ATTACHMENT G: CONSTRUCTION DETAILS

Facility Information

Facility name: Kansas Small Scale Test Wellington Field
KSS191GS0001

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Well location: Sumner County, Kansas
Latitude 37.319485, Longitude -97.4334588

Introduction

The testing activities at the two Arbuckle wells (KGS 1-28 and KGS 2-28) described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

Injection Well Construction Details

Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Conductor	0 – 125	13.375	
Surface	0 – 647	12.25	
Production	0 – 5250	7.875	

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	0 - 125	13.375	12.615	54.5	J-55	STC	29.84	2,730	1,130
Surface	0 - 647	8.625	7.972	24	J-55	STC	29.84	2,950	1,370
Production Casing	0 - 5241	5.5	4.95	15.5	J-55	STC	29.84	4,810	4,040

Tubing Specifications

Name	Depth Interval (feet)[1]	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	0 – 4860	2.875	2.441	6.4	J-55 (lined w/ Tuboscope's TK-70XT coating)	Non upset	7260	7680

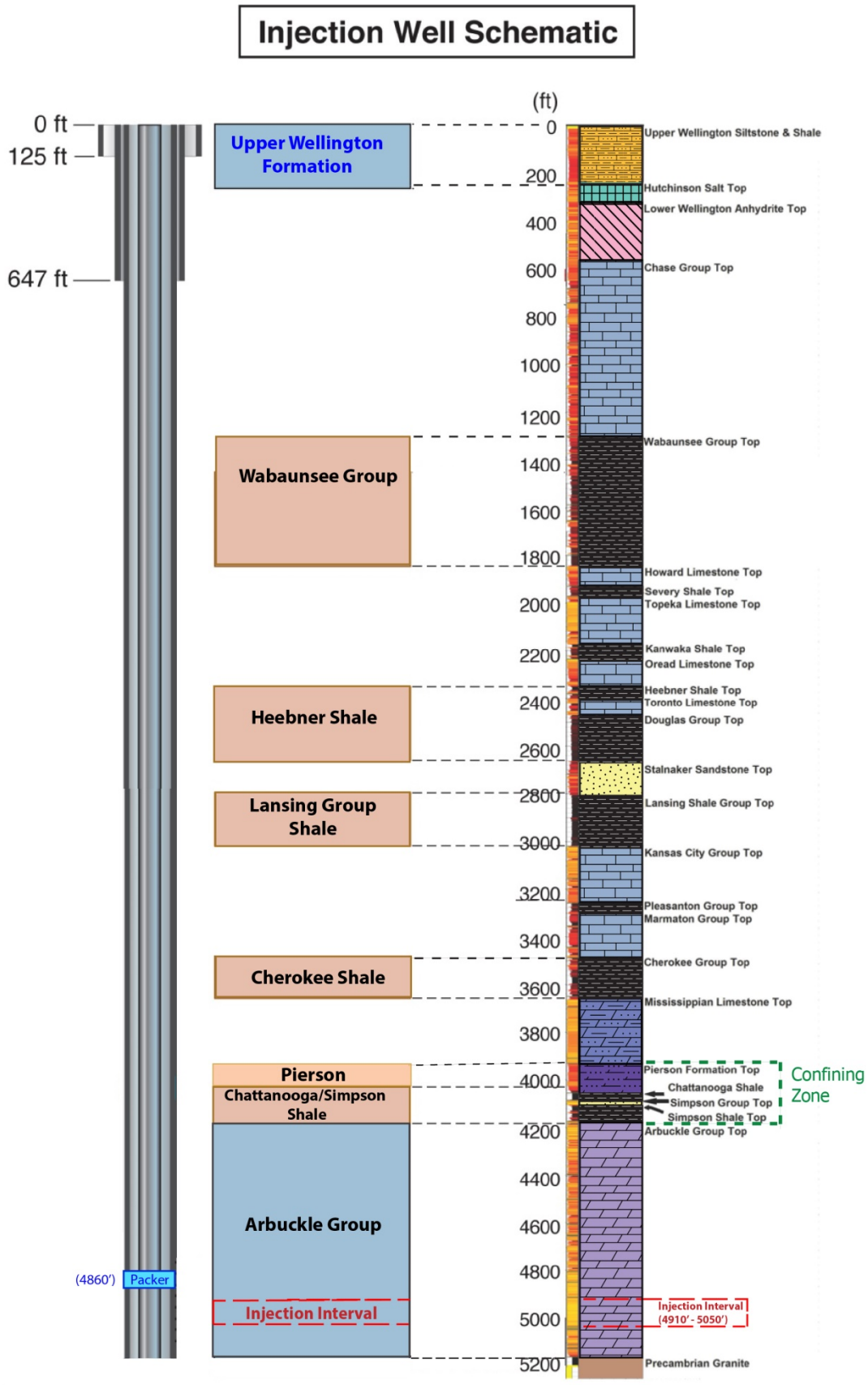
Packer Specifications

Packer Type and Material	Packer setting Depth (bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Hydraulic Set - HNBR seals with chrome plated carbon steel	4860'	103.35"	2-3/8" long string is P-110	4.625"	2-3/8" long string, 4 x 1/4" pass-through

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
105,570	10,570	11,160	4.950	4.670

Injection Well Construction Diagrams

Well construction diagrams appear on the following two pages.

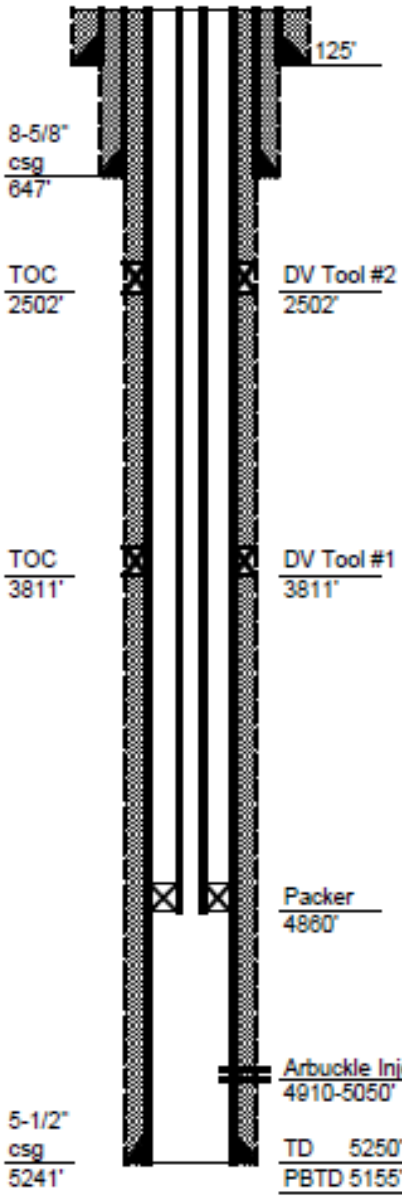

Injection Well Schematic
(ft)
0 ft
125 ft
647 ft
(4860')
Packer
Upper Wellington Formation
Wabaunsee Group
Heebner Shale
Lansing Group Shale
Cherokee Shale
Pierson
Chattanooga/Simpson Shale
Arbuckle Group
Injection Interval
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
3200
3400
3600
3800
4000
4200
4400
4600
4800
5000
5200
Upper Wellington Siltstone & Shale
Hutchinson Salt Top
Lower Wellington Anhydrite Top
Chase Group Top
Wabaunsee Group Top
Howard Limestone Top
Severy Shale Top
Topeka Limestone Top
Kanwaka Shale Top
Oread Limestone Top
Heebner Shale Top
Toronto Limestone Top
Douglas Group Top
Stalnaker Sandstone Top
Lansing Shale Group Top
Kansas City Group Top
Pleasanton Group Top
Marmaton Group Top
Cherokee Group Top
Mississippian Limestone Top
Pierson Formation Top
Chattanooga Shale
Simpson Group Top
Simpson Shale Top
Arbuckle Group Top
Confining Zone
Injection Interval (4910' - 5050')
Precambrian Granite

Wellbore Diagram

LEASE Wellington KGS #1-28 **API 15-191- 22590**

NE SW SE SW Sec 28 31s - 1w Sumner COUNTY KANSAS

Perforate Arbuckle for CO2 Injection 4910' to 5050'



13-3/8" CONDUCTOR, 48#/FT
Set at: 125' 135 sx cement
Top of Cmt @ Circulated to Surface

8-5/8" SURFACE CASING 24 #/FT
Set at: 647' 325 sx cement
Top of Cmt @ Circulated to Surface

DV Tool #2
Set at: 2502' 610 sx cement
Top of Cmt @ Circulated to Surface

DV Tool #1
Set at: 3811' 260 sx cement
Top of Cmt @ 2502'
Circ cement to surface when DV Tool #2 was opened

2-7/8", J-55 Lined Injection Tubing
Packer at: 4860'

5-1/2" PRODUCTION CASING 15.5#/FT, J55
Set at: 5241' 250 sx cement
Top of Cmt @ 3811'
Circ cement to surface when DV Tool #1 was opened

Pre-Injection Testing Plan – Injection Well (KGS 1-28)

Note: This well was drilled as a geologic test well, but constructed to EPA Class VI construction standards in advance of the permit submission. All tests and logs conducted during drilling, casing installation and after casing installation were done in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The whole core or sidewall core samples required by 40 CFR 146.87(b) will be collected from the nearby Arbuckle monitoring well (2-28) during that wells installation due to poor core recovery through sections of the injection interval in the Arbuckle injection well (1-28). The tests and logs conducted during the installation of well 1-28 are still awaiting final review and approval by EPA. The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the permit application.

Deviation Checks

Deviation measurements were conducted approximately every 1,000 feet during construction of KGS 1-28. The average hole deviation was less than 1.25 degrees.

Tests and Logs

During drilling at existing Arbuckle well KGS 1-28 and KGS 1-32 (already completed)

Array Compensated True Resistivity Log
Spontaneous Potential Logs
Caliper Logs
Borehole Temperature Logs
Extended Range Micro Imager (XRMI) Composite Plot
Extended Range Micro Imager (XRMI) Correlation Plot
Compensated Spectral Natural Gamma Log
Magnetic Resonance Imaging Analysis
Spectral Density Dual Spaced Neutron Log
Drill Stem Testing
Mud Logging
Fracture Studies

During and After Casing Installation at Existing Arbuckle Well KGS 1-28 and KGS 1-32 (already completed)

Radial Cement Bond Log
Annular Hole Volume Plot
Variable Density Logs

Demonstration of Mechanical Integrity

Below is a summary of the MITs and pressure fall-off tests to be performed prior to injection:

Class VI Rule Citation	Rule Description	Test Description	Program Period
[40 CFR 146.89(a)(1)]	MIT - Internal	Annulus Pressure Test	Prior to Operation
[40 CFR 146.87(a)(4)]	MIT - External	Temperature Log	Prior to Operation
[40 CFR 146.87(e)(1)]	Testing prior to operating	Pressure Fall-off Test	Prior to Operation

Notice and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Pre-Injection Testing Plan – Deep Monitoring Well (KGS 2-28)

Deviation Checks

Deviation measurements will be taken at approximately every 1,000 feet during construction of KGS 2-28, and the average hole deviation reported to EPA.

Tests and Logs

During Drilling

Array Compensated True Resistivity Log
Spontaneous Potential Logs
Caliper Logs
Borehole Temperature Logs
Spectral Density Dual Spaced Neutron Log
Drill Stem Testing
Mud Logging
Full Wave Sonic (with fracture analysis)

During and After Casing Installation

Radial Cement Bond Log
Annular Hole Volume Plot

Demonstration of Mechanical Integrity

Below is a summary of the MITs to be performed on the deep monitoring well after its installation and prior to injection of CO2 into well 1-28:

Class VI Rule Citation	Rule Description	Test Description	Program Period
[40 CFR 146.89(a)(1)]	MIT - Internal	Annulus Pressure Test	Prior to Operation[1]
[40 CFR 146.87(a)(4)]	MIT - External	Temperature Log	Prior to Operation

Notice and the opportunity to witness the test/log shall be provided to EPA at least 48 hours in advance of a given test/log. Note that the Annulus Pressure Test at KGS 2-28 will be conducted prior to perforating the well.

Annulus Pressure Test Procedures for Injection Well (KGS 1-28):

1. If the well has tubing but no packer at the base of the tubing string or if the tubing and packer are set more than 50 feet above the injection interval, pull tubing strings from the well and follow step two. Otherwise proceed to step three. Newly installed wells with the top plug still in place may also proceed to step three.

2. Set a retrievable bridge plug or packer immediately above the perforations or before the open hole for the purpose of pressure testing the casing. The setting depth shall have the approval of EPA. Provide information describing the packer or plug and the suitability of the packer or plug for use in this pressure test. The packer or plug must be capable of making a tight seal to allow the casing to be hydraulically pressure tested.
3. The well bore or annulus space between the tubing and casing must be fluid filled and in thermal equilibrium before commencing the test (typically left to sit for 24 hours before the test).
4. Hydraulically pressure test the casing. The liquid pressure placed on the casing is to be monitored for the purpose of determining integrity of the casing. It shall be demonstrated to the EPA representative that the casing is liquid filled. This can be demonstrated to the EPA representative upon completion of the test.
5. Once the casing has been pressurized (methods to pressure the well include the use of a pump truck, small pumps or a manual hydraulic pump), vent as much of the air as possible from the well. Re-pressure as necessary. Once the casing has been pressurized for the test, the casing shall be isolated from all external artificial pressure sources capable of introducing pressure to the casing.
6. The wellhead casing test pressure shall be 1.5 times the average maximum operating injection pressure at the wellhead.
7. A description of the pressure gauge to be used to monitor the test pressure must be provided. The gauge must have a scale such that the test pressure is 40% - 60% of full scale. The scale shall measure pressure in increments of no more than 2 psi per division.

The gauge should be tested for accuracy in advance of the mechanical integrity test. A document with a description of the test, the test date, amount of error found on the gauge during the test and a description of the test, the test date, amount of error found on the gauge during the test and a description of corrective action such as recalibration shall be provided to the EPA representative at the time of the mechanical integrity test. It shall be demonstrated the gauge is functioning properly.

8. The test shall be a minimum of 30 minutes in duration.
9. A pressure loss of equal to or less than 10% of the initial test pressure is a satisfactory test and indicates the well has internal mechanical integrity at the time of the test. A pressure gain or greater than 5% of the initial test pressure is not acceptable and may indicate the well has not reached thermal equilibrium. A pressure loss of greater than 10% of the initial test pressure is not acceptable and may indicate the well does not have mechanical integrity or that the bridge plug or packer is not seated properly. At the discretion of the EPA representative, the operator may try reseating the bridge plug or packer and rerunning the test.
10. When the test is complete, it must be demonstrated by the operator that the test was totally hydraulic and the gauge was functioning correctly. This is accomplished by opening a valve to bleed off the water. Water should bleed off immediately. If a significant amount of air bleeds off prior to water, the well was not properly prepared prior to the test. The well need only be bled off enough to demonstrate liquid is in the annulus. The test gauge must drop to zero when the pressure is released or when the gauge is removed from the well demonstrating the gauge functioned properly.
11. If a satisfactory test is not obtained the well shall remain out of service until corrective action approved by EPA has been taken and a satisfactory MIT conducted. The location of the leakage must be determined and the impact to the environment evaluated. An environmental remediation plan and implementation schedule and a plan for repair of the well may be required to be submitted to EPA for review and approval. No work shall commence until plan approval has been obtained from EPA.
12. Failure to follow the EPA approved MIT plan may result in cancellation of the test and shut-in of the well until the MIT is rescheduled and conducted to the satisfaction of EPA.

Annulus Pressure Test Procedures for Monitoring Well (KGS 2-28 – to be conducted prior to perforation):

1. The well bore or annulus space between the tubing and casing must be fluid filled and in thermal equilibrium before commencing the test (typically left to sit for 24 hours before the test).
2. Hydraulically pressure test the casing. The liquid pressure placed on the casing is to be monitored for the purpose of determining integrity of the casing. It shall be demonstrated to the EPA representative that the casing is liquid filled. This can be demonstrated to the EPA representative upon completion of the test.

3. Once the casing has been pressurized (methods to pressure the well include the use of a pump truck, small pumps or a manual hydraulic pump), vent as much of the air as possible from the well. Re-pressure as necessary. Once the casing has been pressurized for the test, the casing shall be isolated from all external artificial pressure sources capable of introducing pressure to the casing.
4. The minimum wellhead casing test pressure shall be 300 psi.
5. A description of the pressure gauge to be used to monitor the test pressure must be provided. The gauge must have a scale such that the test pressure is 40% - 60% of full scale. The scale shall measure pressure in increments of no more than 2 psi per division. The gauge should be tested for accuracy in advance of the mechanical integrity test. A document with a description of the test, the test date, amount of error found on the gauge during the test and a description of the test, the test date, amount of error found on the gauge during the test and a description of corrective action such as recalibration shall be provided to the EPA representative at the time of the mechanical integrity test. It shall be demonstrated the gauge is functioning properly.
6. The test shall be a minimum of 30 minutes in duration.
7. A pressure loss of equal to or less than 10% of the initial test pressure is a satisfactory test and indicates the well has internal mechanical integrity at the time of the test. A pressure gain or greater than 5% of the initial test pressure is not acceptable and may indicate the well has not reached thermal equilibrium. A pressure loss of greater than 10% of the initial test pressure is not acceptable and may indicate the well does not have mechanical integrity or that the bridge plug or packer is not seated properly. At the discretion of the EPA representative, the operator may try reseating the bridge plug or packer and rerunning the test.
8. When the test is complete, it must be demonstrated by the operator that the test was totally hydraulic and the gauge was functioning correctly. This is accomplished by opening a valve to bleed off the water. Water should bleed off immediately. If a significant amount of air bleeds off prior to water, the well was not properly prepared prior to the test. The well need only be bled off enough to demonstrate liquid is in the annulus. The test gauge must drop to zero when the pressure is released or when the gauge is removed from the well demonstrating the gauge functioned properly.
9. If a satisfactory test is not obtained the well shall remain out of service until corrective action approved by EPA has been taken and a satisfactory MIT conducted. The location of the leakage must be determined and the impact to the environment evaluated. An environmental remediation plan and implementation schedule and a plan for repair of the well may be required to be submitted to EPA for review and approval. No work shall commence until plan approval has been obtained from EPA.
10. Failure to follow the EPA approved MIT plan may result in cancellation of the test and shut-in of the well until the MIT is rescheduled and conducted to the satisfaction of EPA.

Pressure Fall-Off Test Procedures:

1. General Operational Concerns
    a. Adequate storage for the waste should be ensured for the duration of the test
    b. Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test.
    c. Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge.
    d. The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period.
    e. The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
    f. Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well.
    g. Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
    h. Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
2. Site Specific Pretest Planning
    a. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
        i. Review previous well tests, if available.
        ii. Simulate the test using measured or estimated reservoir and well completion parameters
        iii. Calculate the time to the beginning of radial flow using the empirically-based equations. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period.
        iv. Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well-developed semilog straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.
    b. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high

enough to produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The viscosity of the fluid should be consistent. Any mobility issues (k/μ) should be identified and addressed in the analysis if necessary.

c. Bottomhole pressure measurements are usually superior to surface pressure measurements because bottomhole measurements tend to be less noisy. Surface pressure measurements can be used if positive pressure is maintained at the surface throughout the falloff portion of the test. The surface pressure gauge should be located at the wellhead. A surface pressure gauge may also serve as a backup to a downhole gauge and provide a monitoring tool for tracking the test progress. Surface gauge data can be plotted during the falloff in a log-log plot format with the pressure derivative function to determine if the test has reached radial flow and can be terminated. Note: Surface pressure measurements are not adequate if the well goes on a vacuum during the test.

d. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type.

3. Conducting the Falloff Test

a. Tag and record the depth to any fill in the test well.

b. Simplify the pressure transients in the reservoir

i. Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.

ii. Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.

iii. Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

c. The test well should be shut-in at the wellhead in order to minimize wellbore storage and afterflow.

d. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.

e. Measure and record the viscosity of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.