing and cement design need to account for any operational pressures and chemical environments that may occur during well stimulation. If the design is not adequate, leakage can result. Leakage along wells as a potential contamination pathway is described in Section 5.1.3.

2.2.2 Directional Drilling and Horizontal Wells

Directional drilling was initially developed in the late 1920s and 1930s (Gleason, 1934; Kashikar, 2005). Directional drilling refers to well construction with at least one section that has a curved axis. A horizontal well is a special case of a directional well in which the well axis is curved by 90 degrees from the vertical followed by a straight horizontal section, also referred to as a lateral. The technology required several improvements before it started to be utilized the 1970s; its application became widespread by the 1990s (Williams, 2004). By the end of 2012, 63% of wells drilled in the U.S. were horizontal, 11% were directional, and only 26% were vertical (Amer et al., 2013).

2.2.2.1 Drilling Process and Drilling Muds

The operations discussed for vertical wells generally apply to the initial phases of drilling a well that will include intentionally curved deeper sections. Directional drilling begins at a kick-off point after the initial vertical section is drilled. One of the first methods developed for establishing a deviation in direction used a mechanical device known as a whipstock, which is a wedge-shaped tool placed in the bottom of the hole that forces the drill to deviate from the vertical direction (Giacca, 2005). A major improvement in directional drilling was the development of steerable systems that use a downhole motor, in which the energy of the drilling fluid can be used to drive bit rotation. The steerable system eliminates the need for a whipstock for directional or horizontal wells. In this system, the direction of the drill bit is bent slightly relative to the drill string axis. Drilling by rotating the drill string causes the bit to drill in a straight line aligned with the drill string. By setting the drill string at a fixed angle and turning the bit through the energy of the drilling mud flow, the angle between the bit and the drill pipe can be maintained. The bit is rotated using the positive-displacement motor and drills ahead at the angle set by the position of the drill string, which does not rotate, and slides behind the bit. This method creates a somewhat tortuous borehole when drilling curved sections, making drilling more difficult, as well as greater difficulty in formation evaluation and running casing (Williams, 2004).

The latest technology, called rotary steerable drilling, allows for continuous drill-string rotation in curving and straight sections. Changes in direction are imposed by either a point-the-bit system similar to the bent steerable system just discussed, or a push-the-bit system in which pressure is applied by pushing against the borehole wall (Downton et al., 2000). The key difference is that the rotary steerable system mechanics allow continuous rotation of the drill string and produces much smoother and less tortuous curved boreholes. The greatest advantage of a rotary steerable system is that continuous

rotation reduces the friction between the drill string and the formation, allowing better transfer of weight to the bit. Sliding (i.e., no rotation) results in less weight on bit and much slower drilling. Control of the drilling direction is done from the surface by sending signals to steering actuators at the drill bit through a series of pressure pulses in the drilling mud (Giacca, 2005), a process referred to as mud pulse telemetry (MPT) (Downton et al., 2000).

In addition to development of improved directional control (inclination and azimuth) and borehole quality, there has been the development of methods to measure the local temperature and pressure conditions, as well as the orientation and motion of the drill bit. This measurement technique is referred to as “measurement while drilling” (MWD), and the information is transmitted to the surface using MPT (Downton et al., 2000; Amer et al., 2013). Thus, the conditions and path of the drill bit is known in real time to help control the drilling process. More recently, sophisticated technology to perform formation evaluation measurements, such as resistivity, gamma ray, sonic, and magnetic resonance measurements, have been integrated into the drilling process and may also be received in real time through MPT (Amer et al., 2013). For drilling in shales, the inclination, azimuth, and gamma ray activity are the most critical data. The information on borehole trajectory and changes in the formation allow for “geosteering,” in which directional drilling is actively controlled using real-time data to properly position the borehole relative to the target formation.

The various drilling muds discussed for drilling of vertical wells are also used for directional drilling. The demands of high-angle and horizontal drilling, and extensive drilling path lengths through shales for unconventional reservoirs, result in greater use of oil-based drilling muds. However, alternative water-based muds for these conditions are being developed because of the greater environmental risks and costs associated with oil-based muds. Success using water-based muds requires development of custom formulations based on the specific reservoir rock and conditions to be encountered (Deville et al., 2011).

Directional wells can be drilled with long, medium, or short radius curves. The longer-radius wells are typically used when the objective is extended horizontal reach (thousands of meters), while medium and short radius wells are used when a shorter horizontal leg (~1,000 m for medium radius and up to 300 m for short radius) is needed, and/or when highly accurate placement is necessary (Giacca, 2005). Directional drilling also allows for the construction of multilateral wells where a single vertical bore is used to kick off one or more lateral legs from a cased hole (Fraija et al., 2002; Bosworth et al., 1998). The lateral leg is initiated using a whipstock and a milling assembly to cut a well lateral from a cased hole (Fraija et al., 2002; Bosworth et al., 1998). The advances in directional drilling technology discussed here have also led to greater capabilities in terms of well depth and lateral drilling distances. Horizontal wells have been drilled to lateral distances in excess of 10 km (32,800 ft) (Sonowal et al., 2009). True vertical well depths up to about 7 km (23,000 ft) have been achieved for horizontal wells with lateral reach up to about 3 km (9,840 ft) (Agbaji, 2009; Bakke, 2012).

2.2.2.2 Well Casing and Cement

The casing and cementing of the vertical section of a directional well are the same as described in Section 2.2.1.2. There is, however, greater variation in the casing and cementing configurations used for horizontal wells. This variation is in part driven by the hydraulic fracturing approach utilized, so the description of horizontal well completions is given in the next section.

2.3 Hydraulic Fracturing

Hydraulic fracturing in general is a relatively old technology for improving gas and oil field production rates. However, there has been a significant evolution of this technology. As discussed in the introduction, the focus of this review effort is on hydraulic fracturing as a means to enhance reservoir permeability.

Hydraulic fracturing was first implemented in 1949; since this time, use of this stimulation method has grown substantially (Montgomery and Smith, 2010). Originally, hydraulic fracturing was used exclusively as a well stimulation method, applied in cases where the natural reservoir permeability was too low for economic petroleum recovery. But in the 1990s, hydraulic fracturing started to be used for higher-permeability reservoirs as a method to remediate formation damage around wells (Ghalambor and Economides, 2002). The general permeability levels used to distinguish high and low permeability reservoirs, which is also influenced by the viscosity of the oil, is shown in Figure 2-1.

Unlike California (Section 3), the main classes of reservoirs where hydraulic fracturing has been used intensively in other areas of the United States are very low permeability, unconventional shale reservoirs and tight-gas sand reservoirs, accounting for over 73% of the hydraulic fracturing activity (Beckwith, 2010). Most of the unconventional shale reservoirs contain natural gas, with the exceptions of the Eagle Ford, which produces oil in the shallower portion of the formation, and the Bakken and Niobrara plays, which mainly contain oil.

The typical hydraulic fracture operation involves four process steps to produce the fractures (Arthur et al., 2008). The long production intervals present in most horizontal wells leads to a staged approach to hydraulic fracturing. For the staged approach, a portion of the well is hydraulically isolated in order to focus the injected fracture fluid pressure on an isolated interval, which is called a “stage.” After isolating the stage, the first phase of the fracturing process is the “pad,” in which fracture fluid is injected without proppant to initiate and propagate the fracture from the well. The second phase adds proppant to the injection fluid; the proppant is needed to keep the fractures open after the fluid pressure dissipates. This phase is also used to further open the hydraulic fractures. The third phase, termed the “flush,” entails injection of fluid without proppant to push the remaining proppant in the well into the fractures. The fourth phase is the “flowback,” in which the hydraulic fracture fluids are removed from the formation, and fluid pressure dissipates. Examples of the stages of hydraulic fracturing including the time spent for each phase is given in Section 2.3.7.

An acid preflush is sometimes used prior to injection of the pad. For instance, Halliburton's (2014) fracture-fluid-composition disclosure indicates it is used in about half of their specific formulations (DOE, 2009). The acid preflush may be needed to remove scale, help clean drilling mud and casing cement from perforations, and to weaken the rock to help initiate a fracture (King, 2010; Halliburton, 2014; DOE, 2009). Prior to injecting the acid, corrosion inhibitor, at a level of 0.2 to 0.5% by mass, is added to the fluid to prevent acid corrosion of steel components, such as the casing (DOE, 2009; King, 2010). The pre-flush acid concentrations range from 7.5 to 15% HCl, and volumes range from 0.946 to 26.5 m³ (33.4 to 936 ft³ or 250 to 7,000 gallons) per stage (Halliburton, 2014) injected at a relatively low rate below the fracture pressure.

In the following sections, aspects of hydraulic fracture geomechanics and the attributes of hydraulic fracture fluids and proppants are presented. In addition, the alternative to proppant use for carbonate reservoirs, called "acid fracturing," is discussed further. Following these discussions of the physical mechanisms and materials involved, various engineering alternatives for completion and isolation of the stages and information on the phases of the fracturing process are discussed.

2.3.1 Hydraulic Fracture Geomechanics, Fracture Geometry, and the Role of Natural Fractures and Faults

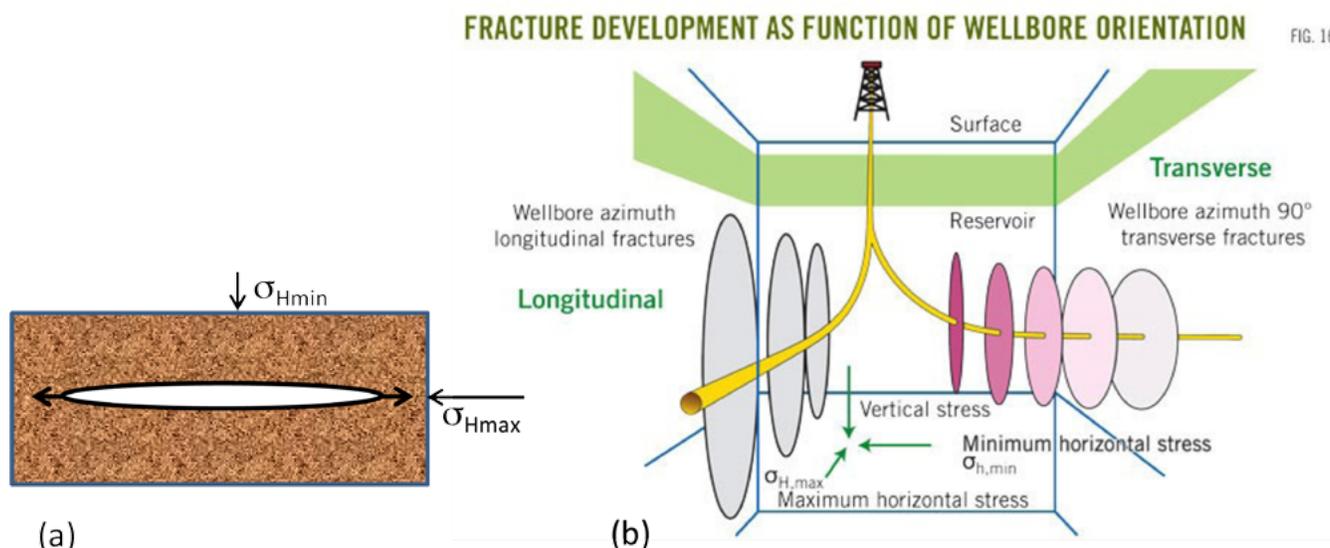


Figure 2-6. Fracture patterns for different orientations of the borehole relative to principal compressive stresses: (a) fractures open in the direction of the minimum principal stress, (b) effects of horizontal well alignment with maximum and minimum horizontal principal stresses (Rahim et al., 2012)

Fluid pumped into deep underground rocks at sufficient pressure will cause the rock to break or “fracture”. The technical description of conditions that result in such hydraulic fractures is this: fractures are formed when fluid pressure exceeds the existing minimum rock compressive stress by an amount that exceeds the tensile strength of the rock (Thiercelin and Roegiers, 2000). The operator cannot easily control the orientation of the hydraulic fractures. Rather, it is the stress conditions in the rock that will determine the orientation. Rocks at depth experience different amounts of compression in different directions. Because the compressive stress in rock often varies with direction, the hydraulic fracture will preferentially push open against the least compressive stress for a rock with the same strength in all directions (Economides et al., 2013). Therefore, the fracture plane develops in the direction perpendicular to the minimum compressive stress, as shown on Figure 2-6.

If the compressive stress in the rock were the same in all directions (or nearly so), then the orientation of the fracture would tend to be random. In addition to stress orientation, rock strength varies and fracture geometry also depends on the variation in rock strength in different directions.

Finally, natural fractures are generally present to some degree in natural rock and affect the formation of hydraulic fractures. These features of the rock are often the pathways for hydraulic fractures (Weijermars, 2011). Gale and Holder (2010) found that fractures filled with secondary calcite in siliceous mudrocks are generally weaker than the surrounding rock and may be susceptible to reopening during hydraulic fracturing. However, fractures filled with secondary quartz may be stronger than the surrounding rock and hinder the development of hydraulic fractures. Williams-Stroud, Barker, and Smith (2012) found that shearing of existing fractures played a significant role in hydraulic fracturing, based on discrete fracture network modeling and microseismic measurements from a hydraulic fracturing field test.

Typically, conditions underground favor hydraulic fractures that are vertical. (Vertical fractures result because most rocks at depth experience greater vertical stress than horizontal stress.) Consequently, the question of the vertical fracture height growth is important when considering the potential migration of fracture fluid or other reservoir fluids out of the typically very low-permeability target oil reservoir. Thousands of microseismic measurements have been conducted in the Barnett, Woodford, Marcellus, and Eagle Ford shales to characterize hydraulic fractures. Fracture heights have been investigated over a range of reservoir depths from 1,220 to 4,270 m (4,000 to 14,000 ft) deep, and found that the tallest fractures formed in deeper sections. However, typical fracture heights are in the range of tens to hundreds of feet (Fisher and Warpinski, 2012). The maximum recorded fracture height from these reservoirs and the Niobrara shale was found to be 588 m (1,930 ft) (Davies et al., 2012) (see also Section 5.1.3.2.1). The statistics of fracture height from these measurements show that the probability of exceeding 350 m (1,150 ft) is about 1% (Davies et al., 2012). Fracture height is limited by a number of mechanisms, including variability of in situ stress, material property contrasts, weak

interfaces between layers, and the volume of fracture fluid required to generate extremely large fracture heights (Fisher and Warpinski, 2012). Finally, the minimum stress at shallow depths (305 to 610 m or 1,000 to 2,000 ft) is typically in the vertical direction, which contrasts with the typical minimum stress being horizontal at greater depth. This stress condition favors a horizontal fracture orientation, which tends to prevent vertical fracture growth from deeper into shallower depths (Fisher and Warpinski, 2012). Interaction of hydraulic fracture fluids with faults may also affect fracture height growth. Simulations of hydraulic-fracturing-induced fault reactivation were conducted by Rutqvist et al. (2013), who found fault rupture lengths to be less than 100 m (328 ft). Consequently, in general fault reactivation does not create permeable pathways far beyond the target reservoir (Flewelling et al., 2013). A fracture design that incorporates these factors into the selection of operational variables (pressure, injection rate, fluid type, etc.) for the hydraulic fracture means that fracture height is controllable to a reasonable degree.

Hydraulic fracture development is also affected by neighboring wells, which may undergo hydraulic fracture treatment at the same or at different times. This typically involves multiple parallel horizontal wells that are separated by 457 m (1,500 ft) or less (King, 2010). The fracturing can be carried out simultaneously or in sequence. The idea is to use the change in stress created by neighboring wells and stimulation treatments to alter fracturing directions and increase complexity in the fractures created. Differences in the effects of simultaneous and sequential fracturing are not large (King, 2010).

Fracture geometry also depends on other factors not related to rock mechanics per se, in particular on the magnitude of the stimulation pressure and the fracturing fluid viscosity. These are discussed in Section 2.3.2, where fracture fluids and operations are presented.

2.3.2 Hydraulic Fracture Fluids and their Effects on Fracture Geometry

The design of a hydraulic fracture requires specification of the type of hydraulic fracture fluid. While there are many additives used in hydraulic fracture fluids, most of these are used to mitigate adverse chemical and biological processes. The main property of hydraulic fracturing fluids that influence the mechanics of fracture generation is the viscosity¹. Both laboratory and field data indicate that low-viscosity fracture fluids tend to create complex fractures with large fracture-matrix area and narrow fracture apertures—as compared with higher viscosity fracture fluids, which tend to create simpler fractures with low fracture-matrix area and wide fracture apertures (Cipolla et al., 2010).

The lowest viscosity fracturing fluid is slickwater, which contains a friction-reducing additive (typically polyacrylamide) and has a viscosity on the order of 0.004 Pa-s (4 cp or 8.36×10^{-5} lbf-s/ft²) (about 4 times that of pure water) (Kostenuk and Browne, 2010).

¹ Viscosity is a fluid property that quantifies resistance to fluid flow. It takes little effort to stir a cup of water (viscosity ~ 1 centipoise (cp)), noticeably more effort to stir a cup of olive oil (viscosity ~ 100 cp), and significantly more effort to stir a cup of honey (viscosity ~ 10,000 cp).

Gelled fracture fluids generally use guar gum or cellulose polymers to increase viscosity (King, 2012). Further increases in viscosity can be achieved by adding a cross-linking agent to the gel that is typically a metal ion, such as in boric acid or zirconium chelates (Lei and Clark, 2004). The cross-linking binds the gel's polymer molecules into larger molecules and that causes an increase in the solution viscosity. Linear gels have viscosities about 10 times that of slickwater, and cross-linked gels have viscosities that are on the order of 100 to 1000 times larger (Montgomery, 2013). Fracture fluids energized using nitrogen and surfactant with linear gels (to create foams) lead to increased viscosity of the energized fluid over the linear gel, and the viscosity of energized cross-linked gels increase by factors of 3 to 10 over those not using a cross-linking agent (Ribeiro and Sharma, 2012; Harris and Heath, 1996). The type of fracture fluid also affects the ability to emplace proppant (see Section 2.3.3). In particular, cross-linked gels are better for transporting proppant than slickwater (Lebas et al., 2013). The effective viscosity is also influenced by the proppant concentration (Montgomery, 2013).

In general fracture length and fracture-network complexity decrease as the viscosity of the fracturing fluid increases as illustrated on Figure 2-7 (Cipolla, Warpinski, and Mayerhofer, 2010; Rickman, Mullen, Petre, Grieser, and Kundert, 2008). Fracture lengths also increase with the volume of injected fracture fluid. Flewelling et al. (2013) found that fracture length could be represented as approximately proportional to fracture height with a proportionality factor that ranged from 0.5 to 1. Fracture apertures (or widths) are on the order of a few tenths of an inch (Barree et al., 2005; Bazan, Lattibeaudiere, and Palisch, 2012) and tend to increase with viscosity, rate, and volume of the fluid injected (Economides et al., 2013).

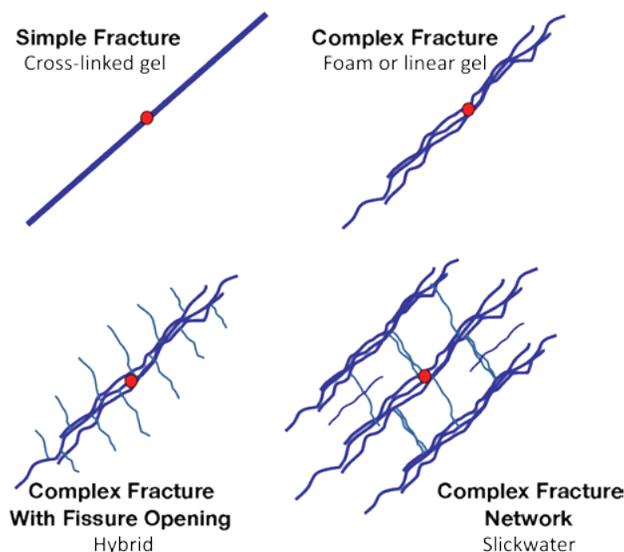


Figure 2-7. Effects of fracture fluid viscosity on fracture complexity (modified from Warpinski, Mayerhofer, Vincent, Cippola, and Lolon (2009)).

The type of fluid used depends on the properties of the reservoir rock, specifically the rock permeability and brittleness (Cipolla et al., 2010; Rickman et al., 2008). Formations with higher intrinsic permeability (but still low enough to warrant hydraulic fracturing) are generally stimulated using a higher-viscosity fracture fluid to create a simpler and wider fracture (Cipolla et al., 2010). The rationale for this selection is that the fracture is needed mainly to help move the fluids as they converge closer to the well, but are able to flow adequately to the fracture farther out in the formation. As reservoir permeability decreases, the resistance to fluid movement through the unfractured portion of the formation increases. Therefore, a denser fracture pattern (narrower spacing between the fractures) is needed to minimize the distance that reservoir fluids must flow in the rock matrix to enter the hydraulically induced fractures (Economides et al., 2013). This leads to the use of lower-viscosity fracturing fluids to create more dense (and complex) fracture networks.

The choice of fracture fluid also depends on rock brittleness (Rickman et al., 2008). Wider fracture apertures are needed as rock brittleness decreases (or as ductility increases) because of the greater difficulty maintaining fracture permeability after pressure is withdrawn (Rickman et al., 2008). Therefore, rock permeability and brittleness both influence the choice of fracturing fluid. Stimulation of natural fractures is also thought to be critical for effective hydraulic fracture treatment in very low permeability shales (Warpinski, Mayerhofer, Vincent, Cippola, and Lolon, 2009; Cramer, 2008; Fisher et al., 2005). Although these characteristics may lead to conflicting requirements for the fracturing fluid, permeability is often found to be lower in brittle rocks and higher in ductile rocks (Economides et al., 2013), and natural fractures are usually more prevalent in brittle rock as compared to ductile rock. Natural fractures in shales can be sealed by secondary minerals. Such fractures do not have much influence on the natural permeability, although in some cases can preferentially reactivate during hydraulic fracturing (Gale and Holder, 2010).

The general trends in fracture fluid types, fluid volumes used, and fracture complexity as a function of rock properties are shown in Figure 2-8. This figure shows that hydraulic fracturing in ductile, relatively higher permeability reservoir rock having low natural fracture density tends to receive a hydraulic fracture treatment using a viscous cross-linked gel with a relatively low volume of fluid injected but a large concentration and total mass of proppant. The fracture response in this case tends to produce a simple single fracture from the well into the rock that has a relatively large aperture filled with proppant. As rock brittleness and degree of natural fracturing increase, and as permeability decreases, hydraulic fracturing treatments tend to use a higher-volume, lower viscosity fracture fluid that carries less proppant. The response of the rock to this fracture treatment is to create more complex fracture networks in which the fractures have relatively narrower apertures and a more asymmetric cross-section in the vertical direction as a result of limited proppant penetration. In short, ductile and more permeable rocks usually receive gel fracture treatments while more brittle, lower permeability rocks with existing fractures are more amenable to slickwater fracturing.

rock characteristics			fracture treatment			fracture response		
brittleness	permeability	natural fractures	frac fluid viscosity	frac fluid volume and flow rate	proppant concentration and volume	fracture complexity	fracture width	fracture width closure profile
brittle ↑ ductile	low < 0.1 μd ↓ high ~ > 1 md	highly fractured ↑ minimal	low ↓ high slickwater ↓ hybrid ↓ linear gel ↓ foam ↓ cross-linked gel	high ↑ low	low ↓ high	network ↑ planar	narrower ↓ wider	asymmetric ↓ symmetric 

Figure 2-8. General trends in rock characteristics, hydraulic fracture treatment applied, and hydraulic fracture response (modified from Rickman et al. (2008)).

Fracture fluids may contain several other additives in addition to those already identified. These include biocides, corrosion inhibitors, clay stabilizers, and polymer breakers (Kaufman et al., 2008). Example concentrations for slickwater and gelled fracture fluids are given in 2- 9.

A summary of the various types of additives is given in Table 2-1. In some cases, acids are injected as a separate pre-flush before injection of the hydraulic fracture pad in order to clean out the casing perforations, help clean out the pores near the well, and dissolve minerals, to aid in initiating fractures in the rock (DOE, 2009). More detailed descriptions of the chemicals used in hydraulic fracturing fluids are given in Section 5.1.2.1.

Recycling of fracture fluid is one way to reduce the amount of water required for hydraulic fracturing. The principal issue involved is that recycled fracturing fluid develops high concentrations of dissolved salts that become highly saline brines. One approach has been the development of more salt-tolerant additives, such as polymers used for slickwater friction reducers (Paktinat et al., 2011). Other processes are also being developed to aid in the reuse of fracturing fluids (Ely et al., 2011).

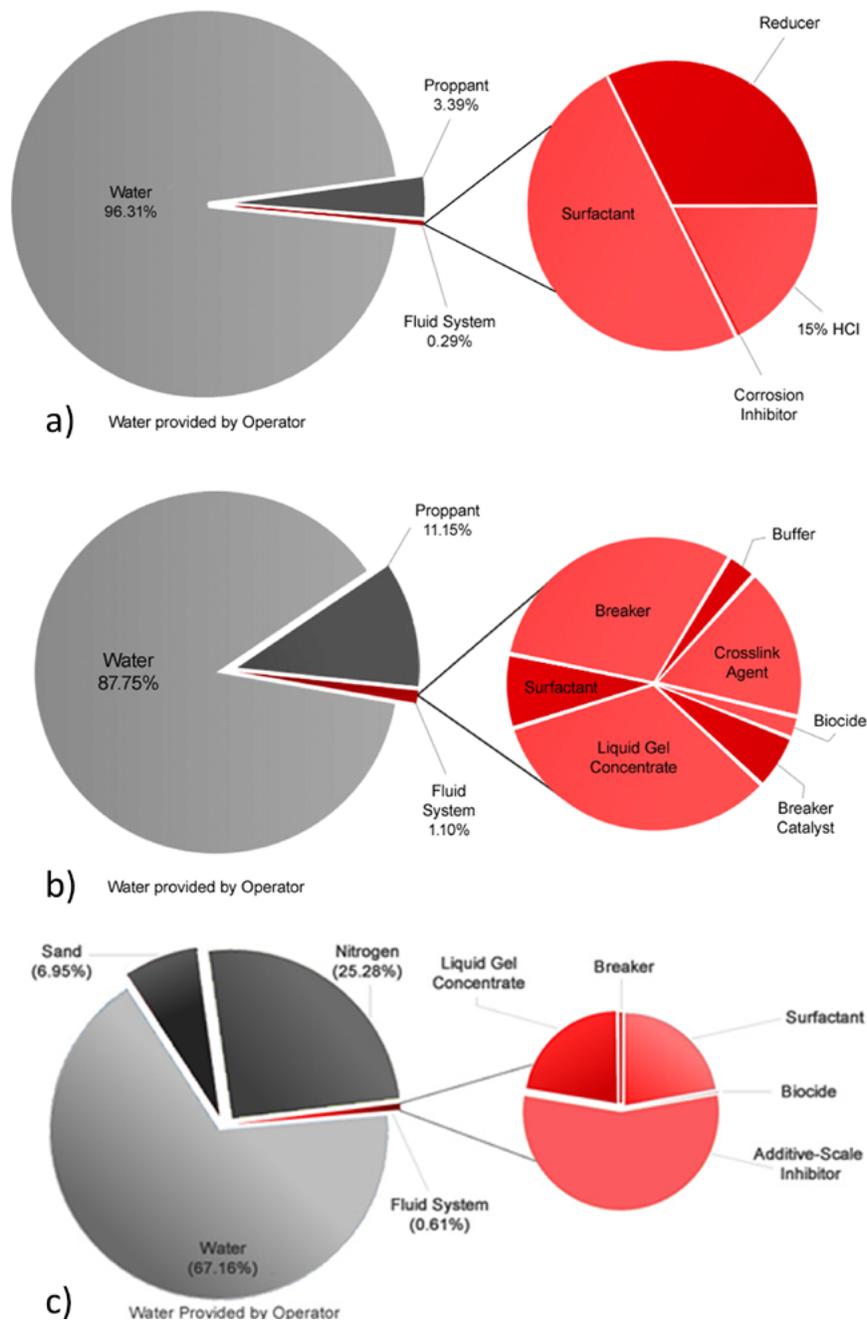


Figure 2-9. Example compositions of fracture fluids a) Colorado DJ Basin WaterFrac Formulation – a slickwater fracturing fluid; b) Utah Vertical Gel Frac Formulation – a cross-linked gel fracturing fluid; c) Pennsylvania FoamFrac Formulation – a gelled nitrogen foam fracturing fluid (source: Halliburton, 2014). Note: although not stated on the website, comparisons of these compositions with information on fracture fluid compositions given on the FracFocus (2014) website indicate these values are percent by mass.

Table 2-1. Additives to Aqueous Fracture Fluids (NYSDEC, 2011)

Additive Type	Description of Purpose	Examples of Chemicals
Proppant	"Props" open fractures and allows gas / fluids to flow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Removes cement and drilling mud from casing perforations prior to fracturing fluid injection	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulfates
Bactericide / Biocide / Antibacterial Agent	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde; 2,2-dibromo-3-nitripropionamide
Buffer / pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers	Sodium or potassium carbonate; acetic acid
Clay Stabilizer / Control /KCl	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g., tetramethyl ammonium chloride Potassium chloride (KCl)
Corrosion Inhibitor (including Oxygen Scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol; ammonium bisulfate for Oxygen Scavengers
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Potassium hydroxide; borate Salts
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamide (PAM); petroleum distillates
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum; petroleum distillates
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid
Scale Inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene Glycol
Solvent	Additive which is soluble in oil, water and acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions	Various aromatic hydrocarbons
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol; isopropanol; ethoxylated alcohol

Alternative fracture fluids are also under investigation. Some of the purposes of alternative fluids are to reduce water use and to reduce formation-damage effects sometimes caused by aqueous fracture fluids and by additives such as gels. These alternatives include supercritical² CO₂ and supercritical CO₂-nitrogen mixtures, CO₂ foam, nitrogen, liquid

propane (LPG), and explosive propellant systems (EPS) (Rogala et al., 2013). These systems generally eliminate or greatly reduce the amount of water involved in fracturing, with attendant benefits according to Rogala et al. (2013) of elimination or reduction of

- Formation-damage effects associated with water sensitivity;
- Formation damage associated with water and chemical (particularly gels) remaining in the reservoir;
- Chemical additives and their environmental effects; and
- Flowback waste water disposal.

Despite the advantages from a water perspective, there are several disadvantages according to Rogala et al. (2013), including,

- Transport and handling of pressurized CO₂ with potential for leakage into the atmosphere;
- Relative difficulty to transport proppant in the fracture, particularly for nitrogen;
- Added problems working with surface pressures/increased injection pressures for CO₂, nitrogen, foams and LPG;
- Risk of explosion with LPG;
- Greater cost except for EPS; and
- Lower fracture lengths for EPS (10 to 50 m).

2.3.3 Proppants

After injecting the hydraulic fracture pad, the proppant is injected in with the hydraulic fracture fluid. As mentioned, proppants are a solid granular material, such as sand, that act to keep the fractures from closing after hydraulic fracture fluid pressure is released. Proppant size and size distribution are key factors affecting the permeability of proppant-filled fractures. Larger, more uniformly sized proppants result in the greatest permeability. Proppant grain sizes generally lie in the range of 10^{-4} to 2×10^{-3} m (3.28×10^{-4} to 6.56×10^{-3} ft) in diameter (Horiba Scientific, 2014).

² *Supercritical CO₂ exists when the temperature and pressure are above the critical temperature (31° C, 88° F) and critical pressure (7.4 MPa, 1070 psi). Supercritical CO₂ is a fluid that has properties between those of a gas and a liquid.*

In addition to these characteristics, the transportability and strength of the proppant also affect the ultimate fracture permeability. The ability of the proppant to be transported by a given fracture fluid depends in part on the proppant size and density. Greater transportability is desirable because it allows for delivery of proppant deep into the formation fractures. Proppants that are smaller and have a lower density are more easily transported (Economides et al., 2013).

Proppant strength is also important. If the closure stress of the fracture exceeds the compressive strength of the proppant, the proppant grains will be crushed. This reduces the effective proppant size and thus the permeability of the fracture.

The most common proppant is natural sand that has been sieved to a uniform size class (Beckwith, 2011). A number of alternative synthetic proppants have been used as well, including sintered bauxite and ceramics. Ceramic and bauxite proppants can be manufactured to have different mass densities and compressive strengths, and the size and shape can be tightly controlled to produce highly uniform grains (Lyle, 2011). Various types of resin coatings have also been used with all types of proppants, including sand (Beckwith, 2011). Resin coatings can be pre-cured or curable on the fly. Pre-cured resin coatings are used to improve proppant strength and to prevent movement of broken proppant fines. Cureable resin coatings are intended to bond proppant together after placement to help prevent proppant flowback during the flowback phase of the fracturing process and during hydrocarbon production (Beckwith, 2011).

The transport of proppant also impacts the choice of hydraulic fracture fluids. Lower-viscosity fluids are not as capable of delivering proppants and generally are used with lower proppant concentrations during the proppant-injection phase of the operations. Higher proppant settling in lower viscosity fluids will tend to deposit proppant in the lower parts of the fracture as compared with higher viscosity fluids (Cipolla et al., 2010). This is indicated schematically on the right-hand side of Figure 2-8. Furthermore, proppant delivery is more problematic in the more complex fracture networks created by lower-viscosity fracture fluids. Therefore, lower-viscosity fracture fluids are sometimes replaced after injection of the pad with high-viscosity fluids to more effectively deliver proppant. The use of two or more different fracture fluids during the same fracturing event is called a hybrid treatment. Slickwater fracture treatments may only deliver a sparse amount of proppant, resulting in conductivity dominated by the unpropped fracture conductivity (Cipolla et al., 2010). The success of such a treatment may hinge on other factors such as the rock compressive stress varying with direction and the presence of natural fractures being “self-propped” as a result of shearing of the fracture surfaces (Cipolla et al., 2010).

2.3.4 Acid Fracturing

An alternative to the use of proppant to maintain fracture conductivity is to inject hydrochloric acid under fracture pressures. This method is called acid fracturing and is

only applicable to strongly reactive carbonate reservoir rock types. The acid etches the faces of the fracture surfaces. The presence of the etched channels allows fractures to remain permeable even after the fracture-fluid pressure is removed and compressive rock stress causes the fractures to close (Economides et al., 2013). Acid fracturing is sometimes preferred in carbonate reservoirs because of the relatively high degree of natural fractures generally present and the difficulties of placing proppant because of fluid leak-off into the natural fracture system. Acid fractures generally result in relatively short fractures as compared with fractures secured with proppant; therefore, it is generally more successful in higher-permeability formations (Economides et al., 2013).

2.3.5 Completions and Multistage Hydraulic Fracturing

As mentioned, multistage hydraulic fracturing refers to the application of the hydraulic fracturing process to multiple, hydraulically isolated intervals along the production interval of the well. Fracturing of a well's entire production interval at once can result in an uneven distribution of fractures. Slight variations in rock strength result in the fracturing fluid flow focused on the weakest rock along the well. The multistage fracturing process allows for greater control over where fractures are generated and produces a more uniform distribution of fractures along the production interval.

The conduct of multistage hydraulic fracturing requires that the completion used in the production interval is capable of stage isolation. The two most common completions used for multistage hydraulic fracturing are cemented liner and uncemented liner (Snyder and Seale, 2011). The cemented liner involves installation of the liner and cementing the annulus following the process discussed in Section 2.2.1.2. For the cemented liner, the cement isolates the annulus between the liner and the rock for multistage hydraulic fracturing. An uncemented liner is called an open-hole completion because of the open annulus outside the liner. However, isolation along the annulus for multi-stage fracturing can still be obtained through the use of a series of hydraulically set mechanical packers that are attached to the outside of the liner (Snyder and Seale, 2011). McDaniel and Rispler (2009) presents a discussion of a wider array of completion configurations for horizontal wells stimulated by hydraulic fracturing.

Multistage stimulation starts at the far end of the production interval first. For blank (unperforated) liners, openings in the liner for communication with the rock are generated using a perforating gun. This device sets off a set of shaped charges. Each shaped charge shoots a fast-moving jet of metal particles that makes a hole (perforation) that penetrates the casing, casing cement, and a short distance (~ 0.4 to 0.9 m or 1.31 to 2.95 ft) into the rock formation (Bell and Cuthill, 2008; Brady and Grace, 2013; Renpu, 2008). The process of multistage hydraulic fracturing using a perforating gun, called "plug and perf," provides the greatest control on placement of fractures. Beginning at the far end of the production interval where a set of perforations are opened, the fracture fluid (pad and fracturing fluid/proppant mixture) is injected and fractures the rock. Then a bridge plug is set that seals off the perforated and fractured segment from the remainder of the

production interval. The next set of perforations is then opened and fractured. This is repeated along the entire production interval (Snyder and Seale, 2011). After all stages have been fractured, the bridge plugs are drilled out to conduct flowback and oil production.

Perforation patterns are typically shot in clusters separated by 10.7 to 22.9 m (35 to 75 ft) or more (King, 2010). Each cluster is 0.305 to 0.71 m (1 to 2 ft) in length with about 20 perforations per meter (6 perforations per foot). The idea of a cluster is to initiate one main fracture from each cluster; the multiple perforations within a cluster help to find the easiest fracture initiation point. With the narrow spacing between perforations in a cluster, only one fracture will grow, because of the effects of the fracture on the local stress field that tend to suppress any other fractures trying to emerge from the cluster (King, 2010). For a typical stage interval of 61 or 91.4 m (200 or 300 ft), this results in about 4 to 7 clusters per stage. The plug and perf and sliding sleeve completions for a horizontal lateral are shown in Figure 2-10.

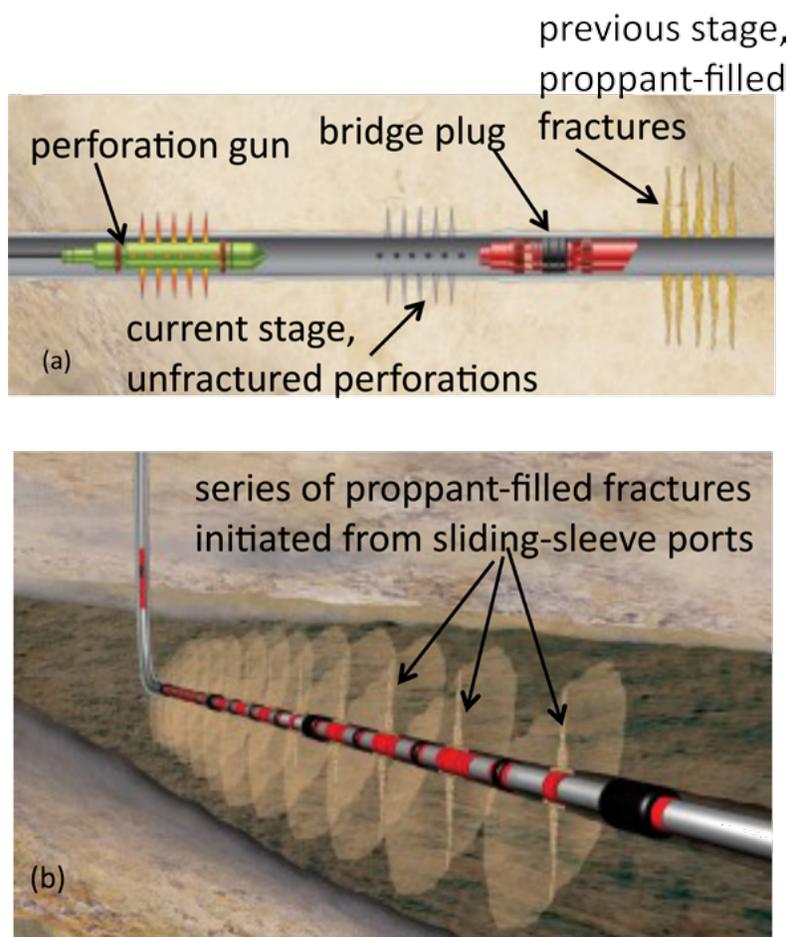


Figure 2-10. Horizontal well completion. a) plug and perf ; b) sliding sleeve (source: Allison (2012))

Open-hole completions can also be accomplished using a sliding-sleeve liner which has pre-set ports that can be opened by size-specific actuator balls (Snyder and Seale, 2011). Multistage fracturing is conducted by dropping a series of actuator balls for each fracturing stage that simultaneously opens the pre-set ports in the uncemented liner and also seals off the far end of the production interval. After performing the fracturing operation, the next actuator ball is dropped and the next section is fractured. This is repeated along the entire production interval (Snyder and Seale, 2011). The actuator balls, which act like check valves, are recovered during the flowback phase after all stages have been fractured. Even more complex sliding sleeve liners can be used in which each sliding sleeve can be individually opened or closed from the surface through remote hydraulic actuators.

2.3.6 Fracturing Fluid Flowback

As mentioned, flowback is the fourth phase of a hydraulic fracturing operation. The flowback rates are typically high (0.00795 to 0.0159 m³/s, equivalent to 3 to 6 bbl/min) initially because of the high-pressure charge just delivered to the reservoir. However, these rates typically decrease quickly to less than 0.00265 m³/s (1 bbl/min) after 24 hours, and to 0.0002 to 0.002 m³/s (100 to 1,000 bbl/day or 4,600 to 46,000 gallons/day) after 2 or 3 weeks (King, 2012).

Natural formation brines get mixed with the recovered fracturing fluid and affect the composition of the flowback fluid. The natural formation waters of petroleum reservoirs often contain high levels of dissolved solids, organic components from contact with *in situ* hydrocarbons, and frequently higher levels of naturally occurring radioactive materials (NORM). The concentrations of dissolved solids, organics, and radioactive materials can be high because of dissolution of these constituents into the formation water during prolonged contact with rock and hydrocarbon (Guerra, Dahm, and Dundorf, 2011; Zielinski and Otton, 1999). These aspects are discussed in greater detail in Section 5.1.2.5.

Very few well-documented cases of detailed flowback rates and composition have been found. One of the more detailed analyses of flowback rates and composition that has been identified is for the Marcellus shale in Pennsylvania, an unconventional gas resource (Hayes, 2009). The flowback rate and total dissolved solids concentration for a particular case are shown in Figure 2-11. The input fracturing-fluid total-dissolved-solids composition ranges from 221 to 27,800 ppm, where higher levels may be due to recycling of fracturing fluid. The rapid increase in total dissolved solids during flowback indicates that a substantial amount of formation brine is mixing with fracturing fluid in the flowback stream after a few days of flowback (Haluszczak, Rose, and Kump, 2013). Another mechanism that can increase the salinity of the flowback is the dissolution of salt or other minerals from the formation into the fracturing fluid (Blauch, Myers, Moore, Lipinski, and Houston, 2009). See Section 5.1.2.5.1 for further discussion.

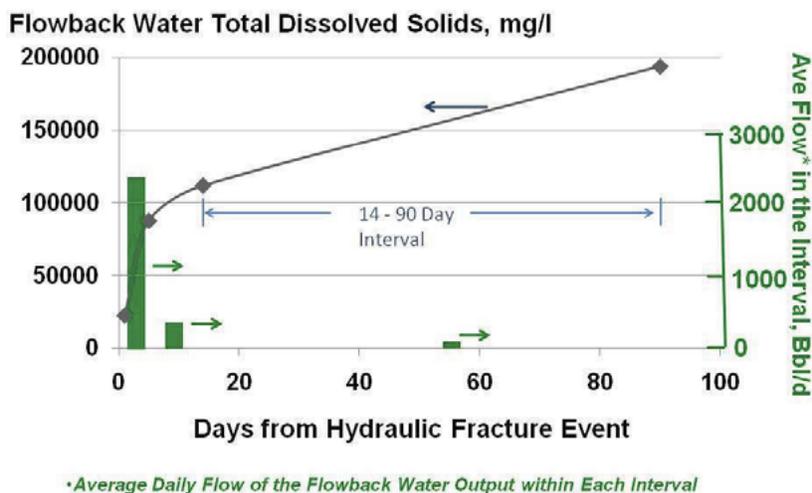


Figure 2-11. Example of flowback rates and totals dissolved solids composition from the Marcellus shale (source: Hayes, 2009).

2.3.7 Hydraulic Fracturing Process: Examples from the Bakken and Eagle Ford Plays

This discussion of the different phases of the hydraulic fracturing process will include examples of fracturing conducted in the Bakken and Eagle Ford plays. These unconventional reservoirs are considered analogous to shale reservoirs in California's Monterey Formation (described in detail in Section 4) because they compare favorably in terms of total organic content, depth, porosity, and permeability. However, there are significant differences in terms of depositional age, extent of natural fracturing, tendency towards great thickness, multiple lithofacies, tectonic activity, and folding (Beckwith, 2013). Section 3 discusses differences between hydraulic fracturing operations as currently implemented in California with hydraulic fracturing for unconventional shale reservoirs such as the Bakken and Eagle Ford.

As mentioned, the Bakken play is located in the Williston Basin in North Dakota, Montana, and Canada (Pearson et al., 2013). The upper and lower members of the Bakken are shales that are source rocks for oil. The middle member is the most frequent production target: It is a silty sandstone to silty dolomite, with permeability in the range of 0.1 md ($9.87 \times 10^{-17} \text{ m}^2$ or $1.06 \times 10^{-15} \text{ ft}^2$), and in North Dakota is found at depths of about 3,050 m (10,000 ft) (Pearson et al., 2013; Wiley, Barree, Eberhard, and Lantz, 2004). Production wells in the Bakken shale are typically horizontal wells with long laterals ranging from 2,290 to 2,900 m (7,500 to 9,500 ft) and use open-hole (uncemented) blank or sliding sleeve liners in the production interval (Pearson et al., 2013). A comparison of fracture

fluid volumes used within the middle Bakken member, shown in Table 2-2, found that slickwater fracture operations used about three times more fluid per length of lateral than wells using a hybrid method, and about four times more than wells employing a cross-linked gel (Pearson et al., 2013). This is in accord with the relationship between fracturing fluid type and volume shown on Figure 2-8.

Table 2-2. Variations in fluid volume and proppant use with treatment type (Pearson et al., 2013)

Treatment type	Average number of stages	Average stage spacing (m (ft))	Average fluid volume per lateral foot (m³/m (bbl/ft))	Average proppant weight per lateral length (kg/m (lbs/ft))
Slickwater	35	84.4 (277)	13.2 (25.3)	613 (412)
Hybrid	26	112.2 (368)	3.91 (7.5)	420 (282)
Cross-linked gel	29	103.3 (339)	3.44 (6.6)	570 (383)

The Eagle Ford play is composed of interbedded calcareous shale and calcisiltite (a rock consisting of fine-grained calcareous detritus), and massive calcareous shale or mudstone (Smith, 1981). The Eagle Ford play ranges in depth from 762 to 4,270 m (2,500 feet to 14,000 ft). Different parts of the play produce either oil and liquid-rich hydrocarbons or mainly gas (Stegent et al., 2010). The permeability of the Eagle Ford ranges from 1 to 800 nanodarcies (nd, which is 10^{-9} darcies) ($9.87 \times 10^{-22} \text{ m}^2$ to $7.9 \times 10^{-19} \text{ m}^2$ or $1.06 \times 10^{-20} \text{ ft}^2$ to $7.9 \times 10^{-19} \text{ ft}^2$). Production wells in the Eagle Ford more commonly used cemented blank liners with plug and perf completions (Greenberg, 2012). In the example discussed below, the horizontal well has a true vertical depth of 4,040 m (13,250 ft) with a lateral length of 1,160 m (3,800 ft), and produces at a high liquid/gas ratio (Stegent et al., 2010).

While acid preflush treatments have not been identified in examples from the Bakken play, Stegent et al. (2010) reported the use of 19.1 m^3 (674 ft^3 or 5,040 gallons) of 15% HCl for several Eagle Ford play horizontal wells prior to injecting fracture fluids for each stage. Examples from the Bakken and Eagle Ford use pad volumes that are about 20% to 30% of the total fluid injected (Wiley et al., 2004; Stegent et al., 2010). In the case of the Eagle Ford example, a hybrid fracture fluid scheme is used in which a linear gel alternating with a cross-linked gel is used as the pad and a cross-linked gel is used to carry proppant (Stegent et al., 2010). Furthermore, alternating injections of proppant-laden fluid with the pad fluids are used to transition to a final period of extended proppant injection. Pearson et al. (2013) report on the use of slickwater, cross-linked gel, and hybrid fracturing fluids for the Bakken shale. Hlidek and Rieb (2011) indicate an increase in the use of linear gel pad and a cross-linked gel for proppant injection.

The proppant injection stage constitutes the bulk of the remaining fluid injected for hydraulic fracturing. The final stage ends with a 37.9 m^3 (10,000 gallons) or less overflush

of fracture fluid without proppant to clear proppant from the well and perforations. The entire injection profiles for the example cases from the Bakken and Eagle Ford plays are shown in Figures 2-12 and 2-13, respectively.

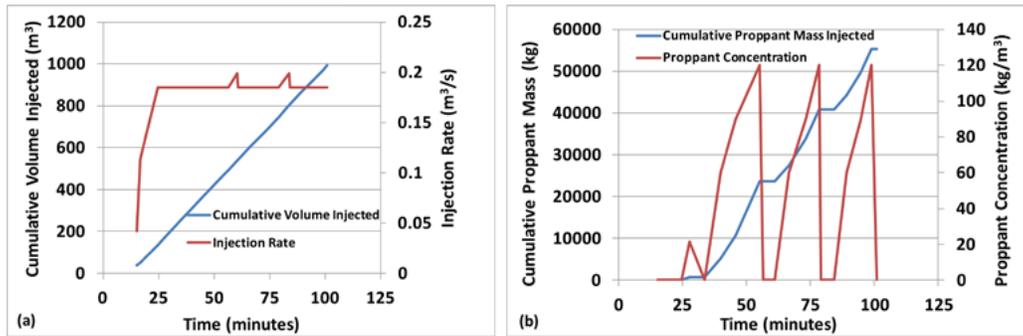


Figure 2-12. Slickwater fluid and ceramic proppant injection profile for the Bakken Shale example (a) Cumulative fluid injection and injection rate; (b) Cumulative proppant injected and proppant concentration (taken from Pearson et al., 2013, Figure 14).

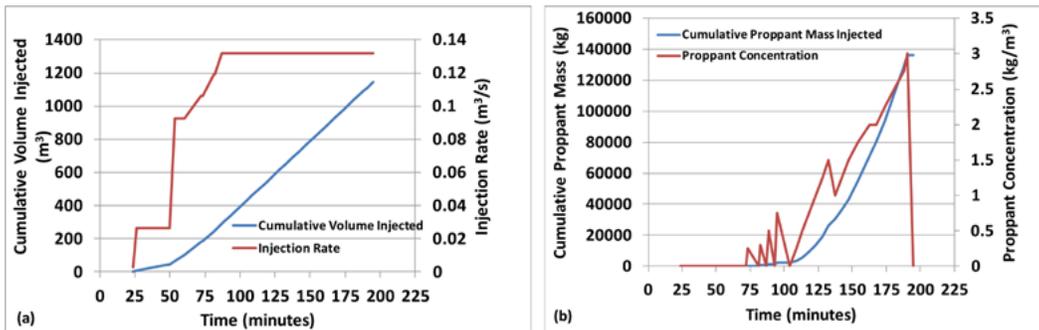


Figure 2-13. Hybrid fluid and sand proppant injection profile for the Eagle Ford Shale example (a) Cumulative fluid injection and injection rate [fluid type initially a linear gel followed by 15% HCl and then by alternating pulses of x-link gel and linear gel, x-link used exclusively from 95 minutes to the end]; (b) Cumulative proppant injected and proppant concentration [proppant mesh size 30/50 initially until 124 minutes and then 20/40 until the end] (Stegent et al., 2010). Note: about 60% of the 20/40 sand was a resin-coated proppant (Stegent et al., 2010).

In the case of the Bakken example, there were up to 30 stages per well for a 2,900-m (9,500-ft) lateral. For the Eagle Ford example, a 1,160-m (3,800-ft) lateral was treated with 11 stages. Therefore, the total fluid usage per well for the Bakken in this example is about 29,900 m³ (1.06 x 10⁶ ft³ or 7.9 million gallons), as compared to about 12,500 m³ (441,000 ft³ or 3.3 million gallons) for the Eagle Ford case.

Based on the number of stages and lateral lengths, the average stage lengths in the two examples were about the same, with a length of 97 m (318 ft) for the Bakken and 105 m (344 ft) for the Eagle Ford. So the volume of fracturing fluid per well length is a bit higher in the Eagle Ford example (10.9 m³/m or 881 gallons/ft [gpf]) than the Bakken example (10.2 m³/m or 824 gpf). The higher fluid volume for the Eagle Ford as compared with the Bakken is consistent with the trend in Figure 2-8 given the lower permeability in the Eagle Ford. However, the much higher permeability in the Bakken than the Eagle Ford suggests there should be a larger difference in fracturing fluid volume. The small difference in fluid volume may result from the choice of fracture fluid not following the trend for permeability in Figure 2-8. The lower permeability of the Eagle Ford suggests that slickwater would be more likely to be used in that play and a gelled fracture fluid in the Bakken instead of the reverse, as was actually done. It may be that the difference in brittleness between the Bakken and Eagle Ford is a more important control on fluid selection than is permeability. These examples suggest the trends in Figure 2-8 may only be true on average, and that individual cases may deviate substantially.

After fracture fluid injection, the well is produced to remove the fracture fluids (but not the proppant). The flowback fluids are initially similar to the injected fracture fluids but gradually are displaced until aqueous-phase fluid compositions are controlled by the aqueous phase present in the reservoir, typically a higher-salinity fluid. The amount of fracture-fluid recovery varies considerably for different reservoirs and generally ranges between 5% and 50% of the injected volume (King, 2012). However, many of the fracture-fluid additives are not recovered because of sorption or are perhaps recovered as products of chemical reactions that occur in the reservoir. Polymers, biocides, and acids react and degrade under *in situ* reservoir conditions, and surfactants are adsorbed on rock surfaces.

2.4 Matrix Acidizing

Matrix acidizing is the oldest well stimulation method, with the first matrix acidizing treatment performed on carbonate formations near Lima, Ohio in 1895 (Kalfayan, 2008). Matrix acidizing may be distinguished from acid fracturing discussed in Section 2.3.4, in that the acid solution is injected below the parting pressure of the formation; therefore, hydraulic fractures are not created by matrix acidizing (Kalfayan, 2008).

The modern application of matrix acidizing is split into two broad categories: carbonate acidizing and sandstone acidizing. Hydrochloric acid (HCl) is very effective at dissolving carbonate minerals. For that reason, carbonate acidizing utilizes concentrated HCl injected into the formation to create wormholes that bypass formation damage around the well. However, because wormholes can penetrate up to 6.1 m (20 ft) from the wellbore, carbonate acidizing may also be used to stimulate carbonate formations that do not have significant formation damage around the well (Economides et al., 2013).

Sandstone acidizing utilizes alternating treatments of concentrated HCl and concentrated mixtures of HCl and hydrofluoric acid (HF), which are effective at dissolving silicate minerals. This type of acidizing treatment dissolves materials (such as drilling mud) that clog the casing perforations and pore networks of the near-wellbore formation. Sandstone acidizing is nearly always limited to treatment of formation damage within one or two feet of the well. The main exception to the limited range of treatment for sandstone acidizing is for naturally fractured siliceous formations, including shales and cherts (Kalfayan, 2008).

Matrix acidizing is not commonly used for stimulation of unconventional reservoirs. This is because these low-permeability reservoirs require the more deeply penetrating and intensive stimulation available from hydraulic fracturing to effectively produce oil or gas. A unique exception that has been identified is the use of sandstone acidizing stimulation to enhance oil production from a producing field in the Monterey Formation in California (Rowe, Hurkmans, and Jones, 2004; Trehan, Jones, and Haney, 2012; El Shaari, Minner, and Lafollette, 2011). Therefore, the remainder of this section will focus on sandstone acidizing.

2.4.1 Sandstone Acidizing

Sandstone acidizing typically consists of three injection phases: (1) an initial injection of HCl preflush; (2) injection of an HCl/HF mixture; and (3) a post-flush of diesel, brine, or HCl. After the injection phases the well is flowed back (Economides et al., 2013). The injection phases are conducted below the fracture pressure. Acid concentrations are dependent on formation mineralogy and permeability. The preflush HCl concentrations typically vary from 5% to 15%, while the HCl/HF mixture may have HCl concentrations from about 13.5% down to 3% and HF from 3% down to 0.5% in various combinations (Kalfayan, 2008). In general, higher permeability formations with lower clay and silt content are treated with higher acid concentrations (Economides et al., 2013).

The purpose of the HCl preflush is to dissolve carbonate minerals and displace formation water. Carbonate minerals react with HF to form insoluble precipitates that can cause formation damage. Organic acids, such as formic-acetic acid blends, are sometimes used alone or in combination with HCl for the preflush (Kalfayan, 2008). The preflush volumes are generally equal to 50 to 100% of the subsequent HCl/HF treatment volume.

The HCl/HF acid treatment is the main acid stage for sandstone acidizing. This acid targets siliceous minerals that are blocking flow paths to the well. These minerals may be siliceous particles from drilling mud, such as bentonite, that have invaded and blocked pores and fractures, or naturally occurring fine-grained sediments in the reservoir. The contact time should be limited to 2 to 4 hours per stage to avoid mineral precipitation damage caused by HF reaction products.

Volumes injected generally range from 0.124 to 3.1 m³/m (10 to 250 gpf) of treated interval (Kalfayan, 2008). Injection rates are also important because of the reaction-rate kinetics, both for mineral dissolution and precipitation, the transport times for the acid to penetrate the formation, and because the injection pressure needs to remain below the fracture pressure (Economides et al., 2013). High-volume, high-rate treatments are typically limited to high-permeability, high-quartz content sands and fractured rock, including shales.

Sandstone acidizing is normally used only when formation damage near the well is impeding flow into the well. This is because penetration of a sandstone acidizing treatment into the formation is generally limited to about 0.3 m (1 foot). The maximum benefit of enhancing permeability in this limited region around the well for an undamaged formation is only about 20% (Economides et al., 2013). However, there is much less known about sandstone acidizing in siliceous reservoirs with permeable natural fractures, such as in some parts of the Monterey Formation (Kalfayan, 2008). In these circumstances, sandstone acidizing may be able to penetrate and remove natural or drilling-induced blockage in fractures deeper into the formation (Rowe et al., 2004; Patton, Pits, Goeres, and Hertfelder, 2003; Kalfayan, 2008). Kalfayan (2008) indicates that HCl/HF acidizing in naturally fractured siliceous rock uses high volumes > 1.24 m³/m (> 100 gpf). However, both low volume 0.248 m³/m (20 gal/ft) and higher volume 3.1 m³/m (250 gal/ft) HCl/HF treatments in fractured Monterey reservoirs have been reported (Patton, et al., 2003; Rowe et al., 2004).

The post-treatment flush displaces any live acid from the well and may be done with diesel, ammonium chloride solutions, and HCl (Economides et al., 2013). The volume of the post-flush should at least be sufficient to displace acid from the wellbore. After the injection phases are completed, the well is typically flowed back to recover spent-acid-reaction products to minimize damage caused by precipitation.

2.4.1.1 Sandstone Acidizing Fluid Composition

Similar to hydraulic fracturing fluids, a number of additives are generally included in the acid treatment fluids. In particular, corrosion inhibitors and iron control agents are always used. Corrosion inhibitors are needed to protect steel components in the well, such as the casing and tubing. Iron control agents react with dissolved iron and other dissolved metals to limit solids precipitation. Surfactants and mutual solvents are also often used, but not in all cases. Surfactants are needed to enhance the removal of spent acid during the backflow and to leave the formation in a water-wet condition (meaning water adheres to the rock more strongly than oil). Mutual solvents have been found to be useful in helping remove corrosion inhibitors that tend to adsorb onto rock and leave it in an oil-wet condition (meaning oil adheres to the rock more strongly than oil, which reduces oil production). Table 2-5 gives further information on these and other additives that are used in some cases.

Table 2-3. Sandstone acidizing additives (Kalfayan, 2008)

Additive type	Description of purpose	Examples of chemicals	Injection phase used	Typical concentration range
corrosion inhibitor	prevent corrosion of metallic well components	cationic polymers	all injection phases	0.1 – 2%
iron control agent	inhibit precipitation of iron, prevention of sludge formation	ethylenediaminetetraacetic acid (EDTA), erythorbic acid, nitrilotriacetic acid (NTA), citric acid	all acid phases	EDTA: 30-60* erythorbic acid: 10-100* NTA: 25-350* citric acid: 25-200*
surfactant	aid in recovery of spent acid products	nonionic, such as polyethylene oxide and polypropylene oxide	all acid phases	0.1-0.4%
mutual solvent	help remove corrosion inhibitors	ethylene glycol monobutyl ether (EGMBE)	post-flush	3-5%
nonemulsifiers	prevent acid-oil emulsions	nonionic or cationic surfactant	all acid phases	0.1-0.5%
antisludging agent	prevents formation of sludge from acid and high asphaltenic oils	surfactant and iron control agents	all acid phases	0.1-1%
clay stabilizer	prevent migration/ swelling of clays	Polyquaternary amines, polyamines	post-flush	0.1-0.4%
finest-stabilizing agent	prevent migration of non-clay fines	organosilanes	all phases	0.5-1%
calcium carbonate / calcium sulfate scale inhibitor	prevent formation of calcium scale	phosphonates, sulfonates, polyacrylates	all acid phases	NA
friction reducer	reduce pipe friction	polyacrylamide	all injection phases	0.1-0.3%
acetic acid	reduce precipitation of aluminosilicates	acetic acid	HCl/HF phase	3%

* pounds per thousand gallons of acid

2.4.1.2 Diversion

Placement of acid is an important element for effective sandstone acidizing. This is because the acid tends to flow into formation pathways that are most permeable. This is problematic, because acidizing treatments are generally intended to contact and improve the permeability of zones that are plugged and have a low permeability. Therefore, methods to divert acidizing treatments away from permeable zones and into the low-permeability zones are needed (Economides et al., 2013).

The main diversion methods are mechanical, including packer systems, ball sealants, and coiled tubing, and chemical, including particulate diverters, foams, and gels. Direct mechanical diversion is provided by packers which isolate the zones where the acid contacts the formation. Packers are an effective but somewhat resource-intensive diversion method.

Ball sealers are also a mechanical diversion method that injects 0.0159 to 0.0318 m (0.0512 to 0.104 ft) diameter balls made of nylon, hard rubber, or bio-degradable materials such as collagen, into the well (Kalfayan, 2008). The balls seat on and seal perforations, preferentially closing perforations that are taking most of the flow, thereby diverting flow to other perforations (Samuel and Sengul, 2003). The method requires high pumping rates and perforations that are in good condition to be effective. Coiled tubing is another mechanical diversion method. Coiled tubing is any continuously-milled tubular product manufactured in lengths that require spooling onto a take-up reel and have diameters ranging from 0.0191 to 0.102 m (0.0625 to 0.333 ft) (ICoTA, 2014). The tubing is sent down the well to the location where treatment is desired, and the treatment fluids are pumped through the tubing. The method is effective at delivering fluids at locations needed, but can result in pump-rate limitations because of the small tubing diameter, and the tubing can be damaged by acid corrosion causing leaks and tubing failure (Kalfayan, 2008).

Particulate diverters are a chemical diversion technique that uses benzoic acid, which precipitates into flakes or fines when the acid solution mixes with formation waters at reservoir conditions. The particulates then plug off the more actively flowing zones, and the acid treatment is diverted to locations where less of the diverting agent has been deposited. Gels and foams are viscous diversion treatments that reduce flow into higher permeability zones by the establishment of a bank of higher viscosity fluid in the region. Gels are more reliable, but can lead to problems if they cannot be subsequently broken and/or removed after the acidizing treatment (Kalfayan, 2008).

A final method that is applicable for high-rate injection schemes is known as maximum pressure differential and injection rate (MAPDIR) (Paccaloni, 1995). A similar approach is also used for carbonate acidizing (Economides et al., 2013). This method pumps the acid treatments at the highest rate possible without exceeding the formation fracture pressure. One of the advantages of this method is that diverting agents may not be needed. The method is useful for treating long, damaged, naturally fractured intervals.

2.5 Main Findings

The main findings of this section that are used in subsequent sections that evaluate hydraulic fracturing in California are the following:

(1) The design of a hydraulic fracture is a function of the reservoir's flow and mechanical characteristics. Reservoirs that are more permeable (within the permeability range where well stimulation is needed) and ductile tend to require less intensive fracturing. This leads to the use of a more viscous gelled fracturing fluid and a relatively smaller fracture fluid volume. Gelled fluids typically have more types and a higher total mass of chemical additives than slickwater. Reservoirs that have relatively low permeability and are brittle tend to require more intensive fracturing. This leads to the use of a less viscous slickwater fluid and a relatively larger fluid volume injected.

(2) Acid fracturing is commonly limited in application to carbonate reservoirs. This is significant because California's oil resources are primarily found in siliceous rock rather than carbonate rock as shown in Section 3.

(3) Matrix acidizing for siliceous reservoirs typically has a very limited penetration distance from the well into the formation. Therefore, this type of matrix acidizing tends to have a small effect on larger-scale reservoir permeability, with the possible exception of reservoirs where permeable natural fractures are present.

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Chapter 2: Advanced Well Stimulation Technologies

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Chapter 2: Advanced Well Stimulation Technologies

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