Appendix D

Designing, Constructing, and Testing Wells for Integrity

Appendix D. Designing, Constructing, and Testing Wells for Integrity

This appendix presents the goals for the design and construction of oil and gas production wells, the well components used to achieve those goals, and methods for testing well integrity to help verify that the goals for well performance are achieved. This information provides additional background for the well component discussions presented in Chapter 6. Information on the pathways associated with the well that can cause fluid movement into drinking water resources is presented in Chapter 6.

D.1. Design Goals for Well Construction

Simply stated, production wells are designed to move oil and gas from the production zone (within the oil and gas reservoir) into the well and then through the well to the surface. There are typically a variety of goals for well design (Renpu, 2011), but the main purposes are facilitating the flow of oil and gas from the hydrocarbon reservoirs to the well (production management) while isolating that oil and gas and the hydrocarbon reservoirs from nearby ground water resources (zonal isolation).

To achieve these goals, operators design and construct wells to have and maintain mechanical integrity throughout the life of the well. A properly designed and constructed well has two types of mechanical integrity: internal and external. Internal mechanical integrity refers to the absence of significant leakage within the production tubing, casing, or packer. External mechanical integrity refers to the absence of significant leakage along the well outside of the casing.

Achieving mechanical integrity involves designing the well components to resist the stresses they will encounter. Each well component must be designed to withstand all of the stresses to which the well will be subjected, including burst pressure, collapse, tensile, compression (or bending), and cyclical stresses (see Section 6.2.1 for additional information on these stresses). Well materials should also be compatible with the fluids (including liquids or gases) with which they come into contact to prevent leaks caused by corrosion.

These goals are accomplished by the use of one or more layers of casing, cement, and mechanical devices (such as packers), which provide the main barrier preventing migration of fluids from the well into drinking water sources.

D.2. Well Components

Casing and cement are used in the design and construction of wells to achieve the goals of mechanical integrity and zonal isolation. Several industry-developed specifications and best practices for well construction have been established to guide well operators in the construction process; see Text Box D-1. (Information is not available to determine how often these practices are used or how well they prevent the development of pathways for fluid movement to drinking water resources.) The sections below describe options available for casing, cement, and other well components.

Text Box D-1. Selected Industry-Developed Specifications and Recommended Practices for Well Construction in North America.

American Petroleum Institute (API)

- API Guidance Document HF1—Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines (API, 2009a)
- API RP 10B-2—Recommended Practice for Testing Well Cements (API, 2013)
- API RP 10D-2—Recommended Practice for Centralizer Placement and Stop Collar Testing (API, 2004)
- API RP 5C1—Recommended Practices for Care and Use of Casing and Tubing (API, 1999)
- API RP 65-2—Isolating Potential Flow Zones during Well Construction (API, 2010a)
- API Specification 10A—Specification on Cements and Materials for Well Cementing (API, 2010b)
- API Specification 11D1—Packers and Bridge Plugs (API, 2009b)
- API Specification 5CT—Specification for Casing and Tubing (API, 2011)

Canadian Association of Petroleum Producers (CAPP) and Enform

- Hydraulic Fracturing Operating Practices: Wellbore Construction and Quality Assurance (CAPP, 2013)
- Interim Industry Recommended Practice Volume #24—Fracture Stimulation: Inter-wellbore Communication (Enform, 2013)

Marcellus Shale Coalition (MSC)

- Recommended Practices—Drilling and Completions (MSC, 2013)

D.2.1. Casing

Casing is steel pipe that is placed into the wellbore (the cylindrical hole drilled through the subsurface rock formation) to maintain the stability of the wellbore, to transport the hydrocarbons from the subsurface to the surface, and to prevent intrusion of other fluids into the well and wellbore. Up to four types of casing may be present in a well, including (from largest to smallest-diameter): conductor casing, surface casing, intermediate casing, and production casing. Each is described below.

The **conductor casing** is the largest diameter string of casing. It is typically in the range of 30 in. (76 cm) to 42 in. (107 cm) in diameter (Hyne, 2012). Its main purpose is to prevent unconsolidated material, such as sand, gravel, and soil, from collapsing into the wellbore. Therefore, the casing is typically installed from the surface to the top of the bedrock or other consolidated formations. The conductor casing may or may not be cemented in place.

The next string of casing is the **surface casing**. A typical surface casing diameter is 13.75 in. (34.93 cm), but diameter can vary (Hyne, 2012). The surface casing's main purposes are to isolate any ground water resources that are to be protected by preventing fluid migration along the wellbore once the casing is cemented and to provide a sturdy structure to which blow-out prevention equipment can be attached. For these reasons, the surface casing most commonly extends from the surface to some distance beneath the lowermost geologic formation containing ground water resources to be protected. The specific depth to which the surface casing is set is often governed by the depth of the ground water resource as defined and identified for protection in state regulations.

Intermediate casing is typically used in wells to control pressure in an intermediate-depth formation. It may be used to reduce or prevent exposure of weak formations to pressure from the weight of the drilling fluid or cement or to allow better control of over-pressured formations. The intermediate casing extends from the surface through the formation of concern. There may be more than one string of concentric intermediate casing present or none at all, depending on the subsurface geology. Intermediate casing may be cemented, especially through over-pressured zones; however, it is not always cemented to the surface. Intermediate casing, when present, is often 8.625 in. (21.908 cm) in diameter but can vary (Hyne, 2012).

Production casing extends from the surface into the production zone. The main purposes of the production casing are to isolate the hydrocarbon product from fluids in surrounding formations and to transport the product to the surface. It can also be used to inject fracturing fluids, receive flowback during hydraulic fracturing operations (e.g., if tubing or a temporary fracturing string is not present), and prevent other fluids from mixing with and diluting the produced hydrocarbons. The production casing is generally cemented to some point above the production zone. Production casing is often 5.5 in. (14.0 cm) in diameter but can vary (Hyne, 2012).

Liners are another type of metal tubular (casing-like) well component that can be used to fulfill the same purposes as intermediate and production casing in the production zone. Like casing, they are steel pipe, but differ in that they do not extend from the production zone to the surface. Rather, they are connected to the next largest string of casing by a hanger that is attached to the casing. A frac sleeve is a specialized type of liner that is used during fracturing. It has plugs that can be opened and closed by dropping balls from the surface (see the discussion of well completions below for additional information on the use of frac sleeves).

Production tubing is the smallest, innermost steel pipe in the well and is distinguished from casing by not being cemented in place. It is used to transport the hydrocarbons to the surface. Fracturing may be done through the tubing if present, or through the production casing. Because casing cannot be replaced, tubing is often used, especially if the hydrocarbons contain corrosive substances such as hydrogen sulfide or carbon dioxide. Tubing may not be used in high-volume production wells. Typical tubing diameter is between 1.25 in. (3.18 cm) and 4.5 in. (11.4 cm) (Hyne, 2012).

D.2.2. Cement

Cement is the main barrier preventing fluid movement along the wellbore outside the casing. It also lends mechanical strength to the well and protects the casing from corrosion by naturally occurring formation fluids. Cement is placed in the annulus, which is the space between two adjacent casings or the space between the outermost casing and the rock formation through which the wellbore was drilled. The sections below describe considerations for selecting cement and additives, as well as cementing procedures and techniques.

D.2.2.1. Considerations for Cementing

The length and location of the casing section to be cemented and the composition of the cement can vary based on numerous factors, including the presence and locations of weak formations, over- or under-pressured formations, or formations containing fluids; formation permeability; and temperature. State requirements for oil and gas production well construction and the relative costs of well construction options are also factors.

Improper cementing can lead to the formation of channels (small connected voids) in the cement, which can—if they extend across multiple formations or connect to other existing channels or fractures—present pathways for fluid migration. This section describes some of the considerations and concerns for proper cement placement and techniques and materials that are available to address these concerns. Careful selection of cements (and additives) and design of the cementing job can avoid integrity problems related to cement.

To select the appropriate cement type, properties, and additives, operators consider the required strength needed to withstand downhole conditions and compatibility with subsurface chemistry, as described below:

- The cement design needs to **achieve the strength** required under the measured or anticipated downhole conditions. Factors that are taken into account to achieve proper strength can include density, thickening time, the presence of free water, compressive strength, and formation permeability (Renpu, 2011). Commonly, cement properties are varied during the process, with a "weaker" (i.e., less dense) lead cement, followed by a "stronger" (denser) tail cement. The lead cement is designed with a lower density to reduce pressure on the formation and better displace drilling fluid without a large concern for strength. The stronger tail cement provides greater strength for the deeper portions of the well the operator considers as requiring greater strength.
- The **compatibility of the cement** with the chemistry of formation fluids, hydrocarbons, and hydraulic fracturing fluids is important for maintaining well integrity through the life of the well. Most oil and gas wells are constructed using some form of Portland cement. Portland cement is a specific type of cement consisting primarily of calcium silicates with additional iron and aluminum. Industry specifications for recommended cements are determined by the downhole pressure, temperature, and chemical compatibility required.

There are a number of considerations in the design and execution of a cement job. Proper centralization of the casing within the wellbore is one of the more important considerations. Others include the potential for lost cement, gas invasion, cement shrinkage, incomplete removal of drilling mud, settling of solids in the wellbore, and water loss into the formation while curing. These concerns, and techniques available to address them, include the following:

- **Improper centralization of the casing within the wellbore** can lead to preferential flow of cement on the side of the casing with the larger space and little to no cement on the side closest to the formation. If the casing is not centered in the wellbore, cement will flow unevenly during the cement job, leading to the formation of cement channels. Kirksey (2013) notes that, if the casing is off-center by just 25%, the cement job is almost always inadequate. Centralizers are used to keep the casing in the center of the hole and allow an even cement job. To ensure proper centralization, centralizers are placed at regular intervals along the casing (API, 2010a). Centralizer use is especially key in horizontal wells, as the casing will tend to settle (due to gravity) to the bottom of the wellbore if the casing is not centered (Sabins, 1990), leading to inadequate cement on the lower side.
- **Lost cement** (sometimes referred to as lost returns) refers to cement that moves out of the wellbore and into the formation instead of filling up the annulus between the casing and the formation. Lost cement can occur in weak formations that fail (fracture) under pressure of the cement or in particularly porous, permeable, or naturally fractured formations. Lost cement can result in lack of adequate cement across a water- or brine-bearing zone. To avoid inadequate placement of cement due to lost cement, records of nearby wells can be examined to determine zones where lost cement returns occur (API, 2009a). If records from nearby wells are not available, cores and logs may be used to identify any high-permeability or mechanically weak formations that might lead to lost cement. Steps can then be taken to eliminate or reduce loss of cement to the formation. Staged cementing (see below) can reduce the hydrostatic pressure on the formation and may avoid fracturing weak formations (Lyons and Pligsa, 2004). Additives are also available that will lessen the flow of cement into highly porous formations (API, 2010a; Ali et al., 2009).
- **Gas invasion and cement shrinkage** during cement setting can also cause channels and poor bonding. During the cementing process, the hydrostatic pressure from the cement column keeps formation gas from entering the cement. As the cement sets (hardens), the hydrostatic pressure decreases; if it becomes less than the formation pressure, gas can enter the cement, leading to channels. Cement also shrinks as it sets, which can lead to poor bonding and formation of microannuli. These problems can be avoided by using cement additives that increase setting time or expand to offset shrinkage (McDaniel et al., 2014; Wojtanowicz, 2008; Dusseault et al., 2000). Foamed cement can help alleviate problems with shrinkage, although care needs to be taken in cement design to ensure the proper balance of pressure between the cement column and formation (API, 2010a). Cement additives are also available that will expand upon contact with certain fluids such as hydrocarbons. These cements, termed self-healing cements, are relatively new but have shown early promise in some fields (Ali et al., 2009). Rotating the casing during cementing will also delay cement setting. Another technique called pulsation, where pressure pulses are applied to the cement while it is setting, also can delay cement setting and loss of hydrostatic pressure until the cement is strong enough to resist gas penetration (Stein et al., 2003).

- Another important issue is **removal of drilling mud**. If drilling mud is not completely removed, it can gather on one side of the wellbore and prevent that portion of the wellbore from being adequately cemented. The drilling mud can then be eroded away after the cement sets, leaving a channel. Drilling mud can be removed by circulating a denser fluid (spacer fluid) to flush the drilling mud out (Kirksey, 2013; Brufatto et al., 2003). Mechanical devices called scratchers can also be attached to the casing and the casing rotated or reciprocated to scrape drilling mud from the wellbore (Hyne, 2012; Crook, 2008). The spacer fluid, which is circulated prior to the cement to wash the drilling fluid out of the wellbore, must be designed with the appropriate properties and pumped in such a way that it displaces the drilling fluid without mixing with the cement (Kirksey, 2013; API, 2010a; Brufatto et al., 2003).
- Also of concern in horizontal wells is the possibility of **solids settling** at the bottom of the wellbore and free water collecting at the top of the wellbore. This can lead to channels and poor cement bonding. The cement slurry must be properly designed for horizontal wells to minimize free water and solids settling.
- If there is free water in the cement, pressure can cause **water loss into the formation,** leaving behind poor cement or channels (Jiang et al., 2012). In horizontal wells, free water can also accumulate at the top of the wellbore, forming a channel (Sabins, 1990). Minimizing free water in the cement design and using fluid loss control additives can help control loss of water (Ross and King, 2007).

D.2.2.2. Cement Placement Techniques

The primary cement job is most commonly conducted by pumping the cement down the inside of the casing, then out the bottom of the casing where it is then forced up the space between the outside of the casing and the formation. (The cement can also be placed in the space between two casings.) If **continuous cement** (i.e., a sheath of cement placed along the entire wellbore) is desired, cement is circulated through the annulus until cement that is pumped down the central casing flows out of the annulus at the surface. A spacer fluid is often pumped ahead of cement to remove any excess drilling fluid left in the wellbore; even if the operator does not plan to circulate cement to the surface, the spacer fluid will still return to the surface, as this is necessary to remove the drilling mud from the annulus. If neither the spacer fluid nor the cement returns to the surface, this indicates that fluids are being lost into the formation.

Staged cementing is a technique that reduces pressure on the formation by decreasing the height (and therefore the weight) of the cement column. This may be necessary if the estimated weight and pressure associated with standard cement emplacement could damage zones where the formation intersected is weak. The reduced hydrostatic pressure at the bottom of the cement column can also reduce the loss of water to permeable formations, improving the quality of the cement job. In multiple-stage cementing, cement is circulated to just below a cement collar placed between two sections of casing. A cement collar will have been placed between two sections of casing, just above, with ports that can be opened by dropping a weighted tool. Two plugs—which are often referred to as bombs or darts because of their shape—are then dropped. The first plug is dropped, once the desired cement for the first stage has been pushed out of the casing by a spacer fluid. It closes the section of the well below the cement collar and stops cement from flowing into the lower portion of the well. The second plug (or opening bomb) opens the cement ports in the collar, allowing cement to flow into the annulus between the casing and formation. Cement is then circulated down the wellbore, out the cement ports, into the annulus, and up to the surface. Once cementing is complete, a third plug is dropped to close the cement ports, preventing the newly pumped cement from flowing back into the well (Lyons and Pligsa, 2004); see Figure D-1.

Another less commonly used primary cementing technique is **reverse circulation cementing.** This technique has been developed to decrease the force exerted on weak formations. In reverse circulation cementing, the cement is pumped down the annulus directly between the outside of the outermost casing and the formation. This essentially allows use of lower density cement and lower pumping pressures. With reverse circulation cementing, greater care must be taken in calculating the required cement, ensuring proper cement circulation, and locating the beginning and end of the cemented portion.

Another method used to cement specific portions of the well without circulating cement along the entire wellbore length is to use a **cement basket**. A cement basket is a device that attaches to the well casing. It is made of flexible material such as canvas or rubber that can conform to the shape of the wellbore. The cement basket acts as a one-way barrier to cement flow. Cement can be circulated up the wellbore past the cement basket, but when circulation stops the basket prevents the cement from falling back down the wellbore. Cement baskets can be used to isolate weak formations or formations with voids. They can also be placed above large voids such as mines or caverns with staged cementing used to cement the casing above the void.

If any deficiencies are identified, **remedial cementing** may be performed. The techniques available to address deficiencies in the primary cement job including cement squeezes or top-job cementing. A cement squeeze injects cement under high pressure to fill in voids or spaces in the primary cement job caused by high pressure, failed formations, or improper removal of drilling mud. Although cement squeezes can be used to fix deficiencies in the primary cement job, they require the well to be perforated, which can weaken the well and make it susceptible to degradation by pressure and temperature cycling as would occur during fracturing (Crescent, 2011). Another method of secondary cementing is the top job. In a top job, cement is pumped down the annulus directly to fill the remaining uncemented space when cement fails to circulate to the surface.

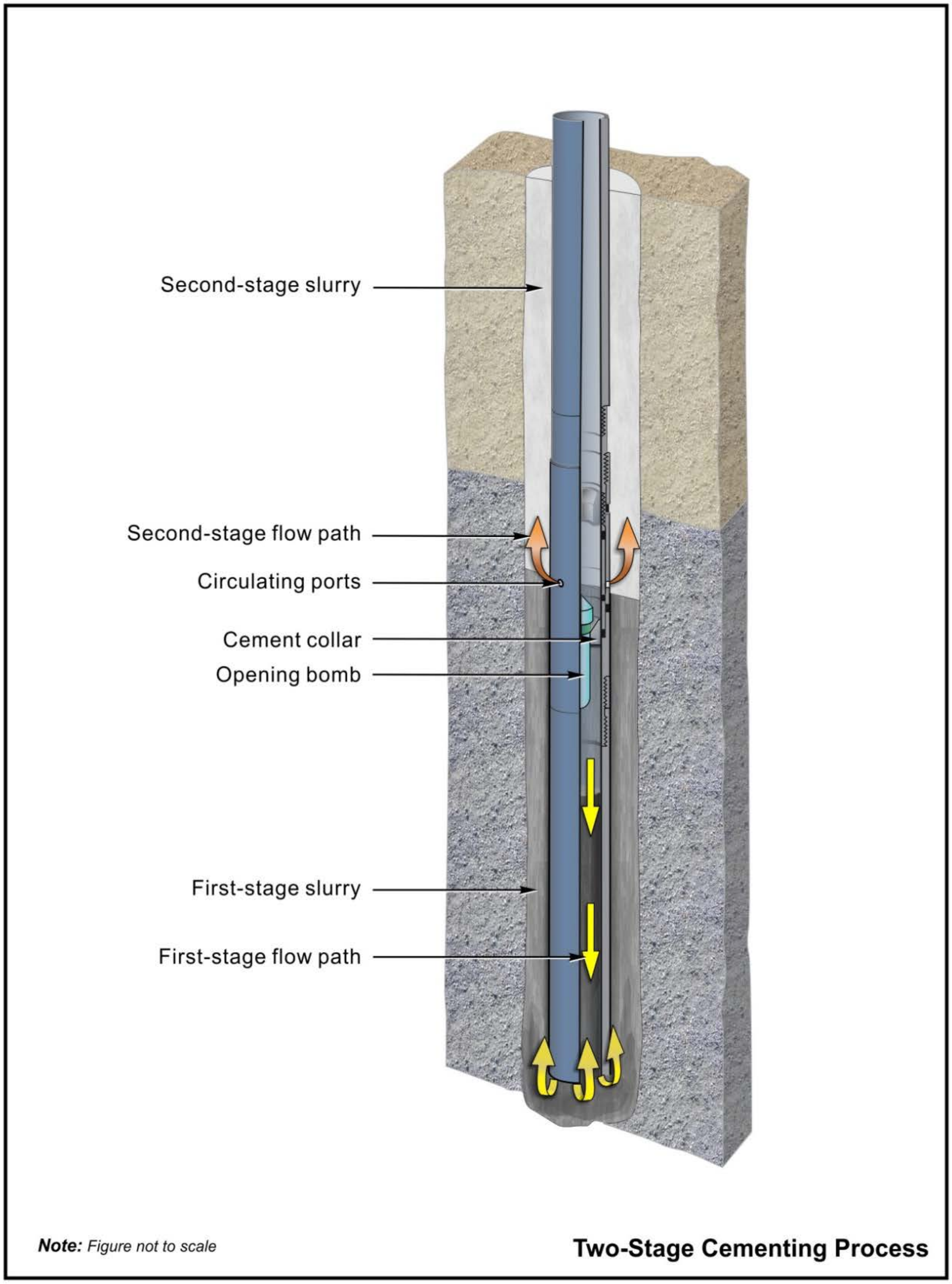

Figure D-1. A typical staged cementing process.

D.3. Well Completions

Completion refers to how the well is prepared for production and how flow is established between the formation and the surface. Figure D-2 presents examples of well completion types, including cased, formation packer, and open hole completion.

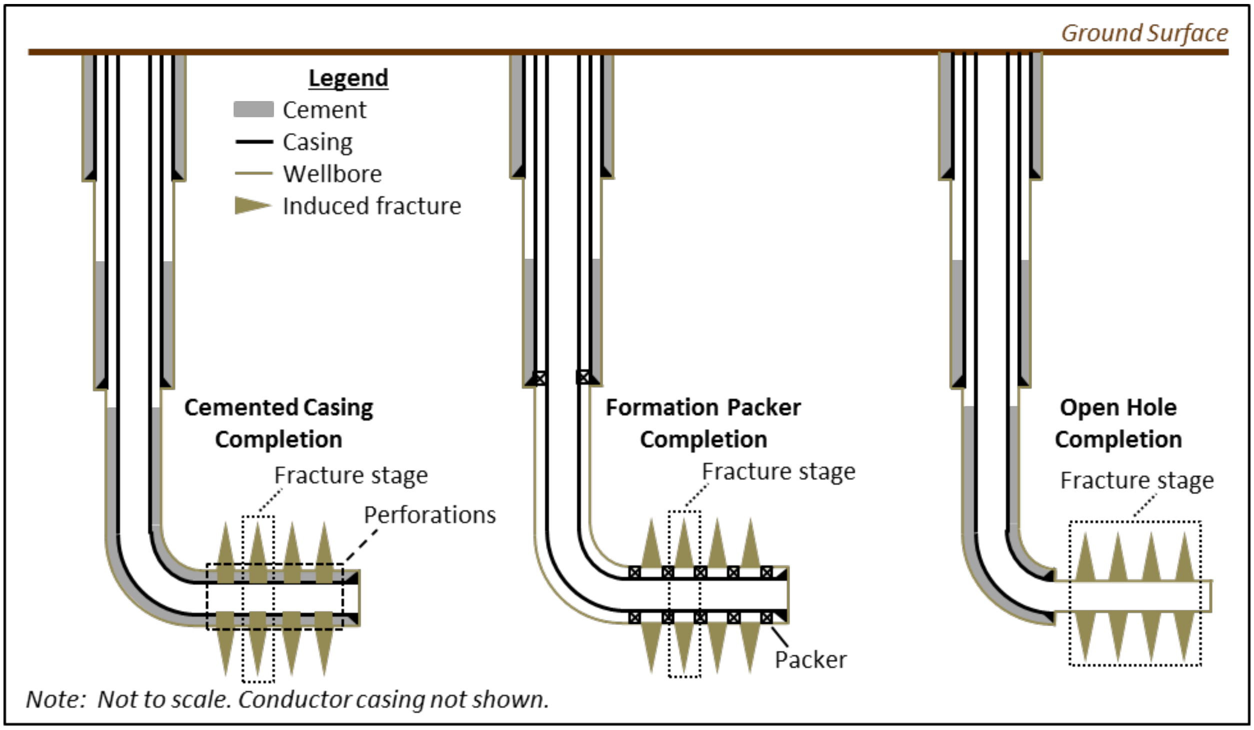

Figure D-2. Examples of well completion types.

Configurations shown include cased, formation packer, and open hole completion. From U.S. EPA (2015f).

A **cased completion**, where the casing extends to the end of the wellbore and is cemented in place, is the most common configuration of the well in the production zone (U.S. EPA, 2015f). Perforations are made through the casing and cement and into the formation using small explosive charges called "perf guns" or other devices, such as sand jets. Hydraulic fracturing then is conducted through the perforations. This is a common technique in wells that produce from several different depths and in low-permeability formations that are fractured (Renpu, 2011). While perforations do control the initiation point of the fracture, this can be a disadvantage if the perforations are not properly aligned with the local stress field. If the perforations are not aligned, the fractures will twist to align with the stress field, leading to tortuosity in the fractures and making fluid movement through them more difficult (Cramer, 2008). Fracturing stages can be isolated from each other using various mechanisms such as plugs or baffle rings, which close off a section of the well when a ball of the correct size is dropped down the well.

A packer is a mechanical device used to selectively seal off certain s ections of the wellbore. Packers can be used to seal the space between the tubing and casing, between two casings, or between the production casing and formation. The packer has one or more rubber elements that can be manipulated downhole to increase in diameter and make contact with the inner wall of the next-largest casing or the formation, effectively sealing the annulus created between the outside of the tubing and the inside of the casing. Packers vary in how they are constructed and how they are set, based on the downhole conditions in which they are used. There are two types of packers: internal packers and formation packers. Internal packers are used to seal the space between the casing and tubing or between two different casings. They isolate the outer casing layers from produced fluids and prevent fluid movement into the annulus. Formation packers seal the space between the casing and the formation and are often used to isolate fracture stages; they can be used to separate an open hole completion into separate fracture stages. Packers can seal an annulus by several different mechanisms. Mechanical packers expand mechanically against the formation and can exert a significant force on the formation. Swellable packers have elastomer sealing elements that swell when they come into contact with a triggering fluid such as water or hydrocarbons. They exert less force on the formation and can seal larger spaces but take some time to fully swell (McDaniel and Rispler, 2009). Internal mechanical integrity tests such as pressure tests can verify that the packer is functioning as designed and has not corroded or deteriorated.

In an **open hole completion**, the production casing extends just into the production zone and the entire length of the wellbore through the production zone is left uncased. This is only an option in formations where the wellbore is stable enough to not collapse into the wellbore. In formations that are unstable, a slotted liner may be used in open hole completions to control sand production (Renpu, 2011). Perforations are not needed in an open hole completion, since the production zone is not cased. An open hole completion can be fractured in a single stage or in multiple stages.

If formations are to be fractured in stages, additional completion methods are needed to separate the stages from each other and control the location of the fractures. One possibility is use of a liner with formation packers to isolate each stage. The liner is equipped with sliding sleeves that can be opened by dropping balls down the casing to open each stage. Fracturing typically occurs from the end of the well and continues toward the beginning of the production zone.

D.4. Mechanical Integrity Testing

While proper design and construction of the well's casing and cement are important, it is also important to verify the well was constructed and is performing as designed. Mechanical integrity tests (MITs) can verify that the well was constructed as planned and can detect damage to the production well that occurs during operations, including hydraulic fracturing activities. Verifying that a well has mechanical integrity can prevent potential impacts to drinking water resources by providing early warning of a problem with the well or cement and allowing repairs.

It is important to note that if a well fails an MIT, this does not mean the well has failed or that an impact on drinking water resources has occurred. An MIT failure is a warning that one or more components of the well are not performing as designed and is an indication that corrective actions are necessary. If well remediation is not performed, a loss of well integrity could occur, which could result in fluid movement from the well.

D.4.1. Internal Mechanical Integrity

Internal mechanical integrity is an absence of significant leakage in the tubing, casing, or packers within the well system. Loss of internal mechanical integrity is usually due to corrosion or mechanical failure of the well's tubular and mechanical components.

Internal mechanical integrity can be tested by the use of pressure testing, annulus pressure monitoring, ultrasonic monitoring, and casing inspection logs or caliper logs:

- **Pressure testing** involves raising the pressure in the wellbore to a set level and shutting in the well. If the well has internal mechanical integrity, the pressure should remain constant with only small changes due to temperature fluctuation. Typically, the well is shut in (i.e., production is stopped and the wellhead valves closed) for half an hour, and if the pressure remains within 5% of the original reading, the well is considered to have passed the test. Usually, the well is pressure tested to the maximum expected pressure; for a well to be used for hydraulic fracturing this would be the pressure applied during hydraulic fracturing. Pressure tests, however, can cause debonding of the cement from the casing, so test length is often limited to reduce this effect (API, 2010a).
- If the annulus between the tubing and casing is sealed by a packer, **annulus pressure monitoring** can give an indication of the integrity of the tubing and casing. If the tubing, casing, and packer all have mechanical integrity, the pressure in the annulus should not change except for small changes in response to temperature fluctuations. The annulus can be filled with a non-corrosive liquid and the level of the liquid can be used as another indication of the integrity of the casing, tubing, and packer. The advantage of monitoring the tubing/production casing annulus is it can give a continuous, real-time indication of the internal integrity of the well. Even if the annulus is not filled with a fluid, monitoring its pressure can indicate leaks. If pressure builds up in the annulus and then recovers quickly after having bled off, that condition is referred to as sustained casing pressure or surface casing vent flow and is a sign of a leak in the tubing or casing (Watson and Bachu, 2009). Monitoring of annuli between other sets of casings can also provide information on the integrity of those casings. It can also provide information on external mechanical integrity for annuli open to the formation (see Section D.4.2 for additional information on external MITs). Jackson et al. (2013) also note that monitoring annular pressure allows the operator to vent gas before it accumulates enough pressure to cause migration into drinking water resources. Measuring annulus flow rate also allows detection of gas flowing into the annulus (Arthur, 2012).
- A newer tool uses **ultrasonic monitors** to detect leaks in casing and other equipment. It measures the attenuation of an ultrasonic signal as it is transmitted through the wellbore. The tool measures transmitted ultrasonic signals as it is lowered down the wellbore. The tool can pick up ultrasonic signals created by the leak, similar to noise logs. The tool only

has a range of a few feet but is claimed to detect leaks as small as half a cup per minute (Julian et al., 2007).

- **Caliper logs** have mechanical fingers that extend from a central tool and measure the distance from the center of the wellbore to the side of the casing. Running a caliper log can identify areas where corrosion has altered the diameter of the casing or where holes have formed in the casing. Caliper logs may also detect debris or obstructions in the well. Casing inspection and caliper logs are primarily used to determine the condition of the casing. Regular use of them may identify problems such as corrosion and allow mitigation before they cause of loss of integrity to the casing. To run these logs in a producing well, the tubing must first be pulled.
- **Casing inspection logs** are instruments lowered into the casing to inspect the casing for signs of wear or corrosion. One type of casing log uses video equipment to detect corrosion or holes. Another type uses electromagnetic pulses to detect variations in metal thickness. Running these logs in a producing well requires the tubing to be pulled.

If an internal mechanical integrity problem is detected, first, the location of the problem must be found. Caliper or casing inspection logs can detect locations of holes in casing. Locations of leaks can also be detected by sealing off different sections of the well using packers and performing pressure tests on each section until the faulty section is located. If the leaks are in the tubing or a packer, the problem may be remedied by replacing the well component. Casing leaks may be remedied by performing a cement squeeze (see the section on cementing).

D.4.2. External Mechanical Integrity

External well mechanical integrity is demonstrated by establishing the absence of significant fluid movement along the outside of the casing, either between the outer casing and cement or between the cement and the wellbore. Failure of an external MIT can indicate improper cementing or degradation of the cement emplaced in the annular space between the outside of the casing and the wellbore. This type of failure can lead to movement of fluids out of intended production zones and toward drinking water resources.

Several types of logs are available to evaluate external mechanical integrity, including temperature logs, noise logs, oxygen activation logs, radioactive tracer logs, and cement evaluation logs.

- **Temperature logs** measure the temperature in the wellbore. They are capable of measuring small changes in temperature. They can be performed using instruments that are lowered down the well on a wireline or they can be done using fiber optic sensors permanently installed in the well. When performed immediately after cementing, they can detect the heat from the cement setting and determine the location of the top of cement. After the cement has set, temperature logs can sense the difference in temperatures between formation fluids and injected or produced fluids. They may also detect temperature changes due to cooling or warming caused by flow. In this way temperature logs may detect movement of fluid outside the casing in the wellbore (Arthur, 2012).

Temperature logs require interpretation of the causes of temperature changes and are therefore subject to varying results among different users.

- **Noise logs** are sensitive microphones that are lowered down the well on a wireline. They are capable of detecting small noises caused by flowing fluids, such as fluids flowing through channels in the cement (Arthur, 2012). They are most effective at detecting fast-moving gas leaks and less successful with more slowly moving liquid migration.
- **Oxygen activation logs** consist of a neutron source and one or more detectors that are lowered on a wireline. The neutron source bombards oxygen molecules surrounding the wellbore and converts them into unstable nitrogen molecules that rapidly decay back to oxygen, emitting gamma radiation in the process. Gamma radiation detectors above or below the neutron source measure how quickly the oxygen molecules are moving away from the source, thereby determining flow associated with water.
- **Radioactive tracer logs** involve release of a radioactive tracer and then passing a detector up or down the wellbore to measure the path the tracers have taken. They can be used to determine if fluid is flowing up the wellbore. Tracer logs can be very sensitive but may be limited in the range over which leaks can be detected.
- **Cement evaluation logs** (also known as cement bond logs) are acoustic logs consisting of an instrument that sends out acoustic signals along with receivers, separated by some distance, that record the acoustic signals. As the acoustic signals pass through the casing they will be attenuated to an extent, depending on whether the pipe is free or is bonded to cement. By analyzing the return acoustic signal, the degree of cement bonding with the casing can be determined. The cement evaluation log measures the sound attenuation as sound waves passing through the cement and casing. There are different types of cement evaluation logs available. Some instruments can only return an average value over the entire wellbore. Other instruments are capable of measuring the cement bond radially. Cement logs do not actually determine whether fluid movement through the annulus is occurring. They only can determine whether cement is present in the annulus and in some cases can give a qualitative assessment of the quality of the cement in the annulus. Cement evaluation logs are used to calculate a bond index which varies between 0 and 1, with 1 representing the strongest bond and 0 representing the weakest bond.

If the well fails an external MIT, damaged or missing cement may be repaired using a cement squeeze (Wojtanowicz, 2008). A cement squeeze involves injection of cement slurry into voids behind the casing or into permeable formations. Different types of cement squeezes are available depending on the location of the void needing to be filled and well conditions (Kirksey, 2013). Cement squeezes are not always successful, however, and may need to be repeated to successfully seal off flow (Wojtanowicz, 2008).

D.5. References for Appendix D

Ali, M; Taoutaou, S; Shafqat, AU; Salehapour, A; Noor, S. (2009). The use of self healing cement to ensure long term zonal isolation for HPHT wells subject to hydraulic fracturing operations in Pakistan. Paper presented at International Petroleum Technology Conference, December 7-9, 2009, Doha, Qatar.

API (American Petroleum Institute). (1999). Recommended practice for care and use of casing and tubing [Standard] (18th ed.). (API RP 5C1). Washington, DC: API Publishing Services.

API (American Petroleum Institute). (2004). Recommended practice for centralizer placement and stop collar testing (First ed.). (API RP 10D-2 (R2010)).

API (American Petroleum Institute). (2009a). Hydraulic fracturing operations - Well construction and integrity guidelines [Standard] (First ed.). Washington, DC: API Publishing Services.

API (American Petroleum Institute). (2009b). Packers and bridge plugs (Second ed.). (API Spec 11D1).

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

API (American Petroleum Institute). (2010b). Specification for cements and materials for well cementing [Standard] (24th ed.). (ANSI/API SPECIFICATION 10A). Washington, DC: API Publishing Services. http://www.techstreet.com/products/1757666

API (American Petroleum Institute). (2011). Specification for casing and tubing - Ninth edition [Standard] (9th ed.). (API SPEC 5CT). Washington, DC: API Publishing Services. http://www.techstreet.com/products/1802047

API (American Petroleum Institute). (2013). Recommended practice for testing well cements [Standard] (2nd ed.). (RP 10B-2). Washington, DC: API Publishing Services. http://www.techstreet.com/products/1855370

Arthur, JD. (2012). Understanding and assessing well integrity relative to wellbore stray gas intrusion issues. Presentation presented at Ground Water Protection Council Stray Gas - Incidence & Response Forum, July 24-26, 2012, Cleveland, OH.

Brufatto, C; Cochran, J; Conn, L; El-Zeghaty, SZA, A; Fraboulet, B; Griffin, T; James, S; Munk, T; Justus, F; Levine, JR; Montgomery, C; Murphy, D; Pfeiffer, J; Pornpoch, T; Rishmani, L. (2003). From mud to cement - Building gas wells. Oilfield Rev 15: 62-76.

CAPP (Canadian Association of Petroleum Producers). (2013). CAPP hydraulic fracturing operating practice: Wellbore construction and quality assurance. (2012-0034). http://www.capp.ca/getdoc.aspx?DocId=218137&DT=NTV

Cramer, DD. (2008). Stimulating unconventional reservoirs: Lessons learned, successful practices, areas for improvement. SPE Unconventional Reservoirs Conference, February 10-12, 2008, Keystone, CO.

Crescent (Crescent Consulting, LLC). (2011). East Mamm creek project drilling and cementing study. Oklahoma City, OK. http://cogcc.state.co.us/Library/PiceanceBasin/EastMammCreek/ReportFinal.pdf

Crook, R. (2008). Cementing: Cementing horizontal wells. Halliburton.

Dusseault, MB; Gray, MN; Nawrocki, PA. (2000). Why oilwells leak: Cement behavior and long-term consequences. Paper presented at SPE International Oil and Gas Conference and Exhibition in China, November 7-10, 2000, Beijing, China.

Enform. (2013). Interim industry recommended practice 24: fracture stimulation: Interwellbore communication 3/27/2013 (1.0 ed.). (IRP 24). Calgary, Alberta: Enform Canada. http://www.enform.ca/safety_resources/publications/PublicationDetails.aspx?a=29&type=irp

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

Jackson, RE; Gorody, AW; Mayer, B; Roy, JW; Ryan, MC; Van Stempvoort, DR. (2013). Groundwater protection and unconventional gas extraction: the critical need for field-based hydrogeological research. Ground Water 51: 488-510. http://dx.doi.org/10.1111/gwat.12074

Jiang, L; Guillot, D; Meraji, M; Kumari, P; Vidick, B; Duncan, B; Gaafar, GR; Sansudin, SB. (2012). Measuring isolation integrity in depleted reservoirs. SPWLA 53rd Annual Logging Symposium, June 16 - 20, 2012, Cartagena, Colombia.

Julian, JY; King, GE; Johns, JE; Sack, JK; Robertson, DB. (2007). Detecting ultrasmall leaks with ultrasonic leak detection, case histories from the North Slope, Alaska. Paper presented at International Oil Conference and Exhibition in Mexico, June 27-30, 2007, Veracruz, Mexico.

Kirksey, J. (2013). Optimizing wellbore integrity in well construction. Presentation presented at North American Wellbore Integrity Workshop, October16-17,2013, Denver, CO.

Lyons, WC; Pligsa, GJ. (2004). Standard handbook of petroleum and natural gas engineering (2nd ed.). Houston, TX: Gulf Professional Publishing. http://www.elsevier.com/books/standard-handbook-of-petroleum-and-natural-gas-engineering/lyons-phd-pe/978-0-7506-7785-1

McDaniel, BW; Rispler, KA. (2009). Horizontal wells with multistage fracs prove to be best economic completion for many low permeability reservoirs. Paper presented at SPE Eastern Regional Meeting, September 23-15, 2009, Charleston, WV.

McDaniel, J; Watters, L; Shadravan, A. (2014). Cement sheath durability: Increasing cement sheath integrity to reduce gas migration in the Marcellus Shale Play. In SPE hydraulic fracturing technology conference proceedings. Richardson, TX: Society of Petroleum Engineers. http://dx.doi.org/10.2118/168650-MS

MSC (Marcellus Shale Coalition). (2013). Recommended practices: Drilling and completions. (MSC RP 2013-3). Pittsburgh, Pennsylvania.

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

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

Sabins, F. (1990). Problems in cementing horizontal wells. J Pet Tech 42: 398-400. http://dx.doi.org/10.2118/20005-PA

Stein, D; Griffin Jr, TJ; Dusterhoft, D. (2003). Cement pulsation reduces remedial cementing costs. GasTIPS 9: 22-24.

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

Watson, TL; Bachu, S. (2009). Evaluation of the potential for gas and CO2 leakage along wellbores. S P E Drilling & Completion 24: 115-126. http://dx.doi.org/10.2118/106817-PA

Wojtanowicz, AK. (2008). Environmental control of well integrity. In ST Orszulik (Ed.), Environmental technology in the oil industry (pp. 53-75). Houten, Netherlands: Springer Netherlands.