CLASS VI PERMIT PRE-OPERATIONAL TESTING PLAN

40 CFR 146.87

LAPIS ENERGY (AR DEVELOPMENT) LP
PROJECT BLUE
EL DORADO, ARKANSAS

Prepared By:
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Revision No. 2 – RAI No. 1
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1.0 FACILITY /PROJECT INFORMATION

Facility/Project Name:	El Dorado Chemical Company / Lapis Energy Project Blue Class VI Injection Wells No. 1 and No. 2
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Well Locations:	Union County El Dorado, Arkansas Project Blue Class VI Injection Well No. 1 Latitude Coordinate (NAD-83): 33. 2613614642 Longitude Coordinate (NAD-83): -92.6911515334 Project Blue Class VI Injection Well No. 2 Latitude Coordinate (NAD-83): 33. 2613625494 Longitude Coordinate (NAD-83): -92.6909878157

The testing activities at the Project Blue Wells described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring Plan, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

This *Pre-Operational Testing Plan* describes how Lapis Energy will obtain data from the drilling and completion of the proposed injection and monitoring wells at or adjacent to the LSB Industries El Dorado Chemical Company (EDCC) in Union County, Arkansas. A total of two Injection Wells, one Above Confining Zone (ACZ) Monitoring Well, and one deep In Zone (IZ) Monitoring Well are proposed to meet the injection and storage needs for the Project Blue site. The injection wells will be completed sequentially into two geologic injection zones as identified within "*Section 2 – Site Characterization*" of the Project Narrative Report (submitted in Module A – Project Information Tracking).

This Pre-Operational Testing Plan meets the requirements of USEPA 40 CFR §146.87.

1.1 INTRODUCTION

This plan contains a comprehensive pre-operational data acquisition strategy across the confining and injection zones (*i.e.*, the sequestration complex) at the Project Blue site. These data will be used for site specific determination to evaluate the injection rates, injection volumes, assist with final surface facility design, and revalidation (and update, if needed) of the site model and Area of Review (AoR). The proposed Injection Zones for the project are:

1. Lower Hosston Formation
2. Cotton Valley Formation

The Injection Zones of the Cotton Valley and Lower Hosston are comprised of alternating sands and shales units and will be sequentially completed (in ascending order) to control plume size of the sequestered carbon dioxide. The primary Confining Zone is the Rodessa/Pine Island/Sligo/Upper Hosston that is located between the Lower Hosston and the Upper Cretaceous Unconformity at the base of the Upper Cretaceous section. For this Class VI application, this group of strata is referred to as the Lower Cretaceous Sequence Boundary (LCSB). In addition to the primary Confining Zone, the regionally extensive Midway Shale, which is predominantly a marine shale that exhibits extremely low porosity and permeability, provides additional containment between the sequestration zones and the lowermost USDW (Wilcox Formation).

This *Pre-Operational Testing Plan* has been designed to reduce uncertainty and define the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the Injection Zones, the overlying Confining Zone, and other relevant geologic formations in the project area. In addition, formation fluid characteristics will be obtained from each of the Injection Zones, the Tokio Formation, which is above the confining zone, and the Sparta Formation, which is a known source of drinking water within the project area. These zones have been selected to establish baseline data that will be measured against data collected as part of the Testing and Monitoring Plan and Post-Injection monitoring portions of the project.

Lapis Energy has designed the sequestration project using two Class VI Injection Wells. These wells will be completed into one of the Injection Zones at a time. The Injection Wells will follow the 40 CFR §146.87(a), (b), (c), and (d) standards for logging and testing requirements. Coring will be adaptive and based upon the well spatial variability, wellbore conditions, core recovery, and core quality. The Injection Wells will demonstrate mechanical integrity prior to receiving authorization to inject. The data obtained in this plan will be used to validate and update, if necessary, the "*Area of Review and Corrective Action Plan*" (submitted in Module B), to define and reduce uncertainties with the site characterization, revise the "*E.1-Testing and Monitoring Plan*" (submitted in Module E), and determine final operational procedures and limits.

This pre-operational logging and testing strategy has been developed based upon the needs and requirements for the Project Blue Injection Well (Section 2.0) and for the ACZ and IZ Monitoring Wells (Section 3.0).

2.0 INJECTION WELL – TESTING STRATEGY

The following tests and logs will be conducted during drilling, casing installation, and after casing installation in accordance with the testing required under 40 CFR §146.87(a), (b), (c), and (d). The tests and procedures are described below and in the "*Section 5.0 - Proposed Injection Well Construction Information*" section of the Project Narrative (submitted in Module A).

All logging and well testing plans will be submitted to the UIC Program Director 30 days prior to commencing the operations. The UIC Program Director will be provided the opportunity to witness all operations for the drilling and testing of the injection wells per the 40 CFR §146.87(f). Any changes to the schedule will also be submitted to the Executive Director 30 days prior to the scheduled test.

2.1 DEVIATION CHECKS

Two Class VI Injection Wells are planned to be drilled on the LSB Industries property at the EDCC facility for Project Blue. Injection Well No. 1 will initially be completed in the deepest injection interval within the Cotton Valley (CV1). Injection operations will then sequentially move upwards to the other injection intervals of Cotton Valley, the CV2 and CV3. Injection Well No. 2 will be completed in the Lower Hosston Formation.

On the single-well pad, for well Blue DM-2 (in-zone monitoring well), the minimum interval for taking surveys along the full length of the well will be every 500 feet by means of a single-shot survey tool, gyro or measurements while drilling (MWD), depending on the drilling tools employed at the time. On the multi-well pad, for INJ-1, INJ-2 and Blue SM-1, the minimum interval for taking surveys along the full length of the wells will be every 100 feet by means of a gyro or MWD. Directional tools will be used in cases of anti-collision concerns (e.g. , SF<1.5). The deviation survey intervals for the injection wells will confirm a vertical hole to limit potential of a diverging hole.

2.2 LOGGING PROGRAM

The well logging program will cover open hole and cased hole for all drilling stages of the Injection Wells. The logging program will meet all requirements set forth by the EPA Class VI standards and will be used to determine *in-situ* formation properties such as: thickness, porosity, permeability, lithology, formation fluid salinity, and reservoir pressure [per 40 CFR 146.87].

A detailed mud logging program will be developed based upon the target depths for the Injection Wells. Cuttings will be caught from surface to total depth (+/-6,475 feet for Injection Well No. 1 and +/-4,700 feet for Injection Well No. 2), with adaptive sampling through the proposed Confining Zone and sequestration complex. Gas chromatograph sampling will also be employed and correlated across the cuttings and drilling for onsite analysis.

Table 1 provides information on potential logging run types and the data that each run may provide. Please note that this table is not all encompassing but includes commercially available logs that are commonly run in the wellbores for data acquisition.

Table 1: Potential Logging Tools and Data Acquisition

Logging tools	Data Acquisition
Gamma Ray (GR), Caliper, Spontaneous Potential (SP), Resistivity, Density, Neutron, RT Scanner	Correlation, Shale Volume, Porosity, Saturations, Hole Size, Resistive Anisotropy
Sonic compressional and shear	Porosity, Mechanical Properties,
Formation Micro-Imager borehole images (resistivity or sonic)	Structure, Env. Deposition, Fractures
Magnetic Resonance	Porosity, free and bound fluids, Permeability
Elemental Capture Spectroscopy	Lithology
Spectral GR	Clay Minerals
Modular formation dynamics tester	*In situ* Fracture Pressure Formation Fluid Samples Mobility
Sidewall Coring Tool (rotary and/or percussion)	Porosity, Permeability, Bulk Density
Temperature Log	Geothermal Gradient Baseline for Fluid Migration.
Vertical Seismic Profile	Tie in to 2D regional profile
Cement Bond Log, Variable Density Log, Casing Collar Locator	Casing & cement integrity

The following sections detail the approach for logging in the open hole and cased hole sections of the Injection Wells and their corresponding completions. The Injection Wells have been designed with two phases: a surface and protection hole.

2.2.1 Water String Logging Program

A water casing string will be installed after the conductor has been driven to a depth of approximately 100 feet.

2.2.1.1 Water String Logging Program – Injection Well No. 1

The water casing hole to +/-900 feet will be analyzed using wireline logging techniques (Table 2A), with the following geophysical logs planned upon reaching casing point below the base of the potable water (Sparta Aquifer) for the project site (~ 900 feet). The water string will be cemented to surface.

Table 2A: Water String Logging Runs and Data Acquisition – Injection Well No. 1

Open Hole – 17-1/2-inch Hole Size – 0 to 900 feet	
Well Log	**Data Acquisition Profile**
Spontaneous Potential	Spontaneous Potential and formation fluid salinity
Resistivity	Fluid conductivity, presence of fresh vs. saline water, saturation
Gamma Ray	Clay content
Neutron-Density Porosity Logs	Formation porosity
Open Hole Caliper	Borehole diameter and log correction; identify washouts
Cased Hole – 13-3/8-inch Casing Size	
Well Log	**Data Acquisition Profile**
Cement Bond (CBL/VDL/CCL)	Determine the integrity of the cement
Flexural Wave Imaging	Radial cement and casing condition
Temperature	Develop temperature profile. Establish Baseline gradient.

Note: Additional diagnostic logs may be run at the discretion of Lapis Energy's geological staff and/or consultants or as directed by the authorized regulatory UIC Program Director.

2.2.1.2 Water String Logging Program – Injection Well No. 2

The water casing hole to +/-900 feet in Injection Well No. 2 (Hosston Injection Well) will be analyzed using wireline logging techniques (Table 2B), with the following geophysical logs planned upon reaching casing point below the base of the potable water (Sparta Aquifer) for the project site (~ 900 feet). The water string will be cemented to the surface.

Table 2B: Water String Logging Runs and Data Acquisition – Injection Well No. 2

Open Hole – 17-1/2-inch Hole Size – 0 to 900 feet	
Well Log	**Data Acquisition Profile**
Spontaneous Potential	Spontaneous Potential and formation fluid salinity
Resistivity	Fluid conductivity, presence of fresh vs. saline water, saturation
Gamma Ray	Clay content
Neutron-Density Porosity Logs	Formation porosity
Open Hole Caliper	Borehole diameter and log correction; identify washouts
Cased Hole – 13-3/8-inch Casing Size	
Well Log	**Data Acquisition Profile**
Cement Bond (CBL/VDL/CCL)	Determine the integrity of the cement
Flexural Wave Imaging	Radial cement and casing condition
Temperature	Develop temperature profile. Establish Baseline gradient.

Note: Additional diagnostic logs may be run at the discretion of Lapis Energy's geological staff and/or consultants or as directed by the authorized regulatory UIC Program Director.

2.2.2 Surface Hole Logging Program

The depth of the surface casing will be set well below the projected lowermost USDW (defined as the Wilcox Formation) and will be cemented to surface. The base of lowermost USDW will be confirmed based upon analysis of the open-hole logs. This section will be drilled with water-based mud to be protective of the freshwater aquifers.

2.2.2.1 Surface Hole Logging Program – Injection Well No. 1

The surface hole in Injection Well No. 1 will be analyzed using wireline logging techniques (Table 3A), with the following geophysical logs planned upon reaching casing point within the Lower Cretaceous Sequence Boundary (LSCB) Confining Zone (~ 3,010 feet).

Table 3A: Surface Hole Logging Runs and Data Acquisition – Injection Well No. 1

Open Hole – 12-1/4-inch Hole Size – 900 – 3,010 feet	
Logging While Drilling	Near bit Gamma Ray
Well Log	**Data Acquisition Profile**
Spontaneous Potential	Spontaneous Potential and formation fluid salinity
Resistivity	Fluid conductivity, presence of fresh vs. saline water, saturation
Gamma Ray	Clay content
Neutron-Density	Formation Porosity
Dipole Sonic	Compressional and shear acoustic transit time; porosity
Formation Imager	Structure, Env. Deposition, Fractures
Open Hole Caliper	Borehole diameter and log correction; identify washouts
Cased Hole – 9-5/8-inch Casing Size	
Well Log	**Data Acquisition Profile**
Cement Bond/Evaluation Tool (CBL/CET/VDL/CCL)	Determine the integrity of the cement
Flexural Wave Imaging	Radial cement and casing condition
Temperature	Develop temperature profile. Establish Baseline gradient.

Note: Additional diagnostic logs may be run at the discretion of Lapis Energy's geological staff and/or consultants or as directed by the authorized regulatory UIC Program Director.

2.2.2.2 Surface Hole Logging Program – Injection Well No. 2

The surface hole in Injection Well No. 2 will be analyzed using wireline logging techniques (Table 3B), with the following geophysical logs planned upon reaching casing point within the Lower Cretaceous Sequence Boundary (LSCB) Confining Zone (~ 3,100 feet).

Table 3B: Surface Hole Logging Runs and Data Acquisition – Injection Well No. 2

Open Hole – 12-1/4-inch Hole Size – 900 – 3,100 feet	
Logging While Drilling	Near bit Gamma Ray
Well Log	**Data Acquisition Profile**
Spontaneous Potential	Spontaneous Potential and formation fluid salinity
Resistivity	Fluid conductivity, presence of fresh vs. saline water, saturation

Gamma Ray	Clay content
Neutron-Density	Formation Porosity
Open Hole Caliper	Borehole diameter and log correction; identify washouts
Cased Hole – 9-5/8-inch Casing Size	
Well Log	**Data Acquisition Profile**
Cement Bond/Evaluation Tool (CBL/CET/VDL/CCL)	Determine the integrity of the cement
Flexural Wave Imaging	Radial cement and casing condition
Temperature	Develop temperature profile. Establish Baseline gradient.

Note: Additional diagnostic logs may be run at the discretion of Lapis Energy's geological staff and/or consultants or as directed by the authorized regulatory UIC Program Director.

2.2.3 Protection Hole Logging Program

The depth of the protection will be set below the Cotton Valley in Injection Well No. 1 and just into the top of the Cotton Valley in Injection Well No. 2. Each casing string will be cemented to the surface.

2.2.3.1 Protection Hole Logging Program – Injection Well No. 1

The protection hole will be analyzed using wireline logging techniques (Table 4A), with the following open and cased hole geophysical logs planned upon reaching total depth (~ 6,475 feet). The protection hole casing will be cemented to the surface for Injection Well No. 1.

Table 4A: Protection Hole Logging Runs and Data Acquisition– Injection Well No. 1

Open Hole – 8-3/4-inch Hole Size – 3,010-6,475	
Logging While Drilling	Near bit Gamma Ray
Well Log	**Data Acquisition Profile**
Spontaneous Potential	Spontaneous Potential and formation fluid salinity
Resistivity	Fluid conductivity, presence of fresh vs. saline water, saturation
Natural Gamma Ray	Clay content
Density/Neutron	Porosity and saturation
Dipole Sonic (long recording time)	Compressional and shear acoustic transit time; porosity
Open Hole Caliper	Borehole diameter and log correction; identify washouts

Formation Micro-Imager	Identify fractures and breakouts in the formation
Modular Dynamics Tester Tool / XPT	Sample formation pressures (XPT) and/or fluids (MDT), and stress testing
Dielectric Scanner	Fluid distribution and rock properties
LithoScanner w/Spectral Gamma Ray	Elemental and clay content; lithology
Magnetic Resonance (CMR/NMR)	Nuclear magnetic resonance; T1 and T2 relaxation times; permeability, bound water, and movable fluid properties
Rotary Sidewall Core (contingent)	Formation samples – contingent on whole coring program results
Sonic Scanner	Acoustic mechanical Properties, compressional and shear wave velocities / travel times
Cased Hole – 7-inch Casing Size	
Well Log	**Data Acquisition Profile**
Cement Bond/Evaluation Tool (CBL/CET/VDL/CCL)	Determine the integrity of the cement
Flexural Wave Imaging	Radial cement and casing condition
Cased hole Nuclear Spectroscopy	Baseline pulsed neutron log
Temperature	Develop temperature profile. Establish Baseline Gradient
Casing Inspection (multi-finger caliper, electromagnetic thickness)	Baseline casing condition
Zero Offset Vertical Seismic Profile	Travel time vs. depth to tie into seismic

Note: Additional diagnostic logs (Table 1) may be run at the discretion of Lapis Energy's geological staff and/or consultants or as directed by the authorized regulatory UIC Director.

Lapis anticipates taking open hole formation pressures in the upper Hosston (+/-3,350 feet), lower Hosston (+/-3,850 feet), Cotton Valley 3 (+/-5,025 feet), Cotton Valley 2 (+/-5,600 feet), and Cotton Valley 1 (+/-6,025 feet). Fluid samples are anticipated from the Cotton Valley 3 (+/-5,025 feet), Cotton Valley 2 (+/-5,600 feet), and Cotton Valley 1 (+/-6,025 feet). Formation stress tests will also be taken in the Cotton Valley intervals, Cotton Valley 3 (+/-5,025 feet), Cotton Valley 2 (+/-5,600 feet), and Cotton Valley 1 (+/-6,025 feet).

2.2.3.2 Protection Hole Logging Program – Injection Well No. 2

The protection hole will be analyzed using wireline logging techniques (Table 4B), with the following open and cased hole geophysical logs planned upon reaching total depth (~ 4,700 feet). The protection hole casing will be cemented to surface for the Injection Well No. 2.

Table 4B: Protection Hole Logging Runs and Data Acquisition– Injection Well No. 2

Open Hole – 8-3/4-inch Hole Size – 3,100 – 4,700 feet	
Well Log	**Data Acquisition Profile**
Spontaneous Potential	Spontaneous Potential and formation fluid salinity
Resistivity	Fluid conductivity, presence of fresh vs. saline water, saturation
Natural Gamma Ray	Clay content
Density/Neutron	Porosity and saturation
Open Hole Caliper	Borehole diameter and log correction; identify washouts
Formation Micro-Imager	Identify fractures and breakouts in the formation
Modular Dynamics Tester Tool / XPT	Sample formation pressures (XPT) and/or fluids (MDT), and stress testing
Rotary Sidewall Core (contingent)	Formation samples – contingent on whole coring program results
Cased Hole – 7-inch Casing Size	
Well Log	**Data Acquisition Profile**
Cement Bond/Evaluation Tool (CBL/CET/VDL/CCL)	Determine the integrity of the cement
Flexural Wave Imaging	Radial cement and casing condition
Cased hole Nuclear Spectroscopy	Baseline pulsed neutron log
Temperature	Develop temperature profile. Establish Baseline Gradient
Casing Inspection (multi-finger caliper, electromagnetic thickness)	Baseline casing condition

Note: Additional diagnostic logs (Table 1) may be run at the discretion of Lapis Energy's geological staff and/or consultants or as directed by the authorized regulatory UIC Director.

Lapis anticipates taking open hole formation pressures, fluid samples , and stress testing in the lower Hosston (+/-4,400 feet).

2.2.4 Analysis and Reporting

After the open and cased hole logging program has been completed, Lapis Energy will prepare an evaluation and interpretation of all the logs prepared by a knowledgeable log analyst [per 40 CFR §146.87(a)]. The report will include:

- The date and time of each test, the date of wellbore completion, and the date of installation of all casings and types of cements.
- Chart (graphical) results of each log and any supplemental data.
- The name of the logging company and log analyst and information on their qualifications.
- Interpretation of the well logs by the 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 upon the analysis of the logs and tests that were run.

Reports will be submitted to the authorized regulatory UIC Program Director. The data acquired will be used to validate and/or reduce uncertanties presented in the "*Area of Review and Corrective Action Plan*" submitted in Module B. Results will also impact final operating parameters for the Project Blue Injection Wells.

2.3 CORE PROGRAM

Petrophysical analysis is used in building the static geologic model. Acquired whole core, rotary sidewall core open-hole, and cased-hole logging data will be utilized to reduce uncertainty in the reservoir quality at the project site. The site-specific data collected during the drilling of the Injection Wells will be used in support of the local geology and future interactions of the static model and dynamic simulations for the project. This data will be used to refine the final model parameters prior to receiving authorization to inject.

The core program strategy (Table 5) developed in this Pre-Operational Testing Plan for Project Blue, accounts for remaining uncertainties, define lateral variabilities, and has been developed specifically for the injection well to meet the standards outlined in 40 CFR §146.87(b).

Table 5: Whole Core Sampling Intervals – Injection Well No. 1

Formation	Regulatory Intervals	Approximate Depth*	Core Acquisition**
Sligo/Upper Hosston Shale	Confining Zone	3,180-3,240	Attempt 60-feet
Lower Hosston Formation	Containment Zone	3,810-3,900	Attempt 90-feet
Lower Hosston Formation	Injection Zone	4,330-4,420	Attempt 90-feet
Cotton Valley Formation	Injection Zone 3	5,015-5,105	Attempt 90-feet
Cotton Valley Formation	Injection Zone 2	5,700-5,790	Attempt 90-feet
Cotton Valley Formation	Injection Zone 1	6,000-6,090	Attempt 90-feet

**Corelative to Shuler Drilling Co., EDC #1 well log*
***Core acquisition values are minimums.*

The whole core will be collected in Injection Well No. 1 from the Confining and Injection Zones using drilling fluids designed to reduce the swelling of formation clays and improve the quality of the retrieved core. The whole core program will be adaptive with the possible acquisition of additional cores optional upon the recoveries from the first core attempt in each zone or to address spatial uncertainty.

The depth at which each whole core will be cut will be projected prior to drilling and then further determined by the company's geologist during the drilling of the well. The site-specific core points will be determined by using the correlative analysis of the lithology and rate of penetration of the well being drilled, along with data from nearby offset open hole well logs and mud logs. If an insufficient amount of the formation core has been recovered in any core run, an additional core point may be selected and cut at the discretion of the company's geologist. Additionally, the insufficiently cored interval may be subsequently evaluated with additional rotary sidewall coring. Whole core depth intervals (as well as mud log depth intervals) will be adjusted (depth-shifted) to be equivalent to open-hole logging depths.

Injection Well No. 1 may have rotary sidewall cores collected from the relevant regulatory intervals and may include core samples of other formations in the wellbore, such as from pressure dissipation intervals or secondary confining layers present within the stratigraphic column, in order to characterize the mitigation potential of overlying and underlying geologic formations. The rotary sidewall coring program will be adaptive, based upon whole core recovery, and the evaluated needs of the project.

2.3.1 Analysis

Detailed core analyses will be performed at a well-respected, experienced core laboratory, to characterize both the injection and confining zones. Samples may be distributed to more than one laboratory, based on their individual capability, schedule considerations, and back-log. Analyses will cover the range of rock properties found in the Injection and Confining Zones and include:

1) Conventional / Routine Core Analysis
    a. Routine Core Porosity, Permeability, Grain Density, Petrography
    b. Thin Sections, SEMs, XRD, XRF
2) Special Core Analysis
    a. Stress Porosity, Permeability
    b. Core NMR
    c. Brine, CO_2 Permeability
    d. Capillary Pressures
    e. Seal Entry Pressure
    f. Fluid Compressibility
    g. Wettability
    h. Relative Permeability
3) Geomechanics
    a. Rock Mechanics and Compressibility measurements
    b. Acoustic – Shear and Compressional velocities
    c. Unconfined Compressive Strength, Tensile Strength

At a minimum, routine core analyses (porosity, permeability, and bulk density) will be performed on a distribution of samples characterizing differing lithologies. Additional analyses are expected to include a lithologic core description, thin section preparation and analyses, x-ray diffraction (XRD), and x-ray fluorescence (XRF) to characterize compositional make-up of the key intervals and to reduce uncertainties that impact the depositional and flow environments. Adaptive special core analyses such as electrical property measurements and/or relative permeability measurements will be conducted based upon quality of the recovered core and needs for reducing uncertainty and risk.

The prescribed analyses of the collected core and fluid samples will be used to refine and enhance site characterization per 40 CFR §146.82(a). Suggested analyses that are to be conducted are listed in the following tabulation (Table 6). Data acquired from the analyses will be used to reduce uncertainties within the model and detail spatial variability in parameters. These testing results will enable "fine-tuning" of the static site model.

Table 6: Whole Core Analytical Program – Injection Well No. 1

Parameter	Measurement	Units
Porosity	Total Porosity Diffuse Porosity	Percent
Permeability	Vertical Permeability Horizontal Permeability	mD/nD
Relative Permeability	Relative Gas Permeability Relative Aqueous Permeability	Dimensionless
Saturation	Fluid Saturation Residual Aqueous Saturation Residual Gas Saturation	Percent
Resistivity	Formation Factor as well as Resistivity Index	Ohm-meters
Compressibility	Bulk Compressibility Pore Compressibility	1/Pa
Physical Properties	Rock Strength Ductility Elastic Properties	PSI % Pa
Lithology	Description	N/A
Rock/Soil Type	Petrology Mineralogy	SEM Thin sections
Capillary Pressure/Relative Permeability	Mercury methods Porous-plate methods Centrifuge methods	Psi/mD

2.3.2 Reporting

Lapis Energy will submit a report prepared by a reputable and experienced core analyst describing the testing and results of the coring program [per 40 CFR §146.87(b)]. It will include information on the collection and testing method, specific reports on the core intervals that were recovered, laboratory instrumentation calibration, analytical results in either tabular or graphic form, and core photographs and photomicrographs as appropriate. This report will be submitted to the UIC Program Director.

2.4 FORMATION PRESSURE AND FLUID ANALYSIS

The formation pressure measurement and sampling system will be used to quantify the pore pressure and sample the *in-situ* formation fluids. Static levels of the fluids will be recorded in all of the Injection Zones per 40 CFR §146.87(c). The tool used to sample and retain free and dissolved gases and the aqueous phases in equilibrium with such gases will be supplied by a third-party vendor (Schlumberger, Expro, or an equivalent vendor using a downhole PVT sampler or equivalent tool). The *in-situ* downhole samples are preferred; however, based on subsurface and well conditions, surface samples may be collected for expediency.

The anticipated sampling protocol will be as follows:

1. Purge the well casing volume to bring fresh fluids that have not reacted with casing and tubing to the sample point within the wellbore.
2. Record the Static Level of the fluid in the Injection Zones.
3. Deploy commercial downhole sampler on slickline to collect a fluid sample at formation pressure at the targeted depth. Upon completion, close sampler to retain the collected fluid and gas as it is pulled out of hole.
4. Conserve fluid and gas volumes in preparation for shipping and analysis.
5. Filter and preserve samples following protocols for brine sampling.

All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers. The sample containers will be sealed and sent to an authorized third-party laboratory.

Repeat sampling and frequency (adaptive program) will be determined based on results.

2.4.1 Analysis

At least one initial baseline fluid sample will be collected from each Injection Zone during the completion activities. This data will be analyzed and used to update the model prior to the commencement of injection operations. These Injection Well fluid samples will provide the baseline measurements for formation fluids and document any spatial variability. Table 7 identifies the potential parameters to be monitored and the analytical methods Lapis Energy may utilize.

The initial parameters identified below may be revised and include additional components for testing dependent on the initial geochemical evaluation. The fluid samples will be sent and analyzed by a third-party accredited laboratory.

Table 7: Summary of potential analytical and field parameters for ground water samples – Injection Wells

Parameters	Analytical Methods
Dissolved CO_2 gas by headspace Dissolved CH_4 gas by headspace	Gas Chromatography (GC) Gas Chromatography (GC)
Hydrocarbons	Gas Chromatography (GC)
Dissolved inorganic carbon	Combustion
Bicarbonate	Titration
δD CH_{24}	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
δC^{13} CO_2	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
δC^{13} CH_4	Gas chromatography combustion isotope ratio mass spectrometry (GC/C/IRMS)
C^{14} CO_2	Accelerated mass spectrometry (AMS).
C^{14} Methane	Accelerated mass spectrometry (AMS).
Isotopic composition of selected major or minor constituents (*e.g.*, Sr $^{87/86,}$ S)	Multicollector-Inductively Coupled Plasma Mass Spectrometer (MC-ICPMS)
Cations: Al, As, B, Ba, Ca, Cd, Cr, Cu, Fe, K, Li, Mg, Mn, Na, Pb, Sb, Se, Si, Ti, Zn,	ICP-MS or ICP-OES, ASTM D5673, EPA 200.8 Ion Chromatography, EPA Method 200.8, ASTM 6919
Anions: Br, Cl, F, NO_3, SO_4,	Ion Chromatography, EPA Method 300.8, ASTM 4327
Total Dissolved Solids	EPA 160.1, ASTMN D5907-10

Parameters	Analytical Methods
Alkalinity	EPA 310.1
pH (field)	EPA Method 150.1
Specific Conductance (field)	EPA 120.1, ASTM 1125
Temperature (field) Hardness	Thermocouple ASTM D1126
Turbidity	EPA 180.1
Specific Gravity	Modified ASTM 4052
Density	Modified ASTM 4052
Viscosity	ASTM D445

2.4.2 Reporting

Lapis Energy will submit a report prepared by a specialist for the details on the fluid sampling results [per 40 CFR §146.87(b)]. The report will include information pertaining to collection and testing methods, specific details on the collection of the samples and the calibration of test instrumentation as appropriate, with results presented in either tabular or graphic form, including any photographs as deemed appropriate for inclusion in said report. The report will be submitted to the UIC Program Director.

2.5 FRACTURE PRESSURE DETERMINATION

The fracture pressure of the confining and injection zones must be determined or calculated pursuant to 40 CFR §146.87(d)(1). This information will be used (along with measured pore pressures in the injection zone) to determine appropriate, safe injection pressures for the project well. Lapis Energy will utilize density and dipole sonic logs run in the Injection Well to determine the vertical stress (S_v). This vertical stress calculation will be conducted in conjunction with a detailed review of the formation micro-imager log run in the well. This evaluation will aid in the identification of any borehole breakouts or open fractures. Log based estimation of fracture pressure will be provided in absence of conclusive tests described below.

The fracture/parting pressure of the sequestration zone and the corresponding fracture gradients will be determined via step rate or leak-off in the Project Blue In-Zone (IZ) Monitor Well (Blue DM-1). These testing and logging activities may be undertaken during the drilling of the IZ Monitor Well to determine the state of stress of the injection zone and the primary confining layer.

In general, mini-frac testing conducted on wireline is less invasive and less destructive on the test interval versus propagating a large fracture out into the formation as would occur during step-rate testing. Experience has demonstrated that fracture half-wing lengths could possibly extend hundreds of feet out into the formation, compromising the future integrity of the well completion across the Injection Zone as well as the overlying Confining Zone.

Immediately following the drilling and logging of the IZ Monitor Well, an open hole Schlumberger Modular Dynamics Tester (MDT), or equivalent, mini-frac testing will be conducted to determine the minimum horizontal stress of the formations (Injection and Confining Zones). These mini-frac operations will be performed using the formation tester set in dual-packer tool configuration and will be conducted on both the Injection Zone and the overlying Confining Zone.

Mini-frac formation stress testing will be used to determine formation breakdown pressure gradient, fracture propagation, and closure pressures. For stress testing to provide accurate information on the state of stress and breakdown pressure for the Injection Zone and the overlying Confining Zone, the tested interval must first be determined to have no pre-existing structural weaknesses, such as natural fractures. A total of 13 mini-fracs are planned for the project site. Formation testing of the Injection Zones and Lower Confining Zone will be performed in the Injection Well 1 (INJ-1) as presented in Table 8. The formation testing of the Upper Confining Zone will be performed in the In-zone Monitoring Well (Blue DM-2) to preserve the integrity of the unit around the injection wells.

Table 8: Proposed Mini-Frac Testing Details

Formation	Regulatory Zone	Proposed Number of Tests	Location of Test
Sligo/Upper Hosston	Upper Confining Zone	4	In-Zone Monitor Well (Blue DM-2)
Lower Hosston	Injection Zone	2	Injection Well 1 (INJ-1)
Cotton Valley (CV3)	Injection Zone	2	Injection Well 1 (INJ-1)
Cotton Valley (CV2)	Injection Zone	2	Injection Well 1 (INJ-1)
Cotton Valley (CV1)	Injection Zone	2	Injection Well 1 (INJ-1)
Buckner	Lower Confining Zone	1	Injection Well 1 (INJ-1)

Final test intervals will be pre-screened with the processed formation micro-imager logging tool to ensure the absence of fractures and to select packer-setting depths within "in-gauge" boreholes for such testing. Lapis anticipates taking open hole formation pressures in the upper Hosston (+/-3,350 feet), lower Hosston (+/-3,850 feet), Cotton Valley 3 (+/-5,025 feet), Cotton Valley 2 (+/-5,600 feet), and Cotton Valley 1 (+/-6,025 feet) in Injection Well No. 1. Formation stress tests will also be taken in the Cotton Vallety intervals, Cotton Valley 3 (+/-5,025 feet), Cotton Valley 2 (+/-5,600 feet), and Cotton Valley 1 (+/-6,025 feet) in Injection Well No. 1. Potential mini-frac stress testing is anticipated for the Deep Monitor Well. Targeted intervals are the Sligo Formation at +/-3,100 feet and the Hosston at 3,600 feet.

Confining Zone – Alternate Diagnostic Fracture Injection Test (DFIT)

In a diagnostic fracture injection test (DFIT), a relatively small volume of fluid is injected into the subsurface, creating a hydraulic fracture. DFITs were originally developed for use in low permeability formations, so there is an applicability to testing the confining zones in injection wells as they are going to have relative lower permeability than the injection formation. The DFIT will be used as a validation of the mini-frac tests in the in-zone monitoring well (Blue DM-2).

The testing is essentially similar to the mini-frac test, but the test is conducted in either open or cased hole with dual packers straddling the test interval with injection down a test string or drill pipe. After the fracture has been created and injection has ceased, the pressure in the wellbore is monitored for a set duration, which could range from several hours to several days. Formation pressures measured during the injection and recovery periods are used to infer properties of the formation, including the leak-off coefficient, permeability, fracture closure pressure (related to the magnitude of the minimum principal stress and the net pressure), and formation pressure.

During the initial DFIT injection phase, prior to the formation of a fracture, wellbore storage controls the pressure behavior and pressure increases with increasing injection volume. At formation breakdown pressure, a fracture is initiated in the formation. The initiation of a new fracture will cause a decrease in pressure while the expansion of an already existing fracture will cause pressure to plateau. Following breakdown, continued injection causes the fracture to extend further out into the formation (propagation pressure); once injection ceases, the well is shut in and the ISIP (initial shut-in pressure) is measured. The DFIT analysis primarily focuses on the analysis of the trends in propagation and shut-in pressure that occur in the hours and days immediately following the shutting in of the well.

In general, the DFIT procedure is as follows:

1. In a cased hole, perforate the well (small interval or full set).
2. Install high-resolution surface electronic memory gauges on wellhead and run high-resolution gauges downhole (set recording rate set to 1 second intervals). The use of high-resolution gauges will ensure that virtually all pressure changes are recorded (a 0.100 to 0.001 psi gauge resolution is recommended).
3. Load wellbore with water (KCl or saltwater with minimal additives as needed (to avoid clay swelling, etc.).
4. Start pressure recording before pumping starts and end recording after the fall-off (pressure recovery) is complete.
5. Commence pumping. The injection rate/pressure should be high enough to breakdown the perforations and initiate a small fracture. After breakdown, the fluid injection rate should be increased to the designed maximum pressure limit and injection should be continuous at a steady rate for 3 to 5 minutes.
6. The step-down phase of the DFIT procedure should then commence. The rate should be stepped down to 75%, then 50%, and optionally 30% of the maximum rate. The duration of each step-down rate drop can be as short as 10 seconds.
7. Following the completion of the step-down phase, pumping will be immediately stopped, the total volume pumped will be recorded, and the wellhead will be secured to prevent tampering.
8. Rig down the pumping equipment without disturbing the isolated electronic gauges.
9. Collect the data from the pump unit as well as the acquisition setup.

2.5.1 Analysis

The analysis of mini-frac/DFIT test data is performed in two parts: pre-closure analysis and after-closure analysis. Pre-closure analysis consists of identifying closure and analyzing the early pressure falloff period while the induced fracture is closing. One of the most critical parameters in fracture treatment design is the fracture closure pressure.

The following parameters are determined from the post-closure analysis:

- Instantaneous Shut-In Pressure (ISIP) = Final injection pressure - Pressure drop due to friction
- ISIP Gradient = ISIP / Formation Depth
- Closure Gradient = Closure Pressure / Formation Depth
- Net Fracture Pressure (Δp_{net}) – Net fracture pressure is the additional pressure within the frac above the pressure required to keep the fracture open. It is an indication of the energy available to propagate the fracture.
  - Δp_{net} = ISIP - Closure Pressure
- Fluid efficiency – Fluid efficiency is the ratio of the stored volume within the fracture to the total fluid injected. A high fluid efficiency means low leak-off and indicates the energy used to inject the fluid was efficiently utilized in creating and growing the fracture. Low leak-off is also an indication of low permeability. For mini-frac after-closure analysis, high fluid efficiency is coupled with long closure durations and even longer identifiable flow regime trends.
- Gc is the G-function time at fracture closure.
- Formation leak-off characteristics and fluid loss coefficients.
- Fracture closure pressure (pc)

G-Function Analysis

Post-injection (pre-closure) pressure falloff analysis can be performed using the "G-function" and root time methods. The G-function is a dimensionless time function designed to linearize the pressure behavior during normal fluid leak-off from a bi-wing fracture. Any deviations from this behavior can be used to characterize other leak-off mechanisms. The root time plot exhibits similar behavior and can be used to support the G-function analysis (IHS, 2017).

A straight-line trend of the G-function derivative (Gdp/dG) is expected where the slope of the derivative is still increasing. Position the Fracture Closure Identification line, which is anchored to the origin by default, through the straight-line portion of the G-Function derivative. Fracture closure is identified as the point where the G-Function derivative starts to deviate downward from the straight line as shown in the following graphic (IHS, 2017).

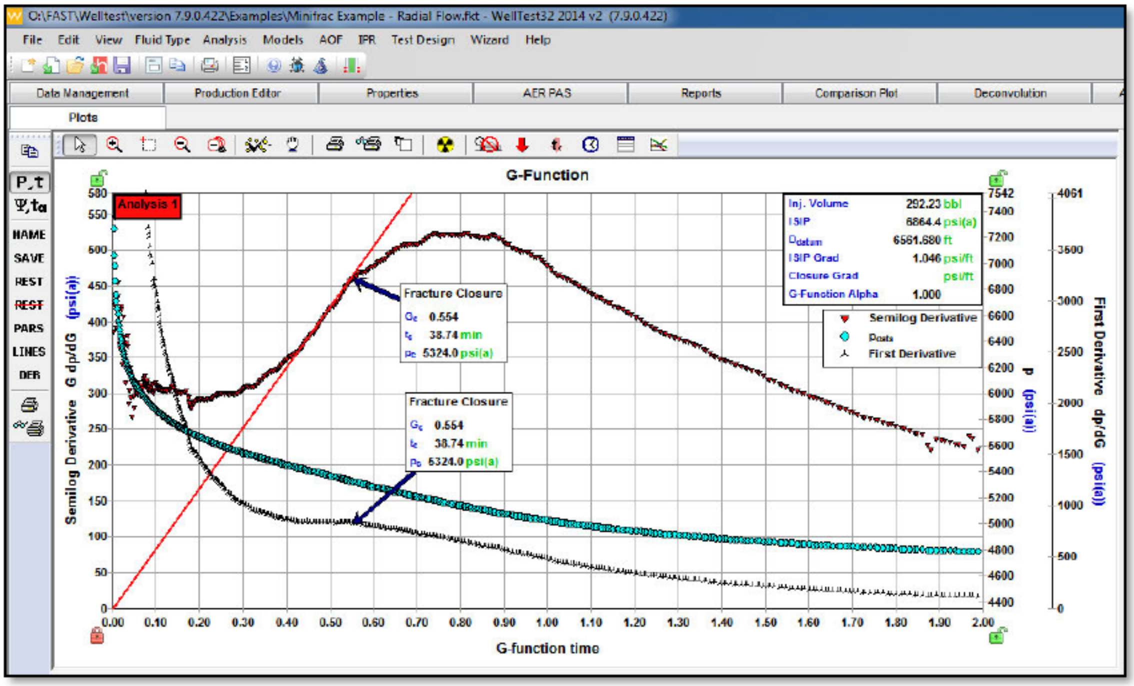

Figure 1: G-Function derivative prior to closure (from IHS, 2017)

https://www.ihsenergy.ca/support/documentation_ca/WellTest/content/html_files/analysis_types/minifrac_test_analyses/minifrac-pre-closure_analysis.htm

<u>Square Root Time Analysis</u>

Fracture closure can be identified by the peak of the first derivative on the sqrt(t) plot, which corresponds to an inflection point on the pressure curve. The semi-log derivative behaves similar to the G-Function Analysis. A user-defined (Sqrt(t)) analysis line may be added to the sqrt(t) plot to help identify the point of inflection (IHS, 2017).

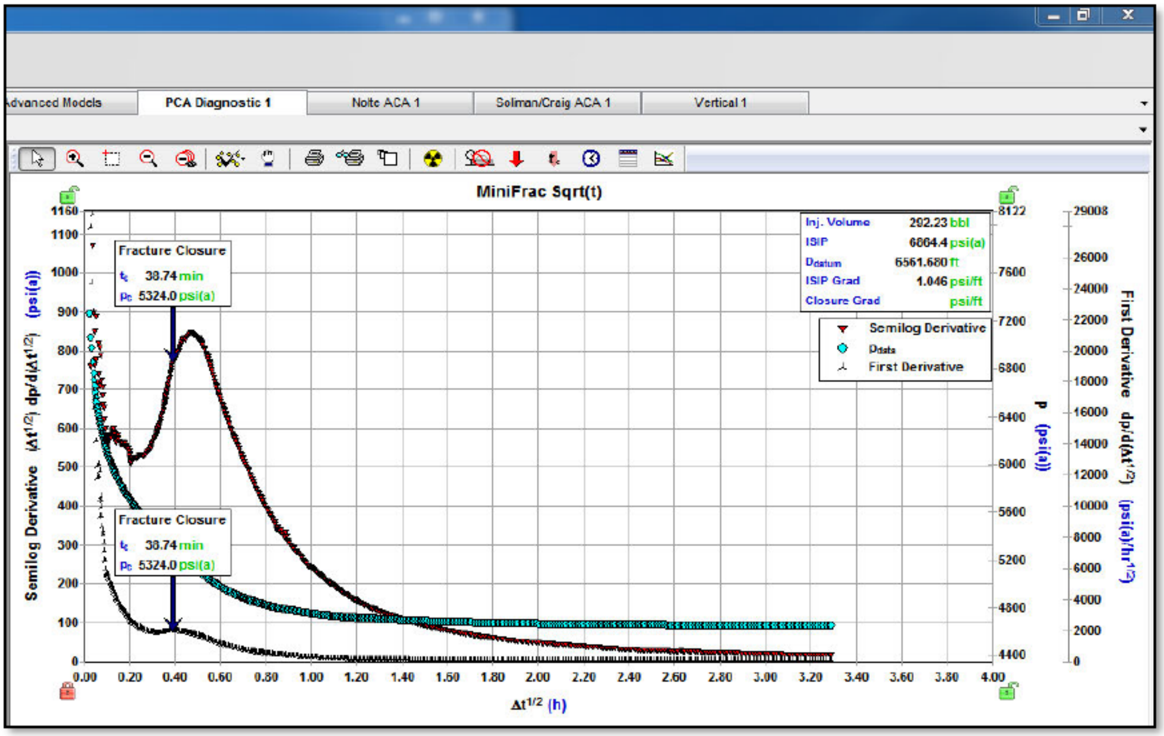

Figure 2: Fracture Closure (from IHS, 2017)

https://www.ihsenergy.ca/support/documentation_ca/WellTest/content/html_files/analysis_types/minifrac_test_analyses/minifrac-pre-closure_analysis.htm

2.6 DEMONSTRATION OF INJECTION WELL MECHANICAL INTEGRITY

Tabulated below is a summary of the Mechanic Integrity Tests (MITs) to be performed on the Injection Wells for the Project Blue site. These tests will be run after installation and prior to commencing sequestration operations. Tests conducted to ensure mechanical integrity of the wells are described in Table 9. The tests will include a pressure test of the well annulus using fluid or gas to ensure there are no leaks internal to the well. Additionally, a radioactive tracer survey or noise log will be run to ensure there is no movement of fluid behind pipe. The purpose of these tests is to ensure that the well's integrity is mechanically sound and that there is no movement of formation fluid along the wellbore. If the well fails to demonstrate mechanical integrity, the well will be repaired prior to advancing to the next phase of drilling and construction.

Table 9: Summary of Mechanical Integrity Testing – Injection Wells

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR §146.89(a)(1)	MIT – Internal	Pressure test using liquid or gas to determine that there is no significant leak in the casing, tubing or packer	After construction
40 CFR §146.87(a)(4)	MIT – External	Pressure test using liquid or gas and a casing inspection log to demonstrate the internal and external mechanical integrity of the well	
40 CFR §146.87(e)(1)	Formation Testing	Pressure fall-off test, pump test and injectivity test to verify the hydrogeologic characteristics of the injection zone	Prior to injection operations. Every 5-years during operation.

Lapis Energy will notify the EPA or the regulatory UIC Program Director at least 30 days prior to conducting the test and provide a detailed description of the testing procedure to be performed. Notice and the opportunity to witness the test/log shall be provided to the EPA or regulatory UIC Program Director at least 48 hours in advance of a given test/log. The wireline logs that will be run during such MITs are listed below (Table 10).

Table 10: Mechanical Integrity Test Logging Summary – Injection Wells

Test	Description	Frequency
Casing Inspection Log (Internal MIT)	To detect deformation, physical wear and or corrosion	After Injection Well Construction
Cement Bond Log (External MIT)	To evaluate integrity of the cement job between the casing and the formation	After Injection Well Construction
Tracer Survey (Oxygen Activation Log)	To detect the movement of fluid behind pipe	After Injection Well Construction Annual Basis during Injection Operations
Temperature or Noise Log (External MIT)	To detect thermal or acoustic anomalies that deviate from the baseline gradient and thus detect the movement of fluid behind pipe	After Injection Well Construction Annual Basis during Injection Operations

In addition to running wireline logs, an Annulus Pressure Test (APT) will be run to verify the well integrity. The test will be run after well completion and prior to injection operations. During injection operations, an MIT will be performed on an annual basis, within 45 days of the anniversary of the preceding year's test which will include either a Tracer Survey, Temperature, or Noise Log. Details on the annual testing 40 CFR §146.87(C) are contained in *"E.1 – Testing and Monitoring Plan"*.

Pressures will be recorded on a time-drive recorder for at least 60 minutes in duration and the chart or digital printout of times and pressures will be certified as true and accurate. The pressure scale on the chart will be low enough to readily show a 5 percent change from the starting pressure. In general, the test procedure will be as follows:

1. Connect a high-resolution pressure transducer to the annulus and increase annulus pressure to at least 100 psig over the permitted maximum tubing/injection pressure. Conduct Annulus Pressure Test (APT) by holding annular pressure a minimum of 100 psig above the well's maximum permitted surface injection pressure for a minimum of 60 minutes.

2. At the conclusion of the APT, annular pressure will be lowered to the well's normal, safe pressure and the pressure recording equipment will be removed from the wellbore.

A successful pressure test will "PASS" if the pressure holds to +/-5 percent of the starting pressure. **IF** the test indicated that the wellbore is not able to hold pressure for a selected time period, then the test will be considered a "FAIL". The test will be repeated and if the well continues to "FAIL", the construction of the well may have lost its integrity. Additional tests at progressively lower pressures may be run to identify the pressure at which the annulus can hold a differential. Continuous monitoring of the annulus system will be reviewed to identify if there are any data that may lead to a potential leak and assist in diagnosing potential issues with the annulus.

Reponses to potential loss of well integrity during the construction and testing phase are included in *"E.4 – Emergency and Remedial Response Plan"* submitted in Module E.

2.6.1 Reporting

Lapis Energy will submit a descriptive report prepared by an experienced log analyst that includes the results of any mechanical integrity test with the application for CCS Project Certification. At a minimum, the report will include:

- Chart and tabular results of each log or test;
- The interpretation of log results provided by a qualified log analyst;
- A description of all tests and methods used;
- The records and schematics of all instrumentation used for the tests and the most recent calibration of any instrumentation;
- The identification of any loss of mechanical integrity, evidence of fluid leakage, and remedial action taken;
- The date and time of each test;
- The name of the logging company that conducted the testing and the log analyst who evaluated the test;
- For any tests conducted during injection, operating conditions during measurement, including injection rate, pressure, and temperature (for tests run during well shut-in, this information must be provided relevant to the period prior to shut-in); and
- For any tests conducted during shut-in, the date and time of the completion of injection and records of well pressure re-equilibration.

Lapis Energy will submit a report prepared by a specialist for the details on the formation fracture testing results [per 40 CFR §146.87(b)]. The report will include information on collection and testing methods employed, specifics on the test run and calibration of instrumentation as appropriate, results in tabular or graphic form, and photographs as appropriate. The report will be submitted to the UIC Program Director.

If a well cannot establish mechanical integrity, a report within 24 hours will be submitted to the UIC Program Director [per 40 CFR §146.91(c)(4)] and Lapis will work with EPA on a path forward.

2.7 FORMATION TESTING

Lapis Energy will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR §146.90(f). Pressure fall-off testing will be conducted upon completion of the Injection Well to characterize baseline formation properties, as well as determine near wellbore/reservoir conditions that may impact the injection of carbon dioxide.

2.7.1 Ambient Pressure Falloff Testing

Lapis Energy will perform an initial (baseline) pressure fall-off test in the Injection Wells using brine or municipal water mixed with a clay stabilizer to avert clay swelling. This will allow for baseline characterization of the transmissibility to fluid within each Injection Zone. The initial pressure fall-off testing will be repeated using carbon dioxide within the first 60 days following initiation of sequestration operations. This will allow for comparison to the baseline fluid-to-fluid test with the change in the injection fluid from brine water to carbon dioxide.

A pressure fall-off test will be performed annually at five -year intervals (within +/-45 days of the anniversary of the previous test), for the lifetime of injection operations per 40 CFR 146.90(f). Periodic testing is expected to provide insight into the performance of the Project Blue sequestration site and potentially aid in assessing the dimensions of the expanding carbon dioxide plume, based on the expected lateral transition from supercritical carbon dioxide near the wellbore to native formation brine beyond the plume. A final pressure fall-off test will be run after the cessation of injection into the Injection Well.

Test Details

Testing procedures will follow the methodology detailed in "*EPA Region 6 UIC Pressure Falloff Testing Guideline-Third Revision (August 8, 2002)*"[1]. Bottomhole pressure measurements will be recorded downhole near the perforations (preferred) due to phase changes within the column of carbon dioxide in the tubing. A surface pressure gauge may also serve as a monitoring tool for tracking the test progress.

[1] https://www.epa.gov/sites/default/files/2015-07/documents/guideline.pdf

The pressure gauge can be either installed as part of the completion or can be deployed via a wireline truck. If a wireline truck deployed gauge is used, the wireline should be corrosion resistant, and the deployed gauges should consist of a surface read-out gauge with a memory backup. Standard gauge specifications are presented in Table 11 as an example.

Table 11: Examples of Injection/Falloff Pressure Gauge Information – Wireline Testing Operations

Pressure Gauge	Property	Value
Surface Readout Pressure Gauge	Range Resolution	0 – 10,000 psi/356 °F +/-0.01 psi/0.01 °F
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 °F)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual
Memory Pressure Gauge	Range Resolution	0 – 10,000 psi/356 °F +/-0.01 psi/0.01 °F
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 °F)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual

The general testing procedure is as follows (and presumes that a wireline-deployed unit is used for the testing). **NOTE**: a dedicated downhole monitoring gauge may be used if installed in the Injection Well:

1. Mobilize wireline unit to the injection well and rig up on wellhead.

2. Rig up a wireline lubricator containing a calibrated downhole surface-readout (SRO) pressure gauge with memory gauge installed in the tool string as a backup, to the adapter above the crown valve. Each gauge should have an operating range of 0 - 10,000 psi. Reference the gauge to kelly bushing (KB) reference elevation as well as the elevation above ground level.

3. Open crown valve, record surface injection pressure, and run-in hole with SRO pressure gauge to just above the shallowest perforations in the completion while maintaining injection at a constant rate. Steady rates of injection should be maintained for at least 24 hours ahead of the planned shut-in of the injection well. Any offset injection well(s) should be either shut-in ahead of the testing or should maintain a constant rate of injection for the entire duration of the testing. This will minimize cross-well interference effects.

4. With the SRO pressure gauge positioned just above the perforations, monitor the bottom-hole injection pressure response for ±1 hour to allow the gauge to stabilize (temperature and pressure stabilization). Ensure that the injection rate and pressure are stable.

5. Cease injection as rapidly as possible (controlled quick shut-in); close the control valve and the manual flowline valve at the well site (start with the valve **closest** to the wellhead so that wellbore storage effect in early time is minimized). Conduct the pressure fall-off test for approximately 24 hours, or until bottomhole pressures have stabilized.

6. Lock out all valves on the injection annulus pressure system so that the annulus pressure cannot be changed during the falloff period. Ensure that valves on the flow line to the injection well are closed and locked to prevent flow to the well during the fall-off period.

7. After 24 hours, download data and make preliminary field analysis of the fall-off test data with computer-aided transient test software to estimate if or when radial flow conditions might be reached. If sufficient data acquisition is confirmed, end fall-off test. If additional data is required, extend the fall-off test until radial flow conditions are confirmed. After confirmation of sufficient data acquisition, end fall-off test.

8. Retrieve the SRO pressure gauge tool out of the well, stopping at 1,000-foot increments and allowing the gauge to stabilize (five minutes for each stop). Record the stabilized temperature and pressure. Repeat the process to collect stabilized pressure data (5-minute stops) at 1,000-foot intervals and in the lubricator.

In performing a fall-off test analysis, a series of plots and calculations will be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. It will also be used to compare formation characteristics such as transmissivity and skin factor of the near wellbore for changes over time. Skin effects due to drilling and completion (possible damage from perforation) will be assessed for the wells injectivity and potential well cleanouts in the future. These tests can also measure drops in pressure due to potential damage/leakage over time. In CO_2, it is anticipated that pressure drops may indicate multiple fluid phases. The analysis will be designed to consider all parameters.

Reports will be submitted to the EPA within 30 days of the test [per 40 CFR §146.91(e) and §146.91 (b)(3)].

3.0 MONITORING WELLS – TESTING STRATEGY

The following tests and log acquisitions may be conducted during drilling, during casing installation, and after casing installation in the project Monitoring Wells. As such, similar data collected for the Injection Wells may be gathered in the Monitoring Wells. The project currently anticipates that one up dip new IZ Monitoring Well will be implemented for the project. The project monitoring well will be located up dip of the sequestered CO_2. The location of the well aligns with the expected plume track and will be completed across each of the Injection Zones. A contingent second IZ Monitoring Well may be located downdip of the sequestered CO_2 plume near the southwestern facility boundary. This well is contingent on the efficacy of the indirect monitoring program to monitor the sequestered CO_2 plume. As part of the indirect monitoring program, Lapis will continually evaluate performance versus target metrics for the selected system. If the selected system is not performing to an acceptable level, Lapis will either select and implement another indirect method or may drill the contingent second IZ Monitoring well.

Additionally, one ACZ Monitoring Well has been designed to target the first permeable zone (the saline Tokio Formation) above the Confining Zone and will monitor downhole conditions and geochemical properties.

Monitoring well construction details, procedures, and schematics are contained in Section 5.4 of the Project Narrative technical report in submitted in Module A.

3.1 LOGGING PROGRAM

The well logging program in the Monitoring Wells will cover open hole and cased hole for all drilling stages. The logging program will generally meet similar requirements as those for the injection wells and will be constructed to the Arkansas State standards. These data will be used to reduce uncertainty and will be used to determine *in-situ* formation properties such as: thickness, porosity, permeability, lithology, formation fluid salinity and reservoir pressure [per 40 CFR 146.87].

The logging program for the Monitoring Wells will be defined based on the initial well design and recompletion, and the logging requirements to track the CO_2 plume and pressure movement.

Table 12 shows an example of a typical logging program expected for a Monitoring Well. Additional data may be gathered as needed.

Table 12: Logging Runs and Data Acquisition – Monitoring Wells

Hole Section	Well Log	Data Acquisition Profile
Open Hole	Spontaneous Potential	Spontaneous Potential and formation fluid salinity
	Resistivity	Fluid conductivity, presence of fresh vs. saline water
	Gamma Ray	Clay content
	Open Hole Caliper	Borehole diameter and log correction; identify washouts
Cased Hole	Cement Bond	Determine the integrity of the cement radially
	Variable Density	Well completion quality/cement integrity
	Temperature	Develop temperature profile. Establish Baseline gradient.

3.2 CORE PROGRAM

Petrophysics is used in building the static geologic model for the project. The uncertainty in the static model is impacted by the amount and quality of open hole log, whole core, and rotary sidewall core data. To account for the limited available data of the Injection Zones in the local area, Lapis plans to acquire 28 rotary sidewall cores in the deep in-zone monitoring well, Blue DM-2. The preliminary plan is to collect rotary sidewall cores across the various injection zones according to Table 13. Final sidewall core acquisition will be dependent on hole conditions and logging analysis to determine the location and number of side wall cores per formation.

Table 13: Proposed Sidewall Core Acquisition – In-Zone Monitoring Well (Blue DM-2)

Formation	Sidewall Cores	Core Analysis
Lower Hosston	7	Routine Core Analysis
Cotton Valley (CV1)	7	Routine Core Analysis
Cotton Valley (CV2)	7	Routine Core Analysis
Cotton Valley (CV3)	7	Routine Core Analysis

3.2.1 Analysis

Routine core analysis (RCA) will be performed to determine the spatial variability of the porosity, permeability, and bulk density of the formations. The results will also be included in the refined model to reduce uncertainties in homogeneity of the zones. Additional analyses may include a lithologic core description, thin section preparation and analyses, XRD, XRF to characterize compositional make-up of the key intervals and to reduce uncertainties that impact the depositional and flow environments. The analyses of the additional collected core and fluid samples maybe used to refine and enhance site characterization per 40 CFR §146.82(a).

3.3 FORMATION FLUID ANALYSIS

Lapis Energy may acquire formation pressure and mobility data in the Monitoring Wells to evaluate the effectiveness of the primary seal and understand connectivity between the formations laterally and vertically.

Lapis Energy will acquire baseline fluid samples for the Tokio Formation as part of the shallow ACZ Monitoring Well construction and completion program. Subsequent fluid samples might also be acquired to track the CO_2 pressure and plume front at future intervals. Additionally, Lapis Energy will acquire baseline samples of the selected USDW formations for one year prior to injection. Baseline samples will be taken from the shallow aquifer monitoring wells (Blue WW-1, Blue WW-2 and Blue WW-3) once constructed. Samples collected will be sufficient to characterize laterally and vertically across the formations. Lapis Energy will follow the USEPA guidelines for pressure and fluid sampling.

3.4 DEMONSTRATION OF MONITORING WELL MECHANICAL INTEGRITY

Cement bond and cement evaluation tools will be run on the final casing string in each monitor well and will include a Flexural Wave Imaging tool run. A baseline Nuclear Spectroscopy Log (Pulsed Neutron Tool) will be run in cased hole in each Monitoring Well after installation and completion. The logs will be run prior to commencement of sequestration injection operations to establish initial conditions. Thereafter, an adaptive program of repeat surveys will be performed if indications of carbon dioxide approaching the monitoring locations are indicated on the pressure/temperature gauges. Additionally, a baseline temperature survey will be run in each

Monitoring Well and thereafter under an adaptive program to ensure there is no movement of fluid behind the pipe. The purpose of these tests is to ensure that the well's integrity is mechanically sound and that there is no movement of formation fluid along the wellbore annulus.

3.5 FORMATION TESTING

Lapis Energy may perform baseline pressure fall-off tests during the construction of the Monitoring Wells. These tests, if conducted, will be used to quantify spatial variability both laterally and vertically. Procedures will follow those as specified in Section 2.7 for the Injection Wells.