# Environmental Guidance Document: Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations

API BULLETIN E3
FIRST EDITION, JANUARY 31, 1993

Reaffirmed 1 June 2000

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## FOREWORD

This document, prepared by the API Underground Injection Control Issue Group (UICIG), provides guidance on environmentally-sound abandonment practices for wellbores drilled for oil and gas exploration and production (E&P) operations. The guidance is focused primarily on onshore wells. Guidance is provided for the practices that may be used and for the selection and placement of materials necessary to accomplish the following:

- Permanently abandon wells.
- Place wells on inactive status.

Permanent abandonment should be performed when there is no further utility for a wellbore by sealing the wellbore against fluid migration. Inactive well practices may be performed when a wellbore has future utility, such as for enhanced oil recovery projects. This permits the operator to hold the well in a condition that facilitates restoring its utility.

The purpose of this document is to address the environmental concerns related to well abandonment and inactive well practices. The primary environmental concerns are protection of freshwater aquifers from fluid migration, as well as isolation of hydrocarbon production and water injection intervals. Additional issues discussed herein are protection of surface soils and surface waters, future land use, and permanent documentation of plugged and abandoned (P&A) wellbore locations and conditions.

The guidance contained in this document is presented by the following process:

1. Discussing a methodology for assessing the contamination potential of wells.
2. Describing the environmental concerns that justify proper wellbore abandonment procedures.
3. Describing permanent plugging and abandonment procedures.
4. Establishing risk based guidelines for monitoring inactive wells.
5. Summarizing major environmental legislation and associated regulations applicable to wellbore abandonments.

API encourages use of well abandonment practices based on the methods presented in this document. API also supports any Federal and state well abandonment programs consistent with its guidance. There are numerous Federal and state statutes, rules, and regulations specifying proper well abandonment practices. Users of this document should review the current requirements of Federal, state, and local regulations to ensure that this guidance is consistent with those regulatory requirements.

# SECTION 1
# ENVIRONMENTAL CONSIDERATIONS FOR PLUGGED AND ABANDONED WELLS

## 1.1 GENERAL

This section presents the results of a literature and research review concerning well plugging and abandonment. The purpose of the review was to ascertain the risk of fresh water aquifer contamination that may exist from wells. The means of contamination was considered to be from fluid migration through the wellbore. From the information presented in this section, criteria may be ascertained for operator use in evaluating the fluid migration potential within existing wells.

Existing wells have been regarded as a potential source of fresh water aquifer contamination. It has been estimated that approximately 3.3 million wells have been drilled in the United States petroleum extraction industry since the 1859 oil discovery well at Titusville, Pennsylvania. Of the total wells drilled, API estimates that 2.2 million wells are either plugged, abandoned, or inactive. From that figure, API estimates that 1.2 million wells are P&A wells. The P&A wells include former production, injection, and disposal wells as well as dry holes.

Using a methodology derived from the material presented in this guidance document, an operator should be able to identify those existing wells in which there may be a potential for fluid migration. There are conditions in existing wells that may preclude fluid migration.

Cement has long been recognized as an effective material for precluding water entry into the wellbore. An 1899 Texas Plugging Law required operators to plug wells by filling the well with rock, sediment, or with mortar, composed of two parts sand and one part cement, to a depth of 200 ft above the top of the first oil or gas bearing rock. Cementing casing in wells began in 1903 and use expanded in 1910 when [wiper-like] plugs were first used to place the cement pumped in a well. By the mid 1930's, cement plug placement applications for water shut-off and for well plugging had been developed.[1] Cement was found to be effective in these applications because of its chemical reaction with the mix-water, called hydration, that resulted in the formation of a stonelike mass. During the hardening process, the cement would adhere to adjacent formation faces or casing walls, thereby effectively sealing the wellbore from fluid migration.

Wells P&A'd prior to the late 1930's generally were unregulated concerning proper plugging procedures. The majority of past problems cited drinking water contamination from wells drilled prior to the 1930's.[2] Change began, in one case, as early as 1919. Texas then enacted a law requiring operators to plug wells so that oil, gas, and water are confined in the strata in which they are found. Beginning in the late 1930's, most states had begun protecting drinking water resources by regulating E&P well drilling, completions, and abandonments.[3] Regulatory agencies began requiring cement plugs to be placed in the wellbore during abandonment to prevent hydrocarbon and saltwater movement through the wellbore as well as requiring plugs to protect fresh water aquifers.

## 1.2 PLUGGING PURPOSE

The literature review indicated well plugging practices evolved largely from research and field practices that were implemented in response to regulatory program development. Regulatory programs were promulgated, beginning in the late 1930's, to conserve hydrocarbon resources and to protect fresh water aquifers. Generally, fluid migration from a well would occur from either or both of the following:

1. the well becomes a conduit for fluid flow between penetrated strata, fresh water aquifers, and the surface;
2. surface water seeps into the wellbore and migrates into a fresh water aquifer.

Conversely, fluid migration could be prevented by properly plugging a well. Not only could the plugging operations prevent a wellbore from becoming a conduit for fluid migration, but well construction methods and various natural phenomena could also contribute to preventing fluid migration.

## 1.3 INJECTION AND PRODUCTION WELL CONSTRUCTION

States were concerned with the protection of usable quality waters long before the Safe Drinking Water Act was enacted by Congress in 1974. All of the major oil and gas producing states have had injection and production well programs in place since the mid-1940's. The state programs regulated the construction, operation, monitoring, and plugging of these wells.

Most injection and production wells constructed after the late 1930's were required to have multiple barriers to prevent the migration of injected water, formation fluids, or produced fluids into fresh water aquifers. The barriers most effective in preventing fluid migration are shown in the following:

1. surface casing that is set below all known fresh water aquifers and is cemented to the surface (even for dry holes);
2. production casing (long string casing) extending from the surface to the injection or production zone and is cemented to prevent vertical migration of injected or produced fluids behind pipe.

These *modern* well construction safeguards helped protect fresh water aquifers, surface soils, and surface waters from contamination during injection and production operations over the life of these wells. Just as important, the construction safeguards enhanced the success of plugging operations, upon well abandonment, by improving the effectiveness of the cement plugs (placed during the plugging operation) to permanently prevent soil and water resources contamination.

*Modern* cementing materials and methods can effectively achieve an annular wellbore seal and casing support/protection as long as controllable problems are properly addressed. As Brooks established, the time frame for *modern* cementing began in the mid-1940's. Since that time, over 65 percent of existing wells were drilled nationwide.[3]

Also, during the *modern* cementing period, various industry groups, such as the American Petroleum Institute, have studied oil well cements and cementing practices.

API adopted standards in 1952 for the manufacture of six classes of oil well cements generally used in casing string cementing and in plugging operations. In 1953, API published "API Specification for Oil-Well Cements".[1] API has reviewed oil well cement standards annually since 1953; and some revisions have been made. The cementing standard is now known as "API Spec 10 A, Specification for Materials and Testing for Well Cements,"[4] and the specification now covers manufacturing requirements for eight cement classes. It has been demonstrated that when the appropriate cement is selected and properly placed, the durability of the cement and the cement job is indefinite.[3]

## 1.4 ENVIRONMENTAL SAFEGUARDS

The literature and research review also revealed that P&A wells have safeguards that protect natural resources. Proper plugging procedures yielded the primary safeguards in a P&A well that permanently[3] prevented fluid migration through the wellbore. Well construction methods as well as natural phenomena were found to provide additional safeguards that prevent natural resources contamination.

### 1.4.1 WELL CONSTRUCTION AND ABANDONMENT SAFEGUARDS

Several safeguards utilized during well construction and during plugging operations prevent fluid migration in P&A wells. The construction safeguards include surface casing and production casing installed and adequately cemented. Cement or mechanical plugs placed at critical points in the wellbore during either prior remedial or plugging operations prevent fluid migration within the wellbore.

1. **Well Construction.** As discussed in Section 1.3, surface and production casing strings cemented in place provide multiple barriers to injected or formation fluid migration during well operations and after plugging.

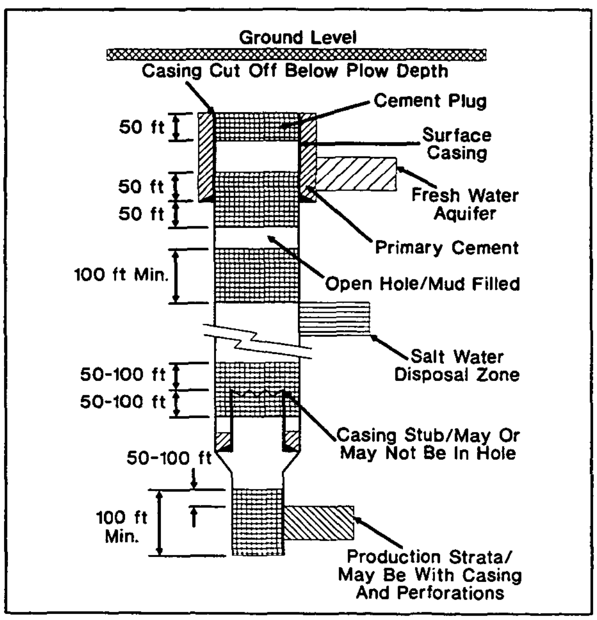


**FIGURE 1-1**
**SCHEMATIC OF PROPERLY PLUGGED WELL**

2. **Abandonment.** Safeguards provided during plugging and abandonment operations are cement plugs set in open holes as well as cement or mechanical plugs set above perforated intervals in production or injection zones, at points where casing has been cut, at the base of the lowermost fresh water aquifer, across the surface casing shoe, and at the surface. Proper placement of plugs prevents fluid migration through the casing or between the casing and borehole. Cement classes selected to meet wellbore conditions provide durable plugs.[3] Figure 1-1 is a schematic of a typical properly P&A'd well. State agencies have specified additional plug placements in some situations.

### 1.4.2 NATURAL SAFEGUARDS

The research review indicated cases in which natural factors can impede the migration of fluids and complement the effectiveness of plugging operations. These include wellbore impediments, subsurface formation effects, and formation pressure equalization. These phenomena may occur naturally to enhance the effectiveness of the cement or mechanical plugs in a P&A well to prevent environmental damage. Any or all of these natural safeguards may occur in a given well:

1. **Wellbore Impediments.** Wellbore impediments such as mud left in the P&A wellbore, sloughing shales, or collapsed formations can prevent or impede the migration of fluids. Mud properties such as viscosity, density, and its propensity to form filter cake with low permeability, provide resistance to fluid flow into and through the wellbore. In addition, the mud fluids typically left in the well have sufficient weight to suppress formation pressures, even those exceeding the normal pressure gradient, which further reduces the chances of fluid migration.

   In certain geological provinces, such as the Gulf Coast, sloughing shales or collapsing formations may seal the uncemented intervals behind the casing during either well operations or after plugging. In long open-hole intervals, such as a dry hole without production casing, sloughing shales or collapsing formations may naturally seal the wellbore.

2. **Subsurface Formation Effects.** Formation fluids will naturally move from higher pressure zones to lower pressure zones within a wellbore when there is a flow path.[5] The flow path taken by fluids in response to pressure differentials that exist between formations in communication depends on the properties of the formations (thickness, porosity, and permeability) and their fluids (density and viscosity). Formation fluids or injection fluids that may flow upwards through a wellbore may also encounter a formation below the fresh water aquifer which accepts the fluid, preventing fluid migration above that point.[6]

3. **Formation Pressure Equalization.** Fluid injection projects generally arrest the rate of reservoir pressure decline, or fluid injection may, in some cases, actually increase the reservoir pressure. The

reservoir pressure performance during a fluid injection project depends on the reservoir properties, the fluid injection rate, and the fluid withdrawals. If the difference between total fluid injection and total fluid withdrawal is small in comparison with the total reservoir volume, then the resulting reservoir pressure will be at or near the reservoir's original pressure. When injection results in locally over pressured conditions, that condition will not remain indefinitely. After injection stops, the pressure in the injection zone will equalize, and the pressure gradient will approach that existing prior to reservoir development as the pressure transients caused by the injection are absorbed in the supporting aquifer. Thus, formation pressure equalization should result in fluid injection zones posing long-term crossflow risks no greater than those of other normally pressured zones penetrated by the wellbore.

## 1.5 ENVIRONMENTAL RISK SUMMARY

There are many factors that prevent fluid migration in existing wells. In the early 1900s cement was used to preclude or control water entry into wellbores; this practice continues to be a significant factor in preventing fluid migration. The evolution of regulatory controls, beginning in the 1930's, on well construction and well plugging is a major element in the prevention of fluid migration. Construction practices, such as setting and cementing surface casing below all known fresh water aquifers, and the setting and cementing production casing to the production/injection zone, provide multiple barriers to fluid migration. These barriers also enhance the effectiveness of the plugging procedures in preventing fluid migration. Plugging practices that confine formation fluids and protect fresh water aquifers are the critical factors in preventing fluid migration. Finally, natural factors, such as wellbore impediments, subsurface formation effects, and formation pressure equalization, may also prevent fluid migration into a fresh water aquifer.

Operators should consider these factors as well as the presence of pressured formations and fresh water aquifers in developing a methodology for assessing the fluid migration potential within existing wells. The use of such a methodology should enable operators to identify those existing wells that have a potential for fluid migration. For those wells identified as having a potential for fluid migration, further evaluation should be done to determine if fresh water aquifers or the surface are threatened. UICIG research indicates that wells drilled or P&A'd after the advent of regulatory controls in the 1930's likely have a low potential for fluid migration.

# SECTION 2
# PLUGGING AND ABANDONMENT OPERATIONS

## 2.1 GENERAL

This section provides guidance on procedures for permanently plugging and abandoning a well used in onshore E&P operations. The procedures involve setting cement plugs at critical intervals to prevent the wellbore from becoming a conduit for fluid migration. The primary objectives of a well abandonment operation are protecting fresh water aquifers and confining hydrocarbon resources. The plugging and abandonment procedures provided in this document address environmental concerns by focusing on the following five objectives:

1. protecting fresh water aquifers from contamination by formation fluid migration or surface water runoff,
2. isolating productive or non-completed producible hydrocarbon intervals,
3. protecting surface soils and surface waters from contamination by formation fluid migration to the surface,
4. isolating injection/disposal intervals, and
5. minimizing conflict with surface land use.

The objectives are accomplished by placing cement or mechanical plugs at selected intervals in the wellbore to prevent fluid movement. Any interval which must be isolated in order to achieve one of the objectives is a critical interval. To assist in designing an effective plugging program, geologic strata penetrated by the wellbore should be characterized.

Plugging operations are focused primarily on protecting fresh water aquifers — the first objective. Plugs isolating hydrocarbon and injection/disposal intervals and a cement plug at the base of the lowermost fresh water aquifer accomplish this primary purpose. A surface plug also prevents surface water runoff from seeping into the wellbore and migrating into fresh water aquifers. Surface water entry into a well without a surface plug is a concern because the water may contain contaminants from agricultural, industrial, or municipal activities. Note that the plugs also work to protect surface soils and surface waters from wellbore fluids by confining those fluids in the well.

When EPA first promulgated final underground injection control (UIC) regulations in 1980 under the Safe Drinking Water Act (SDWA), they provided for protection of all aquifers or parts of aquifers which meet the definition of an *underground source of drinking water* (USDW), except where exempted (see 40 CFR 144.7 and 146.4). USDW is defined by EPA as an aquifer or its portion which supplies any public water supply system or currently supplies drinking water for human consumption, or which contains sufficient water to supply a public water system or has a total dissolved solids (TDS) concentration of less than 10,000 mg/l. EPA may exempt an aquifer if it will not serve as a source of drinking water in the future because:

1. it is economically or technically impractical to recover the water or to render it fit for human consumption, or
2. the aquifer produces or is expected to commercially produce minerals, hydrocarbons, or geothermal energy.

Oil producing states have been concerned with protecting fresh water aquifers long before EPA's role in the protection of drinking water sources was established. State agencies typically identified usable waters for protection. Operators were then required to set surface pipe at sufficient depths to protect fresh water sources. Existing state programs identify or define fresh water aquifers (or potable water, usable quality water, etc.) as those sources containing water suitable for human or livestock consumption. Therefore, state programs have generally protected water sources having a maximum TDS concentration of 3000 mg/l. Many state programs, which have existed prior to the enactment of the SDWA, may have fresh water protection requirements that differ from the EPA's UIC program. Consequently, this document only focuses on fresh water aquifers as defined in the glossary.

API recommends that operators set a cement plug at the base of the lowermost fresh water aquifer — or USDW — during plugging and abandonment operations as required by the rules and regulations applicable to the well.

Plugs isolating either productive or non-completed producible hydrocarbon zones or injection/disposal completion intervals will accomplish the second, third, and fourth objectives. In addition to protecting fresh water aquifers, these plugs should confine the hydrocarbons/injection fluids to their respective formations thereby preventing fluid migration to other zones in the wellbore. Care should be taken in the plug placement to ensure that existing production or injection intervals, as well as those identified producible hydrocarbon zones or injection intervals, are isolated. Open hole plugs, casing plugs, cement squeezed through casing perforations, or mechanical plugs will isolate the target formations in most cases. However, special procedures, such as perforating casing and circulating cement, may be necessary to isolate those non-completed producible hydrocarbon zones or injection intervals existing behind uncemented casing. It is important to prevent interzonal flow in a P&A well so that such cross-flow does not interfere in the commercial exploitation of the zones through nearby wellbores.

Minimizing the P&A well's conflict with surface land use, which is the fifth objective, is accomplished by removing the wellhead and cutting off the surface casing below plow depth, as well as restoring the surface location. Operators should be advised, however, that some states require an identifying marker be installed at the well site. After the wellbore plugging operations are completed, the operator should restore the well site consistent with the criteria presented in API's environmental guidance document entitled "Onshore Solid Waste Management in Exploration and Production Operations"[7] (order no. 811-10850 from: American Petroleum Institute, Publications and Distribution Section, 1220 L Street, N.W., Washington, DC 20005). The operator may have other surface restoration requirements imposed by the lease agreement or landowner.

Operators should consult appropriate Federal, state, and local regulatory agencies prior to commencing well plugging and abandonment operations. This will ensure that an operator's plugging program complies with applicable

Federal, state, and local regulations. Both the regulatory community and the oil and gas production industry recognize that properly P&A'd wells prevent fresh water aquifer contamination and fluid migration to the surface. Figure 1-1 is a schematic of a properly P&A'd well. State agencies may specify additional plug placements in some situations.

Plugging and abandonment operations should incorporate prudent methods to maintain well control throughout the job.

### 2.1.1 STATIC EQUILIBRIUM

The wellbore fluids should be static during balanced cement plug placement operations. Excessive fluid movement before the cement hardens could result in a nonsealing plug. To be static, wellbore fluids should be the same density at all depths in the wellbore, and if there are perforated or openhole intervals open to the wellbore, the wellbore fluid column should balance the formation pressures. Generally, water-based muds or water are used in plugging operations, and they are left in the well after cement plug placement. The type and weight of fluid left in the well between cement plugs may be stipulated by state or local rules.

#### 2.1.1.1 High Pressure/Lost Circulation Zones

High pressure zones or lost circulation zones can prevent static equilibrium from being achieved in the wellbore. Therefore, before setting balanced cement plugs in non-static conditions, methods such as spotting viscous high density mud pills, pumping lost circulation material, or other proven control measures should be used during plugging operations. Mechanical devices, such as bridge plugs, inflatable packers, or cement retainers may be appropriate for use in wells with high pressure/lost circulation zones. Squeeze cementing may also be an appropriate method for isolating a high pressure/lost circulation zone.

### 2.1.2 CEMENTING MATERIALS AND PLACEMENT TECHNIQUES

The cement plug is the key element in accomplishing the objectives (See Sec. 2.1) of abandonment operations. The minimum cement plug length used for wellbore isolation is generally 100 ft. The amount of cement used for a particular plug is calculated from the desired plug length, the hole diameter (based on caliper logs, if available, for borehole or open hole sections), and appropriate allowances for cement contamination by wellbore fluids or cementing spacers and for any unusual wellbore conditions. Note that some cement plug lengths may be specified by Federal or state regulations, or they may be specified by regulatory agencies because of particular wellbore circumstances. Cement isolation plugs may be placed using drill pipe, workstring, coiled tubing, production tubing, or wireline tools.

#### 2.1.2.1 Cement Slurry Design

The selection of a cement composition for plugging operations depends on the well depth, formation temperatures, formation properties, and wellbore mud properties. Class A, C, G, or H cements are typically used in well plugging operations. API Spec 10, "Specification for Materials and Testing for Well Cements" (5th Edition, July 1, 1990),[4] is recommended as a guide. Table 5.2 in API Spec 10 A (21st Edition, Sept 1, 1991) provides mix-water requirements for specification testing of API cements. However, the proportions presented in the following table, Table 2-1, may be a useful guide for field mixing of API cements.

**TABLE 2-1**
**CEMENT SLURRY COMPOSITION**

From API Spec 10A
"Specification for Well Cements," Table 2.2
(21st Edition, Sept. 1, 1991)

| 1 | 2 | 3 | |
|---|---|---|---|
| | | Water* | |
| API Class Cement | Water Percent By Weight of Cement | Gallons per Sack | (Litres per Sack) |
| A & B | 46 | 5.19 | (19.6) |
| C | 56 | 6.32 | (23.9) |
| D, E, F, & H | 38 | 4.29 | (16.2) |
| G | 44 | 4.97 | (18.8) |

* Based on a 94# sack

Cement additives, such as accelerators and retarders, may be added to control the properties of the cement slurry. For example, the thickening time for some slurries may need to be retarded to provide enough time to pump the cement to the desired depth. Accelerators may be needed if it is desirable for the slurry to harden quickly. There are several factors involved in designing an appropriate thickening time in a cement slurry. The factors involved in designing a cement slurry appropriate for the intended application include the following:

1. the effects on the cement slurry of well conditions, gas contamination, formation pressure, and temperature;
2. the estimated time to pump the slurry to the desired depth; and
3. an allowance for mechanical problems.

Water loss control additives may be needed for an effective squeeze slurry.

Volume extending additives or gel cements should not be used in isolation plugs. However, they may have application in controlling fluid influx to the wellbore so that a subsequent isolation plug may be set.

#### 2.1.2.2 Plugging Methods

Plugging and abandonment operations generally commence in the lowermost formation interval in a wellbore. Successive interval isolation operations proceed sequentially up the wellbore to the surface to achieve the abandonment objectives. Interval isolation may be achieved by either cement or mechanical plugs. Following are descriptions of methods commonly used to isolate formation intervals. The method used should be appropriate for the wellbore conditions in the interval being isolated. The SPE Monograph, Cementing, edited by Dwight K. Smith,[8] and Well

Cementing, edited by Erik B. Nelson,[9] are references providing further discussions of cementing materials and placement techniques.

1. **Balanced Plug Method.** The balanced plug method involves pumping the cement slurry through drill pipe, coiled tubing, workstring, or production tubing until the level of cement outside is equal to that inside the drill pipe/tubing string. Fluid spacers may be used both ahead of and behind the slurry to minimize cement contamination by the wellbore fluid, if the wellbore fluid is incompatible with the cement slurry. The pipe is then pulled slowly from the slurry, leaving the plug in place. The method is simple and requires no special equipment, other than a cementing unit to mix and pump the slurry downhole. Knowing the characteristics of the wellbore fluid is important in placing a cement plug, particularly in achieving circulation during placement. The wellbore must be in a static state (neither flowing or losing returns) prior to and subsequent to plug placement. Movement of well fluids before the cement plug hardens will affect plug quality and placement.

   Proper cement slurry design and cement plug setting practices improve the success of achieving the abandonment objectives. One balanced plug method is discussed by R. C. Smith, et al., in "Improved Method of Setting Successful Whipstock Cement Plugs," SPE 11415.[10] The paper is about setting whipstock plugs, but the methods presented may have application to setting abandonment plugs.

2. **Cement Squeeze Method.** The cement squeeze method involves pumping a cement slurry to the desired interval to be isolated, usually through tubing, coiled tubing, or drill pipe. Sufficient hydraulic pressure is then applied to the slurry such that the slurry dehydrates and a high strength filter cake is formed in the perforations, in open channels or fractures, or against the formation face. The cement becomes a barrier which prevents formation fluid movement into the wellbore. The cement squeeze method is often used in isolating wellbore intervals or repairing casing leaks. The cement squeeze method is also useful when wellbore conditions preclude achieving static equilibrium. Cement is generally squeezed through a cement retainer or packer set in the casing. The cement retainer and packer are mechanical tools that seal the casing, protecting the casing above those tools from the pressures associated with squeezing. Alternatively, in the bradenhead squeeze, cement may be squeezed down casing, workstring, tubing, or coiled tubing in which no downhole tools isolate the casing from the squeeze pressure. However, the bradenhead squeeze method is not appropriate if a casing leak, repaired casing, or other problem with the casing exists such that the placement of the cement is in doubt or the casing may fail under squeeze pressure.

3. **Mechanical Plugs.** Mechanical isolation tools such as bridge plugs, retainers, permanent packers with plugs, etc. can be effectively used in casing to isolate sections of the wellbore. These plugs may be set at prescribed depths by wireline, tubing, workstring, or drill pipe. Although the mechanical plug provides the primary sealing mechanism in the wellbore, cement caps may be placed on top of the plug to provide a secondary seal and to assist drilling out the plug if the well is reentered.

4. **Dump Bailer Method.** The dump bailer, containing a measured quantity of cement, is lowered into the well on wireline. The bailer is opened on impact (i.e., striking the bridge plug, cement retainer, etc.) or by electric activation. Typically, the dump bailer method is used for placing cement on mechanical isolation tools. The method's advantage is that the depth of the cement plug is accurately controlled. The primary disadvantages are (1) a limited quantity of cement that can be transported in the dump bailer, (2) it is not easily adaptable to setting deep plugs, and (3) the cement plug can be contaminated with mud. Circulating the hole before dumping cement and having static wellbore fluids at the plug setting depth will reduce the possibility of cement contamination.

### 2.1.3 UNUSUAL ABANDONMENT SITUATIONS

Special abandonment procedures may be necessary for wells with unusual surface or downhole conditions. Procedures for such wellbore conditions are considered beyond the scope of this document. However, operators should ensure their plugging programs address the fluid migration potential associated with unusual conditions. If special procedures are needed for abandoning wells with unusual conditions, the operator is encouraged to develop the procedures and to seek concurrence of the appropriate Federal, state, and local agencies having oversight for well abandonments.

## 2.2 ISOLATING OPEN HOLE COMPLETIONS

Plugging open hole completion intervals (i.e., borehole that is uncased and open to the casing string above) may be done by one of the following methods:

1. **Displacement Method.** A balanced cement plug extending at least 50 ft above and below (or 100 ft above the plug-back total depth (PBTD) if the open hole length is less than 50 ft) the exposed casing shoe should effectively isolate the casing shoe and open hole (see Figure 2-2). Depending on reservoir properties and open hole length, operators may wish to set a plug through the entire open hole interval.

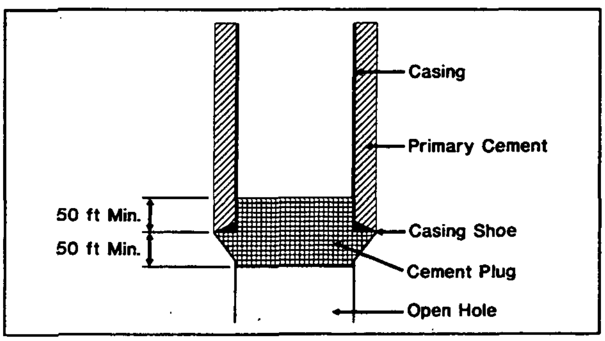


**FIGURE 2-2**
**ISOLATION OF OPEN HOLE WITH CEMENT PLUG**

2. **Cement Retainer Method.** The casing shoe may be isolated by setting a cement retainer 50-100 ft from the casing shoe and squeezing cement below the retainer. The amount of cement used should fill the volume of the casing and the open hole interval 50 ft below the shoe. Cement should also be left on top of the retainer (see Figure 2-3).

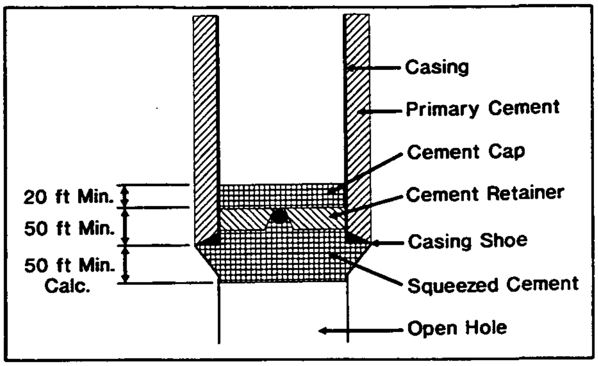


**FIGURE 2-3**
**ISOLATION OF OPEN HOLE WITH SQUEEZED CEMENT BELOW A RETAINER**

3. **Cast Iron Bridge Plug (CIBP) Method.** For some open hole intervals, such as those completions in reservoirs producing under depletion drive, a CIBP set 50-100 ft above the casing shoe may effectively isolate the open hole. Cement should be placed on top of the CIBP as recommended in the *cement retainer method.*

## 2.3 ISOLATING UNCASED HOLE

Long uncased formation intervals frequently occur when dry holes are P&A'd or when the production casing is cut and pulled from existing wells during abandonment operations. In the latter case, a casing stub may have to be isolated before performing interval isolation in the long uncased hole section (see Section 2.4.3). Interval isolation in uncased holes is needed to confine hydrocarbon/injection fluids to their respective formations.

Zonal isolation in an uncased hole is accomplished by setting balanced cement plugs across productive or non-completed producible hydrocarbon zones and injection/disposal zones, and by setting a plug at the base of the lowermost fresh water aquifer (if exposed). The cement plugs should extend 50 ft above and below the zone being isolated (see Figure 2-4). Where the cross-flow potential between these zones would result in a waste of hydrocarbons, or where long intervals of impermeable zones exist, long uncased hole isolation may be achieved by setting a 100 ft plug at the top of the interval rather than isolating geologic horizons.

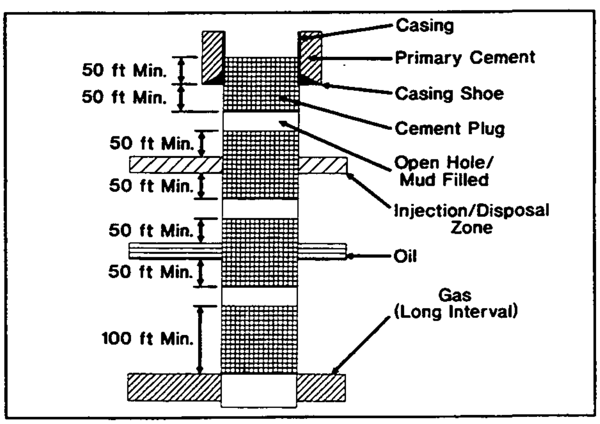


**FIGURE 2-4**
**ISOLATION OF ZONES IN UNCASED HOLE**

Isolating a casing shoe at the top of a long uncased formation interval may effectively isolate the interval if no producible hydrocarbon or injection/disposal zones exist. A casing shoe at the top of a long uncased formation interval should be isolated with a balanced cement plug extending at least 50 ft above and below the casing shoe. Alternatively, the balanced cement plug method or the cement retainer method can be used (see Figures 2-2 and 2-3).

## 2.4 CASED HOLE ABANDONMENT METHODS

Cased hole abandonment methods prevent fluid migration through the casing and through any uncemented annular space between the casing and the borehole or next larger casing. The methods discussed below will address both casing with and without cement in the annular space.

### 2.4.1 PLUGGING PERFORATED INTERVALS

Perforated productive zones and injection/disposal intervals should be isolated and plugged to prevent fluid entry into the wellbore. Wellbore dimensions, formation properties, and reservoir pressures should be considered when selecting a perforation isolation method.

1. **Displacement Method.** A perforated interval may be isolated by setting a balanced cement plug across or above the perforated section. A plug across the perforations should typically extend from at least 50 ft below the perforated interval (or from the PBTD, whichever is less) to at least 50 ft above the perforated interval (see Figure 2-5). Depending on reservoir conditions, long perforated intervals or long intervals composed of discrete perforation sets may be isolated by setting a 100 ft cement plug above the topmost perforation.

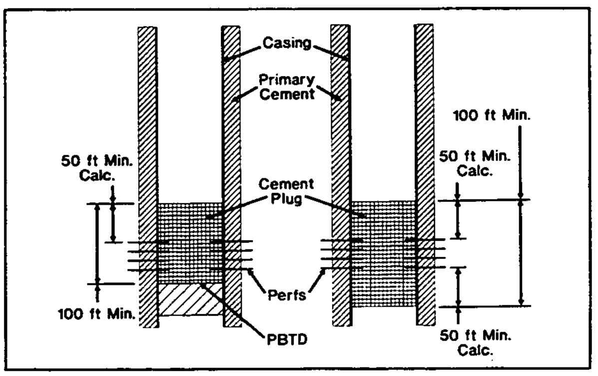


**FIGURE 2-5**
**ZONE ABANDONMENT WITH DISPLACEMENT METHOD**

2. **Squeeze Cementing Method.** Perforated intervals may be isolated by squeezing the perforations (see Figure 2-6). The squeeze is done by pumping cement into the perforations through a cement retainer, retrievable packer, or existing production/injection packer set at least 50 ft above the top set of perforations. The amount of cement used should fill 100 ft of casing below the squeeze tool plus an allowance

for loss through perforations. At least 20 ft of cement should also be placed on any tool left in the well. An alternate squeeze procedure is the bradenhead method (see Figure 2-6).

Squeeze cementing techniques will confine injected fluids (water or gas) to the zone of interest, will isolate high pressure intervals, and will effectively prevent behind-pipe cross-flow.

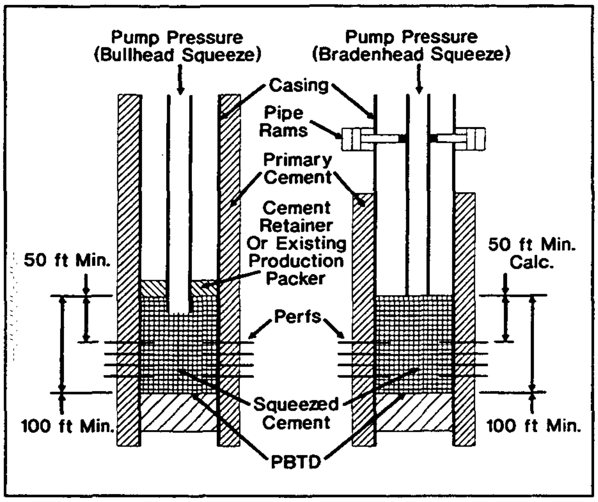


FIGURE 2-6
ZONE ABANDONMENT WITH SQUEEZE CEMENTING

3. **CIBP Method.** Perforated intervals may be isolated by setting a CIBP (or other permanent casing tools, including a permanent production packer with a plug installed) 50-100 ft from the top set of perforations. At least 20 ft of cement should be placed on top of the CIBP (see Figure 2-7).

   The CIBP method and the displacement method are effective in isolating perforation intervals where cement between the casing and the borehole above the perforations prevents behind-pipe fluid migration.

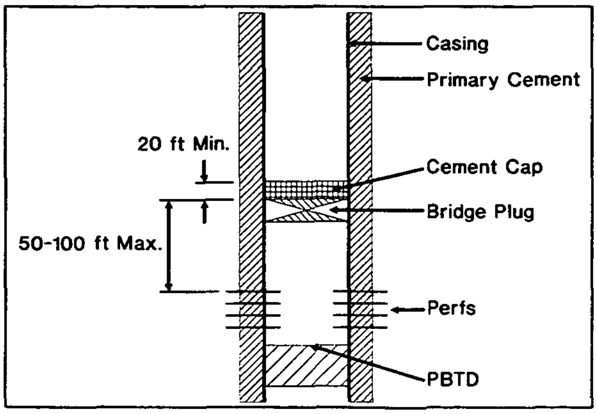


FIGURE 2-7
ZONE ABANDONMENT WITH USE OF PERMANENT BRIDGE PLUG

### 2.4.2 COILED TUBING ABANDONMENT

Coiled tubing or concentric tubing may be used to place cement plugs in wells in the same manner that tubing, drill pipe, or workstring is used to transport cement downhole. Coiled tubing or concentric tubing use may also be an effective alternative method to expensive well work in placing cement at critical points in wells. These methods would be useful in some remote locations, in plugging slim hole completions, and in cases where tubing and other downhole equipment is not recovered from the well.

### 2.4.3 ISOLATING CASING STUBS

A casing stub is the remnant of a casing string when the casing has been cut and partially recovered. Casing stubs may occur either inside open hole or inside the next larger casing string. The casing stub should be isolated to prevent fluid migration through either the remnant casing string or the annular space below the remnant casing. Casing stub isolation may be done with the following methods.

The isolation method selected for casing stubs depends on whether flow occurs from or fluid is lost to the annular space below the stub.

1. **Displacement Method.** A balanced cement plug is placed such that it extends 50 ft inside the remnant casing and 50 ft into the next larger casing or open hole. The calculated annular volume between the stub and the larger casing string or open hole should also be included in the cement plug volume (see Figure 2-8).

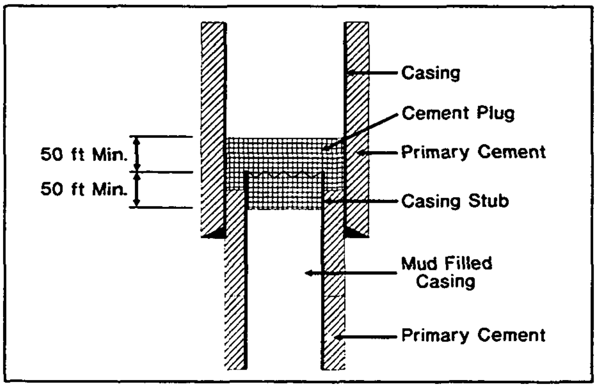


FIGURE 2-8
ISOLATION OF CASING STUB WITH CEMENT PLUG

2. **CIBP Method.** Set a CIBP in the larger casing 20-50 ft above the casing stub. A 20 ft cement cap is commonly placed on top of the CIBP (see Figure 2-9).

3. **Cement Squeeze Method.** Set a cement retainer or squeeze packer in the next larger casing at least 50 ft above the casing stub, and squeeze cement below the tool. The amount of cement used should equal the volume of the casing below the squeeze tool plus that of the top 50 ft inside and outside the casing stub. Twenty feet of cement should be left on top of the retainer (see Figure 2-10).

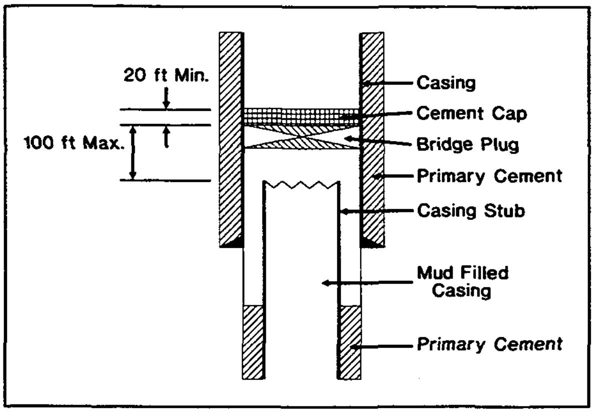


**FIGURE 2-9**
**ISOLATION OF CASING STUB WITH BRIDGE PLUG**

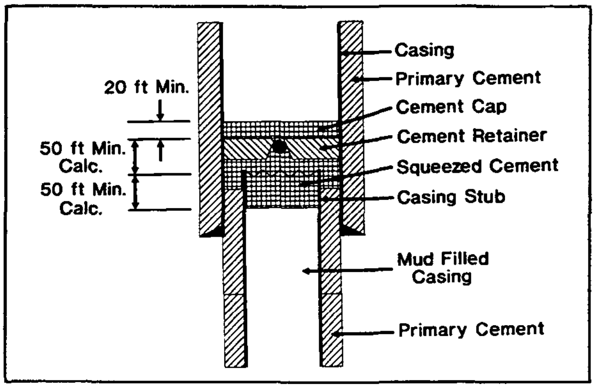


**FIGURE 2-10**
**ISOLATION OF CASING STUB WITH CEMENT RETAINER**

The displacement method is applicable for casing stub isolation when no fluid flow or losses are detected. The CIBP method may be useful for isolating casing stubs in casing when the larger casing is cemented. In most cases the cement squeeze method is preferred when fluid flow or losses occur from below the stub.

### 2.4.4 CASING NOT PULLED FROM THE WELL

Abandonment operations must also prevent fluid migration through the casing when the casing is not cut and recovered. The following procedures address the production casing either with or without cement behind pipe.

#### 2.4.4.1 Casing With Cement Behind Pipe

Any critical intervals existing behind pipe should be identified and then appropriately isolated by setting balanced cement plugs inside the casing. Balanced cement plugs should be set across any critical intervals previously squeezed or patched. The cement plugs should extend 50 ft above and below the critical interval. In addition, if a fresh water aquifer is present, then a 100 ft cement plug should be set in the casing extending at least 50 ft below the base of the lowermost fresh water aquifer.

#### 2.4.4.2 Casing Without Cement Behind Pipe

Casing without cement behind pipe may require special procedures to prevent fluid migration between the casing and borehole if critical intervals exist behind the uncemented casing. There are many wells in which the production casing was not cemented to the surface. Therefore, operators should be aware of the need to determine the top of cement behind the casing and to identify critical intervals in the uncemented annulus. An isolation program should be designed to confine hydrocarbon fluids and injected water below the isolation interval to prevent fluid migration to a fresh water aquifer. As described in Section 2.3, there may be conditions whereby long uncemented casing intervals may be effectively isolated by one cement squeeze operation.

The following procedures apply when there is no cement between the casing and the wellbore and critical intervals exist and need to be isolated.

1. **Squeeze Cementing Method.** When a long interval of uncemented casing can be effectively isolated by one cement squeeze operation, perforate the casing at the critical point. Squeeze the perforations with cement as described in Section 2.4.1, allowing for sufficient slurry volume to yield a 100 ft plug inside the casing and to provide for losses outside the casing and into the adjacent formation face.
2. **Block Squeeze Isolation.** Some critical zones may need to be isolated by perforating and block squeezing above and below the zones. Normally, a block squeeze involves two perforating steps and two squeeze steps to isolate the critical zone.[7] Operators should ensure that sufficient cement volumes and pumping pressures are used. A cement column equal to at least a 100 ft plug should be left in the casing following the block squeeze operations. Block squeezing is an effective isolation method when critical zones should be isolated separately and when it is not possible or practical to isolate critical zones by circulating cement.
3. **Isolation by Circulating Cement.** When wellbore conditions permit its use, one isolation method is to perforate in the uncemented casing interval near the top of cement and to circulate cement through the casing-borehole annulus. However, circulating cement may not be practicable because of downhole conditions (loss of circulation, collapsed casing, etc.).

#### 2.4.4.3 Casing Shoe Behind Pipe

The next larger casing protects any uphole permeable formations from fluid migration originating from below its shoe depth. However, the surface casing shoe is a critical interval because the surface casing generally provides the last level of protection against fluid migration into a fresh water aquifer. Therefore, an additional barrier to fluid migration should be placed at the surface casing shoe. Thus, the production casing opposite the surface casing shoe and the casing annulus opposite the surface casing should be isolated with cement.

Operators should select one of the following surface casing shoe isolation procedures, depending on whether cement has been circulated in the production casing annulus to a depth of at least 100 ft above the surface casing shoe.

1. **Casing With Cement Behind Pipe**. When the production casing is cemented to a depth of at least 100 ft above the surface casing, setting a 100 ft balanced plug in the production casing opposite the behind-pipe shoe will isolate the shoe interval. The cement plug should extend 50 ft above and below the shoe interval. The top of cement in the production casing annulus should be at least 100 ft inside the surface casing for the production casing to be considered adequately cemented for shoe isolation purposes.
2. **Casing Without Cement Behind Pipe**. When the production casing annulus has not been cemented to within 100 ft above the surface casing shoe, then the shoe should be isolated by one of the methods described in Section 2.4.4.2. The cement slurry design should include enough cement to leave the equivalent of a 100 ft plug in the wellbore after squeezing or circulating cement.

#### 2.4.4.4 Isolating Fresh Water Aquifers

A cement plug must be set below the lowermost fresh water aquifer to prevent contamination from any upward fluid migration.

1. **Casing With Cement Behind Pipe**. A 100 ft balanced cement plug set from below the lowermost fresh water aquifer to the base of the lower most fresh water aquifer will isolate this critical interval.
2. **Casing Without Cement Behind Pipe**. Where uncemented casing is in the hole, perforating and squeezing cement should be utilized to isolate the base of the lowermost fresh water aquifer. (see Section 2.4.1, para. 2) Another method for isolating the lowermost fresh water aquifer when the production casing is uncemented is to cut and pull the casing; isolate the casing stub according to Section 2.4.3, isolate any open hole intervals according to Section 2.3, and isolate the lowermost fresh water aquifer behind the next larger cemented casing as described in paragraph 1. If practical, the hole above the casing stub should be completely filled with cement.

The method to isolate the lowermost fresh water aquifer when the production casing is uncemented should be based on an analysis of the risks and problems associated with each method.

If the lowermost fresh water aquifer is behind cemented surface casing, and if the operator does not pull the production casing, the operator should ensure that the surface casing shoe has been isolated. (See Section 2.4.4.3.) Then, the lowermost fresh water aquifer will be isolated. The operator may then proceed with setting a surface plug.

Additional plugs within the fresh water aquifer interval may be appropriate and/or required by state regulations if the interval is long or if there are other reasons to isolate fresh water aquifers, such as significant differences in water quality between freshwater aquifers.

### 2.4.5 SETTING SURFACE PLUGS

A surface cement plug should be used to prevent surface water runoff from entering the P&A wellbore. Before setting a surface plug, the operator should ensure that the lowermost fresh water aquifer has been effectively isolated and that the wellbore fluids are static.

The surface plug is a balanced cement plug set from a depth of 20-50 ft below the surface to just below ground level. The plug is usually set using drill pipe, workstring, production tubing, or coiled tubing; however, other means acceptable to Federal, state, or local agencies may also be used.

The wellhead should then be removed and any remaining casing string(s) should be cut off 3-6 ft below ground level (or deeper if required by the landowner).

If any uncemented annuli are observed after the casing string(s) has been cut off below the ground level, then attempts should be made to fill these voids with cement. If the voids are substantial, consideration should be given to filling them by cementing through small diameter tubing run inside each uncemented annulus. Otherwise, the annuli may be filled by pouring cement into them from the surface.

## 2.5 PLUG PLACEMENT VERIFICATION

Critical plugs are those which isolate hydrocarbon producing zones, injection zones, the lowermost fresh water aquifer, and the surface. Critical plug placement should be verified during plugging operations to ensure any fluid migration pathways have been sealed. Plug verification is important to ensure that the plug is where it is supposed to be and that the cement has hardened.

Tagging the plug is the usual method of verifying plug depth and competence. Tagging the plug with the drill pipe, tubing/coil tubing, or work string is the preferred verification method because it is a relatively simple test, it is a mechanical operation, and it does not expose the wellbore to pressure. Therefore, when using cement for critical plugs, operators should consider using accelerators, such as salt or calcium chloride. This would reduce the time delay between plug placement and plug verification. Plug verification should be attempted only if wellbore conditions will permit such an operation to be conducted safely.

Although plug tagging is the preferred verification method, operators should be advised that some regulatory agencies may require that a pressure differential be applied across the cement plug. Pressure testing a critical plug can be done only when the wellbore has sufficient integrity to withstand the pressure applied in testing the plug. Pressure testing plugs should be attempted only if hole conditions will permit it to be done safely.

A well designed cement slurry and proper placement of cement plugs in the wellbore should be sufficient to assure effective wellbore isolation. As outlined in this Guidance Document, controlling these factors will ensure that a sufficient quantity of cement will harden and become an effective wellbore seal. Therefore, tagging certain critical plugs should be adequate.

### 2.5.1 PLUG TAGGING PROCEDURES

Tagging critical plugs should ensure that the plug is properly placed in the wellbore and has the competence to isolate the critical interval. For plug tagging to be effective, the cement must first be hard enough to support mechanical contact by tubing/coil tubing, work string, drill pipe, or wireline tools. The wellbore and the wellbore fluids must be in a condition such that plug tagging may be conducted safely.

1. **Tubing/Work String/Drill Pipe**. Plug tagging may be accomplished using tubing, work string, or drill pipe by lowering the string until the plug is bumped and setting the string down on (i.e., tagging) the hardened plug until a perceptible change occurs on the rig's weight indicator. A tally of the tubing, work string, or drill pipe in the hole when the plug is tagged will adequately verify the plug depth.

   If tubing, work string, or drill pipe is used to set a cement retainer or CIBP as a critical plug, a pipe tally will also verify the plug setting depth. It is advisable that after setting the plug and releasing, the plug should be tagged to verify that it is set.

   Pipe tallies or other rig operation reports concerning plug tagging should be clearly labeled and maintained with the well abandonment records in the permanent well file.

2. **Wireline Methods.** Zonal isolation in cased holes frequently involves setting cement retainers or bridge plugs on wireline. The plug is usually set at the desired point based on the wireline unit depth indicator. After setting the plug, the plug should be bumped with the wireline assembly to verify it is set.

   Cement plug setting depths in either open hole or cased hole can also be wireline-verified by bumping the plug with the wireline assembly and noting the depth reading.

### 2.5.2 PRESSURE TESTING PLUGS

Tagging is all that is necessary to establish the depth and competence of most critical plugs. However, pressure testing plugs may be required by some regulatory agencies as a means of ensuring that the plug has effectively sealed the wellbore. Normally, pressure tests on the bottom plug and the first plug below the surface plug are the ones required. This would establish the internal pressure integrity of the wellbore. Pressure testing is accomplished by applying a pressure differential across the plug through swabbing (negative pressure differential) or by applying hydraulic pressure (positive pressure differential). Pressure testing is limited to cased holes for practical reasons. If a leak is detected, the operator should determine whether the plug is leaking or the section of the casing above the plug is leaking.

1. **Swabbing Method**. After isolating the plug, swab the well down until the hydrostatic fluid above the plug is below the reservoir pressure gradient of the zone isolated by the plug. Monitor the fluid level in the well for a reasonable time to ensure that it has been stabilized. If no fluid level change occurs, plug competence is considered verified.

2. **Pressure Test Method**. After isolating the plug and ensuring the wellbore is full, hook up the tubing, work string, drill pipe, or casing to a pump. (If tubing/work string/drill pipe and a packer is not run, a casing test may be appropriate.) Apply pressure (slightly greater than the expected pump-in pressure of the zone isolated by the plug), shut-in the well, and monitor the pressure with a chart recorder for a minimum of 15 minutes. If the pressure remains within plus or minus ten percent of the test pressure, the plug is considered to effectively seal the wellbore.

If operators pressure test critical plugs, then pipe tallies or wireline depth readings would be needed to verify plug depth. It is not anticipated that an operator would both tag a critical plug and pressure test it as well. Operators are advised to attempt the pressure testing of plugs only if wellbore conditions are static and if the well can withstand the pressure changes without losing control or creating casing integrity problems.

## 2.6 SURFACE RECLAMATION

After setting the surface plug and removing the wellhead, the operator should fill the cellar, the rat hole, and the mouse hole, if present. The operator should then recover any pit fluids and properly dispose them. Pits should be closed and the site reclaimed pursuant to applicable Federal, state, or local regulations and lease obligations. Production equipment, structures, junk, and trash should be removed from the location and sent to appropriate storage or disposal facilities. Finally, the surface site should be reclaimed, tilled, and reseeded as required by regulation and/or the lease agreement. Consult the API environmental guidance document "Onshore Solid Waste Management in Exploration and Production Operations"[7] for further information.

## 2.7 WELL ABANDONMENT RECORDS

All procedures used and well work records (wellbore clean outs, tubing movements, casing repair work, plug setting records, pipe tallies, etc.) or rig operations reports should be documented and maintained in a permanent well file. Regulatory agency permits and other regulatory required forms should also be maintained in the permanent file.

Furthermore, API suggests that the permanent well file be maintained in perpetuity. That is, the operator that P&A'd the well should preserve the file as the *operator of record.* However, if that property is acquired by another operator, the surviving operator should assume responsibility for preserving the permanent well file and become the *operator of record.* If the *operator of record* ceases doing business and no survivor assumes responsibility for the permanent well files, the appropriate regulatory agency should become custodian of those well files.

## 2.8 SPECIAL ABANDONMENT ISSUES

### 2.8.1 PLUGGING WELLS WHEN SURFACE PIPE NOT SET

Hole conditions or drilling problems sometimes force well abandonment prior to surface casing installation. In this special situation, there is still a potential for fluid migration. A balanced cement plug set from the borehole's total depth to the surface is suggested as an abandonment practice, if the borehole is not too deep or the diameter too large to make such an operation impractical or impossible. Otherwise, long uncased surface boreholes, such as those that may occur in Rocky Mountain drilling operations, should be P&A'd by isolating critical fresh water intervals. Cement plugs should extend 50 ft above and 50 ft below the fresh water zone being isolated, or long intervals may be isolated by setting a 100 ft plug at the top of the interval. In addition, a surface plug should be set as described in Section 2.4.5.

### 2.8.2 SLOTTED LINER COMPLETIONS

Wells completed with slotted liners set through the completion interval should have the completion interval isolated using the procedures for isolating open hole completion intervals (see Section 2.2), if possible. However, any sand control tools that are installed may not permit tubing, work string, or drill pipe to pass so that cement plugs may be set in the completion interval as recommended in Sections 2.2 and 2.4.1. If coiled tubing cannot be used to set cement plugs, then completion intervals in wells containing sand control tools may therefore be effectively isolated by installing tubing plugs in any tubing left in the completion interval, by installing a plug in a gravel pack packer and capping with cement, or by squeezing the zone from above the gravel pack packer. A top isolation plug should be set in an interval that has cement behind the production casing if the slotted liner was isolated by installing tubing plugs inside any remaining tubing.

# SECTION 3
# INACTIVE WELL PRACTICES

## 3.1 INTRODUCTION

As noted in Section 1, approximately 3.3 million wells have been drilled in the United States petroleum extraction industry since the 1859 oil discovery well at Titusville, Pennsylvania. Of the total wells drilled, API estimates that one million are inactive production, injection, and disposal wells.

Regulatory agencies are addressing concerns about inactive wells through rule making which emphasizes mechanical integrity verification. In a number of states, regulations are being promulgated which would subject all wells to the same procedures. Because of the large number of inactive wells, regulatory approaches that apply to all wells and do not include risk as a key variable do not focus on wells that pose the greatest risks, nor are they cost effective.

Inactive well programs should be prioritized based upon the greatest risk reduction. It is important to concentrate on identifying inactive wells where the greatest risks occur, so that timely action can be taken to prevent fluid migration from occurring. This approach is in alignment with recommendations from the Science Advisory Board's Relative Risk Reduction Strategies Committee report to William K. Reilly, EPA Administrator, entitled "Reducing Risk: Setting Priorities and Strategies for Environmental Protection."[11]

## 3.2 DEFINITIONS

This section introduces definitions and concepts relating to inactive wells that were not covered in Sections 1 and 2. Additional definitions pertaining to well abandonment and inactive well practices are presented in the Glossary.

The term *inactive*, when used with regard to well status, is broadly defined by regulatory agencies and covers a wide spectrum of wellbore conditions. Furthermore, Federal and state regulatory programs rarely make a distinction between inactive wells which have the completion interval isolated from the wellbore and those which have open completion intervals. Well status terms such as *shut-in, standing, temporarily abandoned (TA), inactive, suspended,* etc. have generally been used interchangeably by regulatory agencies.

Industry and regulatory agencies should standardize the terminology used to describe inactive wells. API recommends that inactive wells be classified as either *shut-in* or *TA* as defined below.

### 3.2.1 SHUT-IN WELL

An inactive well should be classified as shut-in when the completion interval is open to the tubing or to the casing. A shut-in well may have tubing and packer, which isolates the interior of the casing above the packer from the completion interval. A well may also be shut-in without a packer which exposes the interior of the casing to any fluids from the completion interval.

Shut-in wells may have been removed from active service in anticipation of workover, temporary abandonment, or plugging and abandonment operations. Generally, the wellbore condition is such that its utility may be restored by opening valves or by energizing equipment involved in operating the well. Shut-in status should begin three months after production, injection, disposal, or workover operations cease.

### 3.2.2 TEMPORARILY ABANDONED WELL

An inactive well should be classified as TA when the completion interval is isolated. The completion interval may be isolated using the bridge plug method, the cement squeeze method, or the balanced cement plug method. As an alternative to the bridge plug method, isolation of the completion interval may also be achieved by installing a plug in an existing packer which does not have tubing.

Temporary abandonment should be used when an operator is holding a wellbore in anticipation of future utilization, such as in an enhanced oil recovery project. TA status should begin the day after the completion interval has been isolated from the wellbore.

### 3.2.3 PRESSURED FORMATION

A pressured formation is any producing, injection, disposal, permeable hydrocarbon bearing, or permeable salt water bearing formation penetrated by the well which has sufficient pressure to initiate and sustain significant fluid migration into a fresh water aquifer or to the surface.

### 3.2.4 LEVEL OF PROTECTION

A level of protection is a barrier to fluid migration into fresh water aquifers that has mechanical integrity, and its integrity can be monitored with some degree of confidence. Well construction components, such as surface casing, production casing, tubing and packer, and wellbore plugs, are such barriers.

## 3.3 INACTIVE WELL PROGRAM CONCEPTS

The API inactive well program is a risk-based approach for determining if an inactive well poses a threat to fresh water aquifers, surface soils, or surface waters. The methodology described in the following sections identifies wellbore conditions that prevent fluid migration from pressured formations. Fluid migration potentials for inactive wells are defined based upon the presence of pressured formations and upon the well construction and its mechanical integrity.

### 3.3.1 INACTIVE WELL PROGRAM GOAL

The goal of the API inactive well program is to focus operator efforts on those inactive wells that pose a threat to fresh water aquifers or the surface. The API program involves a risk-based approach to developing effective monitoring programs for inactive wells so that fluid migration into fresh water aquifers, surface soils, or surface waters is prevented. To meet this goal and to provide the greatest flexibility in monitoring program design, it is suggested that operators take appropriate action to add levels of protection whenever practical or appropriate.

For example, temporarily abandoning a producing well completed with a packer in a pressured formation adds a level of protection, since the completion interval is isolated. In such a case, the risk of wellbore fluid migration from the completion interval is reduced, which may justify less frequent monitoring.

### 3.3.2 PRESSURED FORMATIONS

The key risk factor for inactive wells is the presence of pressured formations, which are potential sources of contaminants for fresh water aquifers. If there are no pressured formations, the inactive well does not pose a threat to fresh water aquifers, surface soils, or surface waters. Where pressured formations exist, the potential for fluid migration to occur is a function of the well construction and mechanical integrity.

### 3.3.3 WELL CONSTRUCTION

The construction features of inactive wells which provide the mechanical barriers to fluid migration include: 1) surface casing installed below all fresh water aquifers with cement circulated to the surface; 2) any intermediate casing installed and cemented; 3) production casing installed and cemented into the lowermost confining zone; and 4) any tubing and packer set in the well above the completion interval. The Christmas-tree or stuffing-box assembly isolates the wellbore fluids from the surface and provides readily accessible gauges on all tubing, casing, and annuli outlets for ease of monitoring pressures. The mechanical integrity of these well construction components is the key factor in their ability to provide a barrier to fluid migration.

There are inactive wells which provide adequate protection against fluid migration into a fresh water aquifer or to the surface, but they may not have all of the construction details discussed above. By tailoring the monitoring program to a well's construction, operators can increase monitoring frequency for inactive wells that have fewer barriers to fluid migration.

### 3.3.4 FLUID MIGRATION POTENTIAL

The API inactive well program evaluates the potential for wellbore fluids to migrate through an inactive wellbore. Four fluid migration potential categories are defined in Table 3-1 as *minimum, low, moderate,* and *significant.* The appropriate fluid migration potential category for an inactive well is determined by the presence, or absence, of pressured formations and by the number of levels of protection.

Concerns in evaluating the fluid migration potential are pressured formations existing as the completion interval or pressured formations existing behind uncemented casing in the same uncemented annulus as a fresh water aquifer that is not completely covered by surface casing. Pressured formations behind cemented casing are isolated and have minimum potential for fluid migration.

### 3.3.5 WELL MONITORING PROGRAMS

The API inactive well program describes monitoring that could be used by an operator for wells in the four fluid migration potential categories. The well monitoring program requirements and monitoring frequencies increase as the fluid migration potential increases.

### 3.3.6 INACTIVE WELL MONITORING PROGRAM DESIGN

The procedures discussed in this document are intended for operators use in designing their own inactive well programs.

**TABLE 3-1**
**CATEGORIES OF FLUID MIGRATION POTENTIAL INTO FRESH WATER AQUIFERS**

**Fluid Migration Potential Category**

**Minimum**

- There are no pressured formations, or the only pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing.

**Low**

- The well has two or more levels of protection, there is no sustained pressure on the surface casing annulus, and
  - The completion interval is a pressured formation, and all other pressured formations are isolated from the fresh water aquifers by cementing production casing, liner, or intermediate casing, or
  - The completion interval may or may not be a pressured formation, but there are two or more levels of protection between the shallowest uncemented pressured formation and the lowermost fresh water aquifers.

**Moderate**

- The well has one level of protection, there is no sustained pressure on the surface casing annulus, and
- The completion interval is a pressured formation, and all other pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing, or
  - The completion interval may or may not be a pressured formation, but there is one level of protection between the shallowest uncemented pressured formation and the lowermost fresh water aquifer.

**Significant**

- The well has zero levels of protection, and the completion interval is a pressured formation, or
- There is sustained pressure on the surface casing annulus, or
- The Christmas-tree or stuffing-box assembly design and mechanical integrity is not sufficient to provide long-term containment of the wellbore fluids, or
- A pressured formation and a fresh water aquifer exist in the same uncemented annulus.

The primary concern in managing inactive wells is identifying changing wellbore conditions in a timely manner so action can be taken before fluid migration occurs. For example, if monitoring indicates the completion interval changes from a non-pressured formation to a pressured formation, the operator should reevaluate the well's fluid migration potential and take action, as appropriate. The purpose of the program is to monitor pressures and to take appropriate action when unusual changes occur.

The guidelines and examples presented are not intended to cover all wellbore conditions or pressured formation scenarios. It is assumed that operators will use these concepts to design specific programs to meet any special circumstances that may arise.

NOTE: *When developing inactive well programs, operators should consult applicable Federal, state, and local regulations, as well as consider lease and landowner obligations, to ensure their program meets all requirements.*

## 3.4 INACTIVE WELL PROGRAM METHODOLOGY

This section outlines a procedure for classifying and monitoring an inactive well in a cost-effective manner that is consistent with the well's fluid migration potential. The purpose of the methodology is to (1) establish how effectively wellbore fluids will be controlled by the inactive well's construction components and (2) monitor the well to demonstrate mechanical integrity.

The procedure involves the following steps:

1. Classify the inactive well.
2. Characterize pressured formations penetrated by the wellbore.
3. Identify fresh water aquifers penetrated by the wellbore.
4. Determine the number of levels of protection.
5. Assign a fluid migration potential category.
6. Establish monitoring procedures.
7. Perform follow-up action as needed.

The methodology should be applied to all inactive wells. Operators should consider starting inactive well evaluations for those wells in areas where there is public exposure or proximity to public water supply fields. Operators should be guided in selecting a starting point by their knowledge of operating areas, considering such factors as incidence of casing leaks opposite pressured formations.

The seven steps of the procedure are discussed below. Appendix A should be consulted for information on how to apply the program.

### 3.4.1 INACTIVE WELL CLASSIFICATION

The first step in designing a monitoring program is to classify the inactive well as either shut-in or TA. See Section 3.2 for definitions.

### 3.4.2 CHARACTERIZATION OF PRESSURED FORMATIONS

The second step in designing a monitoring program is to identify and characterize any pressured formations penetrated by the well, since the absence of pressured formations means contamination of fresh water aquifers or the surface can not occur. An important requirement for characterizing a formation as a pressured formation is that there must be *sufficient pressure to initiate and sustain significant fluid migration into a fresh water aquifer or to the surface.* For fluid to migrate from a pressured formation into a fresh water aquifer or to the surface, the hydrostatic head of the pressured formation at the fresh water aquifer level must be sufficient to overcome the aquifer pressure. In addition, there must be sufficient permeability in the pressured formation and a flow path to the fresh water aquifer for significant fluid flow to be sustained.

For example, a salt water injection well that has near-wellbore formation permeability impairment may backflow to surface tankage when injection is discontinued. In many cases, the well will flow a few barrels of salt water and then stop flowing, depending on formation permeability. If the well is then shut-in, the near-wellbore pressure will decline as it approaches the formation pore pressure, and the fluid level in the tubing will drop until the fluid column head balances the formation pore pressure. If the fluid level drops to a depth where the hydrostatic head is not sufficient to overcome the fresh water aquifer head, there would not be *sufficient pressure to initiate and sustain significant fluid migration into a fresh water aquifer or to the surface.* This formation would not be classified as a pressured formation.

### 3.4.3 IDENTIFICATION OF FRESH WATER AQUIFERS

The third step in designing a monitoring program is to identify the fresh water aquifers penetrated by the well. The primary source for identifying and cataloging the subsurface depths of the fresh water aquifers are state regulatory agency records. Frequently, agency studies have identified the depths, total dissolved solids content, and formation name of the fresh water aquifers by field. With this information, the operator can use electric logs and other geologic information to identify and catalog the fresh water aquifers for individual inactive wells.

Where regulatory agency reports have not identified the fresh water aquifers, sources such as electric logs, water sampling data, U.S. Geological Survey reports, and state geologic reports are helpful in defining the fresh water aquifers.

NOTE: *The important point is to identify the subsurface depths of fresh water aquifers for individual inactive wells because this is what the inactive well monitoring program is designed to protect.*

### 3.4.4 LEVELS OF PROTECTION

The fourth step in designing a monitoring program is to evaluate the levels of protection provided by the well construction components. A level of protection is a mechanical barrier to fluid migration into fresh water aquifers that has mechanical integrity, and its integrity can be monitored with some degree of confidence. The well construction components, such as surface casing, production casing, tubing and packer, and wellbore plugs, are such barriers.

**TABLE 3-2**
**LEVELS OF PROTECTION AGAINST POTENTIAL FLUID MIGRATION TO FRESH WATER AQUIFERS**

| Equipment That Protects Against Potential Fluid Migration From Pressured Formations | Number of Levels of Protection |
|---|---|
| • Surface casing that completely covers the fresh water aquifers. | 1 |
| • Each intermediate casing string. | 1 |
| • Production casing. | 1 |
| • Tubing and packer. | 1 |
| • Isolation of completion interval with a bridge plug, cement squeeze, balanced cement plug, or plug in a packer with no tubing. | 1 |

The levels of protection against fluid migration from a completion interval that is a pressured formation are listed in Table 3-2.

The levels of protection are conservative predictors of fluid migration potential. There are a number of other important factors that prevent fluid migration into fresh water aquifers which are not considered as levels of protection because their effectiveness is difficult to evaluate.[12] These impediments to fluid migration are as follows:

- Borehole restrictions such as drilling mud, sloughing shales, and collapsed formations.
- Relatively long vertical distances that are typically found between fresh water aquifers and pressured formations.
- The presence of extremely porous and permeable intervening formations between pressured formations and fresh water aquifers.

One or more of these impediments may demonstrate during long-term field performance that it is an effective barrier to fluid migration. If so, then the operator should count the impediment as a level of protection when a well is in the *significant* fluid migration potential category. Refer to Section 3.4.5.4 for a discussion of the *significant* fluid migration potential category.

### 3.4.5 FLUID MIGRATION POTENTIAL CATEGORIES

The fifth step in developing a monitoring program is to determine the fluid migration potential of the inactive well. As discussed below, the four fluid migration potential categories for inactive wells are *minimum, low, moderate,* and *significant.*

#### 3.4.5.1 Minimum

The *minimum* fluid migration potential category is for wells:

- that do not penetrate a pressured formation, or
- where the only pressured formations penetrated by the well are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing.

As long as these conditions exist, potential for fluid migration to fresh water aquifers is minimal. Therefore, monitoring is designed to detect:

- changes in field operations, such as initiating a miscible carbon dioxide tertiary recovery project, that may result in a reservoir becoming a pressured formation, or
- sustained pressure on the tubing, casing, or casing/casing annuli that indicates the development of a pressured formation.

#### 3.4.5.2 Low

Wells that have a *low* fluid migration potential have two or more levels of protection, no sustained pressure on the surface casing annulus, and

- the completion interval is a pressured formation, and all other pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing, or
- the completion interval may or may not be a pressured formation, but there are two or more levels of protection between the shallowest uncemented pressured formation and the lowermost fresh water aquifer.

Because wells in the *low* category pose more risk of fluid migration than wells in the *minimum* category, the monitoring program for the *low* category is more definitive and recommends that more frequent monitoring occur.

#### 3.4.5.3 Moderate

Wells that have a *moderate* potential for fluid migration have one level of protection, no sustained pressure on the surface casing annulus, and

- The completion interval is a pressured formation, and all other pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing, or
- The completion interval may or may not be a pressured formation, but there is one level of protection between the shallowest uncemented pressured formation and the lowermost fresh water aquifer.

Wells in the *moderate* category are monitored more frequently than wells in the *low* category.

#### 3.4.5.4 Significant

Wells in the *significant* fluid migration potential category have:

- Zero levels of protection, and the completion interval is a pressured formation, or
- Sustained pressure on the surface casing annulus, or
- A Christmas-tree or stuffing-box assembly whose design and mechanical integrity is not sufficient to provide long-term containment of the wellbore fluids, or
- A pressured formation and a fresh water aquifer existing in the same uncemented annulus.

In the API methodology, the *significant* category is a trigger for immediate evaluation work to determine whether fluid migration could be sustained into a fresh water aquifer. For example, long-term field experience may indicate existing impediments, such as collapsed formations, that prevent fluid migration from a pressured formation into a fresh water aquifer (see Section 3.4.4). Also, diagnostic techniques or logging may be useful in designing a monitoring program that would detect flow into a fresh water aquifer. In some cases, wellbore repairs that would add a level of protection or plugging and abandoning the well may be appropriate.

### 3.4.6 MONITORING PROCEDURES FOR PROTECTING FRESH WATER AQUIFERS

The sixth step in designing an inactive well monitoring program is to develop monitoring procedures consistent with the fluid migration potential category. A summary of monitoring procedures and suggested time intervals for protecting fresh water aquifers is presented in Table 3-3. For examples of typical monitoring procedures for each inactive well classification, refer to Appendix A.

As shown in Table 3-3, the periodic monitoring program for each fluid migration potential category becomes more rigorous as the potential for fluid migration into a fresh water aquifer increases. For example, a well in the *minimum* category requires fluid level and pressure monitoring every five years. This contrasts with monitoring pressures monthly and pressure testing the casing every year for a well in the *moderate* category. Note that monitoring procedures and monitoring frequencies increase with increasing fluid migration potential. Operators may want to evaluate the long-term cost of frequent monitoring operations versus the cost of either adding levels of protection or by plugging and abandoning the well.

**TABLE 3-3**
**SUMMARY OF SUGGESTED MONITORING TIME INTERVALS**

| Fluid Migration Potential Category | Monitoring Frequency |
|---|---|
| **Minimum** | |
| Fluid Level and/or Pressures | |
| Initial | 3 Months |
| Periodic | 5 Years |
| Monitor Operations for Changes | As Needed |
| **Low** | |
| Pressures | |
| Initial | 3 Months |
| Periodic | 1 Year |
| Pressure Test Casing | |
| Initial | 3 Months |
| Periodic | 5 Years |
| **Moderate** | |
| Pressures | |
| Initial | 3 Months |
| Periodic | 1 Month |
| Pressure Test Casing | |
| Initial | 3 Months |
| Periodic | 1 Year |
| **Significant** | Evaluate Immediately |

More frequent monitoring than that indicated in Table 3-3 may be appropriate in some areas due to special conditions such as highly permeable pressured formations or pressured formations that contain very corrosive formation waters. Operators should modify the suggested monitoring frequencies to meet those types of special conditions.

### 3.4.7 MONITORING PROCEDURES FOR PROTECTING SURFACE SOILS AND SURFACE WATERS

To protect surface soils and surface waters from potentially damaging wellbore fluids, inactive wells should have Christmas-tree or stuffing-box assemblies whose design and mechanical integrity are adequate to contain the fluids and permit rapid pressure observations of the tubing, casing, and all annuli.

If leaks are identified during a site inspection, repairs should be immediately initiated to stop the leak, or the well should be P&A'd, as appropriate.

For details concerning monitoring inactive wells for potential damage to surface soils and surface waters, refer to Appendix A.

### 3.4.8 FOLLOW-UP ACTION

Follow-up action should be initiated when the monitoring procedures detect a loss of mechanical integrity, sustained pressure on any casing/casing annulus, or a change in a pressured formation. The action taken may depend on the fluid migration potential. It is suggested that the operator first conduct additional diagnostic tests to characterize the situation. The following actions may then be considered:

1. changing the well's fluid migration potential category and implementing the monitoring program appropriate for the new category,
2. repairing the well to add levels of protection and initiating the monitoring program appropriate for the new fluid migration potential category, or
3. plugging and abandoning the well.

These suggested follow-up procedures provide the operator with options of implementing the most cost-effective procedure.

#### 3.4.8.1 Lease Termination

If a leasehold lapses then the operator may still be responsible for plugging and abandoning all wells.

#### 3.4.8.2 Well Signs

The operator should ensure that inactive wells are properly identified on posted signs, or as required by state regulations. Well signs should be appropriately maintained and changed if well ownership changes.

#### 3.4.8.3 Documentation

Site inspection, pressure data, fluid level data, and any mechanical integrity test data should be documented and retained.

## 3.5 SUMMARY

The API inactive well program suggests monitoring procedures and frequencies that are based on the risk of contaminating fresh water aquifers, surface soils, and surface waters. At the low end of the risk scale are those inactive wells that do not penetrate a pressured formation. These wells have minimal potential for fluid migration and require only sufficient monitoring to ensure that pressured formations do not develop in the wellbore.

Those wells that have completion intervals that are pressured formations have monitoring procedures and frequencies that are inversely proportional to their levels of protection. Thus, a well with pressured formations that has three levels of protection will require less monitoring than a well that has one level of protection.

# APPENDIX A
# PROCEDURE FOR DEVELOPING AN INACTIVE WELL PROGRAM

## A.1 PURPOSE

The primary purpose of Appendix A is to provide examples of the procedure for developing inactive well programs to protect fresh water aquifers and the surface. A key element in the procedure is a worksheet that uses well construction and reservoir information in a step-wise process to define a well's potential for fluid to migrate into a fresh water aquifer.

Although the main emphasis of these practices is directed towards providing protection for fresh water aquifers, Appendix A also reviews a program for protecting surface soils and surface waters.

For an overview of the methodology used in classifying and monitoring inactive wells, it is recommended that Section 3 be reviewed.

## A.2 INACTIVE WELL PROGRAM METHODOLOGY

The methodology for developing inactive well programs to protect fresh water aquifers and the surface uses well construction and reservoir data in a worksheet to determine the following individual well information:

- The number of levels of protection.
- The fluid migration potential category.

After the fluid migration potential category has been determined from the worksheet, typical monitoring procedures and time intervals are presented in tabular form as operator guidelines for field implementation. A table also outlines suggested follow-up procedures in the event the monitoring program indicates the loss of one or more levels of protection or a change in a formation's pressure characteristics.

### A.2.1 LEVEL OF PROTECTION

A level of protection is a barrier to fluid migration into fresh water aquifers that has mechanical integrity, and its integrity can be monitored with some degree of confidence.

The number of levels of protection is a function of the following items:

- The depths of the fresh water aquifers that are penetrated by the well.
- The well construction and the mechanical integrity of the well's fluid isolation components, which includes setting depths of tubing, packer, bridge plugs, casings, and their cement tops.
- The depths of the pressured formations that are penetrated by the well.

A list of levels of protection is shown in Table A-1.

#### DEFINITIONS:

A fresh water aquifer is a subsurface formation which generally contains water with less than 3,000 mg/l TDS and which supplies any public water supply system or currently supplies drinking water for human/livestock consumption or which contains sufficient water to supply a public water system.

A pressured formation is any producing, injection, disposal, permeable hydrocarbon bearing or permeable salt water bearing formation penetrated by the well which has sufficient pressure to initiate and sustain *significant fluid migration into* a fresh water aquifer or to the surface.

### A.2.2 FLUID MIGRATION POTENTIAL CATEGORIES

The inactive well program methodology utilizes four fluid migration potential categories. These categories are presented in Table A-2 and summarized below.

- Minimum — there are no pressured formations, or the only pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing.
- Low — there are two or more levels of protection, no sustained pressure on the surface casing annulus, and
  - The completion interval is a pressured formation, and all other pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing, or
  - The completion interval may or may not be a pressured formation, but there are two or more levels of protection between the shallowest uncemented pressured formation and the lowermost fresh water aquifer.
- Moderate — there is one level of protection, no sustained pressure on the surface casing annulus, and
  - The completion interval is a pressured formation, and all other pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing, or
  - The completion interval may or may not be a pressured formation, but there is one level of protection between the shallowest uncemented pressured formation and the lowermost fresh water aquifer.
- Significant
  - The well has zero levels of protection, and the completion interval is a pressured formation, or
  - There is sustained pressure on the surface casing annulus, or
  - The Christmas-tree or stuffing-box assembly design and mechanical integrity is not sufficient to provide long-term containment of the wellbore fluids, or
  - A pressured formation and a fresh water aquifer exist in the same uncemented annulus.

### A.2.3 INITIATING AN INACTIVE WELL PROGRAM

At the time an operator adopts an inactive well monitoring program, there may be wells that were placed on inactive status prior to the decision to adopt the program. For those existing inactive wells, the operator should establish an evaluation time frame based on a plan that assigns the highest priority to oil and gas fields whose wells have the greatest potential for fluid to migrate. See Section 3.4 for more information.

For example, the existence of pressured formations is the dominant factor in potential fluid migration. Operators should consider this, and other factors such as a very corrosive formation water, when determining the order in which they select oil or gas fields for evaluation of the fluid migration potential of all existing inactive wells in that field.

It is suggested that within three months after any inactive well's fluid migration potential has been evaluated, the well should be placed on the monitoring schedule.

## A.3 EXAMPLES OF METHODOLOGY APPLICATION

This Section presents examples of how the worksheet can be used by an operator to determine the number of levels of protection and the fluid migration potential category for an inactive well. In addition to example worksheets shown in Illustrations A-1 through A-5, a blank worksheet is included on pages 45 and 46.

Once the fluid migration potential category has been determined for a given well, suggested monitoring procedures and time intervals for shut-in without packer, shut-in with tubing and packer, and TA wells are presented in Tables A-3, A-4, and A-5, respectively. A summary of suggested monitoring time intervals for these three classes of inactive wells is presented in Table A-6.

NOTES: *All monitoring associated with protecting the fresh water aquifers should include a site inspection to insure there are no leaks that could endanger surface soils or surface waters.*

Refer to Section A.5 for a discussion of monitoring procedures for the protection of surface soils and surface waters.

### A.3.1 MINIMUM FLUID MIGRATION POTENTIAL CATEGORY

An example of how to use the worksheet to define the monitoring program for a shut-in producing well with tubing and without packer is reviewed in this Section.

The A.B. Jones # 1 is a shut-in producing well that has tubing without a packer. As shown in Figure A-1, the well's two levels of protection are the production casing and the surface casing that completely covers the fresh water aquifer. From the worksheet in Illustration A-1, it can be seen that the two levels of protection (questions 17a and 19) do not affect the final fluid migration potential category since the well is in the *minimum* category because:

- The completion interval is not a pressured formation (question 11), and
- The top of the shallowest pressured formation is isolated by the production casing cement (question 20).

Once the operator has established that the Jones # 1 is in the *minimum* category, the following monitoring program suggested in Table A-3 should be initiated:

- Initial Monitoring
  - Since the well's fluid migration potential worksheet was completed on July 1, 1992, the initial monitoring should be completed by October 1, 1992, which is three months after the evaluation was completed. This initial monitoring includes determining the static fluid level and pressure in the tubing or casing to verify the completion interval is not a pressured formation. In addition, the production casing/surface casing annulus should be monitored to verify there are no sustained pressures.

  NOTE: *Operators should insure that their monitoring frequencies meet those specified by applicable Federal, state, and local regulations.*

  Each operator should establish the frequencies for their monitoring program based on a well's fluid migration potential and on any unusual surface or downhole conditions.

- Periodic Monitoring
  - Monitoring of the fluid level, tubing or casing pressure, and production casing/surface casing annulus pressure should be repeated every five years.
  - The operator should be aware of field operations in the area that could result in a formation penetrated by the well becoming a pressured formation. For example, if a miscible carbon dioxide project were initiated in the same formation as the completion interval, the completion interval may eventually become a pressured formation.

  Typical sources of information concerning operations in the area include regulatory agencies, offset operators, drilling and workover contractors, service company personnel, etc.

If monitoring identifies, and diagnostic tests confirm, that the completion interval of the Jones # 1 has developed into a pressured formation, the operator may, as appropriate:

- Reclassify the well to the *low* category and initiate monitoring in accordance with the program outlined in Table A-3, or

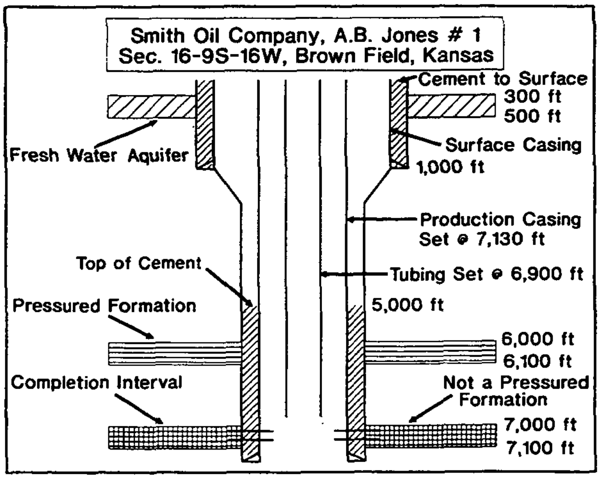


**FIGURE A-1**
**SHUT-IN PRODUCING WELL WITH TUBING AND WITHOUT PACKER IN THE MINIMUM FLUID MIGRATION POTENTIAL CATEGORY**

- Pull tubing and set a bridge plug in order to obtain three levels of protection while monitoring the well in the low category in accordance with the program for TA wells as outlined in Table A-5, or
- P&A the well.

### A.3.2 LOW FLUID MIGRATION POTENTIAL CATEGORY

An example of how to apply the worksheet to a shut-in injection well with tubing and packer is discussed below.

Illustration A-2 is a completed worksheet for the A.B. Jones # 2W shown in Figure A-2. This well has three levels of protection. These are (1) the surface casing that completely covers the fresh water aquifer, (2) the production casing, and (3) the tubing and packer. These elements qualify as levels of protection because they are relatively easy to identify, and they provide barriers to fluid migration that can be readily monitored. Since the well has a completion interval that is a pressured formation (question 11), it can not be placed in the minimum category. The total number of levels of protection recorded in questions 17 through 24 is three, which places the well in the *low* category.

After the operator has established that the Jones # 2W is in the *low* category, the well should be placed on the field monitoring schedule outlined in Table A-4.

If subsequent monitoring procedures identify the loss of one or more of the three levels of protection, and this is confirmed by diagnostic tests, the operator should recalculate the levels of protection and take one of the following actions.

- If the fluid migration potential category does not change, the operator may continue to monitor at the *low* category without repairing the well, initiate remedial work, or P&A the well, as appropriate.
- If the fluid migration potential category changes to *moderate,* the operator may monitor at the *moderate* category without repairing the well, initiate remedial work, or P&A the well, as appropriate.
- If the fluid migration potential category changes to *significant,* the well should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.

### A.3.3 MODERATE FLUID MIGRATION POTENTIAL CATEGORY

The A.B. Jones # 3W is a TA injection well that has a bridge plug that isolates the pressured completion interval from the production casing. As shown in Figure A-3, the production casing has a leak at 4,000 ft. The fresh water aquifer occurs from 300 to 500 ft which is below the base of the surface casing.

As shown on the worksheet in Illustration A-3, the only level of protection against potential fluid migration from the pressured completion interval to the fresh water aquifer is the bridge plug (question 24). This places the Jones # 3W in the *moderate* fluid migration potential category.

Referring to Table A-5, the initial monitoring program for the well is to pressure test the bridge plug to verify its mechanical integrity. In addition, the operator should monitor the casing and production casing/surface casing annulus for sustained pressure.

The Jones # 3W was temporarily abandoned on May 1, 1991, which was before the Smith Oil Company adopted the inactive well monitoring program. In this case, the operator should complete the initial monitoring tests within three months after July 1, 1992, which was the date the worksheet was prepared.

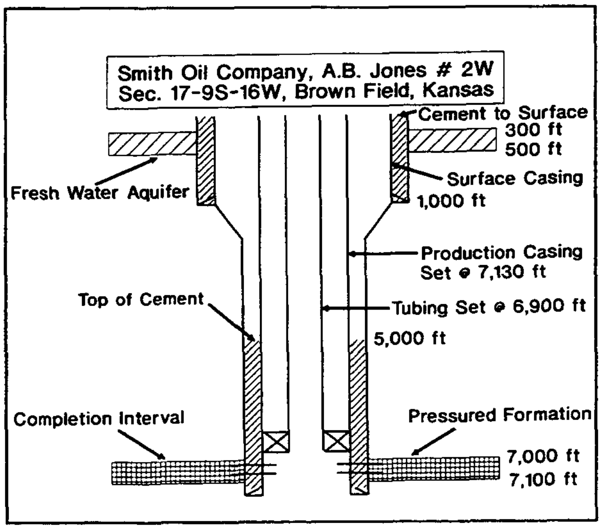


**FIGURE A-2**
**SHUT-IN INJECTION WELL WITH TUBING AND PACKER IN THE LOW FLUID MIGRATION POTENTIAL CATEGORY**

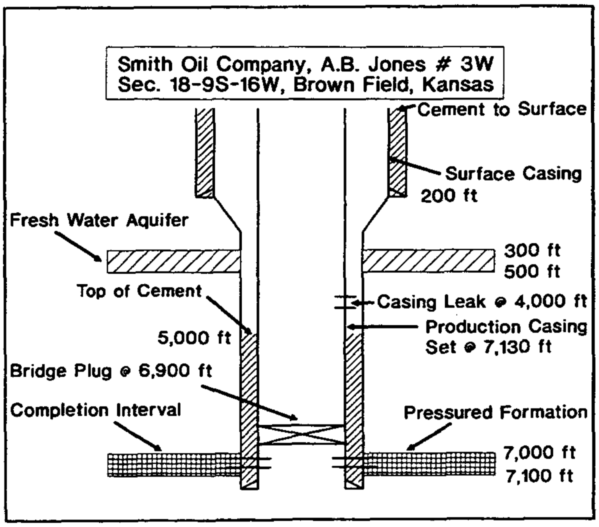


**FIGURE A-3**
**TEMPORARILY ABANDONED INJECTION WELL WITH BRIDGE PLUG IN THE MODERATE FLUID MIGRATION POTENTIAL CATEGORY**

As shown in Table A-5, periodic monitoring of the Jones # 3W includes monthly monitoring of the casing and the production casing/surface casing annulus for sustained pressures. In addition, the bridge plug should be pressure tested each year to verify its mechanical integrity.

In event monitoring indicates, and diagnostic tests confirm, that the bridge plug has lost mechanical integrity, the well should be reclassified to the *significant* fluid migration potential category, and the well should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.

### A.3.4 SIGNIFICANT FLUID MIGRATION POTENTIAL CATEGORY

The A.B. Jones # 4 is a shut-in producing well without tubing or packer. As shown in Figure A-4, the well's surface casing does not cover the fresh water aquifer, the production casing has a leak, and the completion interval is a pressured formation.

As shown on the worksheet in Illustration A-4, the well has zero levels of protection (question 25), which places it in the *significant* fluid migration potential category (question 26). This is because the well (1) has surface casing set at 200 ft, (2) penetrates a fresh water aquifer from 300 ft to 500 ft, (3) is completed in an interval that is a pressured formation, and (4) has a production casing leak at 4,000 ft.

Since the Jones #4 is in the *significant* category, the operator should immediately evaluate the well to determine the appropriate action, which may include repairing the leak in the production casing, or plugging and abandoning the well.

If the operator elects to repair the casing leak, the well should be evaluated and assigned to an appropriate fluid migration potential category. In the case of the Jones #4, the repaired well would be in the *moderate* category because the completion interval is a pressured formation, and the well would have the production casing as the only level of protection.

After remedial work, the well would be monitored in accordance with the procedures outlined in Table A-3 for shut-in without packer wells in the *moderate* category.

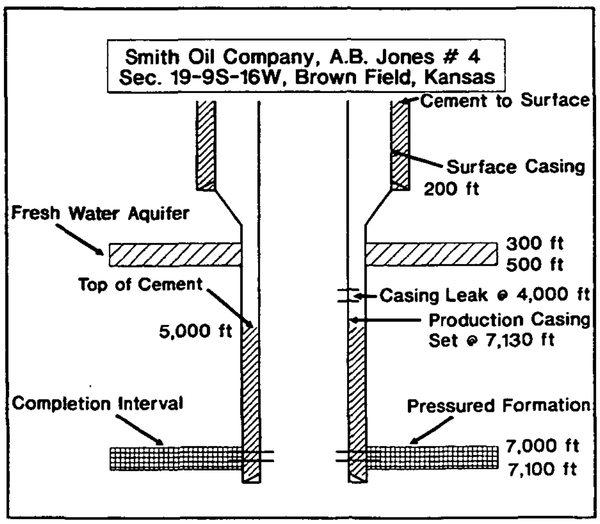


**FIGURE A-4**
**SHUT-IN PRODUCING WELL WITHOUT TUBING OR PACKER IN THE SIGNIFICANT FLUID MIGRATION POTENTIAL CATEGORY**

## A.4 FOLLOW-UP TO MONITORING PROGRAM

Table A-7 presents typical follow-up procedures in event the fresh water aquifer protection monitoring program indicates changes in well conditions as follows.

- A change in field operations that results in a non-pressured formation becoming a pressured formation. For example, if a field undergoing water flood operations is converted to a miscible carbon dioxide project, the completion interval may develop into a pressured formation.
- The loss of one or more levels of protection, such as a leak developing in the production casing.
- A change in field operations that results in a pressured formation becoming a non-pressured formation. For example, if a miscible carbon dioxide project is discontinued, the completion interval reservoir pressure may drop to the point where it is no longer a pressured formation.

The typical follow-up procedures outlined in Table A-7 are suggestions for an operator's consideration. Diagnostic tests would normally be conducted by an operator to confirm the monitoring results before reclassifying the fluid migration potential category, or before conducting repair or P&A operations.

In all cases the operator should check with the appropriate Federal, state, and local regulatory agencies to insure their follow-up actions conform to applicable regulations.

## A.5 SURFACE PROTECTION METHODOLOGY

The major issue on protecting the surface from environmental damage is to evaluate if the wellhead design and mechanical integrity is adequate to prevent wellbore fluids from leaking to the surface.

### A.5.1 WELLS THAT PENETRATE FRESH WATER AQUIFERS

As noted in Section A.3, all monitoring associated with protecting fresh water aquifers should include a site inspection for leaks to surface soils or surface waters. Surface condition observations should be documented at the same time the pressures and fluid levels are recorded.

If surface leaks are observed during a site inspection, repairs should be immediately initiated to stop the leak, or the well should be P&A'd, as appropriate.

### A.5.2 WELLS WITH PRESSURED FORMATIONS THAT DO NOT PENETRATE FRESH WATER AQUIFERS

Recommended monitoring procedures for wells which have pressured formations and that do not penetrate fresh water aquifers are as follows:

- Within three months after the well's fluid migration potential is evaluated, an initial site inspection should be conducted to insure there are no leaks that could endanger surface soils or surface waters.

- Periodic site inspections should be conducted every year.

If leaks are identified during a site inspection, repairs should be initiated immediately or the well should be P&A'd, as appropriate.

### A.5.3 WELLS WITHOUT PRESSURED FORMATIONS THAT DO NOT PENETRATE FRESH WATER AQUIFERS

Recommended monitoring procedures for wells without pressured formations and that do not penetrate fresh water aquifers are summarized below.

- Within three months after the well's fluid migration potential is evaluated, an initial site inspection should be conducted to insure there are no leaks that could endanger surface soils or surface waters.
- Periodic site inspections should be conducted every five years.
- The operator should periodically monitor operations in the area for changes in subsurface injection methods which may result in a pressured formation that is penetrated by the well.

### A.5.4 EXAMPLE OF SURFACE PROTECTION METHODOLOGY APPLICATION

This Section presents an example of how the worksheet can be used to analyze the potential for fluid to leak from the wellbore of an inactive well to the surface.

The A.B. Jones # 5 is a shut-in producing well with rods and tubing in the well. As shown in Figure A-5, the well has two levels of protection. These are (1) the surface casing that completely covers the fresh water aquifer

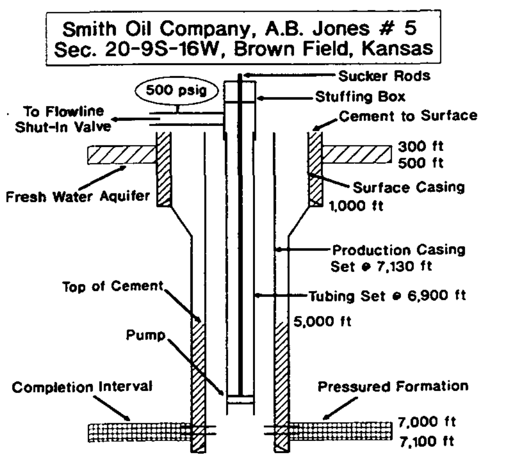


**FIGURE A-5**
**SHUT-IN PRODUCING WELL WITH RODS AND TUBING IN THE SIGNIFICANT FLUID MIGRATION POTENTIAL CATEGORY**

and (2) the production casing. In addition, the completion interval is a pressured formation that has built-up 500 psig on the stuffing box at the surface.

As shown on the worksheet in Illustration A-5, the well is classified as *significant* (question 26) because the operator has determined that wellhead design is not sufficient to provide long-term containment of the wellbore fluids.

In this case, the Jones # 5 should be immediately evaluated to determine the appropriate action. Among several options, the operator may elect to (1) pull the rods and replace the stuffing box with a valve, (2) install and close a polished rod blow out preventer, (3) return the well to production, (4) TA the well, or (5) P&A the well.

If the well remains inactive, the fluid migration potential should be reevaluated and appropriate action taken. Monitoring should begin within three months after the reevaluation and the action is complete.

### A.6 RECOMMENDATIONS

The examples presented in Appendix A are typical of the types of inactive well monitoring situations that an operator may encounter in oil and gas operations. Unless there are special circumstances required by regulatory agencies, monitoring of inactive wells may be patterned after the program presented in this Appendix.

Operators should establish their own inactive well monitoring programs. It is recommended that operators document their monitoring programs and maintain copies of the individual well worksheets, monitoring results, special tests, and results of well work. It is further recommended that operators consult applicable Federal, state, and local regulations, as well as lease and landowner obligations, to be certain these guidelines meet all requirements.

**TABLE A-1**
**LEVELS OF PROTECTION**
**AGAINST POTENTIAL FLUID MIGRATION TO FRESH WATER AQUIFERS[a]**

| | Number of Levels of Protection[b] |
|---|---|
| **Equipment That Protects Against Potential Fluid Migration From Pressured Formations[c]** | |
| • Surface casing that completely covers the fresh water aquifers. | 1 |
| • Each intermediate casing string. | 1 |
| • Production casing. | 1 |
| • Tubing and packer. | 1 |
| • Isolation of completion interval with a bridge plug, cement squeeze, balanced cement plug, or plug in a packer with no tubing. | 1 |

(a) A fresh water aquifer is a subsurface formation which generally contains water with less than 3,000 mg/l TDS and which supplies any public water supply system or currently supplies drinking water for human/livestock consumption or which contains sufficient water to supply a public water system.

(b) A level of protection is a barrier to fluid migration into fresh water aquifers that has mechanical integrity, and its integrity can be monitored with some degree of confidence.

(c) A pressured formation is any producing, injection, disposal, permeable hydrocarbon bearing, or permeable salt water bearing formation penetrated by the well which has sufficient pressure to initiate and sustain significant fluid migration into a fresh water aquifer or to the surface.

**TABLE A-2**
**FLUID MIGRATION POTENTIAL CATEGORIES**

**Fluid Migration Potential Category**

**Minimum**

- There are no pressured formations[a], or the only pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing.

**Low**

- The well has two or more levels of protection[b], there is no sustained pressure on the surface casing annulus, and
  - The completion interval is a pressured formation, and all other pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing, or
  - The completion interval may or may not be a pressured formation, but there are two or more levels of protection between the shallowest uncemented pressured formation and the lowermost fresh water aquifer.

**Moderate**

- The well has one level of protection, there is no sustained pressure on the surface casing annulus, and
  - The completion interval is a pressured formation, and all other pressured formations are isolated from the fresh water aquifers by cemented production casing, liner, or intermediate casing, or
  - The completion interval may or may not be a pressured formation, but there is one level of protection between the shallowest uncemented pressured formation and the lowermost fresh water aquifer.

**Significant[c]**

- The well has zero levels of protection, and the completion interval is a pressured formation, or
- There is sustained pressure on the surface casing annulus, or
- The Christmas-tree or stuffing-box assembly design and mechanical integrity is not sufficient to provide long-term containment of the wellbore fluids, or
- A pressured formation and a fresh water aquifer exist in the same uncemented annulus.

(a) A pressured formation is any producing, injection, disposal, permeable hydrocarbon bearing, or permeable salt water bearing formation penetrated by the well which has sufficient pressure to initiate and sustain significant fluid migration into a fresh water aquifer or to the surface.

(b) A level of protection is a barrier to fluid migration into fresh water aquifers that has mechanical integrity, and its integrity can be monitored with some degree of confidence. Refer to Table A-1 for guidelines for determining levels of protection.

(c) Wells that have a *significant* fluid migration potential should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.

## TABLE A-3
## SUGGESTED TYPICAL MONITORING PROGRAMS FOR SHUT-IN WITHOUT PACKER WELLS

**Fluid Migration Potential Category[a]**

**Minimum**

- Within three months[b] after evaluating the fluid migration potential, determine the static fluid level in the tubing or casing[c] to verify there are no formation fluids at the lowermost fresh water aquifer and record the tubing or casing[c] pressure. In addition, monitor all casing/casing annuli for sustained pressures.
- Periodically monitor operations in the area for changes in subsurface injection methods which may result in a pressured formation.
- Every five years, determine the static fluid level to verify there are no formation fluids at the lowermost fresh water aquifer and record the tubing or casing[c] pressure and monitor all casing/casing annuli for sustained pressures.

**Low**

- Within three months after evaluating the fluid migration potential, pressure test the casing to verify mechanical integrity. In addition, record the tubing or casing[c] pressure and monitor all casing/casing annuli for sustained pressures.
- Every year record the tubing or casing[c] pressure and monitor all casing/casing annuli for sustained pressures.
- Every five years, pressure test the casing to verify mechanical integrity.

**Moderate**

- If the production casing is the only level of protection, within three months after evaluating the fluid migration potential, pressure test the casing to verify mechanical integrity. In addition, record the tubing or casing[c] pressure and monitor all casing/casing annuli for sustained pressures.
- If the surface casing is the only level of protection, within three months after evaluating the fluid migration potential, record the tubing or casing[c] pressure and monitor all casing/casing annuli for sustained pressures.
- Every month record the tubing or casing[c] pressure and monitor all casing/casing annuli for sustained pressures.
- If the production casing is the only level of protection, every year, pressure test the casing to verify mechanical integrity.

**Significant**

- There is no monitoring program because a well in the *significant* category should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.

(a) *Refer to* Table A-2 for guidelines in determining fluid migration potential categories.
(b) **Operators should insure that their monitoring frequencies meet those specified by applicable Federal, state and local regulations.** Each operator should establish the frequencies for their monitoring program based on a well's fluid migration potential and on any unusual surface or downhole conditions.
(c) If well has tubing, the operator can monitor either the tubing or the casing.

## TABLE A-4
## SUGGESTED TYPICAL MONITORING PROGRAMS FOR SHUT-IN WITH TUBING AND PACKER WELLS

**Fluid Migration Potential Category[a]**

**Minimum**

- Within three months[b] after evaluating the fluid migration potential, determine the static fluid level in the tubing to verify there are no formation fluids at the lowermost fresh water aquifer and record the tubing pressure. In addition, monitor the tubing/casing annulus and all casing/casing annuli for sustained pressures.
- Periodically monitor operations in the area for changes in subsurface injection methods which may result in a pressured formation.
- Every five years, determine the static fluid level in the tubing to verify there are no formation fluids at the lowermost fresh water aquifer and record the tubing pressure and monitor the tubing/casing annulus and all casing/casing annuli for sustained pressures.

**Low**

- Within three months after evaluating the fluid migration potential, record the tubing pressure and pressure test the tubing/casing annulus to verify mechanical integrity. In addition, monitor all casing/casing annuli for sustained pressures.
- Every year record the tubing pressure and monitor the tubing/casing annulus and all casing/casing annuli for sustained pressures.
- Every five years, pressure test the tubing/casing annulus to verify mechanical integrity.

**Moderate**

- Within three months after evaluating the fluid migration potential the following monitoring should be initiated:
  - If the only level of protection is surface casing, monitor all casing/casing annuli for sustained pressures.
  - If the only level of protection is the production casing, the casing should be pressured tested to verify mechanical integrity. In addition, monitor all casing/casing annuli for sustained pressures.
- Every month record the tubing pressure and casing pressures and monitor all casing/casing annuli for sustained pressures.
- If the only level of protection is the production casing, every year pressure test the casing to verify mechanical integrity.

**Significant**

- There is no monitoring program because wells in the *significant* category should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.

(a) Refer to Table A-2 for guidelines in determining fluid migration potential categories.
(b) **Operators should insure that their monitoring frequencies meet those specified by applicable Federal, state and local regulations.** Each operator should establish the frequencies for their monitoring program based on a well's fluid migration potential and on any unusual surface or downhole conditions.

## TABLE A-5
## SUGGESTED TYPICAL MONITORING PROGRAMS FOR TEMPORARILY ABANDONED WELLS

**Fluid Migration Potential Category[(a)]**

**Minimum**

- Before the workover rig or wire line unit that is performing the temporary abandonment work moves off location[(b)], monitor the casing and all casing/casing annuli for sustained pressures.
- As needed, monitor operations in the area for changes in subsurface injection methods which may result in a pressured formation in the completion interval or behind uncemented casing.
- Monitor the casing and all casing/casing annuli for sustained pressures:
  - Every year for wells in the immediate vicinity of active injection or disposal operations.
  - Every five years for wells not in the immediate vicinity of active injection or disposal operations.

**Low**

- Before the workover rig or wire line unit that is performing the temporary abandonment work moves off location[(b)], pressure test the casing and the bridge plug[(c)] to verify mechanical integrity and monitor all casing/casing annuli for sustained pressures.
- Every year, monitor the casing and all casing/casing annuli for sustained pressures.
- Every five years, pressure test the casing and the bridge plug[(c)] to verify mechanical integrity.

**Moderate**

- Before the workover rig or wire line unit that is performing the temporary abandonment work moves off location[(b)], pressure test the casing or the bridge plug[(c)] to verify mechanical integrity and monitor all casing/casing annuli for sustained pressures.
- If the production casing or the surface casing is the only level of protection, every month record the casing pressure and monitor all casing/casing annuli for sustained pressures.
- If the bridge plug[(c)] is the only level of protection, every month monitor the casing and all casing/casing annuli for sustained pressures.
- Every year pressure test the production casing or the bridge plug[(c)] to verify mechanical integrity, if the only level of protection is production casing or the bridge plug[(c)].

**Significant**

- There is no monitoring program because wells in the *significant* category should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.

(a) Refer to Table A-2 for guidelines in determining fluid migration potential categories.
(b) **Operators should insure that their monitoring frequencies meet those specified by applicable Federal, state and local regulations.** Each operator should establish the frequencies for their monitoring program based on a well's fluid migration potential and on any unusual surface or downhole conditions.
(c) References to a *bridge plug* also include such TA methods as cement squeeze, balanced cement plug, and a plug in a packer with no tubing.

TABLE A-6
SUGGESTED INACTIVE WELL MONITORING FREQUENCY

| Fluid Migration Potential Category[a] | Monitoring Frequency[b] |
|---|---|
| **Minimum** | |
| Fluid Level and/or Pressures | |
| Initial[b] | 3 Months[c] |
| Periodic | 5 Years |
| Monitor Operations for Changes[d] | As Needed |
| **Low** | |
| Pressures | |
| Initial | 3 Months[c] |
| Periodic | 1 Year |
| Pressure Test Casing | |
| Initial | 3 Months[c] |
| Periodic | 5 Years |
| **Moderate** | |
| Pressures | |
| Initial | 3 Months[c] |
| Periodic | 1 Month |
| Pressure Test Casing | |
| Initial | 3 Months[c] |
| Periodic | 1 Year |
| **Significant**[e] | |

(a) Refer to Table A-2 for guidelines in determining fluid migration potential categories.
(b) **Operators should insure that their monitoring frequencies meet those specified by applicable Federal, state and local regulations.** Each operator should establish the frequencies for their monitoring program based on a well's fluid migration potential and on any unusual surface or downhole conditions.
For a well that becomes inactive after an operator adopts an inactive well monitoring program, or for a well that was inactive before the adoption of an inactive well monitoring program, initial monitoring should begin within three months after evaluating the well's fluid migration potential.
(c) If well work is required to place a well on inactive status, pressure or fluid level measurements should be taken at that time.
(d) Changes in fluid injection practices or installation of new injection/disposal projects in the area may trigger more frequent monitoring frequencies.
(e) A well in the *significant* category should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.

**TABLE A-7**
**TYPICAL FOLLOW-UP PROCEDURES IN EVENT MONITORING INDICATES A CHANGE IN A WELL'S FLUID MIGRATION POTENTIAL CATEGORY**

**Fluid Migration Potential Category[a]**

**Minimum**

- If monitoring[b] indicates that the fluid level has risen to the lowermost fresh water aquifer depth or that sustained pressure has developed in the casing/casing annulus, the well should be reclassified to a *low, moderate* or *significant* fluid migration potential category, as warranted by conditions. If appropriate, the operator[c] may initiate remedial work to isolate the pressured formation or P&A the well.

**Low**

- If monitoring indicates the loss of one or more levels of protection (i.e., packer leak, casing leak, casing/casing annulus sustained pressure build-up, etc.), the operator should determine the remaining levels of protection and redetermine the fluid migration potential category.

  Once the fluid migration potential category has been redetermined, the operator may take one of the following actions:
  - If the fluid migration potential category does not change, the operator may continue to monitor at the *low* category without repairing the well, initiate remedial work, or P&A the well, as appropriate.
  - If the fluid migration potential category changes to *moderate,* the operator may monitor at the *moderate* category without repairing the well, initiate remedial work, or P&A the well, as appropriate.
  - If the fluid migration potential category changes to *significant,* see below.
- If monitoring indicates the reservoir pressure of the completion interval has dropped to the point where it is no longer a pressured formation, the operator should change the well's fluid migration category to *minimum,* and the well should be placed on the field monitoring schedule for that category.

**Moderate**

- If monitoring indicates the loss of one level of protection (i.e., packer leak, casing leak, casing/casing annulus sustained pressure build-up, etc.), the well should be reclassified to the *significant* fluid migration potential category.
- If monitoring indicates the reservoir pressure of the completion interval has dropped to the point where it is no longer a pressured formation, the operator should change the well's fluid migration category to *minimum,* and the well should be placed on the field monitoring schedule for that category.

**Significant**

- Wells in the *significant* category should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.

(a) Refer to Table A-2 for guidelines in determining fluid migration potential categories.
(b) Refer to Tables A-3, A-4 and A-5 for suggested typical monitoring programs for shut-in without packer, shut-in with packer and TA wells, respectively.
(c) Follow-up procedures are suggested for operator guidelines. Operators should insure that their follow-up procedures meet those specified by applicable Federal, state and local regulations.

## ILLUSTRATION A-1

# Inactive Well Worksheet

For Determining Levels of Protection and
Categories of Fluid Migration Potential to Fresh Water Aquifers

| | |
|---|---|
| 1. Operator<br>Smith Oil Company | 2. Location<br>Sec 16 Twn 9S Rng 16W |
| 3. Lease and Well Name<br>A.B. Jones #1 | 4. Field Name<br>Brown |
| 5. State<br>Kansas | 6. Well type (check only one)<br>☐ Injector ☒ Producer |
| 7. Date well became inactive<br>06·01·92 | 8. Date worksheet prepared<br>07·01·92 |

9. Inactive well classification (check only one)
☐ Temporarily Abandoned ☐ Shut-In With Tubing and Packer
☐ Shut-In With Rods and Tubing ☒ Shut-In Without Packer

10. Is a fresh water aquifer (less than 3000 mg/l TDS) penetrated by the well?
☒ Yes ☐ No

10a. If yes, what is the depth of the base of the lowermost fresh water aquifer? 500 ft - Base

10b. If no, do not complete this form. Refer to Appendix A of the API Environmental Guidance Document on "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations" for the monitoring program for an inactive well that does not penetrate a fresh water aquifer.

11. Is the production/injection/disposal formation reservoir pressure high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
☐ Yes ☒ No

11a. If yes, is the Christmas-tree or stuffing-box assembly design and mechanical integrity sufficient to provide long-term containment of the wellbore fluids?
☐ Yes ☐ No

12. *NOTE: If the answer to question 11a is no, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

13. Are there any permeable formations that are shallower than the production/injection/disposal formation with reservoir pressures high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
☒ Yes ☐ No

13a. If yes, what is the depth of the top and base of the shallowest pressured formation?
6000 ft - Top 6100 ft - Base

14. *NOTE: If the answers to questions 11 and 13 are both no, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

15. Is there sustained pressure on the surface casing annulus?
☐ Yes ☒ No

16. *NOTE: If the answer to question 15 is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

**Levels Of Protection**

17. What is the setting depth for the surface casing? 1000 ft - Setting Depth

17a. Does the surface casing completely cover the fresh water aquifer identified in question 10a?
☒ Yes ☐ No

*NOTE: If the answer to question 17a is yes, show 1 level of protection in the box at right.* [1]

18. Were one or more strings of intermediate casing installed in the well?
☐ Yes ☒ No

18a. If yes, what is the setting depth and top of cement for the shallowest string?
________ ft - Setting Depth ________ ft - Top of Cement

*NOTE: For each string of intermediate casing without a leak, show 1 level of protection in the box at right.* [ ]

## ILLUSTRATION A-1

## Inactive Well Worksheet

| | Levels Of Protection |
|---|---|
| 19. What is the setting depth and top of cement for the production casing or production liner?<br>7130 ft - Setting Depth 5000 ft - Top of Cement<br>*NOTE: If the production casing or production liner is without a leak, show 1 level of protection in the box at right.* | 1 |
| 20. If the answer to question 13 is yes, is the top of the shallowest pressured formation identified in question 13a isolated from the fresh water aquifer identified in question 10a by cemented production casing, liner, or intermediate casing?<br>[X] Yes [ ] No<br>20a. If no, and the answer to question 17a is no, is the shallowest pressured formation identified in question 13a located in the same uncemented annulus as the fresh water aquifer identified in question 10a?<br>[ ] Yes [ ] No | |
| 21. *NOTE: If the answer to question 11 is no and the answer to question 20 is yes, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.* | |
| 22. *NOTE: If the answer to question 20a is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.* | |
| 23. Were both tubing and packer installed in the well?<br>[ ] Yes [ ] No<br>23a. If yes, what are the setting depths of the tubing and the packer?<br>______ ft - Tubing ______ ft - Packer<br>*NOTE: If the answer to question 23 is yes, and the depth of the packer is deeper than the top of cement for the production casing or production liner identified in question 19, and the tubing and packer are without a leak, show 1 level of protection in the box at right.* | [ ] |
| 24. Is the perforated or open hole production/injection/disposal formation isolated from the production casing or production liner by a bridge plug, a cement squeeze, a balanced cement plug, or a plug in a packer with no tubing?<br>[ ] Yes [ ] No<br>*NOTE: If the answer to question 24 is yes, show 1 level of protection in the box at right.* | [ ] |
| 25. Total number of levels of protection from boxes of questions 17-24. | [ ] |

26. According to the total number of verifiable levels of protection identified in question 25, categorize this well according to the following:

- [X] Minimum Fluid Migration Potential
  - – the answers to questions 11 and 13 are both no, or
  - – the answer to question 11 is no and the answer to question 20 is yes.
- [ ] Low Fluid Migration Potential - levels of protection = 2 or more
- [ ] Moderate Fluid Migration Potential - levels of protection = 1
- [ ] Significant Fluid Migration Potential - this well should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.
  - – levels of protection = 0 and the answer to question 11 is yes, or
  - – the answer to question 11a is no, or
  - – the answer to question 15 is yes, or
  - – the answer to question 20a is yes.

27. Remarks

| 28. Lease and Well Name | 29. Field Name |
|---|---|
| A.B. Jones #1 | Brown |

## ILLUSTRATION A-2

# Inactive Well Worksheet

### For Determining Levels of Protection and Categories of Fluid Migration Potential to Fresh Water Aquifers

| | |
|---|---|
| 1. Operator<br>Smith Oil Company | 2. Location<br>Sec 17 Twn 9S Rng 16W |
| 3. Lease and Well Name<br>A. B. Jones #2W | 4. Field Name<br>Brown |
| 5. State<br>Kansas | 6. Well type (check only one)<br>[X] Injector [ ] Producer |
| 7. Date well became inactive<br>06·01·92 | 8. Date worksheet prepared<br>07·01·92 |

9. Inactive well classification (check only one)
[ ] Temporarily Abandoned [X] Shut-In With Tubing and Packer
[ ] Shut-In With Rods and Tubing [ ] Shut-In Without Packer

10. Is a fresh water aquifer (less than 3000 mg/l TDS) penetrated by the well?
[X] Yes [ ] No

10a. If yes, what is the depth of the base of the lowermost fresh water aquifer? 500 ft - Base

10b. If no, do not complete this form. Refer to Appendix A of the API Environmental Guidance Document on "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations" for the monitoring program for an inactive well that does not penetrate a fresh water aquifer.

11. Is the production/injection/disposal formation reservoir pressure high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
[X] Yes [ ] No

11a. If yes, is the Christmas-tree or stuffing-box assembly design and mechanical integrity sufficient to provide long-term containment of the wellbore fluids?
[X] Yes [ ] No

12. *NOTE: If the answer to question 11a is no, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

13. Are there any permeable formations that are shallower than the production/injection/disposal formation with reservoir pressures high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
[ ] Yes [X] No

13a. If yes, what is the depth of the top and base of the shallowest pressured formation?
__________ ft - Top __________ ft - Base

14. *NOTE: If the answers to questions 11 and 13 are both no, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

15. Is there sustained pressure on the surface casing annulus?
[ ] Yes [X] No

16. *NOTE: If the answer to question 15 is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

Levels Of Protection

17. What is the setting depth for the surface casing? 1000 ft - Setting Depth

17a. Does the surface casing completely cover the fresh water aquifer identified in question 10a?
[X] Yes [ ] No

*NOTE: If the answer to question 17a is yes, show 1 level of protection in the box at right.* [1]

18. Were one or more strings of intermediate casing installed in the well?
[ ] Yes [X] No

18a. If yes, what is the setting depth and top of cement for the shallowest string?
__________ ft - Setting Depth __________ ft - Top of Cement

*NOTE: For each string of intermediate casing without a leak, show 1 level of protection in the box at right.* [ ]

## ILLUSTRATION A-2

## Inactive Well Worksheet

| | Levels Of Protection |
|---|---|
| 19. What is the setting depth and top of cement for the production casing or production liner?<br>7130 ft - Setting Depth 5000 ft - Top of Cement<br>*NOTE: If the production casing or production liner is without a leak, show 1 level of protection in the box at right.* | 1 |
| 20. If the answer to question 13 is yes, is the top of the shallowest pressured formation identified in question 13a isolated from the fresh water aquifer identified in question 10a by cemented production casing, liner, or intermediate casing?<br>☐ Yes ☐ No<br>20a. If no, and the answer to question 17a is no, is the shallowest pressured formation identified in question 13a located in the same uncemented annulus as the fresh water aquifer identified in question 10a?<br>☐ Yes ☐ No | |
| 21. *NOTE: If the answer to question 11 is no and the answer to question 20 is yes, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.* | |
| 22. *NOTE: If the answer to question 20a is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.* | |
| 23. Were both tubing and packer installed in the well?<br>☒ Yes ☐ No<br>23a. If yes, what are the setting depths of the tubing and the packer?<br>6900 ft - Tubing 6900 ft - Packer<br>*NOTE: If the answer to question 23 is yes, and the depth of the packer is deeper than the top of cement for the production casing or production liner identified in question 19, and the tubing and packer are without a leak, show 1 level of protection in the box at right.* | 1 |
| 24. Is the perforated or open hole production/injection/disposal formation isolated from the production casing or production liner by a bridge plug, a cement squeeze, a balanced cement plug, or a plug in a packer with no tubing?<br>☐ Yes ☒ No<br>*NOTE: If the answer to question 24 is yes, show 1 level of protection in the box at right.* | ☐ |
| 25. Total number of levels of protection from boxes of questions 17-24. | 3 |

26. According to the total number of verifiable levels of protection identified in question 25, categorize this well according to the following:

☐ Minimum Fluid Migration Potential
– the answers to questions 11 and 13 are both no, or
– the answer to question 11 is no and the answer to question 20 is yes.

☒ Low Fluid Migration Potential - levels of protection = 2 or more

☐ Moderate Fluid Migration Potential - levels of protection = 1

☐ Significant Fluid Migration Potential - this well should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.
– levels of protection = 0 and the answer to question 11 is yes, or
– the answer to question 11a is no, or
– the answer to question 15 is yes, or
– the answer to question 20a is yes.

27. Remarks

| 28. Lease and Well Name | 29. Field Name |
|---|---|
| A.B. Jones #2 W | Brown |

Page 2 of 2

## ILLUSTRATION A-3

# Inactive Well Worksheet

### For Determining Levels of Protection and Categories of Fluid Migration Potential to Fresh Water Aquifers

| | |
|---|---|
| 1. Operator<br>Smith Oil Company | 2. Location<br>Sec 18 Twn 9S Rng 16W |
| 3. Lease and Well Name<br>A.B. Jones # 3W | 4. Field Name<br>Brown |
| 5. State<br>Kansas | 6. Well type (check only one)<br>[X] Injector [ ] Producer |
| 7. Date well became inactive<br>05·01·91 | 8. Date worksheet prepared<br>07·01·92 |

9. Inactive well classification (check only one)
[X] Temporarily Abandoned [ ] Shut-In With Tubing and Packer
[ ] Shut-In With Rods and Tubing [ ] Shut-In Without Packer

10. Is a fresh water aquifer (less than 3000 mg/l TDS) penetrated by the well?
[X] Yes [ ] No

10a. If yes, what is the depth of the base of the lowermost fresh water aquifer? 500 ft - Base

10b. If no, do not complete this form. Refer to Appendix A of the API Environmental Guidance Document on "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations" for the monitoring program for an inactive well that does not penetrate a fresh water aquifer.

11. Is the production/injection/disposal formation reservoir pressure high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
[X] Yes [ ] No

11a. If yes, is the Christmas-tree or stuffing-box assembly design and mechanical integrity sufficient to provide long-term containment of the wellbore fluids?
[X] Yes [ ] No

12. *NOTE: If the answer to question 11a is no, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

13. Are there any permeable formations that are shallower than the production/injection/disposal formation with reservoir pressures high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
[ ] Yes [X] No

13a. If yes, what is the depth of the top and base of the shallowest pressured formation?
________ ft - Top ________ ft - Base

14. *NOTE: If the answers to questions 11 and 13 are both no, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

15. Is there sustained pressure on the surface casing annulus?
[ ] Yes [X] No

16. *NOTE: If the answer to question 15 is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

| | Levels Of Protection |
|---|---|
| 17. What is the setting depth for the surface casing? 200 ft - Setting Depth<br>17a. Does the surface casing completely cover the fresh water aquifer identified in question 10a?<br>[ ] Yes [X] No<br>*NOTE: If the answer to question 17a is yes, show 1 level of protection in the box at right.* | [ ] |
| 18. Were one or more strings of intermediate casing installed in the well?<br>[ ] Yes [X] No<br>18a. If yes, what is the setting depth and top of cement for the shallowest string?<br>________ ft - Setting Depth ________ ft - Top of Cement<br>*NOTE: For each string of intermediate casing without a leak, show 1 level of protection in the box at right.* | [ ] |

## ILLUSTRATION A-3

## Inactive Well Worksheet

| | Levels Of Protection |
|---|---|
| 19. What is the setting depth and top of cement for the production casing or production liner?<br>7130 ft - Setting Depth 5000 ft - Top of Cement<br>*NOTE: If the production casing or production liner is without a leak, show 1 level of protection in the box at right.* | ☐ |
| 20. If the answer to question 13 is yes, is the top of the shallowest pressured formation identified in question 13a isolated from the fresh water aquifer identified in question 10a by cemented production casing, liner, or intermediate casing?<br>☐ Yes ☐ No<br>20a. If no, and the answer to question 17a is no, is the shallowest pressured formation identified in question 13a located in the same uncemented annulus as the fresh water aquifer identified in question 10a?<br>☐ Yes ☐ No | |
| 21. *NOTE: If the answer to question 11 is no and the answer to question 20 is yes, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.* | |
| 22. *NOTE: If the answer to question 20a is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.* | |
| 23. Were both tubing and packer installed in the well?<br>☐ Yes ☒ No<br>23a. If yes, what are the setting depths of the tubing and the packer?<br>________ ft - Tubing ________ ft - Packer<br>*NOTE: If the answer to question 23 is yes, and the depth of the packer is deeper than the top of cement for the production casing or production liner identified in question 19, and the tubing and packer are without a leak, show 1 level of protection in the box at right.* | ☐ |
| 24. Is the perforated or open hole production/injection/disposal formation isolated from the production casing or production liner by a bridge plug, a cement squeeze, a balanced cement plug, or a plug in a packer with no tubing?<br>☒ Yes ☐ No<br>*NOTE: If the answer to question 24 is yes, show 1 level of protection in the box at right.* | 1 |
| 25. Total number of levels of protection from boxes of questions 17-24. | 1 |

26. According to the total number of verifiable levels of protection identified in question 25, categorize this well according to the following:

☐ Minimum Fluid Migration Potential
- the answers to questions 11 and 13 are both no, or
- the answer to question 11 is no and the answer to question 20 is yes.

☐ Low Fluid Migration Potential - levels of protection = 2 or more

☒ Moderate Fluid Migration Potential - levels of protection = 1

☐ Significant Fluid Migration Potential - this well should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.
- levels of protection = 0 and the answer to question 11 is yes, or
- the answer to question 11a is no, or
- the answer to question 15 is yes, or
- the answer to question 20a is yes.

27. Remarks

| 28. Lease and Well Name | 29. Field Name |
|---|---|
| A.B. Jones #3W | Brown |

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## ILLUSTRATION A-4

# Inactive Well Worksheet

### For Determining Levels of Protection and Categories of Fluid Migration Potential to Fresh Water Aquifers

| | |
|---|---|
| 1. Operator<br>Smith Oil Company | 2. Location<br>Sec 19 Twn 9S Rng 16W |
| 3. Lease and Well Name<br>A.B. Jones #4 | 4. Field Name<br>Brown |
| 5. State<br>Kansas | 6. Well type (check only one)<br>☐ Injector ☒ Producer |
| 7. Date well became inactive<br>06·27·92 | 8. Date worksheet prepared<br>07·01·92 |

9. Inactive well classification (check only one)

☐ Temporarily Abandoned ☐ Shut-In With Tubing and Packer
☐ Shut-In With Rods and Tubing ☒ Shut-In Without Packer

10. Is a fresh water aquifer (less than 3000 mg/l TDS) penetrated by the well?

☒ Yes ☐ No

10a. If yes, what is the depth of the base of the lowermost fresh water aquifer? 500 ft - Base

10b. If no, do not complete this form. Refer to Appendix A of the API Environmental Guidance Document on "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations" for the monitoring program for an inactive well that does not penetrate a fresh water aquifer.

11. Is the production/injection/disposal formation reservoir pressure high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?

☒ Yes ☐ No

11a. If yes, is the Christmas-tree or stuffing-box assembly design and mechanical integrity sufficient to provide long-term containment of the wellbore fluids?

☒ Yes ☐ No

12. *NOTE: If the answer to question 11a is no, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

13. Are there any permeable formations that are shallower than the production/injection/disposal formation with reservoir pressures high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?

☐ Yes ☒ No

13a. If yes, what is the depth of the top and base of the shallowest pressured formation?

________ ft - Top ________ ft - Base

14. *NOTE: If the answers to questions 11 and 13 are both no, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

15. Is there sustained pressure on the surface casing annulus?

☐ Yes ☒ No

16. *NOTE: If the answer to question 15 is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

**Levels Of Protection**

17. What is the setting depth for the surface casing? 200 ft - Setting Depth

17a. Does the surface casing completely cover the fresh water aquifer identified in question 10a?

☐ Yes ☒ No

*NOTE: If the answer to question 17a is yes, show 1 level of protection in the box at right.* ☐

18. Were one or more strings of intermediate casing installed in the well?

☐ Yes ☒ No

18a. If yes, what is the setting depth and top of cement for the shallowest string?

________ ft - Setting Depth ________ ft - Top of Cement

*NOTE: For each string of intermediate casing without a leak, show 1 level of protection in the box at right.* ☐

## ILLUSTRATION A-4

## Inactive Well Worksheet

Levels Of Protection

19. What is the setting depth and top of cement for the production casing or production liner?

7130 ft - Setting Depth    5000 ft - Top of Cement

*NOTE: If the production casing or production liner is without a leak, show 1 level of protection in the box at right.* [ ]

20. If the answer to question 13 is yes, is the top of the shallowest pressured formation identified in question 13a isolated from the fresh water aquifer identified in question 10a by cemented production casing, liner, or intermediate casing?

[ ] Yes    [ ] No

20a. If no, and the answer to question 17a is no, is the shallowest pressured formation identified in question 13a located in the same uncemented annulus as the fresh water aquifer identified in question 10a?

[ ] Yes    [ ] No

21. *NOTE: If the answer to question 11 is no and the answer to question 20 is yes, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

22. *NOTE: If the answer to question 20a is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

23. Were both tubing and packer installed in the well?

[ ] Yes    [X] No

23a. If yes, what are the setting depths of the tubing and the packer?

______ ft - Tubing    ______ ft - Packer

*NOTE: If the answer to question 23 is yes, and the depth of the packer is deeper than the top of cement for the production casing or production liner identified in question 19, and the tubing and packer are without a leak, show 1 level of protection in the box at right.* [ ]

24. Is the perforated or open hole production/injection/disposal formation isolated from the production casing or production liner by a bridge plug, a cement squeeze, a balanced cement plug, or a plug in a packer with no tubing?

[ ] Yes    [X] No

*NOTE: If the answer to question 24 is yes, show 1 level of protection in the box at right.* [ ]

25. Total number of levels of protection from boxes of questions 17-24. [0]

26. According to the total number of verifiable levels of protection identified in question 25, categorize this well according to the following:

[ ] Minimum Fluid Migration Potential
- the answers to questions 11 and 13 are both no, or
- the answer to question 11 is no and the answer to question 20 is yes.

[ ] Low Fluid Migration Potential - levels of protection = 2 or more

[ ] Moderate Fluid Migration Potential - levels of protection = 1

[X] Significant Fluid Migration Potential - this well should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.
- levels of protection = 0 and the answer to question 11 is yes, or
- the answer to question 11a is no, or
- the answer to question 15 is yes, or
- the answer to question 20a is yes.

27. Remarks

| 28. Lease and Well Name | 29. Field Name |
|---|---|
| A.B. Jones #4 | Brown |

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## ILLUSTRATION A-5

# Inactive Well Worksheet

## For Determining Levels of Protection and Categories of Fluid Migration Potential to Fresh Water Aquifers

| | |
|---|---|
| 1. Operator<br>Smith Oil Company | 2. Location<br>Sec 20 Twn 9s Rng 16W |
| 3. Lease and Well Name<br>A.B. Jones #5 | 4. Field Name<br>Brown |
| 5. State<br>Kansas | 6. Well type (check only one)<br>☐ Injector ☒ Producer |
| 7. Date well became inactive<br>06.01.92 | 8. Date worksheet prepared<br>07.01.92 |

9. Inactive well classification (check only one)
☐ Temporarily Abandoned ☐ Shut-In With Tubing and Packer
☒ Shut-In With Rods and Tubing ☐ Shut-In Without Packer

10. Is a fresh water aquifer (less than 3000 mg/l TDS) penetrated by the well?
☒ Yes ☐ No

10a. If yes, what is the depth of the base of the lowermost fresh water aquifer? 500 ft - Base

10b. If no, do not complete this form. Refer to Appendix A of the API Environmental Guidance Document on "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations" for the monitoring program for an inactive well that does not penetrate a fresh water aquifer.

11. Is the production/injection/disposal formation reservoir pressure high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
☒ Yes ☐ No

11a. If yes, is the Christmas-tree or stuffing-box assembly design and mechanical integrity sufficient to provide long-term containment of the wellbore fluids?
☐ Yes ☒ No

12. *NOTE: If the answer to question 11a is no, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

13. Are there any permeable formations that are shallower than the production/injection/disposal formation with reservoir pressures high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
☐ Yes ☐ No

13a. If yes, what is the depth of the top and base of the shallowest pressured formation?
__________ ft - Top __________ ft - Base

14. *NOTE: If the answers to questions 11 and 13 are both no, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

15. Is there sustained pressure on the surface casing annulus?
☐ Yes ☐ No

16. *NOTE: If the answer to question 15 is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

| | Levels Of Protection |
|---|---|
| 17. What is the setting depth for the surface casing? __________ ft - Setting Depth | |
| 17a. Does the surface casing completely cover the fresh water aquifer identified in question 10a?<br>☐ Yes ☐ No<br>*NOTE: If the answer to question 17a is yes, show 1 level of protection in the box at right.* | ☐ |
| 18. Were one or more strings of intermediate casing installed in the well?<br>☐ Yes ☐ No | |
| 18a. If yes, what is the setting depth and top of cement for the shallowest string?<br>__________ ft - Setting Depth __________ ft - Top of Cement<br>*NOTE: For each string of intermediate casing without a leak, show 1 level of protection in the box at right.* | ☐ |

## ILLUSTRATION A-5

## Inactive Well Worksheet

**Levels Of Protection**

19. What is the setting depth and top of cement for the production casing or production liner?

 ______ ft - Setting Depth ______ ft - Top of Cement

 *NOTE: If the production casing or production liner is without a leak, show 1 level of protection in the box at right.* ☐

20. If the answer to question 13 is yes, is the top of the shallowest pressured formation identified in question 13a isolated from the fresh water aquifer identified in question 10a by cemented production casing, liner, or intermediate casing?

 ☐ Yes ☐ No

20a. If no, and the answer to question 17a is no, is the shallowest pressured formation identified in question 13a located in the same uncemented annulus as the fresh water aquifer identified in question 10a?

 ☐ Yes ☐ No

21. *NOTE: If the answer to question 11 is no and the answer to question 20 is yes, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

22. *NOTE: If the answer to question 20a is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

23. Were both tubing and packer installed in the well?

 ☐ Yes ☐ No

23a. If yes, what are the setting depths of the tubing and the packer?

 ______ ft - Tubing ______ ft - Packer

 *NOTE: If the answer to question 23 is yes, and the depth of the packer is deeper than the top of cement for the production casing or production liner identified in question 19, and the tubing and packer are without a leak, show 1 level of protection in the box at right.* ☐

24. Is the perforated or open-hole production/injection/disposal formation isolated from the production casing or production liner by a bridge plug, a cement squeeze, a balanced cement plug, or a plug in a packer with no tubing?

 ☐ Yes ☐ No

 *NOTE: If the answer to question 24 is yes, show 1 level of protection in the box at right.* ☐

25. Total number of levels of protection from boxes of questions 17-24. ☐

26. According to the total number of verifiable levels of protection identified in question 25, categorize this well according to the following:

 ☐ Minimum Fluid Migration Potential
 – the answers to questions 11 and 13 are both no, or
 – the answer to question 11 is no and the answer to question 20 is yes.

 ☐ Low Fluid Migration Potential - levels of protection = 2 or more

 ☐ Moderate Fluid Migration Potential - levels of protection = 1

 ☒ Significant Fluid Migration Potential - this well should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.
 – levels of protection = 0 and the answer to question 11 is yes, or
 – the answer to question 11a is no, or
 – the answer to question 15 is yes, or
 – the answer to question 20a is yes.

27. Remarks

28. Lease and Well Name: A.B. Jones #5

29. Field Name: Brown

# INACTIVE WELL WORKSHEET FOR DETERMINING LEVELS OF PROTECTION AND CATEGORIES OF FLUID MIGRATION POTENTIAL TO FRESH WATER AQUIFERS

| | |
|---|---|
| 1. Operator | 2. Location ________ ________ ________ |
| 3. Lease and Well Name | 4. Field Name |
| 5. State | 6. Well type (check only one) ☐ Injector ☐ Producer |
| 7. Date well became inactive | 8. Date worksheet prepared |

9. Inactive well classification (check only one)
☐ Temporarily Abandoned ☐ Shut-In With Tubing and Packer
☐ Shut-In With Rods and Tubing ☐ Shut-In Without Packer

10. Is a fresh water aquifer (less than 3000 mg/l TDS) penetrated by the well?
☐ Yes ☐ No

10a. If yes, what is the depth of the base of the lowermost fresh water aquifer? __________ ft - Base

10b. If no, do not complete this form. Refer to Appendix A of the API Environmental Guidance Document on "Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations" for the monitoring program for an inactive well that does not penetrate a fresh water aquifer.

11. Is the production/injection/disposal formation reservoir pressure high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
☐ Yes ☐ No

11a. If yes, is the Christmas-tree or stuffing-box assembly design and mechanical integrity sufficient to provide long-term containment of the wellbore fluids?
☐ Yes ☐ No

12. *NOTE: If the answer to question 11a is no, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

13. Are there any permeable formations that are shallower than the production/injection/disposal formation with reservoir pressures high enough to initiate and sustain significant flow into the lowermost fresh water aquifer identified in question 10a?
☐ Yes ☐ No

13a. If yes, what is the depth of the top and base of the shallowest pressured formation?
__________ ft - Top __________ ft - Base

14. *NOTE: If the answers to questions 11 and 13 are both no, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

15. Is there sustained pressure on the surface casing annulus?
☐ Yes ☐ No

16. *NOTE: If the answer to question 15 is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

| | Levels Of Protection |
|---|---|
| 17. What is the setting depth for the surface casing? __________ ft - Setting Depth<br>17a. Does the surface casing completely cover the fresh water aquifer identified in question 10a?<br>☐ Yes ☐ No<br>*NOTE: If the answer to question 17a is yes, show 1 level of protection in the box at right.* | ☐ |
| 18. Were one or more strings of intermediate casing installed in the well?<br>☐ Yes ☐ No<br>18a. If yes, what is the setting depth and top of cement for the shallowest string?<br>__________ ft - Setting Depth __________ ft - Top of Cement<br>*NOTE: For each string of intermediate casing without a leak, show 1 level of protection in the box at right.* | ☐ |

## Inactive Well Worksheet

Levels Of Protection

19. What is the setting depth and top of cement for the production casing or production liner?

__________ ft - Setting Depth __________ ft - Top of Cement

*NOTE: If the production casing or production liner is without a leak, show 1 level of protection in the box at right.* ☐

20. If the answer to question 13 is yes, is the top of the shallowest pressured formation identified in question 13a isolated from the fresh water aquifer identified in question 10a by cemented production casing, liner, or intermediate casing?

☐ Yes ☐ No

20a. If no, and the answer to question 17a is no, is the shallowest pressured formation identified in question 13a located in the same uncemented annulus as the fresh water aquifer identified in question 10a?

☐ Yes ☐ No

21. *NOTE: If the answer to question 11 is no and the answer to question 20 is yes, proceed directly to question 26, and mark the box for "Minimum." Otherwise, proceed to the following questions.*

22. *NOTE: If the answer to question 20a is yes, proceed directly to question 26, and mark the box for "Significant." Otherwise, proceed to the following questions.*

23. Were both tubing and packer installed in the well?

☐ Yes ☐ No

23a. If yes, what are the setting depths of the tubing and the packer?

__________ ft - Tubing __________ ft - Packer

*NOTE: If the answer to question 23 is yes, and the depth of the packer is deeper than the top of cement for the production casing or production liner identified in question 19, and the tubing and packer are without a leak, show 1 level of protection in the box at right.* ☐

24. Is the perforated or open hole production/injection/disposal formation isolated from the production casing or production liner by a bridge plug, a cement squeeze, a balanced cement plug, or a plug in a packer with no tubing?

☐ Yes ☐ No

*NOTE: If the answer to question 24 is yes, show 1 level of protection in the box at right.* ☐

25. Total number of levels of protection from boxes of questions 17-24. ☐

26. According to the total number of verifiable levels of protection identified in question 25, categorize this well according to the following:

☐ Minimum Fluid Migration Potential
– the answers to questions 11 and 13 are both no, or
– the answer to question 11 is no and the answer to question 20 is yes.

☐ Low Fluid Migration Potential - levels of protection = 2 or more

☐ Moderate Fluid Migration Potential - levels of protection = 1

☐ Significant Fluid Migration Potential - this well should be immediately evaluated to determine the appropriate action, which may include repairing or plugging and abandoning.
– levels of protection = 0 and the answer to question 11 is yes, or
– the answer to question 11a is no, or
– the answer to question 15 is yes, or
– the answer to question 20a is yes.

27. Remarks

| 28. Lease and Well Name | 29. Field Name |
|---|---|
| | |

# APPENDIX B
# SUMMARY OF ENVIRONMENTAL LEGISLATION AND REGULATIONS

The following summarizes legislation and regulations that are applicable to plugging and abandonment operations in the onshore petroleum extraction industry. These regulations impose standards on operators to prevent leakage of formation or injected fluids via P&A wells into underground sources of drinking water (USDW) or surface waters.

Civil and criminal penalties can be imposed on operators who violate regulations promulgated under Federal statutes. The Safe Drinking Water Act prescribes civil penalty liability with a maximum fine of $25,000 per day of violation. The EPA is given authority to issue administrative orders and assess administrative penalties of up to $10,000 per day, with a total maximum penalty of $125,000. The Clean Water Act provides penalties of fines ranging from $2,500 to $25,000 per day of violation and imprisonment up to one year per day of violation for "negligent" violations. For "knowing" Clean Water Act violations, the fines are doubled, and imprisonment may be up to three years per day of violation.

## B.1 SAFE DRINKING WATER ACT (SDWA)

The SDWA was enacted by Congress in 1974. The Act requires the EPA to set drinking water quality standards for public water systems and prevent the endangerment of USDWs from underground injection operations. To prevent USDW endangerment, regulations for the Underground Injection Control (UIC) Program were first promulgated by the EPA in 1980 to regulate underground injection wells. The regulations cover the Class II injection wells used in E&P enhanced recovery and waste water disposal operations in states where the EPA operates the UIC Program.

No owner or operator may construct, operate, maintain, convert, plug, abandon, or conduct any injection activity that causes the movement of fluids containing contaminants into or between a USDW, if the presence of that contaminant violates any national primary drinking water regulation under 40 CFR Part 141, or adversely affects human health.

## B.2 PLUGGING REGULATIONS FOR PRODUCTION AND INJECTION WELLS

State injection well programs are required to meet minimum guidelines (46 FR 27333; May 19, 1981) set by the EPA in 1981 to obtain UIC primacy under Section 1425 of the SDWA. Primacy gives the states authority to regulate the plugging of injection wells. As a result, states have developed plugging regulations or require plugging plans (procedures) which ensure that injection wells are properly P&A'd by operators. The EPA implements and operates UIC programs in states which do not have UIC primacy (i.e., direct implementation states). The UIC program also gives the EPA authority to regulate injection well plugging. The EPA requires operators to submit plugging plans as a part of the UIC permit application and requires 45 days notification to the agency prior to commencement of plugging operations.

Moreover, when permitting a new injection well under Federal or state UIC programs, an area of review analysis (i.e., a review of public records for all wells penetrating the injection zone within a minimum one-quarter mile radius or calculated zone of endangering influence) on existing injectors, producers, and P&A wells is required. Should any of these wells pose a potential pathway for injection fluids to migrate into USDWs, corrective action must be performed by the operator. Such corrective action may include properly plugging any existing P&A wells.

Authority for plugging oil and gas producing wells is strictly regulated by the states (Bureau of Land Management has joint authority over Federal and Indian lands). In all states, regulations require operators to notify the applicable state agency about their intention to plug a producing well. Most states have forms for such notification, which require details about the proposed plugging program. Those states that do not have specific plugging requirements do have general rules which require that a plugging plan must be approved by a state geologist or other designated representative prior to commencing plugging operations.

Most states have specific requirements for the type and location of cement plugs in both production and injection wells. In direct implementation states, the EPA has plug type and placement requirements for injection wells only. All states require an affidavit or notice of completion for the plugging of each well. Most states and the EPA will provide a representative to witness the plugging operation, or in some manner, to inspect the job. About half of the states and the EPA require a permanent marker at the well site detailing ownership, well number, abandonment date, and other pertinent data. All states require the well site to be cleaned up, all holes or pits filled, and equipment removed. The site must be restored to enable beneficial use of the surface lands.

## B.3 CLEAN WATER ACT (CWA)

The CWA of 1972 (originally named the Federal Water Pollution Control Act) was enacted by Congress primarily to control point source discharges into waters of the United States. All point source discharges require National Pollutant Discharge Elimination System (NPDES) permits, or state equivalent permits, under Section 402 of the Act. Discharges of produced water, drilling mud, cooling water, etc., into waters of the United States are examples of point source discharges. The permit conditions usually require periodic monitoring and reporting of effluent constituents, which must be maintained within concentration limits specified by technology-based or water-based concentration standards. Fluids seeping from an improperly P&A'd well to waters of the United States constitute an illegal discharge and violate Section 402 of the Act.

Moreover, under Section 311 of the Act, the discharge or spillage of oil into waters of the United States must be reported to the U.S. Coast Guard National Response Center in Washington, D.C. Operators are subject to civil and criminal fines and penalties, including imprisonment for not more than five years, if spills are not reported as required under the Act. Oil discharged from an improperly P&A'd well to waters of the United States constitutes a prohibited discharge and must be reported to the National Response Center.

## B.4 FEDERAL OIL AND GAS ROYALTY MANAGEMENT ACT OF 1982 (FOGRMA)

The FOGRMA, enacted by Congress in 1982 (30 USC, Sec. 1701 et seq.), assures proper and timely revenue reporting for production from onshore Federal and Indian oil and gas leases, addresses Outer Continental Shelf matters, addresses lease reinstatement, prescribes inspection and enforcement actions concerning onshore field operations, establishes the basis for cooperation with states and Indian tribes for onshore Federal leases, and establishes duties of lessees, operators, and others involved in the production, storage, measurement, and transportation or sale of oil and gas from onshore Federal and Indian leases. The FOGRMA regulations require oil and gas operators on Federal lands to maintain site security and to construct and operate wells and associated facilities in a manner which protects the environment and conserves the Federal resource. The statute implies that oil and gas wells be properly P&A'd.

# GLOSSARY

**Annulus** — The space between the outer wall of one string of pipe (casing or tubing) suspended in a wellbore and the inner wall of the next larger casing or the borehole wall; i.e., the space between concentric pipe strings.

**Balanced Cement Plug** — The result of pumping cement through drill pipe, workstring, or tubing until the level of cement outside is equal to that inside the drill pipe/workstring/tubing. The pipe is then pulled slowly from the cement slurry, leaving the plug in place. The technique is used in both open hole and cased hole applications when the wellbore fluids are in static equilibrium.

**Borehole** — The hole made by drilling a well. Where casing is run in the well, the borehole is the space between the exterior of the casing and the formations. After the casing has been installed, the borehole is normally filled with various materials such as cement, drilling mud, sloughing formations, and water.

**Bradenhead Squeeze** — The process by which hydraulic pressure is applied to a casing, workstring, or tubing, to force fluids, such as cement, outside the wellbore. Annular returns may be prevented by closing the casinghead valves. A packer is not run in the well. Therefore, the inner casing wall is exposed to the pumping pressures.

**Bridge Plug** — A downhole tool (composed primarily of slips, a plug mandrel, and a rubber sealing element) that is run and set in casing to isolate a lower zone while an upper section is tested, cemented, stimulated, produced, or injected into.

In order to facilitate removal by drilling, a bridge plug is often made of cast iron and is commonly referred to as a *cast iron bridge plug* (CIBP).

**Bullhead Squeeze** — The process by which hydraulic pressure is applied to a workstring or tubing to force fluids, such as cement, outside the wellbore. Annular flow (returns) is prevented by a packer set in the casing above the perforated and/or open hole interval. The packer shields the inner casing wall from exposure to the pumping pressures.

**Casing Head (or Braden Head)** — A heavy steel fitting connected to the uppermost end of the surface casing. It provides a pressure seal for subsequent casing strings placed in the well and allows suspension of intermediate casing strings and the production casing. It also provides outlets to release any pressure that might accumulate between casing strings. The casing head is usually connected to the surface casing by a threaded connection, but in deep wells it may be attached by welding.

**Casing Packer** — A downhole tool (composed primarily of slips, an open mandrel, and a rubber sealing element) that is installed in wells to seal the tubing-casing annulus and protect the casing from fluids produced through or pumped down the tubing and to isolate the casing from pressure(s).

**Casing Shoe** — A short, heavy cylindrical section of steel, filled with cement, which is placed at the end (bottom) of the casing string. It prevents the casing from snagging on irregularities in the borehole as it is lowered. A passage through the center of the shoe allows drilling fluid to pass up into the casing while it is being lowered and allows cement to pass through and circulate behind the casing during cementing operations. Also called the guide shoe. When running casing in deeper wells, a float collar is run in addition to a guide shoe.

**Cement** — A powder consisting of alumina, silica, lime, and other substances that hardens when mixed with water. Cements are used in oil, gas, geothermal, injection, or water wells for protecting and supporting casing, isolating intervals within the wellbore, repairing casing leaks, sealing perforated or open hole intervals, and protecting fresh water aquifers. Well cements are manufactured to meet API Specification 10A, which includes chemical, physical, and performance requirements for API Classes A through H.

**Cement Plug** — A volume of cement placed at some interval inside the wellbore to prevent fluid movement.

**Cement Retainer** — A tool (composed primarily of slips, a ported mandrel, and rubber sealing elements) set in the casing which allows cement or other fluids to be pumped through the tool, but seals against any fluid movement when the tubing is released from the tool. The cement retainer is generally used in squeeze cementing work. The cement retainer cannot be unset once it has been set in the casing but it can be drilled out.

**Christmas Tree** — An assembly of valves, fittings, chokes, and gauges used in monitoring and controlling producing, injection, and inactive wells. The Christmas tree is assembled at the top of the well starting with the uppermost flange of the tubing head.

**Coiled Tubing** — A continuous length of small diameter (i.e., usually 1" to 1-3/4") ductile steel tubing which is coiled onto a reel. The tubing is fed into the well by an injector head through a coiled tubing blow-out preventer or stuffing box. The coiled tubing may be used for pumping fluids, including cement, into the wellbore.

**Completion Interval** — The geologic formations in a well where production, injection or disposal operations are taking place.

**Concentric Tubing** — Small diameter tubing installed inside conventional tubing or tubingless completions, normally with the christmas tree in place, using a small rig or hoisting unit.

**Conductor Pipe** — A relatively short string of large diameter pipe which is installed to keep the top of the hole open and provide a means of returning the drilling fluid from the wellbore to the surface drilling fluid system until the first casing string is set in the well. Conductor pipe may also be used in well control when drilling to surface casing depth. Conductor pipe may or may not be cemented.

**Corrosive Oilfield Water** — A water that induces corrosion of the casing, tubing, and wellhead because of low pH and elevated levels of temperature, pressure, bacteria, dissolved gases, and dissolved solids. The severity of the corrosion increases with an increase in the velocity of oilfield waters across the surfaces of the casing, tubing, and wellhead.

Water found in fresh water aquifers typically is near ambient temperature, has low levels of dissolved gases and solids and has a relatively low velocity. As a result, fresh water aquifers are generally not very corrosive.

**Displacement Fluid** — In oil well cementing, the fluid, usually drilling mud or salt water, that is pumped into the well after the cement is pumped to displace the cement from the casing and into the annulus and to prevent the cement from re-entering the casing after pumping stops.

**Dump Bailer** — A cylindrical container with a shear device that is used to release small batches of cement downhole on impact or by electrical activation. Used primarily to install cement on downhole tools such as bridge plugs or cement retainers.

**Float Collar** — A short cylindrical section of steel which is placed in the casing string above the guide shoe. The float collar usually incorporates a ball or spring-loaded backpressure valve which prevents wellbore fluid from entering the casing while the pipe is lowered in the well. This makes the casing buoyant, thereby reducing the derrick stress while running casing.

**Float Shoe** — A guide shoe run on the bottom of the casing string that incorporates a ball or spring-loaded backpressure valve which prevents wellbore fluid from entering the casing while the pipe is lowered in the well. Performs the same function as the float collar.

**Fluid Spacer** — An oil or water based fluid used to separate incompatible drilling fluid from cement. Spacers are compatible with both the drilling fluid and the cement. The purpose of spacers is to minimize cement contamination by drilling fluid and to displace drilling fluid from the wellbore so that the cement can form an effective hydraulic seal.

**Fresh Water Aquifer** — A subsurface formation which generally contains water with less than 3,000 mg/l TDS and which supplies any public water supply system or currently supplies drinking water for human/livestock consumption or which contains sufficient water to supply a public water system.

**Inactive Well** — A well where production, injection, disposal or workover operations have ceased, but permanent abandonment has not taken place. Inactive wells should be classified as either shut-in or temporarily abandoned. Shut-in status should begin 90 days after operations stop, and temporarily abandoned status should commence one day after temporary abandonment operations have been completed.

**Intermediate Casing** — One or more strings of casing run between the surface casing and the production casing or the production liner and is cemented in place. Intermediate casing is generally run in deeper wells to isolate abnormal pressured formations, lost circulation zones, salt sections, and unstable shale sections so deeper drilling can proceed with normal mud weights. A large number of wells are drilled without running intermediate casing.

**Landing Nipple (Profile Nipple)** — A receptacle that can be installed in a tubing string with an internal profile machined to provide a seating surface whereby various types of plugs or valves can be latched and will seal against the machined surface.

**Level of Protection** — A level of protection is a barrier to fluid migration into fresh water aquifers that has mechanical integrity, and its integrity can be monitored with some degree of confidence. The well construction components, such as surface casing, production casing, tubing and packer, and wellbore plugs, are such barriers.

Levels of protection are sometimes referred to as layers of protection.

**Liner** — A string of casing which does not extend to the surface but is hung from inside the previous casing string and is cemented in place. The overlap of the liner could vary from 50 ft to 500 ft depending on the purpose of the liner.

Production liners are set to the top of, or through, the completion interval. Drilling liners are set primarily to case off and isolate zones of lost circulation, highly overpressured zones, and sloughing shales, so drilling may proceed. Repair liners are used to isolate casing leaks and to repair damaged, worn, corroded, or deliberately perforated casing.

A large number of wells are drilled without running liners.

**Mechanical Integrity** — Defined by EPA as "no significant leak in the casing, tubing, and packer and no significant fluid movement into a USDW through vertical channels adjacent to the injection wellbore."

**Mud** — The weighted liquid circulated through the wellbore during rotary drilling and workover operations. In addition to its function of bringing cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids into the formation. Originally a suspension of clays in water, the mud used in modern drilling is often a more complex mixture of liquids, reactive solids, or oil, often containing one or more conditioners. Water base mud made from oil field brine may also be used as a well control fluid in plugging operations. Also known as drilling fluid or drilling mud.

**pH** — A unit to measure the degree of acidity or alkalinity of a liquid. A neutral solution, such as pure water, has a pH of 7. Acidic solutions have a pH less than 7. Alkaline solutions have a pH greater than 7.

**Permeability** — The property of a porous medium which is a measure of the capacity of the medium to transmit fluids within its interconnected pore network. The usual unit of measurement is the millidarcy, or 0.001 darcy.

**Plug** — A device or material which may be temporarily or permanently placed in the wellbore to block off or isolate lower zones so that upper zones may be completed, stimulated, tested, cemented, produced, or injected into.

**Plug and Abandon (P&A)** — Placement of a cement plug or plugs in a well, in which no future utility has been identified, to seal the entire wellbore against fluid migration, and protect fresh water aquifers from contamination.

**Plug Back** — To place cement or other material in the well to seal off a completion interval, to exclude bottom water, or to perform another operation such as sidetracking or producing from another depth. The term also refers to the setting of a mechanical plug in the casing.

**Plug Back Total Depth (PBTD)** — the new bottom of a well that is established when a well is plugged back.

**Pressured Formation** — Any producing, injection, disposal, permeable hydrocarbon bearing or permeable salt water bearing formation penetrated by the well which has sufficient pressure to initiate and sustain significant fluid migration into a fresh water aquifer or to the surface.

**Production Casing (or Long String Casing)** — The casing which is installed from the wellhead to the top of, or through, the completion interval and is cemented in place to seal off producing/injection zones and water-bearing formations. The tubing string, if used, is suspended in the production casing.

In deeper wells, the production casing may be replaced by a production liner.

**Productive Horizon** — Any stratum known to contain oil, gas, or geothermal resources in commercial quantities.

**Retrievable Packer** — A tool consisting of slips, an open mandrel, and rubber sealing elements run on workstring or tubing to isolate the wellbore from pressures encountered during squeeze cementing operations. The tool is intended to be set and released several times by methods specific to the tool design (i.e., tension or compression set).

**Shut-In** — Inactive wells in which the completion interval is open to the tubing and to the casing, or is open to the tubing only. The well may be shut-in without packer and with or without tubing, in which case the interior of the casing is not isolated from the completion interval. Or, the shut-in well may have tubing and packer, which isolates the interior of the casing above the packer from the completion interval.

Shut-in wells have been removed from active service in anticipation of a workover, temporary abandonment, or plugging and abandonment operations. Generally, the wellbore condition is such that its utility may be restored by opening valves or by energizing equipment involved in operating the well. Shut-in status should begin 90 days after production, injection, disposal or workover operations cease.

**Slim Hole Completion** — A well that is completed without tubing. Usually, only small diameter casing is set and cemented. After perforating, formation fluids are produced out of the casing.

**Squeeze Cementing** — Pumping a cement slurry to a specific point in the wellbore with sufficient pressure to force the cement into the location desired. This pressure will also tend to dehydrate the cement and form a high strength filter cake in perforations, in formation voids or fractures, or against the formation face. The filter cake becomes a barrier which will prevent fluid movement. Squeeze cementing is used to seal completion intervals, to repair casing leaks, to seal formation intervals behind pipe, and to protect fresh water aquifers.

**Squeeze Pressure** — That surface pressure required to force a cement slurry into the location desired and result in a differential pressure across the cement slurry that causes cement particles to separate from water (i.e. dehydration) and form a filter cake.

**Stage Cementing** — A procedure that permits using a cement column height in the borehole that normally would cause fracture of a subsurface formation. Stage-cementing operations are conducted after the primary cement job has been completed in a normal manner. When the primary cement hardens, ports are opened in a stage-cementing tool which was placed in the casing string as casing was being installed into the borehole. The second-stage cement is pumped through the ports into the borehole above the top of the primary cement.

**Stage-Cementing Tool** — A tool installed in the casing string through which the stage-cementing operations are conducted. The tool is placed in the casing string as the casing is being installed into the borehole. After the primary cement job has been completed, and the slurry has hardened, ports in the tool are opened so stage-cementing operations can proceed.

**Surface Casing** — The first string of casing to be set and cemented in a well, the principal purpose of which is to protect fresh water aquifers. It also prevents lost circulation while drilling deeper, supports blowout prevention equipment (if used), and supports deeper casing strings and the tubing.

**Temporarily Abandoned (TA)** — Inactive wells in which the completion interval has been isolated from the interior of the casing. The completion interval may be isolated using the bridge plug method, the cement squeeze method or the balanced cement plug method. If a packer is installed in the well, isolation of the completion interval may also be achieved by installing a plug in the packer which has no tubing.

Temporary abandonment is generally used when a well is a candidate for future utilization, such as in a possible enhanced oil recovery project. TA status should begin the day after the completion interval has been isolated from the wellbore.

**Tubing** — Pipe installed in the wellbore inside the production casing, extending from the wellhead to a depth at or above the completion interval, and through which formation fluids are transported to the surface and through which stimulation or injection fluids are transported to the formation.

**Underground Source of Drinking Water (USDW)** — An aquifer or its portion which supplies any public water supply system or currently supplies drinking water for human consumption or which contains sufficient water to supply a public water system or has a total dissolved solids (TDS) concentration of less than 10,000 mg/l. The EPA may exempt an aquifer if it will not serve as a source of drinking water in the future because it is economically or technically impractical to recover the water or to render it fit for human consumption or because the aquifer produces or is expected to commercially produce minerals, hydrocarbons, or geothermal energy.

While the EPA defines a USDW as containing less than 10,000 mg/l TDS, certain states, such as California and Texas, have adopted a producing and injection well surface pipe protection standard for fresh water aquifers that contain less than 3,000 mg/l TDS.

**Wellbore** — The interior surface of the cased or openhole through which drilling, production, or injection operations are conducted.

**Wireline Operations** — Operations performed in a wellbore using tools which are run and pulled on small diameter slick, braided, or electric wirelines.

**Work String** — The drill pipe or tubing used in well workover operations or abandonment operations to perform specific downhole tasks such as running squeeze cementing tools and stimulation packers, as well as performing stimulation, testing, cementing, wellbore cleanout, etc. operations.

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