File I - Proposed Injection Well Construction Information

Note: This document contains Proposed Injection Well Construction information for the Kansas Small Scale Test Wellington Field. The contents were extracted from the original KGS permit document that was prepared prior to the new EPA submission format introduced to KGS on June 3rd 2014. This explains why the information in this Proposed Injection Well Construction document may contain references to figures, tables, and sub-sections in other permit sections that may not be included in this Proposed Injection Well Construction document. Therefore, to facilitate the review process, the entire original permit application has been submitted as a separate document titled "L - Other Information Required by the UIC Program Director", which also contains an Executive Summary, cover letter, application forms, complete table of contents, list of tables and figures, appendices, and a cross reference table which lists sub-sections that address all Class VI 40 CFR sections 146.82 – 146.93 requirements.

The Proposed Injection Well Construction Information is documented in the following subsections of section 8:

Table of Contents
File I: Proposed Injection Well Construction Information

Section 8

System Design, Construction, and Operation

8.1   Introduction

40 CFR § 146.86 (a) requires the owner or operator to ensure that all Class VI wells are constructed and completed to:

1) Prevent the movement of fluid into or between Underground Sources of Drinking Water (USDWs) or into any unauthorized zones,

2) Permit the use of appropriate testing devices and workover tools,

3) Permit continuous monitoring of the annulus space between the injection tubing and long-string casing.

Casing and cement requirements are presented in §146.86 (b) with tubing and packer requirements presented in §146.86(c). Additionally, operational requirements are presented in §146.88 and pre-operational testing is specified in §146.87.

Information in this section is presented to satisfy the above requirements and to ensure that requirements for §146.82(a)(7–12) are satisfied, which require the permit application to include:

(7) Proposed operating data for the proposed small-scale, short-term pilot geologic storage site,

(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) that meets the requirements at § 146.87,

(9) Proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment,

(10) Proposed procedure to outline steps necessary to conduct pilot-scale injection operation;

(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well, and

(12) Injection well construction procedures that meet the requirements of § 146.86.

8.2   Background

Well KGS 1-28 is located in central Sumner County (Figure 1.6a) and will be used to inject CO_2 into the Arbuckle Group during a small-scale, short-term pilot project. Construction of the well started on February 20, 2011, and ended on August 24, 2011. Figure 8.1 shows the well design and construction details. The 5,241-ft deep well penetrated the top of the Precambrian basement rock at a depth of approximately 5,165 feet. The well has subsequently been plugged to a depth of 5,155 feet. As shown in Figure 8.1, the well will be perforated between 4,910 and 5,050 ft for injection into a higher permeable interval within the lower portion of the Arbuckle Group. The well penetrated several shale intervals above the Arbuckle as shown in Figure 8.2, most notable among these being the Simpson Group, Chattanooga Shale, and Pierson formation, which together constitute the primary confining zone.

During construction of the well, an extensive suite of geophysical logs, cores, and other geologic data were obtained to better understand the geology and to derive the petrophysical properties documented in Section 4. Well logs and well construction documents are presented in Appendix B. In addition to other discussion within this permit application, additional details about the KGS 1-28 pilot project injector can be found at the KGS website and include DST information, well logs, the Final Geologist's Report, daily drilling reports, maps, and links to other project information (http://www.kgs.ku.edu/PRS/Ozark/well_1_28.html).

8.3   Geologic Formations (§146.86 [a][1] and [b][1][i and vii])

The injection well penetrates the Simpson/Chattanooga/Pierson confining zone, as well as several additional thick shale layers above the confining zone (Figure 8.2). These additional shale layers provide a secondary level of confinement as discussed in Section 4.7.6. The lowermost USDW is the Upper Wellington Formation, which occurs within 250 ft of ground surface at the site, as shown in Figure 8.2.

The dolomitic Arbuckle Formation, which was completely penetrated in KGS 1-28, occurs between the basal Precambrian granite lower confining zone and the upper confining zone com-

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

TOC 2502'   DV Tool #2 2502'

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

TOC 3811'   DV Tool #1 3811'

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

Packer 4860'

Arbuckle Injection Interval
4910-5050'

8-5/8" csg 647'

5-1/2" csg 5241'

125'

TD   5250'
PBTD 5155'

Wellington KGS #1-28==WellBore Diagram.xls
-bl- Date Printed: 12/8/2011

Figure 8.1—Well design and construction details of KGS 1-28.
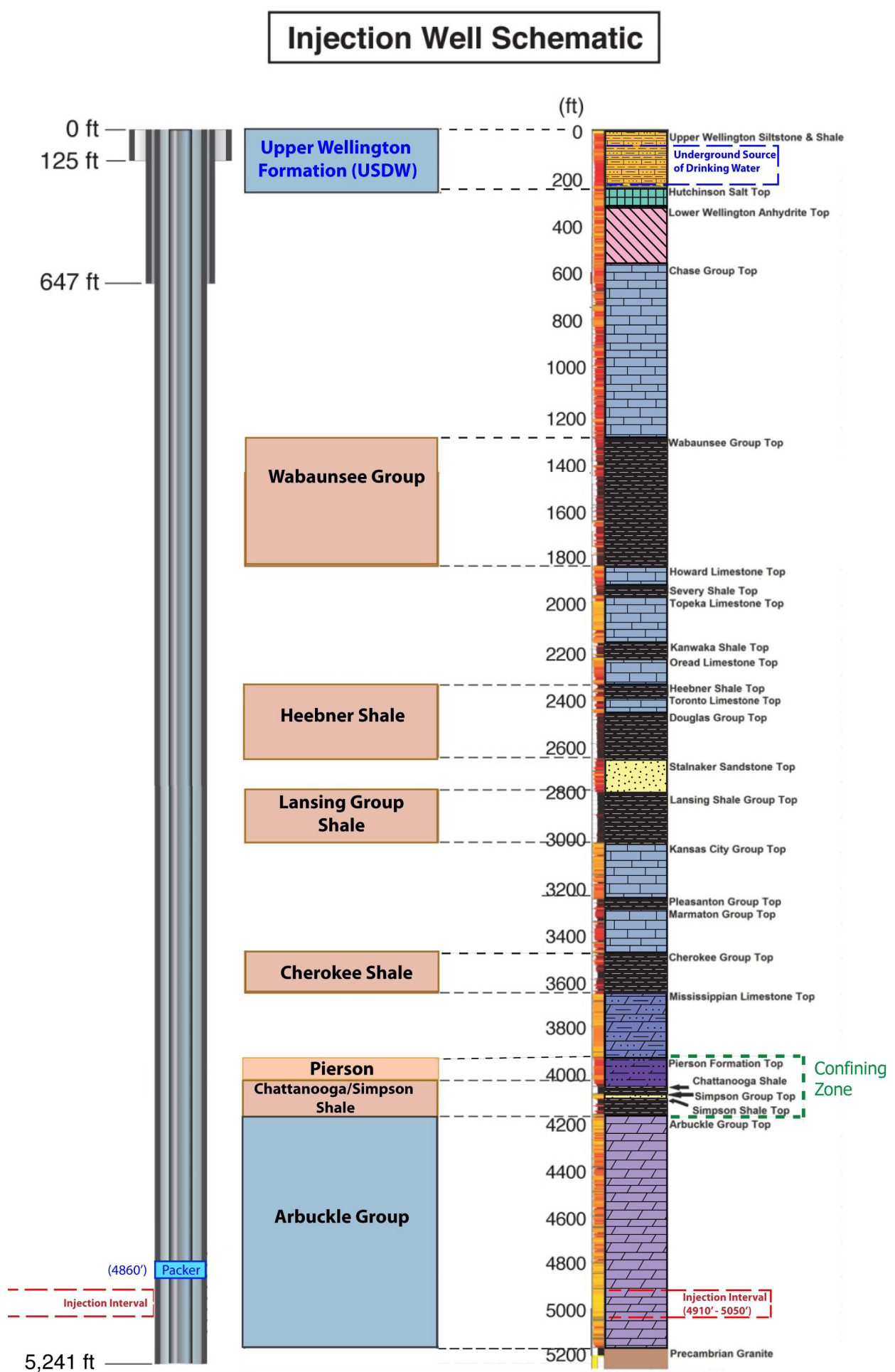
Injection Well Schematic

Figure 8.2—Injection well schematic and geologic formations encountered at KGS 1-28.

prising the Simpson Group, Chattanooga Shale, and the Pierson formation. The Arbuckle Group occurs at a depth of approximately 4,168 ft to 5,160 ft below ground surface (Figure 8.2) and injection is planned to take place in the interval 4,910–5,050 ft, which is in the lowermost portion of the Arbuckle Group as shown in Figure 8.2. The injection interval proposed for completion is a dolomite. The lowermost (and only) USDW in the area is the Upper Wellington Formation, which is limited to the top 250 ft of the geologic column at the site. The water resources in this formation are discussed and characterized in Section 4.5. The base of the USDW is approximately 3,900 ft above the top of the injection formation and approximately 250 ft below land surface.

8.4   Operational Information Relevant to Well Construction (§146.86 [b][1][ii and vi])

As discussed in Section 8.16, the surface facilities at the site will consist of a CO_2 storage tank, an injection skid, wellhead, necessary piping and instrumentation, and a programmable logic controller (PLC) or programmable chart recorder for automated injection operation and monitoring. A majority of this equipment is upstream of the well. Information pertaining to the surface equipment and the operational plans are also presented in Section 8.16. Approximately 150 tons of CO_2 will be transported to the well site on a daily basis during the pilot injection test. Delivery will be via trucks operating daily between the Wellington storage site and the CO_2 source selected for project supply. The controller will be programmed to automatically control the injection flow rate based on the operational parameters discussed below, intended pilot-scale research activities, and the operational limits specified in Table 8.1. Critical issues regarding typical operating conditions and limits are presented in the following subsections.

8.4.1   Temperatures

The temperature of the CO_2 during transportation and in the site storage tank is expected to be between approximately -10° and 10° F upon delivery. This temperature may increase depending on ambient conditions and the duration of CO_2 storage in the tanks. As the CO_2 is stored and travels through surface equipment and approximately 4,900 ft down the injection tubing, the temperature

Table 8.1—Probable Operational Conditions at KGS 1-28.

Parameter	Lower Limit	Average	Upper Limit
Injection Rate	0	150 tons/day	300 tons/day (Intermittent)
Surface Temperature	-10°F	+0°F – +20°F	+30°F
Bottomhole Temperature	+10°F	+20° F – +40°F	+70° F
Surface Pressure	0 psi	100 – 800 psi	1,500 psi
Bottomhole Pressure @ 5,050 ft (bottom of perforation)	2,200 psi	2,500 psi	3,408 psi

will rise depending on ambient conditions, the injection rate, and the temperature in the formations surrounding the well. Near the wellbore, formation temperatures will gradually change over time as the cool CO_2 is injected in the well. The bottomhole temperatures cannot be predicted with certainty, but for purposes of selecting appropriate monitoring gauges and estimating CO_2 density with depth, a temperature range of 10° to 70° F at the bottom hole and -10° F to +30° F at the surface is estimated (Table 8.1).

8.4.2   Pressure

To inject CO_2 into the Arbuckle injection interval, the injection pressure at the downhole perforations must be greater than reservoir pressure. The pressure to be applied at the surface (wellhead) will be a function of the bottomhole pressure necessary to inject the desired rate of CO_2 into the Arbuckle, the friction loss generated as the CO_2 is pumped down the tubing and through the perforated completion, and the density of the CO_2 in the tubing. Each of these components that define wellhead pressure will change with time. This short-term small-scale pilot injection may use variable rates, and the specific injection rates sustainable will be, in part, determined by the CO_2 supply and the pilot-scale testing experiments being conducted. The surface pressure will be limited such that the maximum permitted injection pressure is not exceeded. Friction loss will then be highly variable, depending on the experimental injection rates used, the condition of the perforations over time, and the density/viscosity of the CO_2 injected. The density is a function of both pressure and temperature and is expected to range between approximately 46 lb/cu-ft and 59 lb/cu-ft (specific gravity of 0.75 and 0.95) due to temperature and pressure variation in the borehole.

As a final variable, pressure rise will be generated in the injection zone as more CO_2 is displaced into the Arbuckle but this will vary depending on injected volume, conditions, and instantaneous injection rate. At the end of the pilot-scale injection, a maximum bottomhole pressure of less than 2,535 psi at a reference depth of 5,050 ft has been projected at possible pilot flow rates from the simulation results presented in Section 5. This is less than the 3,408 psi pressure at a depth of 5,050 ft conservatively estimated as an allowable bottomhole injection pressure using 90% of pressure calculated at depth with a gradient of 0.75 psi/ft.

Wellhead pressures may be variable but are generally not expected to exceed 800 psi when the effects of variable fluid density along with perforation and tubing friction loss are included in calculations. Bottomhole pressure will be a primary operational issue of concern and will need to be adjusted based on operational data. Because the well is being used for a pilot study, a downhole pressure transducer is planned for monitoring bottomhole pressure. This will be a point of compliance and the PLC or well controller will be programmed to keep bottomhole pressure at 5,050 ft at values of less than a pressure gradient of 0.675 (0.90 x 0.75) psi/ft. The fracture gradient has been estimated as 0.75 psi/ft for this area (see Section 4.6.9).

Without any friction loss included, maximum wellhead pressure could range from 472 to 814 psi, assuming that the maximum bottomhole pressure of 2,535 psi was sustained at the perforations and the average specific gravity of fluid in the wellbore ranges from 0.79 to 0.95. Depending on injection rate and final well completion materials, friction loss may require a larger wellhead pressure to sustain the required downhole injection pressure at the perforations. At higher flow rates, at least several hundred psi of tubing friction loss is likely. Although wellhead pressure may vary from 100 to 1,500 psi depending on flow rate, temperature, fluid density and viscosity, it is anticipated that the system typically will be operated at wellhead pressures of less than 800 psi.

8.4.3 Injection Rate

The planned volume of CO_2 injection is 150 tons per day. However, depending on the for-

mation properties and the need to maintain the CO_2 in liquid state at the pump (which will require a certain minimum pressure based on the temperature), an operating volume of 150–300 tons per day might potentially be injected into the aquifer during batch operations during a 24-hour period to achieve the desired daily injection volume. The PLC or well controller will be programmed to keep a running total of the injected CO_2 and will cease operations if the injection exceeds more than 300 tons within a 24-hour period. The flow rate, however, will also be controlled so as not to exceed the maximum bottomhole pressure of 3,408 psi as specified in Table 8.1.

8.5   Well Casing (§146.86 [b][1–3])

The borehole and casing specifications for the KGS 1-28 well are shown in Table 8.2 and Figure 8.1. The conductor casing has been run from the surface to 125 ft. The surface casing, cemented to surface to provide a cement sheath to fully isolate the USDW from the well, runs from the surface to a depth of 647 ft. This casing shoe is significantly below the lowermost USDW (Upper Wellington Formation) that occurs within 250 ft of ground surface at the site as also shown in Figure 8.1. The production casing was set from the surface to the bottom of the well at 5,241 ft. The well has subsequently been plugged back to a depth of 5,155 ft. The injection tubing (as discussed below in Section 8.7) will be 2.875-in, 6.4 lb/ft J55 tubing with an internal CO_2 resistant plastic liner or coating (Duoline or suitable equivalent). There are approximately 2 inches of annulus spacing between the production casing and the tubing, which is sufficient for conducting the testing and monitoring activities described in Section 10.

Burst pressure, collapse pressure, and tensile strength were obtained from API Bulletin 5C2, Bulletin on Performance Properties of Casing and Tubulars (API, 1999), which states minimum values. Simple calculations are presented to illustrate the maximum scenarios that the well may have been exposed to during drilling conditions or will potentially be subjected to under operating conditions. Definitions of each and equations used are as follows.

Burst pressure: Maximum internal pressure the pipe may withstand before failure caused from hoop stress. Pressure that causes this failure is the pressure differential between internal

Table 8.2—Casing specifications at KGS 1-28.

Casing	Depth Interval (ft)	Borehole Diameter (in)	Size OD/ID (in)	Weight (lb/ft)	Grade	Connection Type	Collapse Pressure (psi)	Burst Pressure (psi)	Tensile Yield (lbs)	Thread Yield
Conductor	surface: 125	17.5	13-3/8 / 12.615	54.5	J-55	ST&C	1,130	2,730	853,000	514,000
Surface	surface: 647	12.25	8-5/8 / 7.972	24	J-55	ST&C	1,370	2,950	381,000	244,000
Production	surface: 5,241	7.875	5-1/2 / 4.95	15.5	J-55	ST&C	4,040	4,810	248,000	202,000
	Injection Interval: 4,910–5,050									

and external pressure. The only casing string that may experience any pressure events of concern during operations will be the 5.5-in long-string production casing. Maximum internal pressure is calculated at the bottom of the casing string by the following equation:

Internal Pressure = depth x fluid gradient + surface pressure

Collapse Pressure: Maximum external pressure is the pressure exerted on the outside of the pipe that will cause the pipe to be crushed. This is a differential between internal and external pressure. The highest pressure will be at the bottom of the pipe. The worst-case scenario for this well is defined by the following equation:

Collapse Pressure = depth x (pressure gradient of the formation) + (pressure gradient of the cement) - (pressure gradient of water).

Tensile Strength: The amount of pull that can be exerted on the pipe before plastic deformation of the metal occurs. The worst case is to assume the entire string weight is supported by the top joint suspended in air. Under downhole conditions, a large portion of the weight is actually negated due to buoyancy of the pipe in the fluid. The equation in air is as follows:

Tensile weight = weight of the pipe/ft x length

Calculations:

Constants:

Pressure gradient = 2,060 psi at 4,930 ft (depth pressure estimated) = 0.418 psi/ft depth

Freshwater = 0.433 psi/ft depth

Surface Casing Calculations:

14#/gal cement = (14#/gal) x (0.052 psi/ft /#gal) = 0.728 psi/ft

Collapse pressure = 647 ft x (0.418 + 0.728 - 0.433) psi/ft

Collapse pressure = 461 psi

Burst = 647 ft x 0.433 + 500 psi

Burst = 780 psi

Tensile weight = 647 ft x 24 lb/ft

Tensile weight = 15,528 lb

None of the calculated values exceeded minimum standards.

Long-String (injection or production) Casing Calculations:

15#/gal cement = (15#/gal) x (0.052 psi/ft /#gal) = 0.780 psi/ft (from 5,239 ft to 3,811 ft)

14.3#/gal cement = (14.3#/gal) x (0.052 psi/ft /#gal) = 0.743 psi/ft (from 3,811 ft to 2,502 ft)

13#/gal cement = (13#/gal) x (0.052 psi/ft /#gal) = 0.676 psi/ft (from 2,502 ft to surface)

Average cement weight to TD used assuming the unrealistic scenario that no compressive strength developed between cementing stages

Collapse = (5,239 ft-3,811 ft) x (0.418 + 0.780 - 0.433) + (3,811 ft-2,502 ft) x (0.418 + 0.743 - 0.433) + (2,502 ft) x (0.418 + 0.676 - 0.433) psi/ft

Collapse = 3,699 psi

Burst = 1,000 psi + 5,239 ft x 0.433

Burst = 3,268 psi

Tensile strength use weight of entire production string

Tensile weight = 5,239 x 15.5

Tensile weight = 81,205 lbs

None of the calculated values exceeded minimum standards.

8.6   Cement (§146.86 [b][1–4])

The conductor and surface casing cement jobs were each completed in a single stage. The cementing for the production casing was accomplished in three stages using two DV tools (one tool at 2,502 ft and another at 3,811 ft) to promote good cement circulation, placement, bond and annulus isolation (Figure 8.1). The production (long-string) cement was circulated to the surface by pumping the first bottom stage down the casing and circulating up the annulus until the displacement volume

had been pumped, at which time the deeper DV tool was opened so that excess cement could be circulated out of the annulus to the surface. After circulation continued through the DV tool for sufficient time for compressive strength to develop in the first stage, the same process was repeated by pumping the middle stage through the DV tool and up the casing annulus. The final top stage was pumped to ground surface in the same way using the upper DV tool. The staged cementing process allowed cement to remain in the annulus of the production (long-string) casing without larger hydrostatic pressures developing that would potentially cause it to drain from the annulus into higher permeability intervals of the injection zone. The lower cement stage covers the entire Arbuckle formation. A total of 27 centralizers were used to properly align the casing and to ensure that it is completely sealed with the borehole.

As shown in Table 8.3, common portland cement was used to seal the annulus of the conductor casing, and a 60/40 Pozzolanic cement was used for the surface casing. For the production casing, CO_2-resistant cement AA-2 was used in the bottom stage, a combination of AA-2 and CO_2-resistant A-Con was used in the middle stage, and A-Con was used in the top stage. The CO_2-resistant cement (with C-44 additive) is engineered to be more resistant to degradation by CO_2 than common portland cement. This is achieved by reducing the lime content and optimizing the particle size distribution, resulting in cement with a very high solid content, which significantly reduces the permeability of the cement and thereby also reduces the degradation rate due to CO_2 reaction, which dissolves the calcite and increases porosity.

To verify the effectiveness of the cementing operations, cement bond and variable density logs are required after setting and cementing the surface casing and long-string casing (40 CFR 146.87[a][2][ii] and 146.87[a][3][ii]). These logs use sonic signals to determine the condition of cement behind the casings and its bonding to the casings. The two cement logs provide complementary information and can be run simultaneously. Interpreted together, the logs indicate the presence or absence of cement behind the casing and the quality of the pipe-cement-formation bonds. Appendix B presents the cement bond and variable density logs for KGS 1-28 obtained on July 27, 2011. The recorded amplitude is indicative of sufficient cement placement and bond for an

effective seal between the casing and the subsurface formations (USEPA, 2012b). The temperature log run in the KGS 1-28 well presented in Appendix B also does not show any unusual temperature trends that could be indicative of channels or crossflow in the cement. As discussed in Section 10 (Testing and Monitoring Plan), temperature logs will also be obtained before, during, and after injection to ensure integrity of the cement and casing.

Table 8.3—Casing, borehole, and cement specifications for KGS 1-28.

Purpose of String	Size Hole Drilled (in)	Size Casing Set (in)	Casing Weight (lb/ft)	Setting Depth (ft)	Type of Cement	Number of Sacks Used	Type and Percent Additives
Conductor	17.5	13.375	48	125	Common	135	3%cc, ¼# flake
Surface	12.25	8.625	24	647	60/40 POZ	325	3%cc, ¼# flake
Production	7.875	5.50	15.5	5,241	AA-2	250	10% salt, 6% gils, C-44
1st DV Tool	7.875	5.50	15.5	3,811	A-Con & AA-2	260	10% salt, 6% gils, C-44
2nd DV Tool	7.875	5.50	15.5	2,502	A-Con	610	10% salt, 6% gils, C-44

8.7 Injection Tubing (§146.86 [c][1-3])

The tubing will consist of a 2.875-in 6.4 lb/ft J-55 string lined with a plastic (or suitable equivalent) CO_2-resistant internal liner. It will be set with a packer at approximately 4,860 ft. Total string weight (neglecting buoyancy) will be approximately 31,360 lbs, which is substantially less than the allowable tension load ratings based on joint or pipe body yield (Table 8.4). The tubing prevents contact of the CO_2 with the cemented long-string (production) casing. Collectively, the surface casing and the cement in the surface casing in addition to the tubing, the tubing/casing annulus, and the cemented production casing provide multiple levels of isolation between the injected CO_2 and the geologic formations above the injection zone.

Table 8.4—Tubing specifications.

Name	Depth (ft)	Wall Thickness (in)	Inside Diameter (in)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst Strength (psi)	Collapse Strength (psi)	Joint Yield strength (lb)	Body Yield Strength (lb)
2-7/8" J-55 Lined Injection Tubing	surface: 4,900	0.217	2.441	6.4	J55	Non upset	7,260	7,680	72,580	99,661

Note strength-related data values were obtained from the "Halliburton Cementing Tables," 1981.

8.8   Packer (§146.86 [c])

A packer compatible with the CO_2 injection stream will be used to anchor the tubing at a depth of approximately 4,960 ft in the long-string casing. The packer will be lined, coated or constructed of an alloy such that the short-term (less than nine months) pilot project operations can be completed without degradation of the packer performance. The specific packer will be selected based on final details regarding downhole sensors to be deployed through the packer during the scientific investigations planned during the pilot injection. The selection also will take into consideration the temperature range of CO_2 injection likely to be encountered based on the final source and injection rate selected for the study. Before injection, the injection tubing and packer will be tested by applying 500 psi of surface pressure to the annulus and monitoring annulus pressure for a period of 1 hour with less than 5% loss.

8.9   Injection Tubing Stresses (§146.86 [b][1][ii])

The well components will be deployed to withstand the maximum anticipated downhole axial, burst, and collapse stress. The internal loading on the well is determined by the injection pressure and/or the pressure in the annulus between the casing and the tubing. The downhole pressures expected in the tubing and annulus of KGS 1-28 during storage operations are presented in Figure 8.3. As discussed below, the annulus will be filled with corrosion-resistant fluid at hydrostatic pressure. The tubing is expected to experience a surface pressure of approximately 100 to 800 psi to maintain the CO_2 in liquid state and maintain necessary borehole pressure for injection into the Arbuckle. At no time will surface tubing injection pressure exceed 1,500 psi. The non-injection pressures in the tubing are also presented in Figure 8.4 to estimate the "collapse" stresses below.
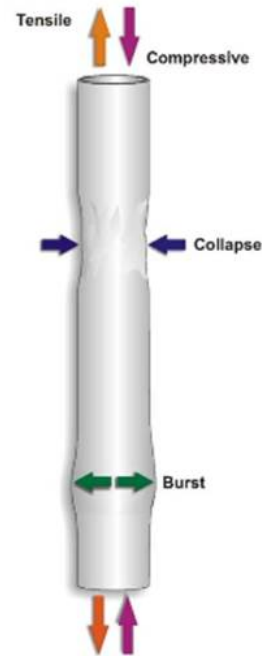

Figure 8.3—Schematic of stresses on the well bore (source; USEPA, 2012b).

The maximum burst pressure will be experienced during injection at the top of the tubing where the landing joint extends out of the wellhead. This is substantially less than the burst strength of the tubing (7,260 psi) specified in Table 8.4 and also shown in Figure 8.4.
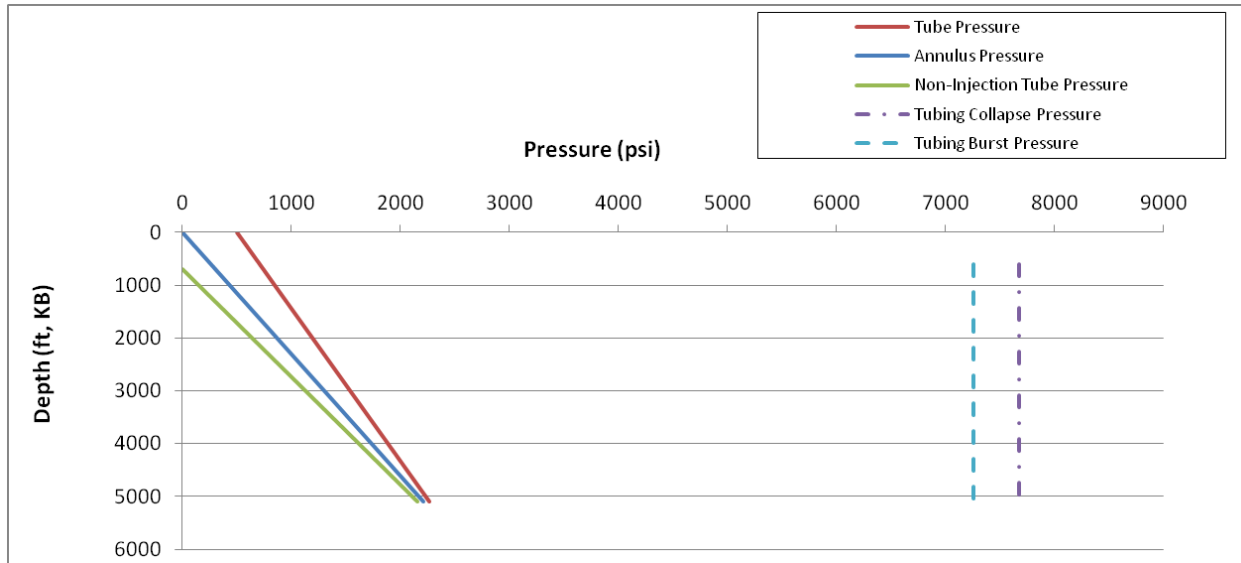

Figure 8.4—Estimated downhole fluid pressures in injection tubing and external casing at KGS 1-28.

8.10   Request for Low-Pressure Annular System

The Class VI rule requires that the annulus be filled with a non-corrosive fluid and that the annular pressure between the tubing and the casing be maintained at a pressure higher than the injection pressure (40 CFR §146.88[c]). The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the director determines that such requirement might harm the integrity of the well or endanger USDWs. Conditions at the small-scale Wellington injection site are such that a casing annulus filled with non-pressurized corrosion-resistant fluid will not jeopardize the integrity of the tubing or casing and will satisfy all objectives for monitoring continuous well integrity.

If a positive pressure annulus (>100 psi above maximum wellhead injection pressure) is required, the high annulus pressures (up to 1,600 psi) resulting at the Wellington site have the potential to threaten well integrity and would not be protective of the USDW. Installation of an annular pressure system, where surface annular pressures are 100 psi greater than surface injection

pressures would create the following conditions:

- Annulus pressure of up to 1,600 psi at surface.

- Annulus pressure of 3,735 psi at the packer (this exceeds formation fracturing pressure).

- 1,235 psi differential during operation.

Some of the risks associated with the pressured annulus include:

- High differential pressure across casing and packer could cause casing leaks.

- Annulus pressure is over the fracturing pressure for the entire length of the tubing string.

- High differential across tubing could cause leaks.

- High annular pressure could create a micro-annulus outside or damage cement isolation capacity.

- Cycling of pressures will put additional stresses on the cement.

- High annular pressures at the surface create additional hazards for those working near the surface equipment.

- If the downhole packer system were to fail, then the pressure would potentially fracture the reservoir and the buffering and sealing formations.

It is proposed that the KGS 1-28 well be equipped with a low pressure annular system designed around atmospheric pressure. The annular pressure will be continuously monitored at the surface to detect anomalies or changes. The annular pressure will be monitored to evaluate potential leakage through the injection tubing or casing or around the injection packer. Additionally, a set of operating limits or a minimum and maximum pressure range would be employed within a sensitive enough range to react to identified pressure losses. It is proposed to use annulus pressure monitoring limits set at -5.0 psi to +100 psi. If there is an identified leak in the production casing, fluid would be lost from the annulus and a negative pressure would be observed. If a leak is present in the tubing, a positive pressure deflection would be observed. Anomalies can be suggestive of potential fluid leaks that could develop in either the injection tubing or the production casing or be associated with

thermal effects. This operating range is set to reduce false alarms resulting from other variations in operating conditions, such as thermal effects, and to continuously monitor and record values.

If a slowly developing vacuum condition is observed in the annulus, indicating a possible annulus leak, the well annulus could be refilled with fluid. Upon stabilized injection conditions (temperature and rate) being maintained, the continued loss of annulus fluid would indicate a leak from the casing into an under-pressurized formation. Upon development of a continued positive annulus pressure trend, the pressure could be bled from the system and the fluid tested for CO_2. If the positive pressure returned under stable operating conditions (temperature and rate), then a leak would be indicated. The presence of CO_2 gas in the annular fluid would confirm a tubing/packer leak.

8.11 CO_2 Compatibility with Injection Well Components (§146.86[b][v])

The tubing, casing, packer, and cement of the injection well are all designed to withstand CO_2 service. Similar completions have been used in Kansas and other states. The chemical composition of the injectate should cause no adverse reactions or degradation of the well components for the nine-month duration of injection. The low water content (expected to be less than 50 ppm) and the low temperatures will result in only a mildly corrosive environment. Quarterly monitoring for corrosion using coupons as specified in Section 10 will also provide early warning of a deteriorating environment. As proposed in Section 10, the annulus pressure will be monitored daily to detect any leakage from the tubing, casing, or the packer. The annulus fluid will not react negatively with the injected CO_2 should a leak occur in the packer. The CO_2-resistant cement between the injection casing and the borehole reduces the potential for fluid migration into the USDW. The formation water geochemistry data presented in Section 4.6.7 indicate that the formation water also is not corrosive.

8.12   Design and Service Life

Due to the CO_2-resistant properties of the cement and casing, the design life of the well is expected to exceed 10 years. As discussed below, however, the lower segment of the well within

the Arbuckle is planned to be plugged at closure within a year of cessation of the injection project. Thereafter, the well will be used in the Mississippian reservoir either as an injection, production, or monitoring well.

8.13   Demonstration of Mechanical Integrity (§146.89)

Before commencing injection, an annulus pressure test will be conducted at the injection well to demonstrate internal mechanical integrity. Testing has already been conducted to provide the information necessary to determine the integrity of the casing and casing-cement bond. The casing, injection tubing, and packer will be further evaluated by means of a pressure test after completion activities are finished and before injection begins. The details of the test are provided in Section 10.3.4.1. Also, discussed in Section 10 are additional tests that are to be conducted to demonstrate mechanical integrity, including daily monitoring of the annular system, and obtaining/analyzing temperature logs during the pre-injection, injection, and post-injection phases.

8.14   Stimulation Plan (§146.82[9], §146.88 [a])

If needed to promote additional injection capacity, standard acid stimulation of the Arbuckle will be completed using standard oilfield practices. Although design parameters may vary depending on conditions encountered, a typical stimulation might involve pumping lease brine as a buffer followed by 1,000 to 2,000 gallons of 15% HCL with iron controls and other additives such as surfactants. This would then be displaced to the perforations by pumping lease brine or with CO_2 as displacement fluid. Due to the cooling effect of CO_2 injection, a short soak time might occur, followed by further displacement of the spending acid into the injection interval using additional lease brine.

8.15   Pre-Injection Testing and Logging (§146.87)

The extensive suite of geophysical log and testing at the injection well site is summarized in this sub-section. Appendix H presents a report on interpretation of the log data by an expert analyst at the Kansas Geological Survey.

8.15.1 Pressure Fall-Off Test

Before commencing injection, a pressure fall-off test will be conducted and the methodology/results submitted to the EPA within 30 days of conducting the test.

8.15.2 Annulus Testing

Before starting injection operations, the annulus and tubing/packer integrity will be tested by applying a minimum pressure of 500 psi at the surface to the annulus for a period of 60 minutes. After stabilization, the pressure will be recorded a minimum of every 10 minutes during isolation. Failure of the pressure to remain within 5% of the starting value would indicate lack of mechanical integrity. At the end of the test, the liquid returned from the annulus will be captured in a container and measured to ensure that the entire length of the annulus was tested. The results of the test will be submitted to the EPA director within 30 days of conducting the test.

8.15.3 Geophysical Logging and Drill-Stem Testing

Table 8.5 presents the geophysical and geological well logs acquired for KGS 1-28. Table 8.6 presents Arbuckle drill-stem test information for well KGS 1-28, and Table 8.7 presents DST recovery information for each Arbuckle DST.

Table 8.5—Geophysical and geological logs acquired at KGS 1-28.

Log Type	Logger/Operator	Log Interval (ft below KB)	Log Date	Comments
Array Compensated True Resistivity	Halliburton/Berexco	648–5,241	March 3, 2011	Gamma Ray log run; BHT 130F
Drilling Time and Sample Log	Geologist's Report/ Berexco	2,650–5,250	March 6, 2011 (final date)	None
Temperature Log	Halliburton/Berexco	50–5,180	March 3, 2011	Gamma Ray log run; BHT 130F
Compensated Spectral Natural Gamma Ray	Halliburton/Berexco	648–5,197	March 3, 2011	Gamma Ray log run
Microlog	Halliburton/Berexco	648–5,241	March 3, 2011	Gamma Ray log run; BHT 130F
Spectral Density Dual Spaced Neutron Log	Halliburton/Berexco	648–5,227	March 3, 2011	Gamma Ray log run; BHT 130F
Annular Hole Volume Plot	Halliburton/Berexco	648–5,241	March 3, 2011	Gamma Ray log run; BHT 130F
Extended Range Micro Imager Correlation Plot	Halliburton/Berexco	648–5,241	March 4, 2011	Gamma Ray log run; SP run, BHT 130F
Radial Cement Bond Log	Halliburton/Berexco	0–5,150	July 27, 2011	Gamma Ray log run, BHT 141F
Composite Plot	Halliburton/Berexco	648-5241	March 4, 2011	Gamma Ray log run
Magnetic Resonance Imaging Log	Halliburton/Berexco	2235-5250	March 4, 2011	Gamma Ray log run; SP run, BHT 130F

Table 8.6—Arbuckle formation drill-stem tests, KGS 1-28.

DST No.	Date/Time	Test Interval (ft KB)	Initial Hydrostatic (1) Pressure and Temperature (psig/°F)	End Shut-In (1) Pressure and Temperature (psig/°F)	Shut-In (2) Pressure and Temperature (psig/°F)	End Shut-In (2) Pressure and Temperature (psig/°F)	Final Hydrostatic Pressure and Temperature (psig/°F)
1	3/5/2011 11:46:24	5,133–5,250	2,501.29/129.43	2,189.46/130.04	202.79/129.54	2,186.18/130.50	2,493.29/131.24
2	3/5/2011 22:20:17	5,026–5,047	2,428.68/124.88	2,137.71/131.45	1,536.67/132.69	2,137.94/131.94	2,362.88/131.15
3	3/6/2011 16:37:17	4,917–4,937	2,411.28/120.02	2,081.64/127.89	598.64/131.52	2,082.44/129.03	2,312.18/127.77
4	3/6/2011 00:31:57	4,866–4,885	2,363.19/125.03	2,060.91/128.85	1,699.12/132.12	2,060.91/130.61	2,348.96/129.35

Table 8.7—Recovery table for Arbuckle DSTs conducted at KGS 1-28.

DST	Test Interval	Recovery Length, (ft)	Description	Recovery Volume (bbl)	Total Length (ft)	Total Volume (bbl)	Salinity (ppm)
1	5,133–5,250	185.00	MW33%M 67%W RW .22 ohms@60 degF	0.910			
		185.00	WM50%w 50%m	0.910	370	1.820	39,000
2	5,026–5,047	239.00	MW 28%M 72%W	1.131			
		2480.00	SW	31.909	2,710.00	33.040	34,000
3	4,917–4,937	686.00	Salt Water	4.649			
		186.00	MCW, 30%M 70%W	2.609			
		196.00	WCM 40%W, 60%M	2.749	1,068.00	10.007	31,000
4	4,866–4,885	1543.00	Salt Water	16.670			
		186.00	MCW 10%M 90%W	2.609			
		372.00	WCM 40%W 60%M	5.218	2,101.00	24.497	30,500

8.15.4 Deviation Checks

Deviation measurements were conducted approximately every 1,000 ft during construction of KGS 1-28. Appendix B presents the deviation survey, which indicates that the average hole deviation was less than 1.25 degrees.

8.15.5 Formation Cores

Whole cores were obtained at KGS 1-32 within the interval 3,540 to 5,179 feet (Figure 4.21), which spans from the granitic basement up into the Cherokee Shale. Well KGS 1-32 is approximately 3,500 ft away from the injection well KGS 1-28. However, as discussed in section 4.6.1 and shown in Figure 4.20, the geologic formations and the stratigraphic column at both sites are remarkably similar. Therefore, the information derived from cores at KGS 1-32 is expected to be applicable at the injection well site (KGS 1-28).

The cores were analyzed to characterize the injection and confining zones and to derive hydrogeologic properties. Specifically, as described in Section 4 (Local Hydrogeology), the cores were analyzed for mineralogical composition, subjected to fracture studies, tested in the laboratory to derive hydrogeology properties such as horizontal/vertical permeabilities and porosity, and used for conducting geochemical testing to determine reaction kinetics.

8.15.6 Formation Data

The formation fluid and rock information in the injection and confining zones is documented extensively in Section 4. Specifically, the fluid temperature is discussed in Section 4.6.5, geochemistry in Section 4.6.7, reservoir pressures in Section 4.6.3, estimated static head in Section 4.6.8, fracture gradient in Section 4.6.9, injectivity test in Section 4.6.4, hydrogeologic properties in Section 4.6.6, and confining zone entry pressure analysis in Section 4.7.4.

8.15.7 Future Logging and Testing Activities

An extensive suite of geophysical logs will be acquired and testing conducted for formation

characterization during construction of the new Arbuckle monitoring well (KGS 2-28) located 400 ft from the injection well site (KGS 1-28) as shown in Figure 1.6b. Due to the close proximity of the monitoring well to the injection well, the information and data gathered at KGS 2-28 is expected to be fairly representative of conditions at KGS 1-28. The EPA director will be invited to witness the testing and logging activities at KGS 2-28 at least 30 days ahead of the planned activities.

8.16 Description of Surface Facilities and Injection Operations (§146.82[a][11])

8.16.1 Surface Facilities

The CO_2 will be delivered to the site in trucks operating daily between the selected CO_2 supplier/vendor and the Wellington site. Each truck will transport approximately 20 tons of CO_2 in liquid state at a pressure of approximately 250 psi and temperature of approximately -10° F.

The surface facilities at the Wellington injection site will consist of a storage tank, a pump, a programmable logic controller (PLC) or suitable equivalent, and flowlines to the wellhead (Figure 8.5). The injection pump and the controller will be mounted on a skid. The CO_2 will be stored in a pressure vessel adjacent to the injection well (KGS 1-28). The storage tank will be connected to the injection pump skid.

The wellhead assembly will consist of a master valve, a swab valve, and flow line valves. The well annulus will also have connections and valves necessary for access and testing. Wetter surfaces will be coated or lined or made of alloys suitable for short-term CO_2 service as available
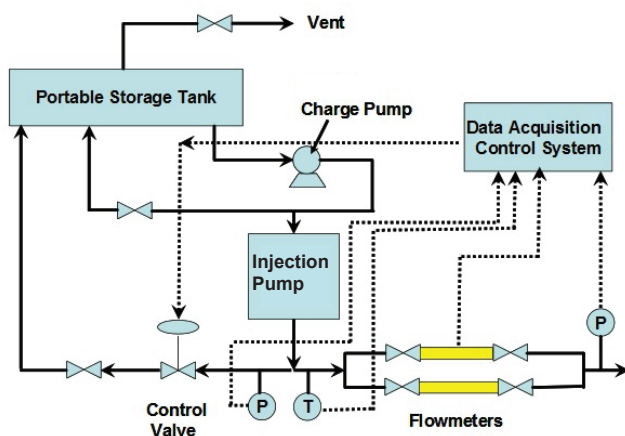

Figure 8.5—Flow schematic of CO_2 injection skid and portable storage tank.

at the time of completion. As discussed in Section 10.3, the bottomhole and wellhead pressures and temperatures will be continuously monitored along with the flow rate at the wellhead, and the data will be fed continuously to the PLC or controller. The controller will manipulate a control valve in the flow line and/or the pump to ensure that the maximum specified flow rate and the bottomhole pressure in the injection well do not exceed the maximum allowable pressure. The CO_2 in the storage tank may experience an increase in pressure as the vessel heats up, which may require occasional venting of the CO_2 to relieve the pressure.

The control system will be programmed to initiate shutdown if emergency events documented in Section 13.3 occur. All operating data (pressure, temperature, and flow rates) will be digitally stored by the control system. Berexco also will store a physical copy of the data in case of a failure of the SCADA system.

8.16.2 Source Fluid (§146.86 [c][3][ii])

8.16.2.1 Source and Chemical Composition

It is expected that the CO_2 source will be acquired from an ethanol production facility in Kansas or a suitable alternative. Regardless of the source, the CO_2 obtained will be analyzed before injection to ensure that it meets the criteria specified in Table 8.9.

Table 8.9—Chemical composition of CO_2 injectate.

Component	Quantity	Comment
CO_2	97%	Dry basis
Inert constituents	1%	
Trace constituents	2%	
Oxygen (O_2)	<20 ppm	
Total Sulfur	<25 ppm	
Arsenic	<5 mg/l	Less than RCRA TC standard
Selenium	< 1 mg/l	Less than RCRA TC Standard
Mercury	< 2 ppb	Less than SDWA standard
Hydrogen Sulfide	< 20 ppm	pipeline quality CO_2
Water vapor	< 30 lb/mmscf	

8.16.2.2 Injection Rate and Volume of Injected Fluid

Approximately 150 to 300 metric tons will be injected daily for a maximum of approximately 40,000 metric tons to be stored over a nine-month period.

8.16.3 Shut-Off System

The PLC or control system used to operate and monitor the well will process flow rate, annulus, and injection pressure transducer data. Set points will be programmed to alert operators regarding well conditions of concern.

In the event of an emergency, the system will be shut off. Depending on the event, the system may be either shut off manually or automatically. The lists of events triggering a shutoff are documented in Section 13.3. They include conditions such as high pressure at the wellhead or bottomhole transducer, exceeding the daily injection volume, or annulus pressure that indicates communication to the injection tubing above a set point based on well operating temperature and pressure. Automatic shutoff will occur if the operational parameters that are being continuously monitored exceed permit limits by the controller cutting the run permissive signal and power to the pump on the skid and closing a valve in the flow line. Manual shutoff will occur in the event of failure of well mechanical integrity, detection of CO_2 during MVA activities, surface infrastructure damage, etc. The controller will have commercially available alarm capabilities to notify Berexco of a shutdown over cellular network as specified in Section 13.