Longleaf CCS Hub

Longleaf CCS, LLC

Pre-Operational Testing Plan

40 CFR 146.82(a)(8), 146.87

<u>Facility Information</u>

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
CO2	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
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mol%	Percentage of total moles in a mixture made up by one constituent
msl	Mean sea level
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
ppmv	Parts per million volume
psi	Pounds per square inch, gauge
psia	Pounds per square inch, absolute
psi/ft	Pounds per square inch per foot
SS	Sub- Sea
TVD	True Vertical Depth

A. Overview of Pre-Operational Testing Plan

The Pre-Operational Testing Plan will be implemented to obtain the chemical and physical characteristics of the injection and confining zones and to meet the testing requirements of 40 CFR 146.87 and the well construction requirements of 40 CFR 146.86. The Pre-Operational Testing Plan will include a combination of logging, coring, formation hydrogeologic testing (e.g., a pump test and/or injectivity tests), and other activities during the drilling and construction of the proposed IOB#1 monitoring well and the LL#1 CO_2 injection well at the Longleaf CCS Hub project in Mobile County, Alabama (**Figure 1**).

The Pre-Operational Testing Plan will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the primary confining zone (Tuscaloosa Marine Shale), the secondary confining interval (Basal Shale of the Wash-Fred), and the injection interval (Paluxy Formation). In addition, formation fluid characteristics will be obtained from the Paluxy Formation to establish baseline data against which future measurements may be compared after the start of injection operations. The results of the testing activities will be documented in a report and submitted to the EPA within 60 days after the well drilling and testing activities have been completed.

Longleaf CCS, LLC will take core and acquire logs from the IOB#1 monitoring well located about 2 miles north of the LL#1 injection well. Longleaf CCS, LLC will bypass taking whole core from the LL#1 injection well. Based on previous coring experience within the Paluxy at the Anthropogenic Test CO_2 demonstration at Citronelle, drilling whole intervals would increase the likelihood of enlarged wellbore as the processes associated with drilling and collecting core require circulation of drilling fluids for long periods of time. These expanded well diameter sections, called washouts, present challenges to well cementing.

Similarly, injection-falloff testing would be conducted in the IOB#1 monitoring well. These tests are used to determine reservoir and confining unit fracture gradients. Detailed geomechanical information gained from core and log analysis will be input into a 1-dimensional Mechanical Earth Model (1-D MEM) to provide understanding of formation mechanical properties and fracture gradients of the Paluxy reservoir and its surrounding confining units.

Longleaf CCS, LLC will rely on information from geologic and petrophysical tests in the IOB#1 monitoring well to satisfy the Class VI rule requirements for drilling and constructing injection wells at the Longleaf CCS Hub. Longleaf CCS, LLC will use the Tuscaloosa Marine Shale, Basal Wash-Fred Shale, and Paluxy Formation whole and/or sidewall core samples collected from the IOB#1 monitoring well to satisfy the requirement of 40 CFR 146.87(b) for the proposed LL#1 injection well (**Figure 1**). Additional details are provided in the subsequent sections of this plan to describe the rationale for opting to forego coring and fracture testing activities in the proposed LL#1 injection well.

Three more injection wells (LL#2, LL#3, and LL#4) are planned to be drilled at the Longleaf CCS Hub, with each well approximately 2 miles from the LL#1 injection well (**Figure 1**). Testing for the LL#2, LL#3, and LL#4 will be identical to the LL#1 except for the collection of sidewall cores and fluid samples, which will be done only in the LL#1.

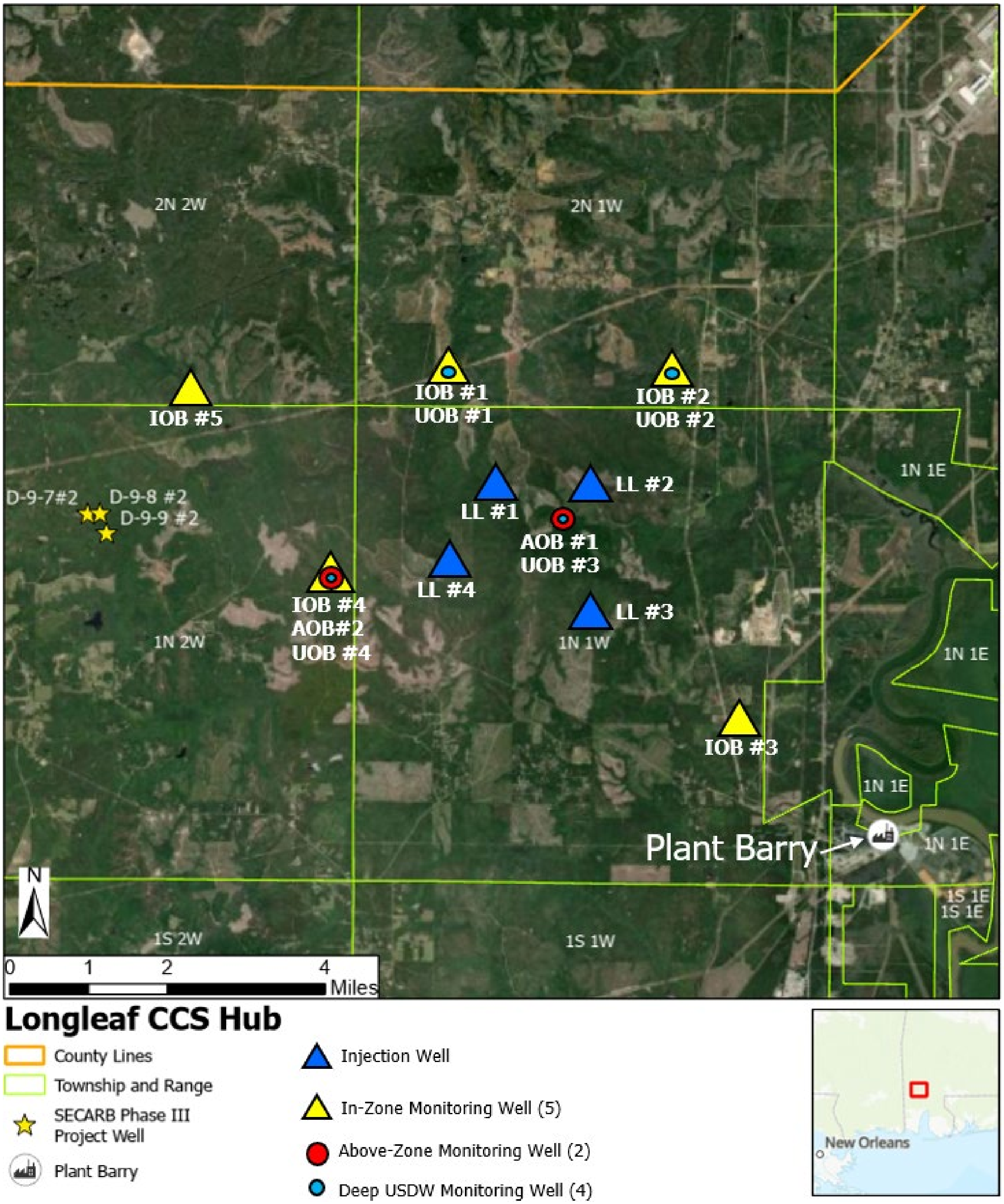

Figure 1: Locations of Proposed Injection and Monitoring Wells at the Longleaf CCS Hub

B. Wireline Logging

Open-borehole logs will be collected in the LL#1 injection well to obtain in-situ structural, stratigraphic, physical, chemical, and geomechanical information for the confining zones and the injection zone. Logs, surveys, and tests will be used to ensure conformance with the injection well construction requirements according to 40 CFR 146.86 and establish accurate baseline data for future comparison. Open-borehole characterization logs will be obtained after reaching the surface casing point and the long-string casing point (i.e., total borehole depth) in the vertical borehole. Open-borehole wireline logs will not be run in the 30-in.-diameter conductor casing borehole because logging tools are not suited for this large-diameter hole size (**Figure 2**).

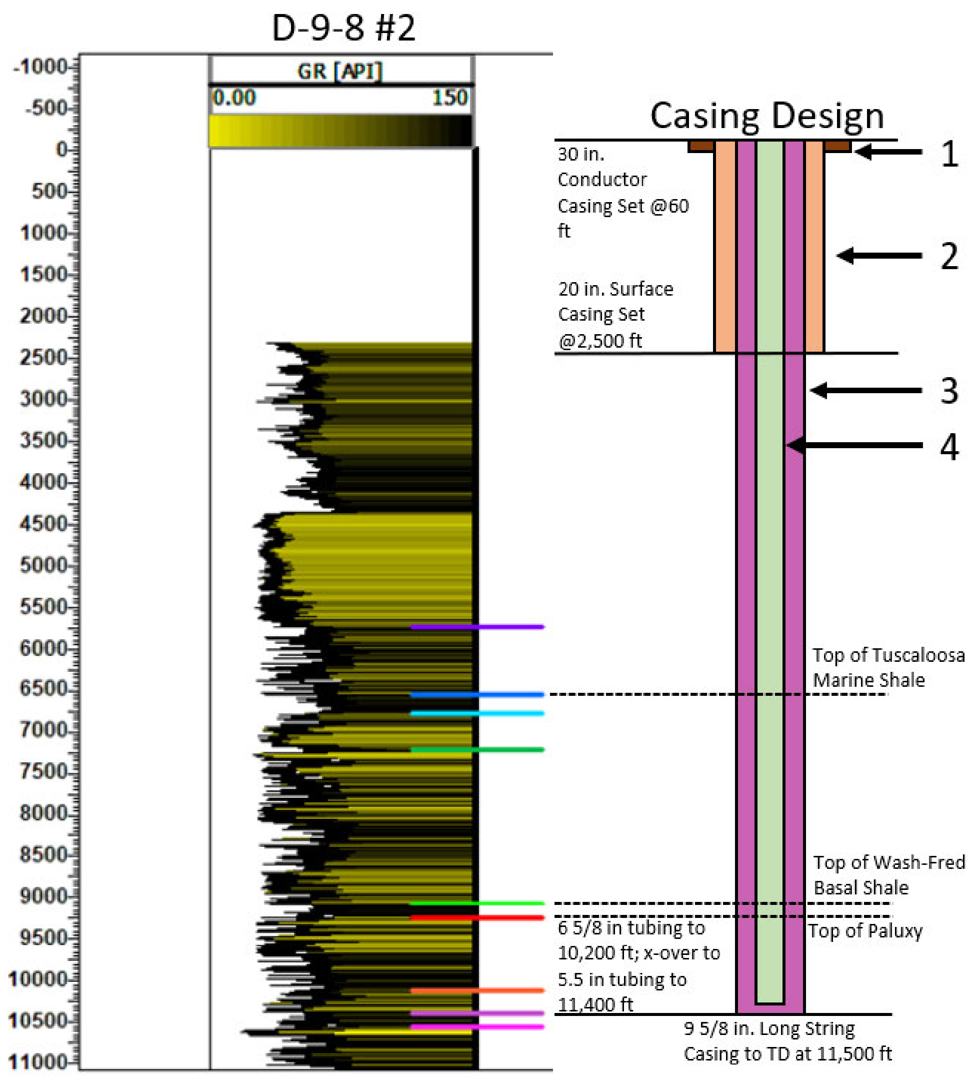

Figure 2. Casing intervals for the LL#1. 1) Conductor 2) Surface 3) Long-string 4) Tubing. Note: Depths in D-9-8 #2 log shown are 1,000 ft up dip from the LL#1 injection well.

A description of each logging method that Longleaf CCS, LLC will include in its logging program at the LL#1 injection and the IOB#1 monitoring well follows:

Open Hole Logs

- **Geologic Description (Mud Log)** – Provides a continuous visual description of the drill cuttings-based lithology of the formations as the well is drilled. Physical cuttings sample datasets are typically collected and cataloged every 20-50 ft for future assessment. Mud logs are also used to evaluate any hydrocarbon or natural gas shows encountered while drilling the well.

- **Triple Combination** – Includes gamma-ray/spontaneous potential, porosity, and resistivity logs.

- **Acoustic Scanning Log (i.e., Dipole Sonic)** – This acoustic log measures elastic properties axially, radially, and azimuthally to support geomechanical, geophysical, fractures, and petrophysical modeling. Furthermore, sonic logs like compressional sonic (DT) can be used along with density logs for preparing synthetic seismic logs.

- **Formation Micro Imager** – Provides micro-resistivity formation images when using water-based mud. Borehole images can reveal bedding planes and associated contacts, fractures (open, healed, and induced), and reservoir textures (sedimentary structures). A multi-arm caliper run with this tool provides information on hole shape and is used for subsurface stress analysis. The tool also provides borehole inclination and azimuthal information which complement the deviation check surveys taken while drilling the well.

- **High-Definition Nuclear Magnetic Resonance** – This log provides nuclear magnetic resonance (NMR) measurements of the buildup and decay of the polarization of hydrogen nuclei (protons) in the liquids contained in the pore space of rock formations. One key measurement provided by this log is the total formation porosity. Permeability and effective porosity can be estimated from the free-fluid to bound-fluid ratio and the pore-size distribution. NMR measurement can also be used for fluid identification because this log also provides a hydrogen index measurement.

- **Pulsed Neutron Spectroscopy** – This logging tool is used for measurements and definitions of mineralogy and matrix properties of injection and confining zones. The data from spectroscopy logging can be used to estimate mineral-based permeability, determine well-to-well correlations from geochemical stratigraphy, and determine sigma matrix for case hole and open hole sigma saturation analysis, among others. Elemental analysis or similar processing of these logs yields the volumetric proportions of mineral composition and pore fluids. For example, these logs can reveal the relative proportions of clay minerals, quartz, calcite, and fluid volume in the formation.

- **Wireline Formation Testing** – This wireline tool suite has the capacity to collect reservoir pressure measurements, static fluid levels and fluid samples that can be kept at formation pressures representative of downhole conditions. The tool can also be run to conduct a *mini-frac* test. These tests provide fracture pressure estimates and far field stress directions (in conjunction with the formation micro imager). Wireline test data can be used as calibration for other stress measurements (sonic logs).

Cased Hole

- **Ultrasonic Imaging Tool** – This log can provide estimates of well integrity and zonal isolation through measurement of cement acoustic impedance. The information from this log can be used to create maps of the casing integrity and cement, to identify corrosion or casing damage, and determine if there is solid (cement), liquid, or gas in between the casing and formation. Modern acoustic cement-evaluation tools, such as ultrasonic logs, are comprised of monopole (axisymmetric) transmitters (one or more) and receivers (two or more). They operate on the principle that acoustic amplitude is rapidly attenuated in good cement bond but not in partially bonded or free pipe. The ultrasonic tool can also provide a casing thickness interpretation.

- **Cement Bond Log (CBL)** – CBL tools use sonic waves to interrogate the integrity of the well's cement. CBLs use acoustic transmitters and receivers to measure signal attenuation to provide a measure of how well the casing and the cement are bonded. CBLs provide an indication of the cement-to-formation bond in the form of a variable density log. Typically, CBLs provide an average measurement but they can also provide maps where logging tools with multiple transmitters and receivers on pads are used.

- **Temperature Logging Surveys** – The temperature log provides a subsurface temperature profile necessary for characterizing in situ conditions. Temperature logging is used to identify the top of cement after cementing to help ensure wellbore integrity.

See **Table 1** for a list of the various Surface and Long String Casing wireline logging tools that will be deployed in the LL#1, LL#2, LL#3, and LL#4. **Table 2** lists the various Surface and Long String Casing wireline logging tools that will be deployed in the IOB#1 well.

Table 1: Wireline Logging Program for LL#1, LL#2, LL#3, and LL#4

Depth Interval (ft)	Log	Purpose/Comments
Surface Casing		
0 – 2,500	Mudlog	Monitor and ensure uninterrupted drilling process as well as provide lithologic information while drilling
0 – 2,500	SP/Resistivity	Characterize basic geology (Lithology, formation tops)
0 – 2,500	Cement Bond Log	Evaluate cement integrity
Long String Casing		
2,500 – 11,500	Mudlog	Monitor and ensure an uninterrupted drilling process as well as provide lithologic information while drilling
2,500 – 11,500	Temperature Log	Determine natural geothermal gradient outside well for comparison to future temperature logs for external mechanical integrity evaluations. Baseline log is run a minimum of 30 days after drilling and casing/ cementing the well because temperature anomalies due to circulation of drilling fluid and/or open-borehole injection testing will persist for several weeks to months.
2,500 – 11,500	Borehole Profile/Caliper	Evaluate borehole condition prior to cementing
2,500 – 11,500	Nuclear Magnetic Resonance Tool	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
2,500 – 11,500	Triple Combination/ Pulsed Neutron Spectroscopy	Characterize basic geology (Gamma Ray, Resistivity, Porosity, Mineralogy)
2,500 – 11,500	Formation Micro Imager	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
2,500 – 11,500	Dipole Sonic	Determine the reservoir fracture pressure gradient and geomechanical properties of the confining and injection zones
2,500 – 11,500 (cased hole)	Cement Bond log/Ultrasonic/Temperature	Evaluate cement integrity, internal and external casing condition

Table 2: Wireline Logging Program for IOB#1 Well

Depth Interval (ft)	Log	Purpose/Comments
Surface Casing		
0 – 2,500	Mudlog	Monitor and ensure uninterrupted drilling process as well as provide lithologic information while drilling
0 – 2,500	SP/Resistivity	Characterize basic geology (Lithology, formation tops)
0 – 2,500	Cement Bond Log	Evaluate cement integrity
Long String Casing		
2,500 – 11,500	Mudlog	Monitor and ensure an uninterrupted drilling process as well as provide lithologic information while drilling
2,500 – 11,500	Temperature Log	Determine natural geothermal gradient outside well for comparison to future temperature logs for external mechanical integrity evaluations. Baseline log is run a minimum of 30 days after drilling and casing/ cementing the well because temperature anomalies due to circulation of drilling fluid and/or open-borehole injection testing will persist for several weeks to months.
2,500 – 11,500	Borehole Profile/Caliper	Evaluate borehole condition prior to cementing
2,500 – 11,500	Nuclear Magnetic Resonance Tool	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
2,500 – 11,500	Triple Combination/ Pulsed Neutron Spectroscopy	Characterize basic geology (Gamma Ray, Resistivity, Porosity, Mineralogy)
2,500 – 11,500	Formation Micro Imager	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
2,500 – 11,500	Dipole Sonic	Determine the reservoir fracture pressure gradient and geomechanical properties of the confining and injection zones
Selected Injection and Confining Zone Points	Wireline Testing	Injection and confining zone mechanical properties (fracture pressure), reservoir fluid samples, reservoir pressure and static fluid level.
2,500 – 11,500 (cased hole)	Cement Bond log/Ultrasonic/Temperature	Evaluate cement integrity, internal and external casing condition

C. Coring

Longleaf CCS, LLC will attempt to collect 60 ft. or more of 4-inch whole core from both the Paluxy Formation (injection interval) and the Tuscaloosa Marine Shale (primary confining unit) while drilling the first Longleaf CCS Hub monitoring well, the IOB#1. Additional whole core may also be taken from the Wash-Fred and Lower Tuscaloosa sandstones to evaluate the potential for future storage opportunities. Due to the risk of wellbore washouts, Longleaf CCS, LLC will forego collecting whole core in the LL#1 injection well. Instead, Longleaf CCS, LLC will attempt to collect approximately 50 rotary sidewall cores in the LL#1 injection well. The planned distribution of these 50 sidewall cores is provided in **Table 3**.

These whole and sidewall cores will be preserved on site and then shipped to a commercial core testing/analysis laboratory for analysis. Properties analyzed will include routine core analysis (porosity, permeability, grain density and residual fluid saturation). Specialized core analysis, including X-ray diffraction (XRD) for mineralogical analysis, and capillary pressure will be conducted on selected whole core samples. If the wireline formation tests fail to determine injection and confining zone mechanical properties, core plug mechanical property tests (e.g. triaxial tests) may be conducted to determine these properties and to estimate fracture pressure. The wireline and/or core mechanical property results will be used to calibrate wireline logs.

Table 3: Planned Sidewall Core Collection by Formation in the LL#1 Injection Well

Formation	# of Core Plugs
Upper Tuscaloosa/Eutaw	5
Tuscaloosa Marine Shale	5
Lower Tuscaloosa Massive Sand	5
Wash-Fred	15
Paluxy	20
TOTAL	50

D. Fluid Sampling

The analysis of reservoir fluid samples will be used to satisfy the requirement of 40 CFR 146.87(5)(c) and ensure that baseline geochemical properties are established for the Paluxy Formation across the AoR for the Longleaf CCS Hub. Longleaf CCS, LLC will collect fluid samples from the LL#1 injection well for the Paluxy Formation. Any fluids introduced into the formation during drilling, borehole conditioning, cementing, perforation acid treatment, and/or formation (injection) testing would first need to be removed before representative formation fluid samples can be collected. Consequently, Longleaf CCS, LLC will attempt to collect fluid samples during the active drilling phase using a Wireline Formation Testing tool rather than collect samples after well completion. The in-zone fluid samples from the LL#1 injection well will be collected using a formation testing tool while the hole is open. If fluid samples cannot be taken via the formation testing tool, fluid samples can be collected after well completion by swabbing fluid or pumping through tubing with a packer set just above the perforated interval. After an appropriate volume of fluid is swabbed from the well, samples can be taken via a slickline deployed tool, such as a Kuster Flow Through Sampler (FTS). Both of these fluid sampling methods will sample reservoir pressure and static fluid levels.

The analytic and field parameters for fluid sampling are presented in **Table 4**. These parameters are consistent with the fluid sampling analysis and processes that are detailed in the ***Testing and Monitoring Plan*** and the ***Quality Assurance Surveillance Plan*** associated with this permit. Longleaf CCS, LLC will also collect hydrogeologic data from the extensive wireline program, as discussed in Section B of this plan.

Table 4: Summary of Analytical and Field Parameters for Fluid Sampling in the Paluxy Formation Injection Interval

Parameters	Analytical Methods
Paluxy Formation (Injection Interval)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3 and SO_4 Dissolved CO_2	Ion Chromatography, EPA Method 300.0 Coulometric titration, ASTM D513-11
Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Gravimetry, APHA 2540C Oscillating body method APHA 2320B EPA 150.1 APHA 2510 Thermocouple

E. Mechanical Integrity Testing

Longleaf CCS, LLC will conduct tests and run logs as needed to demonstrate the internal and external mechanical integrity of the injection well prior to initiating CO_2 injection, satisfying the hydrogeologic testing requirements under 40 CFR 146.87(e). Internal mechanical integrity refers to the absence of leaks in the tubing, packer, and casing above the packer. External mechanical integrity refers to the absence of fluid movement/leaks through channels adjacent to the injection wellbore that could result in fluid migration into an USDW.

Prior to drilling out the plug on each casing string, a casing pressure test will be conducted. The test will be designed not to exceed the rated pressure of the casing. Based on State of Alabama Oil and Gas Board guidance, surface casing should be tested at 1,500 psi for wells deeper than 9,000 ft TVD. Long string casing will be tested at 1,500 psi or 0.2 psi/ft, not to exceed 1,500 psi [1].

If a decline in pressure greater than 10% within the first 30 minutes of testing is noted, or if other indications of a leak are indicated, then the casing string will be recemented or repaired, or have an additional casing string run. Once remedial measures have taken place, the pressure test will be conducted again. After cementing the casing strings, drilling will not commence until a time lapse of 12 hours under pressure has passed. All casing pressure tests will be recorded in the driller's log[1].

After the proposed injection well LL#1 is completed, including the installation of tubing, packer, and annular fluid, a test of the well's internal mechanical integrity will be performed by conducting a standard annular pressure test (SAPT). Class VI regulations do not define a pressure that the test is run. EPA Region 4 requires an annular pressure test of 300 psig for Class II wells, and we propose to use that value here. The annular pressure test is a short-term test wherein the fluid in the annular space between the tubing and casing is pressurized, the well is shut-in (temporarily sealed up), and the pressure of the annular fluid is monitored for leak-off.

The planned procedure will be to provide a comparison of the pressure change throughout the test period to 3% of the test pressure (0.03 × test pressure). If the annulus test pressure decreases by this amount or more, the well has failed to demonstrate internal mechanical integrity. If the annulus pressure changes by less than 3% during the test period, the well has demonstrated internal mechanical integrity. If the well fails the annular pressure test, the tubing and packer will be removed from the well to determine the cause of the leak. During the active CO_2 injection phase, internal mechanical integrity will be continuously monitored by the well annular pressure maintenance and monitoring system, as discussed in more detail in the ***Testing and Monitoring Plan***.

Longleaf CCS, LLC will also employ various methods to demonstrate external mechanical integrity upon the completion of the proposed CO_2 injection well LL#1 and prior to the start of injection operations. Longleaf CCS, LLC will run pulsed neutron

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[1] State Oil & Gas Board of Alabama Administrative Code Oil and Gas Report 1. *Rules and Regulations Governing the Conservation of Oil and Gas in Alabama. Rule 400-1-4-.09. Casing, Cementing, and Test Pressure Requirements.*

capture and temperature logs on the completed injection well in order to demonstrate external mechanical integrity, with these logs also providing supporting hydrogeologic data discussed in Section G. Longleaf CCS, LLC will run an Ultrasonic Imaging Tool to test cement integrity and provide additional confidence that there are no pathways for potential CO_2 or brine migration through the wellbore, casing, or cement prior to injection operations, satisfying the requirement of 40 CFR 146.87(a)(4).

F. Fracture Pressure of Injection and Confining Zones

As discussed above, the LL#1 injection well will be drilled and completed with limited testing after open hole logs are gathered. This will help limit borehole rugosity and provide the highest probability of achieving a mechanically sound cement job. As such, Longleaf CCS, LLC will not plan on completing an open-hole fracture pressure test in the LL#1. As the alternative, prior to installing the long-string casing in the IOB#1 monitoring well, Longleaf CCS, LLC will use the formation testing tool in the IOB#1 monitoring well to conduct formation fracture tests to measure the fracture pressure of the injection formation and the confining unit(s). Then, a *minifrac test* will be used to locally pressure up a small interval in the test formation to the point where it just starts to fracture. This provides the fracture pressure without causing significant damage to the formation being tested.

In addition, to fully satisfy the requirements of 40 CFR 146.87(d), Longleaf CCS, LLC intends to run a dipole sonic log (Stoneley wave analysis) in the LL#1 injection well which will enable calculation of the reservoir fracture pressure of the injection zone and the confining zone.

G. Hydrogeologic Testing

After the LL#1 injection well is completed, including perforating the injection interval and installing the injection tubing and packer, Longleaf CCS, LLC intends to run an injection test on the Paluxy Formation to determine the large-scale composite injectivity (transmissivity) of the injection interval and possible presence of nearby hydrogeologic boundaries (**Table 5**). The injectate for this test will be produced Paluxy Formation water (brine) from the LL#1 well, or fresh water which will serve as a proxy for

CO_2 injection. Longleaf CCS, LLC intends to use the extensive wireline logging program to support and corroborate the hydrogeologic properties that are collected via direct fluid sampling from the injection zone. Additionally, Longleaf CCS, LLC will collect reservoir pressure from the Paluxy Formation in the LL#1 injection well during the injectivity test.

Table 5: Composite Injectivity Evaluation Testing Program

Test	Description	
Paluxy Formation Composite Injectivity Evaluation	Objectives	**Primary objective**: To determine the large-scale transmissivity of the Paluxy Formation and possible presence of nearby hydrogeologic boundaries using produced reservoir brine from LL#1 or fresh water and provide direct information about the injectivity potential of the Paluxy Formation or a selected portion of it.
	Test/Depth Zone	The Paluxy Formation. Approximate depth interval 10,220-11,350 ft measured depth (upper Paluxy). Alternatively, this test may be conducted on one or more discrete depth intervals within the Paluxy Formation.
	Test Activity/ Summary	The injection tubing and packer would be set just above the top of the Paluxy Formation inside the casing string. After the packer is in place, a constant-rate injection utilizing produced reservoir brine from LL#1 or fresh water will be conducted. At the end of injection the recovery pressure for the composite zone will be monitored for a period approximately 1.5 times or more of the injection period.

A pre-operation injection and pressure fall-off test will serve as the baseline test for establishing reservoir and well conditions for comparison to results of subsequent pressure fall-off tests conducted during the operational period (i.e., during CO_2 injection). Specifically, this comparison is intended to confirm that the pressure increase within the injection interval is less than that predicted and ensure that the modeled parameters used in the ***Area of Review and Corrective Action Plan*** modeling analysis represent actual conditions[2].

The guidelines of EPA Region 6[3] define a pressure fall-off test as a pressure transient test that consists of shutting in an injection well after a period of prolonged injection and measuring the pressure fall-off. Longleaf CCS, LLC will follow this practice

[2] EPA (U.S. Environmental Protection Agency). 1990. Ambient Pressure Monitoring. EPA Region 5, Regional Guidance #6. Washington, D.C.

[3] EPA (U.S. Environmental Protection Agency). 2002. EPA Region 6 UIC Pressure Falloff Testing Guideline. Washington, D.C.

for the Longleaf CCS Hub. The fall-off period is a replay of the injection test preceding it; consequently, it is affected by the magnitude, length, and rate fluctuations of the injection period. Fall-off testing analysis provides reservoir and well parameters, including transmissivity, storage capability, skin factor, and well flowing and static pressures. Establishing a baseline value for these parameters will be useful for identifying changes in the well and/or reservoir properties after CO_2 injection begins; for example, an increasing skin factor may be indicative of formation damage which signals a need for well remediation while a decreasing skin factor may indicate near-wellbore cleanup.

The baseline pressure fall-off test will be conducted as part of the post-completion injectivity testing (e.g., constant-rate injection test conducted as either a single-well test and/or multi-well interference test) discussed in the following section. Guidance for conducting the pressure fall-off test in this project is provided by EPA Region 5[4,5]. In general, the recommendations provided in these guidance documents will be followed to the extent practicable. If circumstances dictate steps are required outside of the guidance provided, the proposed operations plan will be cleared with the UIC Program Director prior to initiation.

H. Stimulation Program

The need for considerable well stimulation to enhance the injectivity potential of the Paluxy Formation, such as hydraulic fracturing, is not anticipated. Modeling based on data collected from the geologic site characterization, and the experience gathered from the Anthropogenic Test CO_2 injection demonstration at Citronelle, has concluded that the injection zone is of high quality due to the relatively high porosity and permeability of the Paluxy reservoir. More information regarding the reservoir properties can be found throughout the ***Application Narrative***. However, if there is a need to bypass near-wellbore drilling induced damage, perforations may be flushed with an acid mixture. The acid reacts with the carbonates in the well cement and drilling fluids that may clog the perforations. To further ensure the acid cleans all perforations, soluble ‘perf balls’ may be

[4] EPA (U.S. Environmental Protection Agency). 1990. *Ambient Pressure Monitoring*. EPA Region 5, Regional Guidance #6. Washington, D.C.

[5] EPA (U.S. Environmental Protection Agency). 1998. Planning, Executing, and Reporting Pressure Transient Tests. EPA Region 5 − Underground Injection Control Section Regional Guidance #6. Washington D.C.

pumped to divert fluid from high flow perforations to those with flow constrictions. These ‘perf balls’ temporarily seal perfs, then dissolve completely to leave clear access to the formation. A proposed well stimulation plan is shown below.

1. Move in and rig up service rig, water tanks, pressure control equipment, and mud pump. Fill tanks with fresh water, mix in potassium chloride salt (KCl) to increase the fluid density above reservoir pressure which prevents back flow.
2. Pump KCl brine water mix to kill well.
3. Trip in hole with work string and circulate hole with KCl brine mixture.
4. Rig up acid pumper, bulk acid truck, piping, and ball diverter.
5. Pump approximately 500 gals of acid (typically HCl or HF, 7.5 to 15% concentration) at 3 to 8 barrels per minute, dropping water soluble balls every minute. The number of soluble balls will slightly exceed the number of perforations in the wellbore casing. The final acid type concentration and volume will be determined from modeling of the reactions between the acid and the mineralogy we encounter during drilling.
6. Displace acid to perforations; shut in well to let acid work and perf balls dissolve, approximately 30-60 minutes.
7. Pump KCl brine into formation.
8. Trip work string out of hole, rig down service rig and ancillary equipment. Reconnect flowlines/electronics as necessary.

I. Schedule

Longleaf CCS, LLC will provide the UIC Program Director with the opportunity to witness all logging and testing by this subpart. Pursuant to 40 CFR 146.87(f), Longleaf CCS, LLC will submit a schedule of such activities to the UIC Program Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The scheduled testing will be developed within 90 days following the permission for the construction of the proposed injection well.

J. Reporting

Longleaf CCS, LLC will provide the EPA with a descriptive report(s) prepared by knowledgeable analyst(s) that includes an interpretation of the results of the casing and cement integrity, well logging, well testing, and core data. These report(s) will include:

- The date and time of each pressure test, the date of well bore completion, and the date of installation of all casings and cements, including chart results and interpretations of each cement bond log, cement pressure tests, and any supplemental well data,
- Interpretation of the well logs by a log analyst, including any assumptions, determination of porosity, permeability, lithology, thickness, depth, and formation fluid salinity of relevant geologic formations, and any changes in interpretation of site stratigraphy based on formation testing logs,
- Interpretation of whole and/or sidewall core analysis results, including any changes in interpretation of site stratigraphy based on core analysis, analytical methods, quality assurance information, tabular and/or graphic data, and photographs,
- Reservoir fluid sampling results, including descriptions of the sampling equipment, sampling methodology, sample preservation methods, field and laboratory results, and any changes in interpretation of site stratigraphy based on fluid sample results,
- Reservoir pressure results and geomechanical results to determine injection and confining zone fracture pressure, including type and location of pressure gauge, type of flow meter and calibration records, raw pressure and flow data, and plot of flow rate versus pressure data, and any changes in geomechanical interpretations based on test results, and
- Hydrogeologic test results, including pressure and flow data, testing parameters, discussion of results, and any changes in interpretation of injectivity and storage potential based on injection/falloff test results.