Longleaf CCS Hub

Longleaf CCS, LLC

Injection Well Operations Plan

40 CFR 146.82(a)(7)(10)

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Locations: Mobile County, Alabama
LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W
LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W
LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W
LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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List of Acronyms/Abbreviations

AoR	Area of Review
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
LL	Longleaf
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mg/l	Milligrams per liter
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
psi	Pounds per square inch
psi/ft	Pounds per square inch per foot
SS	Sub-Sea
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A.1 Introduction

By following the injection well operations program for the Longleaf CCS Hub described in this Plan, Longleaf CCS, LLC seeks to safely inject an average rate of 3,425 mt/d per well (65,000 MMcf/day) of CO_2 into the Paluxy reservoir at four injection wells, LL#1, LL#2, LL#3, and LL#4, while avoiding geomechanical effects and maintaining well integrity. At full operations, the four injection wells will be injecting up to 13,700 mt/d (260 MMcf/day) into the Paluxy reservoir (see **Figure 4** in the *Application Narrative* for well locations). The operational details provided in this document satisfy 40 CFR 146.82(a)(7) and (10). The operational design described in this document has been developed to adhere to requirements set forth in 40 CFR 146.88.

A.2 Specifications of the CO_2 Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

The CO_2 injection stream will enter the storage site meeting the anticipated specifications presented in **Table 1**. The CO_2 will be sourced from a series of industrial and power plants located in the Mobile, Alabama area and transported by pipeline to the Longleaf CCS Hub. The CO_2 will enter a distribution header and be piped to each injection wellhead. The CO_2 will be in the liquid phase as it enters the wellhead and will transition to a supercritical phase in the wellbore.

Table 1 displays the chemical composition of the anticipated CO_2 stream.

Table 1. Specifications of the Anticipated CO_2 Stream Composition

Component	Specification	Unit
Minimum CO_2	>96	mole%, dry basis
Water content	<20	lb/MMscf
Impurities (dry basis):		
Total Hydrocarbons	<2	mol%
Inert Gases (N_2, Ar, O_2)	<4	mol%
Hydrogen	<1	mol%
Alcohols, aldehydes, esters	<500	ppmv
Hydrogen Sulfide	<100	ppmv
Total Sulfur	<100	ppmv
Oxygen	<100	ppmv
Carbon monoxide	<100	ppmv
Glycol	<1	ppmv

On average, the CO_2 stream will be 75 ºF and approximately 1,500 psi in the pipeline, with an estimated density of 51.93lb/ft^3 at wellhead conditions. After injection into the Paluxy Formation, the CO_2 stream is anticipated to heat to near formation temperature of approximately 240 ºF at or above the native reservoir pressure of approximately 5,000 psi, with an estimated density of 40.9 lb/ft^3, in a supercritical state[1].

Due to the anticipated low water content within the CO_2 stream, CO_2-induced corrosion affecting well components is not likely - as noted by the U.S. EPA well construction guidance (US EPA, 2012). Longleaf CCS, LLC will, however, monitor for potential corrosion induced by the injectate as outlined in **Section C** of the *Testing and Monitoring Plan*.

A.3 Operational Procedures [40 CFR 146.82(a)(10)]

The operational procedures described here were developed to factor in the thermohydraulic performance of the four injection wells based on wellbore design parameters described in **Section A** of the *Injection Well Construction Designs*. The analysis of the design parameters and ensuing calculations are also described in **Section A** of the *Injection Well Construction Designs.*

A.3.1 Operational Conditions

Longleaf CCS, LLC plans to inject 1.25 Mt/y (3,425 mt/d) of CO_2 at each of four injection wells. As described in **Section A.4** of the *Injection Well Construction Designs*, injection well LL#1 will be equipped with a series of sliding sleeves across the Upper and Lower Paluxy Formation to prevent the injection stream from flashing in a low injection volume scenario. Injection wells LL#2, LL#3, and LL#4 likely will not have sliding sleeves installed. To confirm that this annual injection rate of 1.25 Mt/y can be achieved with the proposed well design, as well as the proposed maximum instantaneous injection rate of 1.50 Mt/y (4,110 mt/d), operational conditions for both well construction types and both

[1] https://webbook.nist.gov/chemistry/form-ser/

injection rates were modeled using SLB *PIPESIM* software, a steady-state multi-phase flow simulator.

Calculations in *PIPESIM* consider the pressure-volume-temperature (PVT) properties of CO_2 flowing through a 6 5/8-inch tubing with sliding sleeves as well as a 6 5/8-inch tubing without sliding sleeves to a bottomhole depth of 11,347 ft. Pressure along the wellbore tubulars was modeled using surface roughness (friction), hydrostatic effects, and fluid velocity. **Table 2** summarizes the operational inputs for the SLB *PIPESIM* analysis. The injection wells will be continually monitored for injection pressure, rate, volume, temperature of the CO_2 stream, and tubing-long string casing annulus pressure and fluid volume. The continuous monitoring program for pressure and injection rates is included in **Section D** of the *Testing and Monitoring Plan*. Injection will occur through the injection tubing string and never between the outermost casing protecting USDWs and the tubing (40 CFR 146.88(b)).

Table 2. Inputs to Wellbore Calculations in SLB *PIPESIM*

Input Parameter	Value	Unit
Injection Zone Permeability	31 - 233	mD
Wellhead Temperature	90	^oF
Injection Zone Temperature	235 - 252	^oF
Damaged Permeability Ratio	1	n/a
Skin Permeability Ratio	1	n/a
Paluxy Top Depth	10,220	ft
Paluxy Bottom Depth	11,347	ft
Injection Zone Top Depth	10,269	ft
Injection Zone Bottom Depth	11,347	ft
CO_2 Purity	>96	%
Perforations (60-degree phase)	6	Shots per Foot
Pressure Gradient	0.463	psi per ft
Temperature Gradient	1.65	^oF per 100 ft

PIPESIM analysis of an injection rate of 1.25 Mt/y in a well that has been constructed without a sliding sleeve resulted in a wellhead pressure of 1,491 psia, shown in **Figure 1**. At the maximum instantaneous injection rate of 1.50 Mt/y, the resulting wellhead pressure is expected to be 1,534 psia, shown in **Figure 2**.

In injection well LL#1 with sliding sleeves, an injection rate of 1.25 Mt/y, and the lower perforations closed and upper perforations open, the *PIPESIM* analysis resulted in a wellhead pressure of 1,500 psia, shown in **Figure 3**. Additional SLB *PIPESIM* nodal analysis inputs and results can be found in **Section A.1** of the *Injection Well Construction Designs.*

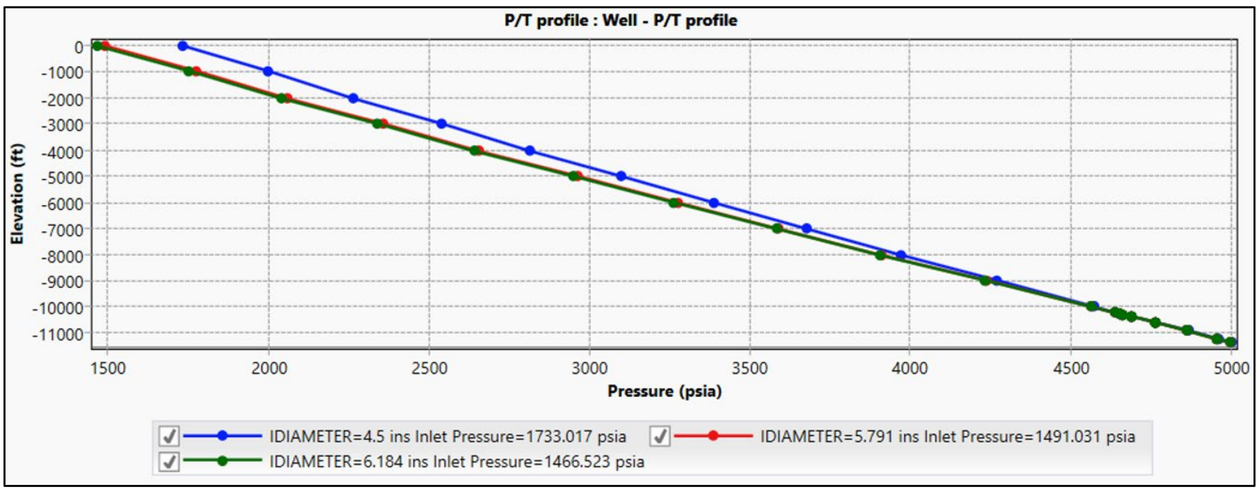

Figure 1. Pressure Profile of a Well Without Sliding Sleeves at an Injection Rate of 1.25 Mt/y

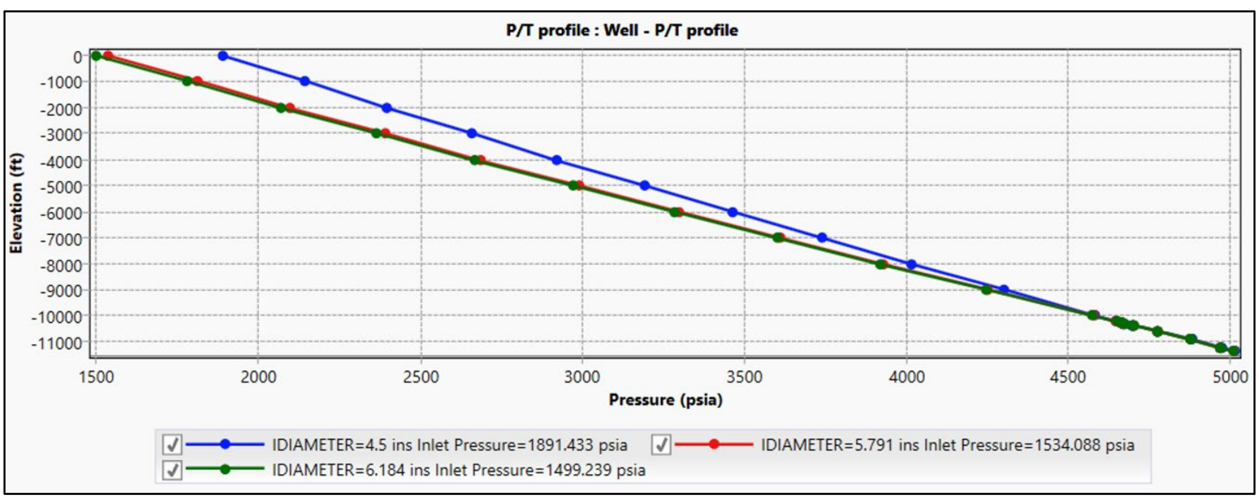

Figure 2. Pressure Profile of a Well Without Sliding Sleeves at an Injection Rate of 1.50 Mt/y

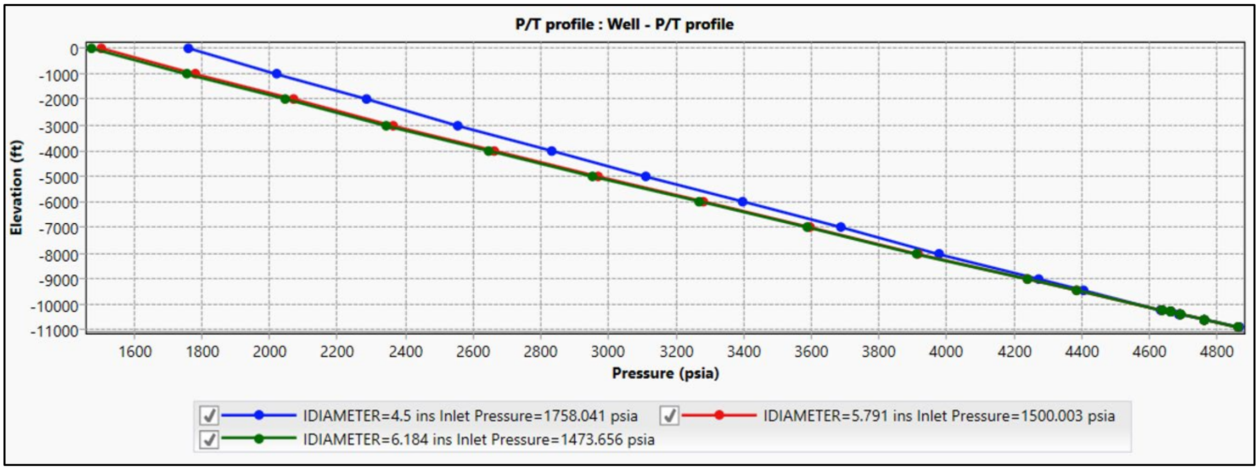

Figure 3. Pressure Profile of a Well with Sliding Sleeves at an Injection Rate of 1.25 Mt/y

The estimated hydraulic fracture gradient and the hydraulic fracture pressure at the injection zone top-depth in the *PIPESIM* model is 7,188 psi (0.7 psi/ft * 10,269 ft), corresponding to a maximum bottomhole pressure of 6,469 psi, as required by 40 CFR 146.88(a) to not exceed 90% of the fracture pressure of the injection zone. See **Table 4** for well specific bottomhole injection pressure limits. The modeled bottomhole pressure and the increased reservoir pressure during injection (See **Section A.3.d** of the *Area of Review and Corrective Action Plan*) for all injection rates was considerably less than 90% of the fracture pressure of the reservoir.

Injection tubing will be deployed and set via a packer placed above the perforations. The injection wells will be monitored for potential annular leaks and external mechanical integrity as outlined in **Section D** of the *Testing and Monitoring Plan*. The annular space between the long-string casing and the injection tubing will be filled with a corrosion inhibitor as described in **Section A.5.1** of the *Injection Well Construction Designs.*

The annular pressure between the tubing and the casing downhole will be maintained at a pressure higher than the injection pressure during injection to satisfy requirements in 40 CFR 146.88(c). Annular pressure may be reduced during periods of well workover (maintenance) approved by the UIC Program Director in which the sealed tubing/casing annulus is disassembled for maintenance or corrective procedures.

A.3.2 Injection Start-Up

Longleaf CCS. LLC will ramp up injection operations as detailed in **Table 3** and conduct operational monitoring of the injection site pursuant to 40 CFR 146.90(b). Specific details of the startup protocol are outlined below.

A multi-stage startup procedure will be implemented in conjunction with data acquired from surface and downhole pressure and temperature gauges in all injection wells, as well as in-zone and above-zone monitoring wells.

During the start-up period Longleaf CCS, LLC will collect daily operational data and include these data in semi-annual reports as required by 40 CFR 146.91(a) and described in **Section K.1** of the *Testing and Monitoring Plan*. At the UIC Program Director's request, Longleaf CCS, LLC will schedule a conference call to discuss the operational data during the start-up.

A series of successively higher injection rates will be used during injection start-up (an example start-up operational procedure is shown in **Table 3** and may be modified to accommodate the available volume of CO_2 at the start of injection), with the elapsed time and pressure values recorded for each rate and time step. Each rate step will last approximately 24 hours. At no point during the procedure will the injection pressure exceed the maximum permitted bottomhole injection pressure which is 90% of the top Paluxy Formation injection interval depth fracture pressure (see Section A.3.1 above). If requested by the UIC Program Director, Longleaf CCS, LLC will provide the final start-up operational procedure.

Table 3. Example Operational Procedure During Start-Up

Rate (mt/d)	Duration (Hours)	Precent of Maximum Injection Rate (%)
572	24	16.7
1,142	24	33.3
1,712	24	50
2,284	24	66.7
2,853	24	83.3

Injection rates will be measured (using a Coriolis flow meter) and data will be continuously recorded. Surface and downhole pressure and temperature data will be collected continuously in the injection and monitoring wells. During the start-up period, a plot of injection rate and the corresponding stabilized pressure values will be graphically represented to demonstrate that well integrity has been maintained.

During the start-up period, the project team will look for any evidence of anomalous pressure behavior. If anomalous pressure behavior is observed, the project team will conduct additional monitoring to better characterize the anomaly. If during the start-up period the project team determines that anomalous pressure behavior indicates a downhole pressure that could lead to formation fracturing, injection will be stopped, and the line valve closed allowing the pressure to bleed-off into the injection zone. The instantaneous shut-in pressure (ISIP) will be measured, and the pressure data will be reviewed for event signatures. In this event, Longleaf CCS, LLC will notify the UIC Program Director within 24 hours of the root cause determination. Longleaf CCS, LLC will consult with the UIC Program Director before initiating further injection.

A.4 Injection Rates

The injection wells will be constructed as shown in **Section A** of the *Injection Well Construction Designs*. Injection will be facilitated through injection tubing set in the long casing string by a packer above the topmost perforations in the Paluxy Formation. **Table 4** summarizes the proposed operational parameters for all injection wells. Operational parameters are expected to remain constant throughout the duration of the injection period. Some variability to operational parameters may stem from variations in volume from a CO_2 source, which may lead to lower injection volumes during limited periods of time. The injection rate values detailed in **Table 4** were modeled in *PIPESIM*, and the nodal analysis results can be found in Section A.1 of the *Injection Well Construction Designs.*

Table 4. Injection Well Operational Parameters

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
At Wellhead (All Injection Wells)	2,220	psia
Downhole – LL #1 (Paluxy Top injection depth of 10,270 ft TVD GL)	6,470	psia
Downhole – LL #2 (Paluxy Top injection depth of 10,340 ft TVD GL)	6,514	psia
Downhole – LL #3 (Paluxy Top injection depth of 10,270 ft TVD GL)	6,470	psia
Downhole – LL #4 (Paluxy Top injection depth of 10,168 ft TVD GL)	6,405	psia
Injection Rates		
Maximum Instantaneous Injection Rate (CO_2) (One Injection Well)	4,110	mt/d
Maximum Instantaneous Injection Rate (CO_2) (One Injection Well)	1.50	Mt/y
Average Injection Rate (CO_2) (One Injection Well)	3,425	mt/d
Average Injection Rate (CO_2) (One Injection Well)	1.25	Mt/y
Maximum Annual Injection (CO_2) (One Injection Well)	1.25	Mt
Maximum Annual Injection (CO_2) (Four Injection Wells)	5.0	Mt
Total Injection Mass (30-year period) (One Injection Well)	37.5	Mt
Total Injection Mass (30-year period) (Four Injection Wells)	150	Mt
Annular Pressure		
Maximum Annulus Surface Pressure (All Injection Wells)	500	psia
Minimum Annulus Pressure at the Wellhead (All Injection Wells)	250	psia

Using a per well average annual CO_2 injection rate of 1.25 Mt/y (3,425 mt/d) and a maximum instantaneous rate of 1.5 Mt/y (4,110 mt/d), the injection tubing string size was selected to meet project requirements. The expected wellhead pressure during injection operations will likely be between 1,200 psia and 1,500 psia but may be as high as 2,220 psia during maximum instantaneous injection periods. At a wellhead pressure of 1,534 psia and a maximum instantaneous rate of 4,110 mt/d, bottomhole pressures are still considerably less than the maximum allowable downhole pressure for all injection wells.

Based on expected operating ranges, the Project proposes to maintain annular pressure at the surface between 250 to 500 psia. Because of the lower CO_2 density in the injection tubing string, this should result in bottomhole conditions whereby the annular fluid is at a higher pressure than that within the injection tubing string. Final design criteria will be developed for the permission to operate the injection well.

A.5 Estimated Maximum Allowable Surface Pressure

In *PIPESIM,* the maximum allowable wellhead pressure observed during simulation of injection in a well with sliding sleeves and a bottomhole pressure of 6,484 psia (90% fracture pressure at a depth of 10,294 ft) was 2,664 psia, **Figure 4**. When injection was modeled using a maximum instantaneous rate of 1.5 Mt/y (4,110 mt/d), the resulting wellhead pressure was 1,534 psia. The maximum allowable surface pressure (MASP) for all injection wells will be 2,220 psia, well below the modeled wellhead pressure of 2,664 psia that corresponds with bottomhole pressures near 90% of fracture pressure. Operating wellhead pressures will likely range from 1,200-2,220 psia.

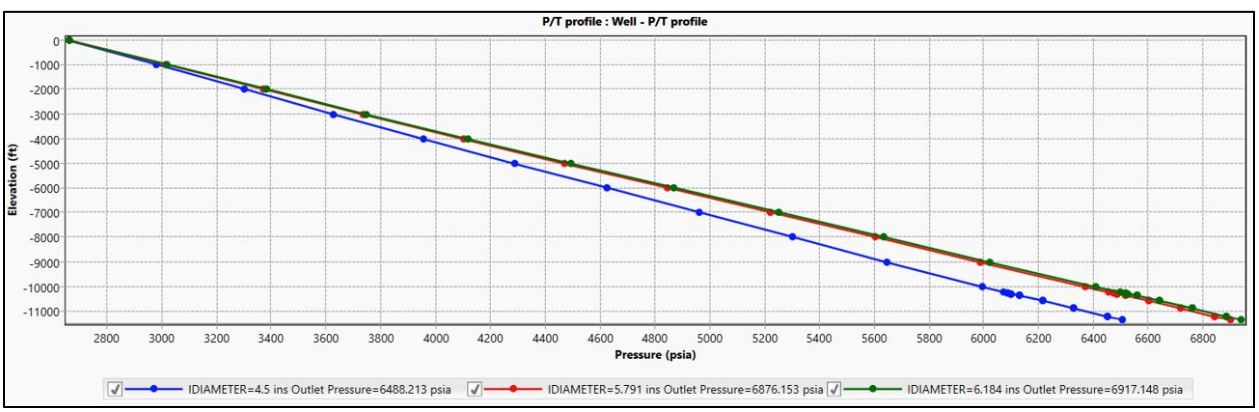

Figure 4. Pressure Versus Depth Profile at 90% of Fracture Pressure at the Top of the Paluxy Formation.

A.6 Injection Well Operational Monitoring

Each injection well will be monitored to ensure safe operations, in compliance with 40 CFR 146.88(e)(2). Operational safety monitoring includes continuous monitoring of the injection pressure at the wellhead and bottomhole, continuous monitoring the pressurized annulus, continuous fiber optic temperature monitoring along the well, and corrosion coupon monitoring to identify corrosion. Each of these monitoring systems is fully described in the *Testing and Monitoring Plan.*

Each injection well will have a wellhead pressure gauge (tubing and annular pressure) and flow computer, both tied into the injection control system and set to trigger an alarm at the project control room and shut down injection in the well if: (1) the MASP is reached; (2) the CO_2 injection rate exceeds maximum permitted rate; or (3) the annulus fluid pressure drops below the injection pressure. Injection parameters, including pressure, rate, volume and/or mass, and temperature of the CO_2 stream, will be continuously measured and recorded. The pressure and fluid volume of the annulus between the tubing and long-string casing will also be continuously recorded.

All automatic shutdowns will be investigated prior to bringing injection back online to ensure that no integrity issues were the cause of the shutdown. If an un-remedied shutdown is triggered or a loss of mechanical integrity is discovered, Longleaf CCS, LLC will immediately investigate and identify, as expeditiously as possible, the cause of the shutdown. Please refer to **Appendix A** of the *Emergency and Remedial Response Plan (ERRP)* for response actions if mechanical integrity is lost.

The annular space between the tubing and long string casing of each injection well will be pressurized with corrosion inhibiting brine and monitored for changes in pressure and volume. The fiber optic cable cemented onto the outside of the long-string casing will be used to continuously monitor temperature along the length of the casing through the primary confining unit, the Tuscaloosa Marine Shale. Rapid temperature changes or other excursions from a normal operating temperature profile will be investigated to ensure that there has been no breach of wellbore integrity.

A.7 Workover and Maintenance

Longleaf CCS, LLC will monitor and maintain mechanical integrity of each injection well at all times. Well maintenance and workovers will be part of normal operations to keep each injection well in a safe operating condition. Procedures for well maintenance will vary depending on the nature of the procedure. All maintenance and workover operations will be monitored to ensure there is not a loss of mechanical integrity. Barriers, such as a downhole plug, will be placed to ensure leakage risk is minimized. As outlined in **Section K** of the *Testing and Monitoring Plan*, Longleaf CCS, LLC will notify the UIC Program Director of any planned workover or injection well test at least 30 days in advance, and the results of any mechanical integrity test, workover, or injection well test will be provided within 30 days after the test or maintenance is completed (40 CFR 146.91).

Each injection well is designed to allow the installation of a temporary plug below the tubing to allow the tubing to be removed and replaced as needed while keeping a barrier in place. The bottomhole temperature and pressure gauge is set above the packer to allow for replacement, if needed, without removing the packer from the well.